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IN THE MATTER OF the *Ontario Energy Board Act, 1998*, Schedule B to the *Energy Competition Act, 1998*, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Toronto Hydro-Electric System Limited for an Order or Orders approving or setting just and reasonable distribution rates and other charges, effective January 1, 2025 to December 31, 2029.

The Applicant, Toronto Hydro-Electric System Limited (the "Applicant, "Toronto Hydro", "THESL", the "Company", or the "Utility"), is a corporation incorporated under the *Business Corporations Act* (Ontario),[1] and is licensed by the Ontario Energy Board (the "OEB") under licence number ED-2002-0497 to distribute electricity in the City of Toronto.

Toronto Hydro hereby applies to the OEB pursuant to section 78 of the Ontario Energy Board Act, 1998 (the "OEB Act") as amended, for approval of its proposed:

1) Electricity distribution rates and other charges effective January 1, 2025; and
2) A Custom Revenue Cap Index ("CRCI") to set distribution rates effective for the period January 1, 2026 to December 31, 2029.

This Application is prepared in accordance with the OEB's:

1) Filing Requirements for Electricity Distribution Rate Applications, issued December 15, 2022 (the "Filing Requirements");
2) Renewed Regulatory Framework, established through a Report of the Board on October 18, 2012 under file numbers EB-2010-0377, EB-2010-0378, EB-2010-0379, EB-2011-0043 and EB-2011-0004 and further developed through additional reports issued under those file numbers; and,
3) Handbook for Utility Rate Applications, issued October 13, 2016.

[1] RSO 1990, c B.16.

This application is supported by pre-filed written evidence, which may be amended from time to time.

I. FORM OF HEARING REQUESTED

Toronto Hydro requests that this application be disposed of by way of an oral hearing.

II. PROPOSED EFFECTIVE DATE

The applicant requests that the OEB make its Rate Order effective January 1, 2025. In the alternative, the Applicant requests an interim Order making the Applicant's current distribution rates and charges effective on an interim basis as of January 1, 2025 and establishing foregone revenue rate riders to recover any differences between the interim rates and the actual rates effective January 1, 2025 based on the OEB's Decision and Order.

III. PROPOSED DISTRIBUTION RATES AND OTHER CHARGES

The Tariff of Rates and Charges proposed in this application is identified in Exhibit 8, Tab 3, Schedule 2. In addition to the evidence in support of those rates and charges for the 2025 test year, Toronto Hydro is filing evidence in support of its 2025-2029 Custom Rate Framework and the rates resulting from it for 2026-2029.

IV. PROPOSED DISTRIBUTION RATES ARE JUST AND REASONABLE

For all the reasons set out in this application. Toronto Hydro submits that the proposed distribution rates and other charges are just and reasonable.

V. SPECIFIC RELIEF REQUESTED

With this application, Toronto Hydro requests:

1) Approval of 2025 base revenue requirement as proposed in Exhibit 6, Tab 1.
2) Approval of 2025 electricity distribution rates and charges as proposed in Exhibits 8 and 9, including a number of credits to customers. In particular:
    a) Base distribution rates as set out in Exhibit 8, Tab 1, Schedule 1;
    b) Specific Service Charges as set out in Exhibit 8, Tab 2, Schedule 1; and
    c) Rate riders as set out in Exhibit 9, Tab 3, Schedule 1.
3) Approval of updated depreciation rates in accordance with Exhibit 2A, Tab 2, Schedule 1.
4) Approvals related to deferral and variance accounts as proposed in Exhibit 9. In particular:
    a) To dispose of balances in existing deferral and variance accounts as detailed in Exhibit 9, Tab 1, Schedule 1;
    b) Approval of the continuation of existing deferral and variance accounts, as set out in Exhibit 9, Tab 1, Schedule 1; and
    c) Approval of new deferral and variance account as proposed in Exhibit 9, Tab 1, Schedule 1:
        i) A variance account in respect of demand-related expenditures and revenues;
        ii) A deferral account in respect of performance incentives earnings;
        (iii) A variance account in respect of the innovation fund; and
        (iv) A deferral account in respect of variable consideration from a real property sale.
5) Approval of the 2025-2029 Custom Rate Framework, including the Custom Revenue Cap Index ("CRCI") and non-CRCI elements, as proposed in Exhibit 1B, Tab 2, Schedule 1.

6) Approval of the 2025-2029 Custom Scorecard metrics, weightings and targets set out in Exhibit 1B, Tab 3, Schedule 1, including the establishment of a second phase of this proceeding to finalize the Custom Scorecard targets post the OEB's decision, as proposed therein.
7) Other items or amounts that may be requested by the Applicant in the course of the proceeding, and such other relief or entitlements as the OEB may grant.

DATED at Toronto, Ontario, this 17th day of November, 2023.

Applicant: TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Daliana Coban, Director, Regulatory Applications & Business Support

14 Carlton Street
Toronto, Ontario
M5B 1K5

ADMINISTRATION

This Schedule provides information relating to the administration of the Application.[1]

1. PRIMARY CONTACT FOR THE APPLICATION

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2. LEGAL REPRESENTATION FOR THE APPLICATION

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Torys LLP
79 Wellington Street West
Toronto, Ontario M5K 1N2

3. INTERNET ADDRESS

Toronto Hydro's main webpage: *www.torontohydro.com*

[1] OEB Filing Requirements for Electricity Distribution Rate Applications, Chapter 2 – Cost of Service (December 15, 2022) at section 2.1.3.

Regulatory documents will be available under the Regulatory Affairs tab:

http://www.torontohydro.com/regulatory-information

4. MEDIA ACCOUNTS

X (formerly known as Twitter) – X.com/torontohydro

Facebook – facebook.com/torontohydro

Instagram – Instagram.com/torontohydro

YouTube – youtube.com/torontohydro

LinkedIn –linkedin.com/company/toronto-hydro/

5. NOTICE OF HEARING PUBLICATION

Toronto Hydro recommends that the Notice of Hearing for its Application be published in the Toronto Star and L'Express, as well as on the utility's website, torontohydro.com.

6. FORM OF HEARING REQUESTED

Toronto Hydro requests an oral hearing.

7. EFFECTIVE REQUESTED DATE

Toronto Hydro requests new rates to be effective January 1, 2025.

8. DEVIATIONS FROM FILING REQUIREMENTS

In preparing this Application, Toronto Hydro has followed Chapters 1, 2, and 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (the "Filing Requirements").[2] Any departures from the Filing Requirements are noted in the checklist filed at Exhibit 1A, Tab 3, Schedule 2.

[2] OEB Filing Requirements for Electricity Distribution Rate Applications, Chapter 1 – Overview (April 18, 2022); Chapter 2 – Cost of Service (December 15, 2022); and Chapter 5 – Distribution System Plan (December 15, 2022).

METHODOLOGY CHANGES

The following methodology changes were applied in this application, relative to Toronto Hydro's 2020-2024 Rate Application:[3]

- A custom revenue cap model to determine the Custom Revenue Cap Index ("CRCI") to be approved in this application and applied in setting rates for the years 2026 to 2029 through annual rate update applications.[4]
- A modified X-Factor in the CRCI for a performance incentive mechanism ("PIM") that is linked to the 2025-2029 Custom Scorecard.[5]
- An Innovation Fund to be collected through a rate rider (outside of base rates) in order to provide transparency on the bill for customers and flexibility to the utility to determine the treatment (i.e. capital or operations) of innovative projects undertaken pursuant to this fund.[6]
- Updated asset useful lives and resulting depreciation rates in accordance with the outputs of a third-party depreciation study.[7]
- Enhanced the capacity planning process consider electrification drivers and municipal energy plans in producing the system peak load forecast that underpins the 2025-2029 Investment Plan.[8]
- Enhanced the load forecast to consider electrification drivers and changes to the availability of conservation and demand management ("CDM") savings in producing the revenue forecast that underpins to 2025-2029 rates.[9]

/C

[3] EB-2018-0165, Toronto Hydro-Electric System Limited Application (filed August 15, 2018, updated April 30, 2019).
[4] See Exhibit 1B, Tab 2, Schedule 1.
[5] See Exhibit 1B, Tab 3, Schedule 1.
[6] See Exhibit 1B, Tab 4, Schedule 2.
[7] See Exhibit 2A, Tab 2, Schedule 1.
[8] See Exhibit 2B, Sections D4 and E2.
[9] See Exhibit 3, Tab 1, Schedule 1.

- Refined the customer forecasting methodology to incorporate economic, demographic, and market conditions as inputs.[10]
- Modified the presentment of shared services revenues and costs to appear under Account 4375 and 4380, in accordance with the Accounting Procedures Handbook.[11]
- Increased the funding for LEAP program to 0.15% of the utility's revenue requirement and proposed exemptions from certain aspects of the LEAP Manual to modernize and enhance the effectiveness of the program in providing customers financial assistance.[12]
- Enhanced the load profile methodology to integrate electrification drivers used as the inputs in the cost allocation model.[13]

9. PREVIOUS OEB DIRECTIONS

Table 1 below summarizes how Toronto Hydro addressed OEB directions specified in the 2020-2024 Decision and Order.[14]

[10] *Ibid*.
[11] See Exhibit 3, Tab 2 and Exhibit 4, Tab 5.
[12] See Exhibit 4, Tab 2, Schedule 19.
[13] See Exhibit 7, Tab 1, Schedule 1.
[14] EB-2018-0165, Toronto Hydro-Electric System Limited Decision and Order (December 19, 2019).

Table 1: OEB Directions

	Direction	Response
1	**General Plant – Fleet and Equipment:** *"The OEB directs Toronto Hydro to provide more detailed cost benefit analysis between EV, hybrid and combustion engines for its fleet program for future rebasing applications. In addition, the OEB directs Toronto Hydro to develop utilization measures beyond fleet use in standard hours."*[15]	Toronto Hydro addressed the OEB's direction. For specific details, please see the Fleet and Equipment capital program in Exhibit 2B, Section E8.3.
2	**Costs of Eligible Investments for the Connection of Qualifying Generation Facilities:** "*The OEB expects Toronto Hydro to provide an assessment of appropriate sharing of benefits for ESS projects as part of any future requests for funding for provincial rate protection.*"[16]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 2A, Tab 5, Schedule 1.
3	**Load Forecasting:** "*The OEB expects Toronto Hydro to enhance its approach to forecasting customers / connections for its next rebasing application. … The OEB expects there to be a greater level of documentation for future rate proceedings. … The OEB expects Toronto Hydro to do a more detailed analysis of the impact of EVs and DERs on load and load profile to be considered for any future load forecasts.*"[17]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 3, Tab 1, Schedule 1.

[15] *Ibid* at pp. 103-104.
[16] *Supra* note 4 at p. 119.
[17] *Supra* note 4 at pp. 126-127.

	Direction	Response
4	**Shared Services:** "*The OEB notes that for Account 4375 Shared Services Recovery, Toronto Hydro does not record the associated expenses in Account 4380, as required by the Accounting Procedures Handbook. Toronto Hydro disclosed this point in its evidence, however, this approach makes it more difficult to assess that there are no cross-subsidies between regulated and non-regulated activities. Toronto Hydro is expected to follow the requirements of the Accounting Procedures Handbook going forward.*"[18]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 3, Tab 2 and Exhibit 4, Tab 5.
5	**Depreciation:** "*For the next rebasing application, the OEB directs Toronto Hydro to file either the annual useful lives reviews to demonstrate that no change is required to the useful lives or a new depreciation study.*"[19]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 2A, Tab 2, Schedule 1, and Appendix D thereto.
6	**Standby Rates:** "*Given the length of time that the standby rates have been set on an interim basis, the OEB requires Toronto Hydro to file a proposal in its next rebasing application to address this situation, unless it has been otherwise superseded by a generic policy.*"[20]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 8, Tab 1, Schedule 1.
7	**Earnings Sharing Mechanism ("ESM"):** "*The 2019 ESM calculation should be filed as part of Toronto Hydro's next rebasing application.*"[21]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 9, Tab 1, Schedule 1.

[18] *Supra* note 4 at p. 131.
[19] *Supra* note 4 at p. 146.
[20] *Supra* note 4 at p. 160.
[21] *Supra* note 4 at p. 182.

	Direction	Response
8	**Other Pension and Employment Benefits ("OPEBs"):** "*The OEB requires Toronto Hydro to commence gathering the necessary information going forward to calculate the accrual OPEB amount based on the annual depreciation associated with its cumulative undepreciated capitalized OPEB costs in rate base.*"[22]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 9, Tab 1, Schedule 1.
9	**Sale of Utility Properties:** "*The OEB directs Toronto Hydro to establish the Gain on Sale of Property variance account as there is considerable variability in the gain on disposal of property. Toronto Hydro is expected to seek disposition of this symmetrical variance account in its next rebasing application.*"[23]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 9, Tab 1, Schedule 1.
10	**In-Service Additions & Capital-Related Revenue Requirement Variance Account ("CRRRVA"):** "*The approach offered by Toronto Hydro to require it to report on in-service additions by investment category for the 2020-2024 period at the time of its next rebasing is approved. … The additional information will assist in reassessing the account in the next rebasing application.*"[24]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 2A, Tab 1, Schedule 1 and Exhibit 9, Tab 1, Schedule 1.

10. CONDITIONS OF SERVICE

Toronto Hydro's current Conditions of Service (Revision 22) can be found at the following link: https://www.torontohydro.com/conditions-of-service. Appendix A to this Schedule provides summaries of the following revisions Toronto Hydro made to its Conditions of Service since the last rebasing application:

[22] *Supra* note 4 at p. 187
[23] *Supra* note 4 at p. 188.
[24] *Supra* note 4 at p. 195.

- Revision 19 – January 1, 2020
- Revision 19.1 – March 1, 2020
- Revision 20 – January 1, 2021
- Revision 22 – January 1, 2022
- Revision 22 – January 1, 2023

Toronto Hydro proposes to increase its basic connection allowance for certain customer classes from $1,396 to $3,059.[25] If this proposal is approved, Toronto Hydro would update the Service Connection and Disconnection Fee column of Table 2 of its Conditions of Service as of January 1, 2025. Toronto Hydro does not expect any other proposals in this Application to result in other material changes to its Conditions of Service.

Toronto Hydro has identified five types of charges listed in the Conditions of Service that are not on its Tariff of Rates and Charges. Consistent with other similar charges that Toronto Hydro directly collects from customers, they are not recorded as a specific service charge in Toronto Hydro's OEB-approved tariff sheet. For more details, please see Exhibit 8, Tab 2, Schedule 1.

11. CORPORATE AND UTILITY ORGANIZATIONAL STRUCTURE

Toronto Hydro's organizational chart is provided in Figure 1 below. A corporate entities relationship chart showing the extent to which the parent company is represented on Toronto Hydro's Board of Directors and a description of the reporting relationships between the utility and parent company is provided in Exhibit 1C, Tab 2, Schedule 1. There are no planned changes in corporate or operational structure.

[25] Exhibit 2B, Section E5.1.

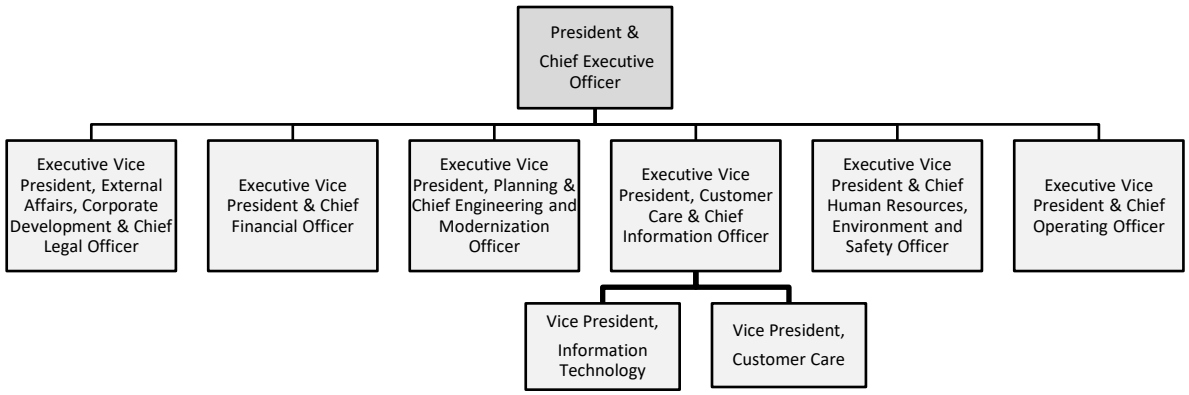

Figure 1: Toronto Hydro's Organizational Chart

12. LIST OF APPROVALS REQUESTED

The list of specific approvals that Toronto Hydro requests as part of this Application is provided in Exhibit 1A, Tab 2, Schedule 1 and OEB Appendix 2-A, and reproduced below:

Pursuant to section 78 of the *Ontario Energy Board Act, 1998*,[26] Toronto Hydro seeks the following approvals:

1) Approval of 2025 base revenue requirement as proposed in Exhibit 6, Tab 1.
2) Approval of 2025 electricity distribution rates and charges as proposed in Exhibits 8 and 9, including a number of credits to customers. In particular:
    a) Base distribution rates as set out in Exhibit 8, Tab 1, Schedule 1;
    b) Specific Service Charges as set out in Exhibit 8, Tab 2, Schedule 1; and
    c) Rate riders as set out in Exhibit 9, Tab 3, Schedule 1.
3) Approval of updated depreciation rates in accordance with Exhibit 2A, Tab 2, Schedule 1.

[26] SO 1998, c 15, Sched B.

4) Approvals related to deferral and variance accounts as proposed in Exhibit 9. In particular:
    a) To dispose of balances in existing deferral and variance accounts as detailed in Exhibit 9, Tab 1, Schedule 1;
    b) Approval of the continuation of existing deferral and variance accounts, as set out in Exhibit 9, Tab 1, Schedule 1; and
    c) Approval of new deferral and variance account as proposed in Exhibit 9, Tab 1, Schedule 1:
        i) A variance account in respect of demand-related expenditures and revenues;
        ii) A deferral account in respect of performance incentives earnings;
        (iii) A variance account in respect of the innovation fund; and
        (iv) A deferral account in respect of variable consideration from a real property sale.
5) Approval of the 2025-2029 Custom Rate Framework, including the Custom Revenue Cap Index ("CRCI") and non-CRCI elements, as proposed in Exhibit 1B, Tab 2, Schedule 1.
6) Approval of the 2025-2029 Custom Scorecard metrics, weightings and targets set out in Exhibit 1B, Tab 3, Schedule 1, including the establishment of a second phase of this proceeding to finalize the Custom Scorecard targets post the OEB's decision, as proposed therein.
7) Other items or amounts that may be requested by the Applicant in the course of the proceeding, and such other relief or entitlements as the OEB may grant.

CONDITIONS OF SERVICE

Revision #19 (effective January 1, 2020)
REVISION SUMMARY

Section	Section Title	Summary of Changes to Toronto Hydro's Conditions of Service
1.8	Disputes	Revised the website address that refers to the Dispute Resolution process which is on Toronto Hydro's website.
2.1.2	Expansions / Offer to Connect	Revised statement from "not exceed" to "be equal to" the generator's share of the present value of the projected capital costs and on-going maintenance costs for the facilities.
2.1.2.2	Capital Contribution Policy	Added statements: - customers having a non-coincident peak demand equal to or greater than 5 MW shall be charged their share of the capital contribution for a new or modified transmitter-owned connection facility, and - where an expansion involves an upstream transmission asset that has been deemed by the OEB to be a distribution asset, Toronto Hydro shall not require a capital contribution from a load customer with a non-coincident peak demand of less than 5 MW.
2.1.2.3	Expansion Deposit	Revised from "may" to "shall" to withhold ten percent of the expansion deposit if an alternative bid option is chosen.
2.1.2.5	Rebates of Capital Contribution	Revised from "load levels" to "non-coincident peak demand" as a factor to consider when apportioning the overall benefits.
2.1.2.7	Bypass Compensation	New section regarding bypass compensation.
2.2	Disconnection	Added a statement that a customer must pay any outstanding arrears prior to the removal of Toronto Hydro equipment.
2.2.1	Disconnection & Reconnection - Process and Charges	Revised statements: - from "… a disconnect notice has been delivered to the Customer" to "… a disconnect notice has been received by the Customer", - from "… on the third business day after mailing." to "… on the third business day after the date on which the notice was printed.", and - customer must remedy the condition within "seven calendar days" to "a reasonable period". Added a statement not to disconnect an occupied residential property for non-payment during a Disconnection Ban Period.
2.4.3	Deposits	Added a statement that a security deposit for a residential account may be waived where the customer enrolls in an equal monthly payment, provided that a deposit may otherwise be required as per the Distribution System Code.
2.4.5	Payments and Overdue Account Interest Charges	Revised statements: - the interest rate used to determine any late payment charges, and - from "Pre-Authorized Payments" to "Pre-Authorized Debits". Added a statement that bills are to be paid in full within 20 days of the statement date.
3.3.1	New Residential Subdivisions or Multi-Unit Developments	Deleted the statements referring to the developer having the choice to complete the expansion work or have Toronto Hydro perform the work, and construction work that is not allowed to be completed by the customer. Added reference to sections in the Conditions of Service that are applicable for non-residential class customers.

CONDITIONS OF SERVICE Revision #19 (effective January 1, 2020) REVISION SUMMARY		
Section	**Section Title**	**Summary of Changes to Toronto Hydro's Conditions of Service**
4	Glossary of Terms	Revised the terms: Customer, embedded distributor, host distributor.
Section 6 - References	Toronto Hydro Requirements for the Design and Construction of Customer-Owned High Voltage Substations	Updated reference document #4 (Revision #11, dated August 30, 2019) Added statements to the following sections: - 9.28.2 Transformers; added note 8 and column headings to Table 5. Revised statements to the following sections: - 3. Definitions; Customer
Section 6 - References	Toronto Hydro Metering Requirements 750 Volts or Less	Updated reference document #6 (Revision #13, dated August 9, 2019) Added content to the following sections: - 7.3.1 Meter Cabinet for Meters Only; added manufacturer and part number to Table I.
Section 6 - References	Toronto Hydro Metering Services and Charges	Updated reference document #9 (Revision #1, dated August 30, 2019) Added content to the following sections: - 1.1 Introduction; determination of the service and metering connections. Revised content to the following sections: - 1.1 Introduction; service connections to separate buildings, - 1.2 Metering Charges Table; associated costs for items 2 and 3, and - 1.3 Metering Configuration and Associated Costing Diagrams; updated diagrams 1, 2, and 3 to illustrate metering for multiple buildings.

CONDITIONS OF SERVICE

Revision #19.1 (effective March 1, 2020)
REVISION SUMMARY

Section	Section Title	Summary of Changes to Toronto Hydro's Conditions of Service
2.2.1	Disconnection & Reconnection - Process and Charges	Revised statements: - the minimum payment period to become 14 calendar days from the date on which the disconnection notice is received before a customer can be disconnected for non-payment, and - where a disconnection notice was sent by mail, the period is to be revised to the fifth calendar day after the date on which the notice was printed. Added statements: - before issuing a disconnection notice for non-payment, an account overdue notice shall be delivered to the customer, and - the customer responsible for a disconnection may be charged for reconnection costs and reasonable costs for repairs of the distributor's physical assets attached to the property in reconnecting the property.
2.4.3	Deposits	Revised statements: - the calculation method in determining the amount of an account security deposit, and - the minimum time period from "5 years" to "3 years" for good payment history for non-residential customers that have a demand less than 50 kW.
2.4.5	Payments and Overdue Account Interest Charges	Revised statements: - payment plans are available to customers, such that equal monthly payment plans are to be offered to residential customers and to general service less than 50 kW customers, and the equal monthly payment plans may not be offered under specified conditions, and - bills are to be paid in full within 24 days of the statement date.

CONDITIONS OF SERVICE, Revision #20 **REVISION SUMMARY**			
Revision #	**Section**	**Section Title**	**Summary of Changes to Toronto Hydro's Conditions of Service**
20-0-01	2.1.5	Relocation of Plant	Revised to reflect the OEB's new relocation cost recovery standard.
	4	Glossary of Terms	Added the term: Relocation
20-0-02	2.1.2.4	Supply Agreement	Removed this section as the terms and concepts are outdated and the same conditions are covered in the Connection Agreements with the Customer. Establishing a Supply Agreement in addition to the Connection Agreement would be redundant.
	2.1.7.5	Operating Agreements (new)	Added a new section to specify that an Operating Agreement may be required between Toronto Hydro and Customer for load connection customers (customers without generator/generation facilities).
20-0-03	2.3.4.2	Supply Voltage	Revised to reflect the equivalent service sizes of the demands loads offered to Customers when supplied from secondary street circuits on road allowance.
20-0-04	2.3.7.1	Metering - General	Added conditions in the section to give Toronto Hydro the right to operate on Customer-Owned switched when conducting meter work and not be liable for any damages or losses sustained resulting from inadequate maintenance of Customer-Owned equipment and infrastructure.
20-0-05	3.8	Unmetered Connections	Revised to better outline and clarify Toronto Hydro requirements for unmetered service connections and the responsibilities between Toronto Hydro and Customer when it comes to the different connection methods offered.
20-0-06	2.2.1	Disconnection & Reconnection	Revised to better align with the new Distribution System Code (DSC) disconnection and reconnection amendment.
20-0-07	2.4.3	Deposits	Revise the wording in the Conditions of Service to better align with the Distribution System Code (DSC) and clarify the time period over which a good payment history must be on file for waiving of new or increased deposit amounts.
20-R-01	Section 6 - References	Toronto Hydro Requirements for the Design and Construction of Customer-Owned High Voltage Substations	Updated reference document #4 (Revision #12, dated September 21, 2020) Added statements to the following sections: - 5.1.3 Dedicated Feeder Supply Revised statements to the following sections: - 7.6 Protection Co-ordination and arch flash studies - 8.8 Communication Lines - 9.21 Line Differential Relay Protection - Sketch I-1 - Updated - Sketch 7 – Revised to Arc Flash Sign; Existing sketch for control cable cabinet removed as it is no longer applicable
20-R-02	Section 6 - References	Toronto Hydro Requirements for the Design and Construction of Customer-Owned Structures	Updated reference document #5 (Revision #6, dated September 21, 2020) Added statements to the following sections: - Section 4.1 Customer Responsibility - Section 4.4.3 Types of Structures - Section 5.2 Vault Location Requirements - Section 5.4 Vault Design and Construction Requirements

			Revised statements to the following sections: - Section 4.1 Customer Responsibility - Section 4.4.1 Location Requirements - Section 4.4.2 Access Requirements - Section 4.4.3 Types of Structures - Section 5.6 Vault Electrical Requirements - Section 5.7 Vault Ventilation Requirements

CONDITIONS OF SERVICE, Revision #21 REVISION SUMMARY			
Revision #	**Section**	**Section Title(s)**	**Summary of Changes to Toronto Hydro's Conditions of Service**
21-0-01	2.1.2.5	Feeder Capacity Optimization	• Moved both "Feeder Capacity Optimization" and "Bypass Compensation" sections one level up from Section 2.1.2 Expansions / Offer to Connect to under the general Section 2.1 Connections. The purpose is to reflect that both policies apply to any type of connection project and not just expansions. • Removed any references to the "realization period" under the "Feeder Capacity Optimization" section to reflect that Toronto Hydro may examine a Customer's peak demand at any time, subject to the terms of the applicable Offer to Connect, the Conditions of Service, and any regulatory requirements.
	2.1.2.6	Bypass Compensation	
21-0-02	2.2.1	Disconnection & Reconnection	Expanded the wording in the Disconnection & Reconnection – Process and Charges section to describe in greater detail the disconnection process that Toronto Hydro follows in accordance with the applicable regulatory requirements.
21-0-03	2.3.4.2	Supply Voltage	• Modified section 2.3.4.2 Supply Voltage to provide more detail with respect to available supply voltages. • Introduced a new section entitled "Supply Offerings" to provide more detail regarding Toronto Hydro's supply offering in the public road allowance and transformer offerings on private property.
	2.3.4.3	Supply Offerings (New)	
21-0-04	2.3.4.4	Number of Connections to Toronto Hydro's Distribution System (renamed)	Renumbered and renamed former section 2.3.4.3 to 2.3.4.4 "Number of Connections to Toronto Hydro's Distribution System" and modified the revision to clarify Toronto Hydro's policy with customer requests for diversity of supply.
21-0-05	2.3.5	Voltage Guidelines	Specified the voltage variation limits for primary voltage offerings as per the latest edition of C.S.A. Standard CAN3-C235-83.
21-0-06	2.4.3	Deposits	• For the purpose of satisfactory credit checks, revised the acceptable Equifax Credit commercial scores for Business customers to align with Equifax scoring for commercial customers. • Revised the wording to further clarify the requirements for a security deposit to be returned to the Customer or Consumer within six weeks of closure of Customer or Consumer's account and when a Consumer or Customer moves from Standard Supply Service ("SSS") to a competitive retailer where the retailer is performing the billing function (retailer consolidated billing), for all account types.
21-0-07	2.6	Temporary Services	Expanded the provision to reflect in greater detail Toronto Hydro's policies with respect to temporary services, including the right to request a certified structural analysis report for any structures housing or supporting Toronto Hydro-owned assets.
21-0-08	3.8	Unmetered Connections	Expanded the provision to reflect in greater detail Toronto Hydro's policies with respect to affixing attachments to Toronto Hydro assets, including the right to require licensed attachment agreements.

21-0-09	3.9	Metered Connections in Public Road Allowance (New)	Added a new section that specifies the connection requirements with respect to metered connections situated entirely in the public road allowance (e.g. sidewalk, boulevard).
21-0-10	3.10	Attachment to Toronto Hydro Assets and Structures (New)	Added a new section to specify the general requirements of attaching Customer or third-party assets (e.g. signages, decorative lighting) to Toronto Hydro-owned assets and structures (e.g. poles, cable chambers).
21-0-11	5	Tables 1 & 2 Demarcation points	• Merged Tables 1.1, 1.2, 1.3, 1.4 and 1.5 as Table 1 for ease of reference. • Specified the ownership demarcation point for civil infrastructure between the Customer and Toronto Hydro based on the customer class and supply method.
		Tables 3 & 4 (New)	• Added new Tables 3 and 4 to provide a summary reference regarding Toronto Hydro's supply offering in the public road allowance and transformer offerings on private property, respectively.
		Table 5 (New)	• Added a new Table 5 to provide a summary reference regarding Toronto Hydro's supply offerings for temporary services.
21-R-01	Section 6 – References	Reference Document #5 - Toronto Hydro Requirements for the Design and Construction of Customer-Owned Structures	Revision highlights: – Customer responsibilities of customer-owned structures, TH lock requirements for TH access – Minimum vertical clearance and minimum truck loads for access routes to customer-owned vaults or substations – Legacy vaults subject to inspection for foreign materials Revised statements to the following sections: – Section 4.1 Toronto Hydro Requirements – Section 4.4.1 Location Requirements – Section 4.4.2 Access Requirements – Section 4.4.3 Types of Structures – Section 4.6 Inspections by Toronto Hydro – Section 5.2 Location Requirements – Section 5.3 Vault Access Requirements – Section 5.4 Vault Design and Construction Requirements – Section 5.5 Vault Grounding Requirements Updated five (5) Construction Standards: – 31-1230 – 31-1350 – 31-1400 – 31-4100 – 31-6030
-	Section 6 – References	Reference Document #6 – Metering Requirements 750 Volts or Less	Contact information for Diagram #2 deviations updated.
21-R-02	Section 6 - References	Reference Document #8 - Contractor Pre-Qualification Application	• Restructured and updated the contractor pre-qualification process to reflect current business operations. • Introducing the new methodology of classifying contractors.

CONDITIONS OF SERVICE, Revision #22 REVISION SUMMARY – Main Document			
Revision #	**Section**	**Section Title**	**Summary of Changes to Toronto Hydro's Conditions of Service**
2022-M-01	1.7.3	Tree and Vegetation Management	Clarified Toronto Hydro and Customer's responsibilities with respect to tree trimming and vegetation management on both public road allowance and private property.
2022-M-02	2.2.1	Disconnection and Reconnection	Expanded the wording in the Disconnection & Reconnection – Process and Charges section to reflect Toronto Hydro's new policy of providing eligible low-income customers (ELIC) one free disconnection and reconnection in a rolling 12-month period.
2022-M-03	2.3.7.1.1	Metering Requirements for MURB and Condominiums	Substituted references to multi-unit residential rental buildings/MURBs with the term "multi-unit complex" (MUC) and other broader terminology to encompass all classes of units (residential and commercial) applicable for unit smart metering.
2022-M-04	2.4.4.1	Rate Reclassification	Added a new section outlining Toronto Hydro's rate reclassification policy.
2022-M-05	2.4.5	Payments and Overdue Account Interest Changes	Revised the provision to clarify the application of non-sufficient fund fees.
-	Section 5	Tables	Updated service size requirement to align with the transformer sizes and/or demand load offered by Toronto Hydro.
-	Section 6 – References	Toronto Hydro Requirements for the Design and Construction of Customer-Owned Structures	Minor housekeeping amendments and corrections in the following sections: • 4.1 Customer Responsibility • 4.4.3 Types of Structures • 5.2 Vault Location Requirements • 5.4 Vault Design and Construction Requirements • 5.5 Vault Grounding Requirements
2022-R-01	Section 6 - References	Metering Requirements 750 Volts or Less	• Clarified Toronto Hydro's meter locations requirements.
2022-R-02	Section 6 - References	Metering Requirements for 13.8 kV and 27.6 kV Customer-Owned Substations	• Clarified Toronto Hydro's remote metering requirements for services 50 kW and greater. • Updated the meter diagram references to better reflect current standards, designs and practices.

CERTIFICATION OF EVIDENCE AND REGARDING PERSONAL INFORMATION

I, Amanda Klein, Executive Vice-President, External Affairs, Corporate Development and Chief Legal Officer of Toronto Hydro-Electric System Limited ("Toronto Hydro"), hereby certify that the evidence (including models and appendices) filed in support of Toronto Hydro's 2025-2029 Custom Incentive Rate-setting Application (EB-2023-0195) is accurate, consistent and complete to the best of my knowledge.

I further certify that, to the best of my knowledge, the evidence filed in support of Toronto Hydro's 2025-2029 Custom Incentive Rate-setting Application (EB-2023-0195) does not include any personal information, as that term is defined in the *Freedom of Information and Protection of Privacy Act,* that is not otherwise redacted in accordance with the requirements set out in Rule 9A of the Ontario Energy Board's *Rules of Practice and Procedure* (updated July 13, 2023).

This certification is given pursuant to Chapter 1 of the Ontario Energy Board's *Filing Requirements for Electricity Distribution Rate Applications* (issued April 18, 2022).

DATED this **17th** day of **November, 2023.**



Amanda Klein

Executive Vice President,
External Affairs, Corporate Development
and Chief Legal Officer

CERTIFICATION OF DEFERRAL AND VARIANCE ACCOUNT BALANCES

I, Céline Arsenault, Executive Vice President and Chief Financial Officer of Toronto Hydro-Electric System Limited ("Toronto Hydro"), hereby certify that Toronto Hydro has robust processes and internal controls in place for the preparation, review, verification and oversight of the balances in all deferral and variance accounts presented in Toronto Hydro's 2025-2029 Custom Incentive Rate-setting Application (EB-2023-0195).

This certification is given pursuant to Chapter 1 of the Ontario Energy Board's *Filing Requirements for Electricity Distribution Rate Applications* (issued April 18, 2022).

DATED this **17th** day of **November, 2023.**

Céline Arsenault

Executive Vice President and
Chief Financial Officer

DISCLAIMER

The information in these materials is provided to the OEB for the purposes of Toronto Hydro's electricity distribution rates application pursuant to the OEB's Custom Incentive Rate-Setting framework (the "Application"). Toronto Hydro does not warrant the accuracy, reliability, completeness, or timeliness of the information and undertakes no obligation to revise or update these materials, except as required for purposes of providing new information that represents a material change to the evidentiary record in the Application before the OEB. Toronto Hydro (including its directors, officers, employees, agents, and subcontractors) hereby waives any and all liability for damages of whatever kind and nature which may occur or be suffered as a result of the use of these materials or reliance on the information therein.

These materials may also contain forward-looking information within the meaning of applicable securities laws in Canada ("Forward-Looking Information"). The purpose of the Forward-Looking Information is to provide Toronto Hydro's expectations and future operational, capital and revenue requirements for 2025 through 2029, and may not be appropriate for other purposes. All Forward-Looking Information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. All information, other than statements of historical fact, which address activities, events or developments that we expect or anticipate may or will occur in the future, are Forward-Looking Information. The words "aims", "anticipates", "believes", "budgets", "commits", "continue", "can", "could", "estimates", "expects", "focus", "forecasts", "future", "impacts", "intends", "may", "might", "must", "plans", "propose", "projects", "schedule", "seek", "should", "strives", "trend", "will", "would" , "objective", "outlook" or the negative or other variations of these words or other similar words or expressions are

often intended to identify Forward-Looking Information, although not all Forward-Looking Information contains these identifying words.

The Forward-Looking Information reflects the current beliefs of, and is based on information currently available to, Toronto Hydro's management. The Forward-Looking Information in these materials includes, but is not limited to, statements regarding Toronto Hydro's future results and performance, as well as expected nature, timing and cost of capital and operational programs. The statements that make up the Forward-Looking Information are based on estimates and assumptions made by the utility's management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management believes to be reasonable in the circumstances, including, but not limited to, expected load and customer growth, externally driven plant relocation requests, changes in funding requirements, no unforeseen delays and costs in capital projects, no unforeseen changes in the legislative and operating framework for electricity distribution in Ontario, the receipt of applicable regulatory approvals and requested rate orders, no unexpected delays in obtaining required approvals, the receipt of applicable IESO approvals, the ability of the utility to obtain and retain qualified staff, equipment and services in a timely and cost efficient manner, no unfavourable changes in government regulation, the level of interest rates and Toronto Hydro's ability to borrow, changes in the frequency and severity of emergency weather conditions arising from climate or environmental changes; costs to achieve modernization and electrification, no unforeseen changes to the key drivers behind the operational needs of Toronto Hydro, including but not limited to cloud-based software solutions, incremental costs to mitigate increased cyber security risks, asset maintenance requirements and evolving customer needs and expectations, and all other assumptions regarding general business and economic conditions.

The Forward-Looking Information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the Forward-Looking Information. The factors which could cause results or events to differ from current expectations include, but are not limited to, risks associated with the rate of deterioration of Toronto Hydro's assets; risks associated with the execution of Toronto Hydro's capital and maintenance programs necessary to maintain the performance of aging distribution assets and make required infrastructure improvements, including to deliver a modernized grid and meet electrification requirements to achieve government net zero GHG emissions targets; risks associated with capital projects; risks associated with electricity industry regulatory developments and other governmental policy changes, including factors relating to Toronto Hydro's distribution activities and to climate change; risks associated with the timing and results of regulatory decisions regarding Toronto Hydro's revenue requirements, cost recovery and rates; risks associated with information system security and with maintaining complex information technology systems; risks associated with maintaining the security of Toronto Hydro's information assets, including but not limited to the collection, use and disclosure of personal information; risks associated with the failure of critical IT systems; risks of external threats to Toronto Hydro's facilities and operations posed by unexpected weather conditions caused by climate change and other factors; risks associated with changing weather patterns due to climate change and resultant impacts to electricity consumption based on historic seasonal trends, terrorism and pandemics, including but not limited Toronto Hydro's limited insurance coverage for losses resulting from these events; risk to Toronto Hydro's employees or the general public of serious/fatal injuries and illnesses relating to or impacting upon Toronto Hydro's activities; risks of municipal government activity, including the risk that the City of Toronto could introduce rules, policies or directives, including those relating to net zero greenhouse gas emissions

targets, that can potentially limit Toronto Hydro's ability to meet its business objectives as laid out in the Shareholder Direction principles; risks associated with the possibility that advances in technology may compete with Toronto Hydro by affecting energy consumption levels and, as a result, customer demand for Toronto Hydro's services; risks related to Toronto Hydro's work force demographic and its potential inability to attract, train and retain skilled employees; risks of being unable to retain necessary qualified external contracting forces relating to its capital, maintenance and reactive infrastructure program; risks associated with possible labour disputes and Toronto Hydro's ability to negotiate appropriate collective agreements; risk that Toronto Hydro is not able to arrange sufficient and cost-effective debt financing to maintain its financial health and performance at acceptable levels; risk that insufficient debt or equity financing will be available to meet Toronto Hydro's requirements, objectives, or strategic opportunities; risk related to the timing and extent of changes in prevailing interest rates and discount rates and their effect on future revenue requirements and future post-employment benefit obligations; risks arising from inflation, the course of the economy and other general macroeconomic factors; Toronto Hydro's ability to earn back its revenue in the next rate period through the Performance Incentive Mechanism; risk associated with the impairment to Toronto Hydro's image in the community, public confidence or brand; risk associated with Toronto Hydro failing to meet its material compliance obligations under legal and regulatory instruments; risk of substantial and currently undetermined or underestimated environmental costs and liabilities; risk that assumptions that form the basis of Toronto Hydro's recorded environmental liabilities and related regulatory balances may change; risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders; unexpected increases or decreases in load and customer growth, and legislative, judicial or regulatory

developments that could affect Toronto Hydro's ability to meet the goals set out in this application. Toronto Hydro cautions that this list of factors is not exclusive.

All Forward-Looking Information in these materials is qualified in its entirety by the above cautionary statements, except as required by law, or by the OEB for the purposes of the Application.

GLOSSARY

"ACA" refers to Toronto Hydro's asset condition assessment.

"ADMS" refers to Advanced Distribution Management System

"ARC" refers to the OEB's Affiliate Relationships Code for Electricity Distributors and Transmitters.

"AFS" refers to Toronto Hydro's audited financial statements.

"AFUDC" refers to Allowance For Funds Used During Construction.

"AILC" refers to Asbestos-Insulated Lead-Covered (cable).

"AM" refers to Asset Management.

"AMS" refers to Asset Management System

"APH" refers to the OEB's Accounting Procedures Handbook.

"APUL" refers to Assets Past Useful Life.

"ARO" refers to Asset Retirement Obligation.

"ATS" refers to Automatic Transfer Switches.

"BCE" refers to business case evaluation.

"BOMA" refers to the Building Owners and Managers Association.

"C&I" refers to Commercial and Institutional customers.

"CAF" refers to Customer Action Form, a notice issued to a customer when any deficiencies are found on customer-owned equipment or structures.

"CAIDI" refers to the Customer Average Interruption Duration Index and is a measure (in hours) of the average duration of interruptions experienced by customers, not including MED. CAIDI represents the quotient obtained by dividing SAIDI by SAIFI.

"Capital Expenditures" or **"Capex"** refers to expenditures relating to property, plant and equipment and intangible assets.

"CBRM" refers to Condition Based Risk Management.

"CC&B" refers to the Customer Care & Billing system, Toronto Hydro's main customer care interface used for billing and customer information.

"CDM" refers to conservation and demand management.

"**CGAAP**" refers to Canadian Generally Accepted Accounting Principles.

"CHI" refers to Customer Hours Interrupted.

"CHP" refers to Combined Heat and Power generation.

"CI" refers to Customer Interruptions.

"CIR" or **"Custom IR"** refers to Custom Incentive Rate-setting.

"CIS" refers to customer information system. Toronto Hydro's current CIS is the CC&B.

"**City**" refers to the City of Toronto.

"CNAIM" refers to the Common Network Asset Indices Methodology (Asset Condition)

"CRCI" or refers to Custom Revenue Cap Index.

"CRD" refers to Compact Radial Distribution assets.

"CSMUR" refers to the Competitive Sector Multi-Unit Residential rate class.

"CWIP" refers to Construction Work In Progress.

"DER" refers to distributed energy resources.

"DERMS" refers to the Distributed Energy Resource Management System

"DG" refers to distributed generation.

"Distribution System Code" or "**DSC**" refers to the OEB's Distribution System Code.

"**DMS**" refers to Toronto Hydro's Distribution Management System.

"DR" refers to Demand Response.

"DSP" refers to Distribution System Plan.

"DST" refers to Distribution System Technologist.

"DVA" refers to Deferral and Variance Accounts.

"EDC" refers to Toronto Hydro's Enterprise Data Centre.

"EDS" refers to the OEB's Electricity Distributor Scorecard.

"EHS" refers to Environment, Health, and Safety.

"EHSMS" refers to the Environmental, Health, and Safety Management System

"Electricity Act" refers to the *Electricity Act, 1998,* S.O. 1998, c. 15, Sched. A (Ontario), as amended.

"EMS" refers to emergency management services (i.e. police, fire, and ambulance).

"ERM" refers to Enterprise Risk Management.

"ERP" refers to an Enterprise Resource Planning system.

"ESA" refers to the Electrical Safety Authority.

"ESG" refers to Environmental, Social and Governance.

"ESQR" refers to Electricity Service Quality Requirements as mandated by the OEB's Distribution System Code.

"EUSR" refers to the Electrical Utilities Safety Rules.

"EV" refers to Electric Vehicle.

"FESI" refers to Feeders Experiencing Sustained Interruptions.

"Filing Requirements" refers to Chapters 1, 2 and 5 of the OEB Filing Requirements for Electricity Distribution Rate Applications, as amended.

"FLISR" refers to Fault Location, Isolation, and Service Restoration.

"FTE" refers to full-time equivalent.

"GEAR" refers to Geo Electrical Mapping Records Viewer.

"GIS" refers to the Geospatial Information System.

"GWh" refers to a gigawatt-hour, a standard unit for measuring electrical energy produced or consumed over time. One GWh is the amount of electricity consumed by one million kWh.

"HR" refers to Human Resources.

"HST" refers to Harmonized Sales Tax.

"HV" refers to High Voltage.

"HVAC" refers to Heating, Ventilation, and Air-Conditioning.

"Hydro One" or **"HONI"** refers to Hydro One Networks Inc.

"HI" refers to Health Index.

"IAS" refers to International Accounting Standards.

"IEEE" refers to the Institute of Electrical and Electronic Engineers Inc.

"IESO" refers to the Independent Electricity System Operator.

"IFRS" refers to the International Financial Reporting Standards.

"IPPR" refers to Toronto Hydro's Investment Planning and Portfolio Reporting (process).

"IRRP" refers to the Integrated Regional Resource Plan.

"ISA" refers to an in-service addition of assets to the utility's rate base.

"IT" refers to Information Technology.

"ITIS" refers to the Interruption Tracking Information System.

"IVR" refers to the Interactive Voice Response technology that assists customers with their account management enquiries by providing updated account balances, payment option information, bill amount predictors and other related tools.

"Key Accounts" refers to large customers with average peak loads over 1 MW and those customers who have critical loads like hospitals, financial institutions, essential public services and developers.

"kW" refers to a kilowatt, a common measure of electrical power equal to 1,000 Watts.

"kWh" refers to a kilowatt-hour, a standard unit for measuring electrical energy produced or consumed over time. One kWh is the amount of electricity consumed by ten 100 Watt light bulbs burning for one hour.

"LCA" refers to a Life Cycle Analysis.

"LDC" refers to Local Distribution Company.

"**LDR"** refers to Local Demand Response.

"LEAP" refers to the financial assistance portion of the OEB's Low-Income Energy Assistance Program.

"LoS" refers to Loss of Supply.

"LRAM" refers to the Lost Revenue Adjustment Mechanism.

"LRAMVA" refers to the Lost Revenue Adjustment Mechanism Variance Account.

"LRT" refers to Light Rail Transit.

"LTEP" refers to the Ontario Long-Term Energy Plan.

"LV" refers to Low Voltage.

"MAIFI" refers to the Momentary Average Interruption Frequency Index.

"MED" refers to major event days as defined by Institute of Electrical & Electronic Engineers Inc. specification 1366.

"mIFRS" or "**MIFRS**" refers to Modified IFRS.

"MS" refers to Municipal Station, a station within the distribution system which is supplied by feeders at 27.6 kV or 13.8 kV and steps down voltage to 13.8 kV or 4.16 kV.

"MW" refers to megawatt, a common measure of electrical power equal to one million watts.

"NBV" refers to Net Book Value.

"NERC" refers to the North American Electric Reliability Corporation.

"**NMS"** refers to Network Management System

"NWS" or **"NWA"** refers to Non-Wires Alternatives/Solutions.

"OCCP" refers to the Operational Centers Consolidation Program.

"OEB" refers to the Ontario Energy Board.

"OEM" refers to the Original Equipment Manufacturer.

"OH&S" refers to Occupational Health & Safety.

"OHSA" refers to the *Occupational Health and Safety Act*, R.S.O. 1990, c. O.1.

"OM&A" refers to Operations, Maintenance, and Administration.

"OMERS" refers to the Ontario Municipal Employees Retirement System, a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario.

"OMS" refers to Toronto Hydro's Outage Management System.

"OPEBs" refers to Other Post-Employment Benefits.

"OSC" refers to the Ontario Securities Commission.

"OTO" refers to Orders to Operate.

"PCB" refers to polychlorinated bi-phenyl.

"PILC" refers to Paper-Insulated Lead-Covered (cable).

"PILs" refers to the Payment In Lieu of Corporate Taxes.

"PIM" refer to the Performance Incentive Mechanism.

"PLT" refer to Power Line Technician.

"PP&E" refers to Property, Plant, and Equipment.

"PPE" refers to Personal Protective Equipment.

"PSC" refers to Power System Controller.

"PWU" refers to Power Workers' Union.

"RCM" refers to Reliability Centered Maintenance.

"REI" refers to Renewable Enabling Improvements.

"REG" refers to Renewable Energy Generation.

"RFP" refers to Request for Proposal.

"RIP" refers to a Regional Infrastructure Plan.

"ROE" refers to Return on Equity.

"RPB" refers to Reverse Power Breaker.

"RRF" or **"RRFE"** refers to the OEB's policy for a Renewed Regulatory Framework for Electricity Distributors.

"RRR" refers to the OEB's Reporting & Record Keeping Requirements.

"RTU" refers to a Remote Terminal Unit.

"SAIDI" refers to the System Average Interruption Duration Index and is a measure (in hours) of the annual system average interruption duration for customers served, not including MED. SAIDI represents the quotient obtained by dividing the total customer hours of interruptions longer than one minute by the number of customers served.

"SAIFI" refers to the System Average Interruption Frequency Index and is a measure of the frequency of service interruptions for customers served, not including MED. SAIFI represents the quotient obtained by dividing the total number of customer interruptions longer than one minute by the number of customers served.

"SCADA" refers to Supervisory Control and Data Acquisition.

"SSS" refers to Standard Supply Service.

"THC" refers to Toronto Hydro Corporation.

"THESI" refers to Toronto Hydro Energy Service Inc.

"Toronto Hydro" or "**THESL**" refers to Toronto Hydro-Electric System Limited.

"TOU" refers to Time of Use billing practices.

"TRIF" refers to Total Recordable Injury Frequency.

"TS" refers to Transformer Station, a point of power supply from the Hydro One transmission system that steps down supply voltage from 230 kV or 115 kV to 27.6 kV or 13.8 kV.

"TTC" refers to Toronto Transit Commission.

"URD" refers to Underground Residential Distribution.

"USGAAP" refers to United States Generally Accepted Accounting Principles.

"USL" refers to the Unmetered Scattered Load rate class.

"USofA" refers to the Uniform System of Accounts set out in the Accounting Procedures Handbook.

"UWPC" refers to Utility Work Protection Code.

"Watt" or **"W"** refers to a common measure of electrical power. One Watt equals the power used when one ampere of current flows through an electrical circuit with a potential of one volt.

"WCA" refers to the Working Capital Allowance.

"WF" refers to Workforce.

"WMS" refers to the Warehouse Management System.

"WSIB" refers to the Workplace Safety and Insurance Board.

"XLPE" refers to Cross-Linked Polyethylene.

TORONTO HYDRO®

Executive Summary and Investment Plan Overview



2025-2029 CUSTOM RATE APPLICATION

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1. OVERVIEW

Toronto Hydro-Electric System Limited ("Toronto Hydro" or the "utility") is proud to present its 2025-2029 Investment Plan (the "Investment Plan"), which proposes investments of approximately $5.9 billion in expanding, modernizing and sustaining the foundations of a safe and reliable grid to serve the current and future electricity needs of the homes, businesses and institutions of Toronto.

A fundamental shift – known as the energy transition – is underway. There is broad societal, academic and policy consensus that the demand for electricity will roughly double over the coming decades.[1] Customers are adopting new technologies powered by electricity at unprecedented rates as part of a societal-wide and international movement to reduce reliance on fossil fuels in order to mitigate the worst existential and economic impacts of climate change. Toronto Hydro needs to get ready for this electrified future now by preparing its grid and operations to serve increases in customer demand and offer customers greater choice with respect to their energy use, while also addressing other major challenges that persist: deteriorating infrastructure, a complex operating environment, rapid population growth, an evolving workforce, more frequent extreme weather events, and the rise of cyber threats.

As the trusted steward of the distribution system in Toronto, the utility recognizes that customers and stakeholders expect it to make the necessary investments to confront these challenges while also balancing price and service quality outcomes in both the near and long term. Toronto Hydro places paramount importance on fulfilling this responsibility. The Investment Plan makes the minimum investments necessary (the "least regrets" investments) to maintain key outcomes in the near-term while also making paced and deliberate progress in readying the grid and utility operations for the future, irrespective of the path the energy transition takes. Investments with long lead times (e.g. infrastructure and human capital) must be made now to provide customers and policymakers a full range of options and choices for a decarbonized future, and the utility must have the flexibility to adapt plans as needed to be responsive to the varying degrees of uncertainty that still remain as to exactly when and how future demand will manifest.

Toronto Hydro developed the Investment Plan through an integrated and iterative planning process that considered customer feedback from start to finish, along with sophisticated system performance analysis, and other technical information produced by subject matter experts who have deep expertise in managing the electrical grid and its enabling operating systems. A record number of energy consumers – over 33,000 residential and business customers – reviewed the Investment Plan, and 84 percent supported the plan as presented or one that does even more to advance key outcomes.[2]

The Investment Plan builds on past improvements in safety, reliability and customer service outcomes, ensuring that this foundation of high-performance continues to be maintained while building a modern,

resilient grid for the decades to come.[3] It is organized around four investment priorities: (a) sustainment and stewardship (maintaining the foundations of a safe and reliable grid); (b) modernization (adopting new technology to improve system performance and reduce costs); (c) growth and electrification (connecting and serving growing demand for electricity); and (d) general plant (decarbonizing and keeping the business running efficiently).

Delivering customer value through performance is Toronto Hydro's ethos. To demonstrate its unwavering commitment, the utility is holding itself financially accountable for achieving key outcomes that matter to customers and deliver long-term value to ratepayers and stakeholders. The utility intends to track and transparently report its performance across 41 unique performance measures annually through its scorecards and regulatory filings, and introduced an innovative performance incentive mechanism which provides customers with an upfront rate reduction benefit of $65 million that the utility only earns back upon achievement of targeted objectives. Toronto Hydro understands that this is the level of accountability that customers and stakeholders deserve and expect.[4]

Toronto Hydro believes that it has struck the appropriate balance between maintaining the reasonable prices and reliable service levels that customers value while making the minimum necessary investments to respond to the imperatives of the ongoing energy transition so that the local grid can safely, reliably and efficiently serve customers for decades to come.

2. BACKGROUND & OPERATING CONTEXT

2.1 Corporate Overview

Toronto Hydro distributes electricity to Canada's largest – and North America's second fastest growing – city.[5] The utility serves over 3 million residents, 28 million visitors annually, approximately 100,000 businesses,[6] more than 35 hospitals and post-secondary institutions,[7] and the financial centre of Canada. Toronto has a dense urban core with approximately 11.5 million trees,[8] and it takes approximately 15,000 circuit kilometres of overhead wires and 13,800 circuit kilometres of underground wires[9] to serve the city's 630 square kilometres.[10] That is enough cable to cross the entire country of Canada nearly six times.

Toronto Hydro takes seriously the duty of serving such a complex service territory. The utility proudly confronts the associated challenges and does so in the safe and reliable manner that customers expect. In order to keep pace with these challenges, Toronto Hydro has spent the last decade renewing its aging and deteriorating grid, hardening the system against increasingly frequent and severe extreme weather, renewing its aging workforce, and investing in key areas such as customer service, cyber security and city growth to meet evolving customer requirements and external pressures.

These investments have lived up to customer and stakeholder expectations for fewer and shorter outages, better customer service and faster problem resolution, more self-serve and information-on-demand tools, an industry-leading safety performance record, and sustained efficiency benefits of a utility mature in its productivity journey.[11]

2.2 Energy Transition and Electrification

While Toronto Hydro is proud of its recent achievements, there is a paradigm shift underway. For nearly two decades, Toronto Hydro's demand has been largely flat, as investments in conservation and energy efficiency helped offset significant growth in Toronto. However, market evolution and public policy are changing this trajectory, driving customers to adopt advanced electrified technologies – such as electric vehicles (EVs), solar panels, home energy storage, heat pumps and electric water boilers – which are increasing customer demand and expectations for outcomes. The utility must evolve and invest in grid-side and operational technologies to address new imperatives flowing from these fundamental shifts in public policy objectives related to climate change, technological advancement, and customer needs and priorities.[12]

In light of these cultural shifts, all levels of government have adopted greenhouse gas (GHG) emission targets and incentives for fuel switching to clean energy sources.[13] The City of Toronto has declared a climate emergency requiring immediate and sustained action. TransformTO – the City's ambitious plan to achieve net zero community-wide emissions by 2040 – recognizes that most emissions come from two sources: buildings (approximately 58% of community-wide emissions, mostly from natural gas used for space and water heating) and transportation (approximately 33% of community-wide emissions, mainly from car and passenger trucks),[14] and has adopted strategies including:

- the Net Zero Existing Building Strategy,[15] which targets decarbonizing existing homes and business, including establishing emissions targets; and
- the Electric Vehicle Strategy, which targets having 30 percent of all registered vehicles in Toronto be electric by 2030, necessitating increased access to EV charging infrastructure across the city (primarily installed by Toronto Parking Authority with support from Toronto Hydro). [16]

The City of Toronto intends to reduce these sources of emissions through by-laws, policy and standards encouraging customer uptake of electrified technologies, including:

- the Toronto Green Standard, which sets sustainable design and performance requirements for new developments, with the goal of all new buildings being near zero emissions after 2030;[17]
- the Home Energy Loan Program,[18] Energy Retrofit Loans,[19] and Green Will Initiative,[20] which provide financial incentives and support services; and

- proposed implementation of a mandatory emissions performance standard that would require all existing buildings to reduce their emissions over time.[21]

These critical climate change mitigation and adaptation efforts demand a bigger, more efficient and more resilient system that will serve customers for generations to come. The grid must be ready when people plug in to decarbonize their lives, and these decarbonization imperatives are driving a fundamental transformation of the energy ecosystem within which Toronto Hydro operates.

However, this transformation introduces a new tension in the utility's planning process. How and when decarbonization and electrification materializes has degrees of uncertainty; whether the pace of change is faster or slower and which technologies customers and policymakers choose exist on a continuum of possible paths.[22] To fulfill its core mandate, Toronto Hydro must ensure that the grid and its operations are capable of serving Torontonians when and where they require electricity. This, by definition, requires the utility to invest ahead of demand materializing – whether that be demand in terms of load or service quality requirements. Hard asset investments and human capital investments both require a long lead time. Just as it can take years to build a new transformer station or complete an overhead rebuild project, it takes years to train and develop new employees, especially with advanced digital skill sets and capabilities.

In order to reconcile the tension between long-lead-time investments and uncertainty, Toronto Hydro has oriented itself around the principle of "least regrets investments" in designing its 2025-2029 Investment Plan to identify investments that can be made in the 2025-2029 period with a high degree of confidence that they will provide value to ratepayers irrespective of what the future holds.[23] This principle is discussed in more detail in the Business Planning & Customer Engagement section below.

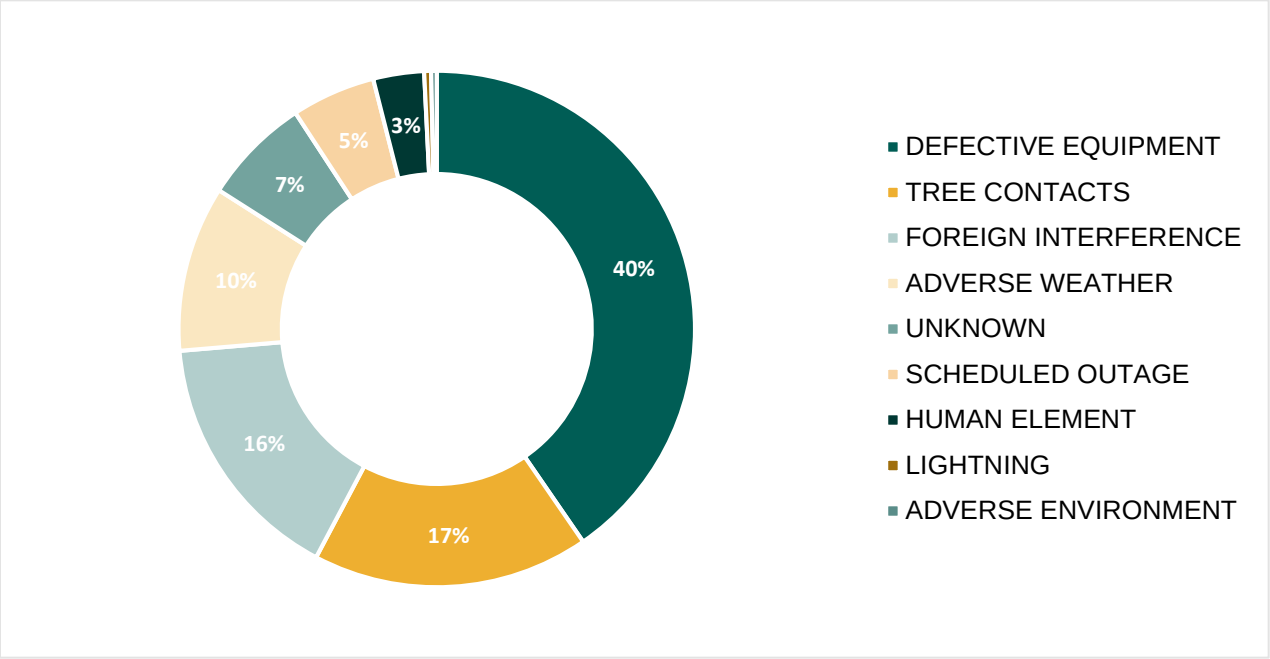
2.3 Material Challenges

At the same time that Toronto Hydro is responding to this paradigm-shifting change, the challenges of the past persist, and continued investments in the foundations of utility stewardship are still necessary to maintain the table stakes of a safe and reliable grid, supported by responsive customer service. Toronto Hydro faces a number of distinct challenges in upkeeping, expanding and modernizing its distribution system. Each of the challenges discussed below exacerbate the energy transition discussed above and are explained in further detail throughout the 39 capital and operations programs that form the 2025-2029 Investment Plan.

2.3.1 Deteriorating Infrastructure

Toronto Hydro owns and operates a mature distribution system. Despite notable achievements in renewing the grid and improving reliability over the last decade, defective equipment continues to be a leading contributor to the duration of outages on the grid, representing approximately 40% of annual power interruptions experienced by customers based on duration (excluding Loss of Supply and Major Events).[24]

Figure 1: SAIDI (Excluding Loss of Supply & Major Events) Breakdown by Outage Cause 2018-2022



Approximately a quarter of the utility's grid equipment continues to operate past useful life. An additional 11 percent is expected to reach that point by 2030, unless the utility invests in upkeeping system infrastructure in the 2025-2029 period. Allowing the number of assets past useful life to grow increases the likelihood of power outages due to equipment failure (which are costlier and take longer to resolve), puts public and employee safety at risk, and leads to negative environmental outcomes. To manage these risks, Toronto Hydro must regularly inspect equipment to maintain its condition, and replace equipment that is in bad condition or performing poorly, before a failure occurs.[25]

2.3.2 Complex Operating Conditions

Toronto Hydro operates in a complex urban environment based on the dense nature of the city's population, the age of the city's infrastructure, and the nature of its customer makeup. These each pose material challenges in the utility's day-to-day operations.

Toronto is an urban service territory with a population density of 4,428 people per kilometer.[26] Table 1 below compares Toronto's population density with the five largest cities in Ontario:

Table 1: Ontario Cities Population Density[27]

Ontario's 5 Largest Cities by Population	Population (People)	Land Mass (km^2)	Population Density (People/km)
Toronto	2,794,356	631.1	4,428
Ottawa	1,017,449	2788.2	365
Mississauga	717,961	292.74	2,453
Brampton	656,480	265.89	2,469
Hamilton	569,353	1118.31	509

Based on Census Subdivision data from 2021 Census

The density of Toronto Hydro's service territory is unique even within an international context due to the ever-increasing number of high-rise buildings. As seen in the table below, New York City is the only urban centre in the world with more high-rise buildings than Toronto:

Table 2: International Cities High-Rise Buildings[28]

Rank	City	Country	High-Rise Buildings
1	New York City	United States	6,223
2	**Toronto**	**Canada**	**2,598**
3	Seoul	South Korea	2,578
4	Dubai	United Arab Emirates	2,360
5	Hong Kong	China	1,916
6	Tokyo	Japan	1,533
7	Busan	South Korea	1,311
8	Kyiv	Ukraine	1,275
9	Chicago	United States	1,247
10	Shanghai	China	1,236

As a dense and old city by North American standards, Toronto also suffers from a challenging combination of legacy standards, limited availably of rights of way for locating distribution equipment, underground congestion which drives a need for increased co-ordination with other utility providers (e.g. water, transit, natural gas, telecommunications), complex permitting and approval processes, longer drive times due to traffic congestion, limitations on the size and scale of distribution assets, and disruptions related to large-

scale local events. All of these considerations translate into significant planning and coordination requirements, adding both time and costs to system maintenance, renewal and enhancement investments.[29]

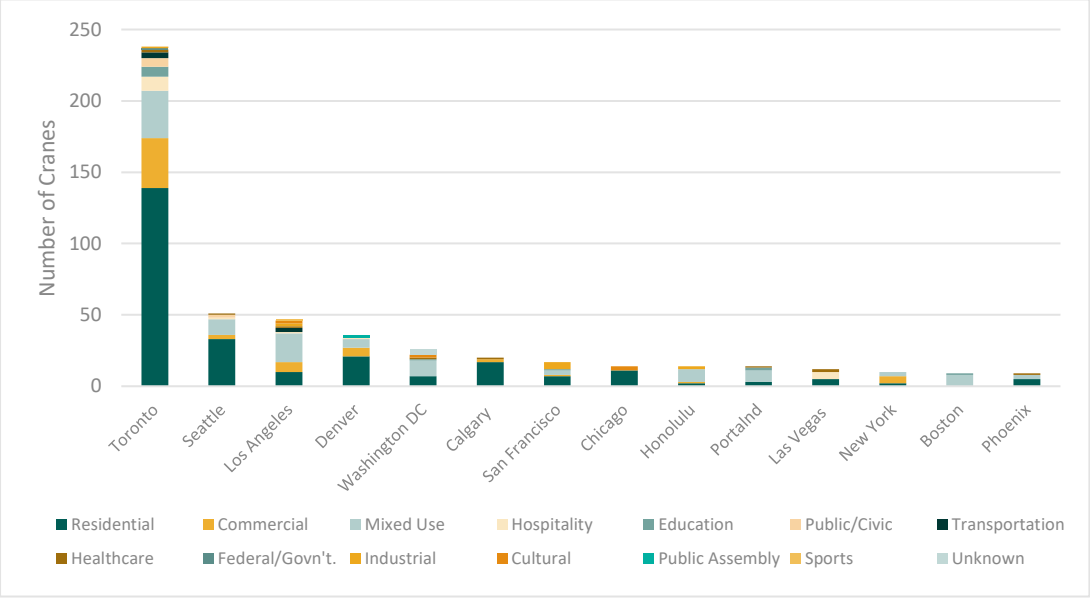
Beyond challenges created by service territory density and asset vintage, the unique customer make-up in Toronto's downtown core also places additional weight on Toronto Hydro's responsibility as a system operator. This customer composition – which includes major hospitals, the provincial legislature, and headquarters of banks, businesses and other critical financial institutions – necessitates elevated requirements for reliability and continuity of service to customers whose operations are critical to the sound functioning of the provincial and federal economy. As a result, Toronto Hydro's downtown system is designed and operated with a high-level redundancy, which in turn requires that additional prudent costs be incurred.[30]

2.3.3 A Growing City

The population of Toronto is also booming and expected to grow by approximately 23.8 percent between 2021 and 2031, a marked increase from the 6.8 percent growth over the prior decade (from 2011 to 2021).[31] The growth is concentrated in certain pockets, namely the downtown core and along transit corridors, and is oriented vertically with a continuing trend of high-rise developments. This has resulted in a marked need for new housing, transit solutions and infrastructure, all of which must be serviced by Toronto Hydro in the years to come.[32]

A salient data point that bears out this staggering growth is that Toronto has led the North American crane count since 2015 by a margin that is almost equivalent to the rest of the cities combined.[33]

Figure 1: RLB Crane Index - Q1 2023



In addition to high-rise buildings, this growth is also driving the development of sustainable new housing communities through the redevelopment of areas such as Downsview, the Golden Mile and the Port Lands, some of which are planned as net zero communities and to meet the highest performance measures of the Toronto Green Standard.[34]

The significant expansion of transit networks is also needed to support this population growth, and there are numerous new projects under construction in the city, including the Yonge North Subway Extension, Finch West LRT, Scarborough Subway Extension, Eglinton Crosstown West Extension, and the Ontario Line.[35]

Finally, this growth is also putting additional stress on the system through the incremental loads associated with technology and digitalization. In addition to organic growth, Toronto has become Canada's largest data center market, with 107 MVA of incremental demand load connected during the 2020-2024 period and 207 MVA forecasted to come online from 2025-2029.[36]

2.3.4 Extreme Weather

Extreme weather amplifies the challenge of distributing electricity to a mature, dense and rapidly growing urban city. Heat, high winds, heavy rainfall, freezing rain and heavy snowfall can cause major system damage and result in prolonged power outages. As evidenced by recent events (outlined in Table 3 below), extreme weather has become a regular operating condition that the utility must consider and manage in its day-to-day operations and long-term planning activities. With the frequency and intensity of adverse weather increasing due to climate change, Toronto Hydro's grid and operations must become more resilient to this challenge.

Table 3: Extreme Weather (January 2020 through May 2022)

Event	Description of Impact
High Winds Storm (May 2022)	• 142,052 customers impacted at its peak • 5 days to restore power to all customers
Flash Storm (August 2021)	• 20,000 customers impacted at peak • 2 days to restore power to impacted customers
Thunderstorm High Volume Event (July 2021)	• A line of thunderstorms with windspeeds in excess of 75 km/h • 12,000 customers were impacted at its peak • Service restored for the majority of customers within 2 days

Event	Description of Impact
High Wind Event (April 2021)	• Wind expected to reach ~95km/h • 22,000 customers impacted at its peak • 1 day to restore power to impacted customers
High Wind Event (November 2020)	• Winds in excess of 100 km/h • Estimated 8,000 customers impacted and 101 outages at its peak
Flash Storm (July 2020)	• Approximately 50-70mm of rain • 50,000 customers impacted at peak • Impacted customers restored within 2 days
Adverse Weather (January 2020)	• Approximately 60mm of rain, 5-15mm of ice and 90 km/h winds • 4,900 customers impacted at its peak • Impacted customers restored within 3 days

Adverse weather affects the distribution system in different ways. The underground system is vulnerable to flooding from extreme rainfall, while the overhead system is susceptible to extreme winds, freezing rain and wet snow, resulting in damage and outages. Broken trees and the weight of ice and snow accretions can bring lines, poles and associated equipment to the ground. For instance, in May 2022, an extreme wind event known as a derecho storm struck Southern Ontario and Quebec with 120+km/h winds. These extreme winds caused substantial damage to vegetation, which in turn took down overhead distribution wires and equipment, leaving approximately 142,000 customers (18% of Toronto Hydro's total customer base) without power at the peak of the storm. While the majority of customers were restored within 48 hours, it took approximately five days and cost approximately $2.35 million to restore power to all customers.[37]

2.3.1 Technology Advancements

Technology and innovation are also driving the need for a more dynamic system that is transitioning away from usual patterns of supply and demand towards more complex interactions and inputs in electricity generated and consumed. The role of the utility continues to evolve to support the a smart grid ecosystem, comprising renewable and other distributed energy resources (DER) such as electric vehicles, solar panels and battery energy storage systems.

Customers are showing a continued interest in participating in the electricity system as both consumers and producers of power. DER connections have grown in recent years as a result of government policies and declining costs of technologies such as solar panels. By the end of the decade, Toronto Hydro expects to

have over 4,400 DER connection projects representing a total installed capacity of approximately 517 MW, an increase of approximately 67 percent compared to 2022.[38]

Integrating DERs into the grid provides customers more tools to actively manage their energy needs and enables the grid to be supplied by locally-generated renewable electricity resources. To advance these outcomes, Toronto Hydro must address the significant challenge of accommodating electrons that flow bi-directionally within a grid that was not built for this type of supply and demand. Equipment that has a high number of DER connections is more likely to experience unstable conditions that pose significant reliability and safety risks to the system and its users. Toronto Hydro monitors all DER connections closely for these factors to ensure that the grid remains safe and reliable for customers, and is building advanced grid capabilities to mitigate against these risks and enable DER adoption by customers in the future.[39]

Technological advancement also poses the challenge of managing a heightened risk of digital security threats, as cybercrime intensifies across Canada due to changing geopolitical dynamics. While smart grid systems, infrastructure automation, and other technological advancements being used by the utility and its customers offer many benefits, they also increase the exposure of the grid (and those connected to it) to greater risk of attack by hostile actors. This intensifying global challenge is particularly acute in major economic centers such as Toronto. Electric utilities are targets for security attacks because of the critical role they play in enabling essential services (e.g. hospitals, public transit, water treatment systems, communications and traffic management) and the databases of sensitive information they possess.[40]

Toronto Hydro needs to prepare itself to assist customers in taking advantage of technological innovation and advancements while also protecting itself and its customers from the risks they introduce.

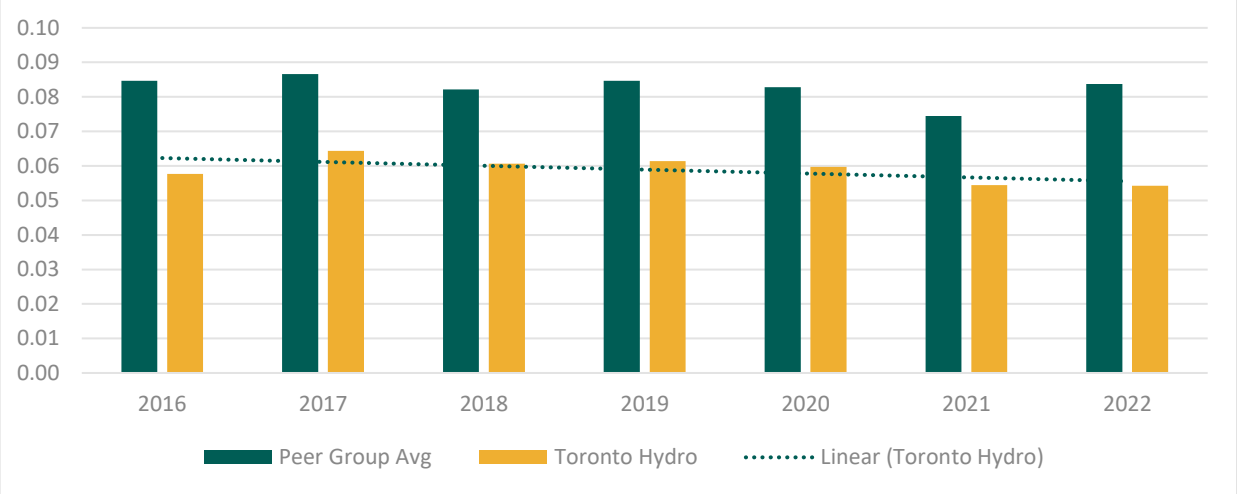
2.3.2 Workforce Challenges

Toronto Hydro relies on its highly-skilled and dedicated workforce to deliver safe, reliable and efficient electricity services to its customers. This workforce consists of approximately 70 distinct roles including: dispatchers that run a 24/7 year-round control center to enable power to be restored as quickly as possible during unplanned events; [41] skilled trades that inspect, maintain and replace assets to remediate critical deficiencies; engineers and other technical experts that diligently plan, design, manage and optimize the grid's performance; information technology experts that keep critical systems reliable for operations and secure against intensifying cyber threats; [42] and customer service and other professionals with expertise in areas such finance, human resources, law and regulation that deliver positive customer experience and ensure the company operates in a compliant, safe and environmentally responsible manner.[43]

Since 2015, Toronto Hydro has served the needs of a growing city, evolving customer and policy demands, and an aging system while addressing intensifying challenges identified above, with a staffing complement

that is essentially flat from 2015 to 2024. Over this period, as Toronto Hydro's replenished a large wave of retirements, it also right-sized its workforce through continuous improvements in productivity, including harmonizing key jobs to create a more agile compliment of staff, and automating manual processes to increase employee output levels.[44] As shown below, compared to its Ontario peers, Toronto Hydro's workforce reflects the utility's past efforts to increase resource throughput and utilization.[45]

Figure 6: FTE per GWh of Load Served



As the utility takes least-regrets actions to expand and modernize the grid to be ready and equipped for a once-in-a century transformation of the energy system, it similarly needs to invest in resources with new and enhanced skill sets to get the work done safely and cost-effectively. Just as it takes years to build new transformer stations or convert an area of the city served by legacy infrastructure to modern standards, human capital investments require long lead times, with the average employee undergoing multiple years of training and development to acquire the specialized skills and experience necessary to become a fully competent contributor. Due to the long lead time required for investment in both grid and human capital, Toronto Hydro must begin work today to be prepared to handle increased demand and consumption, bi-directional power flows, increased societal reliance on electricity, and enhanced customer expectations that naturally flow from these evolutions.

After nearly a decade of managing with a headcount plan that is essentially flat from 2015 to 2024, it is no longer possible for Toronto Hydro to meet its obligations without additional resources. Workforce levels need to grow by approximately 25 percent over the coming years for the utility to have the required resourcing capacity and capabilities to sustain foundations of a safe and reliable grid and meet the imperatives of an urban city and customers who are increasingly relying on electricity to expand, digitize and decarbonize their footprint.[46]

As a result of past achievements in right-sizing its workforce and establishing dynamic partnerships with colleges and universities for direct recruiting and collaborative curriculum building, Toronto Hydro is ready to bring on the additional talent needed to meet the challenges of the next decade and prepare the grid and its operations to serve Toronto's growth and net zero objectives.

3. BUSINESS PLANNING & CUSTOMER ENGAGEMENT

While the preceding discussion sets the operating context for the current challenges facing Toronto Hydro, the utility recognizes that customers and stakeholders expect it to prepare a responsible multi-year plan that balances the need to confront those challenges with price and service quality outcomes. Accordingly, Toronto Hydro has a robust customer engagement program and planning process that ensures customer feedback is incorporated into its investment priorities, plans and projects.

Customer engagement is deeply embedded in the utility's planning process, ensuring that customer feedback informs Toronto Hydro's multi-year investment priorities and draws alignment with needs and expectations. The utility starts with an assessment of customer needs and preferences. Toronto Hydro then develops an initial capital plan that targets certain short and long-term performance goals for the system. From this point, an iterative planning process, including additional customer engagement, refines pacing and other assumptions until the right balance between price and service quality outcomes is met.[47]

The following sections discuss the stages of that engagement and planning process in further detail.

3.1 Assessing Customer Needs and Priorities

Toronto Hydro began the planning process by engaging its customers with a survey to understand their needs and preferences for the 2025-2029 period. The feedback from customers centered around the following core themes:

- **Price and Reliability** – Price and reliability continue to be top customer priorities, with reliability having become more important to residential customers over the last five years. Customers prioritize reducing the length of outages, with a particular focus on outages related to adverse weather. Key Account customers are more sensitive to power interruptions and prioritize reducing the total number of outages, including momentary interruptions.
- **New Technology** – Almost equally to price and reliability, customers expect the utility to invest in new technology that will reduce costs and make the system better in the future, as long as the costs and benefits are clear.
- **System Capacity** – Finally, customers expect Toronto Hydro to invest proactively in system capacity to ensure that high growth areas do not experience a decrease in service levels. It is

worthy of note that the majority of Key Account customers surveyed have goals to reduce their net GHG emissions to zero, and expect Toronto Hydro to support them in meeting their climate objectives by ensuring that the system has capacity for growth and by providing them advisory services to support their decarbonization-through-electrification journey.[48]

These core themes then formed the basis of the planning work to come.

3.2 Integrated Planning

Toronto Hydro began integrating planning by adopting four strategic priorities for the plan, informed by customer feedback: (a) sustainment and stewardship (maintain the foundations of a safe and reliable grid); (b) modernization (adopt new technology to improve system performance and reduce costs); (c) growth and electrification (connect and serve growing demand for electricity); and (d) general plant (decarbonize and keep the business running efficiently). For each of these strategic priorities, Toronto Hydro set performance objectives aligned with customer feedback that provide value for customers and are meaningful to its operations, including to:

- invest enough in the sustainment of asset health and other leading indicators of asset risk to maintain reliability performance;
- prioritize investments in technology to modernize the grid and develop advanced operational capabilities to make the system better for the future; and
- invest proactively in system capacity to ensure that the grid is able to support future growth without compromising other outcomes like safety and reliability.

Through an iterative process that spanned over a year, Toronto Hydro system planners and experts worked diligently to identify the minimum investments necessary to meet these objectives and balance near-and long-term service quality performance with price impacts for customers.[49] Achieving this important balance entailed both top-down direction with respect to price constraints and budget limits, and bottom-up analysis of system requirements and performance levels.

In this process, Toronto Hydro employed the principle of least regrets investment. Through the use of a new tool – the Future Energy Scenarios model – the utility modelled the grid impacts of a range of possible future peak demand scenarios based on the interaction between different policy, technology and consumer behaviour assumptions. Looking at these scenarios, Toronto Hydro was able to test whether the plan: (a) maintains reasonable rates without jeopardizing longer-term system performance outcomes; (b) provides value to customers regardless of what particular technologies are adopted to decarbonize key sectors of the economy; and (c) is able to accommodate a range of possible energy transition scenarios in the next decade so that the local grid can facilitate any path that customers or policymakers choose.[50]

Toronto Hydro also retained external experts to conduct assessments of its current performance, including performing studies on how Toronto Hydro compares to other peers on total cost productivity, reliability performance, compensation and benefits, unit costs, and information technology cost and maturity. The results, which are filed with this application, show that Toronto Hydro's cost performance is comparable to, and in many cases fares better than, its peers when key considerations, such as the density and congestion of its urban operating environment, are considered.[51]

3.3 Plan Validation and Finalization

In the spring of 2023, Toronto Hydro went back to customers for feedback on its draft plan to ensure that the utility met the right balance between price and progress towards outcomes that customers value. Through the use of a comprehensive online survey, more than 33,000 customers (representing roughly 4.3 percent of the total customer base) reviewed the draft plan and provided valuable input. Toronto Hydro was pleased to see such a high level of engagement by its customers. Nearly three times more people completed the workbook compared to the similar study conducted in the lead up to the last major rate application.

To help customers understand the investment priorities and express their preferences, Toronto Hydro broke down the draft plan into seven choices:

- **Modernization** – investments to build a smarter, more efficient and resilient grid for the future.
- **Growth** – investments to increase the grid's capacity to serve customers' growing electricity needs.
- **Sustainment: Reliability** – investments to manage reliability risk due to equipment failure.
- **Sustainment: Stewardship** – investments in the paced upkeep of equipment at or near end of life.
- **Sustainment: Standardization** – investments to standardize outdated equipment.
- **General Plant** – investments in fleet, facilities and IT infrastructure to run the business efficiently
- **Decarbonization** – investments to reduce GHG emissions from Toronto Hydro's operations by electrifying fleet and facilities assets.

For each investment choice, customers were provided with the option of spending more or less for faster or slower progress towards key outcomes such as reliability, system health, customer service, efficiency and environment. This approach made it more accessible for customers to understand the key priorities of the plan and express trade-offs between price and other key outcomes. The feedback provided Toronto Hydro valuable insights into customer preferences, which was applied to refine and finalize the 2025-2029 Investment Plan.[52]

Table 2 below presents the rate impacts of the finalized 2025-2029 Investment Plan. For a typical residential customer, the proposal results in an average monthly distribution rate increase of $3.44 per month, per year, starting in 2025 through 2029. These rate impacts were considered by customers of all rate classes through the online survey, 84 percent of which on average supported the draft plan and its associated rate impacts.

Further, 18 percent of these customers supported a plan that does even more to advance key outcomes. These results validate that Toronto Hydro's 2025-2029 Investment Plan strikes the right balance between price and progress towards outcomes that customers value.[53]

Table 4: Summary of 2025-2029 Proposed Distribution Rate Change[54]

	2025	2026	2027	2028	2029	Monthly Average
Residential	$3.24	$3.40	$3.72	$3.97	$2.86	$3.44
Competitive Sector Multi-Unit Residential	-$1.27	$1.84	$2.18	$2.27	$1.64	$1.33
General Service <50 kW	$14.18	$9.24	$9.61	$10.67	$7.29	$10.20
General Service 50-999 kW	$235.35	$166.42	$175.01	$192.67	$150.45	$183.98
General Service 1,000-4,999 kW	$1,993.46	$1,466.61	$1,516.65	$1,599.65	$1,381.30	$1,591.53
	2025	**2026**	**2027**	**2028**	**2029**	**Monthly Average**
Large Use	$10,124.44	$5,874.70	$8,564.26	$9,530.78	$7,560.71	$8,330.98
Street Lighting	$15,917.30	$12,277.10	$20,691.10	$12,135.60	$15,226.00	$15,249.42
Unmetered Scattered Load	$2.96	$2.41	$2.49	$3.11	$2.01	$2.60

4. CAPITAL INVESTMENT PRIORITIES

Toronto Hydro considered the material challenges outlined above, the feedback received from customers, and the principle of least regrets investment to establish the following four strategic investment priorities for its capital plan:

- **Sustainment and Stewardship:** Risk-based investments in the renewal of aging, deteriorating and obsolete distribution equipment to maintain the foundations of a safe and reliable gird.
- **Modernization:** Developing advanced technological and operational capabilities that enhance value and make the system better and more efficient over time.
- **Growth & City Electrification:** Necessary investments to connect customers (including Distributed Energy Resources ("DERs") and build the capacity to serve a growing and electrified local economy.
- **General Plant:** Investments in vehicles, work centers and information technology (IT) infrastructure to keep the business running and reduce Toronto Hydro's greenhouse gas emissions.

These investment priorities are driven by critical needs that, if not adequately addressed, could impair Toronto Hydro's ability to deliver the outcomes that customers value. In some cases, these risks will materialize in the near term, such as lack of capacity to support urban intensification and economic development. However, in many cases, the risks will materialize in the medium to long term as the grid becomes more heavily utilized and more susceptible to longer and more frequent outages that are complex and costly to resolve. Toronto Hydro must invest in following priorities to manage these risks.[55]

4.1 Sustainment & Stewardship

Sustainment investments to renew aging and deteriorating infrastructure and standardize outdated equipment continue to be the largest part of the 2025-2029 Investment Plan. These investments must be made to maintain system performance, mitigate reliability, safety and environmental risks, and enhance the grid's capability to serve electrified technologies such as electric vehicles, solar panels, energy storage batteries, and electric heat pumps and boilers.

Past investments in the grid and operations have resulted in improvements in reliability, safety and environmental outcomes: the average duration of outages customers experience now compared to a decade ago was reduced by 26 percent over the last decade; the injury rate for employees has decreased by 60 percent; oil spills have been avoided; and the utility is on track to eliminate at-risk PCB transformers from its system by 2025. [56] [57] Investing in the performance and long-term stewardship of an aging, deteriorated and more highly-utilized system remains an urgent priority for the utility, alongside getting the grid ready to serve Toronto's growing electricity needs.

System health is a leading indicator of a safe and reliable grid. Allowing system health metrics – age and condition – to deteriorate would lead to the gradual but steady degradation of system performance. As an example, underground cables are the largest contributor to defective equipment outages and continue to present significant demographic challenges in the coming years, with approximately 73 percent of direct buried cables in the horseshoe area expected to be past their serviceable life by the end 2022.[58] Proactive investment in the replacement of these assets is a key part of sustaining the short and long-term performance of the grid.

Recognizing that customers are generally satisfied with current levels of reliability, and expect the utility to invest in new technology for the future,[59] Toronto Hydro right-sized the sustainment objectives of the Investment Plan to maintain (rather than improve) the overall health of the grid over the 2025-2029 period.[60] Maintaining system health metrics is necessary to sustain grid performance and prevent the accumulation of a backlog of equipment at risk of failure, or otherwise needing to be upgraded. Renewal investment backlogs are problematic not only because they greatly heighten system reliability risk; they also result in rate instability for customers, as well as high-inefficiencies in work execution. Such inefficiencies stem in part

from performing more work reactively – which is typically higher cost – and in part because planned work becomes more expensive due to surges in material and labour needs that could otherwise be smoothed out through paced proactive investment. [61]

Keeping pace on renewal is also important for hardening the grid against more frequent extreme weather events, and standardizing outdated equipment that poses barriers to electrification. For example, legacy 4 kilovolt stations and feeder equipment, restricts the connection of large electrified loads and distributed energy resources. To prepare the grid for electrification these assets must be gradually converted to new standards, and that work is being done in a paced way through sustainment investments that also deliver safety, reliability and environmental outcomes.[62]

The table below provides a summary of Toronto Hydro's sustainment capital programs:

Table 5: Sustainment Capital Programs

Capital Program/Segment	Investment ($M)
Area Conversions[63]	**$237**
Underground Renewal – Horseshoe[64]	**$476**
Underground Renewal – Downtown[65]	**$165**
Network System Renewal[66]	**$123**
Overhead Renewal[67]	**$273**
Stations Renewal[68]	**$218**
Reactive and Corrective Capital[69]	**$328**
Sustainment Capital	**$1,820**

4.2 Growth and City Electrification

The obligation to serve customers who want to connect to the grid is at the heart of Toronto Hydro's mandate as an electricity distributor. What accompanies that core obligation is the responsibility to make reasonable investments to prepare for future growth. This responsibility is more important than ever, as customers, communities and governments at all levels are actively embarking on an unprecedented transformation of the energy system to mitigate the worst impacts of climate change.

It is clear from studies that have been done locally, provincially and internationally that decarbonization-through-electrification imperatives are expected to drive demand for electricity in the next two decades. Experts indicate that demand could increase up to 2 to 3 times depending on the range of technologies and policy tools that are adopted.[70]

The particular drivers of demand are subject to dynamic forces of technological advancement, public policy imperatives and consumer behaviour. As an example, the decarbonization of existing housing and industrial buildings remains a policy puzzle, and a number of options are being considered to find suitable paths.[71] To manage this uncertainty and the cost-consequences for customers, the utility must be measured-but-proactive in its investment plan (as both asset and human capital investments are long lead-time), and must be deliberate in sustaining and modernizing its grid and operations to ensure that it is ready to serve and enable customer choice in all scenarios.

As outlined above, Toronto Hydro has embraced this uncertainty by prioritizing investments that can provide value under all scenarios under the "least regrets" approach. This enables the utility to meet emerging challenges without having to wait for all unknown variables to stabilize. Based on its least regrets investment philosophy, the 2025-2029 Investment Plan accommodates an increase of 23 percent in system peak demand, which includes electrification of transportation (EVs) across residential, industrial and commercial sectors, as well as major transit projects like the Ontario Line and Scarborough Subway Extension, and redevelopment plans for the Downsview, The Port Lands and Green Mile communities.[72]

The 2025-2029 Investment Plan anticipates a material increase to the customer connection portfolio (consistent with the trend observed in recent years) and expands stations capacity to alleviate future load constraints due to growth resulting from EV uptake, digitalization of the economy (e.g. data centers and digital transformations of existing sectors), and city growth and redevelopment (e.g. urban densification and transit expansion). The 2025-2029 Investment Plan also optimizes near-term system capacity through active management measures such as load transfers and balancing, equipment upgrades, and the targeted use of non-wires solutions – both demand-side measures that leverage customer DERs as well as grid-side technologies such as renewable enabling energy storage systems.[73]

By the end of this decade, DER capacity is expected to increase by approximately 67 percent.[74] Getting these resources safely connected to the grid is necessary to enable greater choice and support customers in achieving their electrification objectives (e.g. ESG, net zero, environmental conscientiousness, home/business resiliency). Moreover, integrating these resources into the system is critical to right-sizing system expansion investments, and developing a grid that is more resilient in the future as a result of greater levels of local power supply. To accommodate increasing volumes of connections in this area, the 2025-2029 Investment Plan ensures control and monitoring capabilities for all distributed generation and addresses constraints on restricted feeders through traditional investments such as station bus-ties and alternative technologies such as energy storage.[75]

While there is certainty that fundamental change is ahead, there are still degrees of uncertainty about how that change will unfold. For example, government incentives or market evolution could further accelerate

customer adoption of electric vehicles or other fuel switching technologies. Similarly, provincial procurement programs could create expanded role for DERs in the deployment of coordinated infrastructure solutions to meet Ontario's energy needs.[76] As a result of such external factors, the pacing and level of certain demand-driven expenditures and revenues can change and materially deviate from the forecast. To that end, Toronto Hydro proposes a flexibility mechanism (known as a variance account) to reconcile differences between forecasted and actual demand-driven costs and revenues. During a time of unprecedented change and transformation in the economy and energy system, it is key to protect both ratepayers and the utility from structural unknowns that could have a material impact on the plan.[77]

The table below outlines the programs that enable growth and city electrification:

Table 6: City Growth and Electrification Capital Programs

Capital Program	Investment ($M)
Customer Connections[78]	$476
Externally Initiated Plant Relocations & Expansions[79]	$76
Load Demand[80]	$236
Generation Protection, Monitoring, and Control[81]	$35
Non-Wires Solutions[82]	$23
Stations Expansion[83]	$173
Growth Capital	**$1,020**

4.3 Grid Modernization

Toronto Hydro's grid modernization strategy focuses on accelerating the deployment pace of digital field and operational technologies that can deliver future benefits to customers. These benefits include better outage restoration capabilities to improve grid resilience, and enhanced operational flexibility to manage a more heavily utilized system with increasing bi-directional power flows. Grid modernization investments, once fully implemented and integrated in the next decade, are expected to yield a material step-change improvement in reliability and operational efficiency, to help offset the added reliability and cost pressures associated with electrification.[84]

The modernization plan lays the groundwork for grid automation (commonly known as the self-healing grid) in the horseshoe area of the system starting in 2030 to provide the enhanced levels of reliability and resilience that customers will expect as they electrify their homes and business at a lower cost compared to traditional alternatives. To improve resiliency against major disruptions (e.g. extreme weather; loss of supply) for vulnerable parts of the system, the modernization plan also includes investment in: (a) the targeted

undergrounding of equipment to harden vulnerable areas of the overhead system against more frequent and extreme weather events, and (b) enhanced configuration options for the downtown network which serves critical loads such as major hospitals and financial institutions.

Toronto Hydro's journey towards an intelligent self-healing grid is being implemented through an Advanced Distribution Management System (ADMS), a multi-faceted software platform with advanced capabilities and connected applications that integrate analytics, real-time data and control algorithms to optimize distribution network operation. The system provides a holistic view of the grid and encompasses advanced applications such as Outage Management System (OMS), Fault Location Isolation and Service Restoration (FLISR), Volt/Var Optimization, which allow swift detection and response to outages and grid disturbances, and enable reliable and efficient management of DERs by optimizing voltage levels and reactive power flows throughout the distribution system. [85]

Through operational technology such as sensors, switches and software, Toronto Hydro can better monitor, predict and control the flow of electricity across the system. These capabilities enable the utility to reduce the number and length of outages customers experience, and also pave the way for a more interactive, bi-directional grid that enables customers to choose various technologies to produce, store and sell power back to the grid.[86] In addition, Toronto Hydro plans to invest in overhead and underground line sensors and other condition monitoring and control equipment that provide the utility real-time information about critical assets in the field, and enable more cost-effective system planning and operational decisions.[87]

Modernization investments also create a foundation for the kinds of advanced, real-time and predictive analysis that would be fundamental to Toronto Hydro's evolution toward Distribution System Operator (DSO) model, if and when such a model is either imposed or offered to distributors in an effort to further enable energy transition outcomes. In such a model, Toronto Hydro would be expected to safely and reliably coordinate, dispatch, and optimize thousands of behind-the-meter generators and flexible loads in order to help maximize the value created by the local energy system for customer, including maximizing the penetration and utilization of non-emitting energy sources. While the policy environment surrounding the role of DERs in the energy transition remains unsettled, the grid modernization capabilities advanced by the 2025-2029 Investment Plan create the foundation for this possible future while also delivering many other tangible benefits to customers irrespective of the DSO policy framework.[88]

The table below outlines Toronto Hydro's modernization capital programs:

Table 7: Modernization Capital Programs

Capital Program/Segment	Investment ($M)
System Enhancement[89]	$151
Network Condition Monitoring and Control[90]	$6
Metering[91]	$248
Overhead Resiliency[92]	$86
Stations Control and Monitoring[93]	$65
IT Cyber Security & Software Enhancements[94]	$95
Modernization Capital	**$651**

In addition, to the modernization capital investments summarized above, Toronto Hydro proposed to establish a $16 million 2025-2029 Innovation Fund to support the design and execution of pilot projects focused testing of innovative technologies, advanced capabilities, and alternative strategies that enable electrification grid readiness and facilitate DER integration. The Innovation Fund supports utility investment in innovation work that is more early stage, exploratory and developmental in nature, where the outcomes are less certain, but the potential benefits for the system and customers could be significant. While the benefits of individual projects may not be immediate or certain, and some initiatives may prove to be more or less fruitful than others, this type of work is nevertheless critical to achieving real innovation during a time of transformation in the energy sector. [95]

4.4 General Plant

Toronto Hydro needs to maintain facilities, fleet and information technology (IT) assets and infrastructure to enable efficient business operations. To get maximum value out of its work centers, stations buildings, physical security systems, and fleet, the utility monitors and manages asset age and condition with a view to optimizing total lifecycle costs.

In addition to four work centers that provide the necessary conditions for employees to work effectively, Toronto Hydro manages a broad portfolio of approximately 185 stations which house and protect critical equipment such as cables and transformers. Like electrical equipment, facilities assets that are in poor condition pose an increased risk of failure putting key outcomes such as safety, reliability, customer service and productivity at risk. For example, if a station building has a leaking roof or foundation that allows water to infiltrate, there could be permanent damage to distribution equipment leading to lengthy and costly power interruptions and posing hazards to workers and the public.[96]

Investments in the renewal and maintenance of facilities assets enable the utility to deliver its services in a safe, reliable, and sustainable manner. In addition to these table stakes, Toronto Hydro must also address emerging needs to provide greater resilience against physical threats such as vandalism and natural threats such as extreme weather. The utility plans to address these needs through targeted investments in renewing stations buildings and work centres (e.g. exterior cladding, windows, and roofs where critical equipment is housed), and physical security systems (e.g. network-based cameras and access card readers).

Toronto Hydro crews also need safe and reliable vehicles to execute a wide-range of system capital and operations and maintenance work programs. Toronto Hydro's fleet investments include heavy duty and light duty vehicles and equipment (e.g. forklifts and trailers). These vehicles transport employees and materials to and from job sites, perform distribution work onsite, and serve as working space for field employees. Fleet vehicles must be available to support these operations in a safe and efficient manner. Toronto Hydro's fleet investments aim to optimize vehicle operating costs, minimize fleet downtime due to repairs, increase vehicle efficiency and safety, and importantly reduce emissions.[97]

Toronto Hydro is committed to reducing its direct GHG emissions (referred to as Scope 1 emissions) in order to mitigate the impacts of climate change and reach "net zero" by 2040. The utility intends to reduce the emissions produced by its fleet by gradually increasing the complement of electric and hybrid vehicles. Similarly, Toronto Hydro has a paced plan to reduce its buildings emissions by decreasing its natural gas consumption using a combination of energy efficiency measures and fuel switching projects to replace natural gas fueled heaters with electric heating systems.[98]

Finally, General Plant includes investments in information and operational technology (IT/OT) assets that support a number of business applications and systems which are essential to conducting day-to-day operations such as managing field crews, responding to outages and enabling customer self-serve tools. When these systems are not available, customers service levels decrease, power outages and operational disruptions take longer to fix, and safety of the public and employees is put at risk. Toronto Hydro must invest in upkeeping its IT/OT assets to ensure they remain highly reliable and available for conducting critical operations.[99]

The table below outlines Toronto Hydro's general plant capital programs:

Table 8: General Plant Capital Programs

Capital Program/Segment	Investment ($M)
Enterprise Data Centre[100]	$72
Facilities Management and Security[101]	$145

Capital Program/Segment	Investment ($M)
Fleet and Equipment Services[102]	$44
Information and Operational Technology[103]	$206
General Plant Capital	**$467**

5. OPERATING INVESTMENT PRIORITIES

The capital investment priorities outlined above are enabled by a suite of operational programs that work together with the capital programs to achieve the key objectives of the 2025-2029 Investment Plan and deliver the outcomes that customers value. This part of the plan is comprised of 19 operational programs summarized in Table 9 below that, among many other things, support the execution of an expanded capital program, address a wide-range of legal and regulatory requirements, enable the delivery of timely and satisfactory customer services, and maintain the grid in good working order.

These programs are executed by high-skilled and knowledgeable Toronto Hydro employees and effective third-party resources. As mentioned previously, after nearly a decade of managing operations with a headcount plan that is essentially flat from 2015 to 2024, the utility needs to expand its workforce capacity by approximately 25 percent to sustain foundations of a safe and reliable grid and meet the imperatives of an urban city and customers who are increasingly relying on electricity to expand, digitize and decarbonize their footprint.[104]

The execution of increased volumes of work is a key driver of the workforce requirements across a number of functions and roles within the utility's operations, as summarized below and further detailed in the underlying evidence. The challenge of increasing volumes of work is further compounded by more complex workloads. Priorities such as grid modernization, increased receipt and use of data, pursuit of non-wires solutions to defer or displace the need for traditional infrastructure, intensifying cybersecurity threats, and increased connection and management of DERs all add to the complexity of work completed by Toronto Hydro's devoted staff.

Higher volumes and more complex connection projects necessitate incremental resources in the system planning and work execution functions, as well as back-end support functions such as finance and legal to ensure that project costs are properly accounted, review connection agreements, maintain compliance with regulatory requirements, and resolve customer inquiries in a timely manner.

As traditional energy consumer models evolve to a paradigm where customers are plugging in electrified technologies and are more actively participating in energy management through the use of DERs, Toronto

Hydro's customer-interfacing operations must also follow suit to address emerging needs and requirements, such as: connecting electric vehicles, heat pumps and DERs of varying size and scale; accessing energy data and analytics; and new channels of digital customer information, communication and interaction.[105]

In addition to attracting and retaining the minimum resources necessary to carry out the work and deliver customer outcomes in next rate period and beyond, the OM&A plan addresses other key operational requirements, including:

- integrating cloud computing and non-wires solutions into operations;
- protecting customers' data and the grid against intensifying cybersecurity threats driven by rapid technology advancements and changing geopolitical dynamics;
- complying with new or expanded legal and regulatory requirements, including customer service, safety and environmental obligations;
- maintaining safe, reliable and effective operations across a multitude of key utility functions, including Emergency Response, Supply Chain, Fleet, Facilities and Information Technology ("IT");
- addressing a variety of externally-driven costs, including insurance premiums, bad debt expenses and regulatory costs; and
- keeping up with asset maintenance requirements to ensure the grid remains safe and reliable for customers.

The table below provides a summary of Toronto Hydro's OM&A programs.

Table 9: OM&A Programs

OM&A Programs	Costs ($M)
Preventative and Predictive Overhead Line Maintenance	46.8
Preventative and Predictive Underground Line Maintenance	34.6
Preventative and Predictive Station Maintenance	40.7
Corrective Maintenance	156.8
Emergency Response	136.0
Disaster Preparedness Management Program	10.1
Control Centre Operations	47.3
Customer Operations	68.2
Asset and Program Management	83.2
Work Program Execution	88.6
Fleet and Equipment Services	49.0
Supply Chain Services	122.5

OM&A Programs	Costs ($M)
Facilities Management	145.1
Customer Care	263.2
Human Resources, Environment and Safety	121.6
Finance	138.7
Information Technology	344.6
Public, Legal and Regulatory Affairs	160.2
Charitable Donations and LEAP	8.5
Common Costs and Adjustments	(4.2)
Allocations and Recoveries	(205.2)
Total Operational Plan	**1,856.3**

5.1 Operational Priorities

The utility's operations programs enable critical grid and customer service functions, such as: responding to emergency events and managing planned outages; planning, designing and executing work programs to keep the grid safe and reliable; procuring the necessary materials and services to get work done; and leveraging technology solutions such as non-wires and cloud-based software to displace capital investments.

Responding to emergency events and managing planned outages

The Control Centre Operations program facilitates the safe and reliable operation of the utility's distribution grid through real-time system control and monitoring activities on a 24/7 year-round basis. [106] This program coordinates system switching and restoration work through the utility's control center to mitigate the effects of power outages and enable safe equipment to be de-energized for capital and maintenance work execution.

In the event of an emergency, the utility has a 24/7 Emergency Response program which carries out activities such as dispatching specialized field crews to respond and restore power after severe weather-related events, or other emergencies reported by Toronto EMS or members of the public. [107] This program works together with the Disaster Preparedness Management program to ensure that Toronto Hydro is well-prepared to respond to and recover from larger-scale incidents, such as the recent COVID-19 pandemic, at both the distribution system and corporate levels. Leveraging its pandemic readiness plans and robust incident management framework, Toronto Hydro was able to rapidly adapt its operations when the COVID-19 pandemic suddenly hit, in order to continue to serve customers reliably while protecting the safety of its employees, third-party resources and the public. [108]

Planning, designing and executing capital and maintenance work projects

Toronto Hydro's Asset and Program Management function supports the planning and designing of capital and maintenance work projects. Through this program, Toronto Hydro monitors and analyzes the performance of the distribution system, asset condition and system capacity, and identifies system needs. This analysis forms the basis of Toronto Hydro's capital and maintenance plans, and contributes to individual projects that together enable the utility to achieve its investment objectives.[109]

Toronto Hydro's Finance program oversees the development of the utility's annual and long-term budgets and financial projections. This includes providing regular reports and analysis to maintain compliance with external reporting and audit requirements. By providing these reports, Toronto Hydro is able to track and monitor the execution of its capital plan in accordance with professional standards. The team also collaborates with operational groups to develop, implement and optimize internal controls and processes to maintain the integrity of financial data and improve operational efficiency. These services are essential to Toronto Hydro's ability to comply with legal and regulatory obligations, to produce accurate financial statements, and to successfully deliver the utility's capital work plans. [110]

The oversight, administrative training and other functions performed in the process of executing Toronto Hydro's capital and maintenance work programs are performed by the Work Program Execution program. This program includes administration, planning and execution for the portion of Toronto Hydro's capital and maintenance programs completed by third-party resources. It also includes administrative and support costs for work completed by internal labour – including training costs for employees and apprentices as part of the utility's trade school.[111]

Through its Community Relations functions, Toronto Hydro has comprehensive processes and protocols for communicating information to customers concerning planned capital work, in order to provide a better understanding of the capital program and to help prepare customers for work at or near their property.[112]

Procuring the necessary materials and services to complete work projects

The Supply Chain Services program undertakes procurement and warehousing activities that support the execution of Toronto Hydro's capital and operating programs. This includes facilitating the timely and cost-effective acquisition of services, materials and equipment, maintaining sufficient inventory to ensure uninterrupted work execution, and managing material handling costs. [113]

Procurement activities are supported by the Legal Services function, which provides commercial law advice relating to the purchase of goods and services and other transactions with external vendors.[114] Legal Services assists with review, negotiation and drafting of commercial contracts, including purchase agreements, agreements for professional services, master contractual arrangements for long-term vendors,

and other bespoke agreements as may be required to give effect to the utility's intentions in the applicable commercial transaction.

Leveraging technology solutions to address system needs

Technological advancements offer new digital tools and smart grid solutions to address system needs and deliver cost-effective customer services. Taking advantage of these opportunities requires investment in both capital assets (hard infrastructure like sensors, switches and reclosers, and intangibles like software systems) and in resources (human capital) with new and enhanced skill sets to install and integrate field technology (and analyze the valuable data it provides) into day-to-day operations and system planning functions.

For example, under the Asset and Program Management program, Toronto Hydro staff facilitates the development, integration and implementation of the Grid Modernization Strategy and associated roadmaps. This strategy includes advanced asset analytics that depend on cloud-enabled software solutions and grid readiness activities that leverage technology such as DER management systems to enable non-wires solutions and optimize existing grid capacity. [115]

Non-wires solutions refer to operating practices, activities or technologies that enable the utility to defer the need for specific distribution capital projects (at a lower total cost to ratepayers) by reducing system constraints at times of maximum demand in specific grid areas. Typically, these solutions leverage the use of DERs, often in partnership with utility customers or enabling third-parties. Local Demand Response (established in 2015) is the utility's mature non-wires solutions program to alleviate capacity constraints in high-growth areas of the grid by identifying opportunities where flexible demand response capacity can be procured from customers and third-parties to address system needs cost-effectively.[116]

Further, Toronto Hydro is adopting cloud-based software solutions to address business needs and requirements, such as implementing advanced digital tools needed to enable the utility's Grid Modernization Strategy. These subscription-based services provide access to software applications and other IT systems through an internet connection and shared cloud computing framework. As IT vendors move towards offering more (or exclusively) cloud-based solutions, Toronto Hydro must keep pace with these industry trends.[117]

5.2 Maintenance Priorities

The utility's maintenance programs enable upkeep of distribution and general plant assets by: inspecting and maintaining distribution equipment on routine cycles; remediating asset deficiencies and safety risks; maintaining general plant equipment in good working order; and protecting the grid against intensifying cyber threats.

Inspecting and maintaining distribution equipment on routine cycles

Toronto Hydro's preventative and predictive maintenance programs perform critical work to sustain the integrity of overhead line, underground system, stations and metering infrastructure. This includes inspection and maintenance of equipment for signs of potential failure. These programs are focused on preserving and maximizing the performance of assets over their expected useful life while mitigating a number of key risks. These programs are also designed to minimize overall asset lifecycle costs, maintain safety outcomes for Toronto Hydro work crews and the public, and ensure environmental stewardship and compliance with legal and regulatory obligations.[118]

Remediating asset deficiencies and safety risks

Through its Corrective Maintenance Program, the utility undertakes actions to address deficiencies or substandard conditions across the entire distribution system. This includes signs of potential failure or other risks identified through activities undertaken as part of the Preventative and Predictive Maintenance programs in the course of responding to emergencies. Corrective Maintenance activities are generally higher priority, cover short planning horizons (given the risks that deficiencies and substandard conditions can pose if left unaddressed), and involve repairing and restoring assets to their normal operating conditions through maintenance or refurbishment. Toronto Hydro's primary objective in this program is to uphold safety, environmental integrity and reliability by correcting or repairing deficiencies or substandard conditions on the distribution system.[119]

Maintaining general plant equipment in good working order

Toronto Hydro relies on its fleet,[120] facilities,[121] and IT assets to keep the business running efficiently so the utility can perform its work and deliver customers services safely and reliably.[122] Through its Fleet and Equipment Services Program,[123] Facilities Management Program[124] and IT program,[125] the utility aims to ensure that its vehicle, facilities and IT assets are maintained in good working order. The Fleet and Equipment Services Program ensures that the utility's fleet of 456 vehicles and other work equipment operate safely and reliably at the lowest overall lifecycle cost. The Facilities Management program provides workspace and property management services that enable Toronto Hydro's employees and dedicated third-party resources to perform their work in optimally configured, safe and structurally sound surroundings. For IT hardware and software assets, the IT program maintains the reliability and availability of critical IT systems and infrastructure that the utility relies on to carry out its daily operations.

Protecting the grid against intensifying cyber threats

IT infrastructure and systems must be kept secure to mitigate the risks of cyber-attacks that can disrupt distribution operations, compromise sensitive data, or result in other types of customer interruptions. Cybersecurity controls and software applications are periodically refreshed and enhanced to protect IT systems that support core operations, mitigate emerging digital threats and vulnerabilities, and minimize the

risks of system failure.[126] These investments take the form of asset maintenance, licensing and subscription fees, and resources with the specialized skills needed to support and maintain IT infrastructure security.

5.3 Administrative Priorities

The utility's administrative programs enable the execution of critical grid functions and timely customer service functions, including: connecting customers to the grid in a timely and efficient manner; providing quality customer service and satisfaction; maintaining proactive compliance with legal and regulatory requirements; and ensuring a safe and productive workforce and environmentally responsible operations.

Connecting customers to the grid in a timely and efficient manner

The Customer Operations program ensures that customers are able to obtain timely connections to the grid and provides a consistent and efficient customer experience in that regard. This work includes handling customer requests and communications relating to connection and service upgrade requests, and managing these projects from intake through to completion via a single point of contact to offer customers an effective experience.[127]

The Public, Legal and Regulatory Affairs program facilitates third-party coordination with public infrastructure agencies and partners, and enables capital projects and relocation projects to move forward efficiently. In particular, for customers connections requiring expansion, the Legal Services team drafts, reviews and negotiates connection agreements to maintain compliance with the Distribution System Code and support effective connection processes. The Legal Services function also works closely with the construction, asset management, stations and facilities operational units to address the requirements of the utility and its counterparties related to property access, occupancy, and equipment maintenance and repair. New access and occupancy rights are obtained where necessary, in particular for new infrastructure builds or connections. [128]

Through Asset and Program Management, Toronto Hydro ensures that the grid has sufficient capacity to accommodate customers' growing demand for electricity and the capability to connect to DERs in Toronto Hydro's service area.[129] In addition, the Standards and Policy function develops the utility's design and construction standards, manages the utility's Conditions of Service, and supports the offer to connect process.

Providing quality customer service and satisfaction

Toronto Hydro's customer service programs respond directly to the needs of the utility's large and diverse customer base. The Customer Care program oversees the utility's mobile and digital self-service portal known as the Customer Self Service (CSS) portal, which offers customers 24/7 online access to their account, including the ability to download bills, switch electricity price plans and chat with a customer care

representative.[130] In addition, the program manages a Contact Centre that handles approximately 343,000 telephone calls and 70,000 written (paper mail, fax and email) inquiries per year.[131]

Toronto Hydro's Key Accounts function engages with larger business and institutional customers, such as priority loads (such as hospitals and financial institutions), essential public services and developers. The Key Accounts team manages relationships with these customers and acts as a single point of contact to serve the distinct needs of Key Account customers, including facilitating planning and coordination for major capital and maintenance projects and addressing reliability and power quality issues and concerns.[132]

Toronto Hydro's Media and Public Relations team communicates with customers and other stakeholders through a number of different channels (including the utility's website and social media channels) to ensure that customers receive timely information about programs, services and operations, including power outages.[133]

Maintaining proactive compliance with legal and regulatory requirements

The Public, Legal and Regulatory Affairs program addresses Toronto Hydro's extensive legal and regulatory requirements. The objective of this program is to maintain proactive compliance with these oblications through expert management of the ongoing and evolving external demands and expectations of the legal, regulatory and public policy environment within which Toronto Hydro operates.[134] Similarly, the Finance Program provides robust governance and controls over financial processes to maintain compliance with applicable statutory and regulatory financial reporting requirements.[135]

The Human Resources and Safety Program facilitates Toronto Hydro's compliance with applicable legislative and regulatory requirements such as the Utility Work Protection Code, Electrical Utility Safety Rules, and Occupational Health & Safety Act and Regulations ("OHSA").[136] In addition, the Environmental, Health, & Safety Management System ("EHSMS") mitigates risks and achieves the company's objectives relating to health, safety and environmental performance.[137]

Finally, Toronto Hydro's Customer Care program ensures ongoing functionality and compliance with legislative and regulatory requirements of the meter-to-cash process through a system of robust internal controls and procedures that are reviewed on an annual basis. These safeguards enable the utility to identify any billing errors or irregularities in a timely manner and promptly take corrective actions.[138]

Ensuring a safe and productive workforce and environmentally responsible operations

Toronto Hydro's Human Resources, Environment and Safety ("HRE&S") program provides broad human resource management services to the utility. This includes managing the employee lifecycle through the processes of recruitment, compensation and benefits, onboarding, performance management, training and leadership development, labour relations, and employee communications and engagement. All of these

activities are carried out within a culture of preserving employee wellness, health and safety, and ensuring environmental sustainability.[139]

6. PERFORMANCE ACCOUNTABILITY AND REPORTING

Toronto Hydro holds itself accountable to customers through its performance and transparent reporting of the outcomes that matter most. Over the last decade, the utility improved its performance on a number of key service quality measures, including customer first contact resolution, telephone calls answered on time, new residential and small business services completed on time, and billing accuracy.[140] At the same time, Toronto Hydro achieved the following notable improvements in cost-efficiency:

- the reduction of square footage per employee by 40% through a facilities consolidation strategy that is expected to return more than $200 million to customers by the end of this decade, resulting in an annual credit of approximately $132 on the average residential customer's bill from 2016 to 2029;
- the reduction of its fleet by 163 vehicles (since 2017), resulting in avoided total lifecycle vehicles costs of $26 million (a net 27% reduction);[141]
- increasing the number of customers on eBills by nearly 500% (since 2013), reducing paper that stacks up taller than the CN Tower, and avoiding mailing and postages costs of $4.4 million as of the end of 2022[142]; and
- the delivery of over 30 distinct productivity initiatives which yield material benefits for customers, including over $23 million in costs the utility expects to avoid or reduce by the end of 2024.[143]

The 2025-2029 Investment Plan maintains Toronto Hydro's strong record of performance against 29 service quality measures tracked by the Ontario Energy Board – the independent regulator that sets electricity distribution rates for customers and oversees the utility's performance. The plan also extends accountability to emerging areas of importance for customers through 12 custom metrics that measure results, such as strengthening the utility's defense against physical and cyber-attacks, reducing the company's GHG emissions, providing customer satisfaction in key interactions with the utility, and procuring flexible system capacity to address distribution system needs more cost-effectively and develop DER integration capabilities for the future.

Overall to track its effectiveness in achieving the plan's objectives and continuing to deliver high service quality value to customers, Toronto Hydro intends to measure its results through a performance outcomes framework that reports on 41 distinct measures annually.[144]

In addition to reporting performance on these measures through its public website and regulatory filings, Toronto Hydro intends to link its 2025-2029 Custom Scorecard to an innovative performance incentive

mechanism that holds the utility financially accountable for delivering results across four key areas of focus: (1) System Reliability and Resilience; (2) Customer Service and Experience; (3) Environment, Safety and Governance; and (4) Efficiency and Productivity.

Inspired by similar mechanisms being used in other leading jurisdictions such as New York and the U.K, the PIM provides customers an upfront rate reduction benefit of approximately $65 million that the utility can earn back by achieving set objectives. This proposal is part of Toronto Hydro's ongoing commitment to transparency and accountability for outcomes that provide value to customers and stakeholders now and into the future.[145]

Table 10: 2025-2029 Custom Scorecard Measures

Performance	Measures
System Reliability & Resilience	Outage Duration
	Outage Frequency
	System Security Enhancements
Customer Service & Experience	New Services Connected on Time
	Customer Satisfaction (Post Transactional)
	Customer Escalations Resolution
Environment, Safety and Governance	Total Recordable Injury Frequency (TRIF)
	Emissions Reductions
	ISO Compliance and Certification
Efficiency & Financial Performance	Efficiency Achievements
	Grid Automation Readiness
	System Capacity (Non-Wires)

[1] Exhibit 2B, Section D4
[2] Exhibit 1B, Tab 5, Schedule 1
[3] Exhibit 1B, Tab 3, Schedule 2
[4] Exhibit 1B, Tab 3, Schedule 1
[5] Toronto Metropolitan University, Toronto Second Fastest Growing Metropolitan Area, City of Toronto the Fastest Growing Central City, in the United States/Canada in 2022" (May 23, 2023) <https://www.torontomu.ca/centre-urban-research-land-development/blog/blogentry7311/>
[6] City of Toronto, Toronto at a Glance https://www.toronto.ca/city-government/data-research-maps/toronto-at-a-glance/
[7] City of Toronto, Hospital – Toronto & GTA & long-term care – rehabilitation facilities https://www.toronto.ca/home/311-toronto-at-your-service/find-service-information/article/?kb=kA06g000001cvj8CAA; City of Toronto, Education https://www.toronto.ca/business-economy/industry-sector-support/education/#:~:text=Toronto%20is%20home%20to%20five,universities%20and%20one%20private%20university
[8] City of Toronto, CanopyTO (revised October, 2021) https://www.toronto.ca/legdocs/mmis/2021/ie/bgrd/backgroundfile-173552.pdf
[9] Exhibit 2B, Section D2
[10] City of Toronto, Toronto at a Glance https://www.toronto.ca/city-government/data-research-maps/toronto-at-a-glance/
[11] Exhibit 1B, Tab 3, Schedule 2
[12] Exhibit 2B, Section D4
[13] The Government of Canada passed the *Canadian Net-Zero Emissions Accountability Act*, SC 2021, c. 22 establishing a legally binding requirement for the federal government to establish a GHG emissions reduction plan for achieving net zero emissions in Canada by 2050. The Province of Ontario has established a target of reducing GHG by 30% below 2005 levels by 2030: Government of Ontario, Target to reduce GHG emissions to 30% below 2005 levels by 2030.
[14] City of Toronto, TransformTO 2022 Annual Report (April 19, 2023) https://www.toronto.ca/legdocs/mmis/2023/ie/bgrd/backgroundfile-235849.pdf
[15] City of Toronto, Net Zero Existing Buildings Strategy (March 2021) https://www.toronto.ca/wp-content/uploads/2021/10/907c-Net-Zero-Existing-Buildings-Strategy-2021.pdf
[16] City of Toronto, Electric Vehicle (December 9, 2019) Strategy https://www.toronto.ca/wp-content/uploads/2020/02/8c46-City-of-Toronto-Electric-Vehicle-Strategy.pdf
[17] City of Toronto, Toronto Green Standard https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/toronto-green-standard/
[18] City of Toronto, Home Energy Loan Program https://www.toronto.ca/services-payments/water-environment/environmental-grants-incentives/home-energy-loan-program-help/
[19] City of Toronto, Energy Retrofit Loans https://www.toronto.ca/services-payments/water-environment/environmental-grants-incentives/energy-retrofit-loans/
[20] City of Toronto, The Green Will Initiative https://greenwillto.ca/
[21] City of Toronto, Update on the Net Zero Buildings Strategy and Implementation of Mandatory Emissions Performance Standards (September 6, 2023) https://www.toronto.ca/legdocs/mmis/2023/ie/bgrd/backgroundfile-239097.pdf
[22] Exhibit 2B, Section D4
[23] Exhibit 2B, Section D4
[24] For more information on Toronto Hydro's historic reliability performance see Exhibit 2B, Section C
[25] Exhibit 2B, Section E2
[26] The City of Toronto is home to approximately three million people within a land mass of 631.1km per Statistics Canada, Canada's Large Urban Centres Continue to Grow and Spread (February 9, 2022) https://www150.statcan.gc.ca/n1/daily-quotidien/220209/dq220209b-eng.htm; Statistics Canada, Defining Canada's Downtown Neighbourhoods: 2016 Boundaries (May 11, 2021)
[27] Statistics Canada, Table 98-10-0002-01 Population and dwelling counts: Canada and census subdivisions (municipalities) https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=9810000201

[28] Highrise building categorized as a multi-floor building at least 12 stories or 35m in height. As per data from SkyscraperPage, Global Cities & Buildings Database https://skyscraperpage.com/cities/#notes
[29] Exhibit 1B, Tab 3, Schedule 3
[30] Exhibit 1B, Tab 3, Schedule 3
[31] City of Toronto, Toronto's Population Health Profile (February 2023) https://www.toronto.ca/wp-content/uploads/2023/02/940f-Torontos-Population-Health-Profile-2023.pdf
[32] Exhibit 2B, Section D2
[33] Urbanize Toronto, RLB Crane Index Records 238 Cranes in Toronto During Q1 2023 (April 15, 2023) https://toronto.urbanize.city/post/rlb-crane-index-records-238-cranes-toronto-during-q1-2023#:~:text=According%20to%20the%20latest%20report,%2C%20Chicago%20(14)%2C%20Honolulu
[34] Exhibit 2B, Section D4
[35] Exhibit 2B, E5.2
[36] Exhibit 2B, E5.1
[37] Exhibit 2B, D2
[38] Exhibit 2B, Section E5.1
[39] Exhibit 2B, Section A
[40] Exhibit 2B, Section D8; Exhibit 2B, Section E8.4
[41] Exhibit 4, Tab 2, Schedule, 7
[42] Exhibit 4, Tab 2, Schedule 17
[43] Exhibit 4, Tab 2, Schedules 15, 16 and 18
[44] Exhibit 4, Tab 1, Schedule 1
[45] Exhibit 4, Tab 1, Schedule 1
[46] Exhibit 4, Tab 4, Schedule 1
[47] For more information on Toronto Hydro's planning process see Exhibit 2B, Section E2.
[48] Exhibit 1B, Tab 5, Schedule 1
[49] Exhibit 2B, Section E2
[50] Exhibit 2B, Section D4, Appendix A
[51] Exhibit 1B, Tab 3, Schedule 3
[52] Exhibit 1B, Tab 5, Schedule 1
[53] Exhibit 1B, Tab 5, Schedule 1
[54] Exhibit 8, Tab 1, Schedule 1
[55] Exhibit 2B, Section E2
[56] Exhibit 1B, Tab 3, Schedule 2
[57] Exhibit 4, Tab 4, Schedule 1
[58] Exhibit 2B, Section E6.2
[59] Exhibit 1B, Tab 5, Schedule 1, Appendix A
[60] Exhibit 2B, Section E2
[61] Exhibit 2B, Section E2
[62] Exhibit 2B, Section E2
[63] Exhibit 2B, Section E6.1
[64] Exhibit 2B, Section E6.2
[65] Exhibit 2B, Section E6.3
[66] Exhibit 2B, Section E6.4
[67] Exhibit 2B, Section E6.5
[68] Exhibit 2B, Section E6.6 – includes HONI Switchgear renewal costs of $29M.
[69] Exhibit 2B, Section E6.7
[70] Toronto Hydro's own Future Energy Scenarios forecast a doubling in Toronto's electricity demand by the year 2050 across multiple scenarios (for more information please refer to Exhibit 2B – Section D4, Appendix A). The IESO's Pathways to Decarbonization report forecasts that demand could more than double by 2050 (https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization), while Enbridge's Pathways to Net Zero forecasts an increase in demand of over three times in its electrification scenario (https://www.enbridgegas.com/en/sustainability/pathway-to-net-zero). In the US, utilities such as National Grid (https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-

plan-sept2023.pdf), Eversource (https://www.mass.gov/doc/gmacesmp-drafteversource/download?_gl=1%2Ako8zfs%2A_ga%2ANzUwNDI5MDE3LjE2NTA5ODEyMjQ.%2A_ga_SW2TVH2WBY%2AMTY5MzkyMDE2OS4zNi4xLjE2OTM5MjM1NzQuMC4wLjA.), and Unitil (https://unitil.com/ma-esmp/en) all published modernization plans forecasting demand increases of over 2 times by 2050. ISO New England also completed a study which forecasts a doubling in system peak by 2050 (https://www.iso-ne.com/static-assets/documents/100004/a05_2023_10_19_pspc_2050_study_pac.pdf). National Grid ESO (Great Britain's system operator), also forecasts in an increase of about 2 times across many of it's future energy scenarios (https://www.nationalgrideso.com/document/283101/download).

[71] City of Toronto, Net Zero Existing Buildings Strategy (March 2021) https://www.toronto.ca/wp-content/uploads/2021/10/907c-Net-Zero-Existing-Buildings-Strategy-2021.pdf

[72] Exhibit 2B, Section D4
[73] Exhibit 2B, Section D4
[74] Exhibit 2B, Section E5.1
[75] Exhibit 2B, Section E3
[76] Exhibit 2B, Section D4
[77] Exhibit 1B, Tab 4, Schedule 1
[78] Exhibit 2B, Section E5.1
[79] Exhibit 2B, Section E5.2
[80] Exhibit 2B, Section E5.3
[81] Exhibit 2B, Section E5.5
[82] Exhibit 2B, Section E7.2
[83] Exhibit 2B, Section E7.4
[84] Exhibit 2B, Section D5
[85] Exhibit 2B, Section E8.4, Appendix A
[86] Exhibit 2B, Section D5
[87] Exhibit 2B, Section E7.1
[88] Exhibit 2B, Section D5
[89] Exhibit 2B, Section E7.1
[90] Exhibit 2B, Section E7.3
[91] Exhibit 2B, Section E5.4
[92] Exhibit 2B, Section E6.5
[93] Exhibit 2B, Section E6.6
[94] Exhibit 2B, Section E8.4
[95] Exhibit 1B, Tab 4, Schedule 2
[96] Exhibit 2B, Section E8.2
[97] Exhibit 2B, Section E8.3
[98] Exhibit 2B, Section D7
[99] Exhibit 2B, Section E8.4
[100] Exhibit 2B, Section E8.1
[101] Exhibit 2B, Section E8.2
[102] Exhibit 2B, Section E8.3
[103] Exhibit 2B, Section E8.4
[104] Exhibit 4, Tab 4, Schedule 1
[105] Exhibit 4, Tab 4, Schedule 1; Exhibit 4, Tab 4, Schedule 3
[106] Exhibit 4, Tab 2, Schedule 7
[107] Exhibit 4, Tab 2, Schedule 5
[108] Exhibit 4, Tab 2, Schedule 6
[109] Exhibit 4, Tab 2, Schedule 9
[110] Exhibit 4, Tab 2, Schedule 16
[111] Exhibit 4, Tab 2, Schedule 10
[112] See Communications and Public Affairs Segment – Public Legal and Regulatory Affairs program at Exhibit 4, Tab 2, Schedule 18

[113] Exhibit 4, Tab 2, Schedule 13
[114] Exhibit 4, Tab 2, Schedule 18
[115] Exhibit 4, Tab 2, Schedule 9
[116] Exhibit 4, Tab 2, Schedule 9
[117] Exhibit 4, Tab 2, Schedule 19
[118] Exhibit 4, Tab 2, Schedules 1-3
[119] Exhibit 4, Tab 2, Schedule 4
[120] Exhibit 4, Tab 2, Schedule 11
[121] Exhibit 4, Tab 2, Schedule 12
[122] Exhibit 4, Tab 2, Schedule 17
[123] Exhibit 4, Tab 2, Schedule 11
[124] Exhibit 4, Tab 2, Schedule 12
[125] Exhibit 4, Tab 2, Schedule 17
[126] Exhibit 4, Tab 2, Schedule 17
[127] Exhibit 4, Tab 2, Schedule 8
[128] Exhibit 4, Tab 2, Schedule 18
[129] Exhibit 4, Tab 2, Schedule 9
[130] Exhibit 4, Tab 2, Schedule 14
[131] Exhibit 4, Tab 2, Schedule 14
[132] Exhibit 4, Tab 2, Schedule 8
[133] Exhibit 4, Tab 2, Schedule 18
[134] Exhibit 4, Tab 2, Schedule 18
[135] Exhibit 4, Tab 2, Schedule 16
[136] RSO 1990, c. O.1
[137] Exhibit 4, Tab 2, Schedule 15
[138] Exhibit 4, Tab 2, Schedule 14
[139] Exhibit 4, Tab 2, Schedule 15
[140] Exhibit 1B, Tab 3, Schedule 2
[141] Exhibit 1B, Tab 3, Schedule 3
[142] Exhibit 1B, Tab 3, Schedule 2
[143] Exhibit 1B, Tab 3, Schedule 3
[144] Exhibit 1B, Tab 3, Schedule 1
[145] Exhibit 1B, Tab 3, Schedule 1



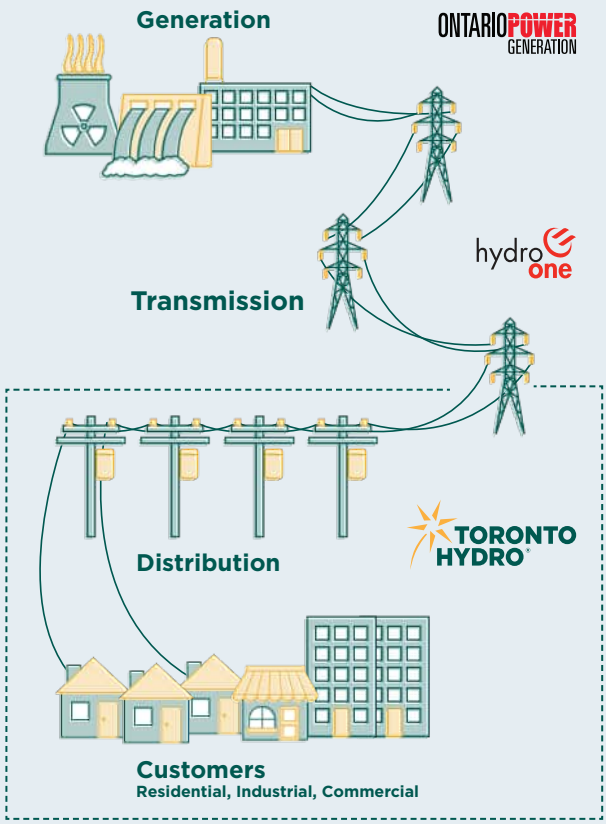
Powering Forward, Together: Our 2025–2029 Investment Plan

As the local electricity distributor for the city of Toronto, Toronto Hydro is responsible for delivering electricity to more than 3 million people across Canada's largest city. We've owned and operated the poles, wires and other equipment that have powered homes and businesses safely and reliably for more than a century. But the way we power our city is evolving.

PREPARING OUR NEXT FIVE-YEAR PLAN

As Toronto continues to grow, digitize and electrify, we've developed a **five-year investment plan for 2025 to 2029** to get the grid ready to serve the city's evolving electricity needs. Our plan will help ensure that our grid and operations will continue to be safe, reliable and environmentally responsible as we power our customers through this decade and beyond.

OUR ROLE IN THE ELECTRICITY SYSTEM



Key facts and figures*

3 million
people across the city

790,000
customers

37
terminal stations

17,060
primary switches

61,300
distribution transformers

139
municipal stations

183,620
poles

13,765km
underground wires

15,393km
overhead wires

* Numbers are approximate.

INVESTMENT NEEDS AND CHALLENGES

Our 2025–2029 investment plan is focused on responding to the needs and challenges of delivering safe, reliable and clean electricity in Toronto, including:



Powering a mature and growing urban city: We serve Canada's largest and North America's second fastest growing city (by population). We also operate in a dense urban environment, which makes it more complicated and more expensive for us to plan and build infrastructure. As Toronto continues to grow, we need to prepare the grid to power new condo towers, residential communities and businesses.

FACT: Toronto has **238 cranes** in operation* — more than any other city in North America.

* As of Q1 2023.



Fixing and replacing equipment in poor condition: A large percentage of our grid was installed in the 1950s and 60s. We need to continue monitoring the condition of our grid and replace equipment most at risk to keep it safe and reliable for customers.

FACT: **40% of power outages** are caused by defective equipment.



Keeping up with how customers use electricity: Customers are increasingly adopting electrified technologies like electric vehicles and heat pumps for their day-to-day energy needs, and using new technologies like solar panels and battery storage to manage their energy usage. We need to upgrade our equipment and modernize our grid to keep up with these changes.

FACT: Did you know that when an EV is charging, it can use as much electricity as **two average homes**?



Responding to extreme weather and cyber security threats: Extreme weather events such as high heat, high winds, flooding and ice storms are becoming more common due to climate change. In addition, cybercrime is on the rise across Canada. We need to invest in making our grid and operations more resilient against these emerging threats.

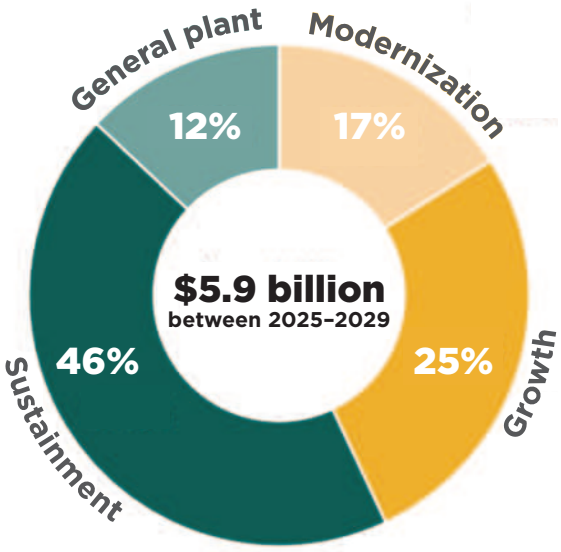
FACT: Between 2018 and 2022, Toronto Hydro experienced **seven major event days**,* impacting a total of **624,000 customers**.

* A major event day is a day when an unforseeable, unpredictable, unpreventable or unavoidable event occurs that disrupts normal business operations, potentially affecting our services for a substantial number of customers.

OUR STRATEGIC PRIORITIES

In order to help ensure the delivery of safe, reliable and clean electricity now and into the future, we need to focus on four strategic priorities:

1. **Modernization:** Develop advanced technological capabilities to make the system and our operations more reliable, resilient and efficient over time.
2. **Growth:** Connect customers on time and get the grid ready to serve the city's growing need for electricity.
3. **Sustainment:** Upkeep and renew aging, deteriorating and outdated equipment to maintain reliability, reduce safety risks and enhance our grid's capacity to serve customers.
4. **General plant:** Keep our business running efficiently with safe and reliable vehicles, work centres and IT equipment, and reduce our emissions.



HOW CUSTOMER FEEDBACK SHAPED OUR PLAN

Customer engagement is an essential part of our investment planning and rate application process. Before we prepared our plan, we asked our customers for feedback about their needs and priorities for electricity services.

Customer engagement process



1. Identify customer needs, preferences and priorities.



2. Use customer feedback to guide development of draft plan.



3. Collect customer feedback on draft plan.



4. Use customer feedback to finalize plan.



5. Submit plan to the Ontario Energy Board (OEB).

Customer feedback

The feedback from customers centred around three core areas:

- **Price and reliability**
- **New technology to reduce costs and improve the system**
- **System capacity to serve high-growth areas**

Our draft plan was developed with these needs and priorities in mind and put back to customers through an interactive online survey.

Rate class	Survey participation	Support for our draft plan*
Residential	32,187	80%
Small business	695	77%
Commerical and industrial	264	82%
Key accounts	52	96%
Total	33,198	84%

*Includes customers who supported a plan that does even more to improve services.

RATE IMPACTS

To fund our proposed investment plan, we're seeking approval from the Ontario Energy Board (OEB) for 2025–2029 distribution rates and charges (Toronto Hydro's portion of the bill). The OEB and various consumer groups will review and test our plan in a rigorous, transparent public process known as a rate application.

Under our proposed plan, the average distribution charges for a **typical residential customer** (who uses 750 kWh per month) would increase by **$3.44 per month**, annually from 2025 to 2029.

Proposed bill impacts

Rate class	Typical usage	Monthly bill impacts	2025	2026	2027	2028	2029	Average annual change (per month)
Residential	750 kWh	Distribution charges	$45.93	$49.33	$53.05	$57.02	$59.88	**$3.44**
		$ change	$3.24	$3.40	$3.72	$3.97	$2.86	
Residential suite-metered service*	300 kWh	Distribution charges	$34.22	$36.06	$38.24	$40.51	$42.15	**$1.33**
		$ change	-$1.27	$1.84	$2.18	$2.27	$1.64	
Small business (General service < 50 kW)	2,000 kWh	Distribution charges	$132.67	$141.91	$151.52	$162.19	$169.48	**$10.20**
		$ change	$14.18	$9.24	$9.61	$10.67	$7.29	

* Refers to customers in the Competitive Sector Multi-Unit Residential Service rate class.

ACCOUNTABILITY TO CUSTOMERS

Our 2025–2029 investment plan is focused on delivering results that matter to customers and stakeholders. To help ensure we achieve these outcomes, we'll be holding ourselves financially accountable through a performance management framework that tracks and reports our performance on 12 distinct measures across four areas:

System reliability and resilience
- Outage duration
- Outage frequency
- System security enhancements

Customer service and experience
- New services connected on time
- Customer satisfaction
- Customer escalations resolution

Efficiency and financial performance
- Efficiency achievements
- Grid automation readiness
- System capacity (non-wires)

Environment and safety
- Total Recordable Injury Frequency (TRIF)
- Emissions reductions
- ISO compliance and certification

OUR PRODUCTIVITY AND PERFORMANCE

Toronto Hydro strives to provide value for money for customers through continuous improvements in productivity and performance.

We've generated **$2.2 billion** in savings for our customers since the company was formed in 1999, through activities such as improved asset management, efficient material handling and workforce optimization.

We resolve **92%** of customer issues on first contact.

We connect new residential and small business customers to the grid on time more than **99%** of the time.

We completed a facilities consolidation strategy that reduced our square footage per employee by approximately 40% and is expected to return more than **$200 million** to customers by the end of this decade.

APPLICATION SUMMARY

This schedule provides a summary of Toronto Hydro's 2025-2029 Custom Rate Application, in accordance with section 2.1.2 of the Filing Requirements.[1]

1. BILL IMPACTS

Table 1 below provides a summary of the proposed change in the monthly total bill impacts for typical customers in all rate classes.[2] Total bill impacts for all classes are below the 10 percent threshold, therefore mitigation measures are not required.

Table 1: 2025-2029 Total Bill Impacts – Proposed Change in Monthly Bill

	Change	2025	2026	2027	2028	2029
Residential	$/30 days	$0.91	$3.44	$3.77	$3.61	$2.90
	%	0.7%	2.5%	2.6%	2.4%	1.9%
Competitive Sector Multi-Unit Residential	$/30 days	-$2.10	$1.86	$2.21	$1.88	$1.66
	%	-2.8%	2.6%	3.0%	2.5%	2.1%
General Service <50 kW	$/30 days	$7.34	$9.36	$9.73	$10.39	$7.38
	%	2.0%	2.5%	2.5%	2.6%	1.8%
General Service 50-999 kW	$/30 days	-$73.44	$188.05	$197.76	$217.72	$170.01
	%	-0.5%	1.3%	1.4%	1.5%	1.2%
General Service 1,000-4,999 kW	$/30 days	-$1,565.72	$1,657.27	$1,713.81	$1,807.60	$1,560.87
	%	-1.0%	1.1%	1.1%	1.2%	1.0%
Large Use	$/30 days	-$7,459.85	$6,638.41	$9,677.61	$10,769.78	$8,543.60
	%	-1.1%	1.0%	1.4%	1.6%	1.2%
Street Lighting	$/30 days	$13,867.36	$13,873.12	$23,380.94	$13,713.23	$17,205.38
	%	4.4%	4.2%	6.8%	3.7%	4.5%
Unmetered Scattered Load	$/30 days	$1.88	$2.44	$2.52	$3.15	$2.04
	%	3.0%	3.7%	3.7%	4.5%	2.8%

[1] OEB Filing Requirements for Electricity Distribution Rate Applications, Chapter 2 (December 15, 2022).
[2] Includes all rate riders and holding commodity rates and regulatory charges constant.

Table 2 below provides the proposed monthly distribution bill impacts per sub-total A of Tariff Schedule and Bill Impacts spreadsheet model for: (i) a typical residential customer using 750 kWh per month and for (ii) a General Service < 50kW customer using 2,000 kWh per month on time-of-use pricing, as well as other customers in all rate classes.

Table 2: Proposed Distribution Bill Impacts (Per Sub-Total A of Tariff Schedule)

	Change in Bill	2025 Proposed	2026 Proposed	2027 Proposed	2028 Proposed	2029 Proposed
Residential	$/30 days	$3.24	$3.40	$3.72	$3.97	$2.86
	%	7.6%	7.4%	7.5%	7.5%	5.0%
Competitive Sector Multi-Unit Residential	$/30 days	-$1.27	$1.84	$2.18	$2.27	$1.64
	%	-3.6%	5.4%	6.0%	5.9%	4.0%
General Service <50 kW	$/30 days	$14.18	$9.24	$9.61	$10.67	$7.29
	%	12.0%	7.0%	6.8%	7.0%	4.5%
General Service 50-999 kW	$/30 days	$235.35	$166.42	$175.01	$192.67	$150.45
	%	13.0%	8.1%	7.9%	8.1%	5.8%
General Service 1,000-4,999 kW	$/30 days	$1,993.46	$1,466.61	$1,516.65	$1,599.65	$1,381.30
	%	13.4%	8.7%	8.3%	8.0%	6.4%
Large Use	$/30 days	$10,124.44	$5,874.70	$8,564.26	$9,530.78	$7,560.71
	%	13.1%	6.7%	9.2%	9.4%	6.8%
Street Lighting	$/30 days	$15,917.30	$12,277.10	$20,691.10	$12,135.60	$15,226.00
	%	11.0%	7.6%	11.9%	6.3%	7.4%
Unmetered Scattered Load	$/30 days	$2.96	$2.41	$2.49	$3.11	$2.01
	%	9.5%	7.1%	6.8%	8.0%	4.8%

2. REVENUE REQUIREMENT

Table 3 below summarizes Toronto Hydro's 2025 forecasted revenue requirement.

Table 3: 2025 Forecast Revenue Requirement ($ Millions)

Revenue Requirement Component	2025 Test Year (April 2, 2024)
OM&A Expenses (incl. property taxes)	343.0
Amortization/Depreciation	290.4
Income Taxes (grossed up)	28.9
Deemed Interest Expense	142.9
Return on Deemed Equity	220.9
Service Revenue Requirement	**1,026.0**
Revenue Offsets	(48.2)
Base Revenue Requirement	**977.8**

/C

Table 4 below summarizes the service revenue requirement variances between the last OEB-approved year (2020) and the proposed 2025 test year. For more information about Toronto Hydro's revenue requirement, please see Exhibit 6, Tab 1.

Table 4: 2020 versus 2025 Service Revenue Requirement ($ Millions)

	2020 Approved	2025 Forecast	Variance ($)	Variance (%)
OM&A	266.7	343.0	76.3	28.6%
Depreciation	263.7	290.4	26.7	10.1%
Deemed Interest Expense	98.5	142.9	44.4	45.1%
Return on Equity	153.9	220.9	67.0	43.5%
PILs	9.7	28.9	19.2	197.9%
Total Service Revenue Requirement	**792.5**	**1,026.0**	**233.6**	**29.5%**

/C

The main drivers for the proposed increase in the 2025 service revenue requirement are:

(i) additions to rate base from capital investments undertaken in the current 2020-2024 rate period (driving increases in depreciation, deemed interest expense, and return on equity) as summarized in Exhibit 2A, Tab 2, Schedule 1 and detailed in the Distribution System Plan at Exhibit 2B, and

(ii) an increase in OM&A expenses as summarized in Exhibit 4, Tab 1, Schedule 1 and detailed in the programmatic evidence at Exhibit 4, Tab 2.

Tables 5 and 6 below summarize the 2020-2024 and the 2025-2029 revenue requirement.

Table 5: 2020-2024 Revenue Requirement ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2020-2024 Total
OM&A Expenses (incl. property taxes)	292.0	285.2	287.0	301.2	320.5	**1,485.9**
Amortization/Depreciation	261.0	274.7	287.0	259.9	276.6	**1,359.1**
Income Taxes (grossed up)	(3.0)	(3.1)	9.2	13.0	10.8	**26.9**
Deemed Interest Expense	99.0	102.1	107.2	113.1	121.4	**542.7**
Return on Deemed Equity	107.1	132.4	146.0	140.8	189.4	**715.7**
Service Revenue Requirement	**756.1**	**791.2**	**836.5**	**828.0**	**918.6**	**4,130.3**
Revenue Offsets	(43.1)	(47.8)	(54.1)	12.3	(46.9)	**(179.6)**
Base Revenue Requirement	**712.9**	**743.5**	**782.3**	**840.3**	**871.7**	**3,950.7**

/C

Table 6: 2025-2029 Revenue Requirement ($ Millions)

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2025-2029 Total
OM&A Expenses (incl. property taxes)	343.0	358.0	370.1	385.5	399.6	**1,856.2**
Amortization/Depreciation	290.4	303.9	322.7	344.0	356.9	**1,618.0**
Income Taxes (grossed up)	28.9	31.1	20.7	56.5	48.3	**185.4**

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2025-2029 Total
Deemed Interest Expense	142.9	152.1	162.4	173.5	183.9	**814.7**
Return on Deemed Equity	220.9	235.1	251.0	268.1	284.2	**1,259.2**
Service Revenue Requirement	**1,026.0**	**1,080.2**	**1,126.9**	**1,227.6**	**1,272.8**	**5,733.5**
Revenue Offsets	(48.2)	(49.2)	(50.2)	(51.2)	(52.2)	**(251.0)**
Base Revenue Requirement	**977.8**	**1,031.0**	**1,076.7**	**1,176.4**	**1,220.6**	**5,482.5**

/C

As described in Exhibit 1B, Tab 2, Schedule 1, section 3.2.1, Toronto Hydro's rate framework proposes a proactive 0.6 percent performance incentive factor that further reduces revenues by over $65 million over the rate term, providing customers an additional upfront rate reduction.

3. LOAD FORECAST SUMMARY

Table 7 below summarizes Toronto Hydro's customer and load growth changes from 2018 to 2029. Please see Exhibit 3, Tab 1 for more information about the utility's customer and load forecast.

Table 7: Customer and Load Growth Changes for 2018-2029

Year		Total Normalized GWh	Total Normalized GWh (% Change)	Total Normalized MVA	Total Normalized MVA (% Change)	Total Customers	Customer Count Change (%)
2018	Actual	24,691.6		39,813.3		770,333	
2019	Actual	24,421.7	-1.1%	39,115.3	-1.8%	777,369	0.9%
2020	Actual	23,664.4	-3.1%	36,801.2	-5.9%	781,374	0.5%
2021	Actual	23,564.8	-0.4%	36,624.9	-0.5%	786,258	0.6%
2022	Actual	23,981.0	1.8%	37,635.2	2.8%	790,699	0.6%
2023	Actual	23,908.0	-0.3%	37,425.9	-0.6%	793,465	0.3%
2024	Bridge	23,603.5	-1.3%	36,735.8	-1.8%	796,787	0.4%
2025	Forecast	23,412.8	-0.8%	36,167.8	-1.5%	800,430	0.5%

/C

Year		Total Normalized GWh	Total Normalized GWh (% Change)	Total Normalized MVA	Total Normalized MVA (% Change)	Total Customers	Customer Count Change (%)
2026	Forecast	23,433.6	0.1%	35,949.7	-0.6%	803,655	0.4%
2027	Forecast	23,431.4	0.0%	35,648.1	-0.8%	806,407	0.3%
2028	Forecast	23,525.0	0.4%	35,489.2	-0.4%	808,736	0.3%
2029	Forecast	23,393.8	-0.6%	34,964.1	-1.5%	811,363	0.3%

Notes:
1. Total Normalized GWh are purchased GWh (before losses) and are weather normalized to the Test Year heating and cooling degree day assumptions.
2. Total Normalized MVA are weather normalized MVA.
3. Total Distribution Revenue is weather normalized and includes an adjustment for the Transformer Allowance.
4. Total Customers are an annual average and exclude street lighting devices and unmetered load connections.

/C

4. RATE BASE AND DISTRIBUTION SYSTEM PLAN

4.1 Distribution System Plan

Toronto Hydro forecasts $2,841.1 million in net capital expenditures over the current 2020-2024 period, which is approximately five percent higher than the $2,710.7 million 2020-2024 Distribution System Plan approved by the OEB fur the purposes of setting rates in the last application. In the 2025-2029 Distribution System Plan (the "DSP"), the utility forecasts net capital expenditures of $3,928.7 million, which is $1,087.5 million or 38 percent higher than the 2020-2024 Distribution System Plan that the utility expects to deliver. Table 8 below summarizes the capital expenditures by investment category for the 2025-2029 rate period. Investments in System Access and System Service to expand and modernize the utility's grid are the biggest drivers of the 2025-2029 DSP (on a percentage basis). For more information about the utility's capital expenditures over the current and the future rate period please refer to Exhibit 2B, Section E4.

/C

/C

Table 8: Capital Investment Expenditures by Categories ($ Millions)

Category	Total 2020-2024 Forecast	Total 2025-2029 Forecast	Var. ($)	Var. (%)
System Access	653.6	1,052.5	398.9	61%
System Renewal	1,456.6	1,970.3	513.7	35%
System Service	226.0	301.7	75.8	34%
General Plant	419.0	562.5	143.4	34%
Other	85.9	41.7	(44.2)	(51%)
Total	**2,841.1**	**3,928.7**	**1,087.5**	**38%**

4.2 Rate Base

Table 9 below summarizes Toronto Hydro's 2020 approved and 2020 actual rate base, and presents the utility's forecasted rate base for the current 2020-2024 period. Table 10 presents the rate base for the 2025 to 2029 period.

The requested rate base for the 2025 test year is $5,899.1 million, representing an increase of approximately $1,384.3 million, or 30.7 percent from the 2020 rate base of $4,514.8 million approved by the OEB in the utility's last rebasing application.

Rate base variances are primarily driven by changes in Property Plant & Equipment ("PP&E") and Net Book Value ("NBV") due to in-service additions derived from the utility's actual and forecasted capital investments per the DSP. These changes are discussed in Exhibit 2A, Tab 1, Schedule 1. Other major drivers of rate variances, namely depreciation and working capital allowance ("WCA"), are discussed in Exhibit 2A, Tab 2, Schedule 1, and Exhibit 2A, Tab 3, Schedule 1, respectively.

Table 9: 2020-2024 Rate Base Summary ($ Millions)

	OEB Approved	Actuals				Bridge
	2020	**2020**	**2021**	**2022**	**2023**	**2024**
Opening PP&E NBV	4,229.4	4,233.2	4,419.2	4,628.1	4,893.9	5,227.4
In-Service Additions	527.4	447.9	485.2	554.4	594.7	619.8
Depreciation	(265.4)	(262.0)	(276.2)	(288.7)	(261.2)	(277.8)
Closing PP&E NBV	4,491.3	4,419.2	4,628.1	4,893.9	5,227.4	5,569.4
Monthly Avg PP&E NBV	**4,298.6**	**4,284.3**	**4,457.7**	**4,686.3**	**4,960.0**	**5,327.0**
Working Capital Allowance	216.2	249.8	217.2	220.7	216.8	230.0
Rate Base	**4,514.8**	**4,534.1**	**4,674.9**	**4,907.0**	**5,176.8**	**5,557.0**

/C

Table 10: 2025-2029 Rate Base Summary ($ Millions)

	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
Opening PP&E NBV	5,569.4	5,931.4	6,325.7	6,796.1	7,219.9
In-Service Additions	653.8	699.9	795.1	770.1	860.1
Depreciation	(291.8)	(305.7)	(324.8)	(346.2)	(359.5)
Closing PP&E NBV	5,931.4	6,325.7	6,796.1	7,219.9	7,720.4
Monthly Avg PP&E NBV	**5,667.5**	**6,042.1**	**6,460.6**	**6,912.2**	**7,334.3**
Working Capital Allowance	231.6	237.2	242.6	249.8	255.7
Rate Base	**5,899.1**	**6,279.3**	**6,703.2**	**7,162.0**	**7,590.1**

5. OPERATIONS, MAINTENANCE AND ADMINISTRATION ("OM&A") EXPENSE

Toronto Hydro forecasted OM&A expenses for the future 2025-2029 rate period are $1,856 million, representing an increase of $395.6 million or 27 percent from the actual and forecasted OM&A expensed of $1,461 million in the current 2020-2024 rate period. /C

Table 11 below provides a summary of the overall drivers and cost trends for operating expenditures over the current and future rate period. For more information please refer to Exhibit 4, Tab 1 and the supporting evidence at Tabs 2 through 5 of this Exhibit.

Table 11: OM&A 2020-2029 Cost Drivers ($ Millions)

Programs	Actual				Bridge	Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance	266.7[3]	288.1	277.5	280.4	294.2	320.5	343.0	358.0	370.2	385.5
Distribution Operations	4.1	(1.4)	1.8	(0.2)	13.2	15.4	7.4	6.0	6.6	7.0
Customer Care	17.2	(16.4)	-	4.1	5.0	0.2	3.0	0.9	1.9	1.7
Human Resources, Environment and Safety	-	2.1	(0.9)	1.4	3.2	1.3	0.6	1.0	1.1	1.0
Information Technology	-	2.6	2.9	2.4	1.7	5.7	2.5	2.9	3.0	3.4
Common Corporate Costs	-	(0.1)	(0.7)	1.3	(1.2)	-	-	0.1	-	-
Facilities Management	-	1.7	(1.0)	1.4	1.5	-	0.5	0.5	0.7	0.7
Other Various	0.1	0.9	0.8	3.4	2.9	(0.1)	1.0	0.8	2.0	0.3
Closing Balance	**288.1**	**277.5**	**280.4**	**294.2**	**320.5**	**343.0**	**358.0**	**370.2**	**385.5**	**399.6**

/C

Note: Toronto Hydro confirms that no costs for dedicated conservation and demand management ("CDM") staff to support IESO programs funded under the 2021-2024 CDM Framework are included in the revenue requirement.

[3] In EB-2018-0165, the OEB approved a 2020 OM&A budget of $272.2 million and directed Toronto Hydro to amend the presentation of shared services within Other Revenue, under USoA Accounts 4375 and 4380 for revenues and expenses of non-rate regulated utility operations. Normalized for this change, the 2020 OEB-approved OM&A budget was $266.7 million.

Toronto Hydro proposes a 2025-2029 LEAP funding allocation of 0.15 percent of its service revenue requirement, resulting in a total LEAP amount of $8.6 million. Please refer to Exhibit 4, Tab 2, Schedule 19 for more information. /C

6. COST OF CAPITAL

Table 12 below outlines the proposed capital structure and cost of capital parameters in accordance with the OEB's cost of capital parameters. The 2025 return on equity forecast, which was derived in accordance with the OEB's Cost of Capital Report (EB-2009-0084) methodology, was applied to determine the 2025-2029 revenue requirement presented in Exhibit 6, Tab 1. Toronto Hydro intends to update the return on equity forecast during the Draft Rate Order ("DRO") process to align with the return on equity approved by the OEB in the final quarter of 2024. For more information please refer to Exhibit 5, Tab 1. /C

Table 12: Proposed Capital Structure and Cost of Capital Parameters /C

Capital Structure			Cost Rate
Debt			
Long-term Debt	56.00%	$3,304,672,000	3.95%
Short-term Debt	4.00%	$236,048,000	5.25%
Total Debt	60.0%	$3,540,720,000	4.04%
Equity			
Common Equity	40.00%	$2,360,480,000	9.36%
Preferred Shares	0.00%	$ -	
Total Equity	40.0%	$2,360,480,000	9.36%
Total / WACC		$5,901,200,000	6.17%

7. COST ALLOCATION AND RATE DESIGN

7.1 Cost Allocation

Toronto Hydro's revenue requirement, as detailed in Exhibit 6, is allocated to rate classes in order to calculate distribution rates for the 2025 rebasing year. This is performed using the OEB's latest cost allocation model, including the OEB's policy related to the Street Lighting class[4] and subject to the adjustments noted in the Cost Allocation evidence.[5]

Consistent with the methodology relied upon in the utility's last two custom rate application (EB-2014-0116 and EB-2018-0165), Toronto Hydro completed a cost allocation study for 2025 test year, and extended the results to allocate the 2026 to 2029 revenue requirement to rate classes.

Table 13 below shows the revenue to cost ratios calculated prior to and after the proposed test year rate design in comparison with the OEB's "target ranges" (all ratios exclude revenues and costs related to transformer ownership allowance). The proposed revenue to cost ratios for all Toronto Hydro rate classes are within the OEB's guideline ranges. For more information about cost allocation, please refer to Exhibit 7, Tab 1.

Table 13: Revenue/Cost Ratios (%)

Rate Class	2020 OEB Approved	2025		OEB's Guideline Ranges
		Model	Proposed	
Residential	100.0%	102.1%	100.0%	85-115
Competitive Sector Multi-Unit Residential	100.0%	111.7%	100.0%	n/a
General Service <50kW	93.7%	97.4%	99.2%	80-120

[4] Ontario Energy Board, Issuance of New Cost Allocation Policy for Street Lighting Rate Class (June 12, 2015), "online", https://www.oeb.ca/oeb/_Documents/EB-2012-0383/LTR_CostAllocation_Streetlighting_20150612.pdf
[5] Exhibit 7, Tab 1, Schedule 1.

Rate Class	2020 OEB Approved	2025		OEB's Guideline Ranges
		Model	Proposed	
General Service 50-999kW	105.6%	96.4%	98.9%	80-120
General Service 1000-4999kW	94.8%	94.4%	98.3%	80-120
Large Use	93.6%	97.2%	99.2%	85-115
Street Lighting	111.3%	119.4%	119.4%	80-120
Unmetered Scattered Load	120.0%	121.7%	120.0%	80-120

7.2 Rate Design

In this application, Toronto Hydro requests approval of new base distribution rates and new rate riders effective January 1, 2025. Toronto Hydro calculated the rebased distribution rates for 2025 using the OEB's standard revenue requirement methodology as set out in the Filing Requirements.[6]

For the 2026-2029 rate period, Toronto Hydro calculated distribution rates using a Custom Revenue Cap Index ("CRCI").[7] For each of these years, base revenue requirements will be brought forward for final approval in Toronto Hydro's annual rate update applications, inclusive of actual inflation factors applicable to those years. In each annual rate update application, Toronto Hydro will propose new distribution rates based on the escalated base revenue requirement resulting from application of the CRCI, in accordance with the OEB's Decision in this proceeding.

Toronto Hydro proposes that for the years 2026 to 2029, the final approved base revenue requirements be allocated to each rate class based on the same allocations to rate classes established in this proceeding for 2025. Toronto Hydro will hold constant the fixed/variable revenue split for each rate class determined in 2025 for the purpose of designing rates from

[6] OEB Filing Requirements for Electricity Distribution Rate Applications, Chapter 2 (December 15, 2022), section 2.8.
[7] See Exhibit 1B, Tab 2, Schedule 1 for more information on the CRCI.

2026 to 2029. Subsequently, the utility will calculate rates in each year relying on Toronto Hydro's five-year customer and load forecast as approved in this application.

Please see Exhibit 1B, Tab 4, Schedule 1 for more information about the proposed CRCI, and Exhibit 8, Tab 1 fore more information about rate design.

7.3 Specific Service Charges

For this application, Toronto Hydro proposes to leave its specific service charges unchanged, with the exception of the wireline pole attachment charge, which Toronto Hydro will update at the draft rate order stage and annually in accordance with the latest OEB rate orders. Please refer to Exhibit 8, Tab 2, Schedule 1 for more information about specific service charges.

8. DEFERRAL AND VARIANCE ACCOUNTS ("DVA")

The total net DVA balance proposed for clearance is $113.3 million (credit/refund) to customers beginning January 1, 2025. Tables 14 and 15 provide a summary of Group 1 and Group 2 DVA balances, respectively. With the exception of the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA"),[8] the amounts proposed for clearance include the balances as reflected in the audited financial statements for the fiscal year ended December 31, 2023. The amounts also include the forecasted principal activity and carrying costs calculated to December 2024. /C

[8] Toronto Hydro notes that the balances in the LRAMVA were not reported in RRR or AFS filings because, as the OEB Decision noted in EB-2022-0065, the utility did not have sufficient information at the time those filings to estimate the balances in the account.

Table 14: Deferral and Variance Account Summary ($ Millions)

Accounts		Principal Balance as of Dec 31, 2023	Carrying Charge Balance as of Dec 31, 2023	Balances as of Dec 31, 2023	Proposed for Disposition (Yes/No)	To Be Continued (Yes/No)
Group 1 Accounts						
Various	**Retail Settlement Variance Account ("RSVA")[9]**	**163.0**	**10.8**	**173.8**	**Yes**	**Yes**
1550	Low Voltage Variance Account	0.8	0.1	0.9	Yes	Yes
1580	Wholesale Market Service Charge	28.0	3.3	31.3	Yes	Yes
1580	WMS – Sub-account CBR Class A	-	-	-	Yes	Yes
1580	WMS – Sub-account CBR Class B	0.8	(0.2)	0.6	Yes	Yes
1584	Retail Transmission Network Charge	56.0	3.4	59.4	Yes	Yes
1586	Retail Transmission Connection Charge	38.0	1.7	39.7	Yes	Yes
1588	Power (excluding Global Adjustment)	35.3	1.8	37.0	Yes	Yes
1589	Global Adjustment	7.6	0.9	8.5	Yes	Yes
1551	Smart Meter Entity Charge	(3.6)	(0.1)	(3.7)	Yes	Yes
1595	**Disposition and Recovery/Refund of Regulatory Balances ("RARA")**	**(37.0)**	**(14.2)**	**(51.1)**	**No**	**Yes**
	Total Balance	**126.0**	**(3.4)**	**122.6**		

/C

[9] Includes Account 1588 – Power ($RSVA_{Power}$) and Account 1589 Global Adjustment ($RSVA_{GA}$)

Accounts		Principal Balance as of Dec 31, 2023	Carrying Charge Balance as of Dec 31, 2023	Balances as of Dec 31, 2023	Forecasted Principal Balance as of Dec 31, 2024	Forecasted Carrying Charge Balance as of Dec 31 2024	Balances as of Dec 31, 2024	Proposed for Disposition (Yes/No)	To Be Continued (Yes/No)
Group 2 Accounts									
1508	Capital-Related Revenue Requirement ("CRRRVA")[10]	-	-	-	-	-	-	No	No
1508	Customer Choice Initiative Costs	0.3	-	0.3	0.6	-	0.6	Yes	No
1508	Excess Expansion Deposits	(7.8)	(0.5)	(8.3)	(7.8)	(1.1)	(8.7)	Yes	Yes
1508	Externally Driven Capital Variance Account ("EDCVA")	5.2	(0.1)	5.1	8.3	0.3	8.6	Yes	No[11]
1508	Gain on Sale of Properties[12]	(1.1)	(0.0)	(1.2)	(1.9)	(0.2)	(2.1)	Yes	Yes
1508	Impact for USGAAP Deferral Account	(9.7)	-	(9.7)	(9.7)	-	(9.7)	No	Yes
1522	Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	-	-	-	-	-	-	No	Yes
1592	PILs and Tax Variances – CCA Changes[13]	(1.6)	(0.1)	(1.7)	(1.6)	(0.2)	(1.8)	Yes	Yes
1508	THESL Wireless Attachment Costs & Revenues	(2.4)	(0.2)	(2.6)	(3.3)	(0.3)	(3.6)	Yes	Yes[14]
1508	Wireline Pole Attachment Revenue Variance	2.7	0.1	2.8	4.0	0.3	4.3	Yes	No

/C

[10] Balance relates to 2015-2019 activity which was approved for clearance in 2020 CIR.
[11] Toronto Hydro proposes to track the types of variances that are currently captured in the EDCVA in the new the Demand Related Variance Account ("DRVA"). Please refer to section 9.2 for further details.
[12] As noted in 3-SEC-85(b), the amount was corrected from pre-filed evidence (November 17, 2023) and now includes proceeds from the sale of utility vehicles.
[13] Balance relates to 2015-2019 activity which was approved for clearance in 2020 CIR.
[14] Toronto Hydro requests this account to be converted from a deferral account to a variance account, which would track variances from the utility's forecast of relevant revenues and costs that is incorporated in Other Revenue. This modified approach passes through the benefit of the associated revenues to ratepayers up front, rather than deferring disposition to the next rebasing. See 3-VECC-55 for a breakdown of forecasted wireless attachment revenues in 2025-2029

Accounts		Principal Balance as of Dec 31, 2023	Carrying Charge Balance as of Dec 31, 2023	Balances as of Dec 31, 2023	Forecasted Principal Balance as of Dec 31, 2024	Forecasted Carrying Charge Balance as of Dec 31 2024	Balances as of Dec 31, 2024	Proposed for Disposition (Yes/No)	To Be Continued (Yes/No)
1533	Renewable Generation Connection Funding Adder Deferral Account – Provincial Rate Protection Payment Variances	(4.7)	-	(4.7)	(7.3)	-	(7.3)	Yes	Yes
1508	Local Initiatives Program Costs	-	-	-	-	-	-	No	Yes
1568	Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA")	-	-	-	-	-	-	Yes	Yes
1508	Operating Centres Consolidation Program ("OCCP")[15]	1.8	0.2	2.0	1.8	0.3	2.1	Yes	Yes
1508	Gains on Sale of Properties related to the Operating Centres Consolidation Program ("OCCP")[16]	(23.8)	(0.9)	(24.7)	(23.8)	(2.2)	(26.0)	Yes	Yes
1508	Useful Life Changes	(61.3)	(1.4)	(62.7)	(129.2)	(6.4)	(135.6)	Yes	No
1508	Ultra-Low Overnight ("ULO") Implementation Costs	(0.6)	-	(0.6)	0.1	-	0.1	Yes	No
1508	Green Button Initiative Costs	-	-	-	(0.4)	-	(0.4)	Yes	No
1508	50/60 Eglinton Proceeds of Sale Deferral Account [16, 17]	(7.3)	(0.3)	(7.6)	(7.3)	(0.7)	(8.0)	Yes	Yes
1508	Carillion Insolvency Payments Receivable Account	0.3	-	0.3	0.3	-	0.3	No	Yes

/C

[15] This entry relates to a residual balance in relation to the Operating Centres Consolidation Program of $2.0 million (debit) in the updated Group 2 account continuity schedule and that is comprised of a $1.7 million overpayment to ratepayers and $0.3 million in related carrying charges. Please refer to interrogatory response 9-Staff-336 for more information supporting the amounts recorded in this account.

[16] The proposed claim amount per the continuity schedule has been grossed-up to include the tax savings proposed to be returned to ratepayers

[17] Toronto Hydro seeks approval to create of this deferral account to capture and dispose additional proceeds received from the sale of 50/60 Eglinton. Please refer to Exhibit 9, Tab 1, Schedule 1 at section 9.4 for more information.

Accounts		Principal Balance as of Dec 31, 2023	Carrying Charge Balance as of Dec 31, 2023	Balances as of Dec 31, 2023	Forecasted Principal Balance as of Dec 31, 2024	Forecasted Carrying Charge Balance as of Dec 31 2024	Balances as of Dec 31, 2024	Proposed for Disposition (Yes/No)	To Be Continued (Yes/No)
1508	Getting Ontario Connected Act Variance Account[18]	0.9	-	0.9	2.5	0.1	2.6	Yes	Yes
1511	Cloud Computing Incremental Implementation Costs[19]	0.5	-	0.5	4.0	0.1	4.1	Yes	No[20]
	Total Balance	**(108.8)**	**(3.0)**	**(111.8)**	**(170.8)**	**(9.7)**	**(180.5)**		

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/C

[18] Please see interrogatory response 4-Staff-296(e) for supporting details for the amounts booked in this account.
[19] This account was added as part of the April 2, 2024 evidence update in accordance with OEB Letter re Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs (November 2, 2023).
[20] For the reasons described in the response to interrogatory 2B-Staff-263(b), Toronto Hydro does not propose to continue this account.

Toronto Hydro proposes to allocate the DVA balances to the customer classes based on the methodologies described in the OEB's Deferral and Variance Account Review ("EDDVAR").[21] For accounts where the EDDVAR report indicated allocation was to be determined on a case-by-case basis, Toronto Hydro has proposed an allocator. The allocation between customer classes is set out in Table 15 below. /C

[21] EB-2008-0046, Ontario Energy Board Deferral and Variance Account Review Initiative.

Table 15: Proposed Allocators for Rate Classes

/C

Allocators	Total (%)	Residential (%)	CSMUR (%)	GS < 50kW (%)	GS – 50-999 kW (%)	GS > 1,000 to 4,999 kW (%)	Large User =>5,000 kW (%)	Street Lighting (%)	USL (Connections) (%)	USL (Customer) (%)
Distribution Revenue (2022)	100.0	38.9	4.8	15.5	26.1	8.3	3.9	2.0	0.5	0.0
Revenue Offsets (2025)	100.0	35.9	4.4	15.0	17.4	4.8	1.8	20.5	0.3	0.0
LRAMVA	100.0	-0.9	-0.1	-23.9	60.4	15.6	48.9	0.0	0.0	0.0
Distribution Revenue GS>50 kW (2022)	100.0	0.0	0.0	0.0	64.0	20.3	9.6	5.0	1.1	0.0
# of RPP Customers (2022)	100.0	78.8	11.9	8.8	0.4	0.0	0.0	0.0	0.1	0.0

Toronto Hydro proposes various recovery periods for specified DVA accounts, beginning January 2025, in order to minimize the bill impacts to all affected customers set out in Table 16 below. /C

Table 16: Proposed Rate Rider Allocators and Recovery Periods /C

Rate Riders	Allocators	Proposed Recovery Period (Years)	Rate Rider Start Year	Rate Rider End Year
PILs and Tax Variance	Distribution Revenue (2022)	1.00	2025	2025
Wireline Pole Attachments Rev	Revenue Offsets (2025)	1.00	2027	2027
Gain on Property Sale	Distribution Revenue (2022)	1.00	2027	2027
Impact for USGAAP (Actuarial loss on OPEB)	Distribution Revenue (2022)	1.00	2025	2025
Customer Choice Initiative	# of RPP Customers (2022)	1.00	2027	2027
External Driven Capital	Distribution Revenue (2022)	1.00	2026	2026
Operations Center Consolidation Plan	Distribution Revenue (2022)	1.00	2025	2025
Excess Expansion Deposits	Distribution Revenue GS>50 kW (2022)	5.00	2025	2029
Change in Useful Life of Assets (2025-2026)	Distribution Revenue (2022)	2.00	2025	2026
Lost Revenue Adjustment Mechanism (LRAMVA)	LRAMVA	5.00	2025	2029
Innovation Fund	Distribution Revenue (2022)	1.00	2029	2029
Ultra-Low Overnight Rate Costs	# of RPP Customers (2022)	1.00	2025	2025
Green Button Initiative Costs	Distribution Revenue (2022)	4.00	2025	2028
Wireless pole attachments Rev	Revenue Offsets (2025)	3.00	2026	2028
50/60 Eglinton Proceeds of Sale Deferral Account	Distribution Revenue (2022)	4.00	2026	2029
Change in Useful Life of Assets (2026-2029)	Distribution Revenue (2022)	4.00	2026	2029
Change in Useful Life of Assets (2025-2027)	Distribution Revenue (2022)	5.00	2025	2029

Toronto Hydro seeks approval for the following four new Deferral and Variance Accounts: (1) the 50/60 Eglinton Proceeds of Sale Deferral Account, (2) the Performance Incentive

Mechanism Deferral Account, (3) Demand Related Variance Account, and (4) the Innovation Fund Variance Account.

Toronto Hydro requests discontinuation of the following accounts:

- Account 1508 - subaccount - Capital-Related Revenue Requirement ("CRRRVA")
- Account 1508 - subaccount - Customer Choice Initiative Costs
- Account 1508 - Subaccount - Externally Driven Capital Variance Account ("EDCVA")
- Account 1508 - subaccount - Wireline Pole Attachment Revenue Variance
- Account 1508 - subaccount - Useful Life Changes
- Account 1508 - subaccount - Ultra-Low Overnight Rate Costs
- Account 1508 - subaccount - Green Button Initiative Costs

For more information about Toronto Hydro's DVA accounts and amounts proposed for clearance, please refer to Exhibit 9, Tab 1.

RATE FRAMEWORK

This schedule outlines Toronto Hydro's 2025-2029 custom incentive rate-setting framework: an evolved rate framework (rooted in the Renewed Regulatory Framework (the "RRF"), the Rate Handbook (the "Handbook"), and performance-based regulation principles) that enables the utility to deliver customer outcomes in the context of an energy transition driven by imperatives to electrify key sectors of economy (2025-2029 Custom Rate Framework).

Toronto Hydro followed a principled approach in developing the 2025-2029 Custom Rate Framework. In this approach the utility was guided by the following principles:

- deliver customer outcomes and advance public policy objectives;
- maintain rate stability and funding predictability to enable effective multi-year utility and customer planning and decision making,
- provide flexibility to execute multi-year plans in increasingly dynamic circumstances;
- protect customers and the utility from structural forecasting risks in times of uncertainty; and
- balance the interests of customers, the utility and its shareholder.

Toronto Hydro's framework is informed by enhanced performance-based regulation ("PBR") approaches employed in other leading jurisdictions that are undergoing an energy transition. To that end, Toronto Hydro retained a third-party expert (Scott Madden) to review the 2025-2029 Custom Rate Framework against a set of elements that were derived from a jurisdictional scan. A copy of this evidence is attached as Appendices A and B to this schedule to assist the OEB in evaluating the proposed framework.

The current custom rate framework, which was established in the 2015-2019 Rate Application (EB-2014-0116), provided stability and flexibility as Toronto Hydro grappled with the significant challenge of renewing a rapidly deteriorating distribution system.

The 2025-2029 Custom Rate Framework detailed in this schedule is structurally consistent with the rate framework approved by the OEB in past applications, with purposeful evolutions to achieve the objectives summarized below.

1. Provide multi-year funding certainty and flexibility for Toronto Hydro to:
    (i) continue to sustain a reliable grid and safe and effective operations; and
    (ii) address current and emerging (externally-driven) needs and challenges that the utility faces in delivering its services and preparing the grid for the energy transition.
2. Establish an appropriate balance between customer benefit and risk to the utility and its shareholder to:
    (i) protect consumers with respect to price and service quality outcomes in the next rate period and beyond, as consumers increase their reliance on the Toronto Hydro's grid for day-to-day energy needs; and
    (ii) maintain the utility's financial integrity with sufficient funding to deliver capital and operations programs to achieve outcomes that customers need and value now, and in an electrified future.

The following elements, as further described in this schedule, make up the comprehensive 2025-2029 Custom Rate Framework:

- A cost of service rebasing in 2025, the first year of a five-year rate term.

- A Custom Revenue Cap Index ("CRCI"), applied in years two through five (i.e. 2026 to 2029), to set rates for each year based on: (i) the expected growth in revenue that is required to fund the utility's investment plan, taking into account (ii) inflation minus productivity ("I-X") escalators and (iii) expected annual growth in billing determinants in each rate class per the five-year load forecast.
- The CRCI includes a Revenue Growth Factor ("RGF") to fund Toronto Hydro's incremental capital and operational investment needs in the outer years of the rate period (i.e. 2026-2029) so that the utility can make necessary investments in the grid and its operations to deliver outcomes that customers need and value.
- Base Revenues are adjusted annually by inflation and incentive factors (I-X):
    - The inflation factor ("I") is aligned with standard OEB methodology /C
    - The incentive factor ("X") includes a 0.15 percent efficiency-factor supported by empirical total cost benchmarking evidence, and a pro-active 0.6 percent performance factor that balances risk and reward by providing:
        - customers a significant upfront rate reduction benefit of approximately $65 million over the 2025-2029 rate term; and
        - Toronto Hydro the opportunity to earn back this revenue in the next rate period through an innovative Performance Incentive Mechanism ("PIM") if the utility achieves set objectives.
- The PIM shifts cost and performance risk to the utility, ensuring greater accountability to customers for outcomes, while maintaining the utility's financial integrity by providing Toronto Hydro the opportunity (not the guarantee) to make its full rate of return by delivering performance outcomes in the areas of: (i) reliability and resilience, (ii) customer service and experience, (iii) environment, safety and governance, and (iv) efficiency and financial performance. These performance

outcomes are measured through twelve custom metrics with set targets on the utility's 2025-2029 Custom Scorecard.

- An Innovation Fund to further the OEB's objectives set out in the Framework for Energy Innovation ("FEI"), and enable Toronto Hydro to overcome practical challenges of pursuing innovation during the 2025-2029 rate period, including:
    - a prudence standard of review that requires a higher level of certainty in proving beneficial outcomes,
    - a rate term that generally requires investment plans to be developed far in advance, and
    - a revenue requirement approach that requires spending to be classified either as a capital or operating expense, with limited flexibility during the rate period to trade-off between these types of expenditures.
- A Demand-Related Variance Account ("DRVA") to protect ratepayers, the utility and its shareholder, from structural unknowns in forecasted costs and revenues related to demand growth in a time of unprecedented change and transformation in the economy and energy system.

For ease of reference, Table 1 below compares the key elements of the current 2020-2024 Custom Rate Framework and the proposed 2025-2029 Custom Rate Framework.

Table 1: Comparison of Current and Proposed Custom Rate Frameworks

	2020-2024 Custom Rate Framework	2025-2029 Custom Rate Framework
Year 1	Standard COS rebasing	Standard COS rebasing
Year 2	Custom Price Cap Index ("CPCI"): $I_n – X + C_n – S_{cap} * (I + X_{cap}) - g$	Custom Revenue Cap Index ("CRCI"): $I_n – X + RGF_n$
OM&A	One-year plan escalated by inflation less productivity (I-X)	Five-year plan funded through the Revenue Growth Factor ("RGF")
Capital	Five-year plan funded through a capital factor ("C-Factor")	Five-year plan funded through the Revenue Growth Factor ("RGF")
Inflation	OEB Inflation Factor	OEB Inflation Factor
X-Factor	0.6 percent reduction on non-capital related revenue requirement, and 0.9 percent reduction on capital related revenue requirement, resulting in a blended X-factor of 0.81-0.82 percent over the rate term	0.75 percent reduction on all revenue requirement with the opportunity to earn-back up to 0.6 percent of the X-factor through a Performance Incentive Mechanism ("PIM") by achieving results measured through custom metrics with set targets on the utility's 2025-2029 Custom Scorecard
Growth	Growth factor added to CPCI derived from five-year load and customer forecast	CRCI sets rates annually based on projected growth in billing determinants in each rate class
Deferral and Variance Accounts (DVAs)	Capital-Related Revenue Requirement Variance Account[1]	Demand-Related Variance Account
		Performance Incentive Mechanism Deferral Account
	Externally Driven Capital Variance Account[1]	Innovation Fund Variance Account
		Getting Ontario Connected Act Variance Account[2]
	Earning Sharing Mechanism	Earning Sharing Mechanism
	Property Sales	Property Sales[2]

[1] Toronto Hydro proposes to discontinue these accounts. For more information about these accounts, please see Exhibit 9, Tab 1, Schedule 1 at sections 4.2 and section 5.3.
[2] For more information about these accounts, please see Exhibit 9, Tab 1, Schedule 1 at sections 4.4 and 4.16.

Toronto Hydro's proposal evolves the existing custom rate-setting approach in a manner that is consistent with the RRF and aligned with the OEB's guidance in the 2016 Rate Handbook. Specifically:

- The custom index is derived from five-year forecasts and includes financial incentives for continuous improvement, including efficiency targets.
- The proposed X-Factor is higher than the OEB-approved X-Factor under standard Price Cap Incentive Regulation.
- The framework is supported by empirical evidence of the utility's productivity, as well as internal and external benchmarking.
- Annual updates are limited to updating the inflation factor.
- The inflation factor adjusts Toronto Hydro's rates and revenues annually to reflect the prevailing economic conditions, ensuring the utility has necessary funding to execute its multi-year investment plans.
- The framework includes a comprehensive scorecard with performance metrics that are aligned with the outcomes identified in the Application.
- The framework includes an Earning Sharing Mechanism ("ESM") to protect customers in the event of utility overearning in excess of 100 basis points of its OEB-approved regulated rate of return.

The sections that follow provide context and further explanation for the evolutions that Toronto Hydro proposes in the 2025-2029 Custom Rate Framework to address the needs and challenges that the utility faces, while maintaining its financial integrity and protecting customers with respect to service quality, reliability, and price outcomes both in the near- and longer-term.

1. THE PLANNING IMPERATIVES

Over the 2025-2029 rate period, Toronto Hydro's operations and capital investment needs are growing by approximately 37.5 percent due to a number of distinct and interrelated drivers. In particular:

- Responding to the extraordinary inflationary pressures experienced over the 2020-2024 rate period, wherein the Non-Residential Construction Index in the Toronto Census Metropolitan Area rose 37.7 percent from Q1 2020 through Q2 2023.[3]
- Toronto Hydro's asset base continues to age and deteriorate requiring significant sustained investment to maintain system health during the next rate period and beyond – especially since the importance of a safe and reliable grid is only increasing as customers rely on electricity for more of their daily energy needs.[4]
- Asset maintenance requirements are increasing due to (i) evolving legal and regulatory requirements, (ii) a growing level of corrective maintenance issues that need to be rectified, and (iii) increased volumes of assets that the utility must inspect and maintain.[5]
- Investment is required to prepare Toronto Hydro's grid and operations for the energy transition to ensure customers will not be underserved or unserved when demand materializes, including investments to expand and modernize the distribution system and increase operational capacity and capabilities to:[6]
    - serve customers' growing and changing electricity needs,
    - execute higher volumes of capital and operational work,
    - meet rising customer expectations with respect to service levels,[7]

[3] Exhibit 1B, Tab 3, Schedule 3.
[4] Exhibit 2B, Sections D2.2, E2.2, E2.4.2, E4.2.2, and E6.
[5] Exhibit 2B, Section D3.1.1.3; Exhibit 4, Tab 2, Schedules 3 and 4.
[6] For more information please refer to Exhibit 2B, Sections D4 and D5 and Exhibit 4, Tab 1, Schedule 1.
[7] For more information please refer to Exhibit 1B, Tab 5, Schedule 1.

- plan and execute more complex work in a dense, mature and urban operating environment,[8] and
- leverage technology and pursue innovation to modernize utility operations, increase operational efficiency, optimize the use of new and existing assets, and support the integration of distributed energy resources ("DERs").[9]

- Technological changes are shifting certain types of investments such as demand-side non-wires solutions and cloud-based software solutions from capital to operational program expenditures.
- Environmental, social and governance ("ESG") imperatives are driving key account customers to pursue zero plans that will require investment in grid expansion and modernization, as well as services to support these customers in their decarbonization-through-electrification journey.

In addition to addressing grid and operational needs and laying the foundation for the unfolding energy transition in a paced manner, Toronto Hydro's 2025-2029 investment plan aims to deliver key objectives with respect to four key areas of performance: (i) reliability and resilience, (ii) customer service and experience, (iii) environment, safety and governance, and (iv) efficiency and financial performance outcomes. These outcomes are measured through custom metrics with set targets on the utility's 2025-2029 Custom Scorecard which is filed at Exhibit 1B, Tab 3, Schedule 1.

The investment priorities and associated outcomes are aligned with customers' needs and preferences, as demonstrated by the results of Toronto Hydro's two-phased customer engagement process detailed in Exhibit 1B, Tab 5, Schedule 1 whereby:

[8] For more information about these challenges please refer to Exhibit 1B, Tab 3, Schedule 3, section 1 at page 2.
[9] For more information about please refer to the Grid Modernization Strategy at Exhibit 2B, Section E5.

- over 33,000 customers reviewed Toronto Hydro's draft plan, and
- an average of 84 percent of the customers surveyed supported the rate increase associated with the draft plan, or one that does even more to advance outcomes.

Toronto Hydro is the steward of a mature, diverse and complex distribution system serving a dense urban territory powering Canada's largest, and North America's second fastest growing city. The last two custom rate applications, and Toronto Hydro's 2012-2014 Incremental Capital Module ("ICM") application, were marked by the need for significant multi-year capital funding in excess of what can be funded through base rates under the OEB's Price Cap Incentive Rate-Setting Mechanism ("IRM") approach.

Past rate applications predominately focused on addressing significant system renewal needs and keeping up with the City's growth and densification. These investments delivered reliability improvements and many other service quality benefits to customers, as detailed in Exhibit 1B, Tab 3, Schedule 2.

Despite these achievements, Toronto Hydro continues to face asset condition and demographic pressures across all parts its system, which necessitate continued proactive investments over the next rate period to maintain a safe and reliable grid for customers.[10] At the same time, an energy transition is gradually unfolding across key sectors of the economy with residents, businesses and institutions adopting electrified technologies such as electric vehicles ("EVs"), heat pumps, solar panels and energy storage systems. Toronto Hydro must sustain, expand and modernize the grid to be ready and equipped to serve customers' growing demand for safe and reliable electricity during this transition.

[10] For more information please refer to Exhibit 2B, Section E2.2.2.1.

While the pace and nature of electrification required to decarbonize the economy remains unsettled, there is broad societal and public consensus that an energy transition is required to mitigate the existential and economic impacts of climate change. In order to continue to serve the needs of the customers in an electrified future, Toronto Hydro is oriented around taking responsible, least-regret and paced actions in the 2025-2029 rate period to prepare the local grid and its operations for a fundamental shift in how customers rely on electricity in the decades to come.

To gain insight into the challenge posed by the energy transition, Toronto Hydro commissioned an industry leading consumer-choice modelling Future Energy Scenarios study to assess the impacts of different energy transition scenarios on Toronto Hydro's distribution system.[11] The Future Energy Scenarios study reveals that over time, a significant increase in peak demand across all scenarios is expected to occur, including the least ambitious steady progression scenario that falls short of meeting Net Zero 2050 objectives. This outlook is consistent with other leading studies, such as the Independent Electricity System Operator's ("IESO") Pathways to Decarbonization ("P2D") report, which estimates that in a high-growth scenario, in less than 30 years, Ontario could need more than double its electricity generating capacity.[12,13]

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[11] Exhibit 2B, Section D4, Appendix A and Appendix B.

[12] Toronto Hydro's own Future Energy Scenarios forecast a doubling in Toronto's electricity demand by the year 2050 across multiple scenarios (for more information please refer to Exhibit 2B – Section D4, Appendix A). The IESO's Pathways to Decarbonization report forecasts that demand could more than double by 2050 (https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization)

[13] Enbridge's Pathways to Net Zero forecasts an increase in demand of over three times in its electrification scenario (https://www.enbridgegas.com/en/sustainability/pathway-to-net-zero). In the US, utilities such as National Grid (https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan-sept2023.pdf),Eversource(https://www.mass.gov/doc/gmacesmp-drafteversource/download?_gl=1%2Ako8zfs%2A_ga%2ANzUwNDI5MDE3LjE2NTA5ODEyMjQ.%2A_ga_SW2TVH2WBY%2AMTY5MzkyMDE2OS4zNi4xLjE2OTM5MjM1NzQuMC4wLjA.), and Unitil (https://unitil.com/ma-esmp/en) all published modernization plans forecasting demand increases of over 2 times by 2050. ISO New England also completed a study

The Future Energy Scenarios reveal that system peak demand could grow significantly, or more moderately, depending on technology, policy and consumer choices that will be made in the future. Toronto Hydro must both ensure that the grid is ready ahead of when demand increases (to avoid under-served or unserved customers), and also be reasonably cautious in building new capacity for the future. Building too much too soon could result in stranded assets and high rate impacts for customers, and building too late would result in the grid not being available to meet customer needs and expectations related to electrification.

To manage this uncertainty and the cost-consequences for customers, the utility must be: (i) measured-but-proactive in its investment plan (as both asset and human capital investments have long lead-times), (ii) deliberate in sustaining and modernizing its grid and operations to ensure that it is ready to serve and enable customer choice in a range of electrification scenarios, and (iii) oriented around a base of least-regret investment choices (i.e. investments that are required under most or all of the possible futures outlined in the *Future Energy Scenarios* study). Striking this important balance is at the heart of the 2025-2029 investment plan and the proposed Custom Rate Framework. In this regard, Toronto Hydro's Plan is aligned with the expanded priorities and expectations articulated by the Minister of Energy in the 2022 *Letter of Direction to the OEB*, and the recent *Powering Ontario's Growth* report.[14,15]

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which forecasts a doubling in system peak by 2050 (https://www.iso-ne.com/static-assets/documents/100004/a05_2023_10_19_pspc_2050_study_pac.pdf). National Grid ESO (Great Britain's system operator), also forecasts in an increase of about 2 times across many of it's future energy scenarios (https://www.nationalgrideso.com/document/283101/download). Electricity North West, *Distribution Future Electricity Scenarios* (December 2022) online: <https://www.enwl.co.uk/globalassets/get-connected/network-information/dfes/current/distribution-future-electricity-scenarios-2022.pdf>; National Grid ESO, *Future Energy Scenarios* (July 2023) online: <https://www.nationalgrideso.com/document/283101/download>.

[14] Ministry of Energy, *Letter of Direction from the Minister of Energy to the Chair of the OEB* (October 21, 2022) online: <https://www.oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20221021.pdf>.

[15] Ministry of Energy, *Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future* (July 10, 2023) online: <https://www.ontario.ca/page/powering-ontarios-growth>.

2. THE FUNDING NEED

As illustrated in Figure 1 below, the continuation of a custom-rate setting approach is necessary for Toronto Hydro as funding derived from the OEB's standard Price Cap and IRM framework is insufficient to fund the plan's imperatives of system stewardship, growth and electrification, and modernization. Furthermore, Toronto Hydro's ability to deliver its investment plan and advance the public policy objectives and customer benefits is dependent on a rate-setting approach that builds on, and necessarily evolves the current approved custom-rate setting approach.

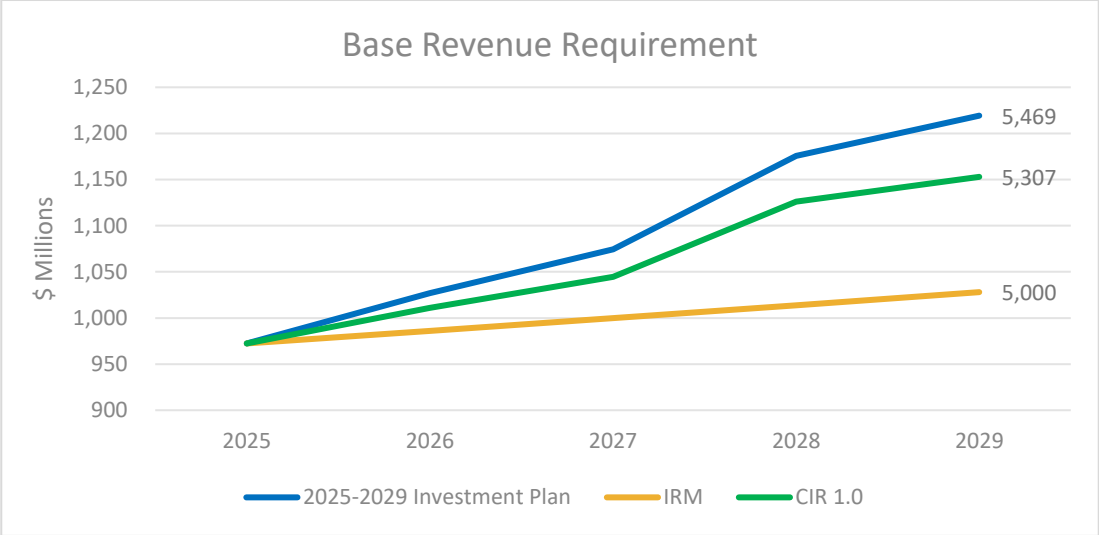

Figure 1: Cumulative 2025-2029 Base Revenue Requirement

Left unmitigated, the funding gaps depicted in Figure 1 above between IRM (the orange line), the existing custom rate-setting approach (the green line) and Toronto Hydro's 2025-2029 investment plan (the blue line) would result in hundreds of millions of dollars of underinvestment in Toronto Hydro's grid and operations. In these scenarios, system performance and customer outcomes would be adversely affected and energy transition objectives would be compromised or unmet. For the reasons detailed in the paragraphs that

follow, Toronto Hydro submits that these scenarios do not serve the public interest or align with the OEB's statutory objectives.[16]

Under a standard IRM scenario, Toronto Hydro's 2025-2029 capital investment plan would be underfunded by approximately 35 percent or $1.5 billion. Adoption of a plan constrained by this funding envelope would force the utility into a sustainment plan that would be almost entirely reactive in nature, resulting in roughly an 8 percent deterioration in system reliability by the end of the rate period, along with increases in safety and environmental risks and reactive replacement costs due to increasing numbers of asset failures.[17] Such deterioration in system performance would: (i) put Toronto Hydro out of alignment with good utility practice, (ii) delay or prohibit the advancement of energy transition objectives that must be met over the 2025-2029 rate period in preparation for increasing peak demand and transition in the next decade, and (iii) harm ratepayers' interest with respect to long-term service quality and affordability outcomes.

While the gap between what standard IRM can fund and the revenue that the utility needs to execute its 2025-2029 investment plan is best addressed by a custom rate-setting approach, the needs of Toronto Hydro's 2025-2029 investment plan remain unmet under the current custom framework. Specifically, under the current framework, Toronto Hydro's 2025-2029 investment plan would be underfunded by approximately $450 million (i.e. approximately $360 million in capital expenditures and $90 million in OM&A expenses) due to a 0.9 percent stretch-factor on capital-related revenue requirement, and an approach to funding OM&A where operational budgets are rebased in the first year of the rate period

[16] Section 1(1) of the *Ontario Energy Board Act*, 1998, SO 1998, c. 15, Sched. B.
[17] For more information please review the SAIDI custom metric in Exhibit 1B, Tab 3, Schedule 1.

and then adjusted annually by a rate that is less than inflation. Table 2 presents the return on equity ("ROE") implications of the existing framework.

Table 2: ROE Implications of the Existing Custom Framework ($ Millions)

	2025	2026	2027	2028	2029
2025-2029 Investment Plan Revenue Requirement (A)	972	1,027	1,074	1,176	1,219
2025-2029 funding under the existing custom framework (B)	972	1,011	1,044	1,126	1,153
Variance (A) – (B)	-	16	30	50	66
ROE Impact (basis points) *	-	59.6	110.8	183.5	245.6

*Estimated where $27 million per year equals approximately 100 basis points.

Since 2012, Toronto Hydro has been operating under high stretch factors and has achieved significant productivity gains by harvesting operational efficiencies such as fleet and facilities consolidation, job harmonization and process automation that have delivered significant benefits to customers. While the utility remains committed to productivity and efficiency and intends to continue on a path of achievement in this area, Toronto Hydro has already targeted and adjusted the most significant areas for productivity improvements. The various benchmarking studies filed in this application show that Toronto Hydro is a good cost performer relative to its peers, and in many cases exceeds the performance of its peers when the appropriate operating conditions (e.g. dense urban environment) are taken into consideration.[18]

After more than a decade of living under a top-down constrained funding model serving a growing urban service territory that poses significant operational challenges and material cost drivers, Toronto Hydro cannot eliminate the funding gap identified above through

[18] For more information about productivity and benchmarking, please refer to Exhibit 1B, Tab 3, Schedule 3.

productivity efforts such as absolute cost reductions or reprioritizing capital and operational work. While deferral of work may have been a viable strategy in past periods, it is not in the current circumstances where the utility must tackle both persisting and new challenges and requirements, and prepare the grid and its operations for a major transformation in how customers use electricity.

A choice to defer work planned within the 2025-2029 Distribution System Plan found at Exhibit 2B does not serve the interests of ratepayers. For example, a deferral of work contained within the Grid Modernization Strategy at Exhibit 2B, Section D5 would mean that customers can expect a deterioration in reliability performance over the next rate period, higher customer interruption costs and much higher costs in the next decade as the system becomes more heavily utilized by customers. Similarly, investments to increase grid capacity to connect new or expanded loads in a timely and efficient manner, and enable customers to adopt DERs could be compromised – jeopardizing customer choice and impeding progress towards energy transition goals.

Similarly, deferring investment in OM&A to manage within the funding provided by the current framework, would lead to attrition of up to 200 employees by the end of the rate period, putting Toronto Hydro's staffing complement at precariously low level, and setting the utility back with respect to a multitude of outcomes and risks which are summarized in section 2.1 below and further detailed in Exhibit 4, Tab 1, Schedule 1.

The funding challenges depicted above are already being felt in the current rate period given the capital and operational needs that the utility is managing, and notwithstanding the productivity achieved through various initiatives detailed in Exhibit 1B, Tab 3, Schedule 3. For example, from 2020 to 2022, Toronto Hydro's achieved regulatory ROE averaged at 6.81

percent, which is 1.71 percent lower than its deemed ROE of 8.52 percent. The funding deficiency in the current rate period is due to multiple factors including the load-related impacts of COVID-19,[19] and the need to invest in prudent operational expenditures (above what base rates can fund under the current framework) in order to: (i) to implement the 2020-2024 workforce plan and (ii) address various incremental requirements summarized in the OM&A Overview schedule at Exhibit 4, Tab 1, Schedule 1 and detailed throughout the programmatic evidence in Exhibit 4, Tab 2.

Toronto Hydro proposes a number of evolutions to the existing custom-rate setting approach that are purposefully designed to address the funding challenges described above, re-balance utility and ratepayers' risk and reward, and critically – continue to pursue outcomes that matter to customers including achieving efficiency gains. To that end, the Performance Incentive Mechanism ("PIM") and the Custom Revenue Cap Index ("CRCI") outlined in section 3 are key elements of the proposed Custom Rate Framework.

2.1 Operational Funding Needs

The paradigm of a single rebased OM&A year subject to a growth rate that is less than inflation over the rate term (i.e. an I-X approach) is incompatible with Toronto Hydro's evolving operational needs, as the utility must expand and modernize the grid and its operations to facilitate the energy transition that customers and stakeholders expect. The key drivers behind the operational need in the current period are summarized in Exhibit 4, Tab 1, Schedule 1, and throughout the programmatic evidence at Exhibit 4, Tab 2.

[19] For more information please see Exhibit 3, Tab 1, Schedule 1 and Exhibit 1B, Tab 3, Schedule 3 at section 2.1.

After a decade of realizing sustained operational efficiencies to be able to manage its operations with a workforce complement that is essentially flat from 2015 to 2024, it is no longer possible nor prudent for Toronto Hydro to meet its obligations without hiring additional resources. From 2024 through to 2029, Toronto Hydro's workforce must grow by roughly 25 percent to support the execution of an expanded capital program as detailed in Exhibit 2B, while also addressing the policy, technology and customer imperatives of a changing energy landscape. Greater volumes of capital work require more skilled trades working in the field and operating the distribution system, as well as staff executing a broad range of support functions, such as corporate services professionals administering the utility's financial processes and accounting records, and legal and regulatory professionals negotiating contracts (e.g. offers to connect) and maintaining compliance with legal and regulatory requirements in the face of increasing volumes and complexity of work outlined in the plan. Furthermore, as traditional energy consumer models evolve to a paradigm where customers are using more electricity and actively participating in energy management through new technologies such as DERs, Toronto Hydro's customer-interfacing operations must also follow suit. Customer-related utility functions need to be expanded and enhanced to successfully address emerging customer needs and requirements such as: connecting EVs, heat pumps and DERs of varying size and scale; accessing energy data and analytics and new channels of digital customer communication and interaction.

It is not possible for the utility to meet these requirements, and in particular its workforce needs, with the operational funding levels provided by the current framework. As noted in the OM&A Overview evidence at Exhibit 4, Tab 1, Schedule 1, managing workforce-related costs downwards to live within a standard IRM funding paradigm would put Toronto Hydro's staffing complement at a precariously low pre-2015 level. Since the utility already has a demonstrably lean workforce compared to other distributors in the province (as evidenced

by benchmarking) such a reduction would compromise the utility's performance with respect to a multitude of outcomes and risks, including safety, customer service and efficiency.

Under a constrained operational plan, the utility would also face a reduced absorption rate of the Certified and Skilled Trades such as Distribution System Technologists ("DSTs") that are critical to the execution of Toronto's capital and operations programs. DSTs operate, install, commission, construct, repair, maintain, and decommissions all types of protective relay and control systems, distribution automation equipment, and SCADA systems that are integral to implementing key components of the utility's Grid Modernization Strategy outlined in Exhibit 2B, Section D5. Other consequences of not having the operational funding that is necessary to attract and retain the level of resourcing outlined in Toronto Hydro's workforce plan, include:

- Less efficient and effective system and capacity planning compromising:
    - (i) the execution of the 2025-2029 Distribution System Plan ("DSP") and the development of future DSPs,
    - (ii) the optimization of investments to meet future load growth and connection capacity, including the identification of non-wires solutions opportunities,
    - (iii) the integrity of regional planning and coordination efforts, and
    - (iii) the implementation of grid modernization and innovation initiatives that can provide long-term value and significant future benefits to customers;
- Safety, reliability, and poor customer service outcomes if distribution system records and data updates cannot be maintained and synchronized with equipment or system configuration changes;

- Lack of skill sets necessary to support evolution of control centre operations, including to undertake the data modelling and system analysis required to enable the self-healing grid and other distribution automation functions;
- Insufficient cyber security capacity and expertise to manage the widespread threat of advanced cyber attacks against critical infrastructure;
- Insufficient staffing levels and skill sets to meet customers service expectations, including knowledge management expertise to ensure accurate and timely responses to increasingly complex customer inquiries, as well as, data analytics to deploy and fully optimize automated quality management powered by artificial intelligence and machine learning technologies;
- Reduced governance and oversight of financial planning activities that can limit the organization's ability to maintain financial integrity outcomes;
- Ineffective or unfavourable negotiation of contract terms, resulting in substandard performance by contracted parties or foregone recourse to appropriate remedies, reducing the value to ratepayers;
- Non-compliance or incorrect implementation of new requirements, policies or programs resulting in increased customer complaints, potentially compromising the advancement of public policy objectives;
- Increased frequency of inaccurate or delayed information resulting in customer confusion and dissatisfaction; and
- A reduced ability to successfully recruit and develop the skilled and specialized resources that Toronto Hydro requires to execute its current and future investment plans.

The operational consequences highlighted compromise Toronto Hydro's ability to execute the 2025-2029 investment plan, deliver the performance results detailed in Exhibit 1B, Tab

3, Schedule 1, and advance energy transition objectives that are important to its customers and stakeholders. For these reasons, Toronto Hydro 2025-2029 Custom Rate Framework includes a mechanism (the Revenue Growth Factor further described in section 3.1.3.1 below) to fund operational investments over the rate period that exceed what can be funded under a standard IRM approach.

3. 2025-2029 CUSTOM RATE FRAMEWORK

This section describes the elements of Toronto Hydro's proposed 2025-2029 Custom Rate Framework. The information is organized to first describe the components of the rate formula known as the Custom Revenue Cap Index (the "CRCI"), followed by the non-CRCI elements of the Custom Rate Framework.

3.1 Custom Revenue Cap Index ("CRCI")

3.1.1 Revenue Cap Approach

In the last two custom rate applications (EB-2014-0116 and EB-2018-0165) Toronto Hydro proposed, and the OEB approved, a rate-setting approach centered around a modified price-cap rate model. This approach established rates in the rebasing year (2015 and 2020, respectively) after which established rates were escalated annually by an index known as the Custom Price Cap Index ("CPCI"). On completion of the rebasing year, no further consideration was given to customer billing determinants (i.e. customer count, kWh and kVa) or changes in these determinants over the rate plan.

In EB-2014-0116, where the current custom framework was first proposed and adjudicated, a growth adjustment was added to Toronto Hydro's CPCI to ensure that capital costs were not over-collected. This took the form a 0.3 percent factor – termed the growth-factor or "g-factor" – derived from the top-line of the utility's five-year customer and load forecast. A g-

factor of 0.2 percent was carried forward for inclusion in the utility's current rate framework based on 2020-2024 load and customer forecast.[20]

The g-factor translates billing determinant growth across customer count, kWh, and kVa in all rate classes into a simplistic top-line figure that is applied formulaically to base rates. In doing so, it lacks specific consideration of the details embedded in the five-year customer and load forecast. In particular, it does not recognize different patterns of growth amongst the rate classes and their billing determinants.

The g-factor was adopted in 2015 at a time where the growth in billing determinants was more stable and linear. However, in the current period and looking ahead to the end of the decade, growth in demand is becoming more dynamic due to a multitude of factors (e.g. a more volatile housing market and supply mix, shifting immigration policies, and electrification-related policies, technology and consumer preferences). A more nuanced mechanism is suitable to capture billing determinant growth within this changing and more dynamic environment to ensure that rates for each of the customer classes continue to be just and reasonable.

Toronto Hydro proposes a shift in its rate-setting approach from price-cap to a revenue-cap model. Rather than escalate rates themselves each year, and use a simplistic g-factor to account for expected billing determinant growth, Toronto Hydro proposes to escalate revenue requirement each year, and design rates for each revenue requirement on the basis of forecasted customer and load growth over the rate term. This approach captures expected billing determinant growth in a more precise manner, considering shifting

[20] EB-2014-0116, Decision and Order (December 29, 2015) at pages 28-29 and EB-2018-0165, Decision and Order (December 19, 2019) at pages 41-42.

customer make-up and changes to energy usage patterns as amongst kWh and kVa in a period of energy transition.

It is also worth noting that Toronto Hydro's proposal is a true revenue cap as the utility proposes a sub-account within its Demand-Related Variance Account ("DRVA") to record revenue differences as a result of variances in weather normalized billing determinants at the rate class level. The DRVA is further described in section 3.2.3 of this schedule.

3.1.2 Year 1: Standard Rebasing

The first year of the proposed rate application is a cost of service rebasing year, consistent with the OEB's standard IRM approach. The rebasing is derived from Toronto Hydro's 2025 forecasted revenue requirement based on its capital and operational plans for the year, as further detailed in its Distribution System Plan ("DSP") at Exhibit 2B and the OM&A evidence in Exhibit 4. The revenue requirement resulting from these projections is presented in Exhibit 6, Tab 1.

With the 2025 revenue requirement established, Toronto Hydro used the OEB's cost allocation model to allocate the revenue requirement to its rate classes, maintaining revenue-to-cost ratios for each class within the guidelines set out in the OEB's 2011 Review of Electricity Cost Allocation Policy.[21] For more information about Toronto Hydro's Cost Allocation and Rate Design, please refer to Exhibits 7 and 8, respectively.

[21] EB-2010-0219, EB-2012-0383 and OEB letter issued June 12, 2015 Issuance of New Cost Allocation Policy for Street Lighting Rate Class.

3.1.3 Years 2-5: Custom Index

In year two through five of the rate period (i.e. 2026 to 2029), rates are set by the implementation of the Custom Revenue Cap Index ("CRCI"). The CRCI produces a percentage factor by which base revenue requirement must be escalated from one year to the next during the rate term in order to fund Toronto Hydro's investment plan.

The CRCI formula to be applied in years 2 through 5 (2026 to 2029) is: **$CRCI = I_n - X + RGF_n$**

Where,

- **I** = an Inflation-factor to be updated annually as per the OEB's standard methodology. /C
- **X** = an X-Factor of 0.75 percent which consists of (i) a 0 percent productivity-factor, plus (ii) a 0.15 percent efficiency-factor, supported by total cost benchmarking, plus (iii) a proactive 0.6 percent performance factor that enables the PIM.
- **RGF** = a Revenue Growth Factor which represents the amount by which base revenue requirement must increase each year to fund the utility's proposed investment plan, and is adjusted as outlined in Table 3 to remove a forecast of the inflation factor so that the base revenue requirement can be escalated by the actual inflation-factor through a mechanistic annual rate update process.
- **n =** the rate year in question.

The following sections describe the components of the CRCI.

1. <u>Revenue Growth Factor</u>

The OEB's decision in EB-2014-0116 marked the establishment of a new mechanism to account for multi-year capital needs in excess of what base rates can fund under standard IRM – this mechanism is known as the Capital or "C-factor". The C-factor is an attrition relief mechanism that implements additional rate escalations each year, beyond those provided

for through base rates escalated at inflation less productivity, to account for the utility's growing capital-related revenue requirement as a result of implementing the multi-year capital investment plan known as the DSP. Over the last two custom rate applications, the C-factor provided a means to fund multi-year capital investment plans beyond what could be achieved under a standard IRM approach.

As noted in this schedule and detailed in Exhibit 4, Toronto Hydro's operational funding needs are growing due to a number of distinct and interrelated factors, including the need to hire and retain more resources to deliver a larger and more complex work program, which is necessary to sustain, expand, and modernize the grid, and deliver key outcomes that customers and stakeholders value. To address the emerging need for multi-year operational funding in excess of what can be achieved under standard IRM, Toronto Hydro proposes a Revenue Growth Factor ("RGF"). The RGF, similar to the existing C-factor, enables year-over-year rate increases to fund incremental revenue requirement related to both capital and OM&A investments. As further described below, the RGF escalates revenue requirement annually by a factor that accounts for the difference between one year's revenue requirement and the next.

In Exhibit 6, Toronto Hydro submitted the revenue requirement resulting from its capital and OM&A programs and other revenue forecasts over the 2025 to 2029 rate period. To calculate the RGF, the difference between each subsequent year's revenue requirement is determined as a percentage by which revenue requirement must escalate to fund the investment plan for the upcoming year.

The forecasted capital and OM&A expenditures presented in Exhibits 2B and 4, and the resulting revenue requirement presented in Exhibit 6, include inflationary assumptions with

respect to the underlying cost inputs (i.e. labour, materials, and other costs). To allow updates of the annual inflation factor in rates without double-counting the impact of inflation, Toronto Hydro adjusted the RGF by removing a 2 percent forecasted annual inflation factor for the 2026 to 2029 period, thereby presenting the RGF as an increase in revenue requirement on an inflation-adjusted basis for rate-setting purposes.

Table 3 below outlines the proposed RGF values for years two through five (2026-2029) before and after the inflation adjustment.

Table 3: 2026-2029 Revenue Growth Factor ($ Millions)

	2025	2026	2027	2028	2029
Base Revenue Requirement (BRR)	972	1,027	1,074	1,176	1,219
Difference	-	55	47	101	44
RGF before Inflation Adjustment	**-**	**5.61%**	**4.62%**	**9.43%**	**3.71%**
Forecast Inflation Factor (%)	-	(2.00%)	(2.00%)	(2.00%)	(2.00%)
RGF after Inflation Adjustment	**-**	**3.61%**	**2.62%**	**7.43%**	**1.71%**

The RGF value for each year, as determined and approved by the OEB in this application, is applied to the prior year base revenue requirement to set rates from 2026 to 2029 through the implementation of the CRCI in annual rate applications. Aside from achieving the objective of providing funding certainty and stability in rates which is necessary to enable effective multi-year planning and operations, the RGF offers the added benefit of simplicity relative to the current C-factor since the entire revenue requirement is being escalated by the same inflation and productivity factors as further detailed below.

2. Inflation Factor

An annual inflation adjustment based on objective economic factors is an important element of establishing just and reasonable rates under standard OEB policy.[22] This element is even more important in light of the current volatility in national and global inflation, which may or may not subside over the 2025 to 2029 rate period.

Toronto Hydro's proposed approach to account for inflation in annual rate setting is consistent with standard OEB policy. The utility proposes to use the OEB's I-factor in its CRCI. As the value for the I-factor is updated annually per the OEB's standard methodology, Toronto Hydro will incorporate the updated value in its CRCI appropriately adjust base distribution rates for the following year. /C

3. X-Factor

Toronto Hydro proposes an X-Factor of 0.75 percent which consists of:

- 0 percent productivity-factor consistent with OEB policy, plus
- 0.15 percent efficiency-factor supported by empirical evidence, plus
- 0.6 percent proactive performance incentive mechanism factor.

The study prepared by Clearspring Energy Advisors at Exhibit 1B, Tab 3, Schedule 3, Appendix A supports an efficiency-factor of 0.15 percent based on empirical total cost benchmarking against relevant peers accounting for known and accepted operational differences between utilities which require adjustment.[23] By the end of the rate period (i.e. in 2029) the 0.15

[22] EB-2010-0379, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (updated December 4, 2013).
[23] In the 2020-2024 Rate Application (EB-2018-0165), OEB Staff's expert Pacific Energy Group (PEG) accepted the appropriateness of a variable that accounts for urban congestion. The OEB Panel presiding over that case echoed the comment in the Decision and Order (December 19, 2019) at page 29. Similarly, in Hydro One's 2023 Joint Rate

percent efficiency-factor yields an approximate annual revenue reduction of $6.9 million relative to Toronto Hydro's forecasted revenue requirement set out in Exhibit 6.

This revenue reduction represents the annual value of the efficiency benefits that customers would reasonably expect to receive through the utility's productivity efforts over the rate term. As is customary within IRM, Toronto Hydro takes the risk of this efficiency gain upfront giving customers the benefit of the rate reduction during the rate period – a benefit that amounts to approximately $16.4 million over the entire rate period by adding up the values in the last row of Table 5 below.

Table 5: Efficiency Factor (0.15%) Revenue Reduction ($ Millions)

	2025	2026	2027	2028	2029
Revenue Requirement based on the 2025-2029 Investment Plan	972.4	1,027.0	1,074.4	1,175.7	1,219.2
Revenue Collected after 0.15% Efficiency Factor	972.4	1,025.5	1,071.3	1,170.9	1,212.2
Revenue Reduced by 0.15% Efficiency Factor	-	1.5	3.1	5.0	6.9

Note: There could be minor differences due to rounding.

Furthermore, as part of the 2025-2029 Custom Scorecard outlined in Exhibit 1B, Tab 3, Schedule 1, the utility set a goal through the Efficiency Achievements metric to sustain these benefits for customers into the next rate period by achieving quantified efficiency gains of at least $6.9 million per year by 2029. These gains can be achieved through cost avoidances, reductions or other efficiency gains that result in a lower revenue requirement at the next rebasing, than would otherwise be put forward if the efficiency gains were not achieved.

Application (EB-2021-0110), PEG through an OEB-ordered conferral process with Clearspring Energy Advisors accepted the inclusion of a substation variable within the custom total cost benchmarking study.

In addition to the efficiency-factor, Toronto Hydro's rate framework proposes a proactive 0.6 percent performance incentive factor that further reduces revenues by approximately $65 million over the rate term, providing customers an additional upfront rate reduction. This proposal (i) demonstrates Toronto Hydro's commitment to be held financially accountable to customers for key outcomes of the proposed investment plan, and (ii) gives effect to an innovative Performance Incentive Mechanism ("PIM") that provides the utility the opportunity to earn-back the foregone revenue, if it delivers the target performance results on the Custom Scorecard. The PIM proposal is further detailed in the section 3.2.1 below.

3.2 Key Custom Elements (Non-CRCI)

The following sections discuss three key elements of the 2025-2029 Custom Rate Framework that enable an evolved approach to custom incentive rate-setting: (1) the Performance Incentive Mechanism ("PIM"); (2) the Innovation Fund; and (3) the Demand Related Variance Account ("DRVA"). Together with the CRCI rate formula described above in section 3.1, and the existing Earning Sharing Mechanism ("ESM"), Off-Ramp and Z-Factor mechanisms summarized below in section 3.3, these elements form a balanced custom rate framework that is integral to the utility being able to function effectively within the operating context that it faces – a transition that is expanding the role of electricity within the energy system, and customers, communities and stakeholders who expect the utility to enable this future-state in a paced and deliberate manner.

3.2.1 Performance Incentive Mechanism (PIM)

As noted above, the PIM is a key enhancement and regulatory innovation within Toronto Hydro's 2025-2029 Custom Rate Framework. This section describes the mechanics of the PIM in further detail.

The custom total cost benchmarking study performed by Clearspring Energy Advisors supports an efficiency-factor of 0.15 percent. This reflects Toronto Hydro's productivity achievement and ordinarily should be used for purposes of setting rates. However, instead of the empirically-derived efficiency-factor of 0.15 percent, Toronto Hydro proposes the adoption of a higher factor of 0.75 percent that is composed of the 0.15 percent efficiency-factor and a proactive performance incentive of 0.6 percent. The former drives continuous improvement in efficiency consistent with benchmarking expectations, and the latter functions as an incentive mechanism to achieve outcomes and deliver customer benefits associated with the 2025-2029 investment plan.

Any combination between the empirical efficiency-factor and the performance incentive that make-up the total X-factor should be capped at 0.75 percent in order to maintain balance between the utility risk and customer reward derived from the PIM. The balance is assessed by the cost of the incentive to be paid by customers over the 2030-2034 rate period relative to the value of the direct benefits to ratepayers over that period derived from meeting the targets proposed in the 2025-2029 Custom Scorecard. This analysis is presented in Exhibit 1B, Tab 3, Schedule 1 at section 3.

Toronto Hydro carries the risk of achieving the performance outcomes since, if the targets are not achieved, Toronto Hydro cannot earn its approved return on equity ("ROE"). As such, the PIM is an asymmetrical incentive to the benefit of customers in that it provides Toronto Hydro with the opportunity (not the guarantee) to earn the approved ROE and make a fair return for its shareholder. It is aligned with the RRF, and responsive to the OEB's feedback in Toronto Hydro's 2020-2024 decision encouraging the utility to consider an alternative

approach in the future that meets RRF requirements and improves the balance of risk between customers and the utility.[24]

The PIM balances efficiency and other important performance outcomes within an incentive mechanism that places greater accountability on the utility for delivering value for money and benefits to ratepayers. In the event that some (or all) of the outcomes are not achieved, the PIM is not met, which means that ratepayers keep some (or all) of the incentive that was credited to them during the 2025-2029 rate period. This approach protects ratepayers and shifts risk onto the utility to manage the funding challenge described in this schedule while balancing grid performance and service quality outcomes that are important to customers and stakeholders now and in the future.

The PIM is linked with the 2025-2029 Custom Scorecard detailed in Exhibit 1B, Tab 3, Schedule 1. The scorecard includes weighted metrics and proposed targets which capture key objectives and outcomes of Toronto Hydro's plan, including but not limited to efficiency. As it is tied to a comprehensive five-year plan, the Custom Scorecard is established on a five-year basis, covering the entire 2025-2029 rate period. Though Toronto Hydro has proposed a continuation of annual reporting against the scorecard, the targets on the scorecard are set on a five-year basis, and do not include annual targets as Toronto Hydro's application is based on an integrated five-year investment plan and not five annual plans. This is important since Toronto Hydro requires the flexibility to execute its multi-year plan and adapt to externally-driven changes and more complex operating dynamics that it may face in that regard.[25]

[24] EB-2018-0165, Decision and Order (December 19, 2019) at page 24.
[25] For a summary of the operational and work execution challenges that the utility faces operating in a dense urban environment please refer to Exhibit 1B, Tab 3, Schedule 3 at pages 3 to 9.

The targets proposed in Exhibit 1B, Tab 3, Schedule 1 are carefully calibrated to Toronto Hydro's proposed plan, as outlined in this application. To the degree final approval of Toronto Hydro's 2025 to 2029 investment plan and rate-setting approach varies materially from what the utility proposed in pre-filed evidence, the performance results identified in the targets must be reviewed and recalibrated to align with the implications of the OEB's decision. Further, given the careful establishment of proposed targets, their relationship with top-line capital and OM&A funding in rates is dynamic and multi-dimensional, which means that a simple pro-ration of proposed targets would not yield appropriate outcomes. For these reason, Toronto Hydro proposes to defer the finalization of the targets to a second phase of this proceeding that can be run in parallel with the Draft Rate Order process. Putting in place a dedicated process to consider updated targets, armed with full knowledge of approved funding and other OEB Decision parameters, enables Toronto Hydro, intervenors and the OEB to finalize PIM targets which appropriately balance incentives, risk, achievability, and difficulty.

To implement the PIM, Toronto Hydro proposes a new deferral account – the Performance Incentive Mechanism Deferral Account (PIM-DA) – to record the PIM earnings. This account would be brought forward for review and disposition in the utility's next rebasing application, based on known (or forecasted) performance results for the 2025-2029 rate period. Only if the set performance targets are achieved (or forecasted be achieved with a high degree of confidence) by the end of the rate term would the incentive be recovered from customers in the next decade. As such, Toronto Hydro confirms that that there would be no rate recovery associated with the PIM in the 2025-2029 period.[26]

[26] Please refer to Exhibit 9, Tab 1, Schedule 1, Appendix C for a Draft Accounting order for the PIM-DA.

The earnings under the PIM, if targets are fully achieved, allow Toronto Hydro to earn its foregone revenue associated with the proactive 0.6 percent reduction provided to customers upfront through the X-factor. Earning this amount back is only sufficient to enable the utility to achieve its approved ROE. In other words, the PIM is an asymmetrical mechanism to the benefit of customers, as meeting the performance targets set out in 2025-2029 Custom Scorecard does not give rise to the possibility of utility overearnings.

3.2.2 Innovation Fund

In alignment with the OEB's statutory objective to facilitate innovation in the electricity sector, Toronto Hydro proposes to establish an Innovation Fund to support the design and execution of innovative pilot projects over the 2025-2029 rate period.[27] The pilot projects undertaken through the Innovation Fund would be focused on testing new technologies, advanced capabilities and alternative strategies that enable electrification grid readiness and are responsive to the OEB's expectations with respect to facilitating DER integration, as expressed in the Framework for Energy Innovation (FEI*)* report.[28]

The proposed Innovation Fund is an important part of Toronto Hydro's 2025-2029 Custom Rate Framework because it addresses needs that are not adequately met by existing funding mechanisms which favour investment where the beneficial outcomes are proven or certain. The Innovation Fund supports important utility work that is more early stage, exploratory and developmental in nature, and as such where the outcomes are less certain, but the potential benefits for the system and customers could be significant. While the benefits of individual projects may not be immediate or certain, and some initiatives may prove to be

[27] Please refer to Exhibit 1B, Tab 4, Schedule 2 for more information about the Innovation Fund proposal.
[28] Ontario Energy Board, Framework for Energy Innovation: Setting a Path Forward for DER Integration (January 2023) https://www.oeb.ca/sites/default/files/FEI-Report-20230130.pdf

more or less fruitful than others, this type of work is nevertheless critical to achieving real innovation during a time of unprecedented change and transformation in the energy sector.

The Innovation Fund would also assist Toronto Hydro in overcoming the challenges of pursuing innovation in the context of a rate cycle that generally requires investment planning to be carried out far in advance and that requires spending to be classified either as a capital or operating expense. It provides Toronto Hydro with operational flexibility to identify and pursue the research, development and piloting of new technologies, capabilities and strategies throughout the rate period, and to determine the types of expenditures (i.e. capital or operating) in real time based on project specific details. For these reasons, the Innovation Fund would enable the utility to be more responsive to emerging needs and technologies as they arise during the rate period, and to scope, design and implement pilot projects and other exploratory initiatives more effectively.

Toronto Hydro carefully considered the amount of funding requested for this proposal. Based on research, the utility decided to allocate 0.3 percent of the proposed revenue requirement to the Innovation Fund, which amounts to approximately $16 million over the 2025-2029 rate period. This is the low end of a range found in research of comparable ratepayer-funded initiatives aimed at facilitating innovation by utilities and regulatory bodies in other jurisdictions, as well as general data on utility spending for research and development activities.

Toronto Hydro proposes to collect the amount allocated to the Innovation Fund through a rate rider (rather than through base rates) in order to provide transparency to ratepayers on the bill and flexibility to the utility to determine how the funds should be allocated across capital and operational expenditures on the basis of the selected pilot projects. Toronto

Hydro proposes to establish a new variance account to record variances between the amounts collected by the rate rider and the actual costs incurred to execute the selected pilot projects as part of the Innovation Fund.

For more information about the Innovation Fund proposal, please refer to Exhibit 1B, Tab 4, Schedule 2, which (i) outlines the Governance Framework to administer the proposed Innovation Fund, (ii) discusses the areas of innovation targeted by the fund, and (iii) describes various pilot project concepts that are being considered as part of this proposal.

3.2.3 Demand Related Variance Account (DRVA)

This application is being filed during a time of unprecedented change and transformation, as customers, communities and governments at all levels are actively embarking on an energy transition to mitigate the existential and economic impacts of climate change. Decarbonization is expected to create new roles for electricity, including as an energy source for transportation and building heating systems. While there is certainty that fundamental change is ahead, there are degrees of uncertainty about how that change will unfold (e.g. the pace and adoption of electrified technologies such as EVs and heat pumps; the role of low-emission gas; and the scale of local vs. bulk electricity supply). To address this uncertainty within its 2025-2029 Custom Rate Framework, Toronto Hydro proposes a symmetrical variance account that protects both ratepayers and the utility from structural unknowns in forecasted costs and revenues, during this time of change and evolution with respect to the role of electricity in the energy system.

Subject to OEB approval, Account 1508 – Demand-Related Variance Account (DRVA) would record: (i) the demand-driven revenue requirement impacts arising from variances in actual versus forecast capital and operational expenditures for certain demand-based programs

(the Expenditure Variance Sub-Account); and (ii) the revenue impacts arising from variances in forecast versus actual billing determinants over the rate period (the Revenue Variances Sub-Account). To that end, the account will consist of two subaccounts:

1. The Expenditure Variances subaccount would record the symmetrical revenue requirement impacts, including PILs, arising from the variance between 2025-2029 planned and actual expenditures related to the following capital and operations programs: Customer Connections, Customer Operations, Stations Expansion, Load Demand, Non-Wires Solutions, Generation Protection Monitoring and Control and Externally-Initiated Plant Relocations and Expansions (collectively the "Demand-Related Investments").
2. The Revenue Variance subaccount would record the revenue impacts resulting from weather-normalized variances in billing determinants (i.e. customer count, kWh and kVA).

The DRVA satisfies the OEB's eligibility criteria of causation, prudence and materiality.

- **Causation**: The amounts to be captured in the DRVA are outside of the base upon which the rates proposed in the current application are derived, as they relate to variances driven by external factors (e.g. customer demand, public policy and technology changes) that are clearly outside of the utility's control.
- **Prudence**: With respect to prudence, the incremental costs that would be captured in the DRVA are presumptively prudent in that they are necessary to ensure that Toronto Hydro is able meet its obligation to serve customers and provide non-discriminatory access to the grid.
- **Materiality**: While Toronto Hydro makes significant efforts to forecast cost and revenues, as discussed below and throughout the evidence, the pacing and level of

demand can deviate from the levels forecasted.[29] Given the breadth, scale and potential variability of the demand drivers considered in the plan, Toronto Hydro believes that the amounts recorded in the proposed account could be material and over time, exceed the utility's $1 million materiality threshold.

1. DRVA: Expenditure Variance Subaccount

The need for the Expenditure Variance Subaccount arises from Toronto Hydro's statutory obligation to serve and provide non-discriminatory access to the grid, together with the compounding effect of potential variability in Demand-Related Investments due a multitude of factors outside the utility's control that can affect the pace and type of demand growth over the period. These factors include:

- public policy changes mandating or encouraging customers to decarbonize-through-electrification,
- customer adoption rates of electrified technologies such as EVs, heat pumps, solar panels and energy storage systems, and
- technology market advancements providing customers and/or the utility access to new or more cost-effective demand-management tools.

Demand-Related Investments are tied to factors that are external to Toronto Hydro causing the need, pacing and prioritization of these investments to be externally-driven by third-parties or other factors outside of Toronto Hydro's control. For example, policy objectives related to decarbonization-through-electrification could accelerate customer adoption of EVs or other fuel switching technologies. Similarly, government policies or procurement programs could create an expanded role for Distributed Energy Resources ("DERs") in the deployment of coordinated infrastructure solutions to facilitate electrification, or other

[29] See Capacity Planning evidence in Exhibit 2B, Section D4 and the Load Forecast evidence in Exhibit 3, Tab 1.

policy objectives. As a result of such external factors, the pacing and level of certain expenditures can unexpectedly change and materially deviate from forecasted investment levels ultimately approved for recovery in base rates. The utility risk is that, over the rate period, these investment needs could be materially higher than the forecast embedded in rates. The pace and magnitude of potential change due to the combination of organic growth volatility observed in the current rate term, and the acceleration of an unprecedented energy transition renders this risk outside of tolerance from a forecasting perspective. [30]

Toronto Hydro faced a similar, albeit less pervasive risk, a decade ago related to externally-driven plant relocations to enable major infrastructure projects including the development of new and expanded transit lines across the Greater Toronto Area. To manage this risk in the context of a multi-year plan, in the 2015-2029 rate application Toronto Hydro requested (and the OEB approved) the Externally-Driven Capital variance account recognizing that "[*a]s these projects are completely outside Toronto Hydro's control as to both need and timing, they are appropriate for a variance account*."[31] This account continued in the 2020-2024 rate period. For the 2025-2029 period, Toronto Hydro proposes to consolidate this account into the DRVA in order to improve regulatory efficiency by reduce the number of Group 2 accounts that the utility needs to manage.

[30] For example, in the current rate period capital in-service additions related to System Access investments where approximately $153 million (32.5 percent) greater than the amounts included in base rates in the 2020-2024 rate period primarily due to increased expenditures in demand-driven programs such as Customer Connections (Exhibit 2B, Section E5.1) and Load Demand (Exhibit 2B, Section E5.3). Toronto Hydro had to make additional investments in these programs in order to fulfil its core obligation to connect new and expanded services to the grid, including a higher than anticipated volume of system access requests for large projects (greater than 5 MVA demand) over this period.
[31] EB-2014-0116, OEB Decision and Order (December 29, 2016) at page 50.

In the current rate period, Toronto Hydro saw a significant increase in the volume and complexity of load connections. From 2020 to 2022, high voltage connections (which often require expansion work) increased by 27.6 percent, with a substantial increase in larger commercial and multi-use projects requiring greater than 10 MVA of demand load per project, as well data centers with larger loads (e.g. 30-50 MVA) than ever before. These circumstances resulted in gross expenditures in the 2020-2024 Customer Connections program that are expected to be approximately 1.75 times greater than initially planned in order to meet these requirements and preserve other key outcomes of the 2020-2024 plan (e.g. maintain reliability, remove transformers at risk of containing PCBs from the grid by 2025).

The trend in Customer Connections is expected to continue in the 2025-2029 rate period. Projects in the City of Toronto's development pipeline from 2017 through 2022 established a new five-year record with over 717,327 residential units and 14,484,961 square meters of non-residential gross floor area planned for completion in the next rate period, or shortly thereafter. This pace could increase further as a result of *Ontario's More Homes Built Faster Act, 2022* which is intended to expedite development approvals and encourage development with tax incentives and funding mechanisms.[32] This likewise impacts the Customer Operations program which includes activities such as field work and support functions to safely, efficiently, and promptly meet customer connections related requests.

In addition to the foregoing, the City is experiencing a shift to clean energy and electrification through the adoption of technologies such as EV charging, electric heat pumps and water heaters. Immediate growth areas being supported by Toronto Hydro's distribution system

[32] *More Homes Built Faster Act*, 2022, S.O. 2022, c. 21 - Bill 23; Ontario, Backgrounder More Homes Built Faster Act, 2022 (November 28, 2022) https://news.ontario.ca/en/backgrounder/1002525/more-homes-built-faster-act-2022.

include EV charging for public streets, City fleet vehicles (including TTC), Toronto Parking Authority parking lots, residential homes, commercial and residential developments. Ongoing and other evolving areas include heating and cooling systems (i.e. heat pumps) and complete home electrification at single-family residential home and residential complex levels.

On August 24, 2023, for example, the OEB issued a Staff Bulletin on Residential Customer Connections and Service Upgrades to provide guidance as a result of OEB staff receiving questions and complaints regarding residential customer connection practices pertaining to cost responsibility.[33] Within this bulletin, OEB staff noted that with the shift to electrification currently underway in Ontario, an increasing number of prospective homeowners will likely seek residences that can readily support electrical service that can accommodate the demands of equipment such as EV chargers and heat pumps. Observing this change in consumer preferences and attitudes, OEB staff highlighted the need for distributors to ensure their distribution systems will support the increasing demand for residential electrification. OEB staff expressed that "*it is good practice for distributors to provide new residential customers with capacity (both transformation and conductor) to accommodate a 200-amp service under their Basic Connection policy*."[34] Toronto Hydro recognizes that similar policy guidance may be forthcoming requiring quick response and effective implementation to help enable decarbonization-through-electrification public policy objectives.

[33] OEB Staff Bulletin *RE: Residential Customer Connections & Service Upgrades* (August 24, 2023): https://www.oeb.ca/sites/default/files/OEB-Staff-Bulletin-Residential-Customer-Connections-20230824.pdf
[34] *Ibid* at page 2.

When faced with incremental distribution investment needs as a result of external drivers, Toronto Hydro must typically defer necessary expenditures in other investment priority areas, such as System Renewal, System Service and General Plant. Yet, to the extent Toronto Hydro does not carry out the planned investments in these areas, there could be significant reliability, safety or environmental risks that remain unmitigated, or customer needs and outcomes that are unmet.[35] The proposed Expenditure Variance Subaccount, if approved, would enable Toronto Hydro to respond to unforeseeable increases in demand-related investment needs without having to defer other priority work within the plan and put customer outcomes at risk.

Although Toronto Hydro does not expect that demand-related investments would be lower than forecast, it is possible that material changes in economic conditions, such as a recession, could slow down the pace of forecasted demand, or that a change in geopolitical dynamics affecting global supply chains could hinder the availability of electrified technologies such as EVs and heat pumps. In circumstances where demand-related investments are lower than planned, the subaccount would protect ratepayers by ensuring that (i) they do not pay for demand-driven work that can be deferred, and (ii) funds are not repurposed to manage variances in other aspects of the plan that are not driven by demand.

Unanticipated demand changes can impact the plan in different ways. The paragraphs that follow explain the nature of the Demand Related Investments programs and provide context

[35] For example, in the current rate period, Toronto Hydro decided to defer planned investments in Underground System Renewal (Exhibit 2B, Section E6.2 and E6.3) and Overhead System Renewal (Exhibit 2B, Section E6.5) programs to balanced capital funding pressures driven by the 0.9 percent capital stretch factor and by higher than forecasted expenditures in Demand-Related Investments in Customer Connections (Exhibit 2B, Section E5.1), Load Demand (Exhibit 2B, Section E5.3) and Stations Expansion (Exhibit 2B, Section E7.2). For more details please refer to Exhibit 2B, Section E4.1.2.

with respect to the unanticipated demand changes and factors that can impact actual expenditures in these programs.

a. Load Demand Program

The Load Demand program (Exhibit 2B, Section E5.3) alleviates emerging capacity constraints to ensure that there is sufficient capacity available to connect customers to Toronto Hydro's distribution system in a timely and efficient manner. To satisfy connection obligations, Toronto Hydro must maintain adequate capacity on its system to keep pace with load growth and to ensure that its assets are not overloaded. The rapid influx of dense load in the downtown core and horseshoe areas of the City pose a challenge to Toronto Hydro's ability to meet its service requirements. Over the 2025-2029 rate period, Toronto Hydro expects multiple station buses to reach their rated capacity. The forecasted growth in the distribution system is based on the System Peak Demand Forecast outlined in Exhibit 2B, Section D4. However, actual demand will vary by the actual realization of load in the system. This can depend on the above noted factors, including emerging trends such as EV uptake and pacing of heating electrification. To meet these requests in a timely and cost-effective manner and maintain reliability and service quality for existing customers, Toronto Hydro has to invest in infrastructure upgrades and load transfers to alleviate localized capacity constraints.

b. Stations Expansion Program

The Stations Expansion program (Exhibit 2B, Section E7.4) is driven by capacity constraints at the station or regional level, which can no longer be effectively managed by the Load Demand program. Uncertainty regarding increased and continued densification, population growth, and electrification could driver further need to relieve the station loading and expand system capacity. Depending on policies implemented by different levels of

government, changes in customer behaviour, and ongoing societal decarbonization efforts, there are a wide range of potential impacts on Toronto Hydro's distribution system. For example, using the Future Energy Scenarios model, the impact of the high electrification/low efficiency scenario ("NZ40 – Low") projects a large increase in system load which would translate into additional investment in the Stations Expansion Program in order to meet system capacity needs in this scenario, as shown in Table 6 below.

Table 6: Incremental Stations Expansion Investment under NZ40-Low Scenario

Rate Period	Additional Investments ($ Million)[36]
2025-2029	44
2030-2034	186
2035-2039	527

c. Regional Planning Process

Another variable that could affect demand-related investments is the regional planning process described in Exhibit 2B, Section B3. While the investments planned in the Stations Expansion program are aligned to meet the needs identified in the most recent Needs Assessment at the regional planning level, Toronto Hydro is currently in the middle of a regional planning cycle that will not conclude until 2025. This process will draw from a number of options to meet the electricity needs identified in Toronto, including conservation and demand management ("CDM"), distributed generation, non-wires solutions, and traditional wires-only solutions. Outputs of this process, or additional updates during the rate term, could modify planned investments under the Stations Expansion program, or other Demand Related Investment programs, resulting in the need to change or increase the level of investment.

[36] This is the additional investment needed incremental to the 2025-2029 investment proposed in this Program, and incremental to the 2030-2034 expenditures forecasted for the Downsview TS and Scarborough TS expansion projects.

d. Connection and Integration of Distributed Energy Resources (DER)

As of 2022, Toronto Hydro connected 2,424 DERs to its grid totaling 304.9 MW in capacity. The utility forecasts DER connections (including energy storage) to reach an estimated 516.7 MW by the end of 2029.[37] Policy, economic conditions and consumer preferences, could facilitate growth in DERs beyond anticipated levels. These changes can be spurred by existing or forthcoming government action at the global, national and local levels, such as the federal clean electricity tax credit, or recent provincial regulatory changes enabling third-party ownership of net-metered generation facilities.[38]

The Generation Protection, Monitoring, and Control (Exhibit 2B, Section E5.5) program enables Toronto Hydro to fulfill its regulatory obligations to connect DER projects to its grid in a safe manner, and alleviate restrictions on the grid such as short circuit capacity constraints to enable the connection of DERs. Depending on the system location and extent of the unanticipated demand change, and the penetration of DER including renewable electricity generation ("REG") projects, Toronto Hydro could also explore additional Non-Wires Solutions ("NWS") investments in either demand-side Flexibility Services or grid-side Renewable-Enabling Battery Energy Storage Systems (Exhibit 2B, Section E7.2) as alternatives to conventional poles and wires solutions.

e. Customer Operations

Toronto Hydro receives a high volume of requests for connections and upgrades for residential and commercial developments each year, which are address through the

[37] Exhibit 2B, Section E3 at pp. 1-3.
[38] Government of Canada, Budget 2023, *Chapter 3: A Made-In-Canada Plan: Affordable Energy, Good Jobs, and a Growing Clean Economy* (March 28, 2023) online: <https://www.budget.canada.ca/2023/report-rapport/chap3-en.html#m17>.; O. Reg. 386/22: Net Metering under *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15, Sched. B

Customer Operations program (Exhibit 4, Tab 2, Schedule 8). Toronto Hydro may be required to undertake expansion and enhancement work to enable certain connections particular in the dense downtown core or rapidly growing transit corridors. Over the past three years, both the volume and average complexity of expansion work has remained high. Toronto Hydro's Key Account customers (i.e. the largest customers and those customers who have critical loads like hospitals, financial institutions, essential public services and developers), have unique needs in relation not only to complex connections and expansions, but also other priorities like power quality, resilience, ESG objectives and behind-the-meter energy solutions. A material increase in the volume or complexity of Customer Connections as described above, yields a corresponding increase in the need for operational support to address customer needs and expectations.

f. Externally Initiated Plant Relocations and Expansions

The City is experiencing a period of significant infrastructure renewal, neighbourhood revitalizations, commercial development and large transit expansions. The Externally Initiated Plant Relocations and Expansion (Exhibit 2B, Section E5.2) program captures work that the utility must undertake to relocate its infrastructure in response to third-party relocation requests and to enable third-party construction projects to proceed in a timely manner. Relocation requests by third parties are usually received from those required to maintain, upgrade, expand and improve existing public infrastructure such as roads, bridges, highways, transit systems, transmission stations and rail crossings. The timing, pace and expenditures under this program are driven by third-party projects that are entirely outside of Toronto Hydro's control, which is why in the last two rate applications the utility requested and the OEB approved the Externally-Driven Capital variance account.[39] For the

[39] EB-2014-0116, Decision and Order (December 29, 2016) at page 50 and EB-2018-0165, Decision and Order (December 19, 2019) at page 198.

2025-2029 rate period, Toronto Hydro proposes to consolidate this account into the DRVA in order to reduce the number of Group 2 accounts that the utility needs to manage and improve regulatory efficiency.

2. Demand-Related Revenue Variance Subaccount

The same external factors (i.e. policy, technology and consumer behaviour) that drive variances in expenditures can also yield variances in billing determinants (i.e. kVa, kWh and customer count) relative to the load and customer forecast set out in Exhibit 3, Tab 1. Such variances in billing determinants can result in lower or higher revenues than forecasted when setting base rates for 2025-2029 that can pose a risk to both ratepayers and the utility. This is a structural forecasting risk that emanates from entering a period of energy transition that results in greater uncertainty and the potential for greater variability with respect to how demand manifests in terms of revenues. To hold the utility and ratepayers harmless from this risk, Toronto Hydro proposes the Revenue Variance subaccount to symmetrically record revenue variances resulting from differences between forecasted and actual billing determinants on a weather normalized basis. The revenue variances recorded in the Revenue sub-account would be tracked at a rate class level so that they can be properly disposed to the same rates classes at the next rebasing.

With this subaccount, Toronto Hydro's CRCI becomes a true revenue cap model (subject to weather-driven variances), rather than a revenue requirement cap, with the revenue variance sub-account operating similar to a decoupling true-up mechanism.[40] Whereas in the past the merits of revenue decoupling were explored through the lens of declining use and resulting earnings attrition due to energy efficiency, Toronto Hydro sees equal merit to

[40] EB-2010-0060, Review of Distribution Revenue Decoupling Mechanisms, (March 19, 2010) at page iv: <https://www.oeb.ca/oeb/_Documents/EB-2010-0060/Report_Revenue_Decoupling_20100322.pdf>.

using revenue decoupling as a means to address energy transition forecasting challenges, including but not limited to the role of energy efficiency measures. As the pace of change in the 2025 to 2029 period remains subject to degrees of uncertainty, Toronto Hydro believes this mechanism is an appropriate means to ensure that neither ratepayers nor the utility or its shareholder are unduly burdened or rewarded by billing determinant variances during this transitional time.

3.3 Other Aspects of the Framework

3.3.1 Earnings Sharing Mechanism (ESM)

In the 2020-2024 rate application (EB-2018-0165), the OEB approved an asymmetrical earnings sharing mechanism ("ESM") with a 100-basis point dead band on a cumulative five-year basis.[41] The approved ESM represented a transition from Toronto Hydro's previous ESM over the 2015 to 2019 period; transitioning away from a symmetrical ESM to an asymmetrical ESM, and calculating ESM amounts based on ROE as opposed to a comparison of Non-Capital Related Revenue Requirement variances.[42]

Toronto Hydro proposes to continue the ESM as approved by the OEB in EB-2018-0165, including the OEB's finding that "*certain adjustments will be required for a ROE-based ESM calculation in order to account for out-of-period items and to ensure there is no double counting*."[43] Where such adjustments are required, Toronto Hydro intends to make them when evaluating ESM entries (or non-entries) at the end of the next rate term. All of the above is consistent with the methodology presented in Exhibit 9, Tab 1, Schedule 1 as it relates to Toronto Hydro's current ESM.

[41] *Supra* note 26 at page 193.
[42] *Ibid*.
[43] *Ibid.*

With respect to the PIM Deferral Account ("PIM-DA"), under Toronto Hydro's proposal there is no interaction between the PIMDA and ESM. Earnings under the PIM (only if targets are fully achieved) allow Toronto Hydro to earn the foregone revenue associated with the 0.6 percent portion of the X-factor that was proactively reduced from the utility's revenue and given to customers upfront as a rate reduction. Earning this amount back is only sufficient to enable the utility to achieve its approved ROE. As such, it would not be suitable for the 2025-2029 ESM proposed in this application to include the PIM earnings associated with earning back the 0.6 percent.

To the degree Toronto Hydro's 2030 to 2034 rate-setting approach incorporates a continuation of the ESM, or a similar ESM, Toronto Hydro expects ROE for the purpose of determining any ESM amounts would be adjusted for out-of-period transactions, consistent with the OEB's standard practice for determining Regulated ROE.[44] Such adjustments would include earnings associated with 2025-2029 PIM amounts, as these earnings relate to investments made during the 2025 to 2029 rate period.

3.3.2 Off-ramps and Z-factor

Toronto Hydro proposes to continue to apply the OEB's generic policy with respect to off-ramps for the 2025-2029 rate term (as outlined in the Rate Handbook), and proposes that it continue to be allowed to have Z-factor relief available based on the OEB's generic criteria for such relief (as set out in the Report of the Board on 3rd Generation Incentive Regulation).[45]

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[44] Ontario Energy Board, *Electricity Reporting and Record Keeping Requirements* (March 8, 2023) at Section 2.1.5.6.
[45] Ontario Energy Board, *Handbook to Utility Rate Applications* (October 2016) at page 28; see also Ontario Energy Board, *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (July 14, 2008) at pp. 35-36 and Appendix A at pp. 4-6.

Review of Rate Framework

Submitted On Behalf of

Toronto Hydro-Electric System Limited

d/b/a Toronto Hydro

November 17, 2023



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Appendix A Summary of Qualifications

Appendix B Jurisdictional Review of Modernized Performance-Based Regulation

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Timothy S. Lyons. My business address is 3 Speen Street, Suite 150, Framingham, Massachusetts 01701.

Q. What is your current position?

A. I am a Partner at ScottMadden, Inc. ("ScottMadden").

Q. Please describe your work experience and educational background.

A. I have more than 30 years of experience in the energy industry. I started my career in 1985 at Boston Gas Company, eventually becoming Director of Rates and Revenue Analysis. In 1993, I moved to Providence Gas Company, eventually becoming Vice President of Marketing and Regulatory Affairs. Starting in 2001, I held management consulting positions in the energy industry first at KEMA and then at Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at Vermont Gas Systems, Inc. before joining Sussex Economic Advisors, LLC ("Sussex") in 2013. Sussex was acquired by ScottMadden in 2016.

I hold a bachelor's degree from St. Anselm College, a master's degree in economics from The Pennsylvania State University, and a master's degree in business administration from Babson College.

A summary of my qualifications is attached as Appendix A.

Q. Are you sponsoring other appendices in connection with your testimony?

A. Yes. I am sponsoring Appendix B 'Jurisdictional Review of Performance-Based Regulation Mechanisms'.

II. EXECUTIVE SUMMARY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present our review of Toronto Hydro's (the "Company") proposed changes to its Custom Rate Framework ("Rate Framework"). The testimony describes how the Company's proposed changes are appropriate in the context of how other electric utility ratemaking practices have responded to developments in the energy industry.

The review relied on a jurisdictional scan of performance-based regulation conducted by ScottMadden. The jurisdictional scan is attached as Appendix B of this testimony.

Q. What is the principal conclusion of ScottMadden's review?

A. The principal conclusion presented in this testimony is that the Company's proposed changes to the Rate Framework are generally consistent with how other electric utilities have responded to developments in the energy industry, recognizing there are differences in service areas and jurisdictional requirements.

The energy industry is going through a period of significant change driven by new technologies, policy goals, and consumer expectations. These changes are driving significant utility investments and related costs to support an increasingly decarbonized, decentralized, and digitalized electric grid while maintaining safe and reliable service. For example, capital spending across the electric industry has increased significantly over the past decade, with capital spending increasing from $32.1 billion in 2011 to $70.4 billion in 2021, or a

Compound Annual Growth Rate ("CAGR") of 8.17 percent. Capital spending is expected to continue to increase in the future.[1]

Toronto Hydro has also projected significant investment needs in its five-year plan. As discussed in Toronto Hydro's application, these investments are informed by customer expectations and priorities, such as reliable service, support for new technologies, and support for system capacity infrastructure.

Given these developments in the energy industry, many regulatory jurisdictions have implemented changes to ratemaking frameworks and practices. These changes are designed to incorporate expanded objectives and priorities, such as clean energy goals, affordability, reliability, emission reduction, and utility financial integrity. The changes also include revisions to rate setting mechanisms (such as 'I-X' indexing mechanisms) to ensure adequate cost recovery, flexibility in cost recovery to address uncertainties, performance incentives, and funding for innovative projects.

Q. Please elaborate on how other electric utilities have modified ratemaking practices in response to developments in the energy industry.

A. The changing energy industry has prompted various modifications to ratemaking frameworks and practices. These changes are generally designed to provide cost recovery flexibility and stability to help address challenges related to the changing grid needs. Specifically, multi-year rate plans and performance-based regulation ("PBR") frameworks and practices have been modified as follows:

[1] EEI, Statistical Yearbook of the Electric Power Industry (Published August 2023). Investments reflect nominal dollars.

1. **Attrition Relief Mechanisms ("ARMs")** modified to reflect the scale and timing of investments.
   - For example, regulatory jurisdictions, such as the United Kingdom ("UK"), Australia, Philippines, and Malaysia, utilize a "building blocks" approach that reflects forecasted capital investments and operations, maintenance, and administration ("OM&A") expenditures within multi-year ratemaking frameworks.[2] This approach better aligns cost recovery with the scale and timing of capital and OM&A needs.
2. **Alternative Cost Recovery Mechanisms** to reflect uncertainties including technology adoption, policy developments, customer demands, and cost forecasts.
   - For example, the UK RIIO[3] framework includes uncertainty mechanisms that provide investment flexibility regarding the timing and adoption of low-carbon technologies. The UK regulating agency Ofgem recognized the importance of such mechanisms, stating: "…[uncertainty mechanisms ensure that] if the uptake of EVs or HPs [heat pumps] is faster than expected, then investment can track these changes and flex quickly and efficiently in response".[4]
3. **Performance incentive mechanisms ("PIMs")** to align utility priorities with policy objectives.

[2] London Economics International, Study of Retail Rates of Kansas Electric Public Utilities, January 8, 2020, at p.156
[3] Revenues = Incentives + Innovation + Outputs
[4] Ofgem, RIIO-ED2 Draft Determinations – Core Methodology Document, June 29, 2022, p. 32

- For example, jurisdictions, such as Hawaii, New York, and UK have PIMs in place. The Hawaii Public Utilities Commission ("HPUC") noted that PBR mechanisms offer a way to "restructure utility financial incentives to achieve specific, identified desirable or beneficial outcomes, such as meeting renewable energy targets, reducing greenhouse gas emissions, or improving reliability and resilience."[5]

4. **Separate funding for innovative projects** that provide lessons learned on new technologies and cost-saving initiatives that support the energy transition.
    - For example, New York and UK jurisdictions have created separate cost recovery mechanisms for utilities to fund innovative projects and have developed processes to share lessons learned across the utilities.

Q. How is Toronto Hydro's proposed changes to the Rate Framework consistent with the changes in ratemaking frameworks and practices discussed above?

A. Toronto Hydro is facing similar changes in the energy industry as other electric utilities. The changes drive the scale and timing of Toronto Hydro's investment priorities that in turn drive an evolution of Toronto Hydro's ratemaking framework and practices, similar to other electric utilities.

Changes to the Company's proposed Rate Framework and how these align with other electric utilities are summarized in Figure 1 (below):

[5] Docket No. 2018-0088, Order No. 35411 Proceeding to Investigate Performance-Based Regulation, Hawaii Public Utilities Commission, April 18, 2018, p. 14

Figure 1: Comparison of Toronto Hydro's Proposed Changes

Proposed Rate Framework Modifications	Comparison with Industry Ratemaking Practices
1. Revenue Growth Factor – Reflects Company's forecasted capital and OM&A needs	■ UK, Australia, and other jurisdictions utilize "building blocks" approach that includes forecasted capital and OM&A ■ New York electric utilities utilize a "stair-step" approach to forecast capital and OM&A for each year of their rate plan ■ This approach helps ensure adequate cost recovery for both capital and OM&A needs.
2. Modified Inflation Factor – Reflects Toronto Salary and Wage Index	■ California utilizes utility-specific cost indices to more accurately align cost recovery with costs
3. Demand-Related Variance Account – Provides flexible investment recovery to address uncertainties	■ UK RIIO framework includes uncertainty mechanisms that provide investment flexibility based on the timing and adoption of low-carbon technologies
4. Performance Incentives – Aligns utility and customer interests	■ Hawaii, New York, and UK have PIMs in place ■ These help align policy objectives and Company incentives ■ PIMs have been recognized as important to achieve desired policy outcomes
5. Innovation Fund – Provides funding for innovative projects that provide lessons learned for new technologies and initiatives	■ New York and UK have created separate cost recovery mechanisms for utilities to fund innovative projects and developed processes to share lessons learned across utilities

The Figure summarizes how the Company's proposed changes to the Rate Framework align with the industry ratemaking practices.

First, Toronto Hydro proposes a revenue growth factor ("RGF") that reflects year-over-year increases in its forecasted revenue requirements. The RGF captures the Company's projected needs in both capital and OM&A expenditures. Jurisdictions, such as UK and New York, have recognized the need to ensure adequate cost recovery of both capital and OM&A costs by including forecasted revenue requirements in their multi-year revenue requirements.

Second, Toronto Hydro proposes an updated inflation factor that better reflects its labor costs. There is also recognition in jurisdictions, such as California,

that indexing factors (such as inflation) should closely align with the underlying cost drivers.

Third, Toronto Hydro proposes a Demand-Related Variance Account ("DRVA") intended to provide investment flexibility to address uncertainties related to external drivers such as scale and pace of technology adoption, policy changes, macro-economic drivers, and global events. These variance accounts are similar to uncertainty mechanisms in place for UK utilities as part of the RIIO framework, which provide investment flexibility to address uncertainties related to the pace of electrification adoption.

Fourth, Toronto Hydro proposes performance incentives that better align utility interests with public policy goals and customer expectations. These have been recognized in the industry (such as in Hawaii, New York, and UK) as important tools to achieve desired policy outcomes.

Finally, Toronto Hydro proposes a separate funding mechanism for innovative projects. Innovative projects provide lessons learned on new technologies and cost-saving initiatives that support the energy transition. Jurisdictions, such as New York and UK, have created separate cost recovery mechanisms for utilities to fund innovative projects and have developed processes to share lessons learned across the utilities.

In conclusion, Toronto Hydro's proposed Rate Framework aligns with recent industry changes in ratemaking frameworks and practices that provide for increased investment flexibility, stable cost recovery, performance incentives that

align utility performance with customer priorities, and funding for innovative projects.

Q. How is the remainder of your testimony organized?

A. The remainder of this testimony is organized into the following sections:

Section III – Discussion of Toronto Hydro's proposed changes to the Rate Framework

Section IV – Comparison of the proposed Rate Framework in context of industry ratemaking practices

Section V – Summary and Conclusions

III. OVERVIEW OF RATE FRAMEWORK

Q. Please briefly describe Toronto Hydro.

A. Toronto Hydro is a wholly owned subsidiary of Toronto Hydro Corporation, whose sole shareholder is the City of Toronto. The Company delivers electricity to approximately 790,000 residential, commercial, and institutional customers. Toronto Hydro serves the largest city in Canada and distributes approximately 18% of the electricity consumed in Ontario. Toronto Hydro serves its customers using approximately 30,000 kilometers of wire and cable, 180,000 poles, and over 200 stations and substations.

Q. Please provide an overview of Toronto Hydro's currently approved 2020-2024 rate framework.

A. The Ontario Energy Board ("OEB") approved Toronto Hydro's Custom Incentive Rate-Setting ("CIR") framework to establish the Company's distribution rates over 2020-2024 period. Distribution rates for 2020 were established on a cost-of-service basis using a forecasted test year, whereas rates for 2021-2024 were established using a Custom Price Cap Index ("CPCI") formula.

The CPCI formula includes an inflation ("I") factor, a productivity ("X") factor, a capital growth factor ("C_n") offset for incremental funding from inflation and productivity factor ("S_{cap}*(I+X)"), and a growth ("g") factor.

$$\mathbf{CPCI = I - X + C_n - S_{cap} \times (I + X_{cap}) - g}$$

Capital investments in the Company's approved plan are based on forecasts for the plan term, adjusted for inflation and productivity stretch factors. The OM&A expenses are forecasted for the first year (2020) and then adjusted for inflation

and productivity factors over the course of the rate period. The inflation factor represents OEB's two-factor Input Price Index ("IPI") for electricity distributors, which is a weighted average of labour (30%) and non-labor (70%) annual price changes.

Q. Is Toronto Hydro proposing modifications to the currently approved rate framework?

A. Yes. Toronto Hydro proposes modifications that are intended to align the currently approved rate framework with the Company's evolving needs.

1. Introduce a Revenue Growth Factor ("RGF") to reflect Company's forecasted capital and OM&A needs
2. Modify the Inflation Factor to reflect changes in Toronto-specific Salary and Wages
3. Introduce a Demand-Related Variance Account to provide flexibility in investments to address uncertainties
4. Introduce Performance Incentives to align customer priorities and policy objectives
5. Introduce an Innovation Fund to provide a separate funding mechanism for innovative projects

Q. What is the purpose of the RGF?

A. The RGF more accurately reflects forecasted changes in capital and OM&A expenses over the term of the plan. Toronto Hydro projects substantial capital and OM&A expenses to sustain, expand, and modernize its network in alignment with customer and policy objectives.

The Company's rationale for RGF is discussed in further detail in the Company's application.

Q. What is the purpose of the modified inflation index?

A. The modified inflation index includes a custom labor index for Toronto Salary and Wages that better reflects Toronto Hydro's labor costs. The Company's rationale for the modified inflation factor is discussed in further detail in the Company's application.

Q. What is the purpose of the DRVA?

A. The DRVA is a two-way variance account mechanism that reflects uncertainties related to the energy transition, including the scale, pace, and location of technology adoption, policy developments, demand patterns, and cost forecasts. The DRVA is intended to ensure flexibility in cost recovery for demand-related investments. These investments are intended to address customer demands, which can vary depending on external factors.

The Company's rationale for DRVA is discussed in further detail in the Company's application.

Q. What is the purpose of the proposed performance incentives?

A. The proposed PIMs are intended to better align the Company's operating performance and its financial benefits. Specifically, the PIMs measure customer priorities and policy objectives, such as system reliability and resilience, efficiency and financial performance, customer service and experience, and environment, safety, and governance.

The Company's rationale for performance incentives is discussed in further detail in the Company's application.

Q. What is the purpose of the innovation fund?

A. The innovation fund provides funding for innovation projects that provide lessons learned on new technologies and cost-saving initiatives that support energy transition. Separate funding for these projects is necessary as there is inherent uncertainty in the benefits, costs, and timing of these projects.

The Company's rationale for the innovation fund is discussed in further detail in the Company's application.

Q. Are the Company's proposed changes to the Rate Framework generally aligned with how electric utilities are evolving their ratemaking frameworks and practices?

A. Yes. The Company's proposed changes to the Rate Framework are generally consistent with how other electric utilities have responded to developments in the energy industry, recognizing that there are differences in service areas and jurisdictional requirements. A comparison of the Company's proposed changes to industry ratemaking practices is discussed in the next section (below).

IV. COMPARISON WITH INDUSTRY RATEMAKING PRACTICES

Q. As an initial matter, are the Company's Rate Framework's objectives consistent with other ratemaking frameworks in the industry?

A. Yes. Ratemaking objectives have expanded within industry frameworks beyond traditional requirements of providing safe, reliable, and affordable service to better align with changing customer expectations and regulatory requirements.[6] Since 2018, U.S. jurisdictions have cited as many as 17 different policy goals for PBR frameworks, with reliability, emissions reductions, and cost control among the most commonly cited.[7] Common objectives, such as in Hawaii and UK, include a desire to advance policy objectives using administratively efficient frameworks that preserve utility financial integrity, provide flexibility, and protect customer interests.[8]

The Company's objectives in its Rate Framework are generally consistent with other electric utility ratemaking objectives. These include:[9]

- Deliver customer outcomes and advance public policy objectives.
- Balance the interests of customers and utilities/ shareholders.
- Ensure stability and predictability to facilitate effective multi-year planning and decision making.
- Provide flexibility to execute multi-year plans in dynamic circumstances.

[6] Rocky Mountain Institute, States Move Swiftly on Performance-Based Regulation to Achieve Policy Priorities, March 31, 2022, at: https://rmi.org/states-move-swiftly-on-performance-based-regulation-to-achieve-policy-priorities
[7] *Ibid.*
[8] Docket No. 2018-0088, Decision and Order No.36326, Hawaii Public Utilities Commission, May 23, 2019, p. 6. Ofgem, RIIO-2 Framework Decision, at p.4
[9] OEB File No. EB-2023-0195, Toronto Hydro Pre-Filing Stakeholder 2025-2029 Rate Application Engagement (October 4, 2023) at 20

- Protect customers and the utility from forecasting risk in times of uncertainty.

Specific changes to the Company's proposed Rate Framework and how these align with the industry ratemaking frameworks are discussed below.

A. Revenue Growth Factor

Q. Is the proposed Revenue Growth Factor consistent with other electric utility mechanisms?

A. Yes. The RGF, which includes forecasted capital and OM&A expenditures, is generally consistent with 1) the 'building blocks' approach used in jurisdictions, such as the UK, Australia, Philippines, and Malaysia, and 2) the 'stair-step' approach utilized by New York utilities.

Q. What is the building blocks method?

A. The building blocks method includes establishing revenues based on forecasted capital and OM&A expenditures for each year of the rate period. Forecasted costs are assessed using historical performance metrics, unit cost comparison, and industry-wide benchmarks.[10] Once the forecasted capital and OM&A costs are established, these form the basis for revenue requirements for the rate period.[11] The revenue requirements may be updated annually to account for performance incentives, tax impacts, inflation, or other supplementary funding mechanisms.

Q. What is the stair-step approach?

[10] London Economics International, Study of Retail Rates of Kansas Electric Public Utilities, January 8, 2020, at p.157
[11] *Ibid.*

A. The stair-step approach consists of predetermined increases in rates or revenues based on cost forecasts. This approach is also referred to as a "multiple forward test year approach".[12]

New York utilities, such as Consolidated Edison, utilizes the stair-step adjustment mechanism within their three-year gas and electricity distribution plans. The revenue escalation within the rate plan is based on detailed capital and OM&A forecasts for each of the three years. The detailed forecasts include sales, property taxes, depreciation expenses, capital additions, OM&A expenses, and other anticipated investments and expenditures.[13]

Q. Why is it important to forecast both capital and OM&A costs?

A. Forecasting both capital and OM&A, as demonstrated in the building blocks method, presents several advantages.

For example, the building blocks method provides greater alignment between costs and revenue recovery.[14] An indexed approach to OM&A funding during attrition years, for example, may result in inadequate OM&A funding relative to costs incurred.

In addition, the building blocks approach allows for the implementation of a clearly defined planning process for multi-year grid investment.[15] The approach considers both current and future system development when determining a price path.[16]

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[12] LBNL, State Performance-Based Regulation Using Multiyear Rate Plans, July 31, 2017, at p.4.2
[13] New York Public Service Commission (NYPSC), "Order Approving Electric and Gas Rate Plans," Dockets 16-E-0060, 16-G-0061, and 16-E-0196, January 25, 2017, p. 3-5
[14] London Economics, Case Studies: Comparator Industry Design and Regulation, prepared for the Department of Energy of Nova Scotia, at p.18
[15] Id., at p.153
[16] Australian Energy Market Commission, Perspectives on the building block approach, July 30, 2009, at p.5

B. Modified Inflation Factor

Q. Is Toronto Hydro's proposed change to the inflation factor consistent with other electric utility ratemaking practices?

A. Yes. There is recognition in industry ratemaking practices to align index factors (such as inflation) more accurately with underlying utility cost drivers.

For example, the California Public Utilities Commission ("CPUC") allows for utility-specific cost indices rather than a general inflation index such as Consumer Price Index ("CPI"), noting that "[t]he CPI reflects consumer retail price changes, not the escalation in wholesale purchase of utility goods and services."[17]

C. Demand-related Variance Account

Q. Is the DRVA consistent with similar mechanisms employed by electric utilities?

A. Yes. Similar to Toronto Hydro, electric distribution companies in the UK[18] face uncertainties relating to policy developments, demand patterns, cost forecasts, and the scale, pace, and location of technology adoption.

Similar to the DRVA, the UK RIIO framework includes uncertainty mechanisms that provide investment flexibility based on the timing and adoption of low-carbon technologies.

For example, the volume-driven uncertainty mechanism employed in RIIO ED-2 allows for adjustments in revenue allowances to accommodate changes in

[17] PG&E 2023 GRC. Exhibit-11, at p. 1-16
[18] Also referred to as 'Network Companies'.

volume (e.g., new connections, low carbon technology uptake).[19] The mechanism allows utilities to be flexible to a range of potential scenarios.

The UK regulating agency Ofgem recognized the need for mechanisms that provide investment flexibility to address uncertainty, stating that " …[uncertainty mechanisms ensure that] if the uptake of EVs or HPs [heat pumps] is faster than expected, then investment can track these changes and flex quickly and efficiently in response".[20]

D. Performance Incentive Mechanism

Q. Are Toronto Hydro's performance incentive mechanisms consistent with similar mechanisms employed by other electric utilities?

A. Yes. Certain jurisdictions, such as Hawaii, New York, and the UK, have noted the importance of performance incentives and have adopted mechanisms to support earnings opportunities aligned with policy objectives and customer interests.

For example, Hawaii Public Utilities Commission noted that PBR mechanisms offer a way to "restructure utility financial incentives to achieve specific, identified desirable or beneficial outcomes, such as meeting renewable energy targets, reducing greenhouse gas emissions, or improving reliability and resilience".[21] In addition, the New York Public Service Commission ("NYPSC") stated that outcome-based incentives are "the most effective approach to address the mismatch between traditional revenue methods and modern electric system

[19] Ofgem, Handbook for Implementing the RIIO Model, October 4, 2010, at p.92
[20] Ofgem, RIIO-ED2 Draft Determinations – Core Methodology Document, June 29, 2022, p. 32
[21] Docket No. 2018-0088, Order No. 35411 Proceeding to Investigate Performance-Based Regulation, Hawaii PUC, filed April 18, 2018, p. 14

needs".[22] Lastly, Ofgem emphasized the importance of performance incentives, placing "strong emphasis on the need for [distributors] to develop suitable network output measures and to commit to delivering against these measures".[23]

Q. Do other electric utility performance incentive mechanisms address similar objectives as Toronto Hydro's proposed mechanisms?

A. Yes. Certain jurisdictions are using performance incentive mechanisms to drive outcomes beyond traditional service obligations such as utilizing distributed energy resources, ensuring resilience, and reducing greenhouse gas emissions.[24]

For example, both Hawaii and UK have adopted a portfolio of incentives, that include metrics related to reliability, customer service, system efficiency and emissions reductions.[25]

E. Innovation Fund

Q. Is funding for innovation projects consistent with other electric utility mechanisms?

A. Yes. Jurisdictions, such as UK and New York, have created separate cost recovery mechanisms and funds for innovative projects and created processes to share lessons learned across the utilities.[26] These projects inform decisions regarding developing new revenue streams, scaling new technologies, measuring customer

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[22] Case 14-M-0101, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, Reforming the Energy Vision Proceeding, New York Public Service Commission, May 19, 2016, p. 62

[23] Ofgem, Electricity Distribution Price Control Review Methodology and Initial Results Paper, May 8, 2009, p. 107

[24] RMI, PIMs for Progress, at p.10

[25] Docket No. 2018-0088, Decision and Order No. 37507 Instituting a Proceeding to Investigate a Performance-Based Regulation, Hawaii Public Utilities Commission, p. 15; Ofgem, RIIO-ED2 Final Determinations Overview Document, p.22-23

[26] Ofgem, Regulating Energy Network for the Future RPI-X@20 Emerging Thinking, January 20, 2010, at p.34; NY PSC, Memorandum And Resolution On Demonstration Projects, December 12, 2014, at p.10

response to new programs and price strategies, and determining the most effective implementation of distributed energy resources.[27]

V. SUMMARY AND CONCLUSION

Q. Please summarize your findings and conclusions?

A. Our principal conclusion is that the Company's proposed changes to the Rate Framework are generally consistent with how other electric utilities have responded to developments in the energy industry (recognizing that there are differences in service areas and jurisdictional requirements).

Q. Does this conclude your testimony?

A. Yes, it does.

[27] New York PSC, Case 14-M-0101, Memorandum and Resolution on Demonstration Projects, December 12, 2014, at p.6-10

Qualifications

Tim Lyons is a partner with ScottMadden with more than 30 years of experience in the energy industry. Tim has held senior positions at several gas utilities and energy consulting firms. His experience includes rates and regulatory support, sales and marketing, customer service and strategy development. Prior to joining ScottMadden, Tim served as Vice President of Sales and Marketing for Vermont Gas. He has also served as Vice President of Marketing and Regulatory Affairs for Providence Gas Company, Director of Rates at Boston Gas Company, and Project Director at Quantec, LLC, an energy consulting firm.

Tim has sponsored testimony and evidence before more than 25 state regulatory commissions and 3 Canadian regulatory boards. Tim holds a B.A. from St. Anselm College, an M.A. in Economics from The Pennsylvania State University, and an M.B.A. from Babson College.

Areas of Specialization

- Regulation and Rates
- Retail Energy
- Utilities
- Natural Gas

Capabilities

- Regulatory Strategy and Rate Case Support
- Strategic and Business Planning
- Capital Project Planning
- Process Improvements

Articles and Speeches

- "Country Strong: Vermont Gas shares its comprehensive effort to expand natural gas service into rural communities." ***American Gas Association***, June 2011 (with Don Gilbert).
- "Talking Safety With Vermont Gas." ***American Gas Association***, February 2009 (with Dave Attig).
- "Consumers Say 'Act Now' To Stabilize Prices." ***Power & Gas Marketing***, September/ October 2001 (with Jim DeMetro and Gerry Yurkevicz).
- "Rate Reclassification: Who Buys What and When." ***Public Utilities Fortnightly***, October 15, 1991 (with John Martin).

Sponsor	Date	Docket No.	Subject
Regulatory Commission of Alaska			
Cook Inlet Natural Gas Storage Alaska, LLC	7/21	Docket No. U-21-058	Sponsored testimony supporting the lead-lag study/cash working capital requirement for a general rate case proceeding.
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted and sponsored testimony supporting a lead-lag study for a general rate case proceeding.
Arizona Corporation Commission			
Southwest Gas Corporation	12/21	Docket No. G-01551A-21-0368	Sponsored testimony supporting class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Arkansas Public Service Commission			
Liberty Utilities (The Empire District Electric Company)	2/23	Docket No. 22-085-U	Sponsored testimony supporting the class cost of service, rate design, bill impact studies, and revenue decoupling for a general rate case proceeding.
Liberty Utilities (Pine Bluff Water)	10/18	Docket No. 18-027-U	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
California Public Utilities Commission			
Bear Valley Electric Service, Inc.	10/22	Application No. 22-08-010	Sponsored testimony supporting marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Liberty Utilities (CalPeco Electric)	5/21	Application No. 21-05-017	Sponsored testimony supporting the lead-lag study/cash working capital, marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Southwest Gas Corporation (Southern California, Northern California, and South Lake Tahoe jurisdictions)	8/19	Application No. 19-08-015	Sponsored testimony on behalf of three separate rate jurisdictions supporting revenue requirements, lead-lag/ cash working capital, and class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Connecticut Public Utilities Regulatory Authority			
Yankee Gas Company	07/14	Docket No. 13-06-02	Sponsored report and testimony supporting the review and evaluation of gas expansion policies, procedures and analysis.
Delaware Public Service Commission			
Artesian Water Company	04/23	Docket No. 23-0601	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
Illinois Commerce Commission			
Ameren Illinois Company d/b/a Ameren Illinois	1/23	Docket No. 22-0487	Sponsored testimony supporting a Multi-Year Integrated Grid Plan (Grid Plan). Prepared research and analysis evaluating the reasonableness of the Grid Plan through comparison to how other electric utilities have responded to the changing energy landscape.
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. 16-0401	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes and a decoupling mechanism.
Iowa Utilities Board			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. RPU-2016-0003	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes.
Kansas Corporation Commission			
The Empire District Electric Company	12/18	Docket No. 19-EPDE-223-RTS	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Kentucky Public Service Commission			

Sponsor	Date	Docket No.	Subject
Bluegrass Water Utility (Central States Water Company)	02/23	Case No. 2022-00432	Sponsored testimony supporting the rate design and bill impact studies for a general rate case proceeding.
Maine Public Utilities Commission			
Northern Utilities, Inc. d/b/a Unitil	05/23	Docket No. 2023-00051	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
Maine Water Company	03/21	Docket No. 2021-00053	Sponsored testimony supporting a proposed rate smoothing mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/15	Docket No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.
Maryland Public Service Commission			
The Potomac Edison Company (FirstEnergy)	03/23	Case No. 9695	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.
Massachusetts Department of Public Utilities			
Berkshire Gas Company, Eversource Energy, Liberty Utilities, National Grid, and Unitil	03/22	Docket No. DPU 20-80	Sponsored report that summarizes research, findings, and recommendations for regulatory mechanisms, methodologies, and policies that support Massachusetts's achievement of its net zero climate goal by 2050. The regulatory designs were informed by the results of quantitative and qualitative analysis of decarbonization pathways to achieve the Commonwealth's climate goals.
Liberty Utilities (New England Gas Company)	08/20	Docket No. DPU 20-92	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2020/2021 through 2024/2025.
Eversource Energy, National Grid, and Unitil	02/20	Docket No. DPU 19-55	Sponsored report that summarizes research and evaluation of funding approaches for infrastructure modifications that interconnect Distributed Generation (DG) projects.
Liberty Utilities (New England Gas Company)	07/18	Docket No. DPU 18-68	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2018/2019 through 2022/2023.
Liberty Utilities (New England Gas Company)	07/16	Docket No. DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.
Boston Gas	10/93	Docket No. DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.
Boston Gas	03/90	Docket No. DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
Michigan Public Service Commission			
Lansing Board of Water & Light and Michigan State University	04/23	Docket No. U-21308	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/20	Docket No. U-20650	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.

Sponsor	Date	Docket No.	Subject
Lansing Board of Water & Light and Michigan State University	04/19	Docket No. U-20322	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Minnesota Public Utilities Commission			
Northern States Power Company (XcelEnergy)	10/21	Docket No. E002/GR-21-630	Sponsored testimony supporting a Return on Equity (ROE)adjustment mechanism that would allow the Company to symmetrically adjust its ROE to reflect significant changesin financial market conditions.
Missouri Public Service Commission			
Confluence Rivers Utility Operating Company	12/22	Case No. WR-2023-0006/ SR-2023-0007	Sponsored testimony supporting the rate design and bill impact studies for a general rate case proceeding.
The Empire District Gas Company	08/21	Docket No. GR-2021-0320	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
The Empire District Electric Company	05/21	Docket No. ER-2021-0312	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Spire Missouri, Inc.	12/20	Docket No. GR-2021-0108	Sponsored testimony supporting class cost of service, rate design, and lead-lag study proposals for a general rate case proceeding. The testimony also included support for a proposed revenue adjustment mechanism.
The Empire District Electric Company	08/19	Docket No. ER-2019-0374	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a weather normalization mechanism.
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a revenue decoupling/ weather normalization mechanism as well as tracker accounts for certain O&M expenses and capital costs.
Missouri Gas Energy	04/17	Docket No. GR-2017-0216	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Laclede Gas Company	04/17	Docket No. GR-2017-0215	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Nevada Public Utilities Commission			
Southwest Gas Corporation	09/23	Docket No. 23-09012	Sponsored testimony supporting the class cost of service,rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
Southwest Gas Corporation	09/21	Docket No. 21-09001	Sponsored testimony supporting the class cost of service,rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
Southwest Gas Corporation	02/20	Docket No. 20-02023	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
New Hampshire Public Utilities Commission			
Unitil (Northern Utilities, Inc.)	8/21	Docket No. DG 21-104	Sponsored testimony supporting a revenue decoupling mechanism.
Unitil Energy Systems, Inc.	4/21	Docket No. DE 21-030	Sponsored testimony supporting a revenue decoupling mechanism.

Sponsor	Date	Docket No.	Subject
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
New Jersey Board of Public Utilities			
Jersey Central Power and Light Company (FirstEnergy)	03/23	Docket No. ER23030144	Sponsored testimony supporting the class cost of service and Lead/Lag studies for a general rate case proceeding.
South Jersey Gas Company	04/22	Docket No. GR22040253	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	12/21	Docket No. GR21121254	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
South Jersey Gas Company	03/20	Docket No. GR20030243	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	04/19	Docket No. GR19040486	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company	08/16	Docket No. GR16090826	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
New Mexico Public Regulation Commission			
New Mexico Gas Company, Inc.	9/23	Case No. 23-00255-UT	Sponsored testimony supporting the class cost of service, rate design, bill impact and weather normalization adjustment mechanisms for a general rate case proceeding.
Corporation Commission of Oklahoma			
The Empire District Electric Company	02/21	Cause No. PUD 202100163	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The proposed rate design included a three-year phase-in of the proposed rate increase.
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	04/17	Cause No. PUD 201600468	Adopted direct testimony and sponsored rebuttal testimony supporting the revenue requirements for a general rate case proceeding. The testimony included proposals for alternative ratemaking mechanisms.
Rhode Island Public Utilities Commission			
Providence Gas Company	08/01 09/00 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Providence Gas Company	06/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.

Sponsor	Date	Docket No.	Subject
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas adjustment clause, for a rate design proceeding.
Providence Gas Company	02/96	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.
Providence Gas Company	01/96	Docket No. 2076	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.
Providence Gas Company	11/92	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Railroad Commission of Texas			
Texas Gas Service Company – West Texas, North Texas, and Borger/ Skellytown Service Areas	06/22	Case No. 00009896	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Central Texas and Gulf Coast Service Areas	12/19	GUD No. 10928	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Beaumont/ East Texas Division	11/19	GUD No. 10920	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Borger/ Skellytown Service Area	08/18	GUD No. 10766	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – North Texas Service Area	06/18	GUD No. 10739	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – South Texas Division	11/17	GUD No. 10669	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Rio Grande Valley Service Area	06/17	GUD No. 10656	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Atmos Pipeline – Texas	01/17	GUD No. 10580	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Texas Gulf Division	11/16	GUD No. 10567	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Public Utility Commission of Texas			
CenterPoint Energy Houston Electric, LLC	04/19	Docket No. 49421	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Vermont Public Utilities Commission			
Vermont Gas Systems	12/12	Docket No. 7970	Sponsored testimony describing the market served by $90 million natural gas expansion project to Addison County, VT. Also described the terms and economic benefits of a special contract with International Paper.
Vermont Gas Systems	02/11	Docket No. 7712	Sponsored testimony supporting the market evaluation and analysis for a system expansion and reliability regulatory fund.
Virginia State Corporation Commission			
American Electric Power - Appalachian Power Company	3/23	Case No. PUR-2023-00002	Sponsored testimony supporting the Lead/Lag study for the 2023 triennial review of base rates, terms, and conditions.

Sponsor	Date	Docket No.	Subject
Rappahannock Electric Cooperative	10/22	Case No. PUR-2022-00160	Sponsored report and studies related to revenue requirements, class cost of service, rate design, and bill impact analysis for a streamlined application to increase base rates.
American Electric Power - Appalachian Power Company	3/20	Case No. PUR-2020-00015	Sponsored testimony supporting the Lead/Lag study for the 2020 triennial review of base rates, terms, and conditions.
West Virginia Public Service Commission			
Monongahela Power Company and The Potomac Edison Company (FirstEnergy)	06/23	Case No. 23-0460-E-42T	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Nova Scotia Utility and Review Board			
Nova Scotia Power	01/22	Matter No. M10431	Sponsored evidence supporting the cash working capital requirement and lead/Lag study for a general rate case proceeding.
Ontario Energy Board			
Ontario Energy Association	01/21	Docket No. EB-2020-0133	Sponsored evidence regarding policies and ratemaking treatment related to COVID-19 costs in U.S. and Canadian regulatory jurisdictions. The evidence was used to support Ontario Energy Association's response to Staff's proposals
Commission of Canada Energy Regulator			
Trans-Northern Pipelines, Inc.	06/23	Docket No. RH-001-2023	Sponsored evidence related to application for approval of incentive tolls.

Toronto Hydro-Electric System Limited
EB-2023-0195
Exhibit 1B
Tab 2
Schedule 1
Appendix B
ORIGINAL
(49 Pages)

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Jurisdictional Review of Modernized Performance-Based Regulation

Prepared for Toronto Hydro

August 2023

TORONTO HYDRO

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1.0 Executive Summary

Energy Transition

The changing energy landscape is driving new investments and priorities, while continuing to focus on safe and reliable service

- Utilities continue traditional investments in electric system, such as replacing aging infrastructure and implementing new technologies
- At the same time, utilities invest in new initiatives (e.g., grid modernization) to support energy transition including increased electrification and development of DER

The changing energy landscape is leading to industry enhancements, including ratemaking reforms

- Distributed energy resources, beneficial electrification, public policy mandates, and increased use of information technologies are driving changes within the energy industry
- Enhancements include safety protocols, reliability considerations, and customer protections for affordability
- Ratemaking reforms address certain limitations, such as limits on utility revenue and return opportunities that create challenges for utilities adapting to the changing energy landscape

Various jurisdictions have developed ratemaking approaches that provide cost recovery flexibility to help address challenges related to changing grid needs

- Hawaii's EPRM, for example, provides cost recovery flexibility for eligible projects (primarily, clean energy-related infrastructure and grid modernization investments) placed in service between rate cases
- UK RIIO framework developed uncertainty mechanisms that provide flexibility regarding the timing and adoption of low-carbon technologies

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1.0 Executive Summary (Cont.)

Need for a 'Modernized' PBR Mechanism

PBR mechanisms have been "modernized" to reflect energy transition

- Modernized PBR mechanisms address cost recovery uncertainties that facilitate meeting policy objectives and utility financial health

PBR objectives have been expanded to address changes related to energy transition

- Hawaii Public Utilities Commission (PUC) recognized that "factors driving [the] energy transition were of sufficient breadth and magnitude that [its] regulatory framework must evolve to enable the State's electric utilities to meet these new challenges, maintain safety and reliability, offer new opportunities to create value for customers, and produce affordable rates"

PBR mechanisms have been enhanced to align utility financial health with consumer interests

- The Hawaii PUC noted, "The PBR Framework approved in this D&O has been carefully designed to include multiple safeguards and review opportunities to protect the Companies' financial health from extreme hardship"
  - In the proceeding, the Consumer advocate stated: "If inadequate consideration in the implementation of PIMs and/or PBR results in the increase of capital costs needed to build that infrastructure and/or downgrades in the utility credit rating, those results would be contrary to the public interest"

PBR mechanisms have been enhanced to provide for cost recovery of clean energy investments

- UK RIIO framework developed uncertainty mechanisms to help manage uncertainty over the timing and adoption of low-carbon technologies
- Separate funding mechanisms have been approved for costs related to achieving clean energy goals, such as:
  - New York adopted cost trackers for separate treatment and cost recovery to help achieve public policy goals, such as clean energy initiatives
  - Hawaii created Exceptional Project Recovery Mechanism (EPRM) that enables cost recovery of approved "eligible projects" that are not otherwise provided for during the PBR rate period

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1.0 Executive Summary (Cont.)

Elements of Modernized PBR Mechanism

1. Expanded Objectives: Include public policy objectives, such as emissions reduction, affordability, and clean energy goals
2. Modified Attrition Relief Mechanisms (ARMs): Re-evaluate the role of attrition relief mechanisms, such as the I-X framework
3. Alternative Cost Recovery Mechanisms: Allow cost recovery of clean energy initiatives through alternative separate mechanisms such as cost trackers
4. Performance Incentives: Align utility performance incentives and public policy objectives such as clean energy goals
5. Funding for Demonstration Projects: Cost recovery of innovative programs through separate funding mechanisms

1. Expanded Objectives

- Energy transition
  - Hawaii Public Utilities Commission (PUC): “factors driving [the] energy transition were of sufficient breadth and magnitude that [its] regulatory framework must evolve to enable … utilities to meet these new challenges, maintain safety and reliability, offer new opportunities to create value for customers, and produce affordable rates”
- Reduction of carbon emissions and enhanced customer knowledge and tools
  - New York Reforming the Energy Vision (REV) policy objectives include system reliability and resiliency, reduction of carbon emissions, system wide efficiency, and enhanced customer knowledge and tools
- Reliability, emissions reductions, and cost controls
  - Rocky Mountain Institute (RMI) study found 17 different policy goals related to PBR, including reliability, emissions reductions, and cost control
- Financial health of the utility
  - Hawaii PUC: “The PBR Framework … has been carefully designed to include multiple safeguards and review opportunities to protect the Companies’ financial health from extreme hardship”
  - Hawaii Consumer Advocate: “If inadequate consideration in the implementation of PIMs and/or PBR results in the increase of capital costs needed to build that infrastructure and/or downgrades in the utility credit rating, those results would be contrary to the public interest”

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1.0 Executive Summary (Cont.)

Elements of a Modern PBR Mechanism (Cont.)

2. Modified Attrition Relief Mechanisms

- Attrition Relief Mechanisms (ARMs) modified to ensure adequate cost recovery of investments
- Revenue index mechanisms (such as I-X) create cost recovery challenges for major capital expenditures
  - Hawaii PUC stated that certain projects represent “lumpy” investments with costs not manageable under annual revenues derived from an index-driven revenue formula
  - Maine Public Utilities Commission (PUC) moved away from revenue indexed mechanisms to traditional cost of service cost recovery for large capital projects
- UK RIIO framework adjusts distributor revenue allowances for uncertainties including the scale, pace, and location of technology adoption, policy developments, demand patterns, and cost forecasts

3. Alternative Cost Recovery Mechanisms

- Alternative Cost Recovery Mechanisms, such as cost trackers, provide cost recovery related to certain public policy goals
  - Regulatory Rationales for Cost Trackers: Largely outside the control of a utility, unpredictable and volatile, substantial and recurring
- Cost trackers for traditional utility projects and emerging cost categories (such as clean energy programs)
  - PECO (PA) Distribution System Improvement Charge for aging infrastructure replacement costs (~17% of distribution CapEx)
  - AEP (OH) Enhanced Service Reliability Program (ESRP) Rider for vegetation management costs (~13% of distribution O&M)
  - Con Edison (NY) System Benefit Charge for clean energy programs
- Cost trackers recognized for certain large capital investments do not fit within the traditional PBR construct and require special treatment
  - Hawaii’s Exceptional Project Recovery Mechanism enables cost recovery of “eligible projects” that are not provided for during multi-year rate period
- Aligned treatment of capital and operating expenses
  - UK RIIO’s TOTEX model allows capitalization of operating expenditures

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1.0 Executive Summary (Cont.)

Elements of a Modern PBR Mechanism (Cont.)

4. Performance Incentives

- Align utility performance incentives and policy objectives
  - Review of selected U.S. financial rewards and penalties show magnitude up to ~1-3% of base revenues
  - UK RIIO model has incentives up to 5% of base revenues
- Certain jurisdictions (such as New York, Hawaii, UK) stated that performance incentives are necessary to achieve desired outcomes
  - Hawaii Commission: “incentive mechanisms can achieve … objectives, such as incenting cost reduction, incenting achievement of policy goals, improving performance, integrating technological advances, supporting new types of customer choice, and encouraging a low-cost, customer-centric future”
  - New York Commission: “outcome-based incentives are the most effective approach to address the mismatch between traditional revenue methods and modern electric system needs, while aligning utility shareholder interests with consumer interests”
  - UK RIIO includes performance incentives tied to outputs that include customer satisfaction, reliability, interconnection, and environmental impact
  - California provides 4.0 percent pre-tax incentives for integrating DERs that provide valuable grid services, including voltage support, reliability, and resiliency
- Certain jurisdictions have also provided incentives to achieve cost efficiencies
  - UK RIIO’s Totex Incentive Mechanism (also called the efficiency incentive) encourages distributors to improve their efficiency and shares efficiency benefits between customers and utility

5. Funding for Demonstration Projects

- Funding of innovative projects (or demonstration projects) provide lessons learned on new technologies and cost-saving initiatives that support energy transition
- Certain jurisdictions created separate cost recovery to fund innovative projects and created processes to share lessons learned across the utilities
  - New York utilities recover REV demonstration project costs outside of multi-year rate plans
  - UK RIIO framework includes dedicated funding for innovation, comprising the Network Innovation Allowance (NIA), the Network Innovation Competition (NIC) and the Innovation Roll-Out Mechanism (IRM)

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1.0 Executive Summary (Cont.)

Conclusion

Modernized PBR mechanisms provide utilities with flexibility to address changing grid needs while maintaining safe and reliable service

- Address cost recovery challenges of achieving policy objectives
- Fund traditional and new investments to meet clean energy transition
- Align utility performance incentives and policy objectives

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2.1 Energy Transition Implications

New Investments and Priorities

The changing energy landscape is driving new investments and priorities, while maintaining focus on safe and reliable service

- Utilities continue traditional investments in replacing aging infrastructure and implementing new technologies
- In addition, utilities invest in new initiatives (e.g., grid modernization) to support energy transition including increased electrification and development of DER

Energy transition leads to enhancements in traditional utility responsibilities of providing safe, reliable, and affordable service[1]

- Safety
  - New technologies and increased connection of distributed assets affect safety protocols
- Reliability
  - Probabilistic resource adequacy methods to account for new resources and the changing nature of risk to the system
  - Consideration of reliability services provided by DERs
- Affordability
  - Customer protections (financial protections, expanded choices, cost-benefit analyses)

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2.1 Energy Transition Implications

New Investments and Priorities (Cont.)

In addition, utilities are focusing on achieving environmental goals, ensuring a resilient grid, addressing customer needs, and driving innovation in clean energy technologies and programs[2]

- **Environmental Goals**: Utilities operate under various public policy mandates to achieve decarbonization and other environmental goals
- **Resilience**: Cyber security threats and increased extreme weather events have placed a heightened focus on resilience
- **Customer Choice**: Customers have evolving preferences over energy sources, desire for control over energy usage, and levels of engagement
- **Innovation**: Given uncertainty and change being experienced in the energy sector, utility regulators are promoting innovation programs and funding to enable experimentation of new business models and technologies

Given the evolving industry dynamics, uncertainties exist regarding the costs of new technologies and the pace of their adoption

- There is recognition (such as in UK RIIO) that investment flexibility addresses the uncertainties

Ratemaking reforms (such as New York, Hawaii, UK) have addressed structural limitations that challenge utilities' ability to meet policy and customer requirements and expectations[3]

- Structural limitations include misaligned incentives, limits on utility revenue and profit opportunities, and risk imbalances
- There is recognition that policy objectives cannot be achieved without ensuring cost recovery for necessary investments
- Absent changes, challenges in balancing traditional ("business-as-usual") investments (reliability, resilience, safety) vs. new investments (such as related to clean energy transition)

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2.1 Energy Transition Implications (Cont.)

Need for Investment Flexibility to Address Uncertainty

Various jurisdictions have developed mechanisms that provide investment flexibility to address uncertainty related to changing grid needs while maintaining safe and reliable service

- UK RIIO framework includes uncertainty mechanisms to help manage the uncertainty over the scale, timing, and adoption of low-carbon technologies
- The uncertainties recognized by UK RIIO include scale, pace, and location of technology adoption, policy developments, demand patterns, and cost forecasts[4]
- The UK regulator (Ofgem) noted that its five-year price control period spans a critical time in which "network companies cannot wait for everything to become clear but must proactively manage those uncertainties"[5]

Jurisdictions have implemented cost trackers for traditional utility projects and emerging cost categories (such as clean energy programs)

- PECO (PA) Distribution System Improvement Charge for aging infrastructure replacement costs (~17% of distribution CapEx)[6,7]
- AEP (OH) Enhanced Service Reliability Program (ESRP) Rider for vegetation management costs (~13% of distribution O&M)[8,9]
- Con Edison (NY) System Benefit Charge for clean energy programs[10]

Jurisdictions have recognized that certain large capital investments do not fit within the traditional PBR construct and require special treatment

- Hawaii's Exceptional Project Recovery Mechanism (EPRM) provides cost recovery certainty for eligible projects (primarily clean energy-related infrastructure and grid modernization investments) placed in service between rate cases[11]
- The Commission has taken a broad approach to eligible projects, noting that "limiting eligible projects to pre-determined plans made in other dockets may limit the flexibility to address unforeseen events or take advantage of unexpected opportunities (e.g., improvements in technology, changes in consumption behavior, etc.)"[12]

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2.2 Need for a ‘Modernized’ PBR Mechanism

Need for a ‘Modernized’ PBR Mechanism

Industry review shows that PBR mechanisms have been “modernized” to reflect energy transition

- Addressing cost recovery results in customer savings as the utility’s financial integrity may improve resulting in lower cost of capital
- Challenges in meeting policy objectives without cost recovery mechanisms for necessary investments

Jurisdictions have expanded PBR objectives to address changes related to energy transition

- Hawaii Public Utilities Commission (PUC) recognized that “factors driving [the] energy transition were of sufficient breadth and magnitude that [its] regulatory framework must evolve to enable the State’s electric utilities to meet these new challenges, maintain safety and reliability, offer new opportunities to create value for customers, and produce affordable rates”[13]

Jurisdictions have recognized that financial integrity of the utility aligns with consumer interests

- The Hawaii PUC noted, “The PBR Framework approved in this D&O has been carefully designed to include multiple safeguards and review opportunities to protect the Companies’ financial health from extreme hardship”[14]
  - In the proceeding, the Consumer advocate stated: “If inadequate consideration in the implementation of PIMs and/or PBR results in the increase of capital costs needed to build that infrastructure and/or downgrades in the utility credit rating, those results would be contrary to the public interest”[15]

Jurisdictions have approved separate cost recovery for clean energy investments, recognizing that these can be volatile

- UK RIIO framework developed uncertainty mechanisms to help manage uncertainty over the timing and adoption of low-carbon technologies
- Separate funding mechanisms have been approved for costs related to achieving clean energy goals, such as:
  - Jurisdictions (such as New York) have adopted cost trackers for separate treatment and cost recovery to help achieve public policy goals, such as clean energy initiatives
  - Jurisdictions (such as Hawaii) have created Exceptional Project Recovery Mechanism (EPRM) that enables cost recovery of approved “eligible projects” that are not otherwise provided for during the PBR rate period

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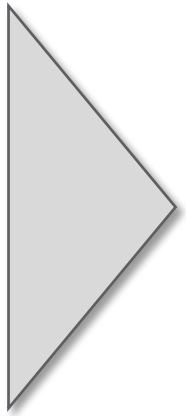
2.2 Need for a 'Modernized' PBR Mechanism (Cont.)

Elements of a Modern PBR Mechanism

Changing Energy Landscape

- **Replacement of aging infrastructure and investment in new technologies to ensure**
  - Safety
    - New technologies, digitalization, and increased grid connections require new safety protocols
  - Reliability
    - New considerations for resource adequacy and reliability as DERs expand
  - Resilience
    - Increased costs due to cybersecurity threats and extreme weather events
- **Growth in building and transportation electrification**
  - Driven by customer demands and policy goals
  - Increased investments required to accommodate electrification
- **Growth in distributed energy resources**
  - Driven by lower cost technologies and policy support for non-carbon-emitting resources



PBR Implications

1. **Expanded Objectives**
   - Prioritize achieving public policy objectives, such as emissions reduction, affordability, and clean energy goals
2. **Modified Attrition Relief Mechanisms**
   - Develop hybrid cost recovery treatment methods
   - Evaluate mechanisms to manage uncertainty
3. **Alternative Cost Recovery Mechanisms**
   - Allow recovery of clean energy initiatives through separate mechanisms
   - Align treatment of capital and operating expenditures enabling the pursuit of the most cost-effective solutions
4. **Performance Incentives**
   - Focus on measuring and incentivizing outcomes rather than program-based performance
   - Align with public policy objectives such as clean energy goals
6. **Funding for Demonstration Projects**
   - Allow recovery of innovative programs through separate funding mechanisms

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3.1 Expanded Objectives

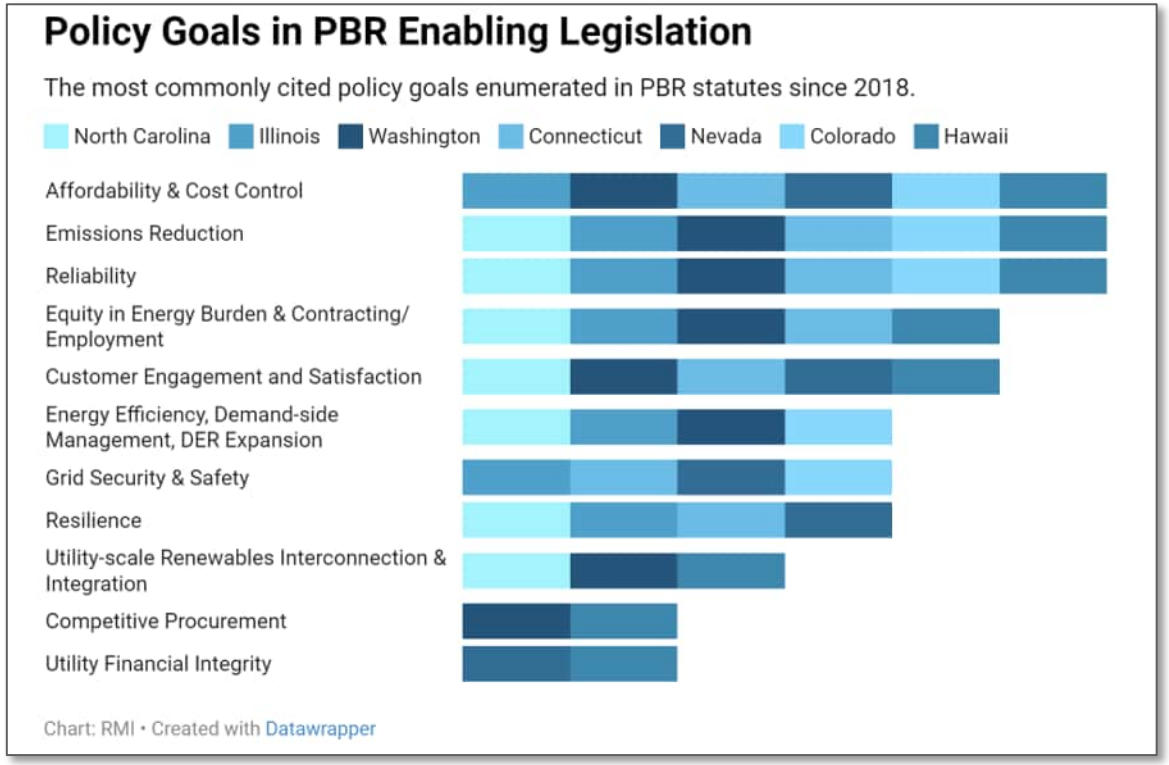
PBR objectives expanded to address changes related to energy transition

- Rocky Mountain Institute (RMI) study found 17 different policy goals related to PBR, including reliability, emissions reductions, and cost control[16]
- New York Reforming the Energy Vision (REV) policy objectives include system reliability and resiliency, reduction of carbon emissions, system wide efficiency, and enhanced customer knowledge and tools[17]
- Hawaii Public Utilities Commission (PUC): "factors driving [the] energy transition were of sufficient breadth and magnitude that [its] regulatory framework must evolve to enable … utilities to meet these new challenges, maintain safety and reliability, offer new opportunities to create value for customers, and produce affordable rates"[18]

Recognition that traditional PBR mechanisms may not result in achievement of customer interests (such as clean energy objectives) without alternative rate mechanisms

- Challenge to achieve policy objectives without cost recovery for necessary investments.

Hawaii, for example, recognized financial integrity of the utility aligns with consumer interests



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3.1 Expanded Objectives (Cont.)

Various jurisdictions have introduced or modified performance based ratemaking objectives to address changing conditions and customer needs

- Hawaii
  - In 2018, the PUC recognized that "factors driving [the] energy transition were of sufficient breadth and magnitude that [its] regulatory framework must evolve to enable the State's electric utilities to meet these new challenges, maintain safety and reliability, offer new opportunities to create value for customers, and produce affordable rates"[19]
  - The Commission adopted three overarching regulatory goals and 12 priority outcomes that served as guideposts for PBR design
- Connecticut
  - Regulatory goals include public policy achievement and empowering customer to take greater control of their energy services (e.g., deploying DERs and other grid-edge technologies, reducing emissions, etc.) and expenditures (e.g., lowering their monthly utility bill)[20]
- New York Reforming the Energy Vision (REV)
  - New York REV policy objectives included, but were not limited to, system reliability and resiliency, reduction of carbon emissions, system wide efficiency, and enhanced customer knowledge and tools[21]
  - The PSC noted the "combination of large impending infrastructure needs, decreasing system efficiency, environmental demands, and an increasing ability for customers to choose other options, presents challenges to utilities and regulators"[22]

Hawaii Regulatory Goals and Priority Outcomes*

Goal	Priority Outcome	
Enhance Customer Experience	Traditional	Affordability
		Reliability
	Emergent	Interconnection Experience
		Customer Engagement
Improve Utility Performance	Traditional	Cost Control
	Emergent	DER Asset Effectiveness
		Grid Investment Efficiency
Advance Societal Outcomes	Traditional	Capital Formation
		Customer Equity
	Emergent	GHG Reduction
		Electrification of Transportation
		Resilience

Source: Hawaii PUC, Summary of Phase 1 Decision & Order Establishing a PBR Framework, May 23, 2019

*Traditional outcomes refer to those which have been ingrained in utility regulation for many years, while emergent outcomes refer to those which in been more recently developed in response to changes in Hawaii's electric industry

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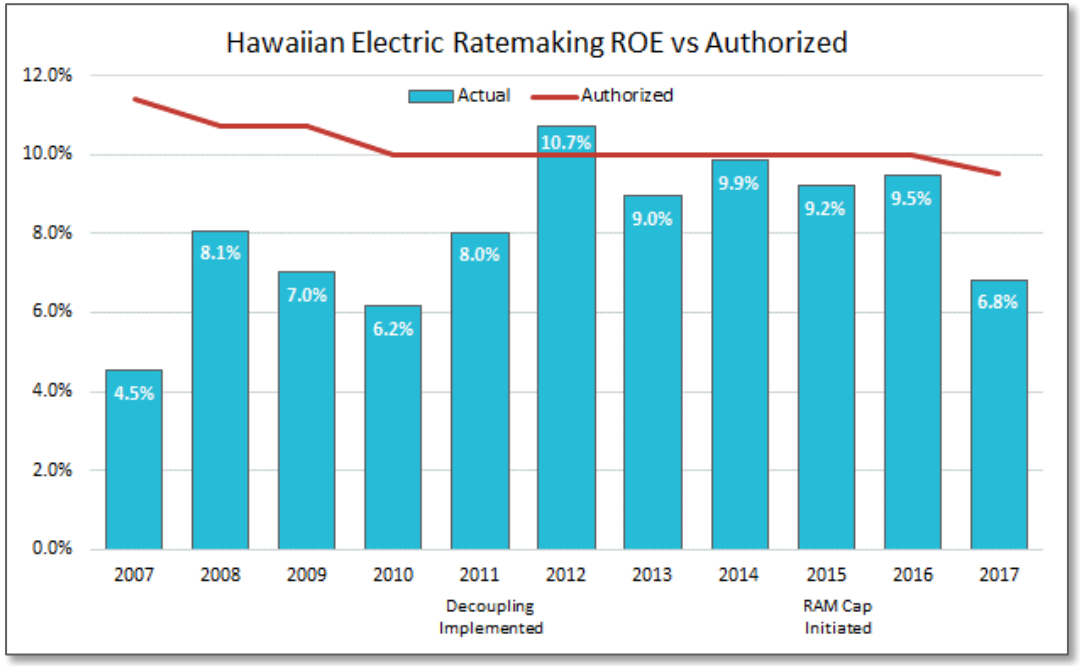
3.1 Expanded Objectives (Cont.)

Balancing Financial Integrity and Public Policy Goals

Jurisdictions (such as Hawaii) have recognized that financial health of the utility aligns with consumer interests

- The performance-based regulation framework in Hawaii ensures that the financial integrity of utility aligns with consumer interests
  - In Hawaii, the Consumer Advocate urged the Commission to ensure that the PBR framework being developed included "reasonable opportunities to recover the cost of investments and a return on those investment"[23]
  - "If inadequate consideration in the implementation of PIMs and/or PBR results in the increase of capital costs needed to build that infrastructure and/or downgrades in the utility credit rating, those results would be contrary to the public interest"[24]
  - In the Commission's Phase 1 decision, it outlined utility financial integrity, including access to low-cost capital, as one of the three guiding principles to inform the PBR framework[25]
  - The Commission noted, "The PBR Framework approved in this D&O has been carefully designed to include multiple safeguards and review opportunities to protect the Companies' financial health from extreme hardship"[26]



Source: Hawaii PUC, Docket No. 2018-0088, Exhibit 7, p.11, filed October 25, 2018

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3.2 Modified Attrition Relief Mechanisms

Attrition Relief Mechanisms (ARMs) need to be modified to ensure adequate cost recovery of necessary future investments

- Revenue index mechanisms (such as I-X) create challenges in the ability of utilities to recover costs from major capital expenditures
  - Hawaii PUC stated that certain projects represent "lumpy" investments with costs not manageable under annual revenues derived from an index-driven revenue formula[27]
  - Maine Public Utilities Commission (PUC) moved away from revenue indexed mechanisms to traditional cost of service cost recovery for large capital projects[28]

Recognition to develop mechanisms that provide investment flexibility to address uncertainty

- UK RIIO includes uncertainty mechanisms to adjust distributor revenue allowances
- Uncertainties include scale, pace, and location of technology adoption, policy developments, demand patterns, and cost forecasts[29]

ARMs Cost Forecasting Methodologies

- **Rate Freeze**
  - Rates remain fixed throughout MYRP term
- **Forecasted/ "Stairstep"**
  - Establishes revenues/ rates based on pre-determined levels
  - Based on forecasted revenue requirements
  - Widely used in U.S., e.g., California, Florida, and New York
- **Indexed ("I-X")**
  - Establishes revenues/ rates based on approved methodology that is indexed to inflation and other cost drivers
  - Methodology based on industry cost trend research
  - Provides for revenue/ rate adjustments using a form of inflation (I) less a productivity factor (X)
  - Some utilities apply "I-X" factor after the first year of MYRP (e.g., ATCO utilities);
  - Others define cost forecasts for entire term and apply a "smoothing" mechanism to define rates for the first year (e.g., Ausgrid)
  - Used in Massachusetts, Hawaii, Alberta, Ontario, and Quebec
- **Hybrid**
  - Establishes revenues/ rates based on combination of methods, such as indexing for O&M expenses and stairstep for Capex
  - Used by Southern California Edison

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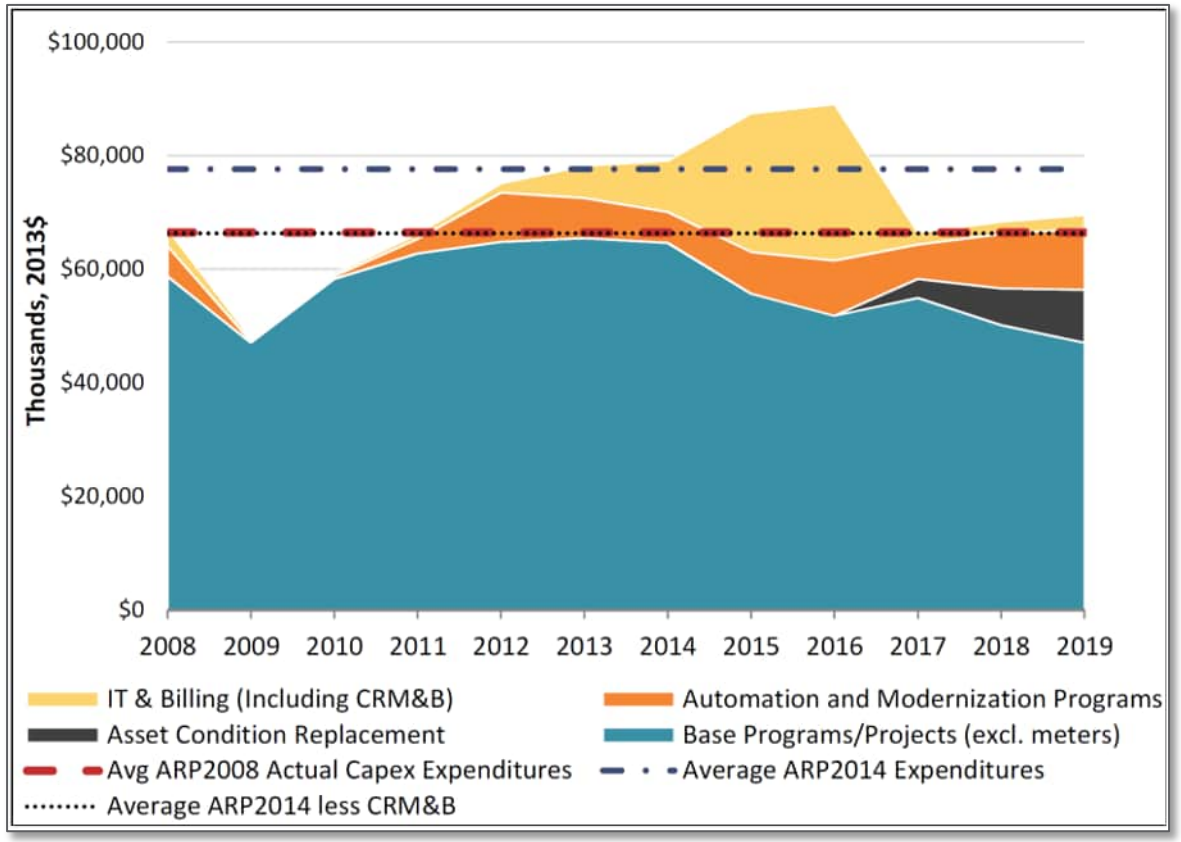
3.2 Modified Attrition Relief Mechanisms (Cont.)

Revenue index mechanisms can challenge the ability of utilities to recover costs from major capital expenditures

- Maine Public Utilities Commission (MPUC)
  - MPUC moved away from revenue indexed mechanisms to traditional cost of service (COS) cost recovery for large capital projects[30]
  - Commission Staff recommended PBR to take a "hiatus" and allow Central Maine Power (CMP) to operate under COS ratemaking[31]
  - Staff stated COS ratemaking allows CMP to address its system and spending needs consistent with the shareholder and ratepayer interests[32]
- Alberta
  - In a 2012 filing, Alberta utilities argued they were experiencing cost pressures on capital expenditures, requiring special treatment[33]
    - ATCO Electric stated its capital investments would result in 10% rate base growth, while its I-X mechanism supported 4.5% growth[34]
  - Commission permitted capital tracking mechanisms to recover specific types of capital outside of the I-X mechanism[35]
- Hawaii
  - In its PBR proceeding, the Hawaii PUC stated that certain projects represent "lumpy" investments with costs not manageable under annual revenues derived from an index-driven revenue formula[36]



Source: Maine Public Utilities Commission, Docket No. 2013-168, Direct Testimony of Tim Woolf, filed December 12, 2013

Central Maine Power requested separate capital cost treatment to recover significant investments in distribution system modernization projects, asset condition projects, and a new IT system

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3.2 Modified Attrition Relief Mechanisms (Cont.)

Mechanisms that provide investment flexibility to address uncertainty

UK RIIO includes uncertainty mechanisms to adjust distributor revenue allowances

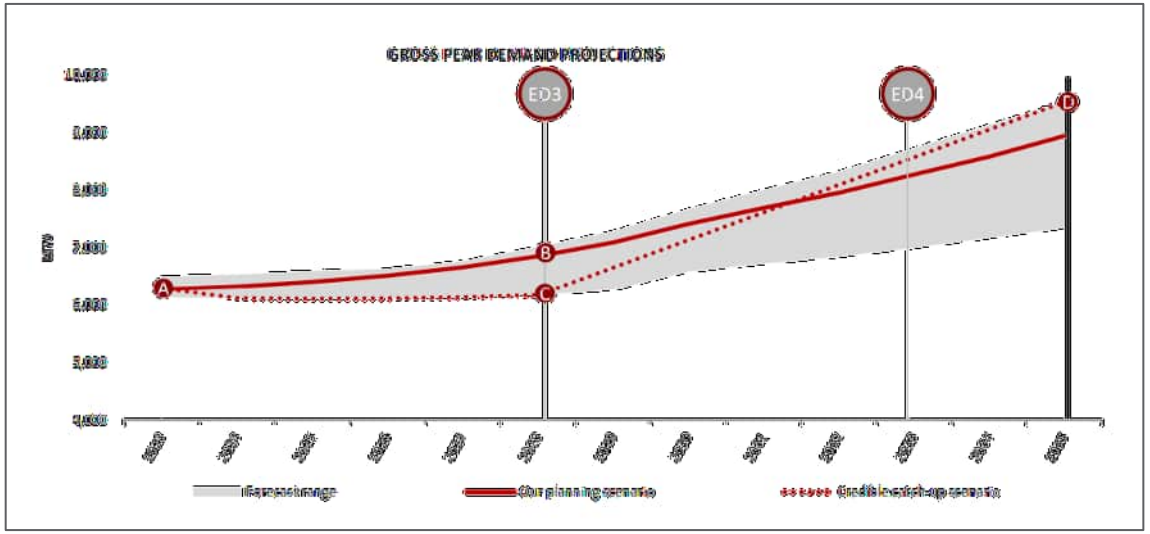
- Revenue adjustments may be made at the price control review, during the price control period, or after actual expenditure has occurred[37]

Uncertainties include scale, pace, and location of technology adoption, policy developments, demand patterns, and cost forecasts

Select quotes from Ofgem:

- "The economic and decarbonization landscape will evolve within the RIIO-ED2 period, and it is vital that networks can invest to avoid [blocking] decarbonization targets" while also "protecting consumers by avoiding investment in networks upgrades that are not required"[38]
- "EV rollout is market-led, and the pace, location, and local network impact is challenging to predict"[39]
- "There is still a degree of uncertainty about the extent to which electricity will be the prime source of heating for most homes. In addition, our requirements for energy may change as we adapt to new patterns of work and life"[40]
- " …[uncertainty mechanisms ensure that] if the uptake of EVs or HPs [heat pumps] is faster than expected, then investment can track these changes and flex quickly and efficiently in response"[41]

Northern Powergrid Gross Peak Demand Projections



Point on chart	No of EVs	No of HPs	Total
A – 2023	125,000	59,000	184,000
C – 2028 (low)	419,000	173,000	592,000
B – 2028 (planning scenario)	941,000	309,000	1,250,000
D – 2035 (high)	3,222,000	1,585,000	4,807,000

Source: Northern Powergrid, Annex 7.4, Decarbonisation Uncertainty and Ofgem Uncertainty Mechanisms, Business Plan 2023-2028

Northern Powergrid projections highlight the uncertainty within forecasting demand over future price controls periods

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3.2 Modified Attrition Relief Mechanisms (Cont.)

RIIO framework evolved to provide uncertainty mechanisms that include greater flexibility for investments

- The RIIO ED-1 framework included mechanisms to help manage the uncertain costs that exceeded a 'fixed materiality' threshold (20% greater or less than original allowances for high-value projects)[42]
- RIIO ED-2 provides more flexible uncertainty mechanisms that avoid delaying investments[43]
  - Distributors argued that the 20% materiality threshold did not provide sufficient flexibility to manage increased market uncertainties[44]

Categories of uncertainty mechanisms within RIIO ED-2

- Automatic Adjustments
  - Volume Driven: adjusts allowances to accommodate changes in volume (e.g., new connections, low carbon technology uptake)
  - Pass Through: adjusts allowances for costs incurred outside the distributor's control (e.g., bad debt, pension funding)
  - Indexation: adjusts allowances in cases where the evolution of prices is unknown, such as for inflation or cost pressures
  - Use-It-Or-Lose-It Allowance: funding is not available unless an expenditure is incurred in delivering a specific output (e.g., improving network reliability for worst served customers)
- Administrative Adjustments
  - Reopener: mechanisms to decide on additional allowances to deliver a project or activity when the needs case, timing, or scope is unclear

Types of Uncertainty Mechanisms with RIIO ED-2

Adjustment Type	Mechanism	Purpose	Examples
Automatic	Volume Driven	Adjusts allowances to accommodate changes in volume (e.g.,new connections, low carbon technology uptake)	Load-Related Expenditures
	Pass-Through	Adjusts allowances for costs incurred outside the distributor's control	Bad Debt, Pension Funding
	Indexation	Adjusts allowances in cases where the evolution of prices is unknown	Inflation, Debt
	Use-it or Lose-it Allowances	Funding is not available unless an expenditure is incurred in delivering a specific output	Improving network reliability for worst-served customers; Cyber Resilience Operation Technology
Administrative	Reopener	Mechanisms to decide on additional allowances to deliver a project or activity when the needs case, timing, or scope is unclear	Net Zero, Digitalization, Street Works

Source: Ofgem, RIIO-ED2 Final Determinations Core Methodology Document, November 30, 2022

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3.3 Alternative Cost Recovery Mechanisms

Alternative Cost Recovery Mechanisms, such as cost trackers, provide recovery of costs related to achieving public policy goals

- Regulatory rationales for cost trackers include:
  - Largely outside the control of a utility
  - Unpredictable and volatile
  - Substantial and recurring

Jurisdictions have implemented cost trackers for traditional utility projects (reliability investments, vegetation management) and emerging cost categories (clean energy programs)

- PECO (PA) Distribution System Improvement Charge for aging infrastructure replacement costs (~17% of distribution CapEx)[45,46]
- AEP (OH) Enhanced Service Reliability Program (ESRP) Rider for vegetation management costs (~13% of distribution O&M)[47,48]
- Con Edison (NY) System Benefit Charge for clean energy programs[49]

Recognition that certain large capital investments do not fit within the traditional PBR construct and require special treatment

- Hawaii's Exceptional Project Recovery Mechanism enables cost recovery of "eligible projects" that are not provided for during multi-year rate period

Aligned treatment of capital and operating expenses

- UK RIIO's TOTEX model allows capitalization of certain operating expenditures

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3.3 Alternative Cost Recovery Mechanisms (Cont.)

Common Regulatory Rationales for Cost Trackers[50]

A. Extraordinary Circumstances

- Regulators have traditionally approved cost trackers only under "extraordinary circumstances"
  - Largely outside the control of a utility
  - Unpredictable and volatile
  - Substantial and recurring
- Regulators have recently approved cost trackers when costs do not meet all three conditions, particularly finding that the criteria relating to substantial and recurring costs is restrictive
  - Bad debt cost trackers are typically not substantial but are difficult to incorporate in base rates due to unpredictability

B. Severe financial consequences

- Historically, regulators have approved cost trackers to avoid the possibility of a utility suffering a financial problem due to costs unforeseen during the last rate case

C. Special Circumstances

- Other costs, such as those relating to fuel and purchased power, are considered "special circumstances" that justify recovery outside of a rate case

Ontario Energy Board Criteria for Capital Trackers

Criteria	Description
Causation	The expense must be clearly outside of the base upon which revenue requirement(s) were derived
Materiality	Amounts must exceed the OEB-defined materiality threshold ($3 million for Hydro One) and have a significant influence on distributor operation
Prudence	The amount must have been prudently incurred. The distributor's decision to incur the amount must represent the most cost-effective option for ratepayers

Based on Decision and Order EB-2017-0049, Hydro One Networks, Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022, filed March 7, 2019

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3.3 Alternative Cost Recovery Mechanisms (Cont.)

Cost trackers across jurisdictions have included traditional utility projects and emerging cost categories

Utility	Rider	Description	Budget
PECO (PA)	Distribution System Improvement Charge[51,52]	• Accelerates investment in new utility plant to replace aging distribution infrastructure • Recovers fixed costs (depreciation and pre-tax return) of certain non-revenue producing, non-expense reducing infrastructure improvement costs place into service between base rate cases	$320M budget from 2016-2020 ($270M for reliability projects and $50M for facility relocation) Budget represented ~17% of distribution capex spending from 2016-2020
AEP Ohio	Enhanced Service Reliability Program (ESRP) Rider[53,54]	• Commission found that AEP faces increased costs for vegetation management, and costs related to a new vegetation initiative were prudent to support reliability and were incremental to costs embedded in distribution rates • Commissions found that the new vegetation initiative was a reasonable program that advanced state policy and approved an ESRP rider to recover costs, subject to review and reconciliation on an annual basis	2020 Annual Revenue: $21.8M Annual recovery represented ~13% of 2020 distribution O&M spending
San Diego Gas & Electric	AMI Balancing Account[55]	• Preapproved multiyear cost forecasts • SDG&E permitted to recover 100% of forecasted costs and 90% of overspends up to a $50M cap without further prudence review. It is permitted to keep 10% of underspends. • Records O&M and capital-related AMI costs against the monthly authorized revenue requirements adjusted for benefits	$358M of capital expenditures from 2007-2011

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3.3 Alternative Cost Recovery Mechanisms (Cont.)

Cost trackers across jurisdictions have included traditional utility projects and emerging cost categories

Utility	Rider	Description	Budget
Con Edison	System Benefit Charge[56]	• Recovers costs associated with clean energy programs conducted by NYSERDA, energy efficiency programs, and costs of the Integrated Energy Data Resource program to collect and integrate energy-related data onto a single statewide platform	$219.6M in 2020-21
PSEG	Energy Strong[57]	• Provides recovery for costs related to storm damage and reinforcing the resiliency of the grid (sample projects include electric station flood mitigation, ADMS systems, expanded system communication and data collection technologies, and redundant distribution investments) • Includes AFUDC, depreciation, income taxes, but excludes O&M related to capital investments	Total electric plant additions: $641M from 2020 to 2023
Xcel Energy (Minnesota)	Renewable Energy Standard Rider[58,59]	• Designed to allow for the automatic adjustment of charges to recover prudently-incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the Renewable Energy Standard Statute	Authorized to recover $101.8M for costs incurred in 2019 and 2020 (represents ~8% of production capex over same time period)

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3.3 Alternative Cost Recovery Mechanisms (Cont.)

Hawaii's Exceptional Project Recovery Mechanism (EPRM)

Hawaii's EPRM enables cost recovery of approved "eligible projects" that are not otherwise provided for during a multi-year rate period[60,61]

- EPRM Context
  - Hawaiian Electric uses a five-year control period with an externally-indexed revenue cap
  - The Hawaii Commission noted that the difficulty of recovering large, lumpy capital or expense-based projects through an externally-indexed attrition relief mechanism formula

- EPRM Cost Recovery Mechanics
  - EPRM recovery is based on actual recorded costs and the depreciation, tax, and authorized return rates in place
  - Recovery of on-going incremental O&M costs are based on actual recorded costs for the previous year
  - Target revenues are recovered through the utility's Revenue Balancing Account tariff
  - Any approval of recovery of costs of an eligible project through the EPRM adjustment mechanism shall continue until new rates become effective that provide cost recovery for the eligible project

EPRM Criteria for Commission Approval

- EPRM relief should be sought sparingly, and shall be reserved for projects which are extraordinary in nature and do not reflect "business as usual" investments or expenses
- In certain instances, EPRM relief may be appropriate for projects or programs previously reviewed by the Commission and prospectively found to be extraordinary or worthy of EPRM relief
- EPRM relief should not perpetuate bias toward capital expenditures

Exceptional Project Recovery Mechanism (EPRM)

Eligible EPRM Projects

- Projects that encourage clean energy choices and/or customer control to shift or conserve their energy use
- Infrastructure that is necessary to connect renewable energy projects
- Projects that make it possible to accept more renewable energy
- Approved or accepted plans, initiatives, and programs
- Utility scale generation and energy storage
- Grid Modernization projects
- Service contracts

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3.3 Alternative Cost Recovery Mechanisms (Cont.)

Hawaii's Exceptional Project Recovery Mechanism (EPRM) (Cont.)

In June 2022, Hawaiian Electric filed an application for $189.7 million in cost recovery through the EPRM[62]

- $156.6 million in capital expenditures and $33.1 million in O&M expenses
- The application was focused on approval for investments over a 5-year period to adapt the Companies' transmission and distribution systems to the changing climate and growing resilience threats
- Guiding Principles of Application
  - **Pragmatism**: Protect against climate change and associated extreme weather events, the Companies note the need to move forward with resilience investments before every project and initiative can be scoped and costed in detail
  - **Flexibility**: Address uncertainty with regard to project scope, timing, and cost
  - **Transparency and Accountability**: Transparency with regard to 1) the initiation, conduct, and progress of projects and initiatives, and 2) accountability for spending
- Projects Specified in Application
  - Projects include: 1) hardening critical transmission lines, 2) hardening and mitigating risks to critical overhead poles, 3) hardening circuits serving critical customers, 4) flood monitoring of substations, 5) upgrading distribution circuits to provide redundant transformer capacity, 6) undergrounding select overhead distribution lines, 7) hazard tree removal, 8) resilience modeling, and 9) wildfire prevention and mitigation

EPRM provides utilities flexibility to address system needs without any potential impact on utility returns

> *"Since incremental revenues are fixed by the ARA formula, there is an incentive for the Companies to reduce project investments and other costs to maintain adequate returns during the five-year multi-year rate plan. However, the Companies continue to invest in needed infrastructure because of the obligations as public utilities to provide electrical service to all customers on a non-discriminatory basis and to implement state energy policy consistent with state statute and Commission orders. [There is] a need to recover large, lumpy capital or expense-based project through the EPRM that would be difficult to recover through an index-based ARA."*
>
> *- Hawaiian Electric Companies, EPRM Application, 2022*

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3.3 Alternative Cost Recovery Mechanisms (Cont.)

CapEx-OpEx Alignment

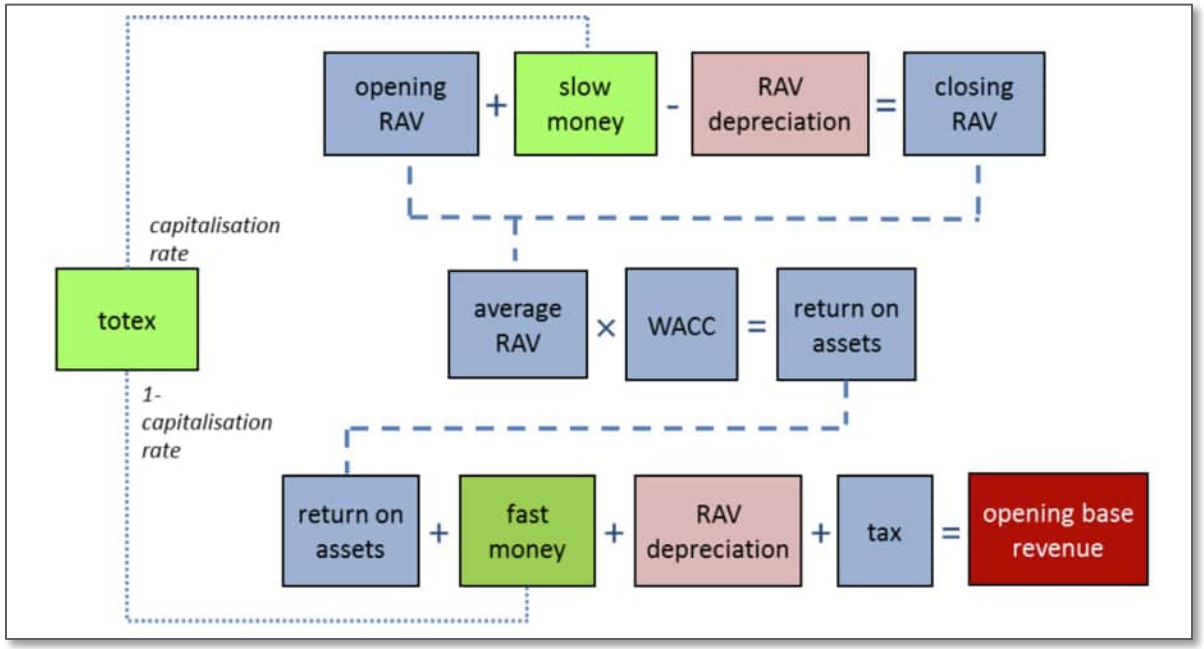
UK RIIO's TOTEX model allows for capitalization of operating expenditures

- Total expenditures ("Totex") consists of "fast" money and "slow" money
  - Fast money represents expenses funded in the year incurred, similar to traditional operating expenses
  - Slow money represents expenses added to the rate base, similar to traditional capital expenditures
  - A capitalization ratio is set to determine the proportion of fast money and slow money, based on the historical and forecasted CapEx-OpEx split
- The Totex Incentive Mechanism (also called the efficiency incentive) encourages distributors to improve their efficiency and shares efficiency benefits between customers and utility

Similar initiatives

- Capitalization of non-wires alternatives expenditures in New York[63]

UK TOTEX: Components of Base Revenues



Source: Ofgem Guide to the RIIO-ED1 Electricity Distribution Price Control

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3.4 Performance Incentives

Performance or earnings incentives align policy objectives and shareholder and customer interests

- Review of selected U.S. financial rewards and penalties show magnitude up to ~1-3% of base revenues[64]
- UK RIIO model has incentives up to 5% of base revenues[65]

Jurisdictions (such as New York, Hawaii, UK) stated that performance incentives are necessary to achieve desired outcomes

- Hawaii Commission: “incentive mechanisms can achieve … objectives, such as incenting cost reduction, incenting achievement of policy goals, improving performance, integrating technological advances, supporting new types of customer choice, and encouraging a low-cost, customer-centric future”[66]
- New York Commission: “outcome-based incentives are the most effective approach to address the mismatch between traditional revenue methods and modern electric system needs, while aligning utility shareholder interests with consumer interests”[67]
- UK RIIO includes performance incentives tied to outputs that include customer satisfaction, reliability, interconnection, and environmental impact
- California provides 4.0 percent pre-tax incentives for integrating DERs that provide valuable grid services, including voltage support, reliability, and resiliency[68]

Jurisdictions have also provided incentives to achieve cost efficiencies

- UK RIIO’s Totex Incentive Mechanism (also called the efficiency incentive) encourages distributors to improve their efficiency and shares efficiency benefits between customers and utility

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3.4 Performance Incentives

Performance or earnings incentives have expanded to prioritize outcome-based achievements (e.g., expansion of DER, overall system efficiency, beneficial electrification), better aligning utility shareholder and customer interests

- Performance incentives provide additional earning opportunities for achieving policy objectives (e.g., environmental, reliability, clean energy)
- Traditionally, performance incentives have been established for utilities to achieve reliability metrics and program-based performance (e.g., achieved kWh savings, kW reduction)

For example, UK RIIO includes performance incentives tied to outputs that include customer satisfaction, reliability, interconnection, environmental impact, and social obligations

- In 2010 prior to RIIO, the UK electricity regulatory, Ofgem, acknowledged they had, "no measures of what customers gain from investment in network assets, which can account for a high proportion of network costs"[69]
- As a result, for RIIO, Ofgem place a "strong emphasis on the need for [distributors] to develop suitable network output measures and to commit to delivering against these measures"[70]

RIIO-II Output Categories

Output Category	Policy Objectives	Example Incentive
Customer Focused	Aimed at securing high-quality customer service, quality service for consumers seeking a connection, and support to consumers in vulnerable situations	Customer Satisfaction Survey – General Inquiries (+/-0.2% of base revenue)
Safety and Resilience Focused	Maintaining reliability, and ensuring the long-term safety and resilience of the network	Interruptions Incentive Scheme (+/- 250 RORE basis points)
Environmental	Aimed at taking appropriate steps to mitigate the environmental impacts of electricity distribution	DSO Incentive (+/-0.2% of RoRE per year)

Source: Ofgem, RIIO-ED2 Final Determinations Overview Document, p.18

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3.4 Performance Incentives (Cont.)

Traditional performance incentives primarily focus on energy efficiency and reliability

- Penalty only incentives are common for essential outcomes, like reliability
  - In 2012, the Alberta Utilities Commission rejected providing utilities with a positive PIM for exceeding service quality[71]
- Four broad categories of EE performance incentives[72]
  - Shared Net Benefits: Incentives based on the net benefits from the energy efficiency programs
  - Energy-Savings-Based: Incentives for meeting pre-established energy savings goals
  - Multi-factor: Incentives for meeting pre-established goals based on multiple metrics, such as energy savings, demand savings, local job creation, improved customer service, and low-income bill savings
  - Rate-of-return incentives: Utilities earn a return on efficiency spending, sometimes with requirements for energy savings performance
- Various jurisdictions express maximum incentives in terms number of basis points of the return on equity
  - In New York, incentives are capped at 100 basis points[73]
  - In Illinois, if Ameren achieves greater than 100% of its energy efficiency goal, it can achieve 8 basis points per percentage above the goal[74]

Incentive amounts relative to total costs by mechanism type

Net benefits		Multifactor		Savings-based	
Xcel electric (MN) 2011	68%	NSTAR (MA) 2013	6%	Consumers 2012 (MI)	15%
Xcel electric (MN) 2012	62%	NGRID (MA) 2013	6%	Consumers 2013 (MI)	15%
Otter Tail Power (MN) 2011	60%	NGRID (MA) 2012	6%	DTE Energy 2012 (MI)	15%
Georgia Power 2013	58%	Efficiency VT 2008	4%	DTE Energy 2013 (MI)	15%
Otter Tail Power (MN) 2012	56%	Efficiency VT 2011	3%	IPL (IN) 2013	8%
Georgia Power 2012	42%	PBFA (HI) 2014	2%	PSNH 2013	8%
AEP Texas Central 2013	36%	PBFA (HI) 2013	2%	PSNH 2012	9%
Xcel Energy (CO) 2012	29%	DC SEU 2012	1%	CT UI 2013	6%
SWEPCO (TX) 2012	26%	DC SEU 2013	1%	CT CL&P 2013	7%
PSO (OK) 2012	25%	WI FOE 2010-14	0.2%	CT UI 2012	6%
Xcel Energy (CO) 2013	22%			CT CL&P 2012	7%
PSO (OK) 2013	21%			RI NGRID 2013	5%
DEC (SC) 2014	18%			RI NGRID 2012	5%
OGE (OK) 2012	18%			NY all IOUs	4%
DEC (SC) 2013	18%				
OGE (OK) 2011	17%				
APS (AZ) 2012	14%				
SCE&G 2013	14%				
APS (AZ) 2013	9%				
SWEPCO AR	8%				
SWEPCO AR	8%				
Entergy Arkansas 2013	7%				
Entergy Arkansas 2012	6%				
SCE&G 2014	6%				

Source: ACEEE 2015 Survey based on Questionnaires completed by State Commission Staff

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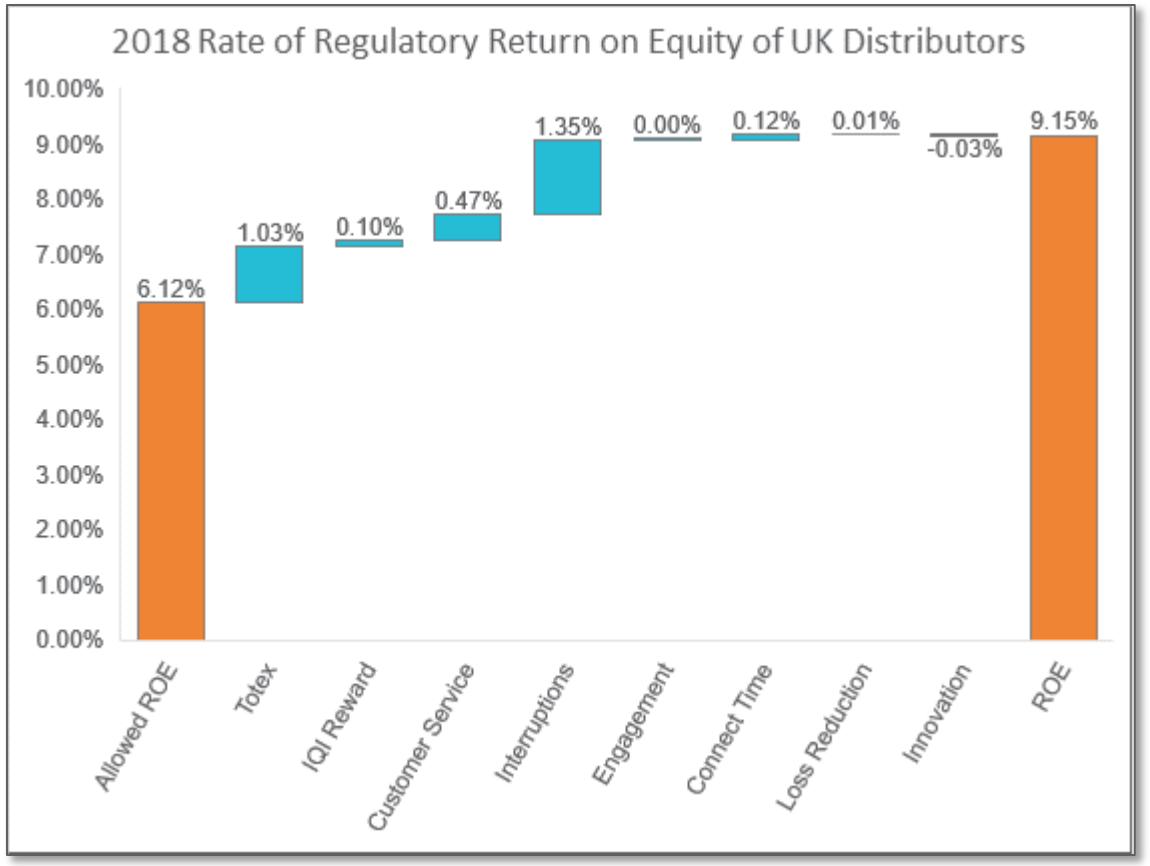
3.4 Performance Incentives (Cont.)

Emerging objectives are increasing earnings opportunities for utilities

- In the United States, the total maximum of all financial rewards / penalties has often been set at approximately 1-3% of base revenues[75]
  - Prior to New York's REV proceeding, incentives for New York electric utilities ranged between 2.77% to 5.69% of delivery revenues on the negative side and between 1.33% to 2.49% on the positive side[76]

- In the UK, the RIIO model could have an impact greater than 5% of base revenues[77]
  - Average return on equity for electricity distributors over the last four years has ranged from 2% to 3% above allowed returns[78]



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3.4 Performance Incentives (Cont.)

Performance incentives to align with desired outcomes

- Hawaii Commission Guidance for Performance Incentive Mechanisms
  - The Commission noted that to focus utilities on performance and alignment with public policy goals, an incentive structure is needed[79]
  - The Commission stated that incentive mechanisms can achieve overarching objectives, such as incenting cost reduction, incenting achievement of policy goals, improving performance, integrating technological advances, supporting new types of customer choice, and encouraging a low-cost, customer-centric future[80]
  - Hawaiian Electric Companies stated that positive incentive mechanisms should be developed to balance and support efforts to achieve desired outcomes that do not involve capital investment[81]
- New York Commission Guidance for Earning Adjustment Mechanisms
  - The Commission stated that if cost-of-service calculations are to remain the basis of utility rates then creating new earning adjustment opportunities are a fair and necessary means of promoting change[82]
  - "Drawing from an exhaustive analysis of trends in technology, markets, and environmental policy, the Commission has concluded that its core statutory duties can no longer be met with the utility regulatory model of the previous century"[83]
  - The Commission stated that outcome-based incentives are the most effective approach to address the mismatch between traditional revenue methods and modern electric system needs, while aligning utility shareholder interests with consumer interests[84]

Objective	Industry Examples	Description	Potential Reward / Penalty
Network Support Services	Hawaii Grid Services PIM	Incentives expedited acquisition of grid service capabilities from DERs	$1.5 million reward (over 2 years) No penalty
	UK RIIO Time to Connect PIM for Small Connections	Measures time taken from quotation acceptance to connection completion	Up to 0.4% of annual base revenue (reward). No penalty
Energy Efficiency and Demand Response	Rhode Island System Efficiency PIM	Cash reward based on achievement of peak demand reduction, structured as a shared savings mechanism	45% of net benefits
	New York (ConEd) Deeper Energy Efficiency Lifetime Savings EAM	Based on deeper lifetime energy efficiency savings, including LMI savings, over three years.	13 basis points (ROR based)
Environmental Goals	Hawaii RPS-A	Incentivizes accelerated achievement of RPS goals	$10-$20/MWh reward MWh above RPS $20/MWh penalty for MWh below RPS
	National Grid (NY) Beneficial Electrification EAM	Based on GHG reductions provided by EVs and heat pumps.	$2.7 million max reward (2020) No penalty
	National Grid (NY) DER Utilization EAM	Based on solar PV, storage and wind adoption rate by customers	$2.3 million max reward (2020) No penalty

Sources: Docket No. 2018-0088, D&O No. 37507, Hawaii Public Utilities Commission; National Grid, Earnings Adjustment Mechanisms, 2020 Annual Report; ACEEE, Climate-Forward Efficiency Performance Incentives, 2022; Synapse Energy Economics, Utility Performance Incentive Mechanisms Handbook

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3.4 Performance Incentives (Cont.)

California provides incentives for integrating distributed energy resources that provide valuable grid services

- California's Integrated Distributed Energy Resources Pilot[85]
  - In 2016, the CPUC adopted an Integrated DER regulatory incentive mechanism pilot to encourage the cost-effective deployment of DERs that defer or displace traditional distribution infrastructure
  - The incentive pilot applies a 4% pre-tax incentive to the annual payment for the DERs that are procured
    - The pilot allowed the utilities to record the value of the incentive in a balancing account for later recovery
  - Utilities were required to identify at least one project for the pilot; however, each utility could identify up to 3 additional projects
    - The optional nature of the additional projects was designed to test how the incentive mechanism affected utilities' energy resources sourcing behavior
  - Potential projects are screened for the value they provide to the grid, as outlined in the distribution services screening criteria

Distribution Services Screening Criteria

Projects must provide value in accordance with at least one of the four screening criteria:

- **Distribution Capacity Services:** Load-modifying or supply services that DERs provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure
- **Voltage Support Services:** Substation and/or feeder level dynamic voltage management services provided by an individual resource and/or aggregated resources capable of dynamically correcting excursions outside voltage limits as well as support conservation voltage reduction strategies
- **Reliability (Back-Tie) Services**: Load-modifying or supply service capable of improve local distribution reliability and/or resiliency
- **Resiliency (Microgrid) Services:** Load-modifying or supply service capable of improve local distribution reliability and/or resiliency

Source: California PUC, Rulemaking 14-10-003, Decision 16-12-036, filed December 15, 2016

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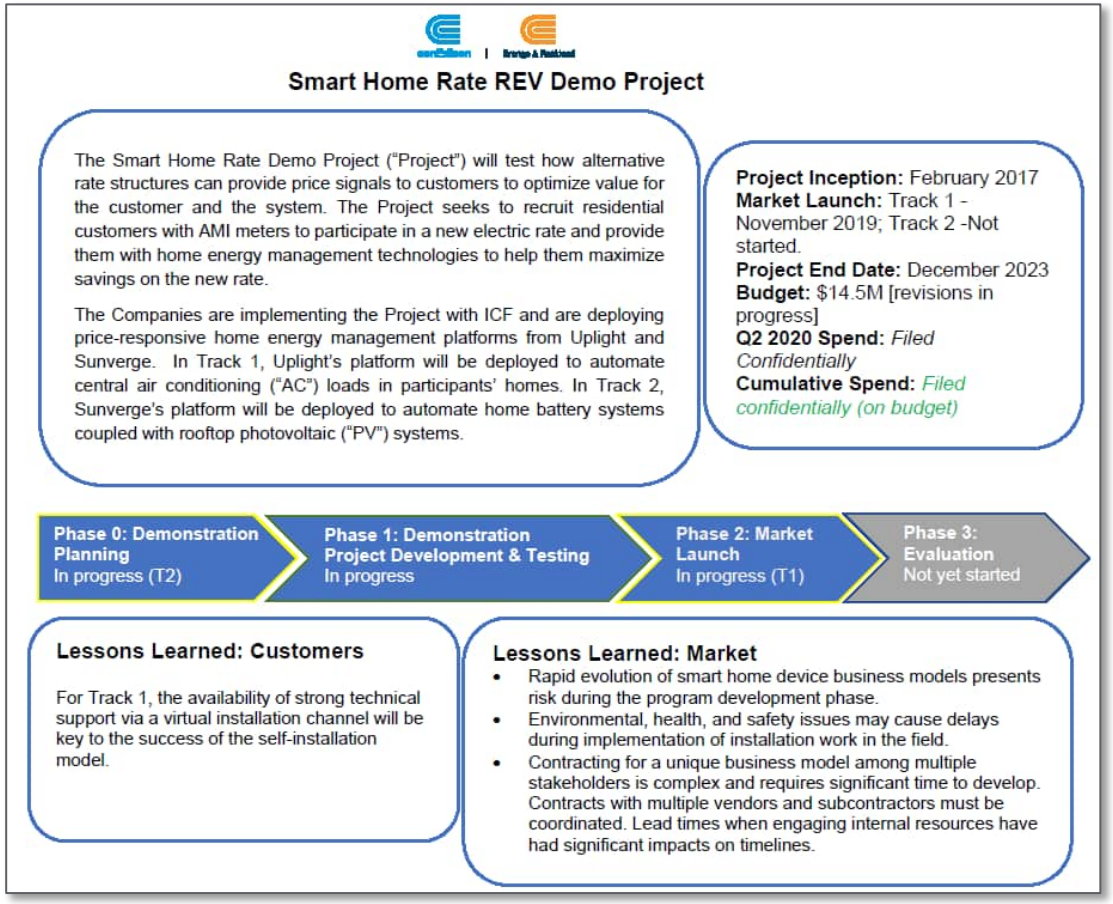
3.5 Funding for Demonstration Projects (Cont.)

Jurisdictions (such as UK and New York) have created separate cost recovery mechanisms and funds for innovative projects and created processes to share lessons learned across the utilities

- Innovative projects (or demonstration projects) provide lessons learned on new technologies and cost-saving initiatives
- Traditionally, utilities have not had cost recovery for innovative projects within PBR mechanisms

For example, New York utilities can recover REV demonstration project costs outside of multi-year rate plans[86]

- Demonstration projects inform decisions regarding developing new revenue streams, scaling new technology approaches, measuring customer response to new programs and price strategies, and determining the most cost-effective implementation of distributed energy resources
- Utilities are authorized to spend up to a specified percentage of their delivery service revenue requirement on REV projects. Spending is typically split between non-capital and capital investment solutions
- Utilities are allowed to recover total program costs over a rolling 10-year period for both non-capital and capital investment solutions through the monthly adjustment clause (MAC)
  - MAC is updated semi-annually to reflect the prior six months actual costs
- Utilities are entitled to earn a return on any deferred REV project costs



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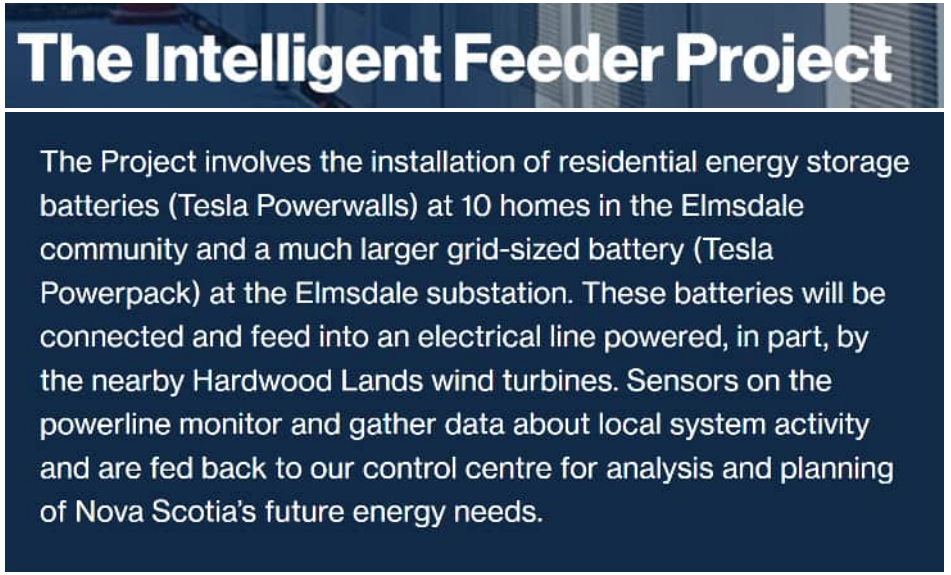
3.5 Funding for Demonstration Projects (Cont.)

Regulators have identified cost recovery mechanisms related to innovative investments by utilities

- Nova Scotia Innovation Justification Criteria[87]
  - Utility commission provides a unique cost recovery mechanism (rider) for projects that meet specific criteria for innovative projects
  - Criteria is justified based on the expectation the projects will provide customer value in some or all of the following areas:
    - Reducing upward pressure on revenue requirement
    - Reliability and grid stability
    - Environmental and other government policy compliance
    - Customer experience improvements
  - Approved projects include AMI deployment, community solar, battery storage, and intelligent feeders

- California Electric Program Investment Charge (EPIC)
  - Uses funds from a rider to sponsor research and development efforts related to electric sector transformation and decarbonization[88]
  - EPIC project categories include renewables and DER integration, grid modernization and optimization, customer focused products and services enablement, and foundation strategies and technologies[89]



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4.0 Conclusion

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4.0 Conclusion

Modernized PBR mechanisms provide flexibility to utilities to address changing grid needs while maintaining safe and reliable service

- Address cost recovery challenges of achieving policy objectives
- Fund traditional investments to meet safety, reliability, and resilience standards while funding investments to meet clean energy transition

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2025-2029 PERFORMANCE OUTCOMES FRAMEWORK

Toronto Hydro's 2025-2029 performance management framework consists of: (1) utility outcomes and measures consistent with the OEB's Renewed Regulatory Framework ("RRF"), and (2) a custom scorecard that is tied to a Performance Incentive Mechanism ("PIM") as part of the utility's 2025-2029 Custom Rate Framework, which is set out in the evidence at Exhibit 1B, Tab 2, Schedule 1.

In respect of the first component – RRF outcomes – Toronto Hydro intends to continue delivering high performance on the Electricity Distributor Scorecard ("EDS") and the Electricity Service Quality Requirements ("ESQR") consistent with the historical results presented in Exhibit 1B, Tab 3, Schedule 2. To that end, each capital and operational program outlined in Exhibit 2B (capital) and Exhibit 4, Tab 2 (operations) includes a performance outcomes table that explains how the program advances specific RRF outcomes. In addition, Exhibit 2B, Section D1 identifies the asset management objectives that the utility set for its Distribution System Plan, and key performance measures that track to the stated objectives.

In respect of the second component of the framework – the 2025-2029 Custom Scorecard and related PIM – this schedule sets out:

- an overview of the PIM and its functioning, including a brief description of the process for developing the proposed Custom Scorecard and metrics;
- the 2025-2029 Custom Scorecard with a detailed explanation of each metric including historical results (where available), the rationale for featuring the metric on the Custom Scorecard and for adopting the proposed target, and a summary of the key investments in the plan that enable the utility to achieve the targets.

- A benefits analysis to demonstrate the value proposition of the PIM for customers based on benefits that can be quantified from the Custom Scorecard.

1. PERFORMANCE INCENTIVE MECHANISM (PIM) OVERVIEW

As described in the Rate Framework evidence at Exhibit 1B, Tab 2, Schedule 1, the PIM holds Toronto Hydro financially accountable for achieving key objectives of its plan, which are informed by and aligned with customers' needs and priorities. In doing so, the PIM provides ratepayers a significant $65 million upfront benefit and shifts risk to the utility for delivering key outcomes that matter to customers.

The PIM begins with approval of the 2025-2029 custom rate-setting formula known as the Custom Revenue Cap Index ("CRCI"). Like all rate-setting methodologies under the RRF, the CRCI relies on an X-factor based on productivity and efficiency (stretch-factor) determinations. As outlined in Exhibit 1B, Tab 2, Schedule 1, Toronto Hydro's proposed X-factor consists of three components:

1. A 0% productivity-factor consistent with OEB policy;
2. A 0.15% efficiency factor, determined by empirical total cost benchmarking; [1] and
3. A 0.6% pro-active performance factor that is linked to the 2025-2025 Custom Scorecard and PIM discussed herein.

The net result is a custom X-factor of 0.75%, which is 0.6% greater than the X-factor supported by the empirical total cost benchmarking. Through the proactive assumption of the 0.6% performance factor, Toronto Hydro provides customers an upfront rate reduction of approximately $65 million over the 2025-2029 term, in addition to the $16.4 million revenue and rate reduction resulting from the 0.15% efficiency factor. In totality, the X-

[1] Exhibit 1B, Tab 3, Schedule 3, Appendix A.

factor constrains the utility's revenue relative to its forecasted costs (i.e. the revenue requirement in Exhibit 6, Tab 1) by approximately $81.4 million over the rate term.

The proposed PIM outlined in this schedule provides Toronto Hydro the opportunity to 'earn-back' the $65 million revenue cut by the 0.6% pro-active performance factor, only if the utility delivers key outcomes, as measured by specific metrics and targets on the balanced Custom Scorecard outlined in section 2 of this schedule.

The achievement of the proposed performance targets provides customer value across multiple aspects of utility performance, not all of which can be quantified. For the benefits that can be quantified however, the Investment Plan and Custom Scorecard that underpin the PIM, yields nominal customers benefits that range from approximately $90 million and $216 million over the 2025 to 2029 period, and lifetime benefits in the range of $890 million to over $1.23 billion, as detailed in section 3 below.

As explained above, the PIM operates in a manner that enables Toronto Hydro to earn back its OEB-approved rate of return on equity ("ROE") by achieving the set performance targets. In other words, the PIM being an asymmetrical mechanism means that awarding Toronto Hydro the proposed incentive at the end of the rate term does not give rise to incremental utility earnings for strong performance. To the degree the utility does not achieve the scorecard targets, customers retain some (or all) of the upfront benefit of the $65 million reduction to 2025-2029 rates. If the utility achieves the targets, the analysis in section 3 below demonstrates that ratepayers get more benefits than the cost of the incentive to be collected at the next rebasing application, in addition to many other valuable benefits that cannot be quantified but are nonetheless important to customers.

The 2025-2029 Custom Scorecard includes 12 metrics across four performance categories: (1) System Reliability and Resilience; (2) Customer Experience and Service; (3) Environment, Safety and Governance; and (4) Efficiency and Financial Performance. These areas of performance were presented to customers in broad terms as part of the Phase 2 customer engagement survey described in Exhibit 1B, Tab 5, Schedule 1, whereby over 33,000 customers (representing more than 4 percent of the utility's total customer base) completed a detailed survey reviewing Toronto Hydro's draft plan and its key outcomes including price. The survey results indicated that an average of 84 percent of customers' surveyed support Toronto Hydro's draft plan or one that does even more to advance key outcomes.[2] From there, the utility created the four categories identified above and identified a suite of relevant metrics within each category to measure performance in a manner that aligns with customer feedback, and also reflects key objectives and underpinnings of the plan.[3]

In the process of developing the 2025-2029 Custom Scorecard, Toronto Hydro was guided by a series of principles as follows:

- focus on long-term goals and accomplishments;
- choose unambiguous and clearly defined metrics;
- focus on actions and outcomes within the utility's control;
- demonstrate customer value through cost-benefit analysis;
- focus on metrics that have strong linkages to the investment plan;
- incorporate stakeholder intelligence and feedback where possible;
- quantify targets using historical data where possible;
- set realistic targets that can be verified against historical data where possible, and account for uncertainty and variability where appropriate; and,

[2] Exhibit 1B, Tab 5, Schedule 1.
[3] For more information about the key objectives of the plan please refer to Exhibit 2B, Sections D1 and E2.

- set continuous improvements targets where possible, taking into consideration both incremental investments as well as higher volumes and complexity of work involved in delivering performance on specific objectives.

Each metric on the 2025-2029 Custom Scorecard includes a five-year target that must be achieved by the end of the rate term (i.e. 2029) in order for the utility to have the opportunity to earn-back the incentive. Toronto Hydro set the targets for each metric with regard to: (i) historical baselines (where available), (ii) 2025-2029 planned investments, and (iii) business conditions expected over the next rate.

The targets established for each metric reflect challenging, but achievable, outcomes based on Toronto Hydro's plan as-filed in this application. To the degree final approval of Toronto Hydro's proposed investment plan and rate-setting approach varies materially from what the utility outlined in the pre-filed evidence, the performance targets in the 2025-2029 Custom Scorecard must be reviewed and recalibrated to align with the funding implications and other parameters of the OEB's decision. Further, given the careful establishment of the proposed targets, their relationship with top-line capital and OM&A funding in rates is dynamic and multi-dimensional, which means that a simple pro-ration of the targets would not yield appropriate outcomes. For these reason, Toronto Hydro proposes to defer the finalization of the targets to a second phase of this proceeding that can be run in parallel with the Draft Rate Order process.

The proposed phased approach would allow the utility and interested parties to calibrate and validate targets (and the weightings if applicable based on the OEB decision) to align with the 2025-2029 investment plan and rate-setting approach approved by the OEB. Toronto Hydro envisions this second phase being a settlement-like process, providing

interested parties the opportunity to collaborate in finalizing the targets. If an agreement cannot be reached on one or more metrics, this process would also provide parties the opportunity to make submissions to the OEB. The OEB would review any potential settlement and/or approve the final targets with regard to parties' submissions.

The recovery of the incentives approved and earned through performance under the PIM are enabled by a Performance Incentive Mechanism Deferral Account ("PIM-DA"), as proposed in Exhibit 1B, Tab 2, Schedule 1 and detailed in Exhibit 9, Tab 1, Schedule 1. This account would be brought forward for review and disposition in the utility's next rebasing application, based on known (or forecasted) performance results for the 2025-2029 rate period. Only if the set performance targets are achieved (or forecasted be achieved with a high degree of confidence) by the end of the rate term would the incentive be recovered from customers in the next decade. As such, Toronto Hydro confirms that that there would be no rate recovery associated with the PIM in the 2025-2029 period.

2. 2025 TO 2029 CUSTOM SCORECARD

As part of 2025-2029 Custom Scorecard, the utility proposes 12 custom measures across four performance categories: (1) System Reliability and Resilience; (2) Customer Experience and Service; (3) Environment, Safety and Governance; and (4) Efficiency and Financial Performance. Table 1 below identifies the outcomes and measures within each performance area, and provides a target and proposed weighting for each measure.

Table 1: 2025 – 2029 Performance Incentive Scorecard Measures

Performance	Weight	Measures	Five-Year Target
System Reliability & Resilience	15%	**Outage Duration:** System Average Interruption Duration Index (SAIDI) excluding Major Event Days (MEDs), Loss of Supply (LoS) and Scheduled Outages	46.2 minutes (five-year average)
	10%	**Outage Frequency:** System Average Interruption Frequency Index (SAIFI) - Defective Equipment	0.38 – 0.45 (five-year average)
	5%	**System Security Enhancements:** Deliver initiatives that enhance Toronto Hydro's physical and cyber security posture against the NIST framework	100% by 2029
Customer Service & Experience	10%	**New Services Connected on Time:** Percentage of new connections and service upgrades completed on time consisting of Low Voltage Connections (70%), High Voltage Connections (20%) and DER Connections (10%)	99% (five-year average)
	5%	**Customer Satisfaction:** Post-transactional customer satisfaction surveys for Customer Inquiries (Phone & Email), Key Accounts Engagements, Customer Connections, and Communications (Outages & Construction Projects)	Maintain historical baselines
	5%	**Customer Escalations Resolution:** Percentage of customer escalations resolved within 10 business days.	98% (five-year average)
Environment, Safety and Governance	10%	**Total Recordable Injury Frequency (TRIF):** Injuries per 100 employees (or 200,000 hours worked) per year.	0.83 (five-year average)
	5%	**Emissions Reductions:** Tonnes of CO2e emissions produced by Toronto Hydro's fleet and facilities.	2.5 kilo tonnes CO2 emissions in 2029
	5%	**ISO Compliance and Certification:** Achieve and maintain certification with select ISO governance standards, specifically achieve ISO 55001 (60%), and maintain ISO14001 (20%) and ISO45001 (20%).	100% by 2029
Efficiency & Financial Performance	15%	**Efficiency Achievements:** Sustained efficiency benefits for customers that will produce a lower revenue requirement in the next rebasing application.	$6.9 million per year by 2029
	10%	**Grid Automation Readiness:** Completion of milestones to enable the automation of the overhead system in the horseshoe areas of the grid starting in 2030.	100% by 2029
	5%	**System Capacity (Non-Wires):** Flexible system capacity procured through demand response offerings.	30 MW by 2029

In the detailed sections below, Toronto Hydro provides: (i) thorough explanations of each metric including historical performance baselines (where available), (ii) the rationale for including the measure on the Custom Scorecard and for adopting the proposed target, and (iii) a summary of key investments in the 2025-2029 plan that enable the utility to achieve the proposed performance target.

2.1 System Reliability & Resilience

Table 2: System Reliability & Resilience Measures

Performance	Weight	Measures	Historical Performance	Target (2025-2029)
System Reliability & Resilience	15%	Outage Duration	48.2 min	46.2 minutes (five-year average)
	10%	Outage Frequency	0.42	0.38 – 0.45 (five-year average)
	5%	System Security Enhancements	94% (Cyber Security)	100% by 2029

2.1.1 Outage Duration

Outage Duration is measured by the 5-year rolling average of System Average Interruption Duration Index ("SAIDI") performance, excluding Major Event Days, Loss of Supply and Scheduled Outages. SAIDI tracks the number of minutes the average customer is without power in a year. It is the quotient obtained by dividing the total customer minutes of interruption (for all outages longer than one minute, i.e. sustained interruptions) by the total number of customers served.

Toronto Hydro proposes to remove the Scheduled Outages cause code from its 2025-2029 custom SAIDI performance measure for two reasons: (1) major forecasting uncertainty caused by the ongoing implementation of Oracle's Utility Analytics ("OUA"), and (2) the

utility expects Scheduled Outages to increase in the 2025-2029 period as the result of a larger work program.[4] Toronto Hydro further submits that excluding the Scheduled Outages cause code will provide more transparency and visibility into reliability performance as it relates to unforeseen interruptions for customers.

For the 2025-2029 period, Toronto Hydro intends to improve Outage Duration performance as measured by the custom SAIDI metric compared to historical performance. This objective aligns with customer needs and priorities based on the Phase 1 Customer Engagement survey results which revealed that when it comes to reliability performance all customers (except Key Accounts) prioritize reducing the overall length of outages rather than the overall number of outages.[5]

Toronto Hydro set a target of 46.2 minutes by 2029 on a 5-year rolling average basis (i.e. the five-year average of 2025-2029 results), consistent with OEB's approach for measuring reliability performance on the EDS. This target is informed by the utility's reliability projection methodology, which is built up from projected performance across various cause codes. Toronto Hydro modeled Defective Equipment outages by projecting failures and outage impacts at an asset class level based on asset demographics and the expected benefits of the utility's 2025-2029 planned sustainment investments. The utility assumed a historical five-year average for other cause codes (e.g. tree contacts). Toronto Hydro also included projections for expected benefits of the reliability-related Grid Modernization investments (i.e. switches and reclosers). The teal blue line in Figure 1 below shows the combined projection for all of these drivers.

[4] Please refer to Exhibit 2B, Section C for more information on the impacts of upgrades to outage tracking systems.
[5] For more information about customer needs and preferences, please refer to Exhibit 1B, Tab 5, Schedule 1.

While the projection suggests that Toronto Hydro's investment plan is sufficient only to maintain Outage Duration as measured by the custom SAIDI metric over the 2025-2029 period, the utility challenged itself to set a modest improvement target, recognizing the importance of outage duration to customers when it comes to reliability performance. To set an achievable improvement target, Toronto Hydro calculated the statistical variability of the historical rolling five-year average (relative to the historical trendline), and on this basis applied two standard deviations to the most recent five-year historical reliability (48.2 min), resulting in an improvement target of 46.2 min.

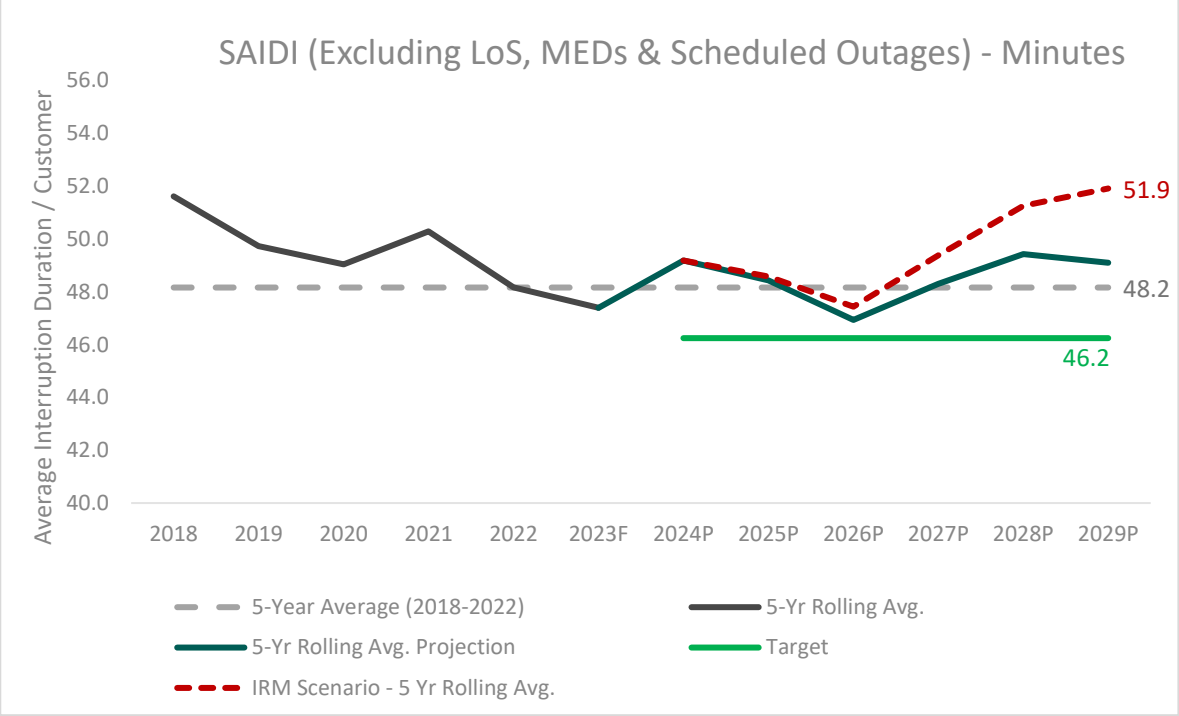

Figure 1: Historical and Projected SAIDI (excluding LoS, MEDs and scheduled outages)

As seen in Figure 1, although Toronto Hydro's SAIDI performance improved over the historical period, in more recent years (2020 through 2022) performance plateaued as the utility had to balance numerous considerations and constraints on its capital program,

importantly including price and financial integrity outcomes.[6] Without sufficient investment, reliability performance is expected to deteriorate as shown in the red line "IRM scenario" in Figure 1. The IRM scenario projects the performance that the utility would expect in circumstances where available rate funding during the outer years of the next rate period is limited to an increase that is less than inflation, as provided under the OEB's standard incentive rate-setting mechanism (IRM) approach.[7] Under this scenario, Toronto Hydro would be able to fund a capital plan of approximately $2.4 billion. Assuming that Toronto Hydro would continue to invest capital in demand-driven programs to be able to meet its obligation to serve customers, the utility expects that an IRM-funded capital plan would remove the entire grid modernization strategy from the Distribution System Plan ("DSP") and reduce proactive investments in sustainment capital programs (i.e. System Renewal) by nearly 75 percent, resulting in a plan that would be almost entirely reactive in nature.

The 2025-2029 DSP includes the minimum level of investment required in the Sustainment and Stewardship category to maintain recent reliability performance for defective equipment related outages. The plan also includes accelerating investments in the Modernization category to modestly improve performance on the custom SAIDI metric in the next rate period, and set the stage for longer-term improvements in overall SAIDI by developing an intelligent and self-healing grid as set out in the Grid Modernization Strategy (Exhibit 2B, Section D5). For further details about historical reliability performance please refer to Exhibit 2B, Section C and Section E2.2.1 which explains how reliability performance and asset risk trends and analyses informed Toronto Hydro's planning process.

[6] Please refer to Section E4 for a summary of the 2020-2024 capital expenditure plan.
[7] Please refer to Exhibit 1B, Tab 2, Schedule 1 for more information about the funding challenges under this IRM scenario.

Key investments that contribute to achieving the performance target on Outage Duration as measured by the custom SAIDI metric are summarized in Table 3 below.

Table 3: Key Enabling Investments to Manage Outage Duration

Program	Description of Key Enabling Investments to Manage Outage Duration
Overhead System Renewal	Investments in the Overhead System Renewal program allows Toronto Hydro to manage the deteriorating population of its overhead assets such as poles, overhead transformers, and overhead switches to reduce the overall associated reliability risks. The utility expects overall wood pole condition demographics to slightly worsen by 2029, but will manage failure risk by prioritizing assets near or at "end-of-serviceable" life condition. Rebuild projects also allow the utility to bring legacy equipment and designs to current distribution standards, resulting in improved reliability performance. Investments in Overhead Infrastructure Resiliency allows Toronto Hydro to manage increasing reliability pressures on the system due to climate change and improve accessibility to assets in difficult to access locations, improving response times especially during adverse weather events (Exhibit 2B, Section E2.4.2 and Exhibit 2B, Section E6.5).
Underground System Renewal (Horseshoe & Downtown)	Sustainment investments within the underground system through the Underground System Renewal - Horseshoe and Underground System Renewal - Downtown programs allow Toronto Hydro to manage the deteriorating population of its underground assets such as transformers, switches, cable chambers and cables. Toronto Hydro will continue to reduce obsolete cable populations, such as direct buried cable and lead cables, to maintain reliability within its underground system. Underground cables continue to be the single greatest contributor to outages caused by defective equipment. Rebuild projects also allow the utility to bring legacy equipment and designs to current distribution standards, resulting in improved reliability performance (Exhibit 2B, Section E2.4.2, Section E6.2, and Section E6.3).
Network System Renewal	Flooding within network vaults can pose significant failure risks due to the potential for catastrophic failure of network units contained within the vaults, especially for non-submersible units. Toronto Hydro will prioritize replacement of deteriorated network units (including non-submersible units) and network vaults or roofs in a paced manner to address this risk and maintain the reliability of its secondary network system. Reconfiguring networks also reduces average restoration time within the network system (Exhibit 2B, Section E2.4.2 and Exhibit 2B, Section E6.4).

Program	Description of Key Enabling Investments to Manage Outage Duration
Stations Renewal	Investments required to address the failure and obsolescence risk posed by station assets such as power transformers, switchgears, circuit breakers, and associated ancillary equipment which are highly critical to system performance. Toronto Hydro is planning to invest at a higher pace than in the 2020-2024 period within its Stations Renewal program to address a significant backlog of aging and deteriorating assets and ensure the long-term reliability performance of station assets. Renewal of assets allow the utility to address legacy equipment and designs, resulting in improved reliability performance. Improving control and monitoring capabilities and replacing obsolete electromechanical relays with modern digital relays will allow Toronto Hydro to reduce the duration of outages (Exhibit 2B, Section E2.4.2 and Exhibit 2B, Section E6.6).
Areas Conversions	Removal of aged, deteriorated, and obsolete 4.16 kV construction types including rear lot construction and box construction support reliability performance. Customers supplied by these construction types tend to experience below-average reliability. Investments in this program allow Toronto Hydro to convert customers to the latest distribution standards and reduce longer outage durations (Exhibit 2B, Section E2.4.2 and Exhibit 2B, Section E6.1).
Reactive and Corrective Capital	Investments for the replacement of failed and defective major assets. This program also allows for near-term corrective actions on high risk asset deficiencies identified through planned inspection or the course of day-to-day work, including deficiencies on Toronto Hydro's worst performing feeders. Investment in this program is required to eliminate failure risks from the system promptly (Exhibit 2B, Section E2.4.2 and Exhibit 2B, Section E6.7).
Network Condition Monitoring and Control	System Control and Data Acquisition ("SCADA")-enabled monitoring and control capabilities within Toronto Hydro's secondary network system allow for monitoring of key system parameters and remote switching capabilities. This in turn enables early detection of unfavorable conditions such as flooding or conditions that can lead to vault fires, and the ability for controllers to see real-time loading information to minimize customers impacted during outage events or contingency scenarios (Exhibit 2B, Section E2.4.3 and Exhibit 2B, Section E7.3).

Program	Description of Key Enabling Investments to Manage Outage Duration
System Enhancements	Investments in this program allow for the installation of SCADA switches, tie-points and reclosers on targeted feeders to improve outage response capabilities and reduce fault isolation times. In addition, upgrading undersized cables and improving the ability to respond to contingency events within the downtown system will also contribute to improved SAIDI performance. This program will form the system configuration required for Toronto Hydro's self-healing grid in 2030 and beyond, contributing to long-term reliability benefits (Exhibit 2B, Section E2.4.3 and Exhibit 2B, Section E7.1).
Load Demand	Investments in this program alleviate emerging capacity constraints within the system to minimize the impact of load growth on asset performance and improve restoration capabilities through targeted load transfers or cable upgrades. Offloading overloaded equipment reduces the risk of failures and improves flexibility for load transfers, thereby improving reliability (Exhibit 2B, Section E2.4.1 and Exhibit 2B, Section E5.3).
Metering	Next generation smart meters, with last gasp functionality installed through this program, improve system observability and enable grid operators to identify outage locations and dispatch repair crews to more precise locations, which results in a quicker and more accurate response. Enhancing data granularity also results in improved reliability by enabling the development of analytical tools to help reduce the likelihood of unexpected equipment failure (Exhibit 2B, Section E2.4.3 and Exhibit 2B, Section E5.4).
General Plant	Investments in Fleet, Facilities and IT equipment that enable TH employees to have access to safe, reliable equipment and tools needed to deliver the services required to manage reliability effectively. Investments to maintain and upgrade critical systems such as the Advanced Distribution Management System ("ADMS") are critical to provide the functionality for Toronto Hydro staff to prevent or respond to outages on the system efficiently, including the critical infrastructure for monitoring and control of Toronto Hydro's grid (Exhibit 2B, Section E8).

Program	Description of Key Enabling Investments to Manage Outage Duration
Operational Investments	Investments in operational programs that support SAIDI include: • Preventative and Predictive Overhead Line Maintenance (Exhibit 4, Tab 2, Schedule 1) and Underground Line Maintenance (Exhibit 4, Tab 2, Schedule 2): Promptly identifying potential asset failure or assets in substandard conditions before failure occurs, through planned inspections. • Corrective Maintenance (Exhibit 4, Tab 2, Schedule 4): Repairing and restoring assets through corrective maintenance to acceptable operating conditions. • Emergency Response (Exhibit 4, Tab 2, Schedule 5): Ensuring crews are available 24/7/365 to respond to power system events and minimizing outage restoration times. • Control Centre Operations (Exhibit 4, Tab 2, Schedule 7): Responding to system disruptions on a 24/7/365 basis and, in conjunction with field crews, taking the necessary actions to restore service in a safe and expedient manner and ensuring compliance with all legislative and regulatory requirements related to grid emergency preparedness and business continuity. • Asset and Program Management (Exhibit 4, Tab 2, Schedule 9): Ensuring ongoing stewardship of the distribution system and its ability to safely and reliably function in the long-term by maintaining asset records, scheduling maintenance activities, and developing capital investment scopes of work. • Work Program Execution (Exhibit 4, Tab 2, Schedule 10): Undertaking oversight, administrative training and other functions performed in the process of executing Toronto Hydro's capital and maintenance work programs. • Corporate Services (Exhibit 4, Tab 2, Schedule 15 [HR and Safety], Schedule 16 [Finance], and Schedule 18 [Public, Legal and Regulatory Affairs]): Corporate services provides organization-wide support in the areas of Finance, Public, Legal and Regulatory Affairs, and Human Resources, Environment and Safety to enable the safe and effective execution of Toronto Hydro's capital programs.

2.1.2 Outage Frequency

Outage Frequency is measured by the five-year rolling System Average Interruption Frequency Index ("SAIFI") for Defective Equipment, which tracks the number of interruptions in a year experienced by the average customer due to failed equipment. It represents the quotient obtained by dividing the total number of customer interruptions

caused by Defective Equipment (for outages longer than one minute – i.e. sustained interruptions) by the total number of customers served.

For the 2025-2029 period, Toronto Hydro intends to maintain SAIFI Defective Equipment compared to its historical performance at a target ranging from 0.38 to 0.45 by 2029 on a five-year rolling average basis.[8] Toronto Hydro's projection indicates that the investment plan is roughly sufficient to maintain Outage Frequency as measured by the custom SAIFI Defective Equipment metric over the 2025-2029 period, with some risk of deterioration relative to the five-year historical baseline (2018-2022). The target to maintain (rather than improve) Outage Frequency recognizes that customers in all classes (except Key Accounts) prioritize outage duration over frequency, and expect the utility to balance reliability performance with price and other key outcomes.[9]

To set a reasonable target while accounting for the inherent volatility of system reliability performance from year to year, Toronto Hydro calculated the variability of the historical rolling five-year average (relative to the historical trendline), and applied two standard deviations on either side of the most recent five-year historical reliability (0.42), resulting in a maintain target of 0.38 to 0.45.[10]

[8] Toronto Hydro modelled SAIFI Defective equipment using the same reliability projection model as discussed above under section 3.1 Outage Duration with respect to the custom SAIDI metric.
[9] Please see Exhibit 1B, Tab 5, Schedule 1 for more information about application-specific customer research.
[10] In effect, this results in a performance target of 0.45, as Toronto Hydro is not proposing an additional incentive for improving beyond the threshold of 0.38.

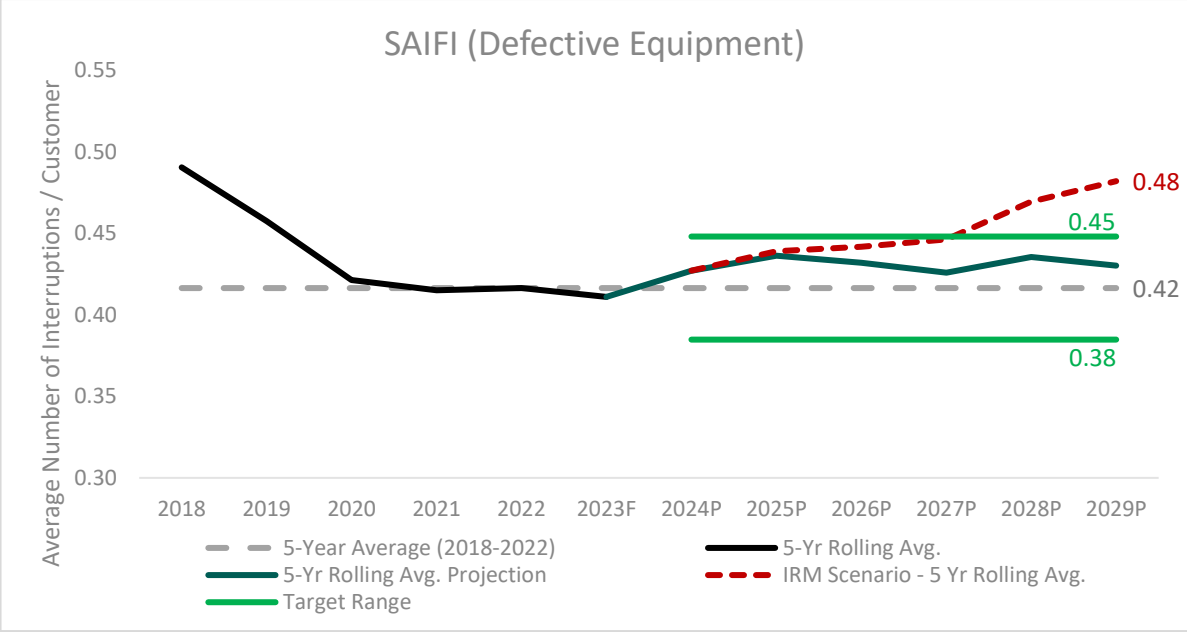

Figure 2: Historical and Projected SAIFI (Defective Equipment)

As seen in Figure 2, although Toronto Hydro's SAIFI Defective Equipment performance improved over the historical period as a result of ongoing investments in Sustainment and Stewardship programs, in more recent years (2020 through 2022) performance plateaued as the utility had to balance numerous considerations and constraints on its capital program.[11]

Asset condition and age demographics are important leading indicators of reliability. Toronto Hydro expects comparable, if not slightly more pronounced, deterioration in its asset demographics between 2023-2029. Given these challenges, Toronto Hydro expects that considerable incremental investment would be required to improve SAIFI performance at a rate that is comparable to historical improvement levels.[12] Through risk-balanced

[11] For further details about historical reliability performance please refer to Exhibit 2B, Section C and Section E2.2.1 which explains how reliability performance and asset risk trends and analyses informed Toronto Hydro's planning process.
[12] These dynamics are further discussed in Exhibit 2B, Section E2.2.1.

investments in Sustainment-related programs, Toronto Hydro proposes to invest the minimum level necessary to manage asset condition and age demographics while minimizing customer rate impacts. Without sufficient investment in this area of the plan, the utility expects performance to degrade, as depicted by the IRM scenario in Figure 2.

Investments that contribute to achieving the performance target on Outage Frequency as measured by the SAIFI Defective Equipment metric are summarized in the Table 4 below.

Table 4: Key Enabling Investments – Outage Frequency

Program	Description of Key Enabling Investments to Manage Outage Frequency
Overhead System Renewal	Investments in the Overhead System Renewal program allows Toronto Hydro to manage the deteriorating population of its overhead assets such as poles, overhead transformers, and overhead switches to reduce the overall associated reliability risks. The utility expects overall wood pole condition demographics to slightly worsen by 2029, but will manage failure risk by prioritizing assets near or at "end-of-serviceable" life condition. Rebuild projects also allow the utility to bring legacy equipment and designs to current distribution standards, resulting in improved reliability performance. Investments in Overhead Infrastructure Resiliency allows Toronto Hydro to manage increasing reliability pressures on the system due to climate change and improve accessibility to assets in difficult to access locations, minimizing elevated failure risks and improving response times especially during adverse weather events (Exhibit 2B, Section E2.4.2 and Exhibit 2B, Section E6.5).
Underground System Renewal – Horseshoe and Downtown	Sustainment investments within the underground system through the Underground System Renewal - Horseshoe and Underground System Renewal - Downtown programs allow Toronto Hydro to manage the deteriorating population of its underground assets such as transformers, switches, cable chambers, and cables. Toronto Hydro will continue to reduce obsolete cable populations, such as direct buried cable and lead cables, to maintain reliability within its underground system. Underground cables continue to be the single greatest contributor to outages caused by defective equipment. Rebuild projects also allow the utility to bring legacy equipment and designs to current distribution standards, resulting in improved reliability performance (Exhibit 2B, Section E2.4.2, Exhibit 2B, Section E6.2, and Section E6.3).

Program	Description of Key Enabling Investments to Manage Outage Frequency
Network System Renewal	Flooding within network vaults can pose significant failure risks due to the potential for catastrophic failure of network units contained within the vaults, especially for non-submersible units. Toronto Hydro will prioritize replacement of deteriorated network units (including non-submersible units) and network vaults or roofs in a paced manner to address this risk and maintain the reliability of its secondary network system. Reconfiguring networks also reduces outage impacts within the network system (Exhibit 2B, Section E2.4.2 and Exhibit 2B, Section E6.4).
Stations Renewal	Investments to address the failure and obsolescence risk posed by station assets such as power transformers, switchgears, circuit breakers, and associated ancillary equipment which are highly critical to system performance. Toronto Hydro is planning to invest at a higher pace than in the 2020-2024 period within its Stations Renewal program to address a significant backlog of aging and deteriorating asset population and ensure the long-term reliability performance of station assets. Renewal of assets allows the utility to address legacy equipment and designs, resulting in improved reliability performance. Improving control and monitoring capabilities and replacing obsolete electromechanical relays with modern digital relays will allow Toronto Hydro to reduce associated reliability risks (Exhibit 2B, Section E2.4.2 and Exhibit 2B, Section E6.6).
Area Conversions	Removal of aged, deteriorated, and obsolete 4.16 kV construction types including rear lot construction and box construction supports reliability performance. Customers supplied by these construction types tend to experience below-average reliability (Exhibit 2B, Section E2.4.2 and Exhibit 2B, Section E6.1).
Reactive and Corrective Capital	Investments in the replacement of failed and defective major assets. This program also allows for near-term corrective actions on high risk asset deficiencies identified through planned inspection or in the course of day-to-day work, including deficiencies on Toronto Hydro's worst performing feeders. Investment in this program are required to promptly eliminate failure risks from the system (Exhibit 2B, Section E2.4.2 and E6.7).
Network Condition Monitoring and Control	System Control and Data Acquisition ("SCADA")-enabled monitoring and control capabilities within Toronto Hydro's secondary network system allow for monitoring of key system parameters and remote switching capabilities. This in turn enables early detection of unfavorable conditions such as flooding or conditions that can lead to vault fires, and the ability for controllers to see real-time loading information to minimize customers impacted during outage events or contingency scenarios (Exhibit 2B, Section E2.4.3 and Exhibit 2B, Section E7.3).

Program	Description of Key Enabling Investments to Manage Outage Frequency
System Enhancements	Investments in this program allow for the installation of SCADA switches, tie-points and reclosers on targeted feeders to improve outage response capabilities and reduce fault isolation times. The introduction of reclosers will reduce the number of customers impacted by an outage event on a feeder. In addition, this program will form the system configuration required for Toronto Hydro's self-healing grid in 2030 and beyond, contributing to long-term reliability benefits (Exhibit 2B, Section E2.4.3 and E7.1).
Load Demand	Investments alleviate emerging capacity constraints within the system to minimize the impact of load growth on asset performance and improve restoration capabilities through targeted load transfers or cable upgrades. Offloading overloaded equipment reduces the risk of failures and improves flexibility for load transfers, thereby improving reliability (Exhibit 2B, Section E2.4.1 and Exhibit 2B, Section E5.3).
Metering	Next generation smart meters with last gasp functionality installed through this program improves system observability and enables grid operators to identify outage locations and dispatch repair crews to more precise locations, which results in a quicker and more accurate response. Enhancing data granularity also results in improved reliability by enabling the development of analytical tools to help reduce the likelihood of unexpected equipment failure (Exhibit 2B, Section E2.4.3 and Exhibit 2B, Section E5.4).
General Plant	Investments in Fleet, Facilities and IT equipment that enable TH employees to have access to safe, reliable equipment and tools needed to deliver the services required to manage reliability effectively. Investments to maintain and upgrade critical systems such as the Advanced Distribution Management System ("ADMS") is critical to provide the functionality for Toronto Hydro staff to prevent or respond to outages on the system efficiently, including the critical infrastructure for monitoring and control of Toronto Hydro's grid (Exhibit 2B, Section E8).
Operational Investments	• Preventative and Predictive Overhead Line Maintenance and Underground Line Maintenance (Exhibit 4, Tab 2, Schedules 1 and 2): identify potential asset failure or assets in substandard condition before failure occurs, through planned inspections. • Corrective Maintenance (Exhibit 4, Tab 2, Schedule 4) - repairing and restoring assets through corrective maintenance to acceptable operating condition. • Emergency Response (Exhibit 4, Tab 2, Schedule 5) - ensuring crews are available 24/7/365 to respond to system events and minimizing outage restoration times.

Program	Description of Key Enabling Investments to Manage Outage Frequency
	• Control Centre Operations (Exhibit 4, Tab 2, Schedule 7) - responding to system disruptions on a 24/7/365 basis and, in conjunction with field crews, taking the necessary actions to restore service in a safe and expedient manner and ensuring compliance with all legislative and regulatory requirements related to grid emergency preparedness and business continuity. • Asset and Program Management (Exhibit 4, Tab 2, Schedule 9) - ensuring ongoing stewardship of the distribution system and its ability to safely and reliably function in the long-term by maintaining asset records, scheduling maintenance activities, and developing capital investment scopes of work. • Work Program Execution (Exhibit 4, Tab 2, Schedule 10) - Undertaking oversight, administrative training and other functions performed in the process of executing Toronto Hydro's capital and maintenance work programs. • Corporate Services provide organization-wide support in the areas of Human Resources, Environment and Safety, Finance, and Public, Legal and Regulatory Affairs (Exhibit 4, Tab 2, Schedule 15, 16 and 18, respectively) to enable the safe and effective execution of Toronto Hydro's capital programs.

2.1.3 System Security Enhancements

System Security Enhancements measures performance on the key objectives of: (1) continual improvement and maintenance of Toronto Hydro's cybersecurity posture in the face of an evolving digital threat landscape; and (2) protecting the physical safety and security of employees, assets, and the public. This metric tracks the completion of key initiatives aimed at improving Toronto Hydro's cybersecurity and physical security posture in a manner that aligns with the National Institute of Standards and Technology ("NIST") Cyber Security Framework and OEB's Cyber Security Framework ("CSF").[13] The selected initiatives are responsive to the cyber and physical security threat landscape that the utility faces, and reflect the utility's cybersecurity roadmap and program maturity.

[13] Framework for Improving Critical Infrastructure Cybersecurity, Version 1.1 (National Institute of Standards and Technology, 2018)< https://nvlpubs.nist.gov/nistpubs/cswp/nist.cswp.04162018.pdf> ; Ontario Cyber Security Framework, Version 1.0 (Ontario Energy Board, 2017) < https://www.oeb.ca/sites/default/files/Ontario-Cyber-Security-Framework-20171206.pdf> .

For the 2025 – 2029 period, Toronto Hydro plans to increase the total number of initiatives that enhance the utility's physical and cyber security posture against the NIST framework by delivering 100 cyber security projects and integrating 10 stations into the Physical Security Operations Centre by the end of the rate period. Completion of these milestones make up the target of 100% on the System Security Enhancements custom metric.

As shown in Figure 3, below, Toronto Hydro implemented 17 projects to date in 2023 out of a possible 18, setting a baseline of 94% for the cybersecurity portion of this measure.

Function	Category (Toronto Hydro Roadmap)	NIST / OEB CSF Category Alignment	2023 Actuals
Identify	Threat Awareness	Asset Management (ID.AM), Business Environment (ID.BE)	0
	Response Readiness	Risk Management Strategy (ID.RM), Awareness and Training (PR.AT)	0
	External Audits	Governance (ID.GV)	1
	Security Posture Validation	Risk Assessment (ID.RA)	2
Protect	External Security	Information Protection Processes and Procedures (PR.IP)	1
	Perimeter Security	Protective Technology (PR.P)	3
	Identity & Access Management	Access Control (PR.AC)	2
	Endpoint & Application Protection	Protective Technology (PR.P), Data Security (PR.DS)	1
	OT Protection	Protective Technology (PR.P), Access Control (PR.AC)	1
Detect	Logging	Anomalies and Events (DE.AE), Security Continuous Monitoring (DE.CM)	0
	Monitoring & Alerting	Anomalies and Events (DE.AE), Security Continuous Monitoring (DE.CM)	2
	Advanced Detection Capabilities	Detection Processes (DE.DP)	0
	Operational Processes	Security Continuous Monitoring (DE.CM)	3
Respond	Response Processes	Response Planning (RS.RP), Communications (RS.CO)	0
	Containment	Analysis (RS.AN), Mitigation (RS.MI)	1
	Eradication	Mitigation (RS.MI), Improvments (RS.IM)	0
Recover	Recovery Processes	Recovery Planning (RC.RP)	0
	Recovery Mechanisms	Protective Technology (PR.P), Improvements (RC.IM)	0
	Clean-up	Communications (RC.CO)	0
Total			17
Attainment Target			18
KPI Baseline			94%

Figure 3: Toronto Hydro's Cyber Security NIST/OEB CSF Roadmap

Investments that contribute to achieving the performance target on the System Security Enhancement metric are summarized in Table 5 below.

1 **Table 5: Key Enabling Investments – System Security Enhancement**

Program	Description of Key Enabling Investments to Enhance System Security
Facilities Management and Security program	Key investments in physical security measures to prevent unauthorized access to stations, while also keeping them accessible for authorized personnel, and to improve response times in the event of breaches of physical security. These initiatives enhance the utility's security posture in the NIST/CSF frameworks categories of physical access, technology and network measures (Exhibit 2B, Section E8.2).
Facilities Management	Operational investments to maintain the building systems of the utilities offices, work centers and buildings housing the utility's transformer and municipal stations, as well as maintain the elements that secure and mitigate the risk of damage to critical infrastructure (e.g. sump pumps, building envelopes) (Exhibit 4, Tab 2, Schedule 12).
Information and Operational Technology	Operational (Exhibit 4, Tab 2, Schedule 17) and capital (Exhibit 2, Section E8.4) investments to protect the security of IT infrastructure and software applications, and enhance cybersecurity preventative and reactive controls. These investments include projects that renew the utility's IT hardware and software assets to maintain a robust cybersecurity posture and mitigate against potential vulnerabilities and threats that may jeopardize the safe and effective functioning of IT/OT assets. These investments are necessary to ensure that existing systems receive support from vendors, keep pace with technology changes in the industry, remain integrated with other relevant hardware and software systems, and are protected against future cyber security threats. When IT systems have surpassed the period of extended vendor support, the vendor and the marketplace do not guarantee availability of qualified resources and expertise needed to resolve any potential issues. As a result, the failure of these systems may result in prolonged downtime, which can significantly affect the utility's operations and its ability to execute planned work programs and deliver services to its customers.
Legal Services and Supply Chain	Operational investments to support procurement (Exhibit 4, Tab 2, Schedule 18) and negotiation of complex IT contracts (Exhibit 4, Tab 2, Schedule 18).

2.2 Customer Service & Experience

Table 6: Customer Service & Experience Custom Performance Measures

Performance	Weight	Measures	Historical Performance	Target (2025-2029)
Customer Service & Experience	10%	New Services Connected on Time	99%	99%
	5%	Customer Satisfaction	84% Phone and Email Inquiries	Maintain historical baselines
	5%	Customer Escalations	98.74%	98%

2.2.1 New Services Connected on Time

The measure of New Services Connected on Time tracks the percentage of new connections and service upgrades completed on time across three categories of connections: Low Voltage, High Voltage and Distributed Energy Resources ("DER") weighted at 70 percent, 20 percent, and 10 percent, respectively. This metric aligns with Toronto Hydro's fundamental obligation to serve and ongoing commitment to provide timely access to the grid for new and existing customers, by measuring the utility's effectiveness in connecting customer services within set performance standards as summarized in Table 7 below.

Table 7: Performance Standard by Connection Type

Connection Type	Performance Standard	Number of Service Requests	Weighting
Low Voltage (LV)	5 business days	5700/year (or more)	70%
High Voltage (HV)	10 business days	120/year (or more)	20%
DERs	5 business days	180/year (or more)	10%

Figure 4 below illustrates Toronto Hydro's five-year historical performance (2018 to 2022) on the New Services Connected on Time composite metric.

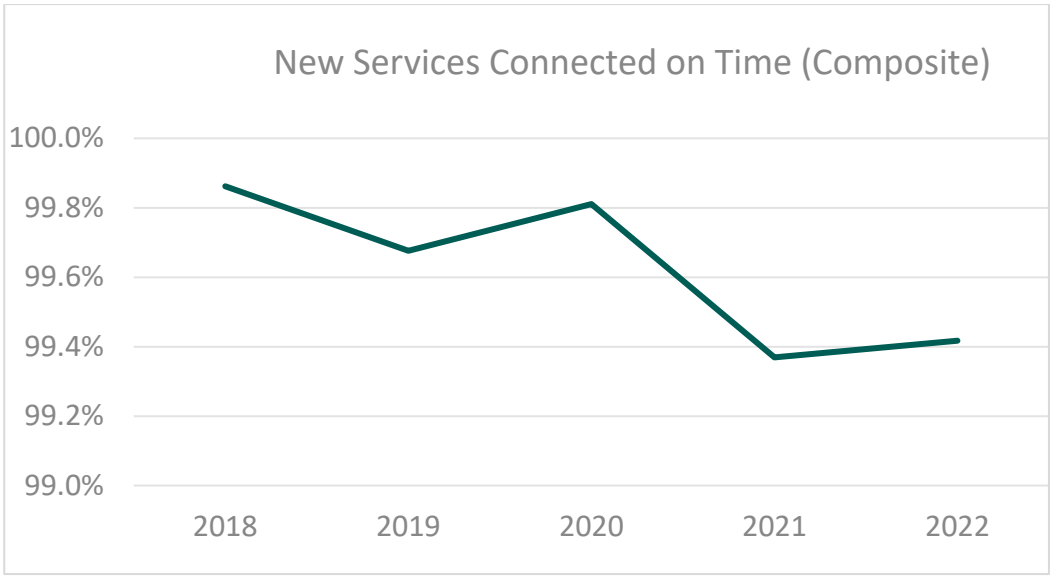

Figure 4: 2018-2022 New Services Connected on Time (Composite)

For the 2025-2029 plan period, Toronto Hydro set the performance target of 99 percent for the composite New Services Connected on Time metric. This target considers Toronto Hydro's forecast of a significant 23 percent increase in system peak demand by the next decade, driven by continued increases in load connections, including larger connections as observed in recent years.[14] It also considers, the forecast of a 56 percent increase in DER connections over the next rate period.[15] Overall, the target reflects the utility's expectation that higher volumes and increasing complexity of connections-related work as customers electrify previously non-electric energy uses (i.e. transportation and building systems) will make it more challenging to maintain performance on this metric.

The investments that contribute to achieving the performance target on the New Services Connected on Time metric are summarized in Table 8 below.

[14] Exhibit 2B, Section D4.
[15] Exhibit 2B, Section E5.1 at page 15.

Table 8: Key Enabling Investments – New Service Connected on Time

Program	Description of Key Enabling Investments for Timely New Service Connections
Customer Connections Capital	Capital investments required to provide new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system for both load and generation connection requests. Investments in this program allow Toronto Hydro to meet regulatory requirements and account for anticipated growth in the 2025-2029 period (Exhibit 2B, Section E2.4.1 and Exhibit 2B, Section E5.1).
Customer Connections OM&A	Operational investments to ensure sufficient planning staff and required tools and resources are available to efficiently plan and design service connections and meet service request volumes (Exhibit 4, Tab2, Schedule 8).
Load Demand	Investments to alleviate emerging capacity constraints to ensure the availability of sufficient capacity to efficiently connect customers to Toronto Hydro's distribution system. Targeted capacity upgrades alleviate highly loaded parts of the system through load transfer or equipment upgrades (Exhibit 2B, Section E2.4.1 and Exhibit 2B, Section E5.3).
Stations Expansion	This program addresses medium to long-term system capacity needs, informed by its Stations Load Forecast. Investment in this program is required to reduce the number of stations unable to connect new large customers effectively, alleviating feeder position limitations, and enabling DER connections by providing increased short circuit capacity (Exhibit 2B, Section E2.4.1 and Exhibit 2B, Section E7.4).
Generation Protection Monitoring and Control	This program allows Toronto Hydro to fulfill its regulatory obligations to connect Distributed Energy Resource ("DER") projects to its distribution system. Investments in this program alleviates technical barriers to connecting DERs. It also improves monitoring and control to ensure safe DER operation (Exhibit 2B, Section E2.4.1 and Exhibit 2B, Section E5.5).
Non-Wires Solutions	Investments in this program, especially in the Energy Storage System segment, target areas with constraints to improve the grid's capacity to connect and integrate Renewal Energy Generation (REG) connections (Exhibit 2B, Section E7.2).
Externally Initiated Plant Relocations and Expansion	This program increases the capacity of Toronto Hydro's system, where efficiencies can be achieved, by integrating expansion work of the electrical system with the required relocation work, supporting Toronto Hydro's ability to connect new customers efficiently (Exhibit 2B, Section E5.2).

Program	Description of Key Enabling Investments for Timely New Service Connections
Asset & Program Management	Operational investments to ensure sufficient staff to process and execute, in a timely manner, customer connection requests and offers to connect for both load and generation customers (Exhibit 4, Tab 2, Schedule 9).
Legal Services	Operational investments in legal professional services to advise on real property matters, including customer connection agreements (Exhibit 4, Tab 2, Schedule 18, Section 5).
Work Program Execution	Operational investments in internal and external resources to complete necessary distribution system work to facilitate customer connections (Exhibit 4, Tab 2, Schedule 10).
General Plant	Investments in Fleet, Facilities and IT equipment that enable TH employees to have access to safe, reliable equipment and tools needed to deliver the services (Exhibit 2B, Section E8).

2.2.2 Customer Satisfaction

The Customer Satisfaction measure reflects Toronto Hydro's ongoing commitment to deliver a positive customer experience and build trust by reaching customers at the right time, with the correct information, and through the right channel to meet their evolving needs. Complimentary to the EDS Customer Satisfaction measure, this custom metric tracks customer satisfaction at a more operational level, using post-transactional customer surveys (across a number of interaction points along the customer journey) to gain actionable insights about customer experience.

Specifically, this proposed metric tracks satisfaction across the following types of customer interactions: Phone and E-Mail Inquiries; Key Account engagements; Customer Connections process; and Customer Communications regarding Outages and Construction Projects. Toronto Hydro conducts post-transactional surveys with respect to the first three type of interactions listed above (i.e. Phone, Email and Key Accounts), and is in the process of establishing surveys related to the other areas of customer experience noted above (i.e.

Customer Connections process, Customer Communications regarding Outages and Construction Projects).

For the 2025-2029 plan period, Toronto Hydro intends to maintain post-transactional customer satisfaction levels in each of the areas noted above as measured against three-year historical baselines. This target is informed by careful consideration and balance of the following factors:(i) increasing volumes and complexity of customer interactions as the city grows and customers turn to electricity for new uses (e.g. transportation and heating); (ii) increasing customer expectations with respect to communications and service levels in an era of greater digital interaction and access to information on demand; and (iii) balancing price and service quality outcomes in light of the above.

Figure 5 illustrates the three-year historical baseline for phone and email inquires. For Key Account engagements, the performance baseline is in the process of being established from 2022-2024, whereas for the other areas of interaction (i.e. Customer Connections process, Customer Communications regarding Outages and Construction Projects), Toronto Hydro intends to (i) establish the performance baselines in 2024 through 2026, and (ii) measure its performance in 2027 through 2029 relative to the target of maintaining these baselines.

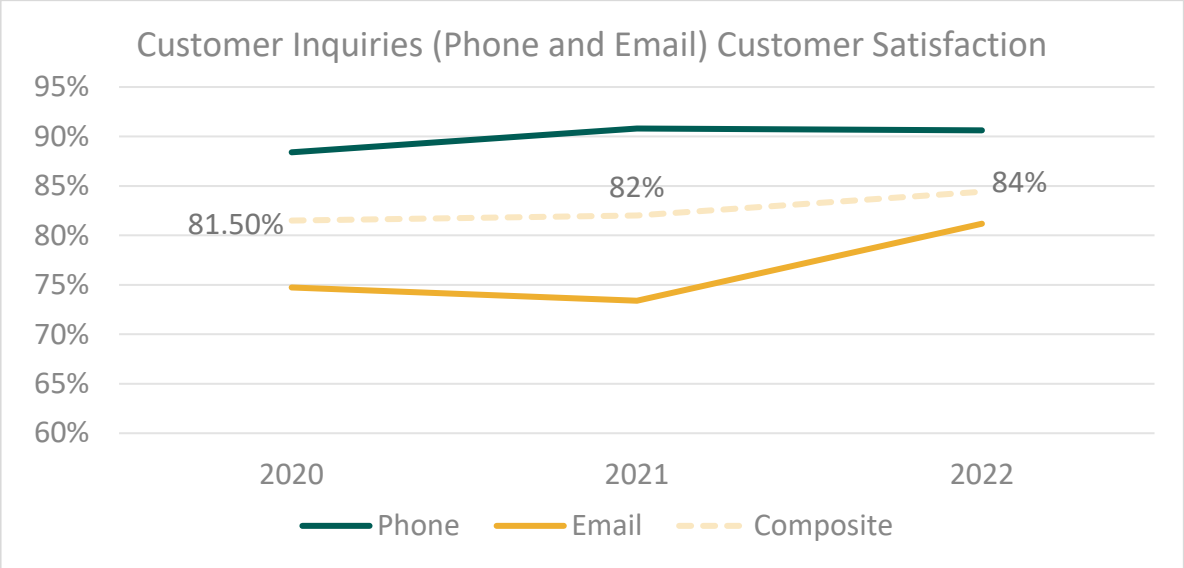

Figure 5: Customer Inquiries (Phone and Email) Customer Satisfaction (2020 – 2022)

Table 9 below summarizes the proposed weighting for this composite custom measure.

Table 9: Customer Satisfaction (Post-Transactional) Composite Measure Weightings

Element	2025 - 2026	2027-29
Customer Inquires (Phone & Email)[16]	80%	70%
Key Account Engagements	20%	20%
Customer Connections	0%	5%
Communications (Outages & Construction Projects)[17]	0%	5%

The investments that contribute to achieving the performance target on the proposed custom Customer Satisfaction metric are summarized in Table 10 below.

[16] Toronto Hydro proposes to weigh phone and email customer inquiries volumetrically. In 2022, approximately 83 percent of customer inquiries were received via phone and 17 percent were received via email.
[17] Toronto Hydro proposes to weigh customer communications related to outages and construction projects volumetrically.

Table 10: Key Enabling Investments to Deliver Customer Satisfaction

Program	Description of Key Enabling Investments to Deliver Customer Satisfaction
Customer Care Program	Operational investments to ensure sufficient staffing to provide timely responses to customer inquiries through multiple channels, including interactive voice response, email, Toronto Hydro's mobile application and the Customer Self Service portal (Exhibit 4, Tab 2, Schedule 14).
Demand-Related Investments	Investments in Customer Connections, Externally Initiated Plan Relocation, Load Demand, Station Expansion, Generation Protection Monitoring and Control, and Non-Wires Solutions programs allow Toronto Hydro to provide new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system for both load and generation connections. Investments address short- and long-term capacity limitations at the feeder, bus, station, or regional levels proactively as well as alleviate technical barriers to connections (e.g. DERs) to ensure that customer expectations can be met on a consistent basis, thereby impacting the customer experience and resulting satisfaction (Exhibit 2B, Section E5 and E7).
Public, Legal and Regulatory Affairs	Operational investments in Community Relations to enable proactive communications to notify customers of planned work, construction and outages. Operational investments in legal professional services to advise on real property matters, including customer connection agreements (Exhibit 4, Tab 2, Schedule 18).
Asset and Program Management	Operational investments in internal and external resources to process and execute, in a timely manner, customer connection requests and offers to connect (both load and generation customers) (Exhibit 4, Tab 2, Schedule 10).
Control Center Operations	Operational investments in staffing levels to facilitate the safe and reliable operation of the utility's distribution grid through real-time system control and monitoring activities on a 24/7, 365-day basis, including the coordination of system switching and restoration work through the utility's Control Centre to mitigate the effects of outages on customers and to enable safe load transfers for capital and maintenance work. (Exhibit 4, Tab 2, Section 7).
General Plant	Investments in Fleet, Facilities and IT equipment that enable TH employees to have access to safe, reliable equipment and tools needed to deliver the services.

2.2.3 Customer Escalations Resolution

Toronto Hydro is committed to addressing customer inquiries in a prompt manner. As reported in Exhibit 1B, Tab 3, Schedule 2, the utility resolves approximately 92 percent of customer inquiries upon first contact and intends to maintain this performance over the next period if there is sufficient funding available for its operations.

In addition, Toronto Hydro recognizes that some customer inquiries are more complex. To that end, the Customer Escalations Resolution measure tracks the utility's effectiveness in resolving inquiries that are referred from front-line contact center agents, or through the OEB E-Portal, within 10 business days per escalation.[18] This measure provides accountability for the timely resolution of more complex customer inquiries related to matters such as: energy and bill management, financial assistance and payment challenges, and service disruptions. Importantly, this metric drives a continued focus on a customer service culture as customer needs and expectations continue to evolve in the next rate period.

For the 2025-2029 plan period, Toronto Hydro set a performance target of 98 percent for this measure. The target is informed by: (1) the 2019 to 2022 historical results presented in Figure 6 below, and (2) the utility's recent experience and ongoing expectation that the volume and complexity of inquires will continue to increase as customers electrify previously non-electric energy usages (e.g. transportation and heating systems), and as technology and policy evolves to offer customers greater choice and more tools to participate in the production and management of their electricity usage.

[18] Total number of escalations resolved within 10 business days divided by the total number of resolved contacts.

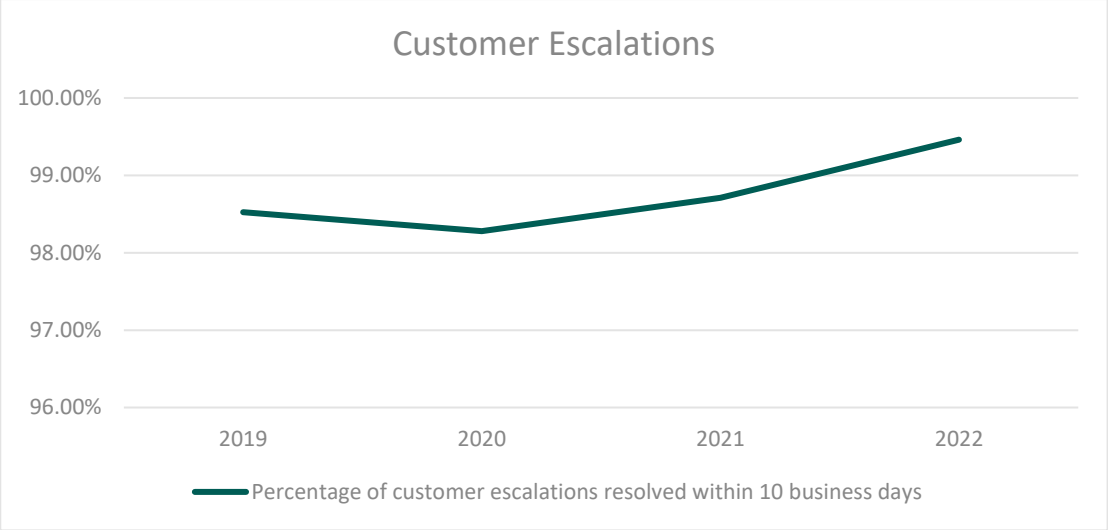

Figure 6: Customer Escalations Performance (2018-2022)

The investments that contribute to achieving the performance target on the Customer Resolutions metric are summarized in Table 11 below.

Table 11: Key Enabling Investments – Customer Escalations Resolution

Program	Description of Key Enabling Investments for Timely Resolution of Customer Escalations
Customer Care	Through the Customer Care program (Exhibit 4, Tab 2, Schedule 16) Toronto Hydro is investing in upskilling its workforce and enhancing its businesses processes and tools to meet evolving customer expectations and address an increasing volume of complex and diverse inquiries.
Public, Legal and Regulatory Affairs	Resource capacity and capabilities of the Regulatory Affairs segment to support the increased volume and complexity of work pertaining to Customer Escalations, notably including escalation through OEB processes. (Exhibit 4, Tab 2, Schedule 18).
Asset and Program Management	Robust records management, enhanced asset analytics and a sufficient compliment of designated technical and professional resources (e.g. engineers and technologists) in the Asset and Program Management area (Exhibit 4, Tab 2, Schedule 9) supports the timely resolution of more complex customer inquiries.

Program	Description of Key Enabling Investments for Timely Resolution of Customer Escalations
Customer Operations	Customer Operations (Exhibit 4, Tab 2, Schedule 8) supports the resolution of customer inquiries related to services provided in the Customer Connections segment of this program, as well as the Public Safety and Damage Protection segment which provides customers access to services such as isolations and underground locates.

2.3 Environment, Safety & Governance

Table 12: Environment, Safety & Governance Custom Performance Measures

Performance	Weight	Measures	Historical Performance	Target (2025-2029)
Environment, Safety and Governance	**10%**	**Total Recordable Injury Frequency (TRIF)**	0.83	0.83
	5%	**Emissions Reductions**	3.6kt/year	2.5kt/year by 2029
	5%	**ISO Compliance & Certification**	ISO14001 & 45001	100%

2.3.1 Total Recordable Injury Frequency (TRIF)

TRIF performance underlies the utility's commitment to ensuring the health and safety of its workforce by measuring the number of recordable injuries per 200,000 exposure hours, where a recordable is defined as any occupational injury or illness that results in an employee experiencing a fatality, lost-time injury, medical treatment injury beyond first aid, restricted work, or any other injury or illness which results in significant occupational injury or illness, or loss of consciousness.

TRIF is not only a measure of safety, but it also reflects productivity as strong TRIF performance yields numerous efficiency benefits including avoided costs related to employee lost-time, avoided costs related to higher Workplace Insurance Safety Board ("WSIB") premiums, and avoided costs related to employee accessing benefits such as

physiotherapy and other paramedical services in order to manage the impacts of the safety incident. Although these benefits are difficult to quantify, they are nonetheless an output of an exceptional safety record.[19] Toronto Hydro is proud to have an industry-leading safety performance record, as compared to the Electricity Canada industry average, and to have been recognized with the 2022 Electricity Canada President's Award of Excellence for Employee Safety - Distribution and the Canadian Occupational Safety Magazine 2022 5-Star Energy and Resource Company award.[20]

Figure 7 below illustrates Toronto Hydro's TRIF performance over the last ten years since the utility increased its capital work program to address infrastructure renewal needs. For the 2025 to 2029 plan period, the utility intends to maintain TRIF performance at an average of 0.83 based on its historical performance over the last ten years (excluding 2013 as the results in this particular year are a clear outlier in the data set). This target is mindful that safety is a shared responsibility across the organization and there are incremental safety risks and considerations that the utility must manage over the 2025-2029 period as it expands and renews its workforce across a number of programs, segments and functions.[21]

[19] EB-2018-0165, Exhibit 1B, Tab 2, Schedule 1 at page 9.
[20] Exhibit 1B, Tab 3 at page 15.
[21] Please see Exhibit 4 at Tab 1, Schedule 1 and Tab 4, Schedule 3 for more information about the utility's workforce plan.

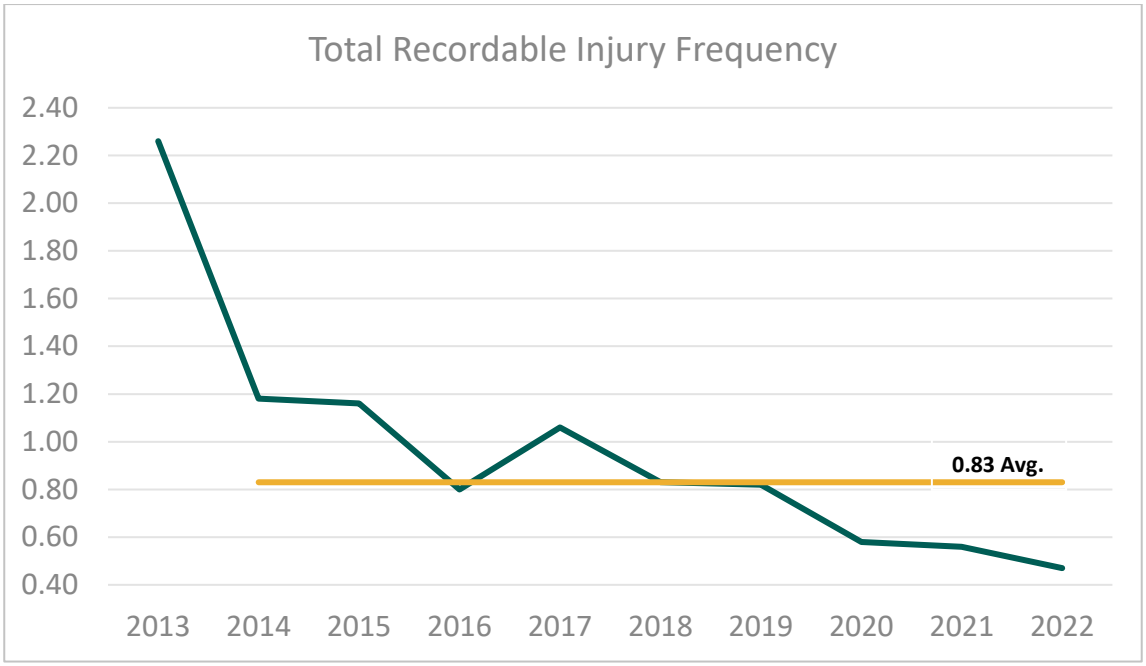

Figure 7: Total Recordable Injury Frequency Rate (2013-2022)

The complex, diverse and legacy configurations of operating a mature system that was amalgamated in 1999 from six different utilities, increases the likelihood of safety-related risks. Examples of operational risks inherent in the execution of Toronto Hydro's DSP are discussed in various programs,[22] and include notable challenges, such as deteriorated cables running through cable chambers that can fail, and potentially cause arcing and igniting gases, which then creates a powerful shockwave, as described in the Underground System Renewal – Downtown (Exhibit 2B, Section E6.3) program. Furthermore, the Area Conversions (Exhibit 2B Section E6.1) program details the increasing risk of equipment failure from obsolete rear lot and box construction systems that pose safety issues arising from crew access and public exposure to rear lot access. The risk and impact of overhead distribution asset failures due to accelerated asset condition degradation resulting from factors such as sustained exposure

[22] Network System Renewal, Exhibit 2B, Section E6.4; Corrective Maintenance, Exhibit 4, Tab 2, Schedule 4; Control Centre Operations, Exhibit 4, Tab 2, Schedule 7; Human Resources, Environment and Safety, Exhibit 4, Tab 2, Schedule 15

to dirt, salt, dust, and assets approaching the end of their useful life presents an operational risk inherent in the Overhead System Renewal (Exhibit 2B Section E6.5) program.

To mitigate these safety risks, investments are planned in a number of areas, including addressing high-risk assets approaching imminent failure, eliminating safety hazards such as poor structural integrity, cable congestion, and cable chambers lid ejections, relocating assets to improve accessibility, and technical training and development programs customized to address the specific needs and challenges of Toronto Hydro's distribution system, and a continued emphasis on safety among the utility's internal and external resource complements.

Organizational safety is managed by the Human Resources, Environment and Safety program outlined in Exhibit 4, Tab 2, Schedule 15. Ensuring that the utility is able to hire and retain the necessary resources with the appropriate skills to execute work safely is paramount to maintaining an industry-leading TRIF-record in the next rate term.

2.3.2 Emissions Reduction

The Emissions Reduction measure reflects Toronto Hydro's commitment to climate action and environmental performance through prudent paced investment in electrification and energy efficiency initiatives. This custom measure tracks Toronto Hydro's progress towards reducing greenhouse gas ("GHG") emissions from its fleet and facilities' operations in accordance with the utility's Net Zero 2040 strategy outlined in Exhibit 2B, Section D7 and in alignment with the City of Toronto's TransformTO Net Zero Strategy.[23]

[23] Transform TO Net Zero Strategy, November 2021, Attachment B at page 8 https://www.toronto.ca/legdocs/mmis/2021/ie/bgrd/backgroundfile-173758.pdf.

Figure 8, below, presents Toronto Hydro's actual (2018 to 2022) and projected (2023 to 2029) GHG emissions related to fleet and facilities, in accordance with the investment plan as filed. As of 2022, GHG emissions from Toronto Hydro's fleet and facilities assets represent approximately 49 percent of the utility's direct (Scope 1) emissions.

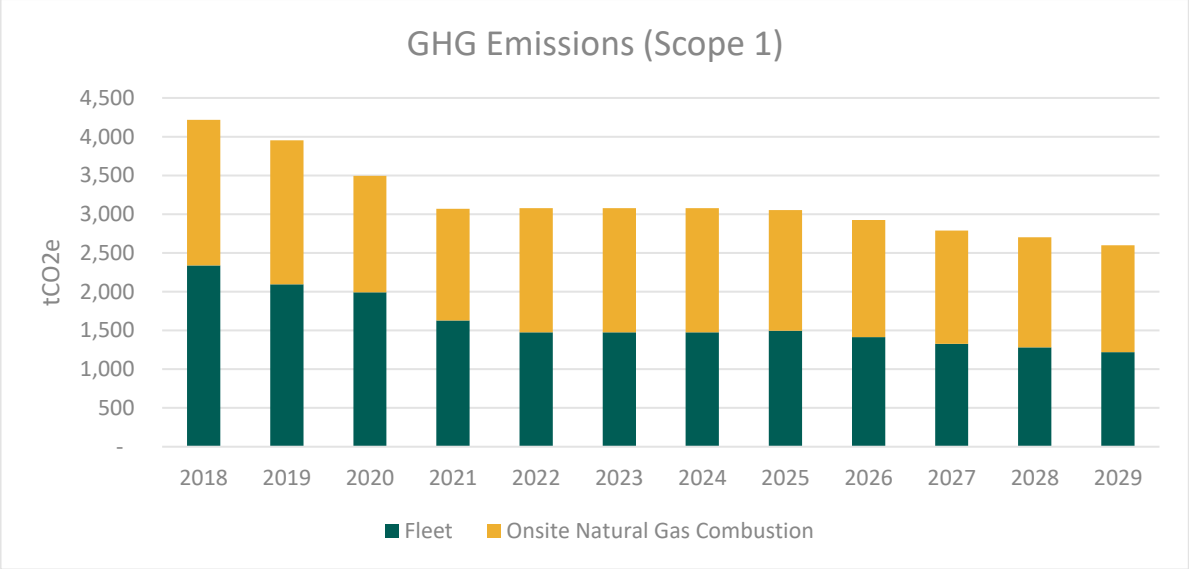

Figure 8: Toronto Hydro's Fleet and Facilities GHG Emissions (2018 – 2029)

Historical results identified in Figure 8 above include a 26 percent reduction of direct GHG emissions as a result of increasing buildings' energy efficiency with the use of building automation, minimizing fleet vehicle idling time, and electrifying light-duty fleet vehicles (i.e. 13 electric and 20 plug- in hybrid-electric).

Over the next rate period, Toronto Hydro intends to sustain historical emissions reductions achievements and further reduce its fleet and facilities emissions to 2.5kt of (Scope 1) CO2e by 2029. The utility plans to achieve this target by: (i) electrifying 50 percent of its fleet by the end of the rate term, and (ii) reducing GHG emissions produced at its work centers by 3

percent annually through fuel switching, conservation and energy efficiency measures. This target enables paced and prudent progress towards the utility's Net Zero 2040 goal, and delivers financial benefits associated with avoided costs of the federal carbon tax as summarized in section 3.5 below.

Investments that contribute to achieving the Emissions Reductions performance target are summarized in Table 13 below.

Table 13: Key Enabling Investments – Emissions Reductions

Program	Description of Key Enabling Investments to Reduce GHG Scope 1 Emissions
Fleet and Equipment	Toronto Hydro's Fleet and Equipment programs (Exhibit 2B, Section E8.3; Exhibit 4, Tab 2, Section 11) outlines investments to reduce Scope 1 emissions. Toronto Hydro plan to reconfigure the composition of its fleet to gradually increase its complement of electric and hybrid operation vehicles using a paced approach, prioritizing EV options as they better meet the requirements necessary for users to carry out distribution work and other day-to-day activities.
Facilities Management and Security	The utility plans to make additional investments in decarbonizing work centers through promoting conservation and improving the energy efficiency of its facilities, as noted in Toronto Hydro's Facilities Management program (Exhibit 4, Tab 2, Section 12) and Facilities Management and Security program (Exhibit 2B, Section E8.2). Decarbonization investments include: (i) fuel-switching projects to replace selected fossil fuel-powered assets with electric assets, (ii) converting to energy-efficient lighting, and the (iii) the implementation of building automation system controls for existing spaces, and retrofitting activities when feasible.

2.3.3 ISO Compliance and Certification

Toronto Hydro is committed to continual improvement and following best-in-class practices with respect to key management systems. The utility is currently certified to ISO14001 for its Environmental Management System ("EMS") and ISO45001 for its Occupational Health & Safety ("OH&S") Management System, and plans to achieve ISO55001 certification for its Asset Management System ("AMS") by the end of the next rate period. The ISO Compliance

and Certification custom measure tracks Toronto Hydro's commitment to achieving and maintaining certification with these international governance standards.

Toronto Hydro became registered with ISO14001 and 45001 standards in 2012 and 2019,[24] respectively. Maintaining compliance with these standards requires ongoing effort and commitment to continuous improvement to successfully complete annual third-party audits of Toronto Hydro's systems vis-à-vis ISO requirements. Over the course of any given year, Toronto Hydro needs to maintain the integrated management systems in question, and pursue many activities that prepare the utility for the audit including, but not limited to:

- Review and update, where required, Toronto Hydro's Occupational Health and Safety as well as Environmental policies on a regular basis to make sure they continue to apply and are in line with goals.
- Find areas for improvement, continually evaluate the effects that activities, assets, and services have on the environment and the safety of the workforce.
- Observe and abide by occupational safety and environmental procedures and regulations that are relevant to the operations of Toronto Hydro.
- Evaluate the effectiveness of the integrated management systems and pinpoint areas for improvement, while conducting routine periodic reviews.
- Closely track and measure important occupational safety and environmental performance metrics to monitor the utility's progress.
- Update and adhere to occupational safety and environmental goals and targets to promote ongoing enhancements in environmental performance.

In addition to maintaining ISO certification for the EHMS and OH&S, this measure tracks Toronto Hydro's objective to achieve certification with the ISO 55001 standard in its AMS. In

[24] Prior to 2019 the utility was registered with OHSAS 18001 since 2012.

putting forward this commitment, Toronto Hydro is holding itself accountable for continuous improvement in its asset management system by aligning to an international best practice benchmark. Organizations like Toronto Hydro that have implemented ISO55001 have reported benefits including:[25]

- A formal AMS resulting in a more effective, efficient, and transparent decision-making process applied consistently across the business;
- Demonstrable alignment between asset performance, risks, costs, level of service delivered to customers, and asset decision making;
- Streamlining efforts in downstream processes such as investment plan development, documentation, or project management;
- Continuous review, governance, and improvement of relevant processes and systems through regular external surveillance audits;
- More effective communication across business units and greater awareness of how assets support business objectives; and
- Maximizing value from assets through informed lifecycle management decisions leading to better asset performance and risk management.

The ISO Compliance and Certification measure is a weighted measure with three parts: (1) achieving ISO55001 certification is weighted at 60 percent due to the incremental effort involved in becoming certified, and maintaining certification with (2) ISO14001 for the EMS and (3) with ISO45001 for the OH&SMS are weighted at 20 percent, respectively.

Investments that contribute to achieving the ISO Compliance and Certification performance target are summarized in Table 14 below.

[25] International Organization for Standardization (ISO), Understanding the Benefits of an ISO 55001 Asset Management System (April, 2019) at page 5; Union Internationale des Chemins de fer (UIC), UIC Railway Application Guide – Practical Implementation of Asset Management through ISO 55001 (November, 2016) at page 12.

Table 14: Key Enabling Investments – ISO Compliance and Certification

Program	Description of Key Enabling Investments
HR, Environment & Safety	Investments in the Human Resources, Environment and Safety program supports the coordination of Health and Safety activities, as well as Environmental, Social and Governance activities, with recognized ISO standards (Exhibit 4, Tab 2, Schedule 15).
Asset and Program Management	Investments in the System Planning and Standards segment support the continuous improvement of the AMS, aligning to relevant ISO standards and developing the long-term asset management strategy (Exhibit 4, Tab 2, Schedule 9).
Finance	Operational investments in resources to enable financial reporting and processes that support ISO certification (Exhibit 4, Tab 2, Schedule 16).
Work Execution	Investments in Internal and External Work Program Execution to undertake oversight, administrative training and other functions performed in the process of executing Toronto Hydro's capital and maintenance work programs, ensuring processes follow the relevant management system, for example the collection and timely return of asset data to support the AMS (Exhibit 4, Tab 2, Schedule 10).

2.4 Efficiency & Financial Performance

Table 15: Efficiency & Financial Performance Custom Performance Measures

Performance	Weight	Measures	Historical Performance	Target (2025-2029)
Efficiency & Financial Performance	**15%**	**Efficiency Achievements**	$5.6 million per year by 2024	$6.9 million per year by 2029
	10%	**Grid Automation Readiness**	N/A	100%
	5%	**System Capacity (Non-Wires)**	4 MW to date	30 MW by 2029

2.4.1 Efficiency Achievements

As outlined in the evidence in Exhibit 1B, Tab 3, Schedule 2, Toronto Hydro is an efficient organization committed to providing value for its customers through continuous improvement in productivity. The Efficiency Achievements metric tracks this commitment

over the next rate period by holding the utility accountable for delivering sustained (and quantifiable) efficiency benefits to customers in the next rebasing application. Such benefits include avoided or reduced costs, or other efficiency gains, that would yield a lower base revenue requirement for customers in the next rebasing application.

In the current rate period, Toronto Hydro expects to achieve efficiencies of approximately $5.6 million per year by 2024, consisting of approximately $1.5 million of cost reductions and $4.1 million cost avoidances, as outlined in Figure 9 below. These achievements stem from continued investments in process automation and technological innovation, as detailed in the utility's productivity narrative at Exhibit 1B, Tab 3, Schedule 3.

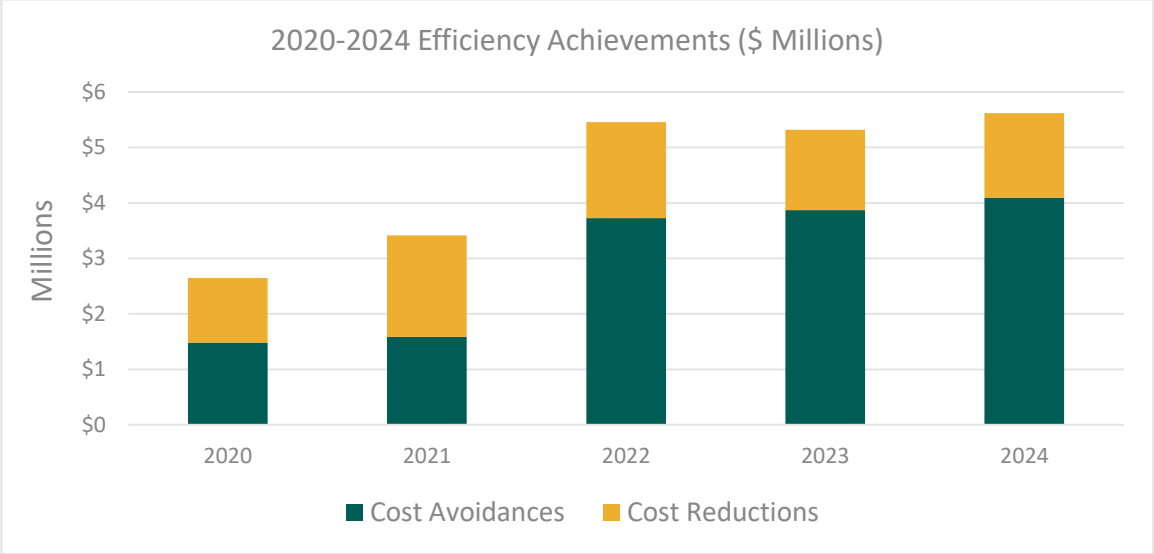

Figure 9: 2020 – 2024 Efficiency Achievements (Actual and Forecast)

Over the next rate term, Toronto Hydro set a target to achieve approximately $6.9 million in sustained and quantified efficiency benefits per year by 2029. As shown in section 3.4 below, this target is based on the 2029 forecasted revenue requirement impact of the empirically-

derived efficiency (stretch) factor included in the Custom Revenue Cap Index at Exhibit 1B, Tab 2, Schedule 1.

Investments that contribute to achieving the Efficiency Achievements performance target are summarized in Table 16 below.

Table 16 – Key Enabling Investments – Efficiency Achievements

Program	Description of Key Enabling Investments to Achieve Efficiency
Grid Modernization Strategy	Grid Modernization Strategy (Exhibit 2B, Section D5) encompasses a suite of investments needed to accelerate the transformation of existing infrastructure to a more technologically advanced distribution system. There are three categories of investments under the Grid Modernization Roadmap, consisting of • Intelligent Grid: investments aimed at expanding observability and controllability of the distribution system using automated tools. • Grid Readiness: Investments in grid readiness to build capabilities to support decentralization with platforms such as the Distributed Energy Resource Management System ("DERMS") and leveraging DER connections for grid operations such as through the use of Demand Response. • Asset Analytics: leverages technology that is being deployed under the intelligent grid and grid readiness programs in order to have an integrated process for governance using tools such as predictive and prescriptive analytics.
Information Technology	Toronto Hydro relies on IT assets and systems to pursue efficiencies and innovation. Toronto Hydro develops Enterprise Technology Portfolio Roadmap of investments in IT/OT based on solutions for applications across the operations, engineering, metering, and customer care areas of the company (Exhibit 1B, Tab 4, Schedule 1). Investments in IT Software (Exhibit 2B, Section E8.4) to enable continued process automation and technological innovation, including upgrades to the SAP Enterprise Resource Planning System, investments in IT Hardware to ensure that software applications remain available and operational investments to carry out this work (Exhibit 4, Tab 2, Schedule 17).
Human Resources, Environment & Safety	Human Resources, Environment and Safety supports recruitment and development of resources such as engineers and analysts with progressive data analytics and coding skillsets that are necessary to unlock efficiency benefits provided by process automation and grid modernization investments (Exhibit 4, Tab 2, Schedule 15).

Program	Description of Key Enabling Investments to Achieve Efficiency
Innovation Fund	Proposal for Innovation Fund (Exhibit 1B, Tab 4, Schedule 2) to support the design and execution of innovative pilot projects that focus on testing new technologies, advanced capabilities, and alternative strategies in the areas of DER integration and inventive solutions (aligned with section 2.17 of Chapter 2 of the OEB's Filing Requirements for Distribution Rate Applications).

2.4.2 Grid Automation Readiness

Toronto Hydro is committed to improving long-term reliability and resilience outcomes for customers while unlocking safety and efficiency benefits by reducing manual work efforts related to switching operations in the field. The utility has been steadily modernizing its distribution system in the Horseshoe areas of the city (i.e. the u-shaped area outside of the downtown core) through sustainment investments in planned renewal work and complementary investments in modernization programs such as Contingency Enhancement (Exhibit 2B, Section E7.1). A primary focus of these efforts has been the deployment of SCADA-operated switches which allow control room operators to remotely transfer load and isolate feeder sections under fault conditions or on a planned basis. These investments have contributed to Toronto Hydro's improving reliability performance as discussed in Section E7.1.3.1, and have enabled the utility to manage its operational costs efficiently over the last decade as outlined in Exhibit 4, Tab 1, Schedule 1.

In the next rate period, the utility intends to make the necessary installations and provisions to prepare the overhead system in the Horseshoe area of the grid for the implementation of distribution automation (self-healing grid) beginning in 2030. This is a key objective of the utility's 2025-2029 Grid Modernization Strategy, and a least regret investment to ensure that the Horseshoe distribution system is ready and equipped to meet the reliability and resilience challenges and expectations in the next decade as more customers adopt

electrified technologies such as electric vehicles, heat pumps, solar panels and energy storage systems.

Once implemented, Toronto Hydro expects self-healing grid capabilities to deliver high-customer value in the form of substantial reliability improvements and more efficient fault location and restoration efforts. For a complete discussion of the need for, and benefits of, Toronto Hydro's Fault Location, Isolation, and Service Restoration ("FLISR") strategy, as well as the broader Intelligent Grid strategy, please refer to the 2025-2029 Grid Modernization Strategy in Exhibit 2B, Section D5.

The Grid Automation Readiness custom measure tracks Toronto Hydro's progress towards achieving the distribution automation component of the utility's 2025-2029 Grid Modernization Strategy presented at Exhibit 2B, Section D5. This includes: (1) ensuring that 90 percent of feeders have a minimum of two SCADA sectionalizing switches and at least one SCADA tie point (or 2.5 switches per feeder), and the achievement of (2) technology milestones related to the implementation of FLISR in all horseshoe distribution station areas, and necessary enhancements to core IT systems to enable fully automated FLISR operation. More specifically, the Grid Automation Readiness custom measure tracks the attainment of the following milestones:

- Increasing the number of horseshoe feeders with a minimum of 2.5 switches from 78 percent (230 feeders) in 2022 to 90 percent (264 feeders) by 2029.
- Achieving 23 operational technology milestones related to FLISR implementation. Specifically, the utility intends to enable "manual FLISR" – an important and necessary step toward fully automated FLISR – for all 20 transformer stations in the horseshoe area, and to achieve three critical software milestones related to the Advanced Distribution Management System ("ADMS"); 1) SCADA software

enhancement release, 2) Network Management System ("NMS") software enhancement release and 3) NMS software enhancement - Auto-FLISR release.

Investments that contribute to achieving the milestones above enabling Grid Automation Readiness are summarized in Table 17 below.

Table 17: Key Enabling Investments – Grid Automation Readiness

Program	Description of Key Enabling Investments for Grid Automation Readiness
System Enhancements	Investments in this program allow for the installation of SCADA switches, tie-points and reclosers on targeted feeders to improve outage response capabilities and reduce fault isolation times. These switches will form the system configuration required for Toronto Hydro's self-healing grid in 2030 and beyond (Exhibit 2B, Section E2.4.3, Exhibit 2B, Section D5, and Exhibit 2B, Section E7.1).
IT/OT Systems and Operations	Investment in hardware, software, and communication infrastructure, as well IT resources to carry out the work planned, are key to Grid Automation Readiness. This includes enabling manual FLISR at Horseshoe stations and ADMS software release milestones which will enable fully automated FLISR operations beginning in 2030. Please see Exhibit 2B, Section E2.4.3 and Section E8.4, as well as Exhibit 4, Tab 2, Schedule 17 for more details.
Asset and Program Management	Investments in the System Planning segment which includes the Grid Modernization function, responsible for facilitating the development, integration, and strategic oversight of Toronto Hydro's long-term Grid Modernization Strategy and associated roadmaps, in addition to providing market intelligence and strategic forecasting of future electricity system needs and opportunities, and change-management support capacity to help accelerate innovation initiatives (Exhibit 4, Tab 2, Schedule 9).
Work Execution	Operational investments to enable oversight, administrative training and other functions performed in the process of executing Toronto Hydro's capital and maintenance work programs **(**Exhibit 4, Tab 2, Schedule 10).

2.4.3 System Capacity (Non-Wires)

The System Capacity (Non-Wires) measure reflects Toronto Hydro's proposal to integrate non-wires incentives into its Custom Scorecard and related PIM for the 2025-2029 rate term,

in a manner that is responsive to emerging policy objectives and aligned with the OEB Filing Guidelines for Non-Wires Incentives, namely the option to set a "*Performance Target or Scorecard-Based Incentive [that] allows a distributor to earn a fixed incentive payment, based on its performance against an established target or scorecard metrics.*"[26] To that end, this section is expanded relative to other metrics canvassed above to explain in greater detail how the System Capacity (Non-Wires) custom measure, and the proposed incentive associated with meeting the target on this measure, aligns with the OEB Filing Guidelines, including an analysis and consideration of how the proposed incentive compares with other incentive options outlined in the OEB Filing Guidelines.

Local Demand Response ("LDR") – Flexible System Capacity

Toronto Hydro plans to invest approximately $5.7 million over the next rate term to deploy an expanded version of its non-wires Local Demand Response ("LDR") initiative to address system capacity constraints. More specifically, Toronto Hydro intends to procure 30MW of flexible system capacity through the LDR program to displace and defer the need for load transfers in the Horseshoe North area over the 2025-2029 period. Load transfers in this area are necessary to alleviate constraints at a number of stations including Finch TS and Bathurst TS. Load transfers address capacity challenges by moving load from one station to another in order to free up available system capacity to connect and serve customers. While load transfers can be effectively deployed to mitigate near-term capacity needs in areas of the grid that are experiencing high or rapid growth, they do not necessarily obviate the need for a broader system expansion in these areas. They can, however, provide the utility with the flexibility to prioritize work and address capacity challenges in the high-growth areas while larger-scale investments, such as stations expansion, are considered, planned or constructed.

[26]OEB, Filing Guidelines for Incentives for Electricity Distributors to Use Third-Party DERs as NWA (March 28, 2023)

LDR can defer or avoid certain load transfer capital investments in Toronto Hydro's service territory by procuring flexible system capacity from third-party or customer-owned DERs. In the optimal use case, LDR can indefinitely avoid the need for a load transfer in a given area. In these instances, capital that would have been spent on load transfers is avoided. This results in significant long-term savings for ratepayers, stemming from the avoided revenue requirement related to the capital assets. In other cases, where there is uncertainty with respect projected demand, LDR can be used to defer load transfers for a period of time until there is greater certainty that the load transfer will be needed. In these circumstances, although the net savings to customers are lower, LDR provides system value as a flexibility tool, enabling planners to better allocate capital when demand is uncertain. This ability to be flexible is increasingly important as capacity planning evolves in response to changes in policy, technology and consumer preferences.

In the current 2020-2024 rate period, Toronto Hydro set out to procure up to 10 MW of demand response capacity. The utility contracted 4 MW for the summer of 2023, and 6 MW for summer 2024, in the vicinity of two transformer stations (TS): Manby TS and Horner TS.[27] Manby TS has been reaching capacity on two busses for several years and overloading at Horner TS has been forecasted in the near-to-mid term. Some load transfers north to the Richview TS have been completed but further transfers would be difficult due to capacity constraints at neighbouring stations, the distance between the stations, geographic barriers, different voltages and a lack of remaining overhead corridors. Work has been undertaken to expand capacity at Horner TS which will be used to relieve Manby TS in 2025. In the meantime, while the expansion work is undertaken, LDR has been leveraged to provide increased flexibility in the Manby TS and Horner TS area. As a result, some transfers from

[27] Exhibit 2B, Section E7.2 at page 11.

Manby and Horner TS were avoided pending the permanent transfer of load from Manby to Horner TS in 2025.

Performance Target/ Scorecard-Based Incentive

In the 2025-2029 Custom Scorecard, Toronto Hydro proposes a System Capacity (Non-Wires) metric that measures the amount of flexible system capacity (MW) procured through the non-wires LDR program, summarized above and outlined in Exhibit 2B, Section E7.2. Toronto Hydro set an ambitious target to procure 30 MW of flexible system capacity through LDR in order to avoid or defer approximately $10 million of load transfer projects in the Horseshoe North area of the city. The target draws on Toronto Hydro's leadership and experience leveraging LDR as a non-wires solution to address distribution system needs, and challenges the utility to triple the amount of non-wires system capacity procured through this program.

Associated with this target, Toronto Hydro proposes a scorecard incentive of approximately $3.3 million, derived from a proposed weighting of the System Capacity (Non-Wires) custom metric at five percent of the total available incentive ($65 million) under the PIM. In adopting a proposed weighting of five percent of the overall PIM for this measure, Toronto Hydro was informed by the net ratepayer benefits, and other incentive options offered under the OEB Filing Guidelines, both of which are discussed below.

However, it is important to note that the scorecard incentive proposal, while having been informed by these inputs, stands on its own merits as an integrated proposal within a broader performance outcomes framework that Toronto Hydro is putting forward in this application. As further outlined in section 3 of this narrative, this framework recognizes that while quantified distribution system benefits are an important aspect of evaluating an innovative proposal, they must be viewed as part of a suite of broader, upstream benefits

that stem from pursuing non-wires solutions. The distributor plays a key role in finding cost-effective ways to leverage DERs to meet its system needs, and in doing so, creating opportunities for these DERs to be leveraged for bulk-system, customer, and societal value and benefits.

These benefits entail the potential for massive curtailment of system peak demand increases associated with decarbonization-through-electrification, depicted in the Consumer Transformation and Net Zero 2040 scenario worlds in the Future Energy Scenario study filed at Exhibit 2B, Section D4. If they can be successfully unlocked, future benefits in this respect include:

- Avoided or deferred upstream transmission and generation investments;
- Lower delivery costs associated with reduced system losses;
- Energy cost reductions, either expressed as a benefit to end-use customers or as a variable generation cost reduction;
- Economic and societal benefits associated with increased reliability and resilience offered by a more diverse and localized supply mix;
- Economic and societal benefits associated with reduced greenhouse gas ("GHG") emissions, and in particular anticipated GHG emission reductions resulting from the avoidance of marginal gas-fired electricity generation; and
- Other economic benefits associated with enhanced distribution system planning where Toronto Hydro can increasingly rely on non-wires solutions to optimize the size and the timing of system capacity expansions, and improve key outcomes such as reliability.

Benefit Cost Analysis (BCA)

Toronto Hydro prepared a benefit-cost analysis ("BCA") to approximate the distribution value to ratepayers of pursuing flexible non-wires solutions to address capacity constraints in the Horseshoe North over the next rate term.

The BCA evaluates net present value ("NPV") of the reduced distribution costs by comparing the costs to ratepayers in rates (i.e. using revenue requirement) of the traditional load transfer capital investments and the flexible non-wires LDR solutions, as the basis for determining the net benefits of the latter option. In this analysis, Toronto Hydro applied the estimated useful life ("EUL") of the capital assets that are typically constructed in a load transfer project as the period over which net benefits to customers are assessed, recognizing the long-term benefits of capital investment avoidance. To that end, and recognizing that some load transfers may only be deferred, the BCA calculates the net benefits of capital deferral and capital avoidance separately. Based on Toronto Hydro's knowledge of the targeted area (Horseshoe North), and experience with the LDR program over the past seven years, the utility assumes that approximately 75 percent of the load transfer projects in scope can be avoided entirely, while 25 percent can be deferred for at least five years until 2030.

In Table 18 below, Toronto Hydro outlines the NPV of the benefits of capital deferral and avoidance based on the LDR program facts outlined above.

Table 18: Toronto Hydro 2025-2029 LDR Flexible System Capacity BCA

	Deferred Capital	Avoided Capital
Parameters	$2.50 million in load transfer capital investment deferred for 5 years at an operational cost of $0.71 million	$7.50 million in load transfer capital investment avoided over the life of the assets (48 years) at an operational cost of $4.99 million
Costs	NPV of the operational costs of the non-wires solution (2025-2029): **$0.57 million**	NPV of the operational costs of the non-wires solution (2025-2029): **$4.00 million**

	Deferred Capital	Avoided Capital
	+ NPV of the revenue requirement associated with the load transfer capital investment to be made in 2030: **$1.80 million** **=** **$2.37 million** NPV Costs	
Benefits	NPV of revenue requirement associated with capital investment deferred from 2025-29: **$2.42 million** *Less (-)* NPV Costs: **$2.37 million** *Equals (=)* **$55.07 thousand NPV Benefits**	NPV of revenue requirement associated with capital investment avoided in 2025 over the 48-year EUL: **$7.27 million** *Less (-)* NPV Costs: **$4.00 million** *Equals (=)* **$3.27 million NPV Benefits**
Total NPV Benefits =$3.32 million		

The following assumptions underpin the calculation of the NPV benefits presented above:

- Deferred / avoided assets are load transfer projects with 48-year EUL, with a Capital Cost Allowance ("CCA") rate of eight percent. 2024 phase out of Accelerated Investment Incentive Program is assumed, which suspends the half-year rule for calculating CCA.
- 2025 ROE and interest rates are held constant per the parameters in Exhibit 5.
- Assumed that five years of LDR is sufficient to avoid the capital investment.
- NPV of five-year deferral assumes that the same asset would be installed five years later, devaluing costs relative to status quo due to future discounting.
- Discount rate based on Weighted Average Cost of Capital ("WACC") utilizing OEB's Toronto Hydro's Cost of Capital Parameters, resulting in WACC of 6.17 percent.[28]

[28] Exhibit 5, Tab 1, Schedule 2.

Comparative Analysis of Other Incentive Options

In this section Toronto Hydro presents a comparative analysis of other incentive options available under the OEB Filing Guidelines: Shared Savings Mechanisms ("SSM") and Margin on Payment. To determine a suitable Margin on Payment incentive amount Toronto Hydro evaluated the disincentives associated with pursuing non-wires solutions under the status quo. More specifically, Toronto Hydro assessed the foregone opportunity to earn a regulated rate of return ("ROE") on the capital investments avoided and deferred, using an NPV approach. The resulting analysis presented in Table 18 below indicates that Toronto Hydro's LDR proposal results in foregone utility ROE of approximately $3.2 million due to the deferral and avoidance of load transfer capital expenditures.

Table 19: Margin on Payment Incentive Approach based on Foregone ROE

	Deferred Capital	Avoided Capital
Approach	Quantify the net present value (NPV) of the foregone ROE associated with the deferred and avoided capital investments.	
Parameters	$2.50 million in load transfer capital investment deferred for 5 years (i.e. from 2025 to 2030)	$7.50 million in load transfer capital investment avoided over the estimated useful life (EUL) of the assets (48 years)
Lost NPV of ROE	NPV of foregone ROE: **$0.99 million** *Less (-)* NPV of ROE associated with capital investment in 2030: **$0.73 million** *Equals (=)* **$0.26 million NPV of Foregone ROE**[29]	NPV of Foregone ROE: **$2.97 million**
Total NPV of Foregone Revenue: $3.23 Million		

To determine a comparable SSM incentive, Toronto Hydro considered two scenarios. The first entails a 50/50 SSM in which the utility is permitted to keep 50 percent of the NPV of

[29] The loss of ROE associated with deferred capital is limited to the reduced/discounted net present value of ROE for the same asset installed in 2030 (deferred) as opposed to 2025 (status quo).

benefits associated with capital investments that are avoided and deferred. Based on the calculated NPV of benefits associated with LDR ($3.3 million) outlined above, a 50/50 SSM yields an incentive of approximately $1.7 million. The second scenario entails a higher incentive of 75/25 SSM in which the utility is permitted to keep 75 percent of the NPV of benefits. This scenario produces an incentive of $2.5 million. In both of these scenarios, Toronto Hydro observed that the SSM framework is not sufficient to level the playing field between the non-wires solution (LDR) and the conventional option (load transfers).

Concluding Remarks re Toronto Hydro's Non-Wires Incentive Proposal

Leveraging DERs as non-wires to defer or avoid conventional capital solutions is a developing strategy in Ontario and other jurisdictions that have embarked on an energy transition.[30] The OEB, industry stakeholders and policy-makers recognize that distribution utilities like Toronto Hydro are essential in enabling this strategy to unlock potential future economic and societal benefits for customers.[31] Distributors must have appropriate incentives to dedicate the resources and develop the operational capabilities that are necessary to enable proliferation of non-wires strategies.

The scorecard incentive proposal aligns with these policy objectives in a manner that is balanced and integrated with the utility's broader performance framework. The proposed weighting of five percent to this metric produces an incentive of approximately $3.3 million, which Toronto Hydro can only earn in the next rate term (i.e. 2030-2034) if it delivers on its

[30] OFGEM, Transition to a net zero energy system, Smart Systems and Flexibility Plan 2021 (July 2021) https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1003778/smart-systems-and-flexibility-plan-2021.pdf; REV Connect – Grid-Edge Flexibility, https://nyrevconnect.com/grid-edge-flexibility/ https://nyrevconnect.com/non-wires-alternatives/

[31] OEB, Framework for Energy Innovation: Setting a Path Forward for DER Integration (January 2023) at pages 11-13; Minister of Energy, Letter of Direction from the Minister to the Chair of the OEB Board of Directors (October 21, 2022) at page 4.

ambitious goal of procuring 30 MW of non-wires system capacity over the 2025-2029 period. This proposal protects ratepayers, as demonstrated by the BCA above,[32] and provides the utility an appropriate incentive to continue maturing in its journey of developing non-wires capabilities to help unlock broader and more significant long-term benefits that are not yet captured in the BCA.

Investments that contribute to achieving the System Capacity (Non-Wires) performance target and more generally enable Toronto Hydro to advance its non-wires capabilities are summarized in Table 20 below.

Table 20: Key Enabling Investments – System Capacity (Non-Wires)

Program	Description of Key Enabling Investments re Non-Wires Solutions
Non-Wires Solutions	Investments in this program help address short-to-medium term capacity constraints at targeted transformer stations where local demand response ("LDR") can be leveraged to support the broader distribution system cost-effectively, thereby expanding the planning toolbox for the utility (Exhibit 2B, Section E7.2).
Generation Protection Monitoring and Control	This program allows Toronto Hydro to fulfill its regulatory obligations to connect Distributed Energy Resource ("DER") projects to its distribution system. Investments in this program alleviates technical barriers to connecting DERs. It also improves monitoring and control to ensure safe DER operation (Exhibit 2B, Section E2.4.1 and Exhibit 2B, Section E5.5).
Customer Operations	The Customer Connections and Key Accounts segments provide customer support for DER connections. The Customer Connections segment is responsible for handling all communications with customers relating to connection (both load and generation) and upgrade requests. The team manages a project from intake through to closure providing a single point of contact for all customer requests and communications related to a connection. This ensures a consistent and efficient customer experience. The Key Accounts team assists Key Account customers (i.e. customers with critical loads, including large customers, hospitals,

[32] The 2025 NPV savings of $3.3 million shown in the BCA compare to a 2025 NPV utility incentive of approximately $2.3 million assuming the incentive is recovered over the 2030-2034 rate term.

Program	Description of Key Enabling Investments re Non-Wires Solutions
	financial institutions, essential public services, and developers) with complex connections and by discussing opportunities for behind-the-meter energy solutions to meet customer goals (Exhibit 4, Tab 2, Schedule 8).
Control Centre Operations	Operational investments to ensure sufficient resources to meet increase in workload associated with growth of DERs and expansion of Flexibility Services (Exhibit 4, Tab 2, Schedule 7).
Legal Services and Procurement	Operational investments to support procurement (Exhibit 4, Tab 2, Schedule 18) and negotiation of capacity contracts (Exhibit 4, Tab 2, Schedule 18, Section 5) are critical to the success of LDR.
Asset and Program Management	Operational investments to support the capacity planning and grid innovation functions including, planning the requisite connection capacity to accommodate current and forecasted levels of DERs in Toronto Hydro's service area, as well as, identifying opportunities for adopting non-wires alternatives to maximize the use of existing distribution system assets. Investments also support the grid modernization function, including the development and execution of the Grid Modernization Strategy and its grid readiness component which will build capabilities to support decentralization with platforms such as the Distributed Energy Resource Management System ("DERMS") and leveraging DER connections for grid operations such as through the use of Demand Response Exhibit 4, Tab 2, Schedule 9).
Innovation Fund	Proposal for Innovation Fund (Exhibit 1B, Tab 4, Schedule 2) to support the design and execution of innovative pilot projects over the 2025-2029 rate period. The pilot projects to be deployed through the Innovation Fund would focus on testing new technologies, advanced capabilities, and alternative strategies in the areas of DER integration and inventive solutions (aligned with section 2.17 of Chapter 2 of the OEB's Filing Requirements for Distribution Rate Applications).

3. BENEFITS ANALYSIS

Toronto Hydro's PIM incentivizes the utility to achieve meaningful and valuable outcomes for customers across a wide set of objectives that: (i) are responsive to fundamental shifts taking place in the external environment as a result of the energy transition, and (ii) align with customer feedback and the strategic underpinnings of the plan. Many of the metrics

included in Toronto Hydro's PIM yield significant but difficult-to-quantify benefits for customers. Nonetheless, where possible, Toronto Hydro took steps to quantify the benefits to customers of achieving the identified performance targets.

The benefit analysis presented in this section illustrates the minimum economic value of the PIM for customers should the utility achieve its proposed targets. While Toronto Hydro recognizes that quantified benefits are an important aspect of evaluating innovative proposals, the utility underscores the practical reality that quantified benefits cannot paint a full picture of the value proposition for customers. The benefits summarized in Table 21 below should be regarded in a comprehensive context with thoughtful consideration of all the other benefits in the performance framework for this application, which although cannot be quantified, nonetheless provide high value to customers.

Table 21: PIM Quantified Benefits Analysis ($ Millions)

Metric	2025-29	Lifetime[33]	Approach
Outage Duration	$32.5M	$605.2M	Customer Interruption Cost Avoidance,[34] Target vs IRM scenario
Outage Frequency	$6.5M - $21.6M	$182.5M - $413.4M	Customer Interruption Cost Avoidance, Target vs IRM scenario
New Services Connected on Time	$31.7M - $142.6M	$31.7M - $142.6M	Value of energy delivered to customers without delaying new connections. Target performance vs a range of typical performance levels
System Capacity (Non-Wires)	$3.1M	$21.0M	Avoided capital-related revenue requirement costs through LDR[35]

[33] Benefits are considered over the applicable asset life. For Efficiency Achievements, this analysis assumes that benefits are likely to be achieved primarily through technology investment (software) that have an average useful life of 5 years.
[34] Based on the values in Tables 1-3 and 1-5 of the Value of Service Study found at Exhibit 2B, Section D3, Appendix D.
[35] Based on nominal benefits resulting from avoidance and deferral of capital investment through non-wires solutions. A full net present value cost-benefit analysis is provided in section 2.4.3 above.

Metric	2025-29	Lifetime[33]	Approach
Efficiency Achievements	$16.4M	$50.7M	Efficiency-factor expectations for 2025-29 are sustained into the next rate term by achieving the target.
Emissions Reductions	$0.2M	$1.5M	Sustained carbon emission reduction vs current emission level
Total Benefits (Nominal)	**$90.3M - $216.3M**	**$892.5M - $1,234.4M**	
Total Benefits (Present Value)	**$74.7M - $180.2M**	**$266.7M - $419.6M**	

Based on the analysis in Table 21 above, the nominal sum of benefits expected in the next period ranges between approximately $90 million and $216 million. The low end of the range of nominal benefits to ratepayers over 2025 to 2029 – $90.3 million – includes $16.4 million resulting from Toronto Hydro's empirically-derived 0.15% efficiency factor, and $0.2 million relating to reduced federal carbon tax payments from emission reductions. The former represents the efficiency benefits customers would normally receive in rates under RRF incentive regulation based on empirical total cost benchmarking, and the latter represents cost reductions which would not be reflected in rates until Toronto Hydro's next rebasing application for 2030 rates. As such, an appropriate calculation of minimum benefits relative to Toronto Hydro's proposed $65 million incentive would remove these amounts. The result is a minimum direct benefit of approximately $74 million over the 2025 to 2029 period.

The analysis supports that customers are better off in all scenarios where the PIM is approved. Customers may receive benefits at the high-end of the estimate ranges that well exceed any potential PIM incentives over the 2025 to 2029 rate term, in addition to significant lifetime benefits that range between approximately $890 million to over $1.23 billion on nominal basis. While achievement of the targets and underlying benefits represents the optimal outcome for ratepayers, if Toronto Hydro does not achieve the targets no incentive (or only a partial incentive) would be rewarded. The result is that

customers are protected upfront, and significant risk is shifted to the utility to deliver value through performance outcomes that customers prioritize in order to earn-back the incentive.

The following sections detail the methodologies that Toronto Hydro relied on to quantify the benefits presented in Table 21 above.

3.1 Outage Duration & Outage Frequency

The System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") are well established metrics to assess key dimensions of grid reliability performance. While SAIDI quantifies the annual average duration (in minutes) of power outages that customers experience, SAIFI calculates the average annual instances of power disruptions per customer. As described in section 2.1, Toronto Hydro's 2025-2029 Custom Scorecard includes a subset of these reliability metrics, namely:

- **Outage Duration**: SAIDI excluding scheduled outages, LoS and MEDs; and
- **Outage Frequency**: SAIFI measuring the interruption frequency index for outages caused by defective equipment only.

3.1.1 Benefits of Outage Duration and Frequency

To quantify the reliability benefit of its 2025-2029 Investment Plan, Toronto Hydro utilized the Customer Interruption Cost ("CIC") methodology, which is also referred to as Value of Service ("VOS") or Value of Lost Load ("VoLL"). These methods are widely used to evaluate the benefits of various programs, reliability improvements included. Toronto Hydro relied on the 2018 Customer Interruption Cost ("CIC") study[36] to determine the value of reliability

[36] Please see Exhibit 2B, Section D3, Appendix D.

to customers in its service area, and used a historical and forecasted Toronto Consumer Price Index (CPI)[37] to adjust these values for the relevant time periods.

Table 22: Outage Duration and Outage Frequency Inputs

	2025	2026	2027	2028	2029
Cost per Average kW Estimates – Event ($/kW)	$15.50	$15.81	$16.12	$16.45	$16.78
Cost per Unserved kWh Estimates – Duration ($/kWh)	$24.53	$25.02	$25.52	$26.03	$26.55
Toronto Consumer Price Index	2.0%	2.0%	2.0%	2.0%	2.0%
Customers	800,374	803,344	806,017	808,731	811,245
Average Load per Customer[38]	3.35	3.33	3.31	3.32	3.30

For assessing the broad benefits accruing to Toronto Hydro's diverse customer base, the utility relied on a "blended" cost from the study; relying on the one-minute or more interruption blended cost per average kilowatt (kW) and average unserved kilowatt-hour (kWh) per customer, where:

- **Cost per Average kW Estimates** is included in the Outage Duration benefit calculation, representing the reduced time when energy is unavailable to customers;
- **Cost per Unserved kWh Estimates** is included into SAIFI Defective Equipment Outage Frequency benefit calculation, indicative of fewer sustained outage events experienced by customers.

[37] For historical values Toronto Hydro relied on the Statistics Canada Consumer Price Index, and for future values the utility relied on the Conference Board of Canada, Major City Insights – Toronto (Released September 13, 2023).
[38] Historical and projected average loads are based on total normalized energy consumption and total number of customers in accordance with Exhibit 3, Tab 1, Schedule 1.

To measure improvements in grid reliability, Toronto Hydro compared its targeted average five-year reliability metrics for 2025-2029 against estimated reliability performance under an IRM scenario as explained above in section 2.1.1 and 2.1.2. Tables 23 and 24 present the reliability benefits that Toronto Hydro's 2025-2029 investment plan offers to customers over this period compared to the IRM base case.

Table 23: Outage Duration Customer Benefits for 2025-2029 ($ Millions)

	2025	2026	2027	2028	2029
Target	$50.6	$51.5	$52.5	$53.8	$54.8
Base Case	$56.8	$57.9	$58.9	$60.4	$61.5
Reliability Benefits	**$6.2**	**$6.4**	**$6.5**	**$6.6**	**$6.8**

Table 24: Outage Frequency Customer Benefits for 2025-2029 ($ Millions)

	2025	2026	2027	2028	2029
Target [39]	$15.8 - $18.7	$16.1 - $19.0	$16.4 - $19.4	$16.8 - $19.9	$17.1 - $20.2
Base Case	$19.9	$20.3	$20.7	$21.2	$21.6
Reliability Benefits	**$1.2 - $4.2**	**$1.3 - $4.2**	**$1.3 - $4.3**	**$1.3 - $4.4**	**$1.3 - $4.5**

The reliability benefits of Toronto Hydro's investments in the 2025-2029 plan extend well beyond this rate period. To quantify these benefits from a longer-term perspective, the present value of avoided CICs for both duration-based and event-based metrics were calculated, based on an average life of 45 years for distribution assets, weighted average

[39] This range reflects the Outage Frequency target set out in section 2.1.2.

cost of capital,[40] and long-term inflation projections.[41] Table 25 presents the lifetime reliability benefits that the 2025-2029 investment plan offers for the utility's customers.

Table 25: Lifetime Value 2025-2029 Outage Duration and Frequency Customer Benefits[42]

Lifetime Value (2025-2070)	
Outage Duration (SAIDI) Benefits	$605.2M
Outage Frequency (SAIFI) Benefits	$182.5M - $413.4M

3.2 New Services Connected on Time

Similar to the Outage Duration and Outage Frequency metrics, the benefits of timely New Services Connected are calculated using adjusted CICs, under the assumption that delayed connection results in loss of service hours, yielding associated economic losses. This approach illustrates the value of the higher level of service that Toronto Hydro has committed to maintain by evaluating the benefit to High Voltage ("HV") and Low Voltage ("LV") customers who are connecting or upgrading their services to the grid.

3.2.1 Benefits of New Services Connected on Time

The benefits of New Services Connected on Time are measured by contrasting the value of energy delivered to the customer on time, against a scenario where service is delayed. This analysis predominantly reflects the needs of HV customers – typically large businesses where delayed connections directly translate to revenue losses. The CIC study calculates CIC as direct losses for commercial and industrial customers indicating acute cost and revenue

[40] Weighted Average Cost of Capital of 6.17% as per Exhibit 5, Tab 1, Schedule 2.
[41] 2% inflation based on the 2025-2027 annual inflation projection by Conference Board of Canada, Major City Insights – Toronto (released September 13, 2023).
[42] The base case scenario estimates the Outage Duration reaching 53.2 min and Outage Frequency reaching 0.51 events in 2029, the last year of the rate term. Toronto Hydro applied an improvement delta between the targeted reliability levels and the base case reliability in the final year to calculate the benefits beyond 2029.

implications of unsupplied energy. In contrast, residential customers typically have lower electricity consumption and the interruptions often mainly affect personal comfort and convenience. Therefore, the methodology to calculate CICs for residential customers is based on estimating the customer's willingness to pay to avoid the outage.

HV customers (connected to High Voltage lines >750kVA) typically fall into the General Service >5MW, General Service 1-5MW, and General Service 50kW -1000kW rate classes. LV customers (connected to lines <750kVA) generally include smaller business and residential customers under the Residential, General Service <50kW and Competitive Sector Multi-Unit Residential rate classes. With small businesses included, the General Service <50kW category would also face tangible costs from connection delays.

To calculate the benefits of timely connections, Toronto Hydro relied on the data shown in Tables 26 and 27, which provide:

- Number of forecasted connections to HV and LV customers[43]
- Average load per HV and LV customers, based on division of total consumption by number of customers, based on rate class
- Average delay time in days/hours
- CIC duration, reflecting the 24 hours cost per unserved kWh for Large Business as HV customers, and a weighted average cost for Residential and Small-Medium Business as LV customers.

As noted above in section 2.2.1, Toronto Hydro's target performance against the New Services Connected on Time metric is 99 percent relative to the OEB's service quality requirement of 90 percent of new connections completed on time. Where connection delays

[43] See section 2.2.1 above.

do occur, the average delay runs 21 days (504 hours) for HV customers and 13.5 days (325 hours) for LV customers. To quantify the value of the higher level of service that Toronto Hydro has committed to maintain over 2025-2029 rate term, the utility compared targeted performance against both the OEB's minimum service quality requirement and the average five-year (i.e. 2018 to 2022) performance of a peer group of Ontario distributors.[44]

Tables 26, 27 and 28, below show that meeting the performance target with respect to New Service Connected on Time custom measure yields a total benefit in the range of $31.7 to $142.6 million over the 2025-2029 period.

Table 26: High-Voltage Connections Customer Benefits for 2025-2029

	2025	2026	2027	2028	2029
Number of HV Customer Connection	120	120	120	120	120
Performance Target	99%	99%	99%	99%	99%
OEB Minimum Service Quality Requirement	90%	90%	90%	90%	90%
Average LDC Performance	97%	97%	97%	97%	97%
Additional Customers Connected on Time relative to Average LDC Performance and OEB Standard[45]	2.4 - 10.8	2.4 - 10.8	2.4 - 10.8	2.4 - 10.8	2.4 - 10.8
Average Delay Time (Hours)	504	504	504	504	504
Average Load (kW)	214	212	210	209	206
CIC Duration ($/kW)	$22.78	$23.23	$23.70	$24.17	$24.65
Benefits ($ Millions)[46]	**$5.9 - $26.5**	**$5.9 - $26.7**	**$6.0 - $27.0**	**$6.1 - $27.4**	**$6.1 - $27.7**

[44] Hydro One, Hydro Ottawa, Alectra Utilities, Elexicon Energy, London Hydro, EnWin Utilities, and Enova Power.
[45] The LDC average performance of 98% that applies to Low Voltage connections is assumed for High Voltage as well.
[46] High-Voltage Customer benefits range given a threshold performance of 90% (OEB minimum service quality requirement) and 98% (2018-2022 Ontario LDC average performance).

Table 27: Low-Voltage Connections Customer Benefits for 2025-2029

	2025	2026	2027	2028	2029
Number of LV Customer Connection	5,573	5,714	5,859	6,008	6,161
Performance Target	99%	99%	99%	99%	99%
OEB Minimum Service Quality Requirement	90%	90%	90%	90%	90%
Average LDC Performance	97%	97%	97%	97%	97%
Additional Customers Connected on Time relative to Average LDC Performance and OEB Standard	111.4 - 501.5	114.2 - 514.2	117.1 - 527.3	120.1 - 540.7	123.2 - 554.4
Average Delay Time (Hours)	325	325	325	325	325
Average Load (kW)	1	1	1	1	1
CIC Duration ($/kW)	$7.28	$7.38	$7.48	$7.59	$7.68
Benefits ($ Millions)[47]	**$0.3 - $1.3**	**$0.3 - $1.4**	**$0.3 - $1.4**	**$0.3 - $1.5**	**$0.4 - $1.6**

Table 28: Total HV & LV Connection Customer Benefits for 2025-2029 ($ Millions)

2025	2026	2027	2028	2029	2025-2029
$6.2 - $27.8	$6.2 - $28.1	$6.3 - $28.5	$6.4 - $29	$6.5 - $29.2	$31.7 - $142.6

[47] Low-Voltage Customer benefits range given a threshold performance of 90% (OEB minimum service quality requirement) and 98% (2018-2022 Ontario LDC average performance).

3.3 System Capacity (Non-Wires)

As noted above in section 2.4.3, in the 2025-2029 rate term Toronto Hydro plans to expand its LDR program to avoid and defer capital expenditures associated with load transfers, which become necessary when serving customers in areas of the grid that experience capacity constraints due to high-growth.

3.3.1 Benefits of Non-Wires Solutions

Toronto Hydro assessed the reductions to distribution costs as a result of deferring or avoiding load transfer projects through the use of LDR as a non-wires solution. The results of this analysis yield nominal ratepayer benefits of approximately $3.1 million in the 2025-2029 rate period, and nominal lifetime benefits of $21 million.[48]

3.4 Efficiency Achievements

As explained above in section 2.4.1, Toronto Hydro's approach to realizing efficiency gains is based on achieving a top-down target equivalent to the 2029 revenue requirement value of the proposed efficiency (stretch) factor within the Custom Revenue Cap Index set out at Exhibit 1B, Tab 2, Schedule 1. This section outlines the methodology used to calculate the annual benefits of these efficiency achievements for the forthcoming years, and explains how these gains align with other performance metrics.

3.4.1 Benefits of Efficiency Achievements

By the end of the rate term, the 0.15 percent efficiency (stretch) factor results in cumulative stretch of 0.6 percent relative to the 2029 revenue requirement, and yields a 2029 revenue reduction of approximately $6.9 million – the target on the Efficiency Achievements metric.

[48] These benefits are based on the BCA in section 2.4.3 but presented on a nominal basis for comparability with the other metrics in the analysis.

A core function of the $6.9 million target, and its associated benefits, is the requirement that efficiencies must persist into the next rate term, which is assumed to be 2030 to 2034. As such, through this metric, Toronto Hydro is incented to pursue sustained efficiencies that will be realized in base rates starting in 2030. To calculate the 2030 to 2034 benefits, the 2029 target of $6.9 million was multiplied by five years. Table 29 below presents the calculation. Overall, from 2025 to 2034, the Efficiency Achievement metric, in combination with the 0.15 percent efficiency factor over the 2025-2029 rate period, yields a total customer benefit of approximately $50.7 million on a nominal basis.

Table 29: 2025-2034 Efficiency Customer Benefits ($ Millions)

	2025	2026	2027	2028	2029	2030-34	Total
Base Revenue Requirement	972.4	1,027.0	1,074.4	1,175.7	1,219.2		
Revenue Requirement with 0.15% efficiency factor	972.4	1,025.5	1,071.3	1,170.9	1,212.2		
Efficiency Factor		0.15%	0.30%	0.45%	0.60%		
Efficiency Benefits		**1.5**	**3.1**	**5.0**	**6.9**	**34.3**	**$50.7**

3.5 Emissions Reductions

As noted in section 2.3.2 above, Toronto Hydro emissions reduction benefit is based on Scope 1 emissions from vehicle fleet and buildings emissions. Table 30 highlights the buildup of the emissions reduction benefits throughout 2025-2029 period. Utilizing the increase in Canada's federal cost of CO2 from $95/ton in 2025 to $155/ton by 2029,[49] Toronto Hydro's Emissions Reductions target would yield $221,510 in savings benefits within the 2025-2029 period. To calculate life-time benefits a value of $170/ton was used for 2030 and beyond over the useful of the assets which is 11 years for fleet and 22 years for facilities. This

[49]Greenhouse Gas Pollution Pricing Act SC. 2018, c. 12, s. 186 at Schedule 4

calculation results in a lifetime quantified benefit from Emissions Reductions of approximately $1.5 million.

Table 30: Emissions Cost Reductions (tCO2e)

	2025	2026	2027	2028	2029
Fleet and Buildings Scope 1 Emissions	2,892	2,782	2,684	2,576	2,478
Annual Savings Relative to 2024[50]	120	230	328	436	534
Canada CO2 price ($/tCO2e)[51]	$85	$110	$125	$140	$155
Annual Emissions Reduction Savings	$11,400	25,300	$41,000	$61,040	$82,770
Emissions Reductions Cumulative Savings	**$11,400**	**36,700**	**$77,700**	**138,740**	**$221,510**

Toronto Hydro notes the obvious, but key observation, that the emissions reductions quantified benefits above do not consider the inherent value of achieving net-zero targets to mitigating the existential and economic impacts of climate change. This observation applies directly to the Emissions Reductions metric and more broadly to this performance incentive framework, and the 2025-2029 investment plan that underpins it. Among other many important objectives, this plan reflects Toronto Hydro's commitment to enable climate action by readying its grid and operations ready to serve Toronto residents, businesses and institutions who want plug-in electrified technologies safely, reliably and efficiently in this rate period and decades to come.

[50] For 2024 Fleet and Buildings Scope 1 emissions are projected at 3,012tCO2e.
[51] https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html

HISTORICAL PERFORMANCE RESULTS

Toronto Hydro is a performance-driven organization focused on delivering value to its customers through outcomes. The utility tracks and reports its performance annually on 45 distinct measures aligned with outcomes in the OEB's Renewed Regulatory Framework for Electricity Distributors. Over the last decade, Toronto Hydro improved its performance on a number of key service quality measures, as detailed throughout this schedule, and summarized in Table 1 below.

Table 1: Toronto Hydro's Performance Improvements over the Last Decade

OEB Outcomes	Categories	Performance Measures	2013	2022	% Change
Customer Focus	Customer Service	Billing Accuracy	96.6[1]	99.11	3%
		Rescheduling a Missed Appointment	98.4	100	1.6%
		Customer Satisfaction Survey Results (%)	91.0[1]	94	3%
		First Contact Resolution (%)	77.0	92	19%
		New Residential/Small Business Services Connected on Time	94.2	99.89	5%
		Customers on eBills (total)	64,163	381,490	495%
Operational Effectiveness	Safety	Total Recordable Injury Frequency (per 100 workers)	2.26	0.47	-60%
	System Reliability	SAIDI - Defective Equipment (hours)	0.46	0.34	-26%
		SAIFI - Defective Equipment	0.53	0.46	-13%
		FESI-6 Large Customers (# feeders)	22	12	-45%
		Emergency Urban Response	74.4	86.5	16.3%

This schedule presents and explains Toronto Hydro's performance results reported in the:

(1) Electricity Distributor Scorecard ("EDS"),

(2) OEB's electricity service quality requirements ("ESQRS"), and

(3) 2020-2024 Custom Scorecard approved in EB-2018-0165.

[1] The OEB started tracking Billing Accuracy and Customer Satisfaction Survey results in 2014.

1. ELECTRICITY DISTRIBUTOR SCORECARD (EDS) PERFORMANCE

Table 2 below summarizes and compares Toronto Hydro's recent five-year (2018-2022) results with its performance over the previous five-year period (2013-2017).[2] The sections that follow the table explain the utility's historical performance for each EDS measure.

Table 2: Toronto Hydro EDS Performance Results (2013-2022)

Performance Measures		2013-2017 (5-year avg)	2018-2022 (5-year avg)
New Residential/Small Business Services Connected on Time		95.72%	99.80%
Scheduled Appointments Met on Time		99.63%	99.68%
Telephone Calls Answered on Time		74.66%	76.15%
First Contact Resolution		83.00%	91%
Billing Accuracy		98.07%[3]	99.15%
Customer Satisfaction Survey Results		87%[3]	94%
Level of Public Awareness		70.33%	69%
Compliance with O. Reg 22/04		C	C
Serious Electrical Incidents	Number of General Public Incidents	1.2	17.6
	Rate per 10, 100, 1000 km of line	0.106	0.608
SAIDI		0.96	0.846
SAIFI		1.26	1.3
DSP Implementation		n/a	n/a
Efficiency Assessment		5	5
Total Cost per Customer		$995	$1,189
Total Cost per km of Line		$53,287	$32,073
Renewable Generation CIA Completed on Time		95.64%	100%[4]
New Micro-embedded Generation Facilities Connected on Time		98.48%	96.71%
Liquidity: Current Ratio		0.68	0.76
Leverage: Total Debt to Equity Ratio		1.47	1.17
Profitability: Regulatory ROE	Deemed	9.41%	8.83%
	Achieved	9.30%	7.64%

[2] This information is derived from Toronto Hydro's 2018-2022 and 2013-2017 EDS which are filed at Appendix A to this schedule.
[3] The OEB started tracking Billing Accuracy and Customer Satisfaction Survey results in 2014.
[4] Value displayed represents the average from 2018 until the first quarter of 2021, as the filing requirement was subsequently removed from the Reporting and Record-keeping Requirements (RRR).

1.1 Service Quality: New Residential/Small Business Services Connected on Time

Toronto Hydro connected new residential and small business services (i.e. new connections less than 750 volts) on time at average of 99.80 percent over the 2018-2022 period, consistently exceeding the OEB's performance standard of 90 percent. In 2022, Toronto Hydro achieved its best result to date, connecting 99.89 percent of the 5,260 new residential and small business connections on time.

Serving one of the fastest growing cities in North America, Toronto Hydro receives high volumes of connections and upgrade requests for residential and commercial developments each year. To meet these challenges, the utility strives for continuous improvement in its planning and execution processes. For instance, in 2017, Toronto Hydro consolidated its connection design teams to enable the allocation and distribution of work across design team members in a more effective and efficient manner. In addition, Toronto Hydro provided electronic means for customers to complete their connections inquiries. These process improvements enabled customer inquiries to be handled efficiently and expeditiously.

The utility's performance under this measure is enabled by a number of programs including Customer Connections and Customer Operations.[5] Provided that sufficient funding is available for these and other supporting programs, the utility intends to maintain high performance on this metric over the 2025-2029 rate period, despite increasing volumes and complexity of customer connections work. Moreover, as part of the 2025-2029 Custom Scorecard outlined in Exhibit 1B, Tab 3, Schedule 1, Toronto Hydro intends to augment its performance on this metric with a custom (composite) measure that includes high voltage and Distributed Energy Resource ("DER") connections.

[5] Exhibit 2B, Section E5.1 and Exhibit 4, Tab 2, Schedule 8.

1.2 Service Quality: Scheduled Appointments Met on Time

Toronto Hydro met an average of 99.68 percent of all requested appointments on time over the 2018-2022 period, consistently exceeding the performance standard set by OEB of 90 percent. In 2021 and 2022, Toronto Hydro achieved its best performance under this measure, successfully meeting 99.92 percent of all requested appointments on time for both years.

Toronto Hydro receives a high volume of appointment requests every year. Customers request, and the utility offers, appointments for a broad variety of services including, disconnections and reconnections for maintenance or service upgrades, connections, underground infrastructure locates, inspections, and other site visits. An increase in the volume of construction, and in particular of larger residential and commercial development projects in the city, has led to an increase in the complexity of requests received by Toronto Hydro during the 2020-2022 period. Specifically, there has been an increase in the number of connections requiring main distribution system expansions, as well as an increase in complex multi-unit segment locates. To mitigate the cost impacts from these conditions, Toronto Hydro continues to work on streamlining its processes. For example, Toronto Hydro is working with the Locate Alliance Consortium to streamline and share costs for the delivery of locates with other infrastructure owners.

The utility's performance under this measure is enabled by a number of programs including Customer Connections and Customer Operations.[6] Provided that sufficient funding is available for these and other supporting programs, the utility intends to maintain high performance on this metric over the 2025-2029 rate period.

[6] *Supra* note 5.

1.3 Service Quality: Telephone Calls Answered on Time

Toronto Hydro answered an average of 76.15% percent of telephone calls on time over the 2018-2022 period, exceeding the OEB performance standard of 65 percent. In 2017, Toronto Hydro extended its Call Centre weekday business hours from 8:00 a.m. to 4:30 p.m. to 8:00 a.m. to 8:00 p.m. The extended Call Centre hours resulted in more manageable call volumes, contributing to improving results.

The utility's performance under this measure is enabled primarily by the Customer Care program.[7] While some year-over-year volatility is to be expected, if sufficient funding is available for Customer Care program, the utility intends to maintain high performance on this metric over the 2025-2029 rate period.

1.4 Customer Satisfaction: First Contact Resolution

First Contact Resolution tracks the successful resolution of a customer's concern or needs the first time they contact the utility. This measure reflects the proportion of telephone enquiries related to a residential or commercial account where the issue was resolved in the first call. Toronto Hydro's performance on this measure averaged 87 percent over the 2013-2022 period.

Toronto Hydro's First Call Resolution performance improved from 77 percent in 2013 to 92 percent in 2022, the best result to-date. This trend demonstrates that Toronto Hydro's customer response model is becoming more efficient at understanding and responding to customer inquiries faster and improving the overall customer service experience. The results are attributed to continuous improvement efforts to create positive customer experiences, including targeted process improvements, resource upskilling and leveraging technology

[7] Exhibit 4, Tab 2, Schedule 14.

(such as the Customer Self-Serve portal and mobile application) to offer customers better tools to engage with the utility.

The utility's performance under this measure is enabled by the Customer Care program,[8] and other supporting areas of Toronto Hydro's operations such as the Asset and Program Management and the Public, Legal and Regulatory Affairs which oversee asset standards and policies, regulatory requirements and customer communications. While some volatility can occur as the nature of customer inquiries evolves, if sufficient funding is available for Toronto Hydro's operations, the utility intends to maintain high performance on the First Contact Resolution metric over the 2025-2029 rate period. Moreover, as part of the 2025-2029 Custom Scorecard, the utility intends to complement this metric with a custom measure that tracks the timely resolution of customer inquiries that are escalated beyond first contact.

1.5 Customer Satisfaction: Billing Accuracy

Billing inaccuracies may be caused by a variety of factors including incomplete or inaccurate meter data, incorrect account or move-in/move-out information, or misapplication of rates. Toronto Hydro issued an accurate bill 99.15 percent of the time on average over the 2018-2022 period, exceeding the OEB's performance target of 98 percent. Over the past decade, Toronto Hydro invested in process improvements and hardware enhancements that enabled it to achieve billing accuracy performance consistently above to the OEB standard since 2016. Process improvements included streamlining the meter to cash process, implementing preventative measures to monitor and reduce billing errors and exceptions, improving training and standard operating procedure documents, and proactively integrating relevant controls in new projects. Replacements of defective meters, increased

[8] *Supra* note 7.

engagement with vendors, enhancements to field service and metering data exception management processes, and investments in metering and meter data collection technologies also contributed to reductions in billing inaccuracies.

Toronto Hydro's performance on this measure is enabled by a number of programs including the Customer Care program,[9] and the Metering program.[10] Regarding the latter, Toronto Hydro intends to upgrade its residential and small commercial meters, under the Advanced Metering Initiative ("AMI") 2.0 deployment. The new meters will allow for improved network range resulting in fewer errors and less manual meter reads enabling the utility to maintain a high degree of billing accuracy even as customer consumption patterns shift and evolve. Provided that sufficient funding is available for these programs, the utility is committed to maintaining high performance on the Billing Accuracy metric over the 2025-2029 rate period.

1.6 Customer Satisfaction: Customer Satisfaction Survey Results

Toronto Hydro first reported this measure in 2014 and surveyed customer satisfaction in the following key areas: (a) power quality and reliability, (b) price, (c) billing and payment, (d) communications, and (e) the customer service experience. In the 2022/2023 survey, Toronto Hydro achieved an overall score of 94 percent. As part of the 2025-2029 Custom Scorecard, the utility intends to complement this EDS metric with a custom measure aimed at measuring customer satisfaction using post-transactional surveys at various points of interaction (e.g. phone and email inquiries, key accounts engagements, customer communication related to outages and construction projects).

[9] *Ibid.*
[10] Exhibit 2B, Section E5.4.

1.7 Safety: Level of Public Awareness of Electrical Safety

Toronto Hydro values safety and proactively ensures awareness and importance of safety in the vicinity of its distribution equipment. These activities include proactive contact voltage scans on street-level assets, taking prompt corrective action where potential safety issues are identified, and fostering a robust corporate safety culture including comprehensive internal safety course work.

Distributors are required to report the results of a standard safety awareness survey of the general public residing within their service territory, who may or may not be direct customers, at least once every two years. The survey is designed by the Electrical Safety Authority ("ESA") and tests the respondents' electrical safety awareness across several topics, including power line clearance distances, emergency procedures related to vehicular collisions with utility equipment and safety precautions related to excavation work. The average Public Safety Awareness Index over the 2018-2022 period was 69 percent. The results remain stable, and within the 4 percent margin of error, given the sample size of 600 customers.

For the 2025 rate period, Toronto Hydro intends to continue to monitor the level of public safety awareness relating to the distribution system. The utility's performance on this measure is enabled by effective customer communications part of the Communications and Public Affairs segment of the Public, Legal and Regulatory Affairs program.[11]

1.8 Safety: Compliance with Ontario Regulation 22/04

[11] Exhibit 4, Tab 2, Schedule 18.

Ontario Regulation 22/04 – Electrical Distribution Safety ("the Regulation") establishes the requirements for electrical distribution safety related to the design, construction, and maintenance of electrical distribution assets owned by the utility.[12] This includes making sure appropriate procedures are in place to prevent general public accidents or incidents, keeping the system in safe working condition, etc. The ESA deemed Toronto Hydro to be compliant with the requirements of the Regulation over the 2018-2022 period. These results were achieved through successful due diligence inspections, resolution of public safety concerns, compliance investigations, and annual compliance audits conducted by the ESA and a declaration of compliance. Toronto Hydro intends to remain in compliance with the Regulation through the 2025-2029 rate period.

1.9 Safety: Serious Electrical Incident Index

The overall number of serious public electrical incidents increased over 2018-2022 due to changes in the ESA's guideline for reporting serious electrical incidents, which broadened the scope of qualifying events under this measure as of 2020. For 2018-2019, Toronto Hydro reported an average of 7 incidents, with an average ratio of 0.227 incidents per 1,000 km of line. Due to more incidents qualifying thereafter, this number increased to an average of 25 incidents and average ratio of 0.862 incidents per 1,000 km of line for the years 2020, 2021 and 2022.

For the 2025-2029 rate period, Toronto Hydro continues to invest in a number of capital and maintenance programs that aim to prevent incidents relating to equipment failures, for instance through the Overhead and Underground System Renewal Program, Tree Trimming Program, Insulator Washing Program, Overhead Infrared Scan Program/Overhead Line

[12] Ontario Regulation 22/04 – Electrical Distribution Safety, under the *Electricity Act, 1998, S.O. 1998, c. 15, Sched. A.*

Patrol and Cable Chamber Inspection and Infrared Scan. The mitigation of public safety risk is enabled by a number of programs included in Exhibit 2B, Section E6 and Exhibit 4, Tab 2.

1.10 System Reliability: SAIDI / SAIFI

Over the last decade, Toronto Hydro's investments to renew the system delivered demonstrable reliability improvements by reducing the average duration of power outages due to defective equipment by 30 percent over the 2013-2022 period, and the frequency of outages due to defective equipment by 13 percent. Over the same period, the average duration of outages – SAIDI excluding Loss of Supply ("LoS") and Major Event Days ("MEDs") – reduced by 26 percent, while the frequency – SAIFI excluding LoS and MEDs – remained steady.

The utility's SAIDI performance improved over the last five years (2018-2022), averaging 0.85 and exceeding the OEB's distributor target of 0.87. The utility's SAIFI performance is slightly worse than the OEB's distributor target of 1.20, averaging at 1.30 during the 2018-2022 period. Please see Exhibit 2B, Section C for a comprehensive discussion on the underlying causes of system interruptions captured by SAIDI and SAIFI.

The utility's performance under the measure is enabled through a number of planned sustainment and modernization work programs in the Distribution System Plan filed at Exhibit 2B, as well as numerous operational programs detailed in Exhibit 4, Tab 2 including Corrective and Preventative and Predictive maintenance programs, Asset and Program Management, Control Center, and Emergency Response.[13] As part of the 2025-2029 Custom Scorecard, Toronto Hydro intends to augment its reliability performance commitments with

[13] Exhibit 4, Tab 2, Schedules 1-5 and 7.

two custom measures: SAIDI excluding LoS, MEDs and scheduled outages, and SAIFI Defective Equipment.

1.11 Asset Management: Distribution System Plan ("DSP") Implementation Progress

The DSP Implementation Progress measure reflects the effectiveness of the utility in implementing its DSP. This measure tracks the ratio of the actual cumulative capital expenditures to the aggregate approved five-year capital expenditure amount.

Toronto Hydro undertakes hundreds of individual capital projects each year, and the selection and timing of those projects varies with dynamic customer and system needs, as well as weather, field conditions, permitting, site access, third party co-ordination, and other factors. A regular part of Toronto Hydro's operations is rebalancing the mix and timing of capital projects to adjust for these factors. As of 2022, the DSP implementation progress was 59 percent and is forecast to be 103 percent by the end of 2024. See Exhibit 2B, Section E4 for more detailed information about the implementation of the utility's 2020-2024 DSP.

1.12 Efficiency Assessment

Efficiency is determined using an econometric benchmarking model that compares actual total costs to average total costs predicted by an econometric model based on Ontario utilities. Utilities' total costs are evaluated to produce an efficiency ranking based on the magnitude of the difference between each utility's actual and predicted costs. For the period 2013-2022, Toronto Hydro's efficiency ranking remained at a "5" as a result of ongoing capital investment needs to sustain a safe and reliable grid, connect and serve customer demand in a growing city, and standardize and modernize legacy equipment.

While Toronto Hydro endorses the importance of an empirical assessment of distributor cost efficiency, it submits that the methodology underlying the reported results for this measure does not adequately assess the efficiency performance of an urban utility with Toronto Hydro's operating characteristics (e.g. density, system configurations and customer make-up). In previous rate applications, econometric experts agreed that an expanded data set including U.S. utilities along with urban variable is more appropriate to benchmark Toronto Hydro's cost performance.[14] To that end, in this application the utility commissioned and filed a custom econometric total cost benchmarking study which can be found at Exhibit 1B, Tab 3, Schedule 3, Appendix A. The study found that Toronto Hydro's total costs from 2020 through 2022 were 28 percent below the predicted benchmark which would place the utility at an efficiency ranking of 1.

1.13 Total Cost per Customer and Total Cost per km of Line

From 2018 to 2022, Toronto Hydro's total cost per customer increased by $189 and total cost per kilometer increased by $5,367 as a result of Toronto Hydro's ongoing investment in prudent and necessary capital and operational work programs to (i) inspect, maintain and renew aging and deteriorating assets that pose safety, environmental and reliability performance risks, (ii) maintain and improve service quality performance on a number of metrics as detailed through this schedule, (iii) serve customer demand in Canada's largest and fastest growing city, (iv) comply with a multitude of existing and evolving legal and regulatory obligations; and (v) address incremental requirements driven by evolving customer preferences and technology advancements. Over the 2018-2022 period, this increase represents a cumulative average growth rate of 4 percent in total cost per customer and 4.3 percent in total cost per kilometer of line, compared to an average inflation rate of 2.68 percent over the period using OEB parameters.

[14] EB-2018-0165, Exhibit 1B, Tab 4, Schedule 2; Exhibit M1; OH Volume 10 (July 15, 2019) at page 116, lines 7-12.

However, as noted in Exhibit 4, Tab 1, Schedule 1, a key observation to highlight when evaluating the utility's cost performance on per customer metrics is that serving Canada's densest and fastest (vertically) growing city, Toronto Hydro serves far more end-use customers through bulk-metering and competitive sub-metering arrangements than its actual customer count would otherwise indicate. Based on self-declarations submitted by multi-unit residential buildings for the purposes of Regulated Price Plan elections and the Ontario Energy Rebate ("OER") program, Toronto Hydro estimates that it serves approximately 340,000 end-consumers or more behind bulk meters. As the sub-metering market has become more mature in Toronto over the last decade, a greater share of new multi-unit buildings is opting for bulk-metering service connections. The practical effect of operating in this urban environment with a deregulated sub-metering market is a slower rate of formally reported customer growth from 2013 to 2022, which is putting artificial upward pressure on cost performance metrics like Total Cost Per Customer and Total Cost per km of Line.

1.14 Generation Connections: Renewables and Micro-Embedded Facilities

As of the end of 2022, Toronto Hydro connected nearly 2,400 distributed generation projects of various sizes totalling approximately 305 MW in capacity. The utility averaged 96.71 percent for New Micro-embedded Generation Facilities Connected on Time over the 2018-2022 period, consistently exceeding the OEB's industry target of 90 percent. Toronto Hydro also completed 100 percent of Renewable Generation Connection Impact Assessments ("CIA") on time over this period. Over the 2025-2029 period, Toronto Hydro intends to include these measures as part of an expanded custom measure for New Service Connected on Time.

The utility's performance on these measures is enabled by the Customer Connections,[15] Generation Protection, Monitoring, and Control,[16] Asset and Program Management,[17] and Non-Wires Solutions.[18]

1.15 Liquidity: Current Ratio (Current Assets/Current Liabilities)

The ratio of current of current assets and current liabilities reflects the company's ability to repay its current liabilities with its current assets. The average liquidity ratio for regulated operations over the 2018-2022 period was 0.76.

Toronto Hydro's "Current Assets" and "Current Liabilities" are determined in accordance with the requirements of the OEB's *Electricity Reporting and Record Keeping Requirements for Electricity Distributors* ("RRR") and the *Accounting Procedures Handbook* ("APH"), and not by reference to *International Financial Reporting Standards* ("IFRS"). As a result, the "Liquidity Ratio" expressed in the EDS may differ from similarly-termed financial ratios or information presented in documents that the utility's parent company, Toronto Hydro Corporation, is required to file under securities laws, and which are available on System for Electronic Document Analysis and Retrieval ("SEDAR").

1.16 Leverage: Total Debt-to-Equity Ratio

The debt-to-equity ratio reflects the relative proportion of shareholders' equity and debt used to finance a company's assets. The average leverage ratio for regulated operations over the 2018-2022 period was 1.17.

[15] Exhibit 2B, Section E5.1.
[16] Exhibit 2B, Section E5.5.
[17] Exhibit 4, Tab 2, Schedule 9.
[18] Exhibit 2B, Section E7.2.

Toronto Hydro's "Total Debt" and "Equity" are determined in accordance with the requirements of the OEB's RRR and APH, and not by reference to IFRS. As a result, the "Leverage Ratio" expressed in the EDS may differ from similarly-termed financial ratios or information presented in documents that Toronto Hydro is required to file under securities laws and which are available on SEDAR.

1.17 Profitability: Regulatory ROE

Toronto Hydro's average achieved regulatory Return on Equity ("ROE") over the 2018-2022 period was 7.64 percent compared to an average deemed ROE of 8.83 percent. As of the end of 2022, Toronto Hydro's average achieved regulatory ROE over the first three years of the current rate period (i.e. 2020-2022) was 6.81 percent, which is 1.71 percent lower than its deemed ROE of 8.52 percent due to funding challenges experienced in the current rate period, including the impacts of COVID-19 in 2020 and 2021 which were reported to the OEB during the pandemic. [19,20]

The regulatory ROE is calculated on the same basis as the methodology used to establish Toronto Hydro's base rates for a year, which is prescribed by the OEB. The Regulatory ROE is not determined in accordance with IFRS. As such, the EDS' "Profitability" performance measures ("Deemed" and "Achieved" Regulatory ROE) may differ from similarly-termed expressions of profitability and return on equity presented in documents that Toronto Hydro Corporation, the utility's parent company, is required to file under securities laws and which are available on SEDAR.

[19] Exhibit 1B, Tab 2, Schedule 1.
[20] Ontario Energy Board, *Temporary Monthly Reporting Requirement Related to the Impact on Distributors Arising from the COVID-19 Emergency* (May 12, 2020) online:<https://www.oeb.ca/sites/default/files/letter-LDC-Liquidity-Reporting-Requirement-20200512-rev.pdf>. For more information about COVID-19 impacts please refer to Exhibit 1B, Tab 3, Schedule 3.

2. ELECTRICITY SERVICE QUALITY REQUIREMENTS PERFORMANCE

Toronto Hydro monitors and reports ESQRs annually to the OEB's RRR and the EDS. In accordance with section 2.1.6 of the OEB's Chapter 2 Cost of Service Filing Requirements, this section discusses the reported ESQRs performance for the last five years (2018-2022). A completed Appendix 2-G, documenting both Service Quality and Service Reliability Indicators, is provided in Exhibit 1B, Tab 2, Schedule 2, Appendix B.

Table 2 below shows that over the last five years (2018 to 2022) the utility met or exceeded the OEB's ESQR standards on all the measures, except Appointment Scheduling for the reasons explained below.

Table 2: 2018-20222 Toronto Hydro ESQR Performance Results

ESQR	OEB Standard	2018	2019	2020	2021	2022	5-Year Avg.
Connection of New Services – Low Voltage ("LV") (EDS)	90	99.8	99.7	99.7	99.9	99.9	99.8
Connection of New Service – High Voltage ("HV")	90	100	99.3	99.7	99.3	99.2	99.5
Connection of Micro-Embedded Generation Facilities (EDS)	90	100	100	100	92.3	91.3	96.7
Appointment Scheduling	90	81.6	91.8	94.1	90.7	81.2	87.9
Scheduled Appointments Met on Time (EDS)	90	99.7	99.0	99.9	99.9	99.9	99.7
Rescheduling a Missed Appointment	100	100	100	100	100	100	100
Telephone Accessibility (EDS)	65	80.2	74.8	69.9	76.9	79.1	76.2
Telephone Call Abandon Rate	10	1.4	3.5	2.7	1.1	1.1	1.96
Written Response to Enquires	80	98.4	99.4	96.3	98.3	99.7	98.4
Billing Accuracy (EDS)	98	99.3	99.2	99.2	99.0	99.1	99.2
Emergency Response (Urban)	80	86.6	92.4	88.3	88.5	86.5	88.5
Reconnection Performance Standard	85	99.7	99.9	99.5	NA	99.5	99.7

The following subsections discuss performance trends on specific ESQRs, excluding metrics where performance is steady over the period (i.e. Rescheduling a Missed Appointment, and Reconnection Performance Standard) or metrics that already are addressed in the EDS section above.[21]

2.1 Appointments Scheduling

Toronto Hydro offers customer appointments for a broad variety of services including disconnections and reconnections for maintenance or service upgrades, connections, underground infrastructure locates, inspections, and other site visits. Of these many different types of appointments, underground infrastructure locates, are the highest volume and the biggest driver of performance on the Appointment Scheduling metric.

Over the 2018-2022 period, Toronto Hydro scheduled 87.9 percent of appointments within five business days, falling slightly below the OEB standard of 90 percent. The performance did not meet the OEB standard over this period because in recent years Toronto Hydro experienced a shift in locate work mix and volumes due to legislative changes and more complex "multi-unit segment" locates relating to projects with large geographic footprints. In light of these developments, Toronto Hydro took numerous steps to improve its locates processes and improve performance on this metric, including:

- Working with Ontario One Call ("OOC") and other utilities to take steps to streamline locate requests to improve performance, including reducing the amount of unjustified locate requests;

[21] Specifically, the metrics for Connection of New Services – Low Voltage, Connection of New Micro-Embedded Generation Facilities, Scheduled Appointments Met on Time, Telephone Accessibility, and Billing Accuracy.

- Working with government and other utilities to transition large projects into the dedicated locator model and potentially create an alternate project stream for large projects separate from standard/residential locates;
- Working with the Locate Alliance Consortium ("LAC") to coordinate locate services with other infrastructure and sharing costs accordingly, which allows a single locate service provider to perform locates on behalf of all participating utilities in a certain area, streamlining the quality, timing and efficiency of the process;
- Establishing alternate locate agreements that enable excavators that meet Toronto Hydro-specified requirements to excavate without the requirement of a utility locate; and
- Expanding the locate request screening process which involves reviews by a trained worker in office, eliminating the need for a site visit (and an appointment) where there is no underground infrastructure owned by Toronto Hydro.

These utility's efforts summarized above led to increase in Appointment Scheduling performance from 2019 to 2021. Over these years, Toronto Hydro scheduled an average of 92.2 percent of all appointments within five business days, exceeding the OEB standard. However, in 2022, performance once again decreased due to execution challenges in the provincial locate industry a result of resourcing shortages and increased demand.

In addition, in April 2022, Bill 93*, Getting Ontario Connected Act, 2022*, received royal assent and resulted in major changes to the *Ontario Underground Infrastructure Notification System Act, 2012* ("OUINSA"), which governs the provision of locates. [22] The new legislative framework is significantly more onerous on utilities and other infrastructure owners due to mandatory, penalty-backed, and increased compliance obligations, intended to impose

[22] SO 2012, Ch 4. ["*Ontario Underground Infrastructure Notification System Act, 2012*"].

stricter performance standards with respect to the timeliness and accuracy of locates. These developments have greatly increased the demand for locate services and relevant input costs, such as wages for workers with appropriate qualifications. There remains a great degree of uncertainty with respect to the volumes of locates in the 2025-2029 rate period, as the Government of Ontario signalled that it will consult on additional enhancements to locate delivery requirements under the OUINSA, which may result in future legislative and regulatory changes affecting demand for locate services.

The utility's performance for Appointments Scheduling is enabled by programs such as Customer Operations.[23] To ensure the availability of funding for locates work necessary to meet performance standards on this metric, without jeopardizing other outcomes and while protecting ratepayers from potential over-recovery of costs in base rates, Toronto Hydro requests the continuation, throughout the 2025-2029 rate period, of the recently approved generic, sector-wide Getting Ontario Connected Act ("GOCA") variance account.[24] Please refer to the Customer Operations program evidence, and the Deferral and Variance Accounts evidence at Exhibit 9, Tab 1, Schedule 1 for more information about this proposal. [25]

2.2 Telephone Call Abandon Rate

The Toronto Hydro's Contact Centre receives approximately 343,000 telephone calls per year. Despite this significant volume of calls, over the 2018-2022 period, Toronto Hydro consistently exceeded the OEB standard for this measure with an average call abandonment rate of 1.96 percent compared to an OEB standard of 10 percent. In 2019 and 2020, call abandonment rates slightly increased to 3.5 percent and 2.7 percent respectively due to a

[23] Exhibit 4, Tab 2, Schedule 8.
[24] EB-2013-0143, OEB Decision and Order (October 31, 2023).
[25] *Supra* note 23.

combination of record high call volumes and resource shortages resulting in less tenured staff for call handling. However, in recent years (2021 and 2022) the call abandonment rate dropped down to 1.1 percent. The improvement is attributed to a more consistent availability of resources for call handling throughout 2021 versus 2020, improved forecasting methodologies and scheduling techniques to better align staffing levels with call arrival patterns, and a higher abandon rate in 2020 resulting from a surge of calls related to launch of the Customer Choice for Regulated Price Plan (giving customers choice to pick between Time of Use or Tiered pricing plans) creating short duration challenges.

For the 2025-2029 rate period, Toronto Hydro intends maintain high performance on this measure, provided that the Customer Care program which incorporates the Contact Centre function is adequately funded and resourced. [26]

2.3 Written Response to Enquiries

A significant portion of customers continue to demonstrate a preference to communicate via email versus telephone and expect shorter response times due to the electronic medium. To be responsive to this evolving customer preference and expectation, over the last decade Toronto Hydro invested in improving its performance in responding to written inquiries. These efforts produced strong results. Over the 2018-2022 period, Toronto Hydro responded to written enquiries within ten business days 98.4 percent of the time, consistently exceeding the OEB standard of 80 percent.

Notably, in 2022, Toronto Hydro responded to over 90 percent of emails within one business day. The utility achieved this result by implementing a number of training and process improvements, including enhancements to internal email routing algorithms, to quickly identify and contact the most appropriate resource to assess the customer enquiry and

[26] *Supra* note 7.

respond to the email. Toronto Hydro found that responding more quickly to customers reduced the total volume of emails annually by 25 percent (approximately 23,000 emails) from 2020 to 2022, and resulted in a 15 percent increase in customer satisfaction in this area, as measured by post-transactional surveys.[27]

For the 2025-2029 rate period, Toronto Hydro intends to maintain high performance on this measure provided that key programs such as Customer Care, and Public, Legal and Regulatory Affairs within the OM&A plan can be adequately funded and resourced. [28,29]

2.4 Emergency Response

Over the 2018-2022 rate period, Toronto Hydro responded to emergency calls within 60 minutes 88.5 percent of the time, consistently exceeding the OEB standard of 80 percent for urban areas. Over the last decade, the utility invested in strengthening its Emergency Response function to be better prepared to respond to more frequent extreme weather events such as storms and high-wind days. These efforts resulted in improved performance on this measure of 16 percent.

For the 2025-2029 rate period, Toronto Hydro intends maintain performance on this measure provided that the Emergency Response program within the OM&A plan can be adequately funded.[30]

3. 2020-2024 CUSTOM PERFORMANCE MEASURES

[27] Exhibit 1B, Tab 3, Schedule 1.
[28] *Supra* note 7.
[29] *Supra* note 11.
[30] Exhibit 4, Tab 2, Schedule 5.

This section presented the results of Toronto Hydro's performance on the 2020-2024 custom scorecard approved by the OEB in the utility's last rebasing application (EB-2018-0165).[31]

Table 3: 2020-2022 Custom Measure Performance

Toronto Hydro Outcome	OEB Reporting Category	Toronto Hydro's Custom Measures	2020 Results	2021 Results	2022 Results
Customer Service	Customer Satisfaction	Customers on eBills	317,341	350,993	381,490
Safety	Safety	Total Recordable Injury Frequency	0.58	0.56	0.47
		Network Units Modernization	61%	63%	65%
Reliability	System Reliability	SAIDI - Defective Equipment	0.36	0.36	0.34
		SAIFI - Defective Equipment	0.40	0.46	0.46
		FESI-7 System (# of feeders)	9	10	27
		FESI-6 Large Customers (# of feeders)	10	5	12
		MAIFI	3.18	3.39	3.36
	Asset Management	System Capacity (# of Stations)	11	11	12
		System Health (Asset Condition) – Wood Poles[32]	11%	14%	9%
		Direct Buried Cable Replacement	729 km	697 km	679 km[33]
		In-Service Additions (Cumulative)	17%	35%	56%
Financial	Cost Control	Average Wood Pole Replacement Cost	$7,779	$7,847	$7,973
		Vegetation Management Cost per Km	$2,158	$2,213	$2,175
Environment	Environment	Oil Spills Containing PCBs (# of spills)	0	0	1
		Waste Diversion Rate	90.3%	91.5%	92.4%

3.1 Customers on Electronic Bills ("eBills")

[31] EB-2018-0165, OEB Decision and Order (December 19, 2019) at pages 44-45. Note that in place of some of these measures, Toronto Hydro has proposed 15 Custom Performance Measures for the 2025-2029 plan period in the current Application. Please see Exhibit 1B, Tab 3, Schedule 1 for more details.

[32] As explained in Section 2.10 of this Schedule and Exhibit 2B, Section D3, Appendix A, Toronto Hydro refined its asset condition assessment methodology for wood poles. With this approach, the System Health (Asset Condition) for Wood Poles decreases to 6% in 2020 and decreases to 8% in 2021.

[33] In preparing this evidence, Toronto Hydro identified a data error in the number of km of direct buried cable remaining on the system reported for 2022 actuals. As of the end of 2022, Toronto Hydro has 666 kilometers of cable remaining rather than 679 kilometers. Please refer to Section 2.11 of this Schedule.

The Number of Customers on eBills measure tracks the number of customers who opt-in to receive an eBill, as opposed to a paper bill. From 2020-2022, Toronto Hydro achieved a 20 percent increase in eBill adoption over the 2020-2022 period converting over 64,000 customers to eBills. Since 2013, Toronto Hydro converted approximately 381,000 customers to eBills yielding cumulative savings of $4.4 million from avoided paper, printing, and postage costs. This accomplishment exceeded Toronto Hydro's target of reaching 347,000 customers on eBills by 2024. The utility achieved this result through targeted customer communication campaigns and continuous efforts to drive higher adoption of eBilling. Please refer to Exhibit 4, Tab 2, Schedule 14 for more details.

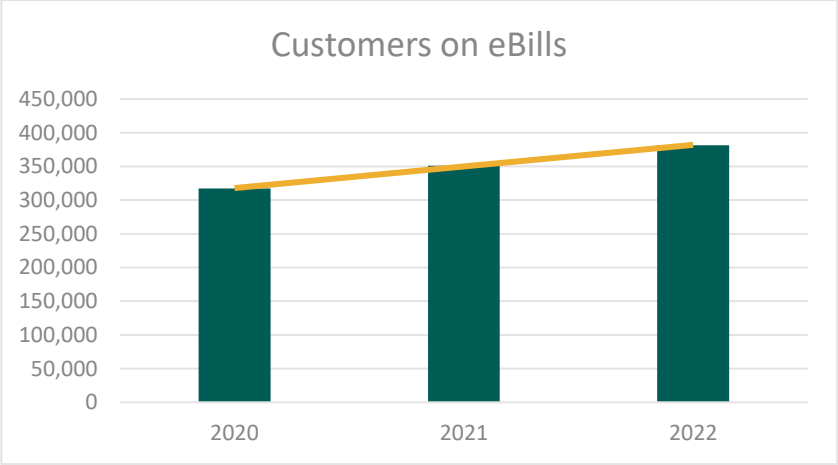

Figure 1: Customer on eBills Performance from 2020-2022

3.2 Total Recordable Injury Frequency ("TRIF")

The TRIF measures tracks the number of recordable injuries per 200,000 exposure hours, where a recordable injury is defined as any occupational injury or illness that results in an employee experiencing a fatality, lost-time injury, medical treatment beyond first aid, restricted work, or any other type of injury or illness associated with a significant injury,

illness or loss of consciousness. TRIF performance reflects the utility's commitment to health and safety.

From 2020-2022, Toronto Hydro reduced TRIF from 0.58 in 2020 to 0.47 in 2022, an improvement of approximately 19 percent. Toronto Hydro intends to continue reporting TRIF as a custom measure over the 2025-2029 period. Please refer to Section 1.4.1 of Exhibit 1B, Tab 3, Schedule 2 for more details.

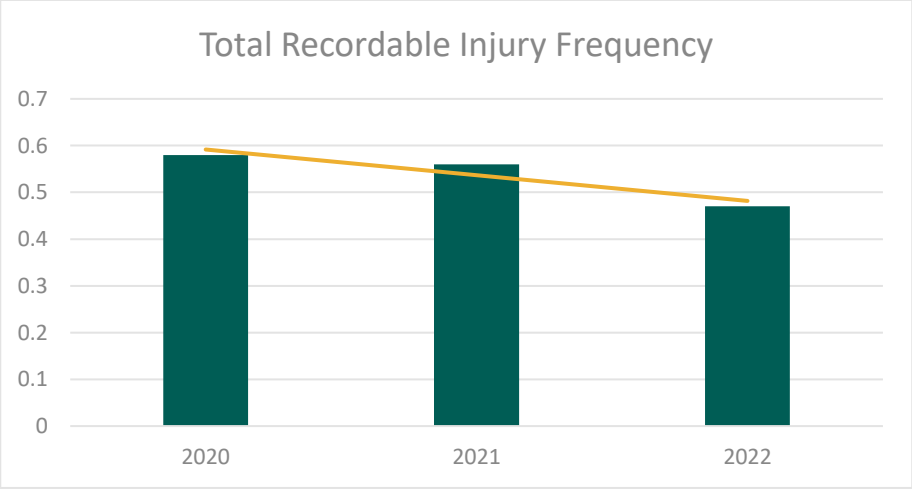

Figure 2: Total Recordable Injury Frequency from 2020-2022

3.3 Network Units Modernization

The Network Units Modernization measure tracks Toronto Hydro's progress in installing network units with resilient submersible protectors. In Toronto's downtown secondary distribution network, there are approximately 1,900 network units that deliver safe and uninterrupted service to customers. Some existing units are not watertight, making them vulnerable to corrosion and rust after prolonged exposure to flooding. To mitigate the safety and reliability risk of this equipment, the utility is actively installing new submersible units –

a more resilient asset that can withstand potential flooding and maintain reliable service to customers.

From 2020-2022, Toronto Hydro increased the percentage of submersible network units from 61 percent in 2020 to 65 percent in 2022 through investments in the Network Unit Renewal program and reactive network unit changeouts. By the end of 2024, the percentage of submersible network units is expected to be 70 percent. This is slightly lower than planned due to emerging needs within the program and cost pressures. For more details, please refer to Exhibit 2B, Section E6.4.

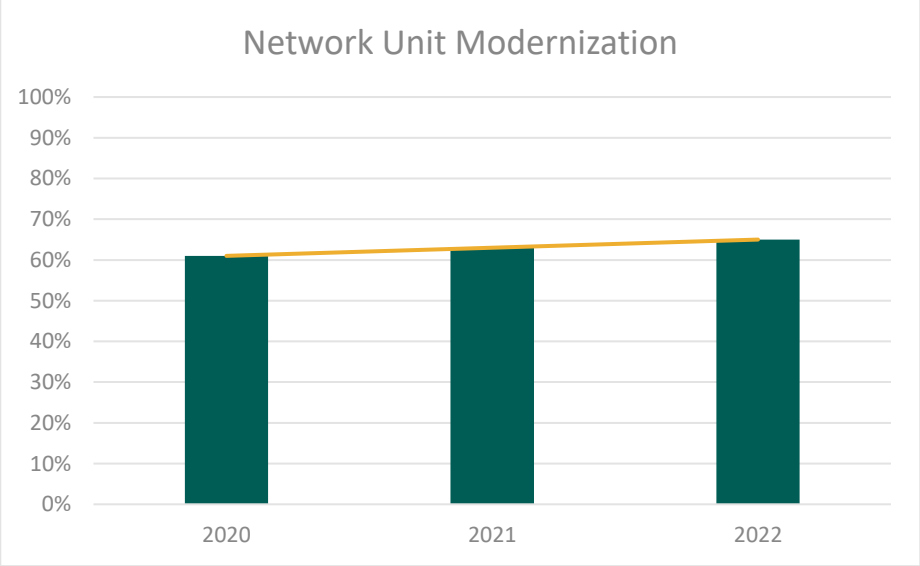

Figure 3: Network Unit Modernization Performance from 2020-2022

3.4 Momentary Average Interruption Frequency Index ("MAIFI")

In the last rebasing application (EB-2018-0165), the OEB required Toronto Hydro to include MAIFI on its custom scorecard to measure the average frequency of momentary interruptions (i.e. less than one minute). The five-year average MAIFI result for 2018 to 2022

is 3.11 compared to the corresponding value of 2.56 reported in the utility's last application (for the period 2013 to 2017). Although it appears from these results that the performance on MAIFI is getting worse, Toronto Hydro notes that its ability to measure MAIFI is affected by SCADA coverage, and that improving SCADA coverage over time (e.g. by converting customers served by 4.16 kV stations without SCADA to 13.8 kV or 27.6 kV ones with SCADA through programs such as Area Conversions) naturally results in capturing a higher proportion of the momentary interruptions that are occurring. Therefore, performance on this metric must be interpreted with a degree of practical caution as it is not necessarily reflective of actual trends with respect to the frequency of momentary interruptions on the system.

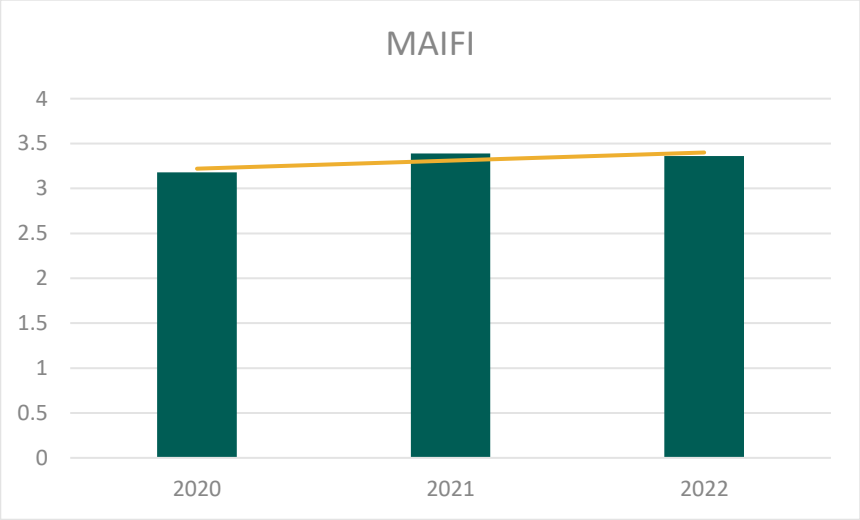

Figure 4: MAIFI Performance from 2020-2022

3.5 System Average Interruption Frequency Index ("SAIFI") – Defective Equipment

SAIFI – Defective Equipment reports the number of sustained customer interruptions caused by equipment failures due to material deterioration from age, utilization or environmental conditions. This particular cause of outages is affected by the health of the distribution

system, and the impact of Toronto Hydro's capital and maintenance investments in maintaining health demographics such as age and condition. From 2020-2022, Toronto Hydro performed within a tight range of 0.40 and 0.46, consistent with its expectations and historical performance.

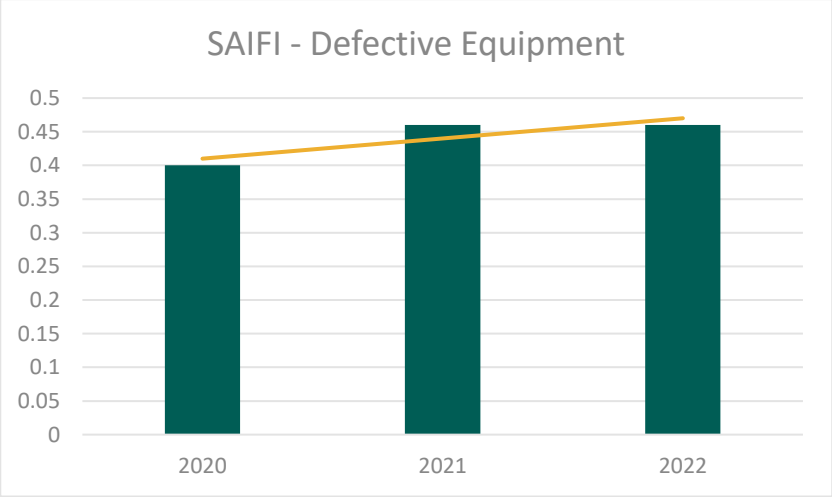

Figure 5: SAIFI – Defective Equipment Performance from 2020-2022

As part of the 2025-2029 custom scorecard, the utility intends to continue reporting on this metric to track customer outages directly attributed to equipment failures. For more details, please refer to Exhibit 1B, Tab 3, Schedule 1.

3.6 System Average Interruption Duration Index ("SAIDI") – Defective Equipment

SAIDI – Defective Equipment reports the average duration of customer interruptions caused by equipment failures due material deterioration from age, utilization or environmental conditions. Toronto Hydro's efforts to renew and modernize the grid affect performance on this metric. From 2020-2022, Toronto Hydro performed within a tight range of 0.32 and 0.36, consistent with its expectations.

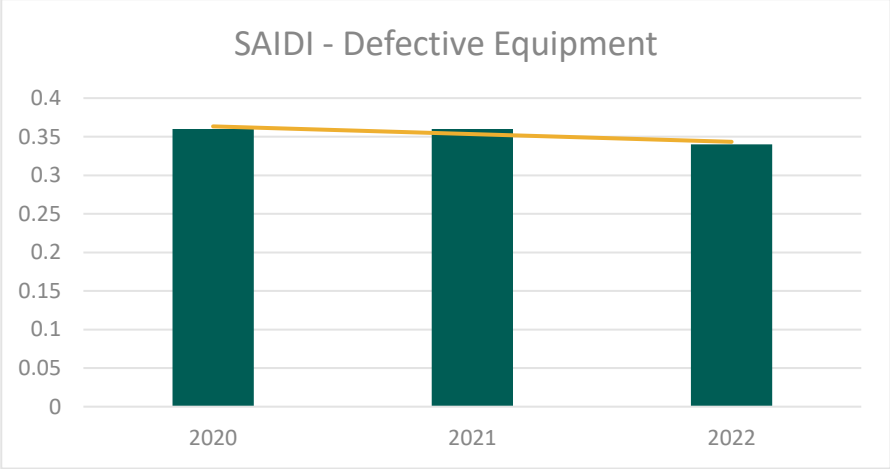

Figure 6: SAIDI – Defective Equipment Performance from 2020-2022

3.7 Feeders Experiencing Seven or More Sustained Interruptions ("FESI-7")

FESI-7 measures the number of feeders on Toronto Hydro's system that experienced seven or more interruptions exceeding one minute within a 12-month period. This measure provides insight into the number of customers experiencing poor reliability service. In the period from 2020-2022, feeders exceeding the threshold have increased from 9 to 27.

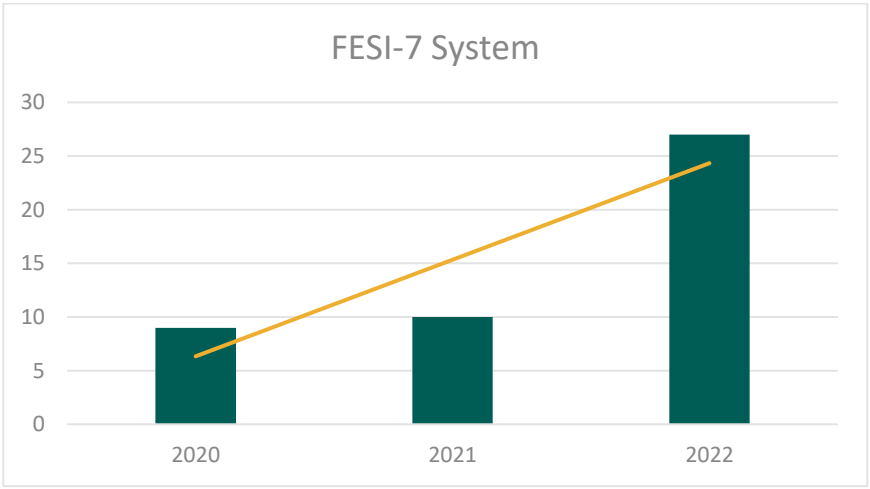

Figure 7: FESI-7 (System) Performance from 2020-2022

This increase is primarily due to implementation of a new commercial software solution, Oracle Utility Analytics ("OUA"), which allows outage data to be captured more accurately. In particular, Toronto Hydro is now benefiting from improved record keeping for very small outages (e.g. outages on the low-voltage secondary side of a transformer, serving only a handful of customers). While the inclusion of these outages had a significant negative impact on the FESI-7 measure (which counts all outages as equal regardless of size), this impact is purely the result of better data quality and does not represent a real-world decline in the customer experience. Furthermore, as many of the incremental outages being recorded are very small (and therefore highly localized), it is less likely that these outages are contributing to an experience of multiple outages per year for a significant number of customers.

This effect is illustrated by Figure 8 below. Over the 2017-2022 period, FESI-7 performance resulted in an average of approximately 14 outages per year, however, when normalized for localized events, FESI-7 performance is an average of about 5 outages per year.

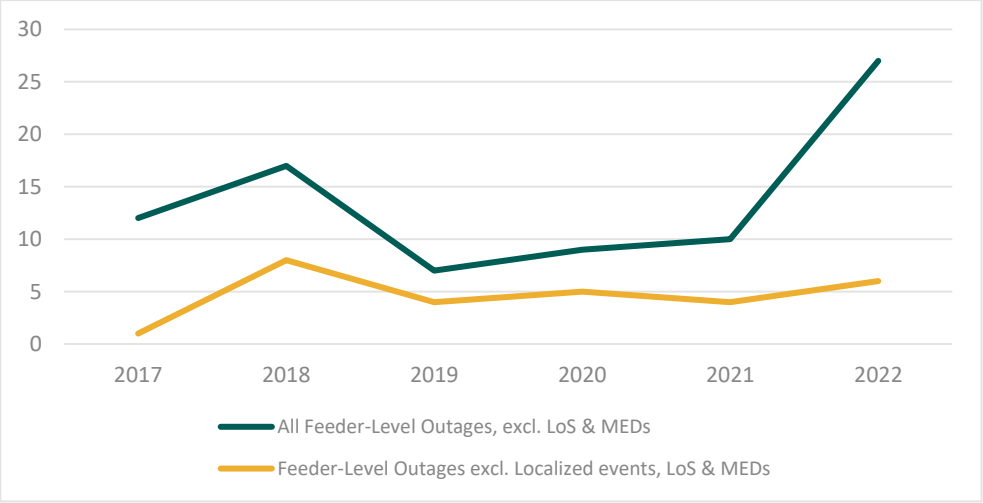

Figure 7: FESI-8 Performance Comparison from 2017-2022

Toronto Hydro continues to perform targeted capital investments and maintenance work, including Worst Performing Feeders investments to reduce the number of FESI-7 feeders.[34]

3.8 Feeders Experiencing Six or More Sustained Interruptions ("FESI-6")

FESI-6 Large Customers tracks the number of feeders serving customers with average monthly peak demand greater than one MW, that experienced six or more interruptions exceeding one minute, excluding Major Event Days and Loss of Supply. Measuring feeders experiencing outages at this threshold enables Toronto Hydro to account for customers with lower tolerance for interruptions and heightened reliability needs such as hospitals, water treatment plants, and commercial manufacturers. In the 2020-2022 period, feeders exceeding the threshold have increased from 10 to 12. This increase is primarily due to implementation of a new commercial software solution, Oracle Utility Analytics ("OUA"), which allows outage data to be captured more accurately (refer to the FESI-7 discussion above for more details).

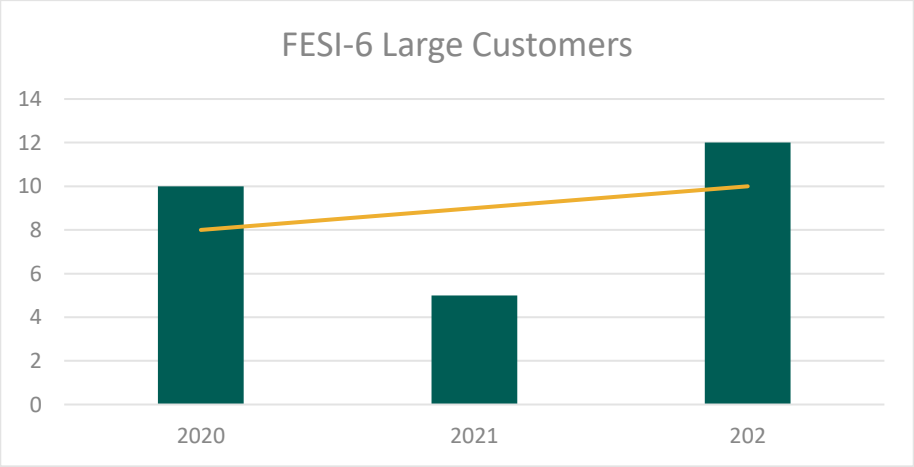

Figure 9: FESI-6 (Large Customers) Performance from 2020-2022

[34] Exhibit 2B, Section E6.7.

3.9 System Capacity

The System Capacity measure tracks potential capacity constraints at the station level by measuring the ability of each station to connect at least one large customer. Focused on transformer stations that supply power to the City of Toronto, this measure considers a variety of factors that contribute to capacity concerns, including bus, transformer and feeder capacity and positions. If any of these factors render the utility unable to connect a large customer to a station, Toronto Hydro will report that particular station as part of this measure. For the period 2020-2022, Toronto Hydro maintained its performance under this measure at 11 to 12 stations.

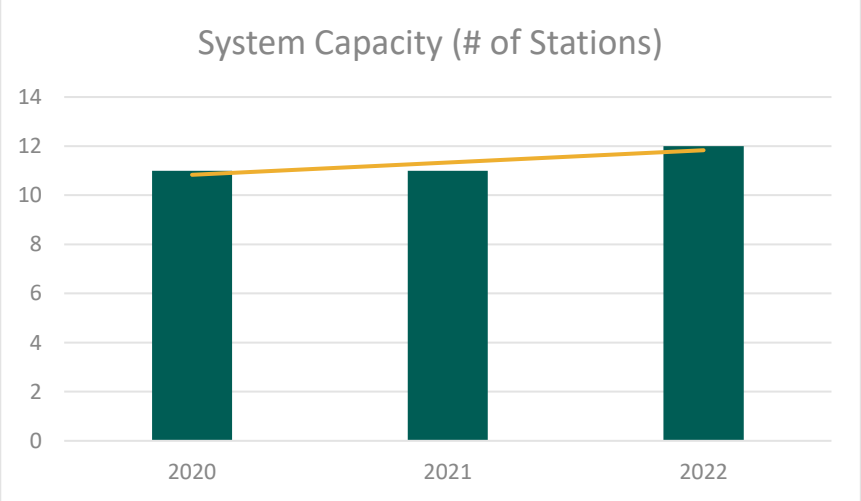

Figure 10: System Capacity Performance from 2020-2022

3.10 System Health (Asset Condition) – Wood Poles

The System Health – Asset Condition (Wood Poles) measure reflects the health of wood poles by tracking the percentage of poles in Health Index ("HI") 4 condition (i.e. "material deterioration"), and in HI5 condition (i.e. "end of serviceable life"). Wood poles are critical assets and serve as an indication of overall distribution system health. This equipment

represents a sizeable portion of the utility's assets and is instrumental in ensuring reliability and safety.

In 2022, the utility refined the asset condition assessment model for wood poles based on its field experience to better reflect specific conditions. With this update, the System Health (Asset Condition) for Wood Poles decreased to 6 percent in 2020 from 11 percent and decreased to 8 percent from 14 percent in 2021. The percentage of asset in HI4/HI5 in 2022 is 9 percent which is a slight deterioration relative to 2020. This decrease is attributed to natural changes in conditions of assets based on the latest inspection information as well as changes in asset population due to system investments to manage deteriorating assets. As explained in Exhibit 2B, Section E4, to balance the execution of the 2020-2024 capital plan with a constrained level of funding relative to the needs and cost of the plan, the utility reprioritized investments and reduced program pacing for the Overhead System Renewal program.[35]

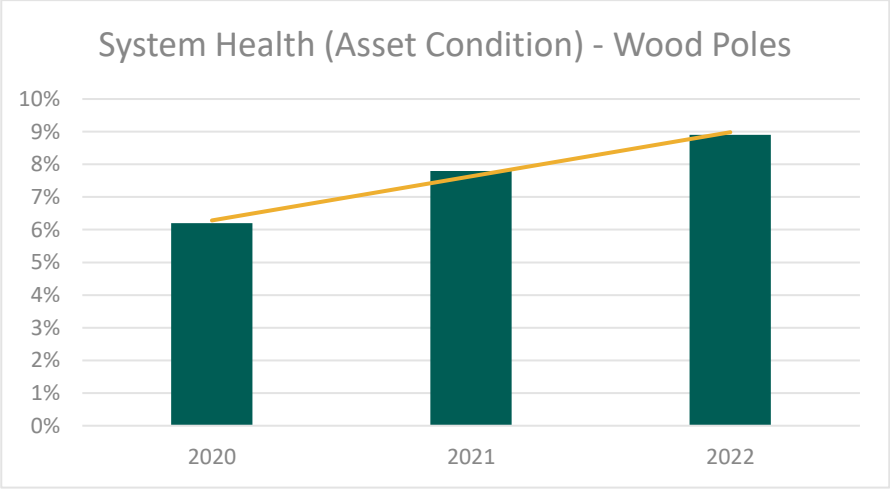

Figure 10: System Health (Asset Condition) – Wood Poles Performance 2020-2022

[35] Exhibit 2B, Section E6.5.

3.11 Direct Buried Cable Replacement

The Direct Buried Cable Replacement measure tracks the number of kilometres of direct buried cable remaining in the distribution system. Customers supplied by feeders containing direct buried cable are more likely to experience lengthy interruptions resulting from increased difficulty in locating and replacing faulty segments. This measure reflects Toronto Hydro's efforts to remove legacy assets from the grid that pose a reliability service risk to customers.

In preparing this evidence, Toronto Hydro identified a data error in the number of kilometers of direct buried cable remaining on the system reported for 2022 actuals. As of the end of 2022, Toronto Hydro has 666 kilometers of cable remaining on the system rather than 679 kilometers. Therefore, for the 2020-2022 period, Toronto Hydro replaced a total of 63 km of direct buried cable, with 666 km of cable still remaining in the system at the end of 2022.

As explained in Exhibit 2B, Section E4, to balance the execution of the 2020-2024 capital plan with a constrained level of funding relative to the needs and cost of the plan, the utility reprioritized investments and reduced the pace of direct buried cables replacement in the Underground System Renewal – Horseshoe.[36]

[36] Exhibit 2B, Section E6.2.

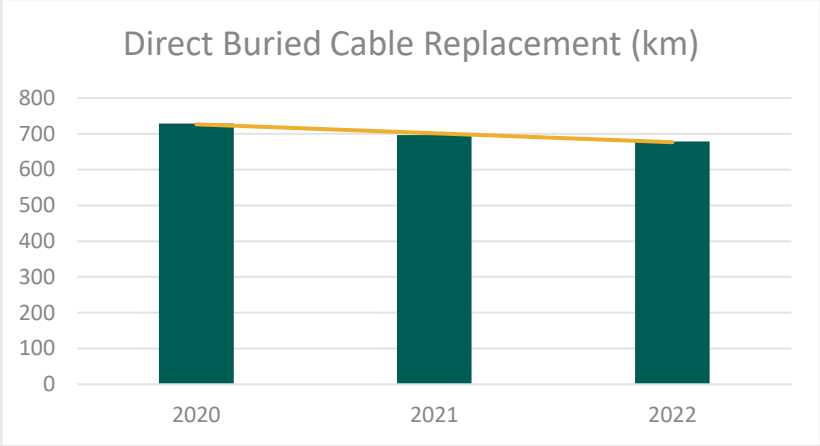

Figure 12: Direct Buried Cable Replacement Performance from 2020-2022

3.12 In-Service Additions (Cumulative)

The In-Service Additions (Cumulative) metric measures the actual cumulative annual in-service additions relative to the total five-year amount approved by the OEB in Toronto Hydro's last major rate application (EB-2018-0165). As of 2022, 56 percent of the total approved amounts were put into service. By the end of 2024, Toronto Hydro expects in-service additions ("ISAs") to be just over 100 percent as outlined in Exhibit 2A, Tab 1, Schedule 1.

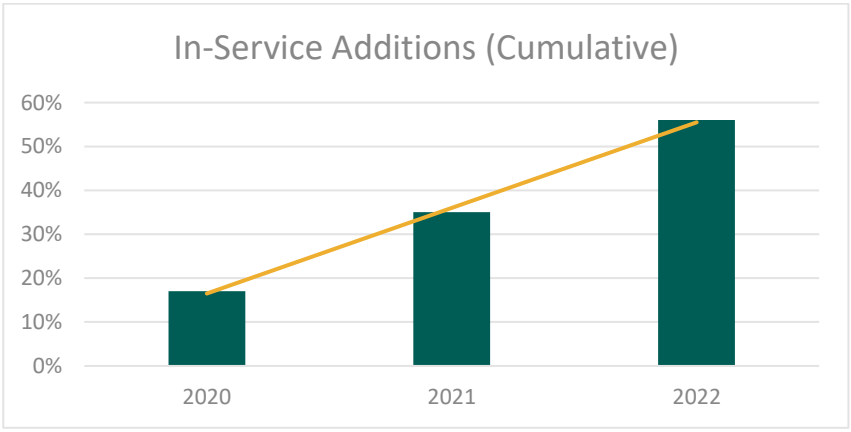

Figure 13: Cumulative In-Service Additions Performance from 2020-2022

3.13 Average Wood Pole Replacement Cost

The Average Wood Pole Replacement Cost measure tracks the unit cost of wooden poles installed in the distribution system using a 3-year weighted average. In 2021, Toronto Hydro refined its unit cost methodology and applied the new methodology retrospectively to ensure year-over-year comparability in the results (i.e. as shown in Figure 14 below). With this approach, the Wood Pole unit cost was $8,101 in 2020, $8,716 in 2021 and $8,317 in 2022. Year-over-year variances are attributed to the mix of programs through which poles are replaced including Area Conversions for both box and rear lot pole configurations, as well as the Overhead System Renewal program. [37,38]

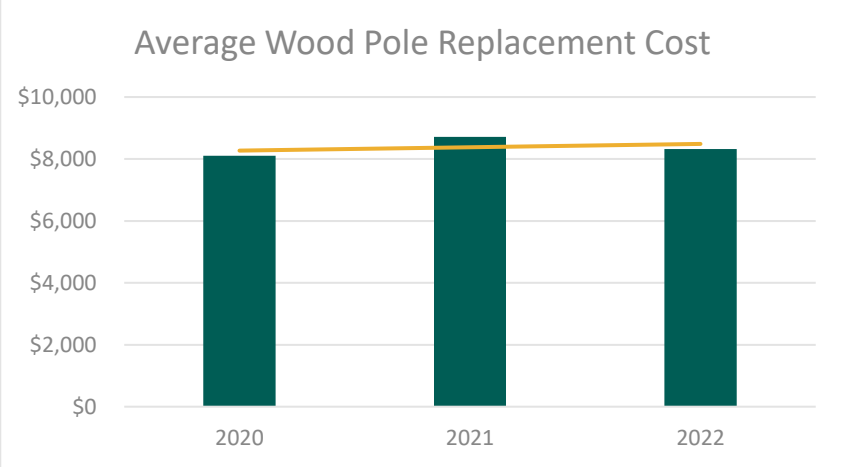

Figure 14: Three-Year Weighted Average Wood Pole Replacement Cost Performance

3.14 Vegetation Management Cost per km

The Vegetation Management Cost per km measure tracks the costs of trimming and clearing of vegetation located near overhead feeders to minimize the risk of power interruptions using a 3-year weighted average. In 2022, the vegetation management cost per km was

[37] Exhibit 2B, Section E6.1.
[38] Exhibit 2B, Section E6.4.

$2,175, which is in line with costs per km in 2020. Toronto Hydro's vegetation management activities are described in Exhibit 4, Tab 2, Schedule 1.

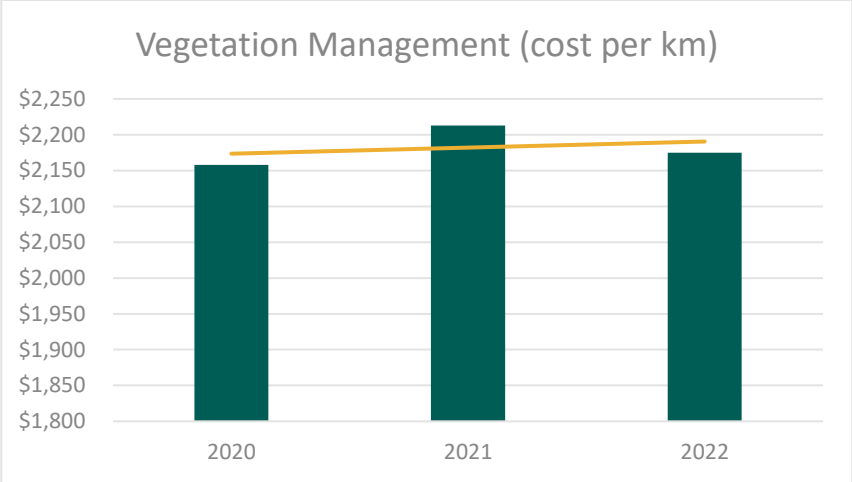

Figure 15: 3-year Weighted Average Vegetation Management Cost Performance

3.15 Oil Spills Containing Polychlorinated Biphenyls ("PCBs")

The Oil Spills Containing Polychlorinated Biphenyls measure tracks the number of oil spills containing PCBs that must be externally reported. Toronto Hydro has various types of transformers (e.g. submersible, pad mounted, vault, pole mounted, network), all of which can potentially contain PCB-contaminated oil. Toronto Hydro reported 1 oil spill containing PCBs in 2022. Toronto Hydro notably reduced the number of PCB spill incidents, from as high as 17 incidents in 2018 to 0 in 2020 and 2021 and 1 incident in 2022.

The decrease in the overall number of PCB spills is attributed to the proactive replacement of transformers at risk of containing PCBs, which was enabled by an improved inspection process put in place in 2018 to identify transformers with the potential to leak (e.g. heavily corroded). These activities mitigate the risk of spills containing PCBs and align with meeting

the December 31, 2025 legislative deadline to remove PCBs with a concentration greater than 50 ppm.

3.16 Waste Diversion Rate

The Waste Diversion Rate measures progress on Toronto Hydro's performance on office and work site waste diverted from landfills. Waste diversion promotes recycling and reusing materials and presents a number of environmental benefits including reducing waste and lowering greenhouse gas emissions. For the period 2020-2022, Toronto Hydro consistently reduced the amount of waste sent to the landfill and increased the amount of waste recycled, achieving its highest waste diversion rate so far of more than 92 percent in the year 2022.

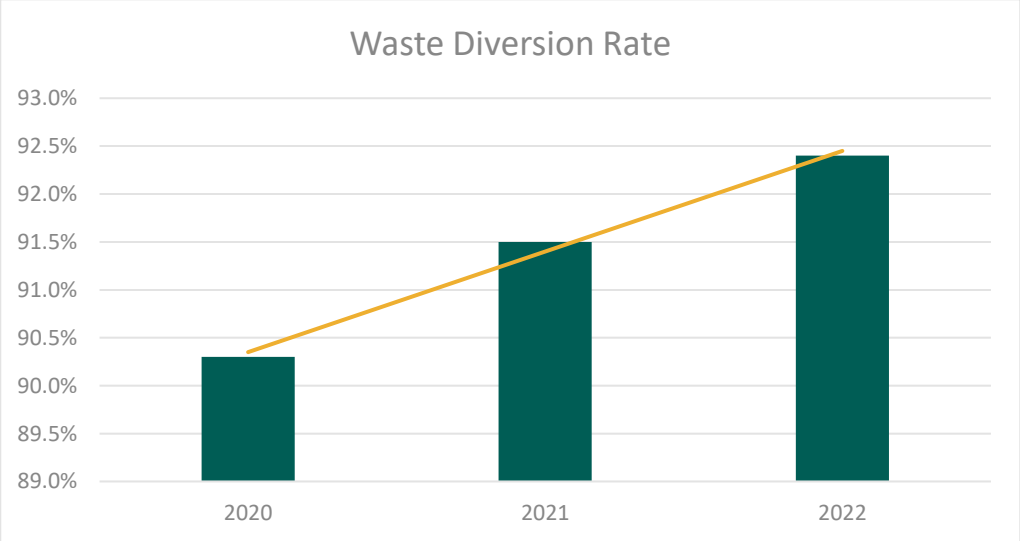

Figure 16: Waste Diversion Rate Performance from 2020-2022

Scorecard - Toronto Hydro-Electric System Limited

8/4/2023

Performance Outcomes	Performance Categories	Measures		2018	2019	2020	2021	2022	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		99.80%	99.74%	99.73%	99.86%	99.89%	up	90.00%	
		Scheduled Appointments Met On Time		99.66%	99.04%	99.85%	99.92%	99.92%	up	90.00%	
		Telephone Calls Answered On Time		80.15%	74.77%	69.89%	76.87%	79.08%	down	65.00%	
	Customer Satisfaction	First Contact Resolution		89%	90%	92%	91%	92%			
		Billing Accuracy		99.25%	99.21%	99.20%	99.00%	99.11%	down	98.00%	
		Customer Satisfaction Survey Results		92%	92%	95%	95%	94%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness		69.00%	70.00%	70.00%	68.00%	68.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	flat		C
		Serious Electrical Incident Index	Number of General Public Incidents	6	7	24	22	29	up		8
			Rate per 10, 100, 1000 km of line	0.209	0.244	0.831	0.758	0.997	up		0.291
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		0.81	0.73	0.90	0.97	0.82	up		0.87
		Average Number of Times that Power to a Customer is Interrupted [2]		1.14	1.09	1.42	1.46	1.39	up		1.20
	Asset Management	Distribution System Plan Implementation Progress		95%	105%	17%	36%	59%			
	Cost Control	Efficiency Assessment		5	5	5	5	5			
		Total Cost per Customer [3]		$1,123	$1,164	$1,159	$1,189	$1,312			
		Total Cost per Km of Line [3]		$30,210	$31,349	$31,120	$32,110	$35,577			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Connection of Renewable Generation**	Renewable Generation Connection Impact Assessments Completed On Time [4]		100.00%	100.00%	100.00%	100.00%				
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	92.31%	91.25%	down	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.53	0.93	0.71	0.95	0.68			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.20	1.15	1.19	1.13	1.17			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.30%	9.30%	8.52%	8.52%	8.52%			
			Achieved	9.33%	8.44%	5.90%	7.08%	7.44%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor 's reported information.
4. Value displayed for 2021 reflects data from the first quarter, as the filing requirement was subsequently removed from the Reporting and Record-keeping Requirements (RRR).

Legend:

5-year trend: up, down, flat

Current year: target met, target not met

Scorecard - Toronto Hydro-Electric System Limited

9/7/2018

Performance Outcomes	Performance Categories	Measures		2013	2014	2015	2016	2017	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		94.20%	91.50%	96.90%	97.70%	98.32%	up	90.00%	
		Scheduled Appointments Met On Time		99.60%	99.80%	99.90%	99.50%	99.37%	down	90.00%	
		Telephone Calls Answered On Time		82.00%	71.90%	76.80%	64.70%	77.92%	down	65.00%	
	Customer Satisfaction	First Contact Resolution		77%	81%	84	86%	88%			
		Billing Accuracy			96.62%	97.54%	98.86%	99.24%	up	98.00%	
		Customer Satisfaction Survey Results			91%	91%	83%	83%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness				71.00%	71.00%	69.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	flat		C
		Serious Electrical Incident Index	Number of General Public Incidents	2	3	0	0	1	down		2
			Rate per 10, 100, 1000 km of line	0.202	0.295	0.000	0.000	0.035	down		0.083
	System Reliability	Average Number of Hours that Power to a Customer is Interruoted [2]		1.11	0.89	0.99	0.91	0.91	down		1.11
		Average Number of Times that Power to a Customer is Interruoted [2]		1.34	1.18	1.31	1.28	1.18	down		1.36
	Asset Management	Distribution System Plan Implementation Progress		105%	147%	100%	113%	99%			
	Cost Control	Efficiency Assessment		5	5	5	5	5			
		Total Cost per Customer [3]		$924	$967	$1,000	$1,044	$1,042			
		Total Cost per Km of Line [3]		$66,793	$70,688	$73,309	$27,819	$27,825			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]				12.51%	34.58%	63.11%			1,556.05 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	97.12%	100.00%	100.00%	81.08%			
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%	92.41%	down	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.80	0.68	0.67	0.61	0.64			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.34	1.65	1.57	1.45	1.34			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.58%	9.58%	9.30%	9.30%	9.30%			
			Achieved	7.10%	7.41%	10.71%	12.18%	9.08%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend:

5-year trend: up, down, flat

Current year: target met, target not met

APPENDIX B: ANNUALLY REPORTED MEASURES

Outcomes	OEB Reporting Category	Electricity Distributor Scorecard Measures	Electricity Service Quality Requirement Measures	2020-2024 Custom Performance Measures[1]
Customer Service	Service Quality	▪ New Residential/Small Business Services Connected on Time ▪ Scheduled Appointments Met on Time ▪ Tel. Calls Answered on Time	▪ Connection of New Services (LV)[2] ▪ Connection of New Services (HV)[3] ▪ Appointments Met ▪ Telephone Accessibility ▪ Appointment Scheduling ▪ Rescheduling a Missed Appt. ▪ Telephone Call Abandon Rate ▪ Emergency Response - Urban ▪ Reconnection Performance Standards	
	Customer Satisfaction	▪ First Contact Resolution ▪ Billing Accuracy ▪ Customer Survey Satisfaction Results	▪ Written Responses to Enquiries	▪ Customers on eBills
Safety	Safety	▪ Level of Public Awareness ▪ Compliance with Ontario Reg. 22/04 ▪ Number of General Public Incidents ▪ Rate per 10, 100, 1000 Km of Line		▪ Total Recorded Injury Frequency ▪ Network Units Modernization

[1] See Exhibit 1B, Tab 3, Schedule 1 for a detailed discussion of Toronto Hydro's 2025-2029 Custom Performance Measures.
[2] Low Voltage ("LV")
[3] High Voltage ("HV")

Outcomes	OEB Reporting Category	Electricity Distributor Scorecard Measures	Electricity Service Quality Requirement Measures	2020-2024 Custom Performance Measures[1]
Reliability	System Reliability	▪ Average Number of Hours that Power to a Customer is Interrupted (SAIDI) ▪ Average Number of Times that Power to a Customer is Interrupted (SAIFI)		▪ SAIDI - Defective Equipment ▪ SAIFI - Defective Equipment ▪ FESI-7 ▪ FESI-6 - Large Customers ▪ MAIFI
	Asset Management	▪ DSP Implementation Progress		▪ System Capacity ▪ System Health (Asset Condition) – Wood Poles ▪ Direct Buried Cable Replacement ▪ In-Service Additions (Cumulative)
Financial	Cost Control	▪ Efficiency Assessment ▪ Total Cost per Customer ▪ Total Cost per Km of Line		▪ Average Wood Pole Replacement Cost ▪ Vegetation Management Cost per Km
	Financial Ratios	▪ Liquidity: Current Ratio ▪ Leverage: Total Debt to Equity Ratio ▪ Regulated ROE - Deemed vs. Achieved		
Public Policy	Connection or Renewable Generation	▪ Renewable Generation Connection Impact Assessments Completed On Time ▪ Micro-embedded Gen. Fac. Connected on Time	▪ Micro-embedded Gen. Fac. Connected on Time	
Environment	Environment			▪ Oil Spills Containing PCBs ▪ Waste Diversion Rate

PRODUCTIVITY

Toronto Hydro strives to provide value for money to its customers through continuous improvements in productivity and performance. The importance of this principle remains paramount even during the upcoming period of change, growth, and development. As noted in the rate framework evidence filed at Exhibit 1B, Tab 2, Schedule 1, Toronto Hydro believes regulatory evolution is necessary to incent productivity and efficiency alongside other outcomes that are important to customers and stakeholders. Therefore, the utility is proposing a custom rate framework that enables this evolution in a manner that is aligned with the principles of performance-based regulation.

Notwithstanding this view and its proposal to evolve the incentives within the rate framework, the utility took note of the OEB's comments in the 2020-2024 Decision, that "Toronto Hydro needs to be more aggressive in its search for increased productivity."[1] The OEB implemented this finding by increasing the stretch factors built into Toronto Hydro's rate framework to a blended rate of approximately 0.82 percent over the rate period, reducing available funding to execute planned work programs to address system and operational needs. The utility challenged itself to deliver the work programs with reduced funding by finding efficiencies where possible and by rebalancing and reprioritizing its plans where productivity gains could not bridge the funding gap.[2]

Beyond taking additional measures to drive productivity as described herein, Toronto Hydro also recognized the need to more clearly articulate its efforts and outcomes in this area of performance and took the steps outlined below to do so. In this narrative Toronto Hydro outlines specific considerations, achievements, and commitments with respect to its past,

[1] EB-2018-0165, Decision and Order (December 19, 2019) at page 29.
[2] Please refer to Exhibit 2B, Section E4.

current, and future productivity efforts to demonstrate to the OEB that the utility has been and remains firmly committed to continuous improvement in efficiency.

- **Urban Distributor:** An overview of the most pressing challenges and costs that Toronto Hydro faces as a unique urban distributor serving Canada's largest and North America's fastest growing city.
- **2020 to 2024 Plan Execution:** An explanation of how the utility managed through unprecedented pressures within the current rate period, most notably the COVID-19 pandemic, significant increases to inflation, upward pressures in customer connections, and unexpected workforce challenges;
- **2020-2024 Productivity:** A detailed account of notable productivity accomplishment over the current rate period. Where the benefits and outcomes of productivity are qualitative in nature, Toronto Hydro made all reasonable efforts to clearly demonstrate improvements to operational effectiveness and value for customers.
- **Benchmarking:** An overview of expert benchmarking studies and key internal benchmarking analyses filed to assist the OEB in evaluating Toronto Hydro's application. In addition, Toronto Hydro discusses the results of the OEB's Activity and Program-Based Benchmarking ("APB") initiative as it relates to the utility's costs.

1. URBAN DISTRIBUTOR

1.1 Density

In Ontario, both Toronto's downtown core and the broader City of Toronto stand apart with respect to population density. The City of Toronto is home to over 3 million people within a land mass of 630 square kilometers, resulting in a population density of over 4,800 people per square kilometer.[3] Toronto's downtown core saw population growth of 16 percent from

[3] City of Toronto, Toronto at a Glance, "online", https://www.toronto.ca/city-government/data-research-maps/toronto-at-a-glance/

2016 to 2021, and is now home to 275,931 people in an area of approximately 16.6 square kilometers, resulting in a population density of 16,608 people per square kilometer. [2,4]

Table 1 shows the population, land mass, and population density of Ontario's ten largest cities by population.

Table 1: Ontario Cities Population Density[5]

Top 10 Largest Cities in Ontario by Population	Population (People)	Land Mass (km^2)	Population Density (People/km)
Toronto	3,025,647	630	4,803
Ottawa	1,071,868	2790	384
Mississauga	771,891	292	2,640
Brampton	745,557	266	2,799
Hamilton	597,010	1,117	534
London	448,051	420	1,066
Markham	352,404	212	1,660
Vaughan	338,891	274	1,239
Kitchener	282,375	137	2,065
Windsor	236,789	146	1,618

Within the downtown core, Toronto Hydro's working environment is unique even within a global context due to an extremely high proportion of high-rise buildings. As seen in the table below, New York City is the only urban centre in the world with more high-rise buildings than Toronto, which is home to nearly one thousand more high-rise buildings than Montreal and Vancouver combined.

[4] Statistics Canada, Canada's Large Urban Centres Continue to Grow and Spread, "online", https://www150.statcan.gc.ca/n1/daily-quotidien/220209/dq220209b-eng.htm; Statistics Canada, Defining Canada's Downtown Neighbourhoods: 2016 Boundaries, "online", https://www150.statcan.gc.ca/n1/en/pub/91f0015m/91f0015m2021001-eng.pdf?st=DqPr0h-x

[5] City Population, Canada: Ontario, "online", https://www.citypopulation.de/en/canada/cities/ontario/

Table 2: International Cities High-Rise Buildings[6]

Rank	City	Country	Highrise Buildings
1	New York City	United States	6,223
2	**Toronto**	**Canada**	**2,598**
3	Seoul	South Korea	2,578
4	Dubai	United Arab Emirates	2,360
5	Hong Kong	China	1,916
6	Tokyo	Japan	1,533
7	Busan	South Korea	1,311
8	Kyiv	Ukraine	1,275
9	Chicago	United States	1,247
10	Shanghai	China	1,236
11	London	United Kingdom	1,146
12	Mexico	Mexico	1,105
13	Incheon	South Korea	1,041
14	Buenos Aires	Argentina	1,037
15	Bangkok	Thailand	964
16	Vancouver	Canada	824
17	Montreal	Canada	810
18	Sao Paulo	Brazil	595
19	Los Angeles	United States	588
20	Moscow	Russia	561

Both population density and the significant number of high-rise buildings have material implications for Toronto Hydro's costs to operate and sustain the grid, and serve customer demand for electricity. More people occupying less space has implications for available rights of way, congestion with other utility providers, traffic congestion and drive times, the size and scale of distribution assets, and disruptions related to large-scale local events.

[6] Highrise building categorized as a multi-floor building at least 12 stories or 35m in height. As per data from SkyscraperPage: https://skyscraperpage.com/cities/#notes

1.2 Customer Base

Beyond density, Toronto's downtown core creates additional requirements on Toronto Hydro as a system operator due to its unique customer make-up. Toronto Hydro customers in the downtown core include, but are not limited to, the following unique customers and customer groups: several hospitals with internationally recognized research and related facilities, the provincial legislature; a major international shipping port, the Toronto Stock Exchange, and, the headquarters of various banks, trading houses, insurance companies, and other critical financial entities.

One effect of this customer make-up is an elevated requirement for reliability and continuity of service to customers whose operations are critical to the sound functioning of the Province and the Country. As such, Toronto Hydro's downtown system is designed and operated with redundancy beyond that typically necessary for an Ontario electricity distributor, which in turn drives additional prudent costs to be incurred for investments and operation.

1.3 Rights of Way & Underground Congestion

As a dense but old City by North American standards, Toronto suffers from a challenging combination of a high volume of local infrastructure, and legacy standards with respect to rights-of-way and general spacing. Toronto's urban core contains major arterial roads, which in a modern planning context are encouraged to be at the top end of the 20-45-meter range.[7] In Toronto's case however, the age of the City results in many major and minor arterial roads having only a 20-meter right-of-way. Similarly, while some of Toronto's newer major roads have the benefit of 3-meter sidewalks, a significant number of legacy 1.2-meter sidewalks remain.

[7] City of Toronto, Road Classification System Summary Document (August 2013) at page 9, "online", https://www.toronto.ca/wp-content/uploads/2018/01/950a-Road-Classification_Summary-Document.pdf

The outcome of smaller rights-of-way in an increasingly dense urban environment is underground congestion, as electricity, natural gas, water, sewer, and communications infrastructure compete for a limited amount of space. Each utility within the right-of-way has standards and clearances, which in turn must be known and respected by other utilities installing or maintaining their own infrastructure within the corridor. This underground congestion ultimately leads to significant incremental planning and coordination, adding time and costs to system maintenance, renewal, or enhancement.

1.4 Municipal Consent Requirements & Road Moratoria

An additional consequence of utility congestion and general urban density is a uniquely involved and thorough set of coordinating, permitting, and approval processes overseen by the City of Toronto. Beyond standard permitting requirements for the location and construction of Toronto Hydro assets themselves, additional permissions for completion of work such as road cuts, lane closures, and pedestrian obstructions require additional time and planning resources.

Beyond the processes themselves, construction in the City of Toronto is dynamic, with frequent instances in which Toronto Hydro is required to advance, delay, or otherwise modify construction plans to accommodate projects overseen by the City, other utilities, or private interests. Road moratoria are a common reality for Toronto Hydro to manage as the City undertakes road or pedestrian refurbishments. At any one point in time, there are thousands of active road moratoria in the City of Toronto, which can range from 5 to 15 years in duration. The result of these road moratoria are requirements, which are not always established well in advance, for Toronto Hydro to re-prioritize projects for early completion, significantly delay projects, or re-organize its resources to complete work in truncated timelines or during specific hours of the day.

The pace of external investment and construction congestion show no signs of easing in the City of Toronto. A breakdown of 2021 infrastructure spending reveals significant investments in city infrastructure, indicative of a growth in future projects which will necessitate the need for municipal consent and planning with respect to road closures. In 2021, transportation infrastructure saw $446 million allocated to bridge repairs, sidewalk upgrades, expressway maintenance, and both major and local roadwork. Water infrastructure garnered over $616 million in expenses, channeled towards projects like water mains, sewers, flood protection, and stormwater management.[8] Water projects, infrastructure developments, and residential construction all require proactive and reactive planning on Toronto Hydro's part, with additional administrative burden applied by approval times which can take up to 34 months.

While some version of the above noted challenges exist for most utilities, the density and complexity of the City of Toronto places unique pressures on Toronto Hydro relative to other electricity distributors in Ontario. The net effect is an increased need for flexibility and adaptability in planning and execution, and in some instances increased costs to execute work under conditions which could not reasonably be anticipated.

1.5 Drive Time

Operating in a dense urban service territory has direct implications for the drive time required for Toronto Hydro technicians and contractors to reach job sites to complete inspections, maintenance, repairs or restoration work. Figure 1 below shows the relative drive time across Toronto Hydro's locations at 500 Commissioners (downtown), 71 Rexdale (Etobicoke) and 715 Milner (Scarborough) locations.

[8] City of Toronto, News Release - Mayor John Tory kicks off more than $1 billion City of Toronto 2021 construction season (March 29, 2021), "online", https://www.toronto.ca/news/mayor-john-tory-kicks-off-more-than-1-billion-city-of-toronto-2021-construction-season/

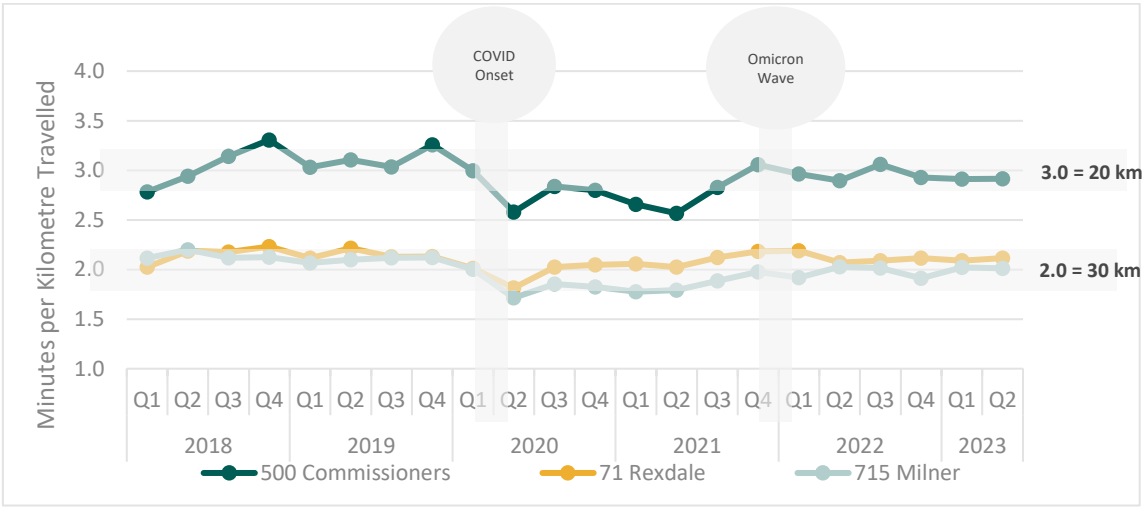

Figure 1: Drive Times Across Toronto Hydro Work Centres

As seen above, drive time for crews operating out of the 500 Commissioners downtown location can be longer by 45 percent or more relative to similar crews operating in less dense areas. Of note, the comparators in this group are not rural or suburban locations, and are themselves urban locations in Etobicoke and Scarborough - highlighting the high levels of congestion inherent to Toronto's downtown core.

Longer drive times increase the amount of time required to complete work, and therefore relative cost of the same work due to extended use of vehicles and labour. Lacking adjustment for this factor, higher drive times inaccurately present an urban utility as less efficient in direct comparison to peers operating in less congested suburban service areas.

In addition to comparing relative drive times, the above figure also demonstrates the impact that COVID-19 had on drive times for crews in Toronto. Notably, the aggressive recovery of drive time at 500 Commissioners in 2021 prior to the Omicron wave in the winter of 2021/2022 indicates that despite some long-term societal changes anticipated to remain post-COVID, lengthy drive times in Toronto's urban core are expected to persist in the future.

As of 2023, drive times in downtown Toronto have stabilized at levels approximating pre-COVID years.

2. 2020 TO 2024 EXECUTION CONSTRAINTS

The following sections addresses three of the most material constraints faced by Toronto Hydro in executing its capital and operational plans over the current rate period.

2.1 Managing the Impacts of COVID-19

Toronto Hydro was deemed an essential service at the onset of the COVID-19 pandemic in March 2020.[9] The pandemic significantly affected normal operating procedures for in-office work and close-contact working conditions in the field. The utility had to rapidly adapt in order to continue reliably distributing electricity to its customers while protecting the safety of its employees, contractors, and the public.

To address these challenges, Toronto Hydro made a Level 2 Emergency Declaration and established an associated Incident Management Team and supporting response infrastructure in March 2020.[10] The utility quickly pivoted to remote and social distancing work for all employees; procured, warehoused, and distributed personal protective equipment to protect working staff; and implemented social distancing rules preventing shared vehicle use so that employees could safely continue to execute their work. These measures increased the utility's fleet mileage and its vehicle utilization.[11]

Toronto Hydro also managed changes to its customer service rules to mitigate the pandemic's financial impacts on its customers.[12] These included reducing the late payment

[9] Ontario Regulation 82.20, section 33.
[10] See Disaster Preparedness Management program at Exhibit 4, Tab 2, Schedule 6.
[11] Exhibit 2B, Section E8.3
[12] Exhibit 4, Tab 2, Schedule 14 at page 27.

charge by 75 percent, waiving the returned cheque charge that is normally collected for payments when customer accounts have insufficient funds, and voluntarily extending its disconnection moratorium for residential and low volume customers. The utility also sent targeted arrears communications to provide its customers with greater payment term flexibility, and promote financial assistance programs.[13] These measures were in effect from March 2020 until July 2022. In 2020, Toronto Hydro recorded an incremental $17.2 million in bad debt expenses as a result of the COVID-19 emergency and related financial pressures.

The pandemic challenged the utility's operations across many areas of the business, including financially. With respect to expenditures, in addition to the incremental bad debt expense noted above, the utility incurred $11.3 million in incremental expenditures from 2020 through 2022 to ensure continued provision of service to customers in a manner which responded to the unique safety needs of the COVID-19 pandemic. With respect to revenues, as of its final COVID-19 reporting to the OEB, Toronto Hydro estimates lost revenues resulting from COVID-19 totalled $45.8 million up to April of 2021.

Social distancing and lockdown measures, in conjunction with a rapidly changing business environment, delayed the implementation of Toronto Hydro's staffing resource plan over the 2020-2021 period.[14] As noted in Exhibit 4, Tab 4, Schedule 3, these measures had a particularly acute impact upon positions requiring specific apprentice-worker ratios and in-person training, such as the Power Line Technician program. In addition, the pandemic gave rise to a spike in retirements in 2020 and 2021 that were expected to occur gradually over the rate period. The combined effect of these pandemic-driven changes to the workforce

[13] LEAP, OESP, the COVID-19 Energy Assistance Program ("CEAP") and COVID-19 Energy Assistance Program for Small Business ("CEAP-SB"), and the Canada Emergency Response Benefit ("CERB").
[14] Exhibit 4, Tab 4, Schedule 3 at pages 19-20.

plan, Toronto Hydro's compensation costs and associated headcount declined to a historically low point of 1,203 FTEs in 2021.

In addition to impacts on the utility's staffing plans, the COVID-19 pandemic disrupted manufacturing capacity and transportation networks, resulting in supply chain challenges that affected Toronto Hydro's capacity to procure materials and equipment in a timely and cost-effective manner.[15] These challenges added another layer of complexity of the capital planning and management process and put upwards pressure on the costs of materials due to higher raw material and labour costs. For example, the cost of padmount transformers increased by approximately 45 to 168 percent (depending on the transformer size) between 2020 and 2022.[16] The utility continues to manage these challenges by updating contract lead times, by reviewing alternative sources of supply for products, and by negotiating forward buys and price increases with suppliers for major components and materials.

2.2 Managing the Impact of Extraordinary Inflation

Over the course of second and third quarters of 2021, COVID-19 vaccines became widely available to the Canadian population, and over the course of late 2021 and 2022, public health measures were gradually relaxed. Though many ongoing COVID-related costs persisted, the passage of time allowed for greater opportunities to accommodate such costs in the course of business planning. Unfortunately, in the second half of 2021, inflation in Canada began to accelerate, and by mid-2022, inflation had reached the highest levels seen in 40 years.[17] Construction cost increases in Toronto were more pronounced than in other urban centers across Canada. From the first quarter of 2020 to the second quarter of 2023, the Non-Residential Buildings Construction Index applicable to the Toronto Census

[15] Exhibit 4, Tab 2, Schedule 13.
[16] For more information, refer to Exhibit 2B, Section D2.1.3.
[17] Statistics Canada, Consumer Price Index: Annual review, 2022, "online", https://www150.statcan.gc.ca/n1/daily-quotidien/230117/dq230117b-eng.htm

Metropolitan Area ("CMA") rose 37.7 percent, well outpacing the already high increase of 28.6 percent in the same metric across a composite of 11 Canadian CMA's, as shown in Table 3.

Table 3: Non-Residential Buildings Construction Index for Metropolitan Areas[18]

		Toronto		Canada 11 Census Metropolitan Area Composite	
		Qtr to Qtr	Cumulative	Qtr to Qtr	Cumulative
2020	Q1	0.0%	0.0%	0.0%	0.0%
2020	Q2	0.5%	0.5%	0.1%	0.1%
2020	Q3	0.7%	1.2%	0.5%	0.6%
2020	Q4	0.2%	1.4%	0.1%	0.6%
2021	Q1	1.9%	3.3%	1.4%	2.0%
2021	Q2	5.0%	8.4%	3.9%	6.0%
2021	Q3	4.3%	13.0%	2.9%	9.0%
2021	Q4	3.4%	16.9%	2.9%	12.1%
2022	Q1	3.8%	21.3%	3.0%	15.5%
2022	Q2	5.0%	27.4%	4.0%	20.1%
2022	Q3	2.6%	30.7%	2.1%	22.6%
2022	Q4	2.5%	33.9%	1.6%	24.6%
2023	Q1	1.7%	36.2%	1.7%	26.7%
2023	**Q2**	**1.1%**	**37.7%**	**1.5%**	**28.6%**

In contrast, the OEB inflation-factor parameters for electricity distributors were 2.2, 3.3, 3.7, and 4.8 percent over the 2021 to 2024 period resulting in a compound increase of 14.73 percent. What's more is that while the Custom Price Cap Index allowed for annual inflationary adjustments to non-capital-related revenue requirement (less the stretch factor), no such inflationary adjustments were available for capital-related revenue requirement. The net result is that as inflation pressures surged to 40-year highs in 2022,

[18] Statistics Canada, Table 18-10-0276-01 Building construction price indexes, by type of building and division, "online", https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810027601

the inflation assumption underpinning Toronto Hydro's capital expenditure envelope remained static at 2 percent less the impact of capital stretch factor of 0.9 percent.

With significant increases in input prices and limited increases in revenue over the current rate period, Toronto Hydro took necessary steps to manage the financial impacts and adapt its plans to balance these constraints and still deliver key objectives. For example, the utility negotiated a proposed price increase for network protectors and protection accessories, driven by material increases in raw material costs, that was approximately 43 percent lower than the supplier's originally requested increase.[19]

In addition to managing input prices, Toronto Hydro slowed down the pace of work in the Underground Downtown, Underground Horseshoe, and Overheard Renewal programs by approximately 22 percent leading to a $189 million reduction compared to forecasted budgets for these programs in the 2020-2024 rate application. The utility reprioritized its work by conducting greater volumes of targeted replacements directed towards the highest risks on the system, including the removal of at-risk PCB transformers and the conversion of legacy box construction equipment. In other aspects of its work plan, such as the demand-driven Customer Connections and Load Demand programs, the utility had no choice but to spend more than forecasted to maintain its obligation to connect and serve customers. For example, in Customer Connections the utility managed a spike in the budget of approximately $147 million (71 percent) compared to 2020 plan budgets.[20]

[19] *Supra* Note 15
[20] For more information about the execution of the 2020-2024 capital plan please refer to Exhibit 2B, Section E4.

2.3 Workforce Challenges

Over the 2020-2024 rate term, Toronto Hydro successfully managed a series of workforce challenges both related to broader shifts in the Toronto-area labour market and Toronto Hydro-specific issues. Workforce challenges encountered during this time include:[21]

- **Retirements:** Toronto Hydro is in the midst of renewing its workforce and developing new entrants. Over the rate period to-date, Toronto Hydro steered a 7 percent reduction in the average age of its employees, which now averages 40 years of age. The utility also filled over 100 trades and technical positions, with another 100 positions forecast to be filled by the end of 2024.
- **Recruiting:** The COVID-19 pandemic temporarily suspended talent acquisition, training, and development for critical areas and skill sets established during the previous rate period. To manage these challenges, Toronto Hydro implemented a system to facilitate remote and hybrid work and a comprehensive infectious disease response plan to address increased safety risks. Coming out of the pandemic, the utility successfully increased the pace of its recruitment to return its staffing levels to pre-pandemic levels and increase resourcing capacity for the next rate period.
- **Changing Labour Market:** The Toronto area experienced increasing competition and strong demand for workers in a digital economy over the 2020-2024 rate period, with notable shortages of workers trained in science, technology, engineering and mathematics ("STEM").[22] Toronto Hydro managed these challenges by pivoting to hybrid work model in line with employee preferences.

Despite the challenges noted above, Toronto Hydro achieved notable workforce successes over the course of 2018 through 2022, including:

[21] Exhibit 4, Tab 4, Schedules 1 and 3.
[22] Mahboubi, Parisa. 2022. The Knowledge Gap: Canada Faces a Shortage in Digital and STEM Skills. Commentary 626. Toronto: C.D. Howe Institute, "online", https://www.cdhowe.org/sites/default/files/2022-08/Commentary_626_0.pdf

- Total recordable injury frequency improved by 43 percent;
- Absenteeism decreased by 1.9 percent;
- Consistently ranked as one of the Best Corporate Citizens in Canada by Corporate Knights placing as high as 2nd overall and 1st in the category of Electricity Transmission and Distribution; and
- Received multiple awards from Electricity Canada, including recognition for Leadership in External Collaboration and Partnerships, CEA President's Award of Excellence for Employee Safety – Distribution, 2021 Centre of Excellence for two innovation projects, and the 2022 Canadian Occupational Safety Magazine 5-Star Energy and Resource Company award.
- Toronto Hydro was recognized as a sustainability leader by Canada's 2024 Clean50, in addition to earning a spot on Canada's Clean16 list as a top contributor in the category of Traditional Energy.

3. 2020 TO 2024 PRODUCTIVITY ACHIEVEMENTS

The following section presents an overview of notable productivity improvements over the course of the 2020 to 2024 rate period. These achievements are incremental to:

- more than $2.2 billion of savings generated by the utility – through activities such as improved asset management, efficient material handling and workforce optimization – since Toronto Hydro was created in 1999 through the amalgamation of the six utilities that served former municipalities which now make-up the city of Toronto.
- A facilities consolidation strategy that reduced the square footage per employee by approximately 40 percent and is expected to return more than $200 million to customers by the end of this decade.

Responsive to the OEB's feedback in the 2020 rate application, and continuing on its journey of continuous improvement in efficiency, Toronto Hydro enhanced its efforts in capturing

the productivity benefits achieved across the organization. In total, over the current rate period the utility implemented over 30 distinct productivity initiatives which yield material benefits for ratepayers. These benefits include over $23 million in costs that the utility expects to avoid or reduce by the end of the rate term, resulting in a 2025 rebasing revenue requirement that is approximately $5.7 million lower than it otherwise would be if Toronto Hydro had not undertaken these initiatives.

The initiatives are summarized below, organized as follows: 1) Corporate Projects; 2) Divisional & Departmental Initiatives; and 3) Additional Productivity Initiatives. Though reduced or avoided costs cannot accurately be calculated for all initiatives, the combined effect of the projects and processes set out below demonstrate the utility's ongoing commitment to become more efficient and productive in its operations.

3.1 Corporate Projects

The following corporate projects are among the larger productivity initiatives undertaken by Toronto Hydro over the 2020 to 2024 rate period, and are expected to continue to yield operational and productivity benefits into the future.

3.1.1 *Enterprise Resource Planning ("ERP"), Enterprise Connect, and People Connect*

The purpose of Toronto Hydro's ERP Implementation is to replace the former Ellipse, as well as more than thirty other legacy systems, to ensure ongoing effective support of applications and databases, avoid significant increases in systems maintenance costs and deterioration of systems' operational performance, ensure a secure, safe, reliable and efficient operation of Toronto Hydro's core business functions, and generate cash and productivity benefits across all of Toronto Hydro's divisions. This initiative had a go-live date shortly before the current rate period, and is forecast to reduce operational expenditures by $5.93 million from 2020 to 2024, while also avoiding operating costs of $4.64 million over the same time period.

Qualitatively, this initiative yields: (i) improved restoration planning and customer communication; (ii) higher systems reliability and stability with secured service support; (iii) improvement in system availability, increasing productive time for managers and staff; (iv) better business processes supported by increased system functionality and improved operational performance of information technology assets; and, (v) increased security and quality of data through decommissioning of multiple, unsupported legacy systems and implementing a supported ERP system with a central database and robust user-access controls.

3.1.2 *e-Tailboard*

Tailboards are used by Toronto Hydro employees to perform risk assessments before beginning planned, reactive, or responsive work in the field. A tailboard is an important document to reduce the risk of incidents by helping employees develop a safe work plan to identify job steps, hazards, and barriers associated with non-routine work. The e-Tailboard project transitioned tailboards to a digital format, yielding both financial and qualitative benefits. The e-Tailboard project is forecast to yield cost avoidance benefits of $2.28 million and cost reductions of $17,339 during the 2020 to 2024 rate period. Qualitative benefits of this initiative include: (i) ability to leverage existing IT assets by completing tailboards using existing Toughbooks and iOS devices; (ii) improved auditing and record management capability; (iii) improved user experience for field crews with quick access to all relevant safety-related information at the work site; (iv) reduced paper and printing supplies; and, (v) electronic tailboards contributed to a decrease in injuries. Recordable injury performance has improved by 16 percent in the year following the introduction of the electronic tailboard and the utility has not had any critical or fatal injury since the electronic tailboard was launched.

3.1.3 *Streetlighting Management System Project*

The purpose of this project was to implement a new Streetlight Work Management Solution to replace the existing legacy Work Activity Log ("WAL") system which had reached end of life. This initiative had a go-live date of November 2021, and is forecast to yield cost avoidance of $1.98 million from 2022 to 2024. Further, the project is expected to provide the following qualitative benefits: (i) enhanced mobile capabilities to view, manage, and dispatch outage tickets efficiently; (ii) dashboarding capabilities to view all details of outages with the ability to zoom into individual outages, as well as analysis and reporting capabilities; and, (iii) an enhanced customer experience by allowing customers to submit an outage in real time, and be able to view outages that are already reported.

3.1.4 *Non-conformance Reporting*

The Non-Conformance Reporting ("NCR") system tracks and records inspection results. Implementation of the cloud-based Intelex Quality Management module from the Intelex suite of applications allows Toronto Hydro to automate and streamline Quality and Compliance processes, including processes for new materials received in the warehouse, failed equipment return processes, normal return inspection processes, and reporting. This project had a go-live date of February 2022, and is forecast to avoid costs of $1.26 million from 2022 through 2024.

3.1.5 *Electronic Red Construction Folder*

The corrective and reactive maintenance management process, known as Red Construction Folder ("RCF"), was digitized using an OpenText solution under a phase 1 project. While phase 1 of the project focused only on activities performed by office staff, phase 2 is addresses the field crew and contractor portions of the process. This initiative had a go-live date of January 2022, and is expected to yield $773,110 in avoided costs and $125,271 in cost reductions over the 2020 to 2024 rate term. Qualitative benefits of this initiative are

expected to include: (i) increased efficiency in searching and retrieving electronic documents; (ii) better compliance with Record Management policy; and, (iii) the ability to attach important supporting documents to the case records.

3.1.6 *Accounts Payable Processing Automation*

The purpose of this project was to provide the Accounts Payable team with an automated solution for the entire invoice process; from receiving, to resolving, to paying and closing invoices, with benefits in IT enablement and controls improvement. This initiative was launched in December of 2020, and is forecast to result in $699,925 in cost reduction from 2020 to 2024. Qualitatively, this initiative enables the reallocation of accounts payable team's time to other more value-added tasks, through reduced burdens in areas such as: (i) time to respond to invoices with problems; (ii) partial elimination of manual processes to troubleshoot invoices with problems; (iii) time to mobilize stakeholders to fix problems on invoices; and, (iv) time to create reports. It also improves analytics leading to better data tracking, fostering better support to decision making, and better records management by storing all data in a centralized system.

3.1.7 *Storm Prediction Impact Tool*

In March of 2021, Toronto Hydro procured an IBM weather dashboard tool to support operational disaster response decision making. The service includes weather forecasts, predictions for number of incidents Toronto Hydro may experience, and meteorologist consultation on demand. This project showed benefits in reliability and controls improvement (i.e. better decision making with corresponding effectiveness and efficiency) as well as data quality improvements. This new tool is forecast to result in over $64,000 in cost reduction from 2020 through 2024. Qualitatively, this initiative is expected to yield the following benefits:

- **Reliability and controls improvements**, including: (i) quantifying the damage and impacts on the distribution system based on forecasted weather conditions, allowing the Emergency Management Team to assess the type and quantity of resources required commensurate to the storm event; (ii) an adaptive model that will increase in accuracy over the coming years as more data points are uploaded in the machine learning algorithms; and (iii) improved accuracy in weather forecasts and predictive modeling for impacts resulting in better decision-making.
- **Data quality improvements**, including: (i) longer forecasts for up to 14 days, improving storm event pre-staging; (ii) ability to make better resourcing decision in advance; better coordination of resources with other utility partners, ensuring resources are available on short notice.
- **Improved customer trust** as a result of improved quality of response and restoration, especially during nights, weekends, and statutory holidays.
- **Single point access**, in that the system provides the ability to access the majority of the required information from one source instead of having to check multiple services and tools for the same information. This functionality has wide ranging efficiency and effectiveness benefits.

3.1.8 *SAP Business Warehouse Project*

This initiative was launched in November of 2020, and is forecast to result in $146,363 in cost avoidance from 2020 through 2024. Qualitatively, this initiative is expected to improve effectiveness, efficiency, and data quality control across numerous functions including, capital and operating portfolio management; accounts payable; accounts receivable; tax, OEB, and financial reporting; labour recoveries; and, forecasting.

3.2 Divisional & Departmental Productivity Initiatives

The following projects were brought forth by Toronto Hydro divisional and departmental leaders as a means to manage costs through productivity gains over the 2020 to 2024 rate period.

Table 4: Summary of Divisional and Departmental Productivity Initiatives

Initiative	Description	Cost Reduction ($000)	Cost Avoidance ($000)
Find It Fix It Program	Enable maintenance crews to perform minor corrective work immediately as part of inspection programs, reducing the time and cost impact of having to send a second crew to perform minor corrective repairs.	N/A	$2,953.1
Regulatory Intelligence Subscription Service	Tracks, analyzes, and reports on applications and proceedings before the OEB on a weekly basis, including rate applications, policy proceedings, and compliance matters. Provide access to low-cost regulatory research services on in-depth issues.	N/A	$396.0
Porcelain Insulator Replacement Initiative	Eliminate on-going need of the Reactive Insulator Washing program by replacing all porcelain insulators at high risk or in contamination areas. City salting operations were studied to determine high-risk areas.	N/A	$200.0
Equipment Failure Analysis Dashboard	Alteryx workflow to collect data related to an equipment failure and display it in a Tableau dashboard reducing time to complete equipment failure investigations.	N/A	$36.7
Standardized Outage Tracking Process	Standardized gated outage process tracking process.	$20.0	$35.0
Online Training	Transition from in-person to online training programs.	$589.6	N/A

Initiative	Description	Cost Reduction ($000)	Cost Avoidance ($000)
RISE 360	Implementation of RISE 360 software for online training program development.	$90.0	N/A
Classroom Maximization	Made more efficient use of underutilized work areas and created larger learning spaces to implement additional COVID precautions.	$69.4	N/A
CenarioVR	Development savings by keeping all design and development of scenarios in house with Toronto Hydro design consultants.	$37.3	N/A
Change Order Billing Process	Standardize process for claiming work done under change orders on monthly billing sheets.	$29.1	N/A

3.3 Additional Productivity Initiatives

Toronto Hydro's pursuit of continuous improvement in productivity and efficiency extends across its operations, as highlighted in the programmatic evidence references below. These examples showcase sustained efficiency improvements which combined with the initiatives above have the net effect of enhancing Toronto Hydro's ability to provide safe, reliable, and efficient service to its customers.

3.3.1 *Fleet and Equipment*

Table 5: Summary of Fleet and Equipment Productivity Initiatives

Initiative	Description
Elimination of Under-Utilized Vehicles	Toronto Hydro optimizes its fleet size on an ongoing basis. On average, each vehicle removed from the fleet reduces operating costs by $2,000-$7,000 per year. Since 2017, Toronto Hydro's fleet size has decreased by 132 vehicles (a net 22 percent reduction). Over the past two rate periods, the utility eliminated costly and specialized vehicles and equipment that were expensive to repair where the relevant services could be obtained through outsourcing (e.g. cable trucks, forestry units).

Initiative	Description
Fuel Consumption Reduction	Toronto Hydro achieved an average annual reduction in fuel needs (estimated to be approximately 20,000 litres per year) as a result of replacing internal combustion engine vehicles with hybrid and fully electric vehicles, in accordance with Toronto Hydro's Decarbonization Strategy discussed in Exhibit 2B, Section D6 and the Fleet and Equipment Services Program in Exhibit 2B, Section E8.3. This contributes to lower fuel costs.
Driver Safety Reporting	Toronto Hydro leveraged driver safety reporting regarding speeding, harsh braking, and reversing from parked position to influence improvement in driver safety behaviour, and help minimize safety incidents and repair costs. From 2020 to 2022 the number of speeding infractions decreased by approximately 93 percent.
Optimization of Vehicle Services	In 2020, Toronto Hydro eliminated costs attributed to truck-to-truck fuelling services and selected a more cost-competitive mobile wash vendor, which collectively resulted in an annual savings of approximately $250,000.
Repair Avoidance	Toronto Hydro is running a 10-year corrosion prevention pilot project with 18 pickup trucks that were put into service in 2020. The goal of this project is to determine the best form of corrosion protection to minimize repair and replacement costs by extending the life of the vehicles. The pilot includes testing three forms of protection on six vehicles each, with the aim to increase the effective useful loves of vehicles in the fleet, as corrosion to critical components of units are one of the primary factors leading to vehicle replacements.

3.3.2 *Asset and Program Management*

Table 6: Summary of Asset and Program Management Productivity Initiatives

Initiative	Description
Asset Deficiency Assessment Priority Tool	In 2021, Toronto Hydro implemented a new tool, Asset Deficiency Assessment Priority Tool ("ADAPT"), resulting in a significant reduction in manual engineering reviews. Specifically, between 2020 and 2021, manual engineering reviews for major assets decreased by 40 percent and escalations by crews were reduced by 25 percent.

Initiative	Description
Alteryx Data Processing	During the 2020 to 2022 period, a number of workflows were developed using Alteryx data processing to automate complex data analytics tasks. In one example, the Preventative Maintenance Units Tracking workflow, developed in 2022, translates Plant Maintenance order status from SAP to maintenance unit attainments. This workflow resulted in approximately 300 hours of time saved per year. Overall, the total recorded 69 workflows within the Program Management and Support segment are estimated to have saved approximately $420,000 per year.
Weekly Switching Work Plan	The Weekly Switching Work Plan ensures optimal feeder switching to deliver the planned Capital and Maintenance program. Toronto Hydro uses bundling to reduce the number of times a feeder is removed from service, leading to savings on switching costs, reduced risk of not completing capital and maintenance programs on time, reduced exposure to high-voltage equipment and improved customer reliability. From 2019 to 2022, approximately 2,606 switching hours per year were saved through bundling of outages

3.3.3 *Control Centre*

Table 6: Summary of Control Centre Productivity Initiatives

Initiative	Description
Hold-Offs	Each hold-off requires a power system controller to research the work location, prepare documentation, apply a condition to the circuit breaker, and verbally issue the hold-off to the requestor. Toronto Hydro issues over 21,500 hold-offs each year, most of which are requested between 6:30 am and 9:00 am on weekdays. Toronto Hydro implemented a planned hold-off process whereby requests are researched and prepared a day in advance. This has resulted in an average transaction time of approximately 3 minutes per hold-off, down from approximately 29 minutes in 2014, which allows crews to spend less time waiting for hold-offs to be issued and more time on their responsibilities in the field.

Initiative	Description
Switching Orders	Most planned distribution system work requires power system controllers to prepare and check multiple switching orders, also referred to as PC17A forms. These documents prescribe the steps necessary to eliminate and/or control electrical hazards in the field. An individual PC17A can be anywhere from 1 step to over 100 steps, depending on the complexity of the distribution system. In 2021, Toronto Hydro issued almost 7,500 PC17A forms to field stakeholders, accounting for a total of nearly 185,000 individual switching steps. In order to schedule and execute field work efficiently, field crews need to have their switching documentation issued prior to the planned start of their work. Control Centre managers monitor PC17A production relative to work volume and allocate resources accordingly. In 2022, 80 percent of PC17As were issued two or more days in advance of the requested work start date, helping to ensure that field crews can start their work on time.
Call Queuing	Toronto Hydro harmonized the primary mode of communication between the field and the Control Centre by establishing the phone system as the primary method, and implementing phone queuing software which provides managers and power system controllers real-time visibility of crew wait times. This insight enables managers to dynamically allocate resources based on need, reducing wait times for field crews. The phone queuing system also provides historical data with respect to call volumes and wait times, enabling performance reporting and process optimization. In 2021, over 94 percent of calls had a wait time of less than 10 minutes.
Automated Model Build	This initiative provides the ability to automatically extract distribution system changes and implement them into the Network Management System ("NMS"), reducing record update latency and the amount of effort required to maintain the NMS network model.
Work Request Tool	Implementation of a single software tool to manage all operational work requests with integration to core systems. This project will result in the retirement of several legacy databases and platforms, and enable efficiencies in scheduling and administering distribution system work requests (work protection, planned outages, hold-offs, design review, etc.).
Digitization	In 2020, the Control Centre completed the digitization of virtually all paper-based processes in the Control Centre. This initiative enhanced business continuity and ensured that critical operational information is readily available to all power system controllers and managers in real time.

3.3.4 *Supply Chain*

Table 7: Summary of Supply Chain Productivity Initiatives

Initiative	Description
Third-Party Procurement	Toronto Hydro uses a Third-Party Procurement ("3PP") provider to complement internal resources and improve productivity, reducing overhead per purchase order, increasing cost certainty, and improving operational flexibility. As 3PP staff have effectively integrated into Toronto Hydro' processes over time, Toronto Hydro has leveraged 3PP staff for additional areas including coordination of equipment repair, recertification of suppliers, acting as liaison between suppliers and quality assurance engineers, providing insight into material cost forecasts, and other areas. By complementing the core Demand and Acquisition Services team, the engagement of the 3PP provider has resulted in a 64 percent reduction in median business days between contract award to fully published state, and a 46 percent reduction in purchase requisition to purchase order conversion days.
Major Asset Equipment Reuse	Major assets such as transformers that were used for temporary connections or capital upgrades go through Toronto Hydro's Major Asset Equipment Reuse Program when they are returned from the field. Engineers from the Quality and Compliance team inspect each unit carefully, and if the unit is deemed fit for reuse, it is returned to stock and issued out to the next capital project. If the unit can be repaired, it is sent back to the manufacturer if it is under warranty, or sent to a third-party repair and recertification supplier for a small fee. By reusing and recertifying the major assets, Toronto Hydro is able to reduce the amount of waste generated and reduce the lead time and costs associated with purchasing a new unit.
Warehouse & Inventory Optimization	Where materials and equipment at the end of their useful lives are replaced with alternatives built to newer technical standards, Toronto Hydro ensures that the existing stock of the obsolete parts are used up first to minimize residual inventory. In certain cases, Toronto Hydro may also return remaining quantities of the obsolete equipment to the supplier, or sell them for scrap. This approach ensures that warehouse storage space is used efficiently without impeding the adoption of new technologies or types of equipment.

3.3.5 *Facilities*

Table 8: Summary of Facilities Productivity Initiatives

Initiative	Description
Building Efficiency Optimization	Toronto Hydro leverages parametric data it receives through its membership in industry associations such as the Building Owners and Managers Association ("BOMA") to improve the utility's operating efficiency. For example, Toronto Hydro studies data from the regional BOMA Experience Exchange Reports ("EER") measuring the cost per square-foot of key facilities management functions against other peer utilities and benchmarking data retrieved from the Energy Star Portfolio Manager. The utility uses this information to measure and track its energy and water consumption against other commercial and institutional buildings, analyze its performance, and make recommendations for improvements to areas such as energy and utilities conservation.
Facilities Maintenance Optimization	Toronto Hydro uses a computerized maintenance management system ("CMMS") that manages, tracks, and schedules maintenance work. The CMMS, in conjunction with departmental performance measures such as the On-Time in Full ("OTIF") metric that steers the completion criteria for tenant requests, enables Toronto Hydro to maximize the effectiveness of its maintenance resource dispatching strategy. The CMMS provides users with a range of functions that display new, existing, and historical work orders for repair, maintenance, cleaning, and external grounds segments and for each work centre, and track the resources allocated to a given activity or segment.

4. BENCHMARKING STUDIES

This application and the investment plan that underpins it has been informed by extensive benchmarking to assess the utility's performance and proposals relative to a range of peers across various jurisdictions, industries and operational areas. Consistent with the Rate Handbook, the utility is filing a number of expert benchmarking studies, along with key internal benchmarking analyses to assist the OEB in evaluating Toronto Hydro's application. This section briefly summarizes each of the benchmarking analyses that are being filed in this application.

4.1 Total Cost Benchmarking ("TCB")

At Exhibit 1B, Tab 3, Schedule 1, Appendix A Toronto Hydro filed a custom Total Cost and Reliability Benchmarking study prepared by Clearspring Energy Advisors, LLC ("Clearspring") under the leadership of expert Mr. Steve A. Fenrick. Mr. Fenrick and Clearspring have significant experience preparing benchmarking studies throughout North America, including studies that informed Toronto Hydro's 2015 and 2020 custom rate applications, as well as the custom rate applications of other large distributors in the province of Ontario.

In the utility's last rate application (EB-2018-0165) an area of notable exploration with respect to the total cost performance was the 'urban core variable' and its value within the context of benchmarking. The econometric experts recognized the statistical significance of an urban core variable in benchmarking Toronto Hydro costs, and the OEB Panel also commented in its Decision and Order that a well-constructed urban variable may be appropriate for Toronto Hydro. [23,24] While there was general recognition in the last application that costs within a dense urban core are different than those experienced in other settings, the complexity of quantification was the subject of discussion, which led the OEB to comment in its decision on how a future custom total cost benchmarking study might be improved. To that end, Toronto Hydro asked Clearspring to refine and further enhance the data relied upon to determine the urban core variable for total cost benchmarking purpose.

Having done that work, in addition to other enhancements that have been recognized as appropriate in major rate applications filed since EB-2018-0165 (particularly Hydro One's 2023-2027 rate application), the Total Cost Benchmarking Study found that Toronto Hydro's costs from 2020 through 2022 were 28 percent below the predicted benchmark, while costs

[23] EB-2018-0165, OH Volume 10 (July 15, 2019) at page 19, lines 10-19.
[24] EB-2018-0165, Decision and Order (December 19, 2019) at page 29.

over the 2025 to 2029 rate term are forecast to be 22.9 percent below the predicted benchmark.

4.2 Reliability Benchmarking

In the same study as noted in 3.1, Clearspring benchmarked Toronto Hydro's system average interruption frequency index ("SAIFI") and customer average interruption duration index ("CAIDI"). The study found Toronto Hydro's 2020-2022 actual SAIFI to be 98.8 percent above the benchmark and its CAIDI to be 104.1 percent below benchmark. Considering these two results together, Clearspring also concluded that Toronto Hydro's system average interruptions duration index ("SAIDI") is 5.3 percent better than the predicted benchmark.

4.3 Enterprise Information Technology Cost Benchmark and Functional Maturity Assessment Study

At Exhibit 2B, Section D8, Appendix A, Toronto Hydro filed an Enterprise Information Technology Cost Benchmark and Functional Maturity Assessment study completed by Gartner Inc. ("Gartner"). This study compares Toronto Hydro's IT costs over time and against a relevant international peer group of electric utility companies. The Gartner study concludes that Toronto Hydro's IT costs benchmark competitively relative to its peers, with the distribution of IT investments by cost category, investment category, and functional area all being comparable to the peer group.

The study also assessed and compared Toronto Hydro's IT maturity across seven domains (Application Development, Data & Analytics, Enterprise Architecture, CIO (IT Governance, IT Finance & Performance, Program & Portfolio Management, Security, Infrastructure & Operations) against a peer group of organizations from the energy and utility industry. The Gartner study concludes that Toronto Hydro's maturity across all domains is slightly higher than its peers.

4.4 Compensation and Benefit Review

At Exhibit 4, Tab 4, Schedule 5, Toronto Hydro filed a Compensation and Benefits Review of the utility's non-executive compensation costs completed by Mercer Canada Limited (Mercer). This review provides an independent, market-based assessment of Toronto Hydro's compensation and benefits practices against relevant general industry and energy peer group. The Mercer study concludes that Toronto Hydro's total compensation is positioned within a market competitive range relative to the 50th percentile of the energy market. With respect to the general industry peer group, total compensation is slightly above market due to pensions and benefits. However, the total cash component of compensation (i.e. salary and wages) is market-competitive at the 50th percentile.[25]

4.5 Operations and Workforce

To assist the OEB in evaluating the Toronto Hydro's request for custom operational funding beyond the 2025 rebasing year, in Exhibit 4, Tab 1, Schedule 1, Toronto Hydro included a benchmarking analysis of operational cost performance against an average of large and mid-sized electricity distributors in Ontario based on publicly available data reported to the OEB through the Electricity Record-keeping and Reporting Requirement ("RRR"). This analysis demonstrates that: (i) despite unique urban challenges and an expanding asset base, Toronto Hydro controlled operational costs over the 2015-2022 period while improving and maintaining high performance on numerous outcomes and service quality metrics as detailed in Exhibit 1B, Tab 3, Schedule 2; (ii) Toronto Hydro has a demonstrably lean workforce contingent when compared to its peers using various key ratio such as net fixed assets ("NFA") per Full-Time Equivalent ("FTE"), FTEs by system load (MWh), and FTEs per kilometer of line.[26]

[25] Exhibit 4, Tab 4, Schedule 5 – Mercer Benchmarking Report at page 5.
[26] Hydro One, Alectra Utilities, Hydro Ottawa, Elexicon Energy, London Hydro, EnWIn, and Enova.

The analysis also shows that despite what at first glance appears to be higher cost performance per customer when benchmarking the utility to its Ontario peers, closer examination shows that Toronto Hydro requires more system capacity, more assets and hence more resources per customer than other large or mid-size distributors in Ontario. In part, this is driven by Toronto Hydro customers serviced behind bulk meters, which skews the evaluation of performance against customer count. Examination of MWh of load relative to customer count demonstrates this reality, with Toronto Hydro providing an average of 31.8 MWh per customer, approximately 35 percent more load per customer relative to the peer group multi-year average of 23.6 MWh. This trend is consistent with observed number of high-rise buildings found within the service territories of the utilities in the peer group that serve cities in Ontario. Toronto Hydro has approximately 46 percent more high-rise buildings in its service territory than the all the utilities in the peer group combined based on publicly available data.[27]

Table 9: Highrise Buildings for Top Ontario Distributors

Distributor	Highrise Buildings
Toronto Hydro	2,619
Ontario Peer Group Combined[28]	1,790

4.6 Unit Cost Benchmarking ("UCB")

At Exhibit 1B, Tab 3, Schedule 3, Appendix C, Toronto Hydro filed a Unit Cost Benchmarking study completed by UMS Group ("UMS"). This study compares Toronto Hydro's 2020-2022 average unit costs for major asset classes and maintenance activities to a peer group of Ontario and U.S. utilities that responded to the survey sent out by UMS in preparing this study. Overall, UMS found that Toronto Hydro's unit costs performance was comparable or

[27] As per data from SkyscraperPage https://skyscraperpage.com/database/country/1
[28] Alectra, Elexicon, London Hydro, EnWin, and Enova.

better than the peer group, ranging from minus 12.2 percent to plus 1.9 percent relative to the median. UMS also noted that if certain qualitative considerations, such as customer density, could be statistically normalized in the data set, Toronto Hydro's comparative ranking would likely be better than shown.

4.7 Activity and Program-Based ("APB") Benchmarking

In accordance with section 2.1.6 of the Chapter 2 Filing Requirements, the following section provides a year-over-year variance analysis for the APB's ten programs. Toronto Hydro is unable to provide a unit cost variance analysis of the 2025 test year versus historical actuals because the utility plans both its capital and OM&A investments programmatically rather than on a unit basis.

- The utility forecasts in-service additions using a reasonable methodology that is subject to certain practical limitations that are noted Exhibit 2A, Tab 1, Schedule 1. Comparing unit cost actuals which are derived from assets as constructed out in the field, with forecasted unit costs derived by an in-service addition forecasting methodology, does not yield an apples-to-apples comparison that lends itself to explaining variances between historical and forecasted unit costs.
- Similarly to its ISA forecasting methodology, to allocate forecast program costs to USoA accounts, Toronto Hydro relies on historical data mapping, which is quite complex. Comparing historical and forecasted USoA-based unit costs would therefore not yield a meaningful comparison that lends itself to explaining variances.

Furthermore, Toronto Hydro notes that the APB econometric model does not account for recognized differences that set Toronto Hydro apart from other Ontario utilities due to its unique urban environment and customer base that includes many high-rise buildings, as

described in sections 1 and 3.1.5 above, respectively.[29] As such Toronto Hydro, is not in a position to comment on the results of the econometric model.

4.7.1 *Billing O&M*

Table 10 below shows Toronto Hydro's annual billing O&M costs per customer. The increase from 2019 to 2020 is primarily attributed to the inclusion of the incremental costs from conversion from bi-monthly to monthly billing in 2020 where they had been previously tracked in the Monthly Billing deferral account.[30] Please see Exhibit 4, Tab 2, Schedule 14 for additional discussion of factors affecting Toronto Hydro's billing costs and the utility's efforts to control those costs.

Table 10: 2018-2022 Billing O&M Cost per Customer

	2018	2019	2020	2021	2022	Avg.
Cost ($1,000) - USoA [5315]	9,626	16,633	22,200	21,444	24,401	18,861
Scale (1,000 Customers)	772.6	777.9	779.2	785.7	790.5	781.2
Unit Cost ($/Customer)	12.46	21.38	28.49	27.29	30.87	24.10

4.7.2 *Metering O&M*

Table 11 below shows Toronto Hydro's annual metering O&M costs per customer. These costs have been relatively stable over the 2018-2022 period with minor variations depending on the volume and mix of metering maintenance and meter reading work required each year. For more detail please see Exhibit 4, Tab 2, Schedules 1 and 14.

[29] As noted by PEG in the APB report "some relevant business conditions will not be measured in the models" (PEG, Report to the Ontario Energy Board Activities and Program Benchmarking: 2021-2022 Results (October 10, 2023 at page 51) and as noted in section 1.1, econometric experts (including PEG) have recognized the statistical significance of an urban core variable in benchmarking Toronto Hydro costs, but no urban core variable (or anything similar) was included in the APB econometric benchmarking.

[30] EB-2018-0165, Exhibit 4A, Tab 2, Schedule 14 and Exhibit 9, Tab 1, Schedule 1.

Table 11: 2018-2022 Metering O&M Cost per Customer

	2018	2019	2020	2021	2022	Avg.
Cost ($1,000) - USoA [5065 + 5175 + 5310]	5,193	5,556	5,656	4,656	4,853	5,183
Scale (1,000 Customers)	772.6	777.9	779.2	785.7	790.5	781.2
Unit Cost ($/Customer)	6.72	7.14	7.26	5.93	6.14	6.64

4.7.3 *Vegetation Management O&M*

Table 12 below shows Toronto Hydro's annual vegetation management O&M costs per pole on the system. The cost per pole for vegetation management will vary depending on the volume of work, which can be planned (i.e. on a cycle of 2 to 5 years) or reactive (spot tree trimming). To track and assess its (planned) vegetation management cost performance, Toronto Hydro has been reporting annually on its 2020-2024 custom measure, Vegetation Management Cost per kilometer. Toronto Hydro also had this measure benchmarked against peer utilities as part of the UMS Unit Cost Benchmarking Study, which showed Toronto Hydro's costs being within 2 percent of the median. For more details on vegetation management and its costs on a per km basis, please see Exhibit 1B, Tab 3, Schedule 2, Appendix C to this schedule, and Exhibit 4, Tab 2, Schedules 1 and 4.

Table 12: 2018-2022 Vegetation Management O&M Cost per Pole

	2018	2019	2020	2021	2022	Avg.
Cost ($1,000) - USoA [5135]	3,309	2,826	3,230	2,083	3,431	2,976
Scale (1,000 Poles)	179.4	180.3	181.8	182.6	183.6	181.6
Unit Cost ($/Pole)	18.44	15.67	17.76	11.40	18.69	16.39

4.7.4 *Lines O&M*

Table 13 below shows Toronto Hydro's annual Lines O&M costs per circuit kilometer of primary line. The cost per circuit-kilometer has been increasing steadily over 2019-2022. This category includes a wide range of inspection and maintenance activities including

underground and overhead, proactive and corrective; as a result, there are many factors driving Lines O&M costs year-to-year. For more details on some of the relevant activities and their cost drivers, please see Exhibit 4, Tab 2, Schedules 1, 2, 4, 5.

Table 13: 2019-2022 Lines O&M Cost per Circuit km

	2019	2020	2021	2022	Avg.
Cost ($1,000) - USoA [5020:5030 + 5040:5050 + 5090:5095 + 5125:5130 + 5145:5155]	21,869	23,264	25,850	29,596	23,661
Scale (Circuit km of Primary Line)	10,528	10,597	10,625	10,663	10,583
Unit Cost ($/Circuit km of Primary Line)	2,077	2,195	2,433	2,776	2,235

4.7.5 *Stations O&M*

Table 14 below shows Toronto Hydro's annual Stations O&M costs per total MVA. The cost per MVA fluctuates year-to-year depending on the number and relative complexity of the station assets due for inspection and maintenance and the volume of unplanned (corrective and emergency) maintenance work required. For more details please see Exhibit 4, Tab 2, Schedules 3-5.

Table 14: 2018-2022 Stations O&M Cost per Total MVA

	2018	2019	2020	2021	2022	Avg.
Cost ($1,000) - USoA [5016 + 5017 + 5114]	12,779	8,051	6,488	9,187	8,602	9,021
Scale (Total MVA)	7,583	7,617	7,774	7,891	7,853	7,744
Unit Cost ($/MVA)	1,685	1,057	835	1,164	1,095	1,167

4.7.6 *Poles, Towers, and Fixtures O&M*

Table 15 below shows Toronto Hydro's annual Poles, Towers, and Fixtures O&M costs per pole. Year-to-year variances in the cost per pole are primarily driven by the volume of unplanned (e.g. corrective and emergency) maintenance work needed for poles. For more details please see Exhibit 4, Tab 2, Schedules 1, 4, and 5.

Table 15: 2018-2022 Poles, Towers, and Fixtures O&M Cost per Pole

	2018	2019	2020	2021	2022	Avg.
Cost ($1,000) - USoA [5120]	581	1,161	2,123	2,102	1,751	1,296
Scale (1,000 Poles)	179.4	180.3	181.8	182.6	183.6	180.6
Unit Cost ($/Pole)	3.24	6.44	11.68	11.51	9.54	7.15

4.7.7 *Stations CAPEX*

Table 16 below shows Toronto Hydro's annual stations capital additions per total MVA. Since the scale used for this metric is relatively stable, these values are largely driven by the annual capital additions, which can fluctuate due to the volume and mix of stations assets installed and the timing of when they are put into service given that these projects typically span more than one year. For more details about the investments contributing to stations capital additions and their cost drivers please see Exhibit 2B, Sections E6.6.

Table 16: 2018-2022 Stations Capital Additions per Total MVA

	2018	2019	2020	2021	2022	Avg.
Cost ($1,000) - USoA [1820] Capital Additions	30,320	16,655	21,541	25,606	26,295	24,083
Scale (Total MVA)	7,583	7,617	7,774	7,891	7,853	7,744
Unit Cost ($/MVA)	3,998	2,186	2,771	3,245	3,348	3,110

4.7.8 *Poles, Towers, and Fixtures CAPEX*

Table 17 below shows Toronto Hydro's annual poles, towers, and fixtures capital addition costs per pole installed. Since 2019, these unit costs have been relatively stable with some year-over-year variance. The costs to install poles can vary due to a number of factors including the type of project (planned versus reactive versus externally driven), site location and conditions, the number of circuits and attachments, and external cost drivers (e.g. supply chain pressures). Toronto Hydro tracks its planned wood pole renewal unit costs

through its 2020-2024 custom measure, Average Wood Pole Replacement Cost, and had it benchmarked against peer utilities through the UMS Unit Cost Benchmarking Study, where it was within 2 percent of the median. For more information on the utility's performance on this measure and the major contributing programs, please see Exhibit 1B, Tab 3, Schedule 2, Appendix C to this schedule, and Exhibit 2B, Sections E6.1 and E6.5.

Table 17: 2018-2022 Poles, Towers, and Fixtures Capital Addition Costs per Pole

	2018	2019	2020	2021	2022	Avg.
Cost ($1,000) - USoA [1830] Capital Additions	21,288	32,866	33,134	33,663	29,573	30,105
Scale (Pole Additions)	3,254	3,525	3,367	3,677	3,312	3,427
Unit Cost ($/Pole Addition)	6,542	9,324	9,841	9,155	8,929	8,758

4.7.9 *Line Transformers CAPEX*

Table 18 below shows Toronto Hydro's annual line transformer capital addition costs per transformer installed. Toronto Hydro's line transformers include overhead, underground (including padmount, submersible, and vault), and network transformers, and the relative volume of each of these in a year impacts the unit costs due to the large variation in costs for each type. As illustrated in the UMS Unit Cost Benchmarking Study, both Toronto Hydro's and the peer group median unit costs for underground transformers were approximately two times those for overhead transformers and network transformer unit costs were more than three times (or over $90,000 more) the underground transformer unit costs.[31] As a result, Toronto Hydro has observed that the year-over-year variations in unit costs in this category are correlated with the relative proportion of transformer types addressed within a given year. For more information on such drivers, please see Exhibit 2B, Sections E6.2-E6.5.

[31] Exhibit 1B, Tab 3, Schedule 3, Appendix C at page 8.

Table 18: 2018-2022 Line Transformer Capital Addition Costs per Transformer

	2018	2019	2020	2021	2022	Avg.
Cost ($1,000) - USoA [1850] Capital Additions	62,026	79,731	84,980	87,980	78,613	78,666
Scale (Lines Transformer Additions)	2,900	2,746	2,716	3,086	2,470	2,784
Unit Cost ($/Line Transformer Addition)	21,388	29,035	31,289	28,510	31,827	28,410

4.7.10 *Meters CAPEX*

Table 19 below shows Toronto Hydro's annual meters capital addition costs per customer. A large portion of these investments are non-discretionary as an inherent part of connecting customers or to replace failed meters to ensure accurate and timely billing. Where Toronto Hydro has some discretion (i.e. planned meter replacements), it still must consider the timing of meter seal expiries. Another factor layered onto these considerations is the types of meters being installed or replaced. For example, in 2020 Toronto Hydro installed 10 of the more expensive ION meters compared to five or less in 2021 and 2022. Please see Exhibit 2B, Sections E5.1, E5.4, and E6.7 for more information on factors impacting Toronto Hydro's metering investments.

Table 19: 2018-2022 Meter Capital Addition Costs per Customer

	2018	2019	2020	2021	2022	Avg.
Cost ($1,000) - USoA [1860] Capital Additions	24,359	14,491	19,983	15,476	17,882	18,438
Scale (1,000 Customers)	773	778	779	786	791	781
Unit Cost ($/Customer)	32	19	26	20	23	24

Econometric Benchmarking Study of Toronto Hydro's Total Cost and Reliability Metrics

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OCTOBER 31, 2023

Clearspring Energy Advisors LLC

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1 Executive Summary

Toronto Hydro - Electric System Limited ("Toronto Hydro" or "Company") engaged Clearspring Energy Advisors, LLC ("Clearspring") to conduct an econometric benchmarking study of Toronto Hydro's past and projected total costs and reliability metrics. The lead researcher of the study is Mr. Steven A. Fenrick. Mr. Fenrick has led numerous benchmarking studies in Ontario and throughout North America, including in Toronto Hydro's last two custom incentive regulation ("Custom IR") applications. In both of those prior applications, total cost and reliability benchmarking was conducted for the Company. A copy of Mr. Fenrick's summary *curriculum vitae* is provided in Appendix B.

Clearspring uses the results of this study to determine the stretch factor recommendation for Toronto Hydro in its 2025-2029 Custom IR application. The benchmarking research uses the econometric approach to evaluate total costs. This approach aligns with the Ontario Energy Board Decision in the 4th Generation Incentive Regulation ("4GIR") proceeding.[1]

The benchmark models use established methodologies that have evolved and been refined through numerous incentive regulation proceedings in Ontario. Most notably, during Hydro One Network's most recent joint rate application, Clearspring and Board Staff's consultant, Pacific Economics Group, undertook a conferral process regarding benchmarking and together issued a joint report.[2] Clearspring used the Joint Report benchmarking research as the starting point for the current total cost study. Clearspring retained all the variables and methodologies used in the Joint Report with the only changes being that we improved the model specification by adding two distribution substation variables and further refining the congested urban core variable to vary over time.

1.1 Research Study Components

The research conducted and described in this report includes total cost and reliability benchmarking of Toronto Hydro. The research consisted of the following three studies:

- **Distribution total cost benchmarking of Toronto Hydro.** This study benchmarks the Company's total cost levels and is the basis for our recommendation for the stretch factor in this Custom IR application.
- **Sustained average interruption frequency index ("SAIFI") benchmarking of Toronto Hydro.** This study benchmarks the Company's SAIFI metrics, both historical and projected, to industry expectations. SAIFI measures the number of sustained outages an average customer on the system experiences.
- **Customer average interruption duration index ("CAIDI") benchmarking of Toronto Hydro.** This study benchmarks the Company's CAIDI metrics, both historical and projected, to industry

[1] Case EB-2010-0379.

[2] The prior Hydro One application was EB-2021-0110. The conferral process produced a report titled, *Clearspring/PEG Joint Report on Hydro One Benchmarking and Productivity Research*, ("Joint Report").

expectations. CAIDI measures the average duration when a sustained outage occurs.

Another reliability metric that is often tracked and reported is the sustained average interruption duration index ("SAIDI"). SAIDI equals the product of SAIFI and CAIDI. We provide the benchmark comparison for SAIDI in this report by multiplying the SAIFI and CAIDI benchmarks.

1.2 Total Cost Benchmark Findings

The first model benchmarks total costs for Toronto Hydro. Total costs are defined as the sum of OM&A expenses and capital costs. The capital cost portion is constructed based on net plant and historical plant additions over time, and includes the estimated economic depreciation and opportunity costs of capital. The components within the calculation of total costs are similar to the components in the distribution portion of revenue requirements.[3] Total cost benchmarking is the approach used in 4GIR to set stretch factors and is the basis for every other Custom IR application that our team has participated in. The total cost method is preferred to partial cost benchmarking approaches, such as OM&A or capital benchmarking, which exclude large portions of pertinent costs and do not account for differences between sampled utilities regarding input substitution or accounting.

Our total cost econometric benchmarking study results indicate the following:

1. The most recent 3-year average of historical total costs (2020 to 2022) of Toronto Hydro are below benchmark expectations. The average benchmark score for Toronto Hydro from 2020 to 2022 is -28.0%.
2. The projected total cost levels during the Custom IR period (2025 to 2029) remain below the benchmark predictions. The average benchmark score for Toronto Hydro during the Custom IR period is -22.9%.

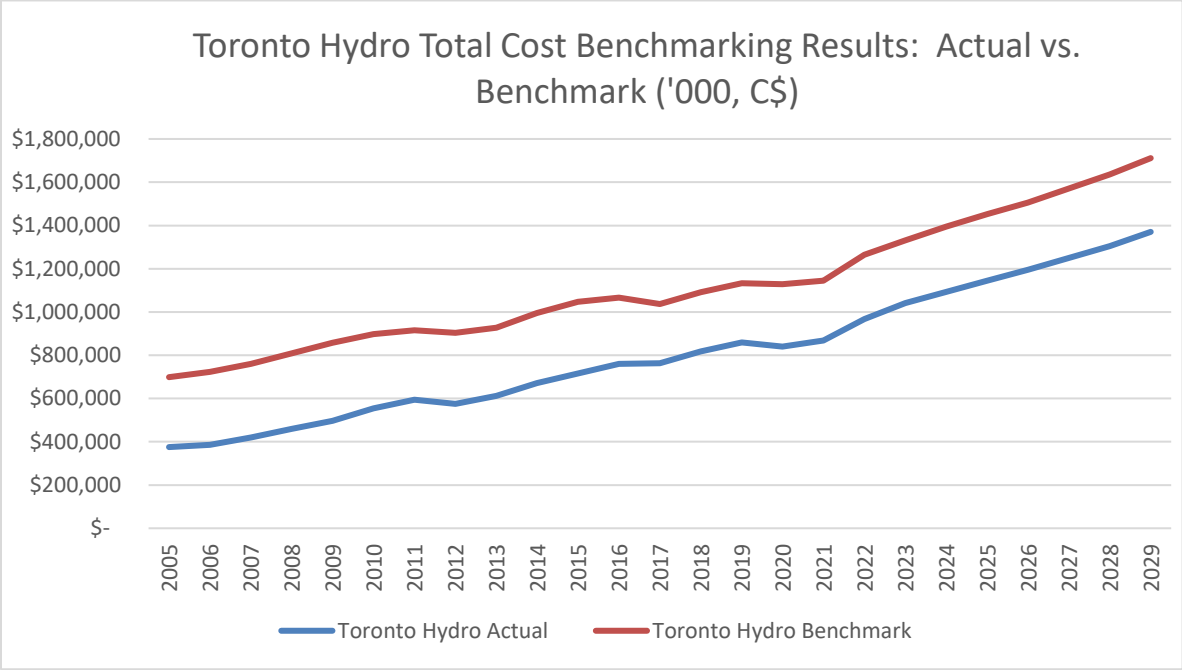
The following table and graph provide the comparison between Toronto Hydro's historical and projected total costs and the model's benchmark total costs.

[3] Total costs are not exactly analogous to revenue requirements because of the generalizations needed to offer a fair analysis between utilities with varying depreciation rates, rate of returns, capital addition patterns, and cost definitions.

Table 1 Toronto Hydro's Total Cost Performance 2005-2029

Year	% Difference from Total Cost Benchmark
2005	-62.1%
2006	-62.9%
2007	-59.3%
2008	-56.5%
2009	-54.5%
2010	-48.2%
2011	-43.1%
2012	-45.2%
2013	-41.6%
2014	-39.5%
2015	-38.1%
2016	-33.9%
2017	-30.7%
2018	-28.8%
2019	-27.6%
2020	-29.4%
2021	-27.6%
2022	-26.8%
2020-2022 average score	**-28.0%**
2023	-24.6%
2024	-24.4%
2025	-23.9%
2026	-23.1%
2027	-22.9%
2028	-22.6%
2029	-22.2%
2025-2029 average score	**-22.9%**

Figure 1 Historical and Projected Total Costs vs. Benchmarked Costs



1.3 Reliability Benchmark Findings

Clearspring Energy additionally conducted econometric reliability benchmarking of Toronto Hydro's SAIFI and CAIDI. The reliability study benchmarks Toronto Hydro's historical (2005 to 2022) data after major event day ("MED") exclusions are made.[4] The metrics include loss of supply outages to remain consistent with the U.S. dataset definition and are based on a five-minute sustained outage definition which matches most of the U.S. sample. The reliability benchmarking, like the total cost study, used a U.S. sample.

Excluding MEDs from the calculation of the metrics enables the study to gauge reliability performance during normal operating conditions. Clearspring Energy gathered U.S. reliability data and their MED definitions from publicly available regulatory filings.

Clearspring Energy's reliability benchmarking analysis indicates the following:

1. The most recent 3-year average (2020 to 2022) for SAIFI is 98.8% above benchmark expectations. During the Custom IR period, SAIFI is projected to be 99.4% above benchmark expectations.
2. The most recent 3-year average for CAIDI is 104.1% below benchmark expectations. During the Custom IR period, CAIDI is projected to be 110.2% below benchmark expectations.

The following table provides the comparison between Toronto Hydro's actual (or projected) SAIFI and CAIDI, the model's benchmark value, and the percentage difference of the actual/projected to the

[4] According to Toronto Hydro, its outage recording methods increased in automation and the ability to identify and track outages more precisely relative to historical metrics. This enhancement in outage tracking has slightly increased the projected reliability estimates.

benchmarks.

Table 2 Toronto Hydro's SAIFI and CAIDI Actuals and Benchmarks 2005-2029

Year	SAIFI (Actual)	SAIFI (Benchmark)	SAIFI (% Difference)	CAIDI (Actual)	CAIDI (Benchmark)	CAIDI (% Difference)
2005	0.93	0.46	70.2%	76.59	110.00	-36.2%
2006	1.11	0.46	88.1%	64.98	110.73	-53.3%
2007	1.14	0.47	89.7%	69.12	111.59	-47.9%
2008	1.08	0.46	85.0%	67.40	112.68	-51.4%
2009	0.95	0.46	72.8%	84.13	113.75	-30.2%
2010	0.98	0.46	75.5%	77.30	115.32	-40.0%
2011	1.05	0.45	83.9%	80.13	117.26	-38.1%
2012	0.88	0.45	67.4%	68.06	118.66	-55.6%
2013	0.95	0.45	75.8%	70.61	120.35	-53.3%
2014	0.92	0.45	72.6%	63.76	123.09	-65.8%
2015	0.97	0.44	78.4%	64.04	125.48	-67.3%
2016	0.93	0.45	73.3%	59.71	128.08	-76.3%
2017	1.09	0.45	87.4%	53.14	129.25	-88.9%
2018	1.09	0.46	86.8%	53.25	130.44	-89.6%
2019	0.95	0.45	73.9%	50.39	132.46	-96.6%
2020	1.11	0.45	91.2%	50.77	135.21	-98.0%
2021	1.20	0.44	100.3%	48.55	136.49	-103.4%
2022	1.24	0.43	105.0%	45.75	138.95	-111.1%
2020-2022 average	**1.18**	**0.44**	**98.8%**	**48.36**	**136.88**	**-104.1%**
2023	1.28	0.43	114.2%	42.76	141.81	-119.9%
2024	1.19	0.43	98.3%	51.28	144.87	-103.9%
2025	1.19	0.43	96.5%	51.49	148.16	-105.7%
2026	1.18	0.43	95.7%	51.54	151.67	-107.9%
2027	1.17	0.43	94.8%	51.68	155.43	-110.1%
2028	1.17	0.43	93.8%	51.85	159.47	-112.3%
2029	1.16	0.43	93.8%	51.96	163.82	-114.8%
2025-2029 average	**1.17**	**0.43**	**99.4%**	**51.70**	**155.71**	**-110.2%**

While SAIFI and CAIDI are modeled separately, the actuals and benchmarks for those metrics can be multiplied together to produce a SAIDI benchmark score. The following table provides the comparison between Toronto Hydro's actual (or projected) SAIDI, the benchmark value, and the percentage difference of the actual/projected to the benchmark.

Table 3 Toronto Hydro's SAIDI Actuals and Benchmarks 2005-2029

Year	SAIDI (Actual)	SAIDI (Benchmark)	SAIDI (% Difference)
2005	71.3	50.7	34.0%
2006	71.9	50.7	34.8%
2007	78.9	51.9	41.8%
2008	72.9	52.1	33.7%
2009	80.2	52.3	42.7%
2010	75.4	52.8	35.5%
2011	84.2	53.2	45.8%
2012	60.2	53.5	11.8%
2013	67.1	53.6	22.4%
2014	58.8	54.9	6.8%
2015	61.9	55.4	11.2%
2016	55.7	57.4	-3.1%
2017	58.1	58.8	-1.1%
2018	57.8	59.7	-3.3%
2019	47.8	60.1	-22.9%
2020	56.3	60.3	-6.9%
2021	58.2	60.1	-3.1%
2022	56.8	60.3	-6.0%
2020-2022 average	**57.1**	**60.2**	**-5.3%**
2023	54.8	61.5	-11.7%
2024	61.0	62.9	-3.0%
2025	61.2	64.3	-5.0%
2026	60.8	65.9	-8.0%
2027	60.6	67.5	-10.8%
2028	60.5	69.2	-13.6%
2029	60.2	71.1	-16.7%
2025-2029 average	**60.6**	**67.6**	**-10.8%**

1.4 Stretch Factor Recommendation

In the 4th Generation IR proceeding, five stretch factor groupings (cohorts) were established based on the most recent average three-year total cost benchmarking scores. A score better than -25% (i.e. costs were more than 25% below benchmark) received the lowest stretch factor of 0.00%. A score between -25% and -10% received a 0.15% stretch factor. Scores that are +/- 10% received 0.30%. Scores between 10%

and 25% received a 0.45% stretch factor, and scores exceeding 25% (i.e., costs were more than 25% above benchmark) received the highest stretch factor of 0.60%.

Our total cost study findings for Toronto Hydro show that during the Custom IR period, the Company's total cost benchmarking score is -22.9%. Based on the 4th Generation IR stretch factors and Clearspring's econometric benchmarking results, the appropriate stretch factor is 0.15%. This stretch factor not only aligns with Toronto Hydro's strong total cost benchmarking results, but also aligns well with other recent stretch factor precedents in Canada and the States.

2 Overview of Benchmarking Methodology, Narrowing of Differences, and Improvements Made

The total cost and reliability models have built upon the foundation laid in prior Custom IR proceedings. Hydro One Network's most recent Custom IR application included a conferral process involving Clearspring and the Board Staff's benchmarking expert, Pacific Economics Group ("PEG"). Clearspring and PEG issued a report titled, "Clearspring/PEG Joint Report on Hydro One Benchmarking and Productivity Research" ("Joint Report") during that application. Both Clearspring and PEG have endeavoured throughout prior Custom IR applications to narrow benchmarking methodological differences. The only consequential difference regarding distribution total cost benchmarking cited by Clearspring and PEG in the Joint Report was the service territory area of Hydro One.[5] That is a non-issue in this proceeding since Hydro One is not included in the sample.

Clearspring used the same methodology for the total cost model as used for Hydro One and the research found in the Joint Report. We made two further improvements regarding included variables. A summary of how prior differences have been narrowed and a discussion on these two improvements is found in the following sub-section (Section 2.1).

The benchmarking study for both the total cost and reliability studies employed the econometric benchmarking approach. This is the most accurate and fair method when comparing utility cost and reliability levels because it explicitly adjusts for the quantifiable differences between utility service territories and business conditions. It is also the same method preferred by the Board in the 4GIR Decision.

Simple comparisons of metrics such as rates, unit costs, or reliability indices do not typically allow regulators to compare utilities in a fair manner. For example, comparing a utility's costs to those of a peer group utilities' costs usually presents an inaccurate picture of the target utility's performance. Factors that cannot be controlled by the utility affect costs and reliability performance. Such factors include geographical size, regional wage levels, rural density, or serving a congested urban territory. It is often difficult or impossible to account for these factors using a peer group approach.

Adjusting for these and other influencing factors is necessary to accurately evaluate performance. With this concept in mind, Clearspring has estimated three econometric models from a large sample of utilities (total cost, SAIFI, and CAIDI) using variable parameters that are statistically influential on distribution utility costs and reliability indexes. The benchmarking method adjusts for service territory conditions and other factors that affect the studied metrics.

Using a large sample of utilities, the econometric model produces an industry-wide estimation of how the variables (e.g. number of customers, peak demand, etc.) affect the studied metric (e.g. total costs). For

[5] In the conferral process, there were a few changes made by the consultants to their original reported research. Regarding Clearspring's research, PEG suggested that both Clearspring and PEG include an O&M based scope variable. Clearspring investigated the merits of this suggestion and then agreed to include this variable and update the model results found in the Joint Report with this new variable. We now include this same variable in our current research for Toronto Hydro.

the present study, the sample used to estimate the models includes U.S. observations from multiple utilities for multiple years. It is a robust sample that produces an accurate benchmark assessment of Toronto Hydro's total cost and reliability metrics.

The high-level method for the three models is similar. In each case, the model uses the industry data over the studied period to determine the relationship between the metric and the factors that drive it. For example, the total cost model estimates the industry-wide relationship between total cost and certain variables, based on the utilities included in the sample. The model is then used to predict Toronto Hydro's "expected" (benchmarked) costs, using the same estimated relationship between the costs and the explanatory variables, and using Toronto Hydro's particular values for the variables. The approach for the reliability metrics is similar, although a different set of explanatory variables is used for each model.

Total cost and reliability predictions are calculated by inserting company-specific variable values into the estimated equation for the metric at hand (total cost, SAIFI, or CAIDI) for each year in the study. The benchmark score is defined as the logarithmic percentage difference of the observed data to the predicted value of the data for a given year, as shown below.

$$Benchmark\ Score = \text{Natural Log}\ \left(\frac{Observed\ or\ Projected\ Cost\ Data}{Predicted\ Cost\ Data}\right)$$

The general approach of our benchmarking analysis is:

1. We assembled a dataset that includes the historical costs (or reliability) of all the observations, along with the variables that affect cost (or reliability), such as customer totals, peak demands, forestation, congested urban, wage levels, customer density, etc.
2. Using the sample data, Clearspring estimated three econometric models. Each model expresses the relationship between the variables and one of the metrics (total cost, SAIFI, or CAIDI).
3. We can then produce "benchmark" values for Toronto Hydro for any given year. The benchmarks denote the expected value for an average-performing utility with identical explanatory variable values for that year. For example, if the SAIFI model predicted a value of X for Toronto Hydro for 2010, that can roughly be translated as: "Given the industry-wide relationship between SAIFI and the variables that drive it (number of customers, % forestation, rural density, etc.), and given Toronto Hydro's specific variable values for that year, we would expect an average-performing utility to have a SAIFI of X in 2010."
4. A comparison between the actual values and the benchmarks can then be made for each year.
5. Future years for Toronto Hydro are also benchmarked and compared to projected costs, using the same model parameter estimates, and *projected* explanatory variable values (instead of *actual* variable values for historical years).

2.1 Prior Methodological Differences Addressed and Improvements Made

There have been several differences that have been addressed and narrowed by both Clearspring and PEG regarding distribution total cost benchmarking. As stated earlier, the only remaining consequential

difference in the Hydro One application was what value to give regarding Hydro One's service territory.[6] This remaining difference is moot regarding benchmarking Toronto Hydro and can be ignored since Hydro One does not enter the sample and Toronto Hydro's service territory is far easier to define and clearly matches how other utilities in the sample have this variable defined.

Other past issues that have already been previously addressed before this study include the following.[7]

- **Sample Period** – Clearspring used 2000 as a start year of the sample for the Hydro One research and also uses 2000 for this Toronto Hydro study, while PEG used 2002 in the Hydro One application for distribution benchmarking. However, this is not a consequential difference.

- **Estimation Procedure** – Both Clearspring and PEG used the Driscoll-Kraay ("DK") method in the Joint Report and Clearspring continues to use the DK method for this study.

- **Model Specification** – Clearspring in the Hydro One research adopted PEG's distribution total cost model variables that it put forth in the prior Hydro Ottawa Custom IR proceeding with only one additional variable (a distribution work variable that was not consequential). In the Joint Report both consultants added a new economies of scope variable. The scope variable measures the O&M of distribution expenses relative to the O&M of distribution, transmission, and generation expenses. This model specification of the Joint Report is continued in this research with two improvements: adding a distribution substation variable and further refining the congested urban core by allowing the variable to change over time.

- **Peak Demand Variable Definition** – Clearspring used a 10-year rolling average for our peak demand variable in the Hydro One research and applied that same definition in this Toronto Hydro research. PEG uses a ratchet definition for its variable in its Hydro One research. Both consultants agreed in the Joint Report that this was not a consequential difference.

- **Capital Asset Price Levels** – Clearspring adjusted its definition of these prices in our Hydro One research in response to PEG raising an issue that the price levels should be based more on all the service territory of each utility rather than just the headquarter city. We are using the same prices as used in the Hydro One research. PEG also used these same prices in its Hydro One research.

- **Canadian Input Price Inflation** – In the Hydro One proceeding, Clearspring and PEG used the same input price inflation assumption. This was based on using a 50% weight of PEG's preferred index and a 50% weight of Clearspring's preferred index. Clearspring continues with this compromise in the current research.

[6] Even regarding this difference, both consultants acknowledged the "difficulty and challenge in getting the perfect number for this variable".

[7] For a fuller description of these, please see the Clearspring report in the most recent Hydro One application. On p. 9, section 2.1 of that report we provide more details on each of these differences and how they were addressed.

- **Older Capital Benchmark Year** – In the Hydro One application, Clearspring undertook considerable efforts to begin the capital stock calculation as early as possible. For most of the sampled utilities, we were able to begin that calculation in 1947. This helped address one of the issues PEG had previously raised. We now use that same 1947 capital benchmark year in the Toronto Hydro research and PEG used that same year in its Hydro One research.

- **Customized Labour and Non-Labour OM&A Weights** – In Hydro One, Clearspring and PEG both used weights based on utility-specific data for the labour and non-labour components of the OM&A price index. Clearspring continues this treatment in the current study.

- **Pensions and Benefits Treatment** – Both Clearspring and PEG agreed to exclude pensions and benefits in the Hydro One proceeding and Clearspring continues this exclusion in the current Toronto Hydro study.

Most of the differences between the consultants have been narrowed considerably. Even a model specification difference such as whether to include the distribution work variable has minor impacts on results. PEG did not include that variable in its distribution Joint Report model, Clearspring did but both consultants agree it has minor implications on the results.[8]

2.1.1 Model Specification Improvements to Joint Report

There are two differences between the Joint Report distribution total cost methodology and model that Clearspring estimated and the model for this application. Clearspring improved the model specification by collecting the data and then adding two distribution substation variables (number of substations and substation capacity) and refined the congested urban variable by adding a time dimension.

Regarding the congested urban variable, Clearspring has further examined and refined the variable consistent with the Board's findings in Toronto Hydro's prior application in EB-2018-0165. Both Clearspring and PEG included a congested urban variable in that application. The Board stated in its December 19, 2019 Decision on page 29, "The OEB accepts that a well-constructed congested urban variable may be appropriate for Toronto Hydro. However, the OEB concludes that the congested urban variable needs further research and refinement before it can be accepted as a meaningful adjustment to the assessment of cost benchmarking performance."

In this study, Clearspring incorporates a refined version of the congested urban variable that has now been agreed to and used by both Clearspring and PEG in multiple proceedings since Toronto Hydro's last Custom IR application. This includes that Clearspring and PEG used this variable in recent years in Hydro Ottawa's latest Custom IR application (EB-2019-0261) and Hydro One's latest Custom IR application (EB-2021-0110) which included the Joint Report. The further refinement to this established variable that Clearspring has made is to vary the congested urban variable by time using an adjusted annual change in

[8] Clearspring tested its model in this application and the variable continues to have minor implications (less than 1%) on the results for Toronto Hydro's total costs.

high-rise skyscrapers for each utility.

This is a better and more accurate approach because Toronto is one of the fastest growing cities in North America. The congested urban cost challenge for Toronto Hydro will be much larger in 2029 than its historical values. Finding a method to allow the congested urban variable to adjust for this substantial growth will produce a more accurate depiction of Toronto Hydro's historical and projected total cost performance during the 2025 to 2029 Custom IR period.

The congested urban core variable data was meticulously gathered in 2016 and 2017 during the research phase for the prior Toronto Hydro Custom IR benchmarking research. This involved multiple engineers and mapping experts spending hundreds of hours going over maps of North American cities to identify areas with buildings that were predominantly seven stories or higher and would most likely cause higher infrastructure challenges, and thus cost challenges, to the utility serving those areas. While this variable continues to be the best available approach to adjust for extreme urban cost challenges for utilities, it does have the drawback of being a snapshot in time of the congested urban variable challenges of each utility. That is, it is time invariant. The 2017 challenges faced by each utility are not the exact same challenges faced in future (or past) years. This is especially true for utilities serving cities that are either rapidly growing or rapidly declining. Adding a time component to the variable also becomes more important as the Custom IR period goes through 2029, twelve years after the initial construction of the variable.

To make this congested urban variable time variant, Clearspring gathered the number of high-rise skyscrapers at or above 100 metres for each year and for each city served within the U.S. sample and Toronto. This data was gathered from the Council on Tall Buildings and Urban Habitat ("CTBUH").[9] The CTBUH dataset spans the years of the sample period, 2000 to 2022, enabling the changes in skyscrapers in each utility's service territory to be used to modify the congested urban variable. For the future years for Toronto Hydro, we used the last ten-year average annual growth rate in high-rise buildings in Toronto to estimate the projected number of high-rises in Toronto.[10]

One issue with using the change in the number of skyscrapers per year to modify the congested urban variable is that some of the increase in skyscrapers may be to infill areas that are already classified as congested urban. For example, a seven-story building might be torn down for a building that is higher than 100 metres. Therefore, it is appropriate to reduce the growth rate escalation to account for this reality. Clearspring created a regression model that estimated how the change in the skyscraper count would impact the congested urban variable. Using the sample observations with a congested urban area, we found that every 1% change in the number of skyscraper buildings equated to a 0.63% change in the congested urban variable.[11]

[9] The CTBUH website and data is available at www.ctbuh.org.

[10] From 2012 to 2022, the number of high-rises in Toronto has increased at an average annual rate of 7.1%.

[11] The econometric equation was simply the natural log of the congested urban area as the left-hand side variable, with a constant and the natural log of the number of skyscrapers in 2017 for those utilities in the sample with a non-zero value for the congested urban variable and skyscrapers (n = 35).

The congested urban variable in 2017 is the same variable value in that specific year as the variable used by PEG and Clearspring in the prior Hydro One and Hydro Ottawa proceedings. To adjust it for years subsequent to 2017 the formula used is:

$$Congested\ Urban_t = Congested\ Urban_{t-1} * exp\left[0.6285 * ln(\frac{Skyscrapers_t}{Skyscrapers_{t-1}})\right]$$

To adjust the congested urban variable for years prior to 2017 the formula used is:

$$Congested\ Urban_t = Congested\ Urban_{t+1} * exp\left[0.6285 * ln(\frac{Skyscrapers_t}{Skyscrapers_{t+1}})\right]$$

The prior time invariant approach assumed there was no change in a city's congested urban area during the sample period. This is the same as assuming a 0.0% impact on skyscraper changes to the congested urban value rather than the 0.6285 value we used in the equations above.

Regarding the substation variables, in the Hydro One benchmarking research both Clearspring and PEG included substation variables for the transmission benchmark models. We did not include distribution substation variables because collecting that data requires a considerable amount of effort which had not been undertaken for that application. However, this effort has been undertaken in this application and we have, therefore, included two new variables which enable the model to account and adjust for the number of distribution substations owned and operated by the utility and the MVa capacity of those stations.[12]

2.2 Benchmarks for Future Years

The same econometric model and its associated parameter values that are estimated using historical data (and used to develop Toronto Hydro's historical benchmarks) are also used to calculate the Company's benchmarks for future years through 2029. These parameter values are combined with projected variable values to calculate the expected total costs of Toronto Hydro in the future years of the Custom IR period.

Clearspring Energy was provided OM&A expense, plant addition, customer counts, and peak demand projections from Toronto Hydro. We then inserted these projections for each future year into the estimated econometric model.

2.3 Other Model Details

The model variables, parameter estimates, cost definition details, and results are provided in the Sections 3 (total cost) and 4 (reliability). Appendix A includes methodology details which include the method used to calculate capital quantities and costs (perpetual inventory method), model estimation approach, model specification, and variable parameter hypothesis testing.

[12] An issue that PEG brought up in the Hydro One research was how best to count substations in the FERC Form 1 data that have the same address. In this research, we used the method that PEG suggested and only counted once if the Form 1 showed stations with the same address.

3 Distribution Total Cost Benchmarking Variables, Model, and Results

Clearspring undertook a total cost econometric benchmarking study of Toronto Hydro's distribution costs. This study provides a comparison of Toronto Hydro's distribution total costs to the benchmark costs after adjusting for the specific output levels, input prices, and business conditions that the Company operates within. These comparisons are made for both historical and forecasted years through 2029. For more information on the benchmarking methods please see Chapter 2 and Appendix A.

3.1 Distribution Variables

The three output variables used in the distribution benchmarking research are:

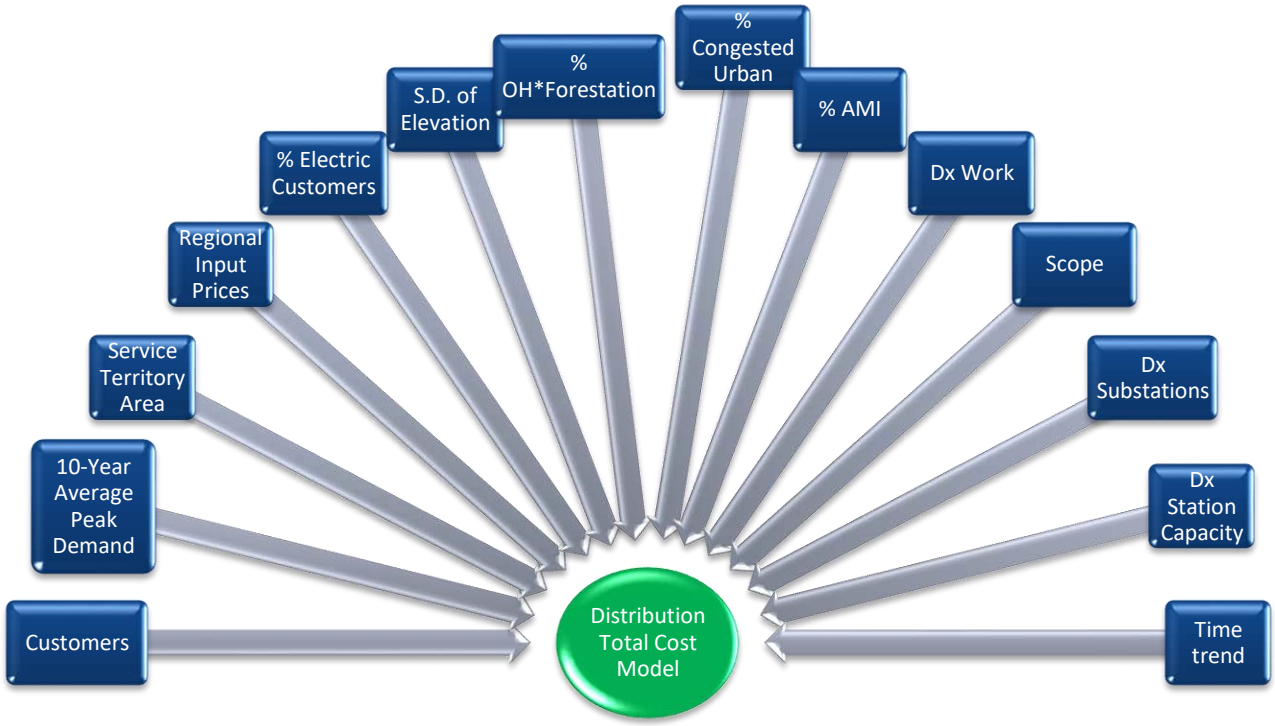
- Total customers served,
- A 10-year rolling average of peak demand, and
- The total distribution service territory of the utility.

The business condition variables used in the distribution benchmarking research are:

- Regional input prices (total costs in the model are divided by the input price index),
- Percent of electric customers in the total of electric and gas customers,
- Standard deviation of elevation,
- Percent of distribution plant that is overhead multiplied by the percent of forestation,
- Percent of congested urban area within each utility's service territory,
- Percent of AMI (smart meters) deployed by the utility in each year,
- The distribution work variable measures the percent of transmission lines classified as being served by transmission that are above 50 kV,
- The O&M based economies of scope variable which measures the percentage of distribution O&M expenses in total distribution, transmission, and generation expenses,
- The number of owned and operated distribution stations,
- The capacity of owned and operated distribution stations, and
- A time trend variable.

The variables included in the distribution benchmark analysis are shown in the figure below.

Figure 2 Variables in Distribution Cost Model



These variables provide a robust accounting of the varying service territory conditions faced by distribution utilities. All first order variables are statistically significant at a 90% confidence level and all variables are correctly signed (i.e., they are signed the way we would expect).

3.1.1 The Definition of Distribution Costs

OM&A and capital costs used in the benchmarking models for the U.S. distribution utilities are derived using FERC Form 1 filing data.[13] United States investor-owned utilities are required to file FERC Form 1 data annually, which includes operation and maintenance expenses broken down into specific cost categories (e.g., distribution, transmission, customer billing, administrative and general). Form 1s also include information regarding "plant in service" and accumulated depreciation that are used in constructing capital costs.[14]

We used a cost definition that is consistent between both the U.S. sample and Toronto Hydro. The cost definition is the same as the latest one used in the Hydro One total cost benchmarking study led by Mr. Fenrick. Clearspring began with the benchmark-based cost definition used by PEG in the 4GIR proceeding.

[13] Some of the FERC Form 1 data was gathered using SNL Energy's database tool.

[14] Clearspring gathered plant addition data going back to 1947 for this study. This data was collected from various EIA annual reports.

To be consistent with the U.S. sample, we added high-voltage expenses to the cost definition for Toronto Hydro. The FERC Form 1 does not break down high- versus low-voltage distribution expenses, as Ontario reporting does. For the same reasons, contributions in aid of construction ("CIAC") have been excluded from Toronto Hydro's cost definition, due to those expenses not being included in the U.S. Form 1 data. Bad debt expenses (called uncollectible expenses in the FERC Form 1) have been excluded for all utilities, to match the 4GIR benchmark-based definition.

The cost definition also excludes customer service and information ("CSI") expenses from total costs for all utilities. This is due to the possibility that the U.S. utilities include conservation demand management ("CDM") expenses in the CSI expense category. This assures cost consistency between the U.S. sample and Toronto Hydro. The table below summarizes the cost definition treatment.

Table 4 Distribution Cost Definitions

Cost Element	Treatment
4th Generation IR Benchmark-Based Costs	This is the starting point for the sample.
Contributions in Aid of Construction (CIAC)	We subtracted from Toronto Hydro distributor costs, since U.S. cost data does not include CIAC.
High Voltage Expenses	We added to Toronto Hydro costs, since U.S. cost data includes distribution high voltage costs.
Customer Service and Information (CSI) Expenses	We excluded CSI expenses for both the U.S. and Toronto Hydro, given the possible inconsistency in CDM reporting.
Pensions and Benefits	We excluded OM&A pensions and benefits from both the U.S. and Toronto Hydro data.

The distribution total cost model includes three output variables. The first is the total number of customers served, the second is the ten-year rolling average of peak demand for each utility, and the third is the total service territory area for each utility. The first two output variables are gathered from FERC Form 1 data. The third uses GIS information on the utility service territory area; this variable uses the same values for the U.S. sample as found in the Hydro One research by Clearspring and PEG. The historical output data for Toronto Hydro regarding the number of customers and peak demands comes directly from the Company. The peak demand variable is calculated based on taking the ten-year rolling average of annual peak demand on the system in the sample that has occurred up to that year. For years without ten years' worth of historical data, the years that are available were averaged.[15]

[15] This is another advantage of the 10-year rolling average method. There is no bias if fewer than ten years for a utility are available since we are taking an average rather than a maximum of the peak demands.

3.1.2 Distribution Business Condition Variables

Beyond the three output variables and the input price index, there are nine business condition variables included in the model (plus a time trend). Each variable is discussed briefly below.

The **percentage of electric customers** measures the percentage of electric customers served by a utility out of total gas and electric customers. This variable measures the economies of scope available from serving both electric and gas customers. Billing and other customer-related activities can be shared between the gas and electric divisions when a utility serves its customers with both commodities. The value is set to 100% for Toronto Hydro since they do not serve natural gas customers. We would expect a positive parameter estimate on this variable.

The **standard deviation of elevation** variable is calculated based on geographic information system ("GIS") elevation topography maps. A higher standard deviation of the elevation indicates increased elevation changes and variance within the utility's service territory. We would expect that a service territory with more hills, mountains, and other elevation changes would be more challenging and costly to serve, *ceteris paribus*. Therefore, a positive parameter estimate is expected (indicating a positive correlation between standard deviation of elevation and costs).

The **overhead percentage times percentage of forestation** variable is based on the overhead plant in service for each utility (for the percent overhead) and GIS land cover maps (for percent forestation). These maps used the GlobCover 2009 product produced by the European Space Agency ("ESA") and the Université Catholique de Louvain. These maps are matched with the areas served by each utility to create the forestation variable. We would expect that the higher the level of overhead lines and forestation, the higher OM&A costs required for right-of-way clearing and service restoration activities.

The **congested urban** variable measures the percentage of a utility's service territory that consists of a major urban load center that is "congested." Congested urban areas have physical constraints that necessitate complex and costly subterranean civil infrastructure for housing and operating electric distribution plant. Congested urban areas also often necessitate electrical equipment unique to such subterranean infrastructure. The variable measures the percentage of service territory classified as "congested urban" area.[16] This variable has been refined and improved to now vary by year based on the estimated impact of the percentage change in skyscrapers in the service territory, as described further above.

We expect a utility that has a congested urban area within its service territory would experience substantial incremental costs as compared to a utility that does not have such an area within its service

[16] It is the same variable used in the prior Toronto Hydro, Hydro Ottawa, and Hydro One applications, with a few minor adjustments made between the prior Toronto Hydro case and the Hydro Ottawa research. The variable is fully described in our Toronto Hydro report titled, "Econometric Benchmarking of Historical and Projected Total Cost and Reliability Levels". Our team, while at Power System Engineering, produced the report in EB-2018-0165. July 16, 2018.

territory. The parameter value for this variable is expected to be positive, indicating a positive correlation of percent congested urban with total costs.

The **percentage of smart meters** variable measures the percentage of customers that have an installed smart meter. Smart meters enable hourly or sub-hourly interval use data to be collected from the meter. While installing more capable meters and the necessary infrastructure is expected to increase distribution costs, these meters enable time-of-use ("TOU") electricity rates that can create efficiencies mainly in the realm of power supply. Since this study is focused on distribution total costs, we would expect a positive coefficient on the percent smart meter variable.

The **distribution work variable** measures the percentage of transmission lines that are classified as transmission and are above 50 kV. This helps adjust for utilities classifying transmission and distribution assets differently. Some transmission utilities own lines that are below 50 kV and others do not. If the transmission system is taking on costs and serving lines that otherwise would be classified as distribution, this will tend to decrease costs for the distributor in that region relative to its peers. Likewise, if the distribution system is serving lines that would sometimes be classified as transmission for other utilities, this will tend to increase distribution costs for that utility relative to its sample peers. We use the 50 kV cut-off because this is the line used in the RRR reporting in Ontario between high voltage and low voltage. We would expect a positive correlation between distribution total costs and the percentage of lines above 50 kV served by the transmission utility.

The **O&M based scope variable** measures the percentage of distribution operation and maintenance expenses in the sum of distribution, transmission, and generation expenses. This variable measures the possible cost savings of serving multiple electric utility functions. We would expect that the increased availability of economies of scope would lower expenses and, therefore, a higher proportion of distribution-related expenses in total expenses is expected to have a positive parameter value.

The **number of distribution substations** measures the count of owned and operated substations that are classified as distribution. As the service territory requires a larger number of distribution stations, we would expect this to increase infrastructure and other costs for the distribution utility. This variable should have a positive parameter value.

The **capacity of distribution substations** measures the MVa capacity of those stations classified as distribution which are owned and operated by the utility. Higher capacity stations will tend to cost more and, thus, we expect to have a positive parameter value for this variable.

The **time trend** variable captures a general industry total cost level trend over the studied period. Time trend variables are often found in translog cost functions and standard in econometric total cost benchmarking research. In the present study, the variable is calculated by taking the current year of the observation and subtracting 1,999. For observations in the year 2000, the time trend variable equals 1. In 2019, the variable equals 20 (2,019 – 1,999). The coefficient value shows how adding an additional year increases or decreases total costs.

3.2 Distribution Sample

The distribution benchmarking sample is comprised of 78 U.S. utilities plus Toronto Hydro. The benchmark sample period begins in 2000 and extends to 2021. The sample is an unbalanced panel, which enables utilities that do not have available and plausible data for all sampled years to still be present in the sample for the years in which they do have available and plausible data. There are 1,642 U.S. utility observations in the sample. This large number of observations enables robust parameter estimates and a strong statistical model.

The sample of utilities within the sample is provided in the following table along with the number of customers for the most recent year within the sample for each utility. The econometric model actually

used to benchmark Toronto Hydro does not include the Company itself to assure a fully external benchmark value.

Table 5 Total Cost Benchmarking Sample

Company	Number of Customers	Company	Number of Customers
Alabama Power Company	1,510,098	Madison Gas and Electric Company	159,249
ALLETE (Minnesota Power)	149,660	MDU Resources Group, Inc.	144,044
Appalachian Power Company	964,442	Metropolitan Edison Company	581,453
Arizona Public Service Company	1,317,266	Nevada Power Company	967,596
Atlantic City Electric Company	564,929	New York State Electric & Gas Corporation	913,611
Avista Corporation	402,518	Niagara Mohawk Power Corporation	1,459,832
Baltimore Gas and Electric Company	1,320,806	Northern Indiana Public Service Company	481,132
Black Hills Power, Inc.	74,150	Northern States Power Company - MN	1,522,746
Central Hudson Gas & Electric Corporation	249,483	Northern States Power Company - WI	265,235
Central Maine Power Company	653,222	Ohio Edison Company	1,062,269
Cleco Power LLC	291,370	Oklahoma Gas and Electric Company	874,592
Cleveland Electric Illuminating Company	755,210	Orange and Rockland Utilities, Inc.	238,798
Commonwealth Edison Company	4,095,261	Pacific Gas and Electric Company	5,479,889
Connecticut Light and Power Company	1,272,110	PacifiCorp	1,967,124
Consolidated Edison Company of New York, Inc.	3,530,570	PECO Energy Company	1,681,439
Consumers Energy Company	1,870,123	Pennsylvania Electric Company	587,567
Delmarva Power & Light Company	539,708	Pennsylvania Power Company	169,371
DTE Electric Company	2,244,945	Portland General Electric Company	902,237
Duke Energy Carolinas, LLC	2,764,820	Potomac Electric Power Company	914,279
Duke Energy Florida, LLC	1,943,012	PPL Electric Utilities Corporation	1,466,253
Duke Energy Indiana, LLC	860,972	Public Service Company of Colorado	1,535,755
Duke Energy Kentucky, Inc.	146,514	Public Service Company of New Hampshire	525,933
Duke Energy Ohio, Inc.	731,414	Public Service Company of Oklahoma	568,226
Duke Energy Progress, LLC	1,644,179	Public Service Electric and Gas Company	2,323,747
Duquesne Light Company	606,085	Puget Sound Energy, Inc.	1,196,851
El Paso Electric Company	445,647	San Diego Gas & Electric Co.	1,370,621
Empire District Electric Company	178,984	South Carolina Electric & Gas Co.	765,965
Entergy Arkansas, Inc.	727,743	Southern California Edison Company	5,071,773
Entergy Mississippi, Inc.	458,987	Southern Indiana Gas and Electric Company, Inc.	153,433
Entergy New Orleans, Inc.	209,159	Southwestern Public Service Company	396,990
Florida Power & Light Company	5,214,245	Tampa Electric Company	802,049
Gulf Power Company	477,672	Toledo Edison Company	314,440
Idaho Power Co.	596,393	**Toronto Hydro**	**790,699**
Indiana Michigan Power Company	604,549	Union Electric Company	1,244,260
Indianapolis Power & Light Company	516,323	Virginia Electric and Power Company	2,698,553
Jersey Central Power & Light Company	1,150,247	West Penn Power Company	733,761
Kansas Gas and Electric Company	337,830	Wisconsin Electric Power Company	1,144,822
Kentucky Power Company	165,416	Wisconsin Power and Light Company	485,194
Kentucky Utilities Company	560,922	Wisconsin Public Service Corporation	454,892
Louisville Gas and Electric Company	427,163		

3.3 Distribution Total Cost Model

The parameter estimates from the total cost model used to calculate Toronto Hydro's total cost

benchmark are presented in the following table.[17]

Table 6 Total Cost Model Estimates

Variable	Coefficient	Standard Error	T-Statistic	P-Value
Constant	12.735	0.074	171.210	0.000
Customers (N)	0.512	0.012	43.130	0.000
Peak Demand (D)	0.397	0.018	22.160	0.000
Area (A)	0.050	0.006	9.040	0.000
N*N	0.490	0.085	5.780	0.000
D*D	0.840	0.065	12.970	0.000
A*A	0.036	0.009	3.910	0.001
N*D	-1.297	0.151	-8.610	0.000
N*A	0.096	0.013	7.260	0.000
D*A	-0.112	0.012	-9.060	0.000
% Electric	0.152	0.029	5.280	0.000
Standard Deviation of Elevation	0.012	0.004	3.320	0.003
% OH*% Forest	0.052	0.003	18.690	0.000
% Congested Urban	22.256	2.552	8.720	0.000
% AMI	0.060	0.013	4.690	0.000
Dx Work (% Tx Lines Above 50 kV)	0.157	0.027	5.740	0.000
O&M Scope Variable	0.088	0.008	11.700	0.000
# of Dx Substations	0.071	0.005	14.490	0.000
Capacity of Dx Substations	0.011	0.007	1.520	0.143
Trend	-0.005	0.001	-4.210	0.000

[17] We note that the capacity of Dx Substations is statistically significant at an 85% confidence level. This is lower than our typical 90% confidence level. Excluding the variable from the model improves Toronto Hydro's total cost score slightly.

All the parameter estimates are plausibly signed and have reasonable magnitudes. The first order terms of all variables have the theoretically expected signs and are statistically significant at a 90% level of confidence, except for the distribution substation variable which is significant at an 85% confidence level. In fact, all the other first order explanatory variables are statistically significant at a 99% confidence level. The adjusted R-Squared of the model equals a robust 0.977.

3.4 Total Cost Results

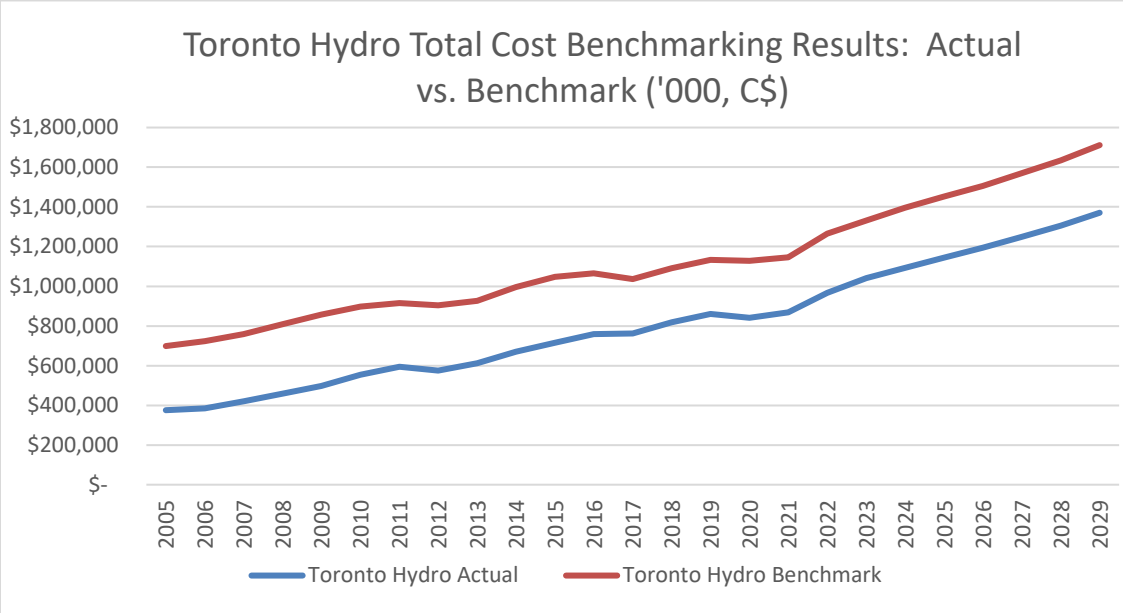
The following table breaks down the historical and forecast year benchmark and Company distribution total costs from 2005 through 2029. We note that the benchmark scores for the projected years assume that all the proposed spending will be incurred. If spending is less than the proposed amounts, the scores will improve; if spending is more than the proposed amounts, the scores will get worse.

Table 7 2005-2029 Total Cost Benchmark Score for Toronto Hydro

Year	% Difference from Total Cost Benchmark
2005	-62.1%
2006	-62.9%
2007	-59.3%
2008	-56.5%
2009	-54.5%
2010	-48.2%
2011	-43.1%
2012	-45.2%
2013	-41.6%
2014	-39.5%
2015	-38.1%
2016	-33.9%
2017	-30.7%
2018	-28.8%
2019	-27.6%
2020	-29.4%
2021	-27.6%
2022	-26.8%
2020-2022 average score	**-28.0%**
2023	-24.6%
2024	-24.4%
2025	-23.9%
2026	-23.1%
2027	-22.9%
2028	-22.6%
2029	-22.2%
2025-2029 average score	**-22.9%**

The following graph displays how Toronto Hydro's actual and projected total costs have compared to the benchmark costs over time and through the Custom IR period, respectively.

Figure 3 Toronto Hydro Total Cost: Actual vs. Benchmark



4 Reliability Benchmarking Models and Scores

Most, if not all, jurisdictions that require reporting of reliability indicators include the metrics of SAIDI, SAIFI, and CAIDI.[18] SAIDI measures the average duration of sustained interruptions per utility customer. SAIFI is a gauge of the average frequency of sustained interruptions per customer. CAIDI evaluates the average duration time per sustained interruption. SAIDI is thus the product of SAIFI and CAIDI.

$$SAIDI = SAIFI * CAIDI$$

The reliability benchmarking study performed by Clearspring focused on the reliability indexes of SAIFI and CAIDI. SAIFI measures the average number of outages a customer experiences per year. It indirectly measures the propensity of the distribution grid to fail. CAIDI measures the average restoration time when an outage does occur. It indirectly measures the Company's response time and preparedness for outage restoration.

Several jurisdictions, including Ontario in recent years, exclude extraordinary events from reliability statistics, with the goal of reducing year over year volatility due primarily to extreme weather. If a day is excluded, it is denoted as a major event day ("MED"). The bulk of MEDs stem from major storms. These severe storms vary in number and intensity from year to year. MED definitions vary by jurisdiction and/or utility; some use the Institute of Electrical and Electronics Engineers ("IEEE") standard 1366 to determine what constitutes a MED.[19] The industry appears to gradually be shifting towards the IEEE standard; however, considerable differences across utilities remain.

The reliability benchmarking study excluded MEDs from the SAIFI and CAIDI metrics but includes loss of supply outages to be consistent with the U.S. data. By excluding MEDs from the reliability indexes, we reduce the variance in the indexes associated with large and uncontrollable weather occurrences. The benchmark evaluation in this study is measuring the performance of utilities during the normal operations and not during severe weather events.

The industry reliability data for U.S. utilities is gathered through the EIA Form 861. This form has been gathering U.S. utility reliability indexes every year since 2013. Therefore, Clearspring's reliability dataset for the U.S. observations begins in 2013 and ends in 2021. Toronto Hydro provided its historical reliability results from 2005 to 2022 and then projections from 2023 to 2029.[20] These metrics exclude MEDs using the IEEE definition and are based on a 5-minute sustained outage definition, which is the predominant definition used in the U.S. data.

[18] Some U.S. states only require reporting of two of these measures. However, the excluded indicator can still be determined by the researcher.

[19] The IEEE 1366 standard defines the "beta" method. If outages for a certain day exceed 2.5 standard deviations from the normal day, a major event day is declared. A normal day and the standard deviation are determined by the utility's previous five years of normal day data (not including the MEDs).

[20] The 2023 reliability data is historical through October 15, 2023 and then forecasted for the remainder of the year.

The following table lists the utilities included in the reliability dataset. The reliability dataset is composed of 80 U.S. distributors, plus Toronto Hydro.[21] There are 687 observations in the reliability dataset. This is sufficient to estimate statistically robust parameter estimates. The econometric model actually used to benchmark Toronto Hydro does not include the Company itself to assure a fully external benchmark value.

[21] As with the total cost model, the sample excludes Toronto Hydro's observations when estimating the model used to calculate the Company's benchmarks.

Table 8 Sampled Utilities for Reliability Benchmarking

Company	Number of Customers	Company	Number of Customers
Alabama Power Company	1,510,098	Metropolitan Edison Company	581,453
ALLETE (Minnesota Power)	149,660	Mississippi Power Company	190,660
Appalachian Power Company	964,442	Monongahela Power Company	395,031
Arizona Public Service Company	1,317,266	Nevada Power Company	967,596
Atlantic City Electric Company	564,929	New York State Electric & Gas Corporation	913,611
Avista Corporation	402,518	Niagara Mohawk Power Corporation	1,459,832
Baltimore Gas and Electric Company	1,320,806	Northern Indiana Public Service Company	481,132
Black Hills Power, Inc.	74,150	Northern States Power Company - MN	1,522,746
Central Hudson Gas & Electric Corpor	249,483	Northern States Power Company - WI	265,235
Central Maine Power Company	653,222	Ohio Edison Company	1,062,269
Cleco Power LLC	290,021	Oklahoma Gas and Electric Company	874,592
Cleveland Electric Illuminating Compa	755,210	Orange and Rockland Utilities, Inc.	238,798
Commonwealth Edison Company	4,095,261	Pacific Gas and Electric Company	5,479,889
Connecticut Light and Power Compan	1,272,110	PacifiCorp	2,002,780
Consolidated Edison Company of Nev	3,530,570	PECO Energy Company	1,681,439
Consumers Energy Company	1,870,123	Pennsylvania Electric Company	587,567
Delmarva Power & Light Company	539,708	Pennsylvania Power Company	169,371
DTE Electric Company	2,244,945	Portland General Electric Company	912,209
Duke Energy Carolinas, LLC	2,764,820	Potomac Electric Power Company	914,279
Duke Energy Florida, LLC	1,943,012	PPL Electric Utilities Corporation	1,466,253
Duke Energy Indiana, LLC	860,972	Public Service Company of Colorado	1,535,755
Duke Energy Kentucky, Inc.	146,514	Public Service Company of New Hampshire	529,986
Duke Energy Ohio, Inc.	731,414	Public Service Company of Oklahoma	568,226
Duke Energy Progress, LLC	1,644,179	Public Service Electric and Gas Company	2,323,747
Duquesne Light Company	606,085	Puget Sound Energy, Inc.	1,196,851
El Paso Electric Company	445,647	South Carolina Electric & Gas Co.	765,965
Empire District Electric Company	178,984	Southern California Edison Company	5,071,773
Entergy Arkansas, Inc.	727,743	Southern Indiana Gas and Electric Company, Inc.	153,433
Entergy Mississippi, Inc.	458,987	Southwestern Public Service Company	396,990
Entergy New Orleans, Inc.	209,159	Tampa Electric Company	802,049
Florida Power & Light Company	5,214,245	Toledo Edison Company	314,440
Gulf Power Company	477,672	**Toronto Hydro**	**790,699**
Idaho Power Co.	596,393	Tucson Electric Power Company	419,845
Indiana Michigan Power Company	604,549	Union Electric Company	1,244,260
Indianapolis Power & Light Company	516,323	United Illuminating Company	342,161
Jersey Central Power & Light Compan	1,150,247	Virginia Electric and Power Company	2,698,553
Kansas Gas and Electric Company	337,830	West Penn Power Company	733,761
Kentucky Power Company	165,416	Wisconsin Electric Power Company	1,144,822
Kentucky Utilities Company	565,153	Wisconsin Power and Light Company	485,194
Louisville Gas and Electric Company	427,163	Wisconsin Public Service Corporation	454,892
Madison Gas and Electric Company	160,976		

4.1 Econometric Reliability Benchmarking Variables and Models

Clearspring did not change the variables for either the SAIFI or CAIDI models that were included in the prior Toronto Hydro research, except to take out the percentage AMI variable in the CAIDI model because it was not statistically significant. The procedure for estimating the two reliability models is much the

same as the procedure for the cost models, except that different variables are used. Refer to Section 2 for a general description of the model creation process.

Both the SAIFI and CAIDI models use reliability metrics with MEDs excluded. The SAIFI model's variables, parameter estimates, and statistical tests used to calculate the benchmarks are presented in the following table. The included variables are signed according to theory and statistically significant at a 90% confidence level.

Table 9 SAIFI Econometric Model Coefficients

Variable	Coefficient	Standard Error	T-Statistic	P-Value
Intercept	0.223	0.041	5.430	0.001
Number of Customers	0.030	0.008	3.960	0.004
% Forestation	0.050	0.014	3.660	0.006
% Plant Underground	-2.240	-0.052	43.400	0.000
Sq. KM per Customer	2.341	0.221	10.570	0.000
IEEE MED Definition	0.190	0.044	4.320	0.003

The CAIDI model statistics are presented in the table below. The included variables are signed according to theory and statistically significant at a 90% confidence level, with the exception of the customer

variable which is typically always included in a reliability model.

Table 10 CAIDI Econometric Model Coefficients

Variable	Coefficient	Standard Error	T-Statistic	P-Value
Intercept	4.693	0.028	167.590	0.000
Number of Customers	0.006	0.006	1.010	0.341
% Forestation	0.048	0.003	15.520	0.000
Standard Deviation of Elevation	0.064	0.003	19.200	0.000
Sq. KM per Customer	0.060	0.004	14.010	0.000
% Congested Urban	20.199	2.341	8.630	0.000

4.2 Econometric Reliability Scores

We find that Toronto Hydro's most recent 3-year (2020 to 2022) SAIFI value is 98.8% above the benchmark value. During the Custom IR period of 2025 to 2029, the SAIFI projection from the Company is 99.4% above the benchmark.

The most recent 3-year CAIDI value is 104.1% below the benchmark value. During the Custom IR period of 2025 to 2029, the CAIDI projection from the Company is 110.2% below the benchmark. The following table displays the SAIFI and CAIDI actuals (or projections), the benchmarks, and the percentage

differences from those benchmarks.

Table 11 Year-by-Year Reliability Benchmarks vs. Actual

Year	SAIFI (Actual)	SAIFI (Benchmark)	SAIFI (% Difference)	CAIDI (Actual)	CAIDI (Benchmark)	CAIDI (% Difference)
2005	0.93	0.46	70.2%	76.59	110.00	-36.2%
2006	1.11	0.46	88.1%	64.98	110.73	-53.3%
2007	1.14	0.47	89.7%	69.12	111.59	-47.9%
2008	1.08	0.46	85.0%	67.40	112.68	-51.4%
2009	0.95	0.46	72.8%	84.13	113.75	-30.2%
2010	0.98	0.46	75.5%	77.30	115.32	-40.0%
2011	1.05	0.45	83.9%	80.13	117.26	-38.1%
2012	0.88	0.45	67.4%	68.06	118.66	-55.6%
2013	0.95	0.45	75.8%	70.61	120.35	-53.3%
2014	0.92	0.45	72.6%	63.76	123.09	-65.8%
2015	0.97	0.44	78.4%	64.04	125.48	-67.3%
2016	0.93	0.45	73.3%	59.71	128.08	-76.3%
2017	1.09	0.45	87.4%	53.14	129.25	-88.9%
2018	1.09	0.46	86.8%	53.25	130.44	-89.6%
2019	0.95	0.45	73.9%	50.39	132.46	-96.6%
2020	1.11	0.45	91.2%	50.77	135.21	-98.0%
2021	1.20	0.44	100.3%	48.55	136.49	-103.4%
2022	1.24	0.43	105.0%	45.75	138.95	-111.1%
2020-2022 average	**1.18**	**0.44**	**98.8%**	**48.36**	**136.88**	**-104.1%**
2023	1.28	0.43	114.2%	42.76	141.81	-119.9%
2024	1.19	0.43	98.3%	51.28	144.87	-103.9%
2025	1.19	0.43	96.5%	51.49	148.16	-105.7%
2026	1.18	0.43	95.7%	51.54	151.67	-107.9%
2027	1.17	0.43	94.8%	51.68	155.43	-110.1%
2028	1.17	0.43	93.8%	51.85	159.47	-112.3%
2029	1.16	0.43	93.8%	51.96	163.82	-114.8%
2025-2029 average	**1.17**	**0.43**	**99.4%**	**51.70**	**155.71**	**-110.2%**

While SAIFI and CAIDI are modeled separately, the actuals and benchmarks for those metrics can be multiplied together to produce a Sustained Average Interruption Duration Index ("SAIDI") benchmark score. The following table provides the comparison between Toronto Hydro's actual (or projected) SAIDI, the benchmark value, and the percentage difference of the actual/projected to the benchmark.

Table 12 Toronto Hydro's SAIDI Actuals and Benchmarks 2005-2029

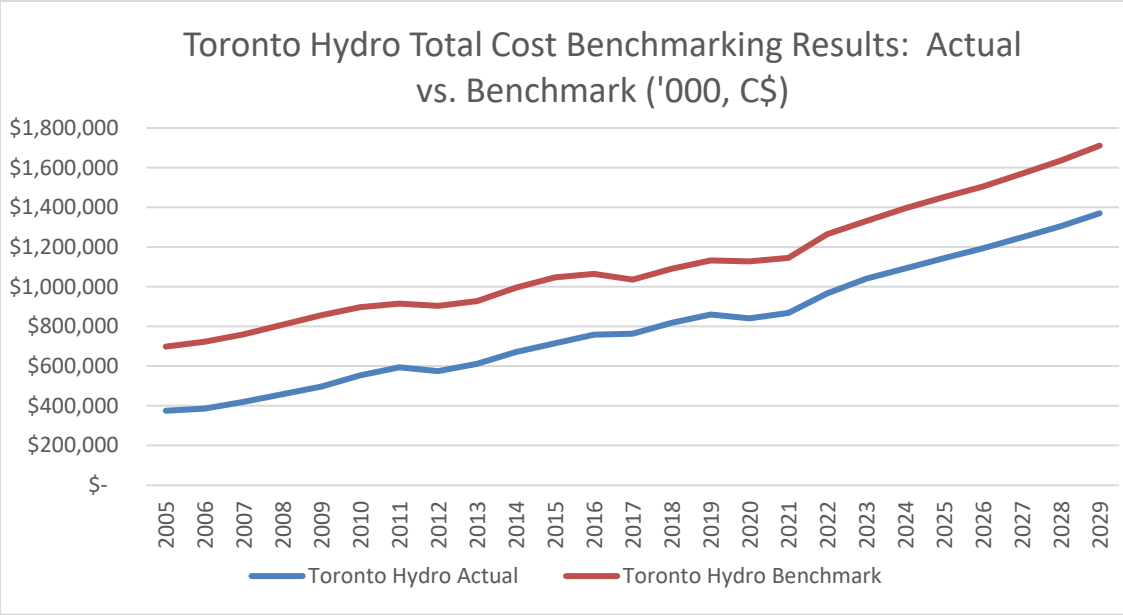
Year	SAIDI (Actual)	SAIDI (Benchmark)	SAIDI (% Difference)
2005	71.3	50.7	34.0%
2006	71.9	50.7	34.8%
2007	78.9	51.9	41.8%
2008	72.9	52.1	33.7%
2009	80.2	52.3	42.7%
2010	75.4	52.8	35.5%
2011	84.2	53.2	45.8%
2012	60.2	53.5	11.8%
2013	67.1	53.6	22.4%
2014	58.8	54.9	6.8%
2015	61.9	55.4	11.2%
2016	55.7	57.4	-3.1%
2017	58.1	58.8	-1.1%
2018	57.8	59.7	-3.3%
2019	47.8	60.1	-22.9%
2020	56.3	60.3	-6.9%
2021	58.2	60.1	-3.1%
2022	56.8	60.3	-6.0%
2020-2022 average	**57.1**	**60.2**	**-5.3%**
2023	54.8	61.5	-11.7%
2024	61.0	62.9	-3.0%
2025	61.2	64.3	-5.0%
2026	60.8	65.9	-8.0%
2027	60.6	67.5	-10.8%
2028	60.5	69.2	-13.6%
2029	60.2	71.1	-16.7%
2025-2029 average	**60.6**	**67.6**	**-10.8%**

5 Concluding Remarks and Stretch Factor Recommendation

This study provides benchmarking results useful for evaluating Toronto Hydro's 2025-2029 Custom IR application. The study has estimated total cost and reliability models that explicitly account and adjust for the service territory characteristics of Toronto Hydro. The models are statistically robust and provide accurate benchmark comparisons.

The total cost results show that Toronto Hydro's historical and projected cost levels are below expected levels. Toronto Hydro has consistently remained below its total cost benchmarks and remains below them throughout the Custom IR period, given its proposed spending levels. The graph below illustrates this consistency.

Figure 4 Actual and Benchmark Total Cost of Toronto Hydro Over Time



In the 4th Generation IR proceeding, five stretch factor groupings or cohorts were established based on the most recent three-year total cost benchmarking score. A score better than -25% (i.e. costs were more than 25% below benchmark) received the lowest stretch factor of 0.00%. A score between -25% and -10% received a 0.15% stretch factor. Scores that are +/- 10% received 0.30%. Scores between 10% and 25% received a 0.45% stretch factor, and scores exceeding 25% (i.e., costs were more than 25% above benchmark) received the highest stretch factor of 0.60%.

Our total cost study findings for Toronto Hydro show that during the Custom IR period, the Company's total cost benchmarking score is -22.9%. Based on the 4th Generation IR stretch factors and Clearspring's econometric benchmarking results, the appropriate stretch factor is 0.15%. This stretch factor not only aligns with Toronto Hydro's strong total cost benchmarking results, but also aligns well with other recent stretch factor precedents in Canada and the States.

Appendix A: Total Cost Benchmarking Methodology Details

Variable Types

In general, there are two types of variables used in econometric cost benchmarking: output variables and business condition variables. Output variables measure the output of the utility in question (i.e. what the utility "produces"). Business condition variables quantify the factors that drive costs in a particular service territory, such as regional input prices, highly congested urban areas, forestation, etc.

Output Variables

The three output variables for the distribution total cost benchmark study are the number of customers, a rolling ten-year average of peak demand, and the service area of each utility. This matches the outputs specified in Clearspring's Hydro One distribution cost benchmarking research. With the exception of a minor difference in the peak demand variable definition, this also matches PEG's Hydro One distribution cost benchmarking research and matches PEG's response to Clearspring's model in the last distribution application for Hydro Ottawa (again, with the slight modification of the peak demand variable).[22]

For the U.S. utilities, the output variables are calculated from FERC Form 1s. The customers are based on the reported data. The peak demand variable is defined for both studies using the annual peak demand value found on p. 401b of the FERC Form 1. This variable consists of the distribution system peak demands plus the required sales for resale. We adjusted the data to take out the proportion of the required sales for resale. This aligns with the treatment of peak demand that both Clearspring and PEG undertook in the Hydro One and Hydro Ottawa application.

The service area used for each utility is based on variables derived from GIS mappings of each utility's service area. The values used correspond to what both Clearspring and PEG used in the last Hydro One and Hydro Ottawa application.

Business Condition Variables: Input Prices

Business condition variables are discussed in following sections. However, one important business condition variable merits detailed discussion: input prices. Input prices are divided into two categories: capital and OM&A. The capital input price calculation used in our research is called the Perpetual Inventory Method and is discussed in detail in a following section. The OM&A input price captures the regional market price level that each utility encounters when procuring OM&A inputs, such as employees or materials and services. There are two components used to construct the OM&A input price. These are labour and non-labour.

[22] PEG "ratchets" the peak demand variable such that it takes the higher of all prior observations or the current annual peak demand value. Thus, the variable value can never decrease. Clearspring uses a ten-year rolling average of the annual peak demand value enabling the variable to decrease over time if peak demands are decreasing.

The labour component is calculated by taking wage levels of numerous job occupations and weighting them based on the U.S. Bureau of Labor Statistics ("BLS") estimates of job occupation weights in the Electric Power Generation, Transmission, and Distribution Industry. The BLS has estimates for wage levels for each job occupation by city and metropolitan area. To ascertain Toronto Hydro's wage level, we gathered job occupation wage estimates from the 2011 Canadian Census, using wage data reported for Ontario, translated job occupations to match their U.S. counterparts, and then weighted the job occupation wages by the BLS estimates. This provides consistency from the U.S. and Ontario regarding labour input prices and puts the input price in terms of each country's currency. We then escalated labour prices for U.S. utilities using BLS employment cost indices for the utility sector and escalated Toronto Hydro prices using the Ontario average weekly earnings estimates.

The non-labour component of the OM&A input price uses the U.S. gross domestic product price index for the U.S. utilities. The Toronto Hydro non-labour component uses the Canadian GDP-IPI in each year, but with a levelization adjustment using the purchasing power parity ("PPP") index in 2012. This translates the non-labour input price component into Canadian dollars.

To construct the overall OM&A input price we weighted each index using the customized labour and non-labour cost shares calculated from the FERC Form 1 data or based on data provided to us from Toronto Hydro. We then took the OM&A input price and combined it with the capital price using the capital and OM&A cost shares. This produces the total input price index.

Total cost is divided by this comprehensive input price index to adjust for regional input price differences between utilities and to account for annual inflation. Dividing total cost by the input price index imposes the requirement that total costs display linear homogeneity with respect to input prices. As the prices of inputs increase by X%, total cost should increase by that same percentage. For example, if all utility input prices (including labour) increase by 10%, its costs would also increase by 10%. This is derived from economic production theory, which states that costs equal input quantity multiplied by input price.

Other Business Condition Variables

Beyond the output variables and input prices, each model contains business condition variables that provide cost adjustments for given service territory conditions. These variables enable unique service territory conditions to be accurately benchmarked on an "apples to apples" basis. This ability to adjust for specific conditions is why the econometric benchmarking approach is more accurate and fair than unit cost approaches. Unit cost benchmarking tends to only reveal which utility has the most challenging service territory, rather than indicating cost performance. This is because service territory conditions have a profound impact on the cost levels of transmission and distribution utilities. Their capital assets are spread across the entire service territory, and the overall cost levels are thus highly influenced by the conditions the utility is faced with. These cost drivers and specific service territory conditions need to be accounted for to reveal and estimate the performance of the utility.

The business conditions used for the distribution total cost and reliability models are described in each model's specific Chapter.

Perpetual Inventory Method

Total cost is defined as the sum of the annual OM&A expenses plus capital costs. Clearspring's calculation of capital cost is based on the capital service price approach. This approach has a solid basis in economic theory; it is the same method used in all the Ontario benchmarking and productivity studies conducted by Mr. Fenrick, and is the same method chosen by PEG in its 4GIR research and its other studies in CIR applications.[23] The approach allows for a consistent way to account for differences between utilities with respect to historical plant additions and depreciation rates. The service price approach is also prominent in government-sponsored cost research. The Bureau of Labor Statistics of the U.S. Department of Labor uses the capital service price approach in computing multi-factor productivity indices for the U.S. private business sector and for several subsectors, including the utility services industry.

The cost of capital in each year *(t)* is the product of the capital service price index and capital quantity index at the end of the prior year (*t-1)*. The formula for this is given by:

$$CK_t = WKS_t \cdot XK_{t-1}$$

CK_t is the cost of capital, WKS_t is the capital service price index, and XK_{t-1} is the capital quantity index value in the prior period.

The capital quantity index (*XK*) is constructed based on the value of net plant in a benchmark year, and on gross plant additions in years subsequent to the capital benchmark year. In an effort to address past concerns of PEG regarding the start year (capital benchmark year) of this capital series, we put considerable effort into gathering and processing U.S. utility data going back to 1947.[24] We use 1947 for most of the U.S. sampled utilities as the capital benchmark year. A few utilities only had consistent data beginning in 1959, for those utilities we used 1959 as the capital benchmark year. We used 2002 as the capital benchmark year for Toronto Hydro, because this is the first year where data is available and can be readily verified.

A "triangulated weighted average" ("TWA") is used to divide the net plant value in order to adjust the net plant value for historical inflation.[25] This results in an estimate of the capital stock in 1947, 1959, or 2002

[23] See Hall and Jorgensen (1967) for a seminal discussion of the use of service price methods for measuring capital cost.

[24] In our past studies prior to the last Hydro One research, we used 1989 for the capital benchmark year, as that was the first year of electronically available data. We considered 1989 to be a sufficient start year for the capital series. However, to reduce the research differences, considerable efforts were invested into gathering and processing these data.

[25] For the U.S. sample, the 1947 or 1959 net plant value is for the total utility. To calculate a transmission or distribution net plant value we multiplied the total net plant value by the percentage of transmission or distribution gross plant in service to total gross plant in service, respectively. We note that any error in this net plant value calculation in 1947 or 1959 will have an extraordinarily minimal impact on the cost levels once the sample starts in 2000. This is because any possible small error in 1947 will have also depreciated for 53 years by the time it enters the sample period.

based on when the capital benchmark year begins for the utility. Subsequent years use the previous year's capital stock multiplied by one minus the depreciation rate and then escalated by that year's plant additions divided by the asset price in that year.[26] This same method is used for both Toronto Hydro and U.S. distributors. The formulas for the capital quantity index in 1947 and in subsequent years are provided below.[27]

$$XK^i_{1947} = \frac{Net\ Plant^i_{1947}}{TWA^i_{1947}}$$

$$XK^i_t = XK^i_{t-1} * (1-d) + \frac{Add^i_t}{WKA^i_t}$$

The capital service price (*WKS*) has two components: opportunity cost and depreciation. The capital service price index is thus given by the formula:

$$WKS_t = r_t * WKA_{t-1} + d_t * WKA_t$$

Here, r_t is the allowed rate of return based on the Board's historical calculated returns. This same annual value is also used in the capital service price computation for the U.S utilities in the dataset. Setting the same rate of return for all distributors provides consistency in determining the capital costs, so that decisions by regulators do not enter the benchmark evaluation, which is attempting to assess the performance of the utility itself. The parameter d_t is the economic depreciation rate. For this depreciation rate, we use the same value as we have used in all our distribution CIR benchmarking applications and the same one PEG used in the 4GIR proceeding and subsequent research: 4.59%.

The asset price deflator (*WKA*) is an index of the price of capital assets in each year. In several CIR applications, this has been an area of contention between PEG and our research team. Historically, Clearspring used the U.S.-based Handy-Whitman indices for both the U.S. sample and Canadian utilities, as these are well-known and provide asset inflation estimates that are specific to electric transmission or distribution.[28] Both Clearspring and PEG (at least historically) use the Handy-Whitman indices for the U.S. sample.

However, when estimating asset inflation for a Canadian utility, PEG has used Handy-Whitman indices in some of its prior research but has sometimes preferred a Canadian-specific asset inflation measure in some applications. The advantage of the latter approach is that it is specific to Canadian asset inflation; the disadvantage is that the measure is a comprehensive measure of water, sewer, gas, and electric utilities (including generation). In the Hydro Ottawa CIR research, PEG compromised between these two asset inflation measures and used a 50% weighting on the Handy-Whitman indices and a 50% weighting on their

[26] The historical data going back to 1948 and forward all have plant in service additions disaggregated by transmission and distribution, enabling us to build up a robust capital quantity and cost estimate for each function.

[27] For the Ontario distributors, the subscripts would change to 2002 in the first equation.

[28] For Canadian utilities we adjust the Handy-Whitman for the purchasing price parity (PPPs) in each given year to put the inflation estimate into Canadian dollars.

implicit capital stock index measure. In the Hydro One research, Clearspring also moved to this compromise of a 50/50 weighting. In that application, both researchers used the 50/50 weighting which eliminated this area as a point of contention. Clearspring is using that same 50/50 weighting index in this application.

For the U.S. sample, we compute this index using data on differences in the cost of constructing utility plant between regions over time. For U.S. distributors, we use the Handy-Whitman indices for total power distribution plant; these indices vary over time and across six geographic regions.[29] For Toronto Hydro, we use the same Handy-Whitman index for total distribution plant in the North Atlantic region and then adjust for the Canadian purchasing power parity in the given year. This is for half of the weight in the index; for the other half, we use PEG's implicit capital stock deflator index found in the Capital Flows and Stocks data provided by Stats Canada.[30] For future years, we escalate the WKA index using a 50/50 calculation of the projections for the average weekly earnings in Ontario and the GDP-IPI index available from the Conference Board of Canada.

We determine the relative levels of utility plant asset prices for 2015 by using the City Cost Indices for electrical work in the 2016 edition of RSMeans' *Heavy Construction Cost Data*. These indices measure differences among cities in the cost of labour needed to install electrical equipment and differences in equipment prices. The construction service categories covered are: raceways; conductors and grounding; boxes and wiring devices; motors, starters, boards, and switches; transformers and bus ducts; lighting; electric utilities; and power distribution.

We modified this calculation in response to concerns put forth by PEG and other stakeholders prior to the most recent Hydro One application. The prior method was to calculate the level of the asset price index for each utility by the headquarter city in the service territory (or the closest available city). The concern was that the headquarter city might not be reflective of the entire service territory of the utility.

In response to this concern, we modified the asset price level calculation in the most recent Hydro One research to be based on a population-weighted average of the RS Means value for each 3-digit zip code served by a given utility. This spreads the levelization across the entire service territory, rather than centering on the headquarter city. We follow this same procedure in the current Toronto Hydro research. The index is already adjusted for currency differences between the two countries.

Model Estimation Procedure and Specification

We assume that the relationship between a utility's cost and the conditions that affect it, called "cost drivers," can be quantified and captured by a statistical function. This function, called a "cost function," allows Clearspring to specify cost as a dependent variable that can be explained by relevant independent or explanatory variables and associated parameters; the latter capture the effect of the independent

[29] Handy-Whitman indexes are widely used throughout the U.S. utility industry. They measure the construction cost trends for specific utility functions in six different regional areas of the U.S. For more information, please see: https://wrallp.com/about-us/handy-whitman-index

[30] We note that at the time of the research, this Canadian index was only available through 2020. For 2021, we escalated the Toronto Hydro index fully by the appropriate Handy-Whitman index.

variables on cost. Such a cost function is estimated using econometric techniques that rest on certain fundamental assumptions.

As implied by the term "independent," one of these assumptions is that the explanatory variables used in the model are factors that are outside the control of utility decision-makers. For instance, the wage paid to labour is driven by market conditions in the service territory and is largely outside the control of a firm's managers. On the other hand, the number of employees hired is within management's control, and thus should not serve as an independent variable.

The data used to estimate this cost relationship can be from a single firm with multiple time observations (time series data), from many firms observed at a single time period (cross-sectional data), or from many firms with multiple time observations (cross-sectional time-series or panel data). The estimation procedure used to estimate model parameters is affected by the type of data used to estimate the model. In our present study, we have a panel dataset with cost data from multiple firms with observations starting in 2000 and extending to 2021. For benchmarks of past years, we use the model to produce benchmarks for each year and compare Toronto Hydro's benchmark costs with its actual costs.

Additionally, for future years we can take Toronto Hydro's cost projections through 2029, allowing us to also benchmark those forecasts "out of sample." We use the model (which is based on historical data) and apply the estimated coefficients and projected independent variable values for Toronto Hydro to calculate a predicted benchmark value. This predicted benchmark value is then compared to Toronto Hydro's projected total cost amount.

Statistical Tests on Parameter Estimates

The precision of parameter estimates is an important dimension of the cost estimation exercise. It identifies business condition variables that have a statistically significant effect on cost. Standard errors of parameter estimates, which measure the precision with which a parameter is estimated, are used to construct a test of a relevant hypothesis. The hypothesis to be tested is "the explanatory variable in question has no statistically significant effect on cost." This procedure is called the *t*-test. A variable is statistically significant if this hypothesis is rejected at a pre-specified level of confidence. We use a 90% confidence threshold in our research for all first order terms. This restriction is not placed on the quadratic and interaction output terms that comprise the translog cost function.

A cost model with plausibly signed and statistically significant parameter estimates is ultimately used to assess the cost performance of each firm in the sample. By "plausibly signed" we mean that its sign (positive/negative) accords with our intuitive understanding of the relationship between that parameter and the variable. For example, we would expect to see distribution costs rise as the number of customers served increases (i.e. we expect that the customer parameter would be positively signed).

Once the industry cost model is estimated, the cost model with estimated parameters is fitted with the business conditions of each utility to generate cost benchmarks, against which actual cost is evaluated. A cost benchmark for a particular utility reflects the performance we would expect from an average hypothetical utility facing the business conditions of that utility.

If a given utility's actual cost is below the benchmark cost, its cost performance is better than average—it spent less than a hypothetical utility (with the same particular characteristics) would be expected to spend. If its actual cost is above the benchmark cost, its cost performance is worse than average. A statistical test of a cost efficiency hypothesis, based on the *t*-test, can also be constructed to identify whether the cost performance identified by the above exercise is statistically significantly different from average.

Model Specification

A translog function is selected for the total cost model estimated in this study. The translog cost function was the same functional form we have used in all our prior CIR research, and the one chosen by PEG in its 4GIR benchmarking research and subsequent CIR research. The function's general form, after suppressing time and firm subscripts, is given by:

$$ln\left(\frac{C}{W}\right) = \propto_0 + \sum_i \alpha_i \, ln\, Y_i + \sum_j \alpha_j ln Z_j + \frac{1}{2}\left[\sum_{i,k} \propto_{ik} \, ln Y_i * ln\, Y_k\right] + \alpha_t t + \varepsilon$$

In this specification, $\alpha's$ are model parameters, and ε is the random noise term. In addition, Y_i quantifies output, W is the input price, Z_j is the other business condition variables, and *t* is a time trend term. This form has been widely used in cost function research.[31] A major advantage is its flexibility, which permits it to provide a good approximation for the wide range of functional forms that the data can reflect.[32]

Estimation Approach

As discussed earlier, the estimation approach has generated considerable discussion between benchmarking consultants in prior CIR proceedings. This is especially difficult for intervenors and the Board, due to the intricacies and difficulties for non-econometricians to evaluate these different approaches. However, it appears this difficulty has been addressed as both PEG and Clearspring used the same estimation approach in the most recent Hydro One application. Clearspring believes this best serves the Ontario industry for the benchmarking consultants to use consistent and pre-determined estimation approaches for all CIR benchmarking research.

The estimation procedure used to estimate model parameters is affected by the type of data used to estimate the models. In our present benchmarking studies, we have an unbalanced panel dataset with cost and reliability data from multiple utilities with multiple observations starting in 2000 and extending to 2021.

In multivariate regression analysis, the constructed model is designed to use a set of independent (often called explanatory or right-hand-side) variables to "explain" movement in the dependent (often called the

[31] In their Monte Carlo studies of functional forms' performance, Gagne and Ouellette (1998) use the translog as a benchmark because "it is the most widely used" functional form.

[32] See Guilkey, et al. (1983)

left-hand-side) variable. The numerical relationship between an independent variable and the dependent variable is provided through an estimated coefficient value. Under the assumptions of the model, this coefficient value is considered an unbiased estimator of the relationship. Multivariate regression analysis also makes statements about the precision of each coefficient value. Precision in this context is a statement about how confident or statistically valid the coefficient value is. When all the assumptions of multivariate regression are satisfied, the coefficient values are the best (or most precise) unbiased estimators that are available.

Two common issues arise in multivariate regression using real world data: heteroscedasticity and autocorrelation. Neither of these issues causes the coefficient values to be biased or less precise. This is important because it means the researcher does not need to worry about correcting the coefficient values: they are not misleading. However, both conditions render the standard error estimates which measure precision problematic. Specifically, the problem with heteroscedasticity and autocorrelation is that they increase the regression variance calculations, which means the researcher is less confident in the calculated coefficient values. For decades, the standard correction procedure involved trying to figure out the nature of each problem and strategically weighting the regression to render heteroscedasticity and autocorrelation less of a problem. One key issue with this strategy is that the researcher may have a hard time truly understanding how to reweight the regression. Additionally, the coefficient values will be different after the reweighting.

More recent treatments for dealing with heteroscedasticity and autocorrelation focus the correction procedures on methods that do not alter the regression or the coefficient values. Instead of reweighting the regression itself, these strategies leave the regression unaltered and focus on altering the way the variances of the coefficients are calculated. These procedures are systematic and do not depend on understanding the underlying reason for the heteroscedasticity and autocorrelation.

For our analysis, we have chosen to estimate the precision of our coefficients using Driscoll-Kraay standard errors.[33] Driscoll-Kraay standard errors have been coded and available in the STATA software suite since 2007.[34] The computer software calculates information crucial to understanding whether each relationship (as described by each coefficient) can be supported statistically.

[33] Driscoll, J., and A. C. Kraay, 1998. "Consistent covariance matrix estimation with spatially dependent data," *Review of Economics and Statistics* 80: 549–560.

[34] Hoechle, Daniel, 2007 "Robust standard errors for panel regressions with cross-sectional dependence," *The Stata Journal* 7(3): 281-312.

Appendix B: Resume of Steve Fenrick

STEVEN A. FENRICK, Principal

Steve.fenrick@clearspringenergy.com (608.334.5994)

SUMMARY OF EXPERIENCE AND EXPERTISE

I have directed project teams and engaged in research in the fields of performance based regulation, performance benchmarking, DSM, load research and forecasting, and survey design and implementation.

I have been an expert witness in a number of cases involving performance-based ratemaking and incentive regulation, load forecasting, and peak time rebates.

PROFESSIONAL EXPERIENCE

Clearspring Energy Advisors, LLC– Madison, WI (2019 to Present)

Principal Consultant

Responsible for providing consulting services and expert witness testimony to utilities and regulators in the areas of reliability and cost benchmarking, productivity studies and other empirical aspects of performance-based ratemaking and incentive regulation. Manage activities in the areas of demand-side management programs, peak time rebate programs, load forecasting, and market research.

Power System Engineering, Inc.– Madison, WI (2009 to 2018)

Director of Economics

Responsible for providing consulting services to utilities and regulators in the areas of reliability and cost benchmarking, incentive regulation, value-based reliability planning, demand-side management including demand response and energy efficiency, ran peak time rebate programs, load research, load forecasting, end-use surveys, and market research.

Pacific Economics Group – Madison, WI (2001 - 2009)

Senior Economist

Co-authored research reports submitted as testimony in numerous proceedings in several states and in international jurisdictions. Research topics included statistical benchmarking, alternative regulation, and revenue decoupling. Managed and supervised PEG support staff in research and marketing efforts.

EDUCATION

University of Wisconsin - Madison, WI

Bachelor of Science, Economics (Mathematical Emphasis)

University of Wisconsin - Madison, WI

Master of Science, Agriculture and Applied Economics

PUBLICATIONS & PAPERS

"Peak-Time Rebate Programs: A Success Story", *TechSurveillance*, July 2014 (with David Williams and Chris Ivanov).

"Demand Impact of a Critical Peak Pricing Program: Opt-In and Opt-Out Options, Green Attitudes and other Customer Characteristics:, *The Energy Journal*, January 2014. (With Lullit Getachew, Chris Ivanov, and Jeff Smith).

"Evaluating the Cost of Reliability Improvement Programs", *The Electricity Journal*, November 2013. (With Lullit Getachew)

"Expected Useful Life of Energy Efficiency Improvements", Cooperative Research Network, 2013 (with David Williams).

"Cost and Reliability Comparisons of Underground and Overhead Power Lines", *Utilities Policy*, March 2012. (With Lullit Getachew).

"Formulating Appropriate Electric Reliability Targets and Performance Evaluations, *Electricity Journal*, March 2012. (With Lullit Getachew)

"Enabling Technologies and Energy Savings: The Case of EnergyWise Smart Meter Pilot of Connexus Energy", Utilities Policy, November 2012. (With Chris Ivanov, Lullit Getachew, and Bethany Vittetoe)

"The Value of Improving Load Factors through Demand-Side Management Programs", Cooperative Research Network, 2012 (with David Williams and Chris Ivanov).

"Estimation of the Effects of Price and Billing Frequency on Household Water Demand Using a Panel of Wisconsin Municipalities", *Applied Economics Letters*, 2012, 19:14, 1373-1380.

"Altreg Rate Designs Address Declining Average Gas Use", *Natural Gas & Electricity*. April 2008. (With Mark Lowry, Lullit Getachew, and David Hovde).

"Regulation of Gas Distributors with Declining Use per Customer", *Dialogue*. August 2006. (With Mark Lowry and Lullit Getachew).

"Balancing Reliability with Investment Costs: Assessing the Costs and Benefits of Reliability-Driven Power Transmission Projects." April 2011. *RE Magazine*.

"Ex-Post Cost, Productivity, and Reliability Performance Assessment Techniques for Power Distribution Utilities". Master's Thesis.

"Demand Response: How Much Value is Really There?" *PSE whitepaper.*

"How is My Utility Performing" *PSE whitepaper*.

"Improving the Performance of Power Distributors by Statistical Performance Benchmarking" *PSE whitepaper*.

"Peak Time Rebate Programs: Reducing Costs While Engaging Customers" *PSE whitepaper*.

"Performance Based Regulation for Electric and Gas Distributors" *PSE whitepaper*.

"Revenue Decoupling: Designing a Fair Revenue Adjustment Mechanism" *PSE whitepaper.*

EXPERT WITNESS EXPERIENCE

Docket EB-2021-0110, Hydro One Networks, Joint Rate Application for Transmission and Distribution. Custom Incentive Regulation Benchmarking and Productivity research.

Docket No. 2020-00299, Big Rivers Electric Corporation, Integrated Resource Plan. Econometric Load Forecasting research.

Docket EB-2019-0261, Hydro Ottawa, Custom Incentive Regulation Application. Econometric Benchmarking research.

Docket EB-2019-0082, Hydro One Networks Transmission, TFP and Econometric Benchmarking research.

Docket EB-2018-0165, Toronto Hydro Electric System Limited, Econometric Benchmarking research.

Docket EB-2018-0218, Hydro One Transmission Sault St. Marie, TFP and Econometric Benchmarking research.

Docket EB-2017-0049, Hydro One Distribution, TFP and Benchmarking research.

Docket EB-2015-0004, Hydro Ottawa, Custom Incentive Regulation Application.

Docket 15-SPEE-357-TAR, Application for Southern Pioneer Electric Cooperative, Inc., Demand Response Peak Time Rebate Pilot Program.

Docket EB-2014-0116, Toronto Hydro, Custom Incentive Regulation Application.

Docket EB-2010-0379, The Coalition of Large Distributors in Ontario regarding "Defining & Measuring Performance".

Docket No. 6690-CE-198, Wisconsin Public Service Corporation, "Application for Certificate of Authority for System Modernization and Reliability Project".

Expert Witness presentation to Connecticut Governors “Two Storm Panel”, 2012.

Docket No. EB-2012-0064, Toronto Hydro’s Incremental Capital Module (ICM) request for added capital funding.

Docket No. 09-0306, Central Illinois Light rate case filing.

Docket No. 09-0307, Central Illinois Public Service Company rate case filing.

Docket No. 09-0308, Illinois Power rate case filing.

CONFERENCE PRESENTATIONS

Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2019.

Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2018.

Panel Moderator at WPUI conference on cost allocation and innovative rate designs at Madison WI. June 2018.

Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2017.

Wisconsin Manager’s Meeting, “Reliability Target Setting Using Econometric Benchmarking”. November 2016.

Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2016.

Wisconsin Electric Cooperative Association (WECA) Conference, “An Introduction to Peak Time Rebates”. September 2016.

Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2015.

EUCI conference chair, 2015. “Evaluating the Performance of Gas and Electric Distribution Utilities.”

Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2014.

Cooperative Exchange Conference, Williamsburg VA. “Smart Thermostat versus AC Direct Load Control Impacts”. August 2014.

EUCI conference chair in Chicago. “The Economics of Demand Response”. February 2014.

Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2013.

EUCI conference chair in Chicago. "Evaluating the Performance of Gas and Electric Distribution Utilities." August 2013.

Presentation to the Ontario Energy Board, "Research and Recommendations on 4th Generation Incentive Regulation".

Presentation to the Canadian Electricity Association's best practice working group. 2013

Conference chair for EUCI conference in March 2013 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."

Presentation to the board of directors of Great Lakes Energy on benchmarking results, December 2012.

Presentation on making optimal infrastructure investments and the impact on rates, Electricity Distribution Association, Toronto, Ontario. November 2012.

Conference chair for EUCI conference in August 2012 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."

2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Reliability Target Setting and Performance Evaluation".

2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Making the Business Case for Reliability-Driven Investments".

Conference chair for EUCI conference in 2012 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". St. Louis.

Conference chair for EUCI conference in 2012 titled, "Demand Response: The Economic and Technology Considerations from Pilot to Deployment". St. Louis.

2012 Presentation in the Missouri PSC Smart Grid conference entitled, "Maximizing the Value of DSM Deployments". Jefferson City.

2011 conference chair on a nationwide benchmarking conference for rural electrical cooperatives. Madison.

2011 presentation on optimizing demand response program at the CRN Summit. Cleveland.

Conference chair for EUCI conference in 2011 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". Denver.

2010 presentation on cost benchmarking techniques for REMC. Wisconsin Dells.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED ("THESL")

UNIT COSTS BENCHMARKING STUDY

October 2023

SECTION I - INTRODUCTION

Toronto Hydro-Electric System Limited ("THESL" or "the Company"), engaged UMS Group to conduct a third-party independent review of the Company's methodology for deriving unit costs, compare it to industry best practices, and perform benchmarking comparisons of a pre-selected set of asset categories and maintenance programs, namely the following:

Asset Categories

- Wood Poles
- UG Cable
- Pole Top Transformers
- Pad mount / UG Transformers
- Network Transformer / Protectors
- Breakers
- Cable Chambers / Manholes

Maintenance Programs

- Vegetation Management
- Pole Test and Treat
- Overhead Line Patrol
- Substation Maintenance
- Building Vault Inspections

In assessing the reasonableness of the derived and actual unit costs, UMS Group formed a peer group panel of comparable North American utilities, conducted "basic normalized comparisons" and identified any external factors (e.g., key technical, environmental, and regulatory drivers) that may need to be accounted for when comparing the peer group panel within the confines of a benchmarking study.

Establishing Context

In establishing context for the analyses and conclusions contained within this report, UMS Group undertook the following:

- Reviewed relevant reports, procedures, and system performance data provided by the Company, (***see Appendix A***).
- Received complete access to the Company's technical and management staff in the form of conference calls and workshops (e.g., Performance Management, Asset Management, Capital Planning, Execution, Project Management Delivery, and OM&A); and
- Formed a Peer Group Panel, comprised of 12 electric utilities with system and customer demographics comparable to those of THESL, each dealing with the unique cost drivers that are prevalent in urban settings (***see Appendix B***).

Comparative Analysis

The actual Peer Group comparisons of unit costs accounted for the fact that though there are similarities among the electric utilities selected, there are also differences to be reconciled, including the following:

- Regional costs,
- Practices in reporting costs,
- System demographics (e.g., Customer Density and underground utility congestion), and
- Other external factors (e.g., mandates and constraints regarding performance of work, weather, and vegetation).

Thus, we developed normalization factors for variations in data conversions and accounting practices, and in a more qualitative fashion, described the system demographics and other external factors that affect unit costs. With respect to our assessment of the Company's unit costing practices, we adopted an industry-wide perspective (*i.e.,* not constrained by those of the Peer Group Panel).

UMS Group Qualifications

THESL retained UMS Group, headquartered at 111 Littleton Road, in Parsippany, NJ, as an independent expert. With over 30 years of experience conducting comparative performance assessments for the global utilities industry, UMS Group has supported multiple assessments and global benchmarking programs on six continents, working with state and provincial public utility commissions as well as more than 300 electric, gas, and water utilities. UMS Group has augmented its analytical capabilities with a team of industry experts who are knowledgeable in best productivity and service-level performance practices to (1) ascertain an electric utility's efficiency and effectiveness in comparison to a qualified peer group, and (2) collaboratively develop aggressive, yet achievable performance improvement plans.

Among other qualifications, UMS Group leads several global learning and benchmarking consortia, which together with our portfolio of ongoing client engagements, facilitates our ability to maintain "real-time" proprietary cost and operational performance data, correlated to industry "best practices," all supported by an analytical framework built on the premise that industry "best performers" can be both efficient and effective. Appendix D provides additional details regarding UMS Group's qualifications and those of the individuals assigned to this effort.

The UMS Group-assigned experts for this effort, Messrs. Jeffrey W. Cummings, and Nicholas Austin, fully acknowledge their duties as experts in accordance with Rule 13 and Form A of the Ontario Energy Board's ("OEB" or "Board") Rules of Practice and Procedure. In so doing, they acknowledge that it is their duty to provide evidence in relation to this report as follows:

- To provide opinion evidence that is fair, objective and non-partisan,
- To provide opinion evidence that relates only to matters that are within his area of expertise, and
- To provide such additional assistance that the Board may reasonably require, to determine a matter in issue.

They acknowledge that the duty referred to above prevails over any obligation which they may owe THESL.

Structure of the Report

The ensuing discussion is divided into three sections:

- Section II – Executive Summary: A summarization of our conclusions on the Company's methodology for deriving unit costs and the benchmarking comparisons with the Peer Group Panel,
- Section III – Project Approach: A description of and rationale for the approaches, methodologies, criteria, and frameworks adopted in conducting our study, and
- Section IV – Summary of Results: An expanded discussion of findings, conclusions, and recommendations around the topic of unit costs.

We have provided additional appendices to supplement the information provided in Sections II through IV in the form of comparative charts, graphs, and tables, as well as more in-depth explanations of the bases for our evaluations and supporting analytics.

SECTION II – EXECUTIVE SUMMARY

Overview of THESL's Unit Cost Initiative

THESL retained UMS Group to conduct a review of THESL's methodology for determining the unit costs underlying its distribution system capital and maintenance programs, and to perform a utility benchmarking study to compare THESL's unit costs with those of a Peer Group Panel. In accomplishing these objectives, UMS Group:

- Conducted a series of workshops / interviews with several THESL stakeholder organizations (e.g., Performance Management, Asset Management, Capital Planning, Execution, Project Management Delivery, and OM&A),
- Reviewed a myriad of requested reports, procedure documents, and system performance data (***see Appendix A***),
- Established a Peer Group Panel of 12 electric utilities, largely based on demographics (customer density, vegetation, and weather / climate), and factors that add complexity to field execution (e.g., technical, legislative, regulatory, and bargaining unit constraints / mandates),
- Designed and administered a survey, seeking fully loaded unit cost comparators and key accounting and local factors to conduct normalization or present qualitative differentiators of the Peer Group Panel (i.e., described and placed in context elements beyond currency conversion rates and regional cost adjustments), and
- Analyzed the results of the survey, resulting in the benchmark of seven asset categories and five maintenance programs and a comparison of THESL's unit cost methodology with that of a representative sampling of industry peers.

The results of this effort summarized below and expanded upon in Section IV, "Summary of Results," yielded insights from both industry and THESL-specific perspectives.

Industry Perspective Regarding Unit Cost Methodology

Unit costing is a simple concept to grasp, yet the reporting of unit costs for productivity measurement or benchmarking across electric utilities can be complex, and often takes the following into account for the purposes of developing both a quantitative and qualitative analytical work product:

- *Unit Cost Approach:* The unit cost methodology typically is not a fundamental tenet for utilities when establishing, forecasting, analyzing, or reporting their financial or operational performance. As a result, efforts like this, undertaken to provide valid comparators, must engage individually with each utility to narrow any gaps in form and / or substance of the variables that drive unit cost calculations.
- *Asset Categories*: There are differences in how utilities track or even categorize asset categories. Frequently there are sub-asset classes that roll up to the asset class level, while others track these costs at the sub-asset class level.
- Direct Versus Overhead Costs: Most utilities map burdened labor (i.e., vacations, holidays, and training less corporate A&G), and material and equipment costs to asset classes based on some form of work order time sheets, and then allocate design, engineering,

permitting, warehousing and AFUDC to arrive at a total cost. One can then infer a unit cost by dividing this "fully loaded" cost by the number of units installed.

- *Maintenance Programs*: The industry remains consistent in not applying overheads to maintenance costs (only salary burdened by statutory costs and benefits). However, there are inconsistencies regarding the extent to which maintenance activities are "unitized" (often they are managed as "buckets" with budgets based on historical spending patterns with little, if any visibility on units inspected, tested, or maintained).

Performed properly with survey instruments such as those used for this effort, unit costing has a variety of applications, ranging from monitoring and forecasting workforce efficiency across a myriad of capital and operational expenditure programs, to forecasting specific project, program and budgetary blanket spends on a single or multi-year basis. Other uses include, but are not limited to, providing a basis for order-of-magnitude estimates, defining staffing levels, creating resource-loaded schedules, and/or supporting financial reporting requirements. Therefore, a sound unit cost methodology can be an adequate tool for utilities, and with respect to providing bases for comparing utility productivity, is viewed as "directionally accurate" (as opposed to "precise").

THESL – Specific Perspective Regarding Unit Cost Methodology

THESL's methodology for identifying and utilizing its unit costs across both its capital and non-capital expenditures constitute an organizational focus for THESL. In its unit cost approach, THESL allows for (1) the collection of labor and material cost information at the asset level (in contrast to the project or work order level), (2) comparison of actual and budgeted unit costs on an on-going basis, and (3) disaggregation of the components of unit cost to expand THESL's view of performance. In other words, THESL is disaggregating the components of unit cost to expand its view of performance by separating labor from material and removing financial loaders on labor to establish a direct labor unit cost.

Unit Cost Benchmarks

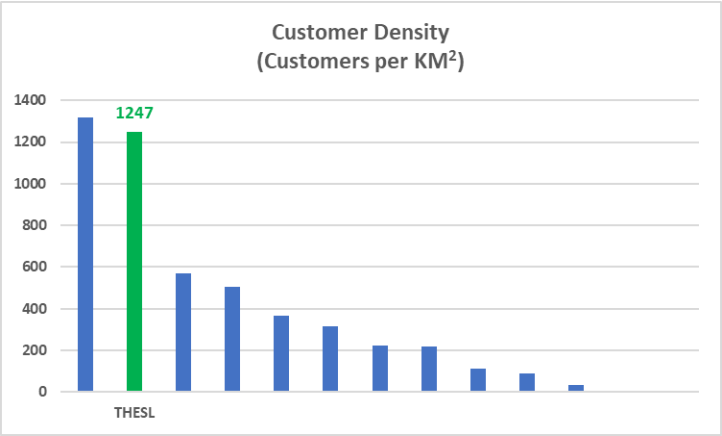
In reviewing the actual benchmarks, relative to a Peer Group Panel of 12 electric utilities spanning the North American continent (***see Section III and Appendix B***), two basic perspectives (or normalizers) are presented:

1. Comparisons after making the data conversion from US$ to CAD$ and from the Imperial to Metric System for the US Utilities, and
2. Incorporating Accounting Adjustments to address the different methods used by electric utilities in applying indirect and overhead costs to unit costs.

UMS Group also considered Congestion Factors and Regional Labor Costs in its review of unit cost differences.

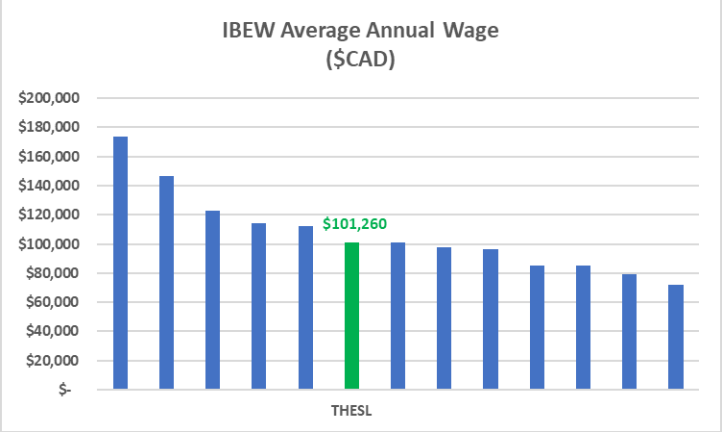
1. From a Congestion Factors perspective, UMS Group compared customer density as an indicator of unit cost pressures due to urban population, building density, and utility congestion. Within this dataset, THESL had the second highest density factor in the peer group (over 5 times the peer group median for customer density), indicating that if considered, congestion would have a material effect on THESL's comparative unit cost ranking.

Figure II-1: Customer Density



2. In its consideration of the Regional Labor Cost perspective, UMS Group reviewed the International Brotherhood of Electrical Workers ("IBEW") average annual wages across the regions represented by the peer group. Within this dataset, THESL represents the median, suggesting that if considered, these factors would have some effect on these comparisons.

Figure II-2: IBEW Average Annual Wage



Due to statistical and data challenges of normalizing for these factors in the context of the methodology and scope of this study, UMS Group opted to present them in qualitative terms (i.e., not part of the "normalized" unit cost value). That said, in UMS Group's professional opinion, these qualitative considerations, particularly the customer density factor, indicate that THESL's actual comparative ranking would be better than presented in the quantitative results summarized below if these factors could be statistically normalized.

Returning to the straight statistical (i.e., quantitative) comparison of THESL against its peer group, Table II-1 presents THESL's unit cost information and ranking of THESL's comparative position to the Median using just the Conversion and Accounting Adjustment normalizations. Adding further context to this information is an indication of the percent variance from the Median for each category / program.

Table II-1: Benchmark Comparisons ($CAD)
Applying Conversion and Accounting Adjustments Only

			Median	Percent from Median	Other Factors
Asset Categories					**Utility, Building and Population Congestion:** UMS Group looked at Customer Density data as a proxy for urban settings (i.e., highly concentrated population centers and resulting buildings, infrastructure, and utility congestion) and their impact on utility costs. As Figure II-1 illustrates, THESL is comparatively unique in this aspect. Statistical and data challenges precluded including this factor in the normalization of the unit costs. However, congestion has a material impact on productivity, and, if considered, would result in a stronger comparative ranking for THESL. **Regional Labor Factors:** Similar in the approach in addressing congestion, UMS Group reviewed the International Brotherhood of Electrical Workers ("IBEW") average annual wages as a proxy, with THESL ranking in the top 50% of the Peer Group Panel. As illustrated in Figure II-2 above, THESL's wage cost position relative to its benchmarking peers is in the top half. And though not utilized for normalization purposes, these differences impact utility costs, and if applied would also have placed THESL in a more favorable light regarding these comparisons.
Wood Pole	Each	$8,317	8,181	1.7%	
UG Cable (XLPE)	Per Meter	$131	131	0.0%	
Pole Top Transformer	Each	$18,691	18,423	1.5%	
Pad mount / UG Transformer	Each	$37.373	37,008	1.0%	
Network Transformer / Protector	Each	$127,649	130,690	-2.3%	
Breaker	Each	$37,983	40,772	-6.7%	
Cable Chambers / Manholes	Each	$136,409	135,571	0.6%	
Maintenance Programs					
Vegetation Management	Per Line KM	$2,175	2,139	1.7%	
Pole Test and Treat	Each	$17	19	-10.1%	
Overhead Line Patrol	Per Line KM	$23	26	-12.2%	
Substation Maintenance	MVA	$1,712	1,681	1.9%	
Building Vault Inspection	Each	$258	268	-3.9%	

NOTE: Shown above as combined, the 2-step basic normalization process is illustrated in Section IV (Figures IV-1 to IV-12) and Appendix C (Tables C-2 and C-3).

Generally, THESL is positioned within each of the categories and programs between approximately 1.9% above the Median (barely third quartile) to negative 12.2% below the Median (well-embedded in the second quartile) when combining the two basic benchmarking perspectives/normalizers. As noted above, UMS Group is of the view that THESL's comparative ranking would be even stronger than presented in the quantitative results found herein if the qualitative factors, particularly congestion, could be statistically normalized. This last statement is grounded by our understanding of the realities of working in confined spaces / congested areas, frequent disruptions in the performance of work, and higher labor costs, which when combined, are conservatively estimated to range between 5 and 10 percent.

Applicability of the Study

As a final step in our assessment, we reviewed the viability of these asset categories / maintenance programs to serve as a proxy for THESL's effectiveness and efficiency in performing work. Two areas were reviewed:

- *Contribution of the Benchmarked Categories and Programs to Capital Expenditures and Maintenance Spending*: According to THESL, the seven asset categories represent approximately 52% of the planned capital budget over the 2020 through 2022 period; and

THESL spends approximately 57% of all preventative and predictive maintenance costs in each year on the five maintenance programs that comprised this study.

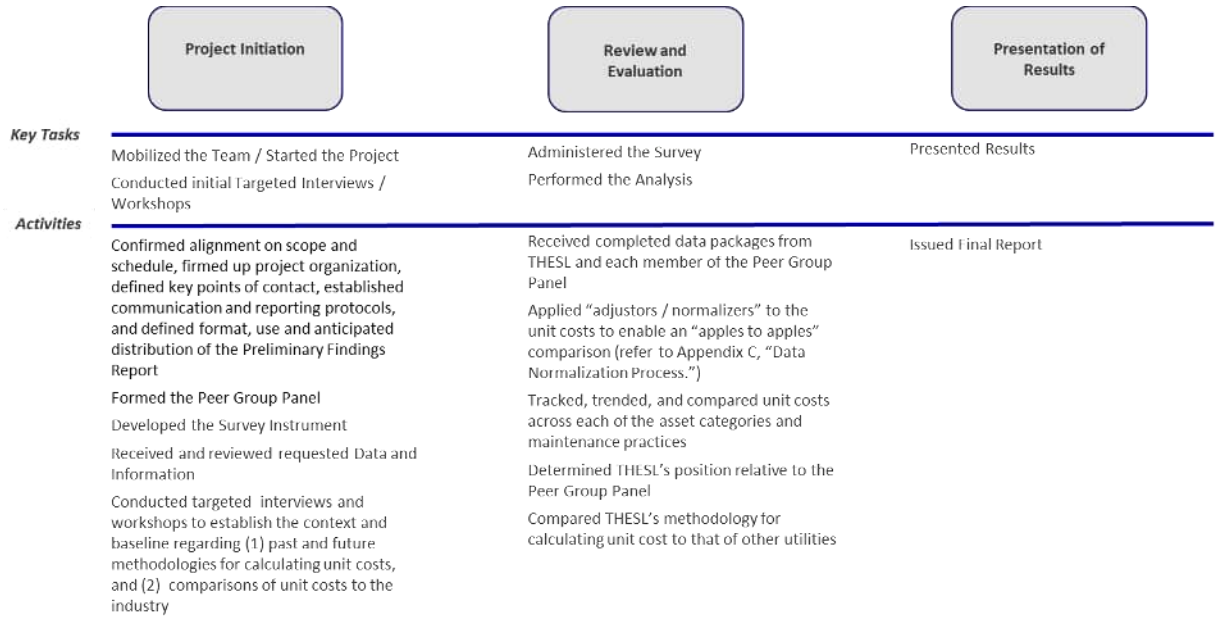
- *Impact on Reliability*: UMS Group has conducted several reliability-related assessments over the past 10 years (ranging from reviewing system performance to adjudging response during major storm events, ***see Appendix E***). In conducting these assessments, the primary areas of concern when assessing a utility's reliability performance revolves around vegetation management, equipment failures, underground facilities, and the overall conduct of inspection, test, and maintenance programs, portions of which are addressed through the asset categories and maintenance programs that comprised this study.

It is therefore our view that any conclusions around performance resulting from benchmarking or trending the unit costs of these seven asset categories and five maintenance programs are reflective of THESL's overall unit cost performance.

SECTION III – PROJECT APPROACH

To assess the Company's methodology for deriving unit costs and perform benchmarking comparisons of a pre-selected set of asset categories and maintenance programs, UMS Group developed and executed the following work plan:

Figure III-1: Unit Cost Performance Assessment Overview



From Project Initiation to the Presentation of Results, UMS Group applied several elements of its proprietary and time-tested benchmarking and practices assessment methodology to independently assess THESL's approach in deriving unit costs; and benchmark the fully loaded unit costs of a representative cross-section of asset categories and maintenance programs. The following discussion will expound on those aspects of our approach that contributed to our achieving the requisite level of objectivity and relevance needed for this report.

Peer Group Panel

The Peer Group Panel used for this study consisted of 12 electric utilities, namely:

- AES-IPL (Indianapolis, IN)
- AES-DPL (Dayton, OH)
- Anonymous Utility (Canada)[1]
- Avista Utilities (Spokane, WA)
- Baltimore Gas and Electric (Baltimore, MD)
- Detroit Edison (Detroit, MI)
- Elexicon Energy (Various Communities, Ontario)
- ENMAX (Calgary, Alberta)
- London Hydro (London, Ontario)
- Portland General Electric (Portland, OR)
- SaskPower (Regina and Saskatoon, Saskatchewan)
- Seattle City Light (Seattle, WA)

NOTE 1: As a prerequisite to participation, one Canadian utility required anonymity in its participation and response.

In selecting these utilities, our goal was to provide comparisons that would be relevant to THESL's operating environment. Focusing first on other Province of Ontario electric distribution systems / organizations, we narrowed our consideration to those serving more than 75,000 customers, thus providing nine candidates for further review. UMS Group then compared these utilities relative to 10 data sets presented in the Ontario Energy Board ("OEB") data provided as part of the Activity and Program-based Benchmarking Initiative. In so doing, we identified Alectra Utilities, Hydro Ottawa, Elexicon Energy, and London Hydro as possible comparators (***See Appendix B, Figure B-3 and prefacing discussion for a listing of the 10 data sets and a summarization of the analysis***). All four were invited to participate, with Elexicon Energy and London Hydro providing input.

In parallel, UMS Group reached out to the utilities that had participated in a similar study conducted by UMS Group for THESL during the 2017 – 2018 timeframe and was successful in enlisting the participation of eight (the remaining balance of nine cited varying more pressing priorities amidst constrained resources as their reason for declining participation). Two additional utilities that had been invited but declined last time accepted this time around: Avista Utilities and a Canadian utility that requested anonymity as a precondition to participating.

As a means of validating the Peer Group Panel, Table III-1 illustrates THESL's relative position across five factors that define the elements that can affect like-for-like unit cost comparisons:

- *Vegetation* (besides the direct correlation to one of the maintenance programs being benchmarked, accounts for the challenges that increased vegetation might pose in gaining access to critical assets),
- *Underground Utility Congestion* (increases the propensity for third-party damage and accounts for the impact of tight spaces, both factors that can contribute to the slowdown of work),
- *Public, Building and Utility Congestion* (potentially impacts accessibility, increases awareness of public safety, and creates added distractions during the performance of work),
- *External Factors* (accounts for varying degrees of technical, legislative, regulatory, and bargaining unit constraints / mandates that dictate the specific practices to be employed in performing work, many of which inhibit the flow of work), and
- *Weather*, (accounts for the differences between harsh and temperate climates and their impact on productivity).

It shows that THESL aligns with most of the utilities across four of the five factors (exception being Public, Building and Utility Congestion) further substantiating the appropriateness of the Peer Group Panel.

Table III-1: Distribution of Peer Group Panel across External Factors (including THESL)[1]

Vegetation		
Low	Medium	High
2	8	3
UG Congestion		
Low	Medium	High
1	4	8
Public, Building and Utility Congestion		
Low	Medium	High
4	5	4
External Factors		
Low	Medium	High
2	2	9
Weather		
Mild	Moderate	Harsh
2	8	3

NOTES: The area shaded in green reflects the position of THESL in each category.

Asset Categories and Maintenance Programs

As stated in Section I – Introduction, the study addressed unit costs for installing / replacing seven categories of assets and conducting five maintenance programs for the Peer Group Panel as identified below:

Asset Categories

- Wood Poles
- UG Cable
- Pole Top Transformers
- Pad mount / UG Transformers
- Network Transformer / Protectors
- Breakers
- Cable Chambers / Manholes

Maintenance Programs

- Vegetation Management
- Pole Test and Treat
- Overhead Line Patrol
- Substation Maintenance
- Building Vault Inspections

As previously stated in the Executive Summary, in assessing the viability of these asset categories / maintenance programs to serve as a proxy for THESL's effectiveness and efficiency in performing work, UMS Group considered the following:

[1] **Appendix B provides further definition of the categorization presented in Table III-1.**

- *Contribution to Capital Expenditures and Maintenance Spending*: According to THESL, the seven asset categories represent approximately 52% of the planned capital budget over the 2020 through 2022 period; and THESL spends approximately 57% of all preventative and predictive maintenance costs each year on the five maintenance programs that comprised this study.
- *Impact on Reliability*: The primary areas of concern when assessing a utility's reliability performance revolves around vegetation management, equipment failures, underground facilities, and the overall conduct of inspection, test, and maintenance programs, portions of which are addressed through the asset categories and maintenance programs that comprised this study.

Survey Instrument

Over the course of this project UMS Group identified 23 electric utilities for inclusion in the Peer Group Panel, striving for the inclusion / participation of at least 10 to assure a valid sample size on which to make meaningful comparisons. We were successful in obtaining the participation of 12, thus enhancing the veracity of the results. The Survey Instrument itself (***see Appendix F***) addressed three areas:

- *Unit Costs* for years 2020 through 2022, requesting the fully loaded installation / replacement, test, and inspection costs and number of assets installed / test and inspections conducted for each asset category and maintenance program. We averaged the responses across the three-year period (weighted by number of replacements, inspections and / or tests each year) to "smooth out" the year-over-year fluctuations that are likely to occur while executing an annual capital investment and maintenance-spending portfolio.
- *Accounting*, requesting (1) brief descriptions of each electric utility's method for determining unit costs, (2) listings of costs (in addition to direct labor and material) that were included in the reporting of costs (in-house), and (3) listings of costs included for contracted work. This information was then used to inform the "Accounting Adjustment" perspective of the normalization process (i.e., account for the different methods used to apply indirect and overhead costs to capital projects), briefly described below and further expanded upon in ***Appendix C***.
- *Local Factors*, providing a listing of any technical, legislative, regulatory, and bargaining unit constraints / mandates (referred to as "external factors") that dictate specific practices to be employed in performing work that could have cost ramifications. This information informed the assessment, providing context to the comparisons presented throughout the report.

THESL first reviewed and tested the survey instrument, after which time UMS Group issued it to each of the electric utilities that agreed to participate in this study. As the completed surveys were returned, UMS Group reviewed the responses and reached out to the respondents as necessary to resolve any apparent outliers and/or address areas where there appeared to be confusion.

Practices Assessment

UMS Group met with several organizations / functions within THESL (e.g., Performance Management, Asset Management, Capital Planning, Execution, Project Management Delivery, and OM&A) to gain insights and perspective regarding its practices (past, current, and future

state) to derive unit costs. We used a variety of sources to compare this input with practices in use across the industry (summarized in Section IV-Summary of Results); namely:

- Insights gleaned from the Peer Group responses in the accounting section of the Survey Instrument, augmented by follow up conversations to clarify / lend context to expressed points-of-view,
- Feedback from electric utilities that are part of UMS Group's Global Learning Consortia (the focus of which includes benchmarking and the sharing of practices to improve performance and reduce costs), and
- UMS Group knowledge and expertise gleaned from working with and on behalf of over 300 utilities across the world since UMS Group's inception thirty-plus years ago.

Benchmarking

UMS Group applied its methodology and a tailored work plan to meet the objective of benchmarking unit costs across seven asset categories and five maintenance programs. Data provided by the previously described Peer Group Panel (***see Appendix B***) established THESL's position with respect to efficiency (cost); and we conducted practices interviews to lend context to these comparisons. In so doing, we were able to ascertain THESL's position relative to the Peer Group Panel across two perspectives, and further inform our views regarding THESL's methodology to calculate unit costs.

The benchmarking process itself consisted of three steps:

- Data Collection and Analysis: As each electric utility indicated its willingness to participate in the Peer Group Panel for this effort, UMS Group transmitted to the utility the survey instrument designed to ensure consistent responses (i.e., the questions were tightly structured) and support the "normalization" process (allow for valid comparison of fully loaded unit costs). In concert with sending the survey instrument, UMS Group provided "real time" instruction, and over time, conducted follow-up sessions to track progress, provide clarification and address any questions that might arise. It should be noted that THESL was the initial recipient of the Survey Tool, enabling the identification and remediation of any unanticipated areas of confusion / ambiguity / difficulty in completing the data package, increasing the likelihood of a valid comparison with the Peer Group Panel. As the surveys were completed, UMS Group performed a validation check for data quality, increasing the overall credence of the results. As UMS Group detected instances of potential misinformation, omissions, or anomalies it contacted the respondent and attempted to resolve any underlying issues.
- Develop Context for the Comparison: The initial formation of a Peer Group Panel represents the first step in assuring valid unit cost comparisons. Table III-1 provides a view of this group relative to five areas that can affect performance (i.e., Vegetation, UG Utility Congestion, Customer Density, External Factors and Weather Climate). As typifies every benchmark comparison, there was not a perfect fit for the 12 electric utilities across all five areas, though each member of the peer group panel was "compatible" with THESL in several of these areas (some in all of them). Though UMS Group has developed data normalization routines in the past to account for these differences, we have opted to present them in a more qualitative manner (i.e., not directly adjusting the figures) to bring context to the results. Thus, we started with raw comparisons (accounting for the conversion from imperial to metric units and US to Canadian dollars), and then applied an adjustor, accounting for different methods used by electric utilities in burdening unit costs

with indirect and overhead costs. Addressed in more detail in ***Appendix C***, this approach provides transparency to the process of data normalization, deemed appropriate given the wide range of factors that can affect these comparisons, and qualitatively acknowledges THESL's uniqueness in the Province of Ontario, namely:

  - City ordinances,
  - Higher cost of living,
  - Amount of underground construction,
  - Greater volatility in customer movements,
  - Amount of electric distribution assets, and
  - Customer density.

- Present the Results: UMS Group presented THESL's position relative to the Peer Group Panel median for each perspective (refer to Table II-1, Figures IV-1 through IV-12, and Tables C-1 and C-2). Recognizing that some might prefer more delineation in the ranking, we also provided a more expansive presentation of THESL's position relative to each member of the Peer Group Panel for the perspective that incorporates the Accounting Adjustment in ***Appendix G***.

SECTION IV – SUMMARY OF RESULTS

The following discussion summarizes the results of an approach that:

- Utilized UMS Group's proprietary and time-tested benchmarking and practices assessment methodology,
- Drew upon our extensive cost and service level database and best practices library,
- Analyzed input from a survey instrument administered to the Peer Group Panel, and
- Captured insights and perspectives from key management staff within the THESL organization.

Assessment of THESL's Unit Cost Methodology

THESL's approach to unit cost methodology is consistent with the methodology employed by similarly situated utilities across North America. More specifically, THESL employs the following documented, specific, and repeatable process when identifying its unit costs:

- As an initial matter, THESL utilizes its financial reporting systems as base source data from which to derive unit costs. This facilitates THESL modifying its financial naming conventions to those that are normalized and more common. THESL can therefore capture relevant costs and quantities, thus minimizing risks related to groups using different naming conventions, while also supporting a more robust and accurate peer collection process across North American utilities.
- For those units that are capitalized, THESL captures the asset in-service date, and determines whether the projects are single or multi-years from a financial perspective. Relevant information for single year projects is captured within the year. For multi-year projects, the costs are aggregated and captured in the year in which most of the project costs are incurred (the "MaxCap" year).
- Next, a series of data aggregation and filtering takes place. These filters allow THESL to focus on work (and as a result, THESL's expenditures) that is controllable and readily manageable. THESL's filtering efforts include:
    - Grouping like projects with like projects in "MaxCap" years,
    - Applying the Distribution System Plan ("DSP") program filter, to appropriately include risk-based and planned work while filtering out demand-based work that is deemed inconsistent with respect to need, cause, controllability, or predictability, and
    - Obtaining a more detailed trimmed mean of unit costs, by finding the inclusive percentiles at 10% and 90% on unit cost, thus eliminating the statistical tails.
- THESL then ensures appropriate project costs are captured, and are not net of capital contributions, by removing the capital contribution line items from the various project-based financial data.

This methodology provides a dataset that is repeatable and capable of duplication on a year over year basis.

In assessing THESL's approach to unit costing, it is our view that THESL's continued maturity, refinement, and utilization of unit cost metrics is in line with (and perhaps ahead of) the industry. Specifically, THESL appropriately created governance around the naming and categorization of assets to ensure an appropriate population of relevant assets is captured. Moreover, THESL's filtering efforts work to exclude extraordinary, unplanned, and otherwise uncontrollable capital

and operational expenditures that can (and often do) significantly eschew unit cost data. Industry value in unit cost analysis is intended to capture spend and compare it to internal and external spend on as much of an apples-to-apples comparison as possible, recognizing all the challenges identified herein. THESL's approach works to accomplish this end and, as a result, is appropriate in all major respects.

Benchmarking of THESL's Unit Costs

In accordance with the approach outlined in the previous section, UMS Group benchmarked THESL's Unit Costs at each of two basic pre-established checkpoints:

- Raw Comparisons, reflecting the conversions from imperial to metric units and US to Canadian dollars, and a few adjustments to the original asset categories / maintenance programs to facilitate Peer Group comparisons, and
- Accounting Adjustors, accounting for the different methods used by electric utilities in applying indirect and overhead costs to unit costs.

Figures IV-1 through IV-12 provide a visual representation of the information presented in Table II-1 comparing THESL's unit costs (a three-year average from 2020 through 2022), as compared to the Peer Group median for each of the categories and programs across these two basic perspectives.

Figure IV-1

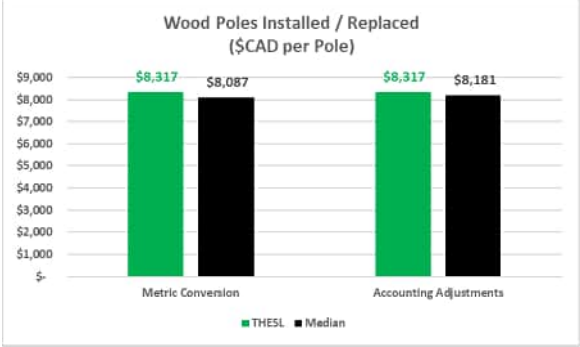


Figure IV-2

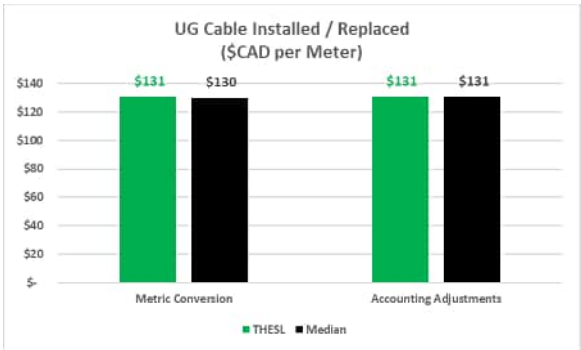


Figure IV-3

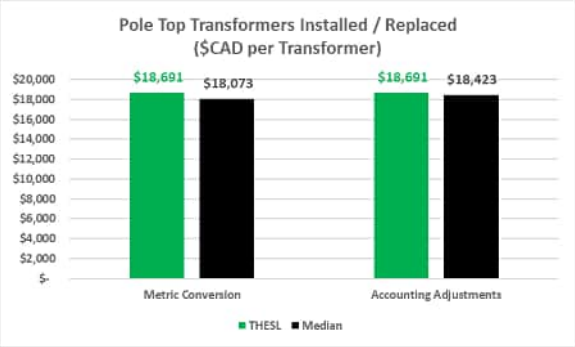


Figure IV-4

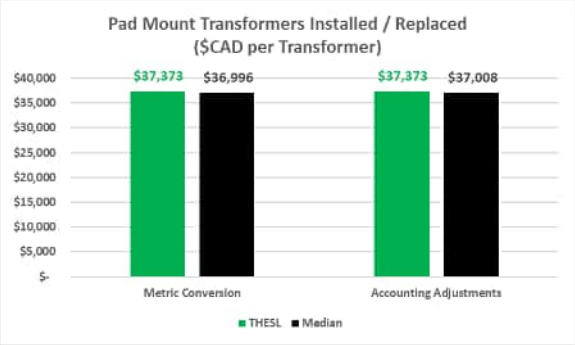


Figure IV-5

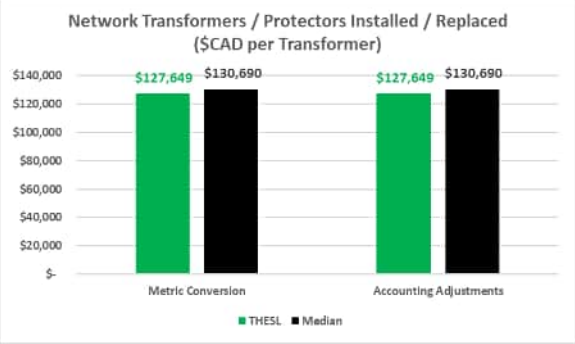


Figure IV-6

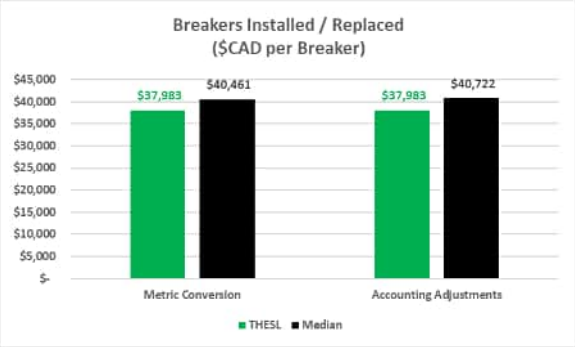


Figure IV-7

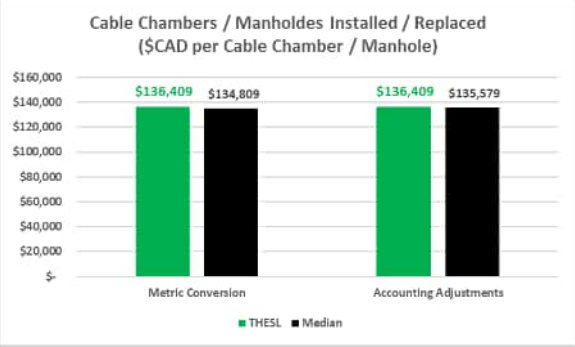


Figure IV-8



Figure IV-9

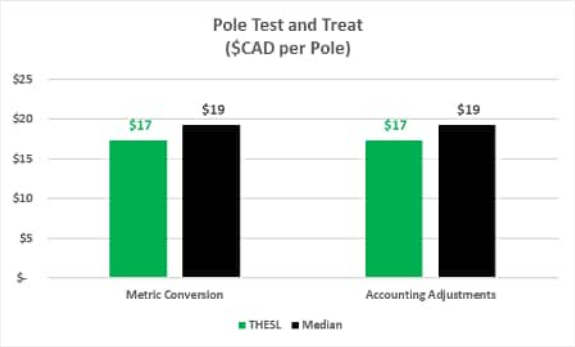


Figure IV-10

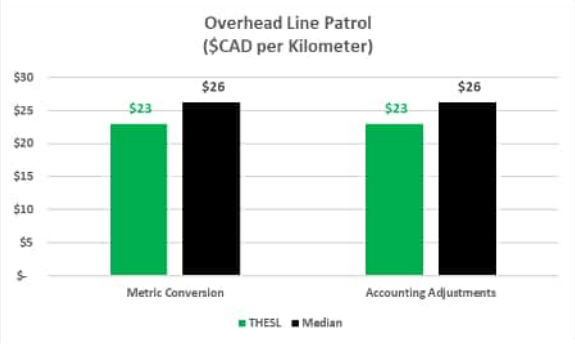


Figure IV-11

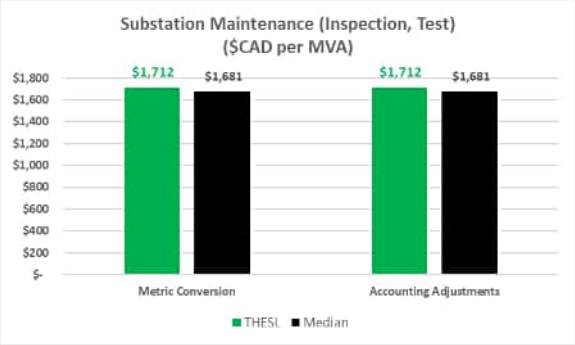
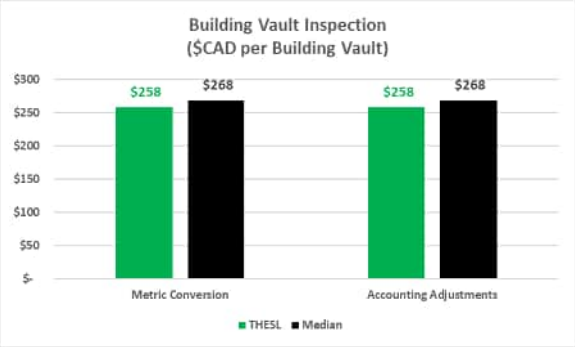


Figure IV-12



Implications of the Study

In reviewing our assessment of THESL's Unit Cost methodology, the subsequent benchmarking across seven asset categories and five maintenance programs, and taking stock of industry practices, the following additional conclusions apply:

- The asset categories and maintenance programs selected by THESL represent a valid proxy for trending its performance, and
- Benchmarking is directionally accurate in identifying opportunities for improvement and/or validating current cost and service levels. In applying this methodology to unit costs, absent detailed specifications regarding their calculation (which were developed for this study but not practical when conducting less rigorous comparisons of publicly available data), there are a wide array of variables to consider.

Appendix A – Supporting Material

UMS Group used the following THESL provided information and data to support or provide context to the study:

- 2020-2020 Capital Expenditures (CAPEX 2020-2022 Actuals_20230424.xlsx)
- 2021 Annual Report (2021-Annual-Report.pdf)
- 2021 OEB Electric Distribution Scorecard (2021-electricity-distributor-scorecard-toronto-hydro.pdf)
- Annual Information Form for the YE 12/31/2022 (2022-annual-information-form.pdf)
- Capital Expenditure Planning Process Overview (2020CIR_2B_E2 - Capital Plan Process Overview.pdf)
- Cable Chamber Description (Cable Chambers Brief Description and Pictures (2).docx)
- Customer Engagement Planning Process (2023-03-17 CE Residential Workbook_FINAL.pdf)
- Maintenance Program Annual Spend 2020-2022 (maintenance_ programs_annual_spend_3yr.xlsx)
- Overview of Distribution Assets (2020CIR_2B_D2 - Overview of Distribution Assets.pdf)
- Reliability Data 2020-2022 (Reliability - 3_yr_breakdowns.xlsx)
- System Maintenance Practices (Maintenance Cycle_Shared_20230424.xlsx)
- THESL System Demographics Summary (Toronto Hydro Asset Demographics.docx)
- THESL Unit Cost Methodology dated December 4, 2023 (UMS workshop_ walkthrough_110423.pdf)
- THESL Unit Cost Survey Response (Unit Cost Survey_FINAL_THESL.xlsx)

Appendix B – Peer Group

The Peer Group Panel used for this study consisted of 12 electric utilities, namely:

- AES-IPL (Indianapolis, IN)
- AES-DPL (Dayton, OH)
- Anonymous Utility (Canada)[1]
- Avista Utilities (Spokane, WA)
- Baltimore Gas and Electric (Baltimore, MD)
- Detroit Edison (Detroit, MI)
- Elexicon Energy (Various Communities, Ontario)
- ENMAX (Calgary, Alberta)
- London Hydro (London, Ontario)
- Portland General Electric (Portland, OR)
- SaskPower (Regina and Saskatoon, Saskatchewan)
- Seattle City Light (Seattle, WA)

NOTE 1: As a prerequisite to participation, one Canadian utility required anonymity in its participation and response.

In selecting the utilities that comprise this group, we strove to provide results based on comparisons that would be relevant to an electric utility of THESL's size and complexity. Table B-1 illustrates THESL's relative position across the myriad factors that need to be considered in conducting like-for-like unit cost comparisons of Electric Distribution Companies; and though no two Electric Distribution Systems / Organizations are identical, THESL is among the highest percentages within this peer group in all but one of the five factors that can influence comparisons to unit costs (and that one, Population, Building, and Utility Congestion was evenly split among the Peer Group Panel).

Table B-1: Distribution of Peer Group Panel across External Factors (including THESL)

Vegetation (Refer to Figure B-1)		
Low (Area Covered by Tree Canopy 0-10) %)	Medium (Area Covered by Tree Canopy 10-40%)	High (Area Covered by Tree Canopy > 40%)
2	8	3
UG Congestion (Refer to Table B-2)		
Low (Other Utilities)	Medium (UG Network and Other Utilities)	High (UG Network, Other Utilities, and Shoring requirements)
1	4	8
Population, Building and Utility Congestion (Refer to Figure B-3 and prefacing discussion)		
Low (Customer Density < 100)	Medium (Customer Density 100-500)	High (Customer Density >500)
4	5	4
External Factors (Refer to Table B-2)		
Low (0 to 6 External Factors)	Medium (7 to 10 External Factors)	High (>10 External Factors)
2	2	9
Weather (Refer to Figure B-2)		
Mild (Mediterranean)	Moderate (Humid Continental)	Harsh (Sub-Arctic)
2	8	3

NOTE: The area shaded in green reflects the categorization of THESL in each category.

UMS Group utilized Figure's B-1 and B-2 to ensure an appropriate comparative capability between the selected peer group set. Electric utility operations, by their very nature, are impacted by geography, and more specifically, by tree vegetation and weather among other factors. These factors impact operations from a broad perspective, ranging from the types of assets that are selected and in-serviced, to the frequency of maintenance programs, to the cost and ease of construction. To the extent possible in balancing "perfect fit" with Peer Group size requirements, UMS Group approached utilities that mirrored THESL within these two categories.

The following extract was used to categorize the Peer Group utilities in terms of **Vegetation** in Table B-1 (Based on percent of area covered by tree canopy):

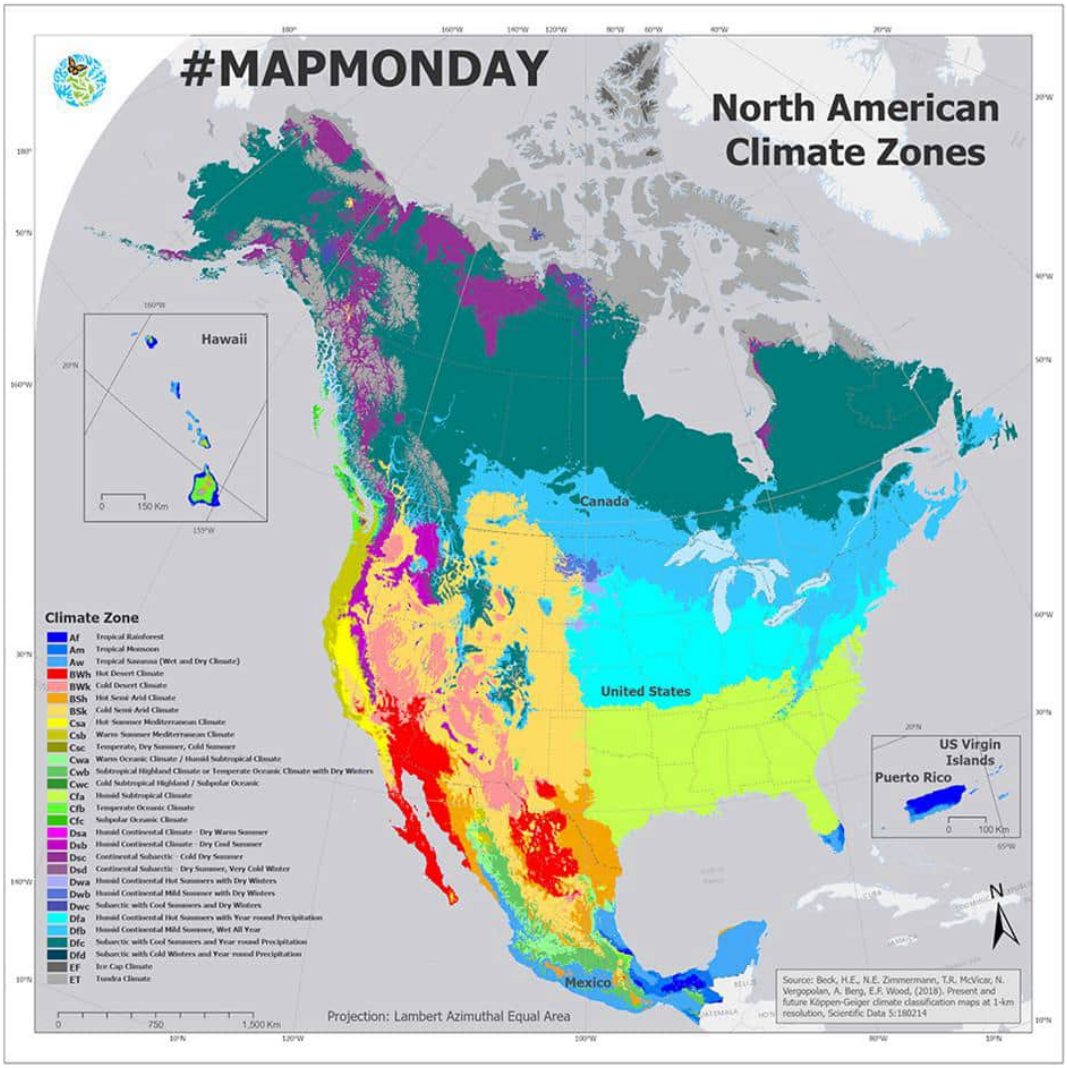
Figure B-1: North American Vegetation Density



Reference: Percentage of surface (green) based on data by the U.S. Geographical Survey together with man-made structures (red, based on data by ESA and major rivers (blue). Areas that are neither red nor green represent other types of land cover such as crops, grass, shrubs, bare rocks, and water.

With respect to **Weather / Climate**, the vast majority of the Peer Group Panel (except Portland General Electric and Seattle City Light) are in areas with similar weather patterns. General descriptions of Climate Zones for the Peer Group Panel include Mediterranean, Humid Continental, and Sub-Arctic.

Figure B-2: Weather / Climate Map



Reference: Commission for Environmental Cooperation applying the Koppen-Geiger Climate Classification System.

The **External Factors** rating reflected responses to our queries regarding applicability of an array of factors that have an adverse effect on field productivity. Based on the responses, an assessment of the level of difficulty confronting each utility was made (high, medium, or low).

Table B-2: Summary of External Factors Ratings

COST IMPACT CATEGORY	THESL	A	B	C	D	E	F	G	H	I	J	K	L
Excessive travel time (over 30 mins)	X	X			X	X		X		X	X		X
Road restrictions which limit working hours	X	X	X	X	X	X	X		X	X	X	X	X
High water table	X				X	X	X	X		X	X		X
Working next to energized lines (requiring dedicated observer, gloves, etc.)	X	X	X	X	X	X	X	X	X	X	X	X	X
Requirements to perform work off hours (i.e., night / weekend)	X	X	X	X	X	X	X			X	X		X
Changed standards requiring rebuilds rather than like-for-like (i.e., clearances)	X	X			X	X	X				X	X	X
Excessive switching requirements (i.e., to isolate on dual radial construction)	X	X	X		X	X	X	X	X	X	X	X	X
Shoring requirements for UG work	X	X	X		X	X					X	X	X
Limitations on tree trimming (e.g., unusually tight clearances)	X	X	X	X	X	X	X		X		X		X
Prior use of lead cables			X	X		X				X			X
High fault currents (impacting equipment sourcing)		X	X							X	X		X
Paid duty for police presence on public roads	X	X	X	X	X	X			X	X	X		
Extensive use of submersible transformers							X						X
Environmental regulations	X	X	X	X	X	X	X	X	X	X	X		X
Insufficient IT Enablement			X	X					X				
Union Work Rules		X			X	X	X		X	X	X		X
City consent requirements (i.e., customer notification, restoration, progressive clean-up, etc.)	X	X	X	X	X	X	X		X	X	X	X	X
Other (please specify in comments)													
LEVEL OF DIFFICULTY	High	High	High	Med	High	High	High	Low	Med	High	High	Low	High

NOTES:

1. **The "alpha" designations are applied to mask the identity of any specific utility in the Peer Group Panel (a commitment that must be adhered to throughout the process, as guarantees of confidentiality were required to garner their participation in the study).**
2. **In assigning "High," "Medium," and "Low" level of difficulty, the following scale was used:**
    a. **LOW: 0 to 6 External Factors**
    b. **MEDIUM: 7 – 10 External Factors**
    c. **HIGH: > 10 External Factors**

Other Utilities Serving the Province of Ontario

There is rationale for defining a peer group outside of the utilities that serve the Province of Ontario (as the peer group determines the comparative position with respect to unit costs). First, from purely a demographic perspective, the City of Toronto ranks among the more urban in North America (let alone the Province of Ontario), and as with all predominantly urban electric utilities, Toronto-based utilities deal with several unique cost drivers, including:

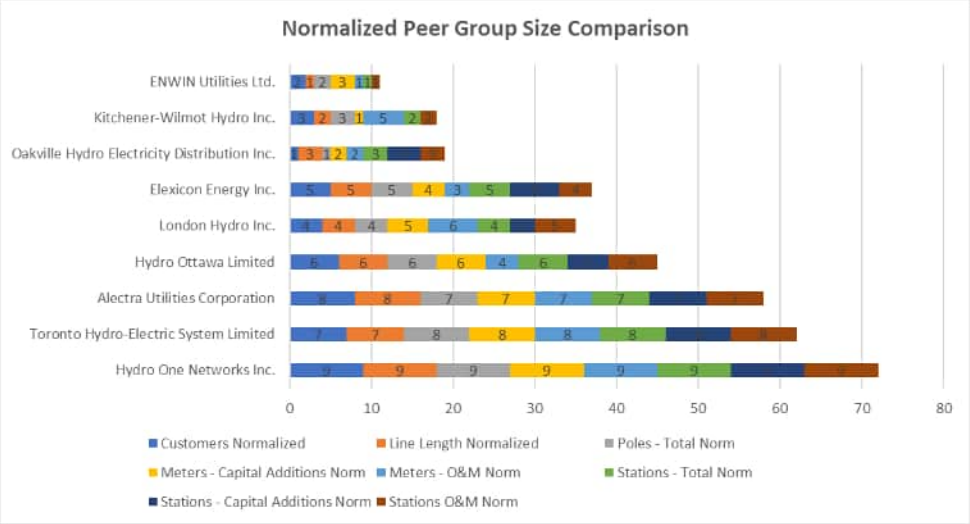
- City ordinances that impact the conduct of work (e.g., restrictions on work hours and additional police / traffic control), logistics that limit access of vehicles and work teams to the work site (e.g., traffic flow considerations and congestion), and system design (e.g., fully enclosed substations with due regard to external appearances and limits on use of overhead construction),
- Higher cost of living leading to higher wage structures and a noted increase in overheads (offices and other facilities),
- Complex underground construction related to secondary networks (e.g., limited access, possible interference with other underground utilities, underground cable through concrete duct banks, increased number of feeder ties and back-feed capability, and increased need for technology to provide more automation),
- More volatility in customer movements causing a higher number of turn-on / turn-offs, and
- With respect to the sheer number of customers, significantly higher density pointing towards increased measures for public health and safety.

However, there are a few utilities in the Province of Ontario that warrant consideration. We first filtered out all utilities associated with the Activity and Program-based Benchmarking Initiative (https://www.rds.oeb.ca/CMWebDrawer /Record/784172/File/document) (the "APB Initiative") with less than 75,000 customers. This narrowed the potential peer group to nine. Then, looking at the input data from the APB Initiative, we narrowed our focus to the following 10 data sets to assess viability for this study:

- Number of Customers
- Line Length (KM)
- Total Poles
- Pole Additions
- Meters – Capital Additions ($)
- Meter – O&M ($)
- Number of Stations
- Stations – O&M ($)
- Poles, Towers, and Fixtures – O&M ($)
- Vegetation Management – O&M ($)

We then performed a simple sum quantification of the data collected to visually depict relative position of each of the nine utilities, forced order ranking them in each of the 10 categories.

Figure B-3: 2021 Comparison of Ontario Utilities



As one can see, five utilities (Elexicon Energy, London Hydro, Hydro Ottawa, Alectra Utilities, and Hydro One) approach parity with THESL. We disqualified Hydro One as it does not serve a population center even remotely like that of THESL (i.e., without the complexities / difficulties confronting other utilities), and reached out to the other four. Two (Elexicon Energy and London Hydro) opted to participate.

Appendix C – Data Normalization Process

Prior to conducting comparative statistical analyses with the Peer Group Panel (***see*** Appendix B), it was necessary to "normalize" the unit cost performance across all participating electric utilities. Normalization involved a two-step approach, thereby presenting two basic perspectives and availing the reader total transparency to the comparisons at both major junctures of the normalization process.

- **Raw Comparisons (Perspective 1)** involved, where appropriate, the conversion from imperial to metric units and US to Canadian dollars. As we opted to adopt a three-year average (2020 through 2022), an average conversion rate of $US to $CDN ($1.00 USD to $1.278 CDN) was applied, and
- **Accounting Adjustors (Perspective 2)**, accounting for the different methods used by electric utilities in applying indirect and overhead costs to unit costs. In informing the bases for these adjustments, we queried each of the electric utilities as to what non-direct labor and material were included in the unit costs, distinguishing between utility and outside contractor performed work. Table C-1 illustrates the differences across the Peer Group Panel and the factor used to account for the differences.

Table C-1: Composition of Unit Costs
(In addition to Direct Labor and Material)

CATEGORY	THESL	A	B	C	D	E	F	G	H	I	J	K	L
Design and permitting costs	X	X	X	X	X	X	X	X	X	X	X	X	X
Project management and supervisory costs	X	X	X	X	X	X	X	X	X	X	X	X	X
Other project-related costs (e.g., fleet and warehouse)	X	X	X	X	X	X	X	X	X	X	X	X	X
Other labor-related costs (e.g., training, conferences, and meetings)	X	X	X	X	X	X							
Employee-related costs (e.g., vacation, sick time, insurance, and pension)	X	X	X	X	X	X		X		X		X	
Administrative and general costs	X	X	X	X	X	X	X	X	X	X	X	X	X
AFUDC / CWIP	x	X	X	X	X	X	x		X		X	X	
ADJUSTMENT FACTOR	1.0	1.0	1.0	1.0	1.0	1.0	1.04	1.03	1.04	1.03	1.04	1.02	1.05

NOTE: In determining the adjustment factor, THESL confirmed that AFUDC / CWIP comprised 0.8% of the fully loaded labor component of unit costs (a figure that is corroborated by data from Global Learning Consortia facilitated by UMS Group as are the 2% figures attributed to other labor and employee-related costs).

Tables C-2 and C-3 present the outputs of the two-stepped approach to normalization across the seven asset categories and five maintenance programs, noting that the Peer Group Panel is intentionally masked to comply with our commitment regarding the confidential handling of this information.

Table C-2: Raw Comparison
(Metric and Canadian Dollar Conversion)

Asset Category / Capital	Units	A	B	C	D	E	F	G	H	I	J	K	L	THESL	Peer Group Median	Quartile	Percent from Median
Wood Poles Installed / Replaced	Each	$ 7,829	$ 7,860	$ 7,977	$ 8,087	$ 9,147	$ 19,398	$ 3,020	$ 8,342	$ 7,943	$ 15,500	$ 14,945	$ 5,214	$ 8,317	$ 8,087	3rd	2.8%
UG Cable Installed / Replaced	Meters	$ 126	$ 117	$ 122	$ 126	$ 138	$ 839	$ 74	$ 134	$ 130	$ 810	$ 657	$ 62	$ 131	$ 130	3rd	0.7%
Pole Top Transformers Installed / Replaced	Each	$ 19,711	$ 17,282	$ 20,761	$ 16,197	$ 22,590	$ 17,456	$ 9,416	$ 22,065	$ 21,141	$ 7,600		$ 6,773	$ 18,691	$ 18,073	3rd	3.4%
Padmount / Vault Transformers Installed / Replaced	Each	$ 39,575	$ 36,643	$ 35,430	$ 32,955	$ 47,762	$ 43,287	$ 33,350	$ 37,350	$ 44,384	$ 15,500		$ 11,001	$ 37,373	$ 36,996	3rd	1.0%
Network Transformers / Protectors Installed / Replaced	Each	$ 125,054	$ 123,432	$ 120,482	$ 130,690	$ 133,554	$ 171,269		$ 131,051	$ 142,327		$ 220,000	$ 3,346	$ 127,649	$ 130,690	2nd	-2.3%
Breakers Installed / Replaced	Each	$ 31,407	$ 32,322	$ 39,301	$ 35,761	$ 42,142		$ 55,850	$ 41,621	$ 44,501	$ 55,000			$ 37,983	$ 40,461	2nd	-6.1%
Cable Chambers / Manholes Installed / Replaced	Each	$ 126,188	$ 133,210	$ 132,727	$ 144,022	$ 147,302		$ 65,200	$ 129,566	$ 160,610		$ 826,230		$ 136,409	$ 134,809	3rd	1.2%
Maintenance Programs / OM&A																	
Vegetation Management (Inspected / Trimmed)	Kilometers	$ 2,104	$ 2,502	$ 2,324	$ 1,789	$ 2,578	$ 480		$ 2,577	$ 2,284	$ 717	$ 1,860	$ 396	$ 2,175	$ 2,139	3rd	1.7%
Pole Test and Treat	Each	$ 15	$ 14	$ 17	$ 15	$ 20	$ 55	$ 47	$ 20	$ 33	$ 18		$ 21	$ 17	$ 19	2nd	-10.1%
Overhead Line Patrol	Kilometers	$ 21	$ 23	$ 29	$ 22	$ 25		$ 80	$ 23	$ 27	$ 48	$ 938	$ 1,665	$ 23	$ 26	2nd	-12.2%
Substation Maintenance (Inspection, Test)	Total MVA	$ 1,668	$ 1,649	$ 1,681	$ 1,553	$ 1,822			$ 2,156	$ 2,175	$ 665	$ 927	$ 6,232	$ 1,712	$ 1,681	3rd	1.9%
Building Vault Inspections	Each	$ 258	$ 268	$ 236	$ 252	$ 289		$ 1,136	$ 272	$ 296	$ 229	$ 700		$ 258	$ 268	2nd	-3.9%

Table C-3: Accounting Adjustment

Asset Category / Capital	Units	A	B	C	D	E	F	G	H	I	J	K	L	THESL	Peer Group Median	Quartile	Percent from Median
Wood Poles Installed / Replaced	Each	$ 7,829	$ 7,860	$ 7,977	$ 8,087	$ 9,147	$ 20,174	$ 3,111	$ 8,675	$ 8,181	$ 16,120	$ 15,244	$ 5,475	$ 8,317	$ 8,181	3rd	1.7%
UG Cable Installed / Replaced	Meters	$ 126	$ 117	$ 122	$ 126	$ 138	$ 873	$ 76	$ 140	$ 134	$ 842	$ 670	$ 65	$ 131	$ 131	Median	0.0%
Pole Top Transformers Installed / Replaced	Each	$ 19,711	$ 17,282	$ 20,761	$ 16,197	$ 22,590	$ 18,154	$ 9,698	$ 22,947	$ 21,775	$ 7,904		$ 7,112	$ 18,691	$ 18,423	3rd	1.5%
Padmount Transformers Installed / Replaced	Each	$ 39,575	$ 36,643	$ 35,430	$ 32,955	$ 47,762	$ 45,018	$ 34,351	$ 38,844	$ 45,715	$ 16,120		$ 11,551	$ 37,373	$ 37,008	3rd	1.0%
Network Transformers / Protectors Installed / Replaced	Each	$ 125,054	$ 123,432	$ 120,482	$ 130,690	$ 133,554	$ 178,120		$ 136,293	$ 146,597		$ 224,400	$ 3,513	$ 127,649	$ 130,690	2nd	-2.3%
Breakers Installed / Replaced	Each	$ 31,407	$ 32,322	$ 39,301	$ 35,761	$ 42,142		$ 57,526	$ 43,285	$ 45,836	$ 57,200			$ 37,983	$ 40,722	2nd	-6.7%
Cable Chambers / Manholes Installed / Replaced	Each	$ 126,188	$ 133,210	$ 132,727	$ 144,022	$ 147,302		$ 67,156	$ 134,749	$ 165,428		$ 842,755		$ 136,409	$ 135,579	3rd	0.6%
Maintenance Programs / OM&A																	
Vegetation Management (Inspected / Trimmed)	Kilometers	$ 2,104	$ 2,502	$ 2,324	$ 1,789	$ 2,578	$ 480		$ 2,577	$ 2,284	$ 717	$ 1,860	$ 396	$ 2,175	$ 2,139	3rd	1.7%
Pole Test and Treat	Each	$ 15	$ 14	$ 17	$ 15	$ 20	$ 55	$ 47	$ 20	$ 33	$ 18		$ 21	$ 17	$ 19	2nd	-10.1%
Overhead Line Patrol	Kilometers	$ 21	$ 23	$ 29	$ 22	$ 25		$ 80	$ 23	$ 27	$ 48	$ 938	$ 1,665	$ 23	$ 26	2nd	-12.2%
Substation Maintenance (Inspection, Test)	Total MVA	$ 1,668	$ 1,649	$ 1,681	$ 1,553	$ 1,822			$ 2,156	$ 2,175	$ 665	$ 927	$ 6,232	$ 1,712	$ 1,681	3rd	1.9%
Building Vault Inspections	Each	$ 258	$ 268	$ 236	$ 252	$ 289		$ 1,136	$ 272	$ 296	$ 229	$ 700		$ 258	$ 268	2nd	-3.9%

Appendix D – UMS Group and Project Team Qualifications

UMS Group is an International Utility Management Consulting firm founded in 1989 to serve the global utility industry. We specialize in enterprise-level value creation, performance management solutions, and utility asset management. We are a private employee-owned company incorporated in New Jersey with headquarters in Parsippany, New Jersey, and major branch offices in Australia, The Netherlands, and The Philippines. This project was managed out of UMS Group's Headquarters Office, located at 111 Littleton Road, Suite 111, Parsippany, NJ 07054.

We bring to our clients a unique knowledge of global industry best practices, an advanced library of diagnostic methodologies and performance benchmarking data, and a strong base of utility strategic and operational expertise. We combine experienced utility consultants and seasoned industry professionals with world class tools and intellectual capital to assist our clients in diagnosing problems, designing solutions, and implementing change.

We offer:

- A team of senior consultants who have "been there and done that" in implementing change in difficult cultural, political, and labor environments.
- Strong insights into key trends and directions across the global utility industry and comprehensive understanding of the underlying drivers and emerging technology and strategies for creating competitive advantage.
- Time-tested and accepted methodologies for conducting current state assessments in four core areas which we believe are the key to achieving best practices or best-in-class performance: Operating (and Accountability) Model, Business Processes and Practices, Competencies, and Technology, Data, and Information Management.
- A comprehensive set of tools and approaches that quickly and effectively build on performance insights gained from assessments, to create actionable improvement strategies and plans.
- Experience in the successful development and implementation management of projects and initiatives that drive improvements in the performance of operations, business and financial, customer service, and asset management.

Our specific product and service offerings fall under the categories of **Performance** or **Asset Management**.

Performance Management

- Performance diagnostics (i.e., ***comparative analyses***) to identify areas in which to improve operational efficiencies (cost level) while increasing operational effectiveness (service level).
- Enterprise-wide and function-specific ***benchmarking*** to substantiate rate case filings, identify reliability improvement initiatives including service interruption mitigation and restoration, and support Capital and O&M budget submittals to external stakeholders.
- Development of ***operational dashboards*** to provide line-of-sight performance tracking between corporate strategy and specific investment and spending programs.

Asset Management

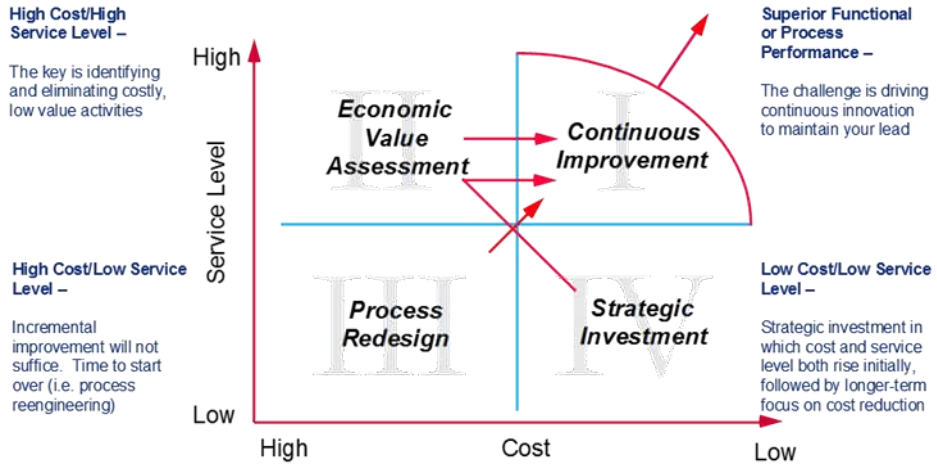
- Asset Management Business Architecture, Strategy and Planning: Major *Strategic Asset Management Transformations* facilitated by UMS Group, have achieved significant cost reductions/productivity improvements, process efficiency and effectiveness improvements, system reliability and customer satisfaction improvements and OPEX and CAPEX optimization. This practice competency has given rise to many decision support tools and a corporate performance dashboard design and implementation practice.
- Life-Cycle Investment Decision-Making and Optimization: Services range from improving practices and methodologies related to *aging infrastructure* to refining existing tools / installing new tools to aid in *Capital Investment and O&M Program Portfolio Optimization* supporting the notion of maximizing value enterprise-wide (comprehensive accounting of benefits aligned to corporate strategy) while operating within a pre-established budget and risk profile.
- Assess Management Program Assessments: As an *endorsed Assessor by the Institute of Asset Management*, UMS Group has conducted a significant number of PAS 55 / ISO55000 assessments, comparing utilities' compliance with basic asset management policies and practices. We view this standard as a lens in ensuring all asset management activities within a utility support the achievement of its business plan, at optimal cost and on a sustainable basis.

UMS Group Competencies and Skills

UMS Group has consistently demonstrated the following key competencies and skills required to complete a unit cost measurement and benchmarking effort in the utility industry:

- *Operational Knowledge of the Industry*: The ability to effectively converse with the utility Subject Matter Experts (critical to discovering the information under the numbers) requires a certain level of conversance with the factors that drive unit costs. The core team of three consultants that contributed to this effort total over 60 years of experience, three of whom have worked (either as full-time staff or in a consulting capacity) within utility organizations.
- *Development of a Performance Management Framework*: UMS Group has perfected the use of a 2-dimensional view of performance, calling for simultaneous measurement of cost and service level in conducting performance diagnostic and comparative analyses. Though this effort was largely cost-oriented, one still had to factor for the reality that maintaining an acceptable level of service (*e.g.,* reliability, power quality and customer service) is vital; and therefore, any comparisons to a Peer Group Panel had to factor for varying levels of customer expectations.

Figure D-1: UMS Group Performance Management Framework



- *Data Normalization*: Comparative Analysis (*i.e.,* Benchmarking), performed correctly, is directionally accurate in that it points towards areas where well-targeted intervention can result in improved performance (in this case reduced unit costs), and provides a point for real-time performance comparisons. However, normalization for factors such as customer density, amount and accessibility of vegetation, and weather need to be accounted for in presenting any comparisons (in the form of adjustments and / or mitigating statements). Specifically, about unit costs, there are issues with the peer data that need to be addressed / adjusted for to ensure an "apples-to-apples" comparison including the use of burdened vs unburdened rates, inclusion of equipment costs, whether work is performed energized or de-energized, comparability of work performed, etc. In forming the Peer Group Panel, these types of variances can be reduced, but never eliminated. Being able to assess the extent to which these factors negate exact comparisons and draw on years of benchmarking experience was critical to managing the presentation and interpretation of these results.
- *Communication*: The ability to frame the conversation in a manner that proactively dismisses the false impressions that benchmarking can reveal yet pose paradigms that are grounded and lead to constructive discussion are critical to any project's success. The previously presented competencies played a key role in conveying the correct message; but so was the operating discipline of thoroughly vetting a developing narrative before issuing any final documentation. Our views were substantiated by the data and information we requested and received and answers to the questions we posed, but may not have, at the first pass, represented the full story. Therefore, the ability to listen, interpret and modify views (requiring evidence of any bases to change them) was at least as important as the technical elements around industry knowledge, performance management and data normalization.

We have accomplished similar projects with clients in various markets around the world. The following table summarizes the successful completion of relevant projects,

Table D-1: Recent UMS Group Comparative Analyses / Benchmarking Efforts

Client / Project	Relevant Analyses
ATCO Electric PBR Rate Filing Support	• Capital Additions • Investment levels for Asset Replacement/ End of Life, Clearance and Safety, and Reliability • System Performance Risk Mitigation • Transmission Construction Costs and Practices
ATCO Electric T&D Performance Diagnostics	• T& D Capital Maintenance Program Frequency • Distribution Projects Efficiency and Budget Adherence • Vegetation Management Spending Levels and Performance • O&M Productivity (internal comparison and external benchmarks)
ATCO Electric T&D Gas Distribution Benchmarking	• O&M Productivity (cost per customer, CJ/Gas, per Km of main, % of net plant) • Total Gas Distribution Costs (O&M +A&G) • Hit Lines /Leaks • Safety
Black Hills Maintenance Program Review	• Substation Maintenance Frequency Practices Benchmarks • Substation Maintenance Task Performance Comparisons • Diagnostic Testing Performed
Dayton Power and Light (AES) Generation and T&D Performance Diagnostics T&D System Refurbishment and Replacement Risk Assessment	• Capital Investment Levels • O&M Spending Levels • System Reliability Performance • Maintenance Performance • Workforce Productivity (Unit Costs) • Aging Infrastructure Trends and Comparisons • Reliability and Equipment Failure • Adequacy of Capital Investment and O&M Spending Levels
Evergy Reliability Benchmarking Process and Accuracy Study	• Electric utility industry-wide benchmarking of CAIDI, SAIDI and SAIFI (MED and non-MED) • Data certainty and accuracy associated with outage reporting. • Comparative analysis associated with event exclusion inclusion.
Evergy Substation Operations Training Study	• Training locations and equipment used. • Simulations and Advanced Technology • Lessons Learned utilization.
FirstEnergy (JCP&L) Investment, O&M Spending and Performance Comparison Study	• Capital Investment Levels • O&M Spending Levels • Reliability Performance • Aging Infrastructure Analysis
Hydro One Capital Project Execution	• Capital project schedule attainment. • Project cost • Project resourcing selection • Scope management • Risk processes • QA/QC • Project communications protocol • Contract methodology
Indianapolis Power and Light Company (AES) Generation and T&D Benchmarking	• Generation Plant Performance Gap Assessment • Generation Asset Management Gap Analysis and Transformation Plan • T&D Asset Management Maturity • T&D Staffing Productivity (Unit Costs)
Lansing Board of Water and Light Power Production and Energy Delivery High Level Performance Diagnostic	• Cost and Service Level Comparison • Infrastructure Renewal Analysis • System Maintenance Performance • Aging Workforce Analysis • Worker Productivity (Unit Costs) • Organizational Effectiveness
Nova Scotia Power Enterprise-wide Performance Diagnostic	• O&M Spending Comparison • Capital Investment Levels Comparison • Investment Renewal and Asset Recovery Comparison • Reliability and Availability Comparison • Work Planning and Execution • Maintenance Program Effectiveness • Workforce Productivity (Unit Costs) • Aging Workforce Analysis

PSE&G-NJ and PSE&G-LI O&M Reduction Program Support Efficiency Improvement and Cost Reallocation Project	• O&M Spending Assessment • Workforce Management Assessment • Overtime Analysis / Comparisons • Organizational Effectiveness Review • Workforce Productivity (Unit Costs) • Aging Workforce Comparisons
PSE&G-LI Efficiency Improvement and Cost Reallocation Project	• Organization Redesign • Work Management • Asset Management • O&M Cost Reduction • Aging Workforce / Succession Planning
PSE&G – NJ Training Center of the Future	• Division of responsibilities • Partner Options with Community Colleges and Vocational Technical Schools • Success of Programs • Curriculum, including field and classroom.
Santee Cooper Organizational Excellence Study	• Generation organization staffing • Transmission and Distribution organization staffing • Customer operations organization staffing
SaskPower Business Renewal Initiative: Capital Efficiency and O&M Spending Assessments (Generation, T&D and Customer Service)	• Capital Investment Levels • O&M Spending Levels • System Reliability Performance • Worker Productivity (Unit Costs) • Maintenance Performance • Aging Infrastructure Trends and Comparisons • Aging Workforce Comparisons

Experience Summaries of UMS Group Core Team

Representing over 120 years of electric utility experience, the individuals provided by UMS Group are knowledgeable in unit costing practices, and conversant with the analytics necessary to perform the comparative analyses required to support an objective, independent third-party assessment. The following table provides a high-level view of their qualifications, followed immediately by resumes of those proposed as Expert Witnesses.

Table D-2: UMS Group Core Team

Name	Project Role	Years of Experience	Relevant Areas of Expertise
Jeffrey Cummings	Project Manager and Expert Witness	42	• Regulatory Support • Comparative Analysis / Benchmarking • Strategic and Operational Planning • T&D Grid Resiliency and Revitalization • Electric Distribution Reliability • Capital Investment and O&M Program Planning and Prioritization • Asset Lifecycle Planning • Maintenance Program Optimization • Repair vs. Replacement Criteria • Labor Relations
Nicholas Austin	SME-Utility Practices and Expert Witness	25	• Regulatory Support • Strategic and Operational Planning • T&D Grid Resiliency and Revitalization • Energy and infrastructure construction, project management and project lifecycle • Electric Distribution Reliability • Capital Investment and O&M Program Planning and Prioritization • Asset Lifecycle Planning • Maintenance Program Optimization • Repair vs. Replacement Criteria • Labor Relations

Johnny Shearman	SME-Comparative Assessments and Benchmarking		• Conducted comparative analyses and benchmarking efforts for multiple public utilities. • Analyzed key performance indicators (KPIs) such as operational efficiency, reliability, and financial metrics. • Evaluated performance of public utilities against industry peers to identify strengths and areas for improvement. • Examined operational processes, infrastructure, and technology adoption to determine best practices. • Identified regulatory and compliance factors affecting public utilities and evaluated their effectiveness.

Jeffrey W. Cummings

SUMMARY AND BACKGROUND

Mr. Cummings has over 42 years of professional consulting experience, with an extensive background in engineering, strategic and operational planning for vertically integrated investor-owned utilities and municipalities in North America and Asia Pacific. His most recent engagements include projects for LUMA (the combined entity of ATCO Electric and Quanta Services that has assumed management of Puerto Rico's electric T&D System), Public Service Electric and Gas-Long Island, Evergy, AES-Indianapolis Power and Light Company, Pacific Gas and Electric, FirstEnergy (Ohio, West Virginia, Maryland, New Jersey and Pennsylvania), NIPSCO (Gas), ATCO Electric, Saskatchewan Power, Ameren (Illinois and Missouri), Ergon Energy, Hydro One, Hydro Ottawa, Portland General Electric, Toronto Hydro (THESL), and Public Service Electric and Gas Company. He has supported the industry in addressing (1) key strategic and operational challenges related to system modernization / resiliency, (2) system cost and service level performance through comparative analyses (benchmarks) and the integration of industry best practices, (3) project and portfolio management, (4) reliability and risk mitigation, (5) energy efficiency, (6) fleet optimization, (7) capital investment planning and prioritization, (8) asset risk strategy and plan development, (9) organizational transformation, and (10) regulatory strategy. When called upon, he has offered expert testimony and/or opinion, most recently for three Canadian Provincial Utilities, the Israel Electric Company, and six US Investor-owned utilities operating in Kansas, New Jersey, Ohio, and Pennsylvania.

Earlier in his career, he held a series of engineering leadership positions at Vectra Technologies (formerly Pacific Nuclear and a publicly traded nuclear services company) and ultimately became Vice President of Nuclear Engineering. In that capacity, he served as the profit/loss manager for over 425 professional engineers across five regional offices in the U.S. In performing this role, he actively engaged in formulating strategies for customer development, product/service expansion, business consolidation, and oversaw the management of over 500 projects annually for approximately 75 percent of the U.S. nuclear utilities. Prior to his tenure with Vectra Technologies, Stone and Webster Engineering Corporation employed Mr. Cummings where he assumed increasing levels of responsibility in the management of large Lignite and Nuclear Power engineering and construction projects, culminating as Project Controls Manager for the completion of the last U.S. commercial nuclear power generating station (Clinton Power Station).

Mr. Cummings holds an M.S. degree in Operations Research from the U.S. Naval Postgraduate School and a B.S. degree from the U.S. Naval Academy at Annapolis, Maryland.

HIGHLIGHTS OF EXPERIENCE

Executive Consultant / UMS Group / March 2020 – present

Most recently supported the pre-commencement activities related to LUMA's takeover of the Puerto Rican Electric Power Authority (PREPA), conducting a gap assessment of its T&D Operations focused on Reliability, System Resiliency, Major Event Management, Asset and Work Management, Technical Services, Materials Management, and Fleet, supporting Regulatory in the development of the System Remediation Plan, and establishing the procedural / process infrastructure for its Asset Management function. Mr. Cummings provided oral testimony during

the Technical Conferences leading up to Commencement and is currently assisting in the implementation of LUMA's Asset and Work Management Practices.

Supported the filing of a Midwest Utility's T&D Grid Modernization and Resiliency Plan, identifying and analyzing the rationale and wide-ranging implications of the Plan on the Company and its customers. Noting that the utility is committed to investing as wisely as possible on its customers' behalf, the final report provides transparency to the proposed investments and decisions driving their selection, quantifying the benefits (most notably those pertaining to reliability) in terms of improved performance or avoided risks.

Developed an Asset Management Plan for an Eastern Utility, addressing gaps that preclude its designation as competent across all elements that define an effective Asset Management system. Applying the ISO 55000 criteria, the resulting plan laid out a plan to achieve this level within three years, with identified / budgeted initiatives and a performance dashboard, against which progress can be measured.

Executive Vice President and Managing Director of Americas and Asia Pacific / UMS Group / September 2004 – March 2020

In connection with a Canadian Utility's Custom Incentive Rate ("CIR") application for transmission and distribution rates, undertook a study to examine the processes used to plan, approve, execute, and monitor transmission capital projects and the results achieved in executing its portfolio of transmission capital projects. In performing this work, Mr. Cummings conducted a series of interviews with utility individuals in relevant lines of business (e.g., Project Control, Project Delivery, Station Services, Transmission Lines, and Station Construction), reviewed relevant reports, procedures, and project performance data, identified and recruited a Peer Group Panel of 12 electric utilities, designed and administered an assessment framework (Maturity Rating Scales used to gauge an electric utility's progress from low ("Novice") to high ("Beyond Standards") across 10 Performance Domains, 9 of which comprise the Project Management Institute's Project Management Book of Knowledge – "PMBOK"), and surveyed the Peer Group Panel and combined with the insights gleaned from the interviews, determined the utility's absolute ("maturity level") and comparative ("quartile") standing across each of the 10 Performance Domains. The report was filed into testimony and Mr. Cummings will be supporting the utility in upcoming Technical Workshops and Oral Hearings (if necessary).

Reviewed the transmission O&M practices, processes, and procedures within 15 lines of business that define the utility's Asset Management and Centralized Services (AMCS), Electric Operations, and Projects and Construction organizations. Thirty-eight improvement and / or scoping initiatives / actions were identified, across seven categories:

1. Asset Growth: Projected increases attributed to the Electric Transmission and Distribution System Buildout (e.g., UG Cable, Relays, Transformers, and GIS Breakers) to improve overall system performance (reliability and resilience)
2. Productivity Improvement: Projected decreases including reduction of unit costs to achieve top quartile performance, right-sizing of crews and adjustment to test and inspection cycles.
3. New Work: Projected increases regarding emerging changes in FERC / NERC requirements, addressing heretofore pending issues (e.g., ROW encroachments and as-

build drawings), establishing new capabilities (e.g., TFI), and expanded scope across the utility (e.g., QA/QC).

4. Reclass to Capital: Projected decreases by revisiting previous capitalizing policies (e.g., Vehicle Leases and Planning Studies) and accounting for capital acquisitions as offsets to previous O&M funded activities (e.g., EMS Upgrades).
5. Technology: Projected changes (increases and decreases) attributed to expanded use of BI applications, installation of new technologies (e.g., EMS Upgrade, VENTYX, MEGA and Aerial Inspections and LMS expansion)
6. Workforce Effectiveness: Projected increases due largely to replacing anticipated retirements.
7. Insourcing: Projected decreases due to internal staff performing actions previously performed by a third party

In support of a Canadian Utility's rate filing application, performed a Unit Costs Benchmarking Study aimed at reviewing how the utility determined the unit costs underlying its distribution system capital and operational programs, performing benchmarking comparisons with a selected peer group of utilities in Canada and the United States, and providing recommendations on how the utility can improve its unit costing practices in the future.

Supported development of an Northeastern Utility's 5-year Base capital budget, providing justification for each element, complete with detailed supporting analysis and benchmarks where needed and appropriate, quantifying the impact of planned Clause and Blanket spend, as well as specific named Capital projects on anticipated asset failure rates and the resulting need for spending of each Capital Blanket, challenging and testing the logic and rationale for options considered and choices made for spend levels proposed, and creating a coherent narrative to explain the reasons and justification for major amounts involved and variances from previous plans, helping the utility harness their historical data on costs, workload volume and unit rates to clarify assumptions regarding cost drivers behind projections of Capital Spend in each area for each year looking forward over the 5 years, and providing support in the design / development of a presentation of the 5-year Capital Budget for Executive Management review.

Conducted an enterprise-wide review of a mid-western electric and water municipality to corporate organization structure considering pre-established strategic goals and six major initiatives, all geared towards its vision as a Utility of the Future. Included was the establishment of a Project Office for a new CCGT plant, the planned retirement of a coal-fired station, four major IT / OT initiatives, considerations regarding aging workforce and the attending opportunities to retool its staff, a mandate to reduce O&M spending by 15 percent, all within the construct of managing risk during a major industry transformation. His efforts included detailed analyses of staffing levels, worker productivity, O&M program execution, and capital efficiency, benchmarking cost and service level performance, and identifying industry best practices to close identified performance gaps, The recommendations were presented and accepted by the utility (with minor adjustments) and is in the process of extending the contract to include implementation support.

Assisted a Southeastern Utility in improving its planning, scheduling, and execution of transmission and distribution capital projects, O&M projects, asset programs and asset maintenance, including a comprehensive assessment of the key processes that underlie work management and development of recommendations to improve (1) process efficiencies and effectiveness, (2) cross-organizational collaboration and (3) process governance.

Worked with a west coast electric utility in establishing a Project and Portfolio Management function. Starting with defining criteria for evaluating and selecting projects for execution, the process framework put in place provided the governance and operating guidelines to manage a portfolio and specific projects throughout the fiscal year, establishing the concepts of "contingent" projects, the capture of value, risk mitigation and transparency in comparing the value of electric production and energy delivery investments.

Conducted several Asset Management Gap Assessments, using ISO 55000 (and its predecessor PAS 55) standard as a point of comparison:

- Provincial Canadian Municipality (Electric Distribution)
- Midwest Municipality (Electric and Water)
- Northwest Investor-owned Utility (Electric and Gas)
- Midwest Investor-owned Utility (Electric)
- Southwest Municipality (Electric and Water)
- Federally owned and operated Utility (Electric)

Further, to the extent requested by each utility, implemented programs and practices to close identified gaps with an eye towards ISO 55000 certification.

Provided expert opinion regarding a northeast utility's restoration performance during a major storm event in October 2017. Filed with the courts, his opinion addressed the utility's comparable position in restoration time, restoration rate, immediate response, restoration practices deployed, and overall prudence of its decisions in the events leading up to and during the storm. He not only provided incontrovertible proof of prudence, but through comparisons (benchmarks) with other major storm events in North America and Europe, he presented a compelling argument that the utility excelled in its performance, effectively managing the trade-offs between performance, cost, and operational risk.

Supported a mid-western electric utility's rate case, testifying to the veracity of its asset, risk, and performance management programs and efforts underway to address significant challenges with its central business district underground network system. Consistent with Mr. Cummings' recommendations, he participated in a collaborative effort to define an oversight process that focuses on a comprehensive performance dashboard of KPIs, and monitoring progress towards an Industry Leading Asset Management process.

Spearheaded efforts to provide third party assessments of a mid-Atlantic electric utility's capital investment, O&M spending levels and service level performance in support of a base rate filing; and later assessed the prudence of decisions made in the events leading up and during three extraordinary storm events during the 2011 - 2012 timeframe. He led a comprehensive benchmarking effort, focused on productivity (unit cost), reliability and overall system resiliency, and storm restoration performance. In both instances, he provided written direct and oral testimony during cross-examination demonstrating the utility's effectiveness in balancing operational performance, cost, and risk mitigation.

Assisted a mid-western utility in developing a System Revitalization and Resiliency Program for submittal to its Board of Directors and State Regulator. The proposed plan provided profiles of projected capital and O&M cash flows, the capture of utility and customer benefits and risks, and an industry context around which to justify such a program. The results of this effort were entered

testimony in support of the utility's filing for a capital rider, for which it received sufficient funds to support the initial 18 months of a 10-year program.

Assisted a Canadian utility in offering an independent third-party assessment of a recent PBR filing performing high-level comparative analyses (benchmarks) of proposed growth and capital investments geared towards infrastructure renewal over a 5-year period; and assessing the risk of returning to previously established lower capital investment plans. This effort included providing testimony as part of a formal hearing with the Provincial Utility Commission.

Served as Project Director for a full-scale business renewal effort, establishing a plan to improve the efficiency of capital investments, and decrease O&M spending by $50 million annually without any noted decrease in system performance or increase in operational risk. Conducted across the entire enterprise with a focus on worker productivity (O&M program unit costs), capital efficiency (capital investment portfolio and unit cost management), this effort launched a series of initiatives that over 10 years will decrease spending levels by a cumulative $500 million and set the stage for transitioning to the Utility of the Future. Areas of focus included comparative cost and service level analyses, work planning and execution, performance dashboards, transmission and distribution reliability, overall system resiliency, capital portfolio optimization, and business value/risk tolerance frameworks; and addressed the necessary infrastructure to construct a "first-of-its-kind" carbon capture generating facility.

Served as Project Director of four comprehensive assessments for separate Transmission and Distribution operating companies of a large US-based electric holding company.

- Three involved a review of practices and processes related to system reliability with a thorough review of historical results (as reported in their outage management systems) and supporting reliability programs. Specifically, these assessments analyzed, trended, and benchmarked service interruptions, service restoration, organization and staffing, and capital/operating spending patterns with the objective immediately and sustainably improving performance; and included formal presentations to Commission staff across 2 regulatory jurisdictions, and
- Another assessment involved a thorough review of a utility's infrastructure from both asset condition and energy efficiency viewpoints, resulting in a long-term strategy and plan to transform the network to 21st century standard. This involved identification of key technical and financial legacy issues, incorporation of several constraints and factors (e.g., financial, technology and social equity), and a holistic portrayal of costs, benefits, and risks from both a portfolio and individual circuit/substations perspectives; and the articulation of the plan tailored for each external stakeholder (e.g., commission staff/regulator, legislators, environmentalists, shareholders, and customers).

Assisted a large Northeastern utility in identifying over $80 million of O&M cost reduction initiatives without impacting service level (e.g., customer service, availability, system reliability or safety). Areas of focus included benchmarking and practices review of the utility's electric transmission and distribution system, customer operations, gas distribution and asset management functions. The outcome has been incorporated into a long-range plan to improve earnings despite an unfavorable outcome in a recent rate case filing.

Performed a capital and O&M spending and risk mitigation diagnostic for a mid-level Midwest utility in support of an overall business case to infuse more capital into its transmission and distribution infrastructure. The case was compelling enough to present to the Board of Directors and the Commission State and will be a cornerstone for subsequent strategic planning and future rate filings.

Supported a mid-level Midwest utility in its energy efficiency/demand response filing with the state regulatory and governing entities. Applied industry comparative analyses in demonstrating value capture / risk avoidance for all stakeholders (investors, customers, and utility), and validated that the proposed program met the intent and letter of the legislative mandate.

Conducted an enterprise-wide capital efficiency assessment for a Canadian Utility spanning electric transmission and distribution and electric generation. In reviewing their planned capital expenditures over a 10-year period, Mr. Cummings led the analyses of worker productivity (unit cost) and capital project execution and developed a plan to (1) reduce the current planned capital expenditures by 25 percent and (2) optimize the allocation of capital over the 10-year planning horizon with due consideration to optimizing the trade-offs between value and asset risk.

Strategic advisor for a major transformation effort within a U.S. Midwest electric and water municipality, that included conducting performance diagnostics (benchmarks) of its engineering and production divisions, development of a work planning and outage management program (and support processes), and several initiatives focused on achieving organizational alignment. Supporting efforts included oversight of the completion of a CCGT Plant (including supporting negotiations with GE for a LTSA), establishing criteria and process for the converging IT/OT, and the creation of an Organizational Efficiency and Effectiveness model.

Assisted a large Australian electricity distribution utility in optimizing the size and mix of its fleet of vehicles and attached equipment, factoring in financial constraints, environmental requirements, and the aligning of work level, staffing and specific task descriptions. The process of arriving at a plan to reduce capital investments by as much as $20.0 million and operating expenses by $1.2 to $2.0 million involved the active participation of the company's internal customers (i.e., users of the fleet assets), resulting in organizational acceptance of the outcome. Mr. Cummings extended this effort to a large Western U.S. electric municipality, developing a strategy and plan to achieve comparative results.

Led the implementation of a process (and supporting software) to optimize the capital spending profile across three operating companies within a large US-based electric and gas company (electric transmission and distribution, gas transmission, distribution and storage, fleet, and electric generation); as well as one of the largest gas utilities in the US Midwest. In performing these projects, Mr. Cummings facilitated the linkage of a proposed investment's value and its contribution to overall corporate strategy as well as the risk should a specific investment be deferred; and equally important, implemented the process in a manner that garnered organizational support for change.

Oversaw the implementation of an industry forum to identify trends and perform causal analyses on the failure of critical transmission equipment and components. In pooling industry equipment/component performance data, the goal was to apply statistically relevant data to predict failure patterns and establish optimum replacement vs. refurbishment criteria. In parallel with the initial formation of this forum, Mr. Cummings also performed the following:

- Comprehensive performance diagnostic across all functions of one of the largest electric municipalities within the US Southwest. In so doing, he provided a plan of action to maintain service levels yet reduce operating costs by as much as 25 percent. The utility adopted the recommendations and integrated them with the municipality's five-year operating plan.
- Development of a preventive and corrective fleet (vehicle and attached equipment) maintenance program, adopting may of the best practices from the petroleum and U.S.

Naval programs, and tailoring them to application in a gas municipality environment. The project team, led by Mr. Cummings, provided a detailed process manual (with supporting process maps), an implementation plan (i.e., process/procedure changes and additions, technology enhancements and organization adjustments), and a series of key measures to assist the utility in adopting the recommendations. The municipality and city government officials embraced the program as submitted.

Executive Consultant / Self-Employed / September 1996 – September 2004

Participated in a task force and subsequently joined the implementation team in developing and executing a five-year plan to revamp the electric transmission and distribution infrastructure for the Chicago business district. This effort involved the translation of highly technical specifications and detailed budgeting information into terms easily understood by commission staff, city government, and the utility's customers. All external stakeholders (i.e., Board of Directors, City of Chicago, Commission Staff and State Regulator accepted the plan.

While supporting implementation, Mr. Cummings developed the strategies and plans for initially routing, certifying, designing, and installing 135kV and 345kV transmission to meet projected load growth and system reliability requirements. He played a key role in shortening the certification period by as much as 50 percent. This required effective liaison and communication with the Illinois Commerce Commission and Army Corps of Engineers as well as coordination of Commonwealth Edison's engineering and construction organizations and their assigned "contractors of choice."

Provided consulting services to several technology-based enterprises including gas and electric utilities, engineering and architectural firms and manufacturers of electric components. The projects included:

- Strategic and Operational Planning and Integration (Linkage of Business Vision, Core Values, Financial Goals and Core Business Processes, maintaining a balance between long-range sustainability of the business and short-range stakeholder expectations).
- Organizational Development (Competency-based Performance Management System Development and Implementation, Business Culture Assessments, Employee 360-degree Evaluations, Leadership Development, Recruiting and Employee Selection).
- Marketing and Sales Support (Branding Strategy Development, Customer Satisfaction Surveys, Product/Service Positioning and Pricing Strategies, and Sales Training).
- Technical and Commercial Management (Ensuring a proper balance between achieving profit/loss targets and meeting the quality standards as specified by the customer)
- Merger and Acquisition Assessment and Implementation

Vice President of Nuclear Engineering / VECTRA Technologies (previously Pacific Nuclear and NUTECH Engineers) / April 1985 – September 1996

Worked in a variety of capacities for a nuclear engineering consulting company, serving initially as a Project Manager and ultimately as the Vice President of Nuclear Engineering. Over this 11-year period, he played a major role in growing annual revenues from $5.0 million to $50.0 million while increasing market penetration to approximately 75 percent of the US nuclear utilities. He

developed many of the skills and competencies used in his roles as management consultant (summarized above) through his hands-on experience in managing over 425 engineering professionals and overseeing the management of over 500 projects annually.

Assistant Project Manager / Stone and Webster Corporation / August 1980 – April 1985

Worked in a variety of capacities for Stone and Webster Corporation, primarily assigned to major nuclear power plant design and construction projects. Specific assignments included:

- Assignment to the Beaver Valley Power Station project, establishing a projects control process and system within the Duquesne Light Company to manage the installation of Three Mile Island modifications in support the second refueling outage, improving actual performance in terms of work performed and schedule duration from the initial refueling outage by a factor of three. Following this effort, Mr. Cummings shifted his focus to the unit under construction (unit no. 2) where he installed a process to facilitate the final turnover of the systems (and accompanying documentation) to plant operations over an 18-months period.
- Assignment to Clinton Power Station, where he acted as Project Controls Manager for the contractor, facilitating the lifting of 12 Nuclear Regulatory Commission (NRC) imposed stop work orders and subsequent construction and turnover of the plant to the Illinois Power Company (IPC). Key activities over a two-year period included a successful Fuel Load Caseload presentation to the NRC, rate case preparation, an information system installation to track the turnover of all systems and instituting an integrated cost and schedule process and system to support weekly and monthly reporting to project and IPC executive management. His role in integrating the construction and system turnover schedules (and subsequent development of computerized detailed system turnover punch lists) served as a primary catalyst for successful completion of the Clinton Power Station project.

Commissioned Officer / U.S. Navy / June 1973 – August 1980

Served in the U.S. Navy in increasingly responsible roles culminating as a Weapons Officer on a destroyer, USS Robert E. Peary (FF-1073). In this capacity, he managed and led three divisions totaling 100 sailors, responsible for the maintenance and operation of all weapon and detection systems, the major equipment necessary to support basic seamanship evolutions, and daily consumables for the entire ship's force. He left the U.S. Navy in 1980, having earned the Navy Achievement Medal for his efforts during two extended deployments and extraordinary performance in the areas of Anti-Submarine Warfare and Naval Gunfire Support.

RECENT ARTICLES AND SPEECHES

- *"Integrated Risk Management-Application to Pipeline Safety*," a white paper written in collaboration with a utility executive in October 2017.
- "*Driving Reliability Improvements-Regulatory Oversight",* presentation given to the EEI Transmission, Distribution and Metering Conference, New Orleans, LA, April 7, 2009.
- *"A Paradox of Thrift: Economic Barriers to T&D Network Modernization."*
- *"Grid Modernization: A Roadmap to Tomorrow's Infrastructure…Don't Get Lost on the Way to AMI*."

Nicholas Austin

SUMMARY AND BACKGROUND

Mr. Austin is a Partner and Managing Director, North America for UMS Group, Inc. He obtained his Bachelor of Science Degree from the University of Dayton, and his Juris Doctorate from The Ohio State University Moritz College of Law. He also completed the Leadership for Senior Executive Program at Harvard Business School.

Mr. Austin started his career in 1998 as an attorney with a large Midwest law firm, practicing initially in Cincinnati, Ohio, and then in Cleveland, Ohio with a focus on construction law. He counseled clients on contract negotiation, drafting and execution matters, advised clients on a wide variety of day-to-day and long-term business issues and decisions ranging from implementation of daily procedures to streamlining operations in anticipation of divestiture action, and managed all aspects of client litigation from matter intake to finalization via settlement, motion practice, alternative dispute resolution or trial.

After a successful career as an attorney, he pivoted to energy, working for FirstEnergy Corp. initially as an analyst in 2007 with increasingly expanding leadership roles over the next 15 years. More specifically, Mr. Austin includes the following as selected examples of his experience and success at FirstEnergy:

- As a lead analyst within FirstEnergy's Corporate Asset, Portfolio and Project Management organization, Mr. Austin lead the creation of a contracting and portfolio management strategy associated with a 2x capital portfolio increase/investment across all of FirstEnergy's distribution and transmission assets.
- Served in a leadership role during the merger of FirstEnergy and Alleghany Energy, guiding a team tasked with the assimilation and operationalization of the two entities' distribution and transmission vegetation management portfolios.
- As Director of Operations Support at the Pennsylvania Electric Company, oversaw all aspects of safety, financial and operational performance in the support organizations including the management of vegetation management, fleet, facilities, meter reading and meter services.
- As Corporate Director of Asset and Capital Portfolio, created a new corporate organization tasked with $1.4B portfolio-level management of FirstEnergy's transmission and distribution capital project lifecycle.
- In his role as Director of Operations Services for the Cleveland Electric Illuminating Company, oversaw 450 management and bargaining unit employees with a total capital and maintenance budget of over $150M.
- And as President of Pennsylvania Electric Company, was responsible for the utility-wide leadership of the organization, including creating a culture of safety excellence while driving performance and accountability across a management and bargaining unit team with a CAPEX budget of over $170M and an OPEX budget more than $70M.

With a desire to expand his entrepreneurial and energy-industry knowledge, experience, and expertise, Mr. Austin left FirstEnergy to join Ashton Gray, LLC as President and Partner of Ashton Gray Energy, LLC. While at Ashton Gray Energy, he helped turn-around the oil field services and infrastructure operating entities, while pivoting both organizations towards renewable energy projects in the central southern U.S. states as well as in generation projects in the Texas/ERCOT

footprint. Upon completing the successful divestiture of Ashton Gray Energy's operations, he joined UMS Group in his current position.

HIGHLIGHTS OF EXPERIENCE

Project team lead to increase capital expenditures by 3x across three state, six division electric utility portfolio that included transmission and distribution line, substation, and facility assets; including therein the creation and initiation of organizational structure comprised of portfolio management, project management and asset management groups.

Oversaw implementation, maintenance, and delivery of Ohio IOU smart grid plans from an operational perspective, including addressing engineering, project planning and execution, work force retention and utilization, as well as benefit capture and reporting to commission.

Successfully led initiative team at large investor-owned electric utility tasked with decreasing divisional operating expenditures by 30%, with partial shift of same to emergent capital portfolio projects.

Managed divestiture efforts associated with sale of investor-owned utility's New York State territory to Rural Electric Cooperative.

Appendix E – UMS Group Reliability Performance Assessments

UMS Group has established credentials in electric distribution reliability, as illustrated by the following more recent engagements:

- *Pacific Gas and Electric:* UMS Group conducted a third-party expert review of Pacific Gas and Electric's distribution reliability to determine what had happened in the areas of *Equipment Failure* and *3rd Party Damage*, and what, if anything, could be done to help mitigate the reliability target shortfalls for the current year. As a result of our review of reliability results (reviewing restoration performance, weather effects, "Blue Sky" SAIFI trends, outage causes, equipment failure-caused outages, metrics – number of outages, customer interruptions, and customer minutes, worst performing circuits and wires down drivers) over a three-year time frame, key findings and recommendations were presented in the areas of Equipment Failure (OH Conductor, Transformers and UG Cable), and Third Party Damage (Vehicles and Metallic Balloons).
- *Public Service Electric and Gas – Long Island:* UMS Group was retained by Public Service Electric and Gas – Long Island (PSE&G-LI) to review its reliability in the context of pre-established performance targets and changes during the year preceding the project. The primary objective was to determine the underlying cause of an apparent deterioration of performance over a three-year period, with specific focus on those factors that resulted in PSEG LI approaching (and in the case of SAIFI exceeding) the minimum performance level specified in its contract with LIPA; and recommend specific actions that could be taken to reverse the trend and return to previous stronger levels of performance. Specific recommendations revolved around vegetation management (danger tree removal and use of herbicides), UG cable replacement, animal guarding, vehicle caused outages, and creating an asset management information repository.
- *Israel Electric Company:* UMS Group provided an expert opinion regarding Israel Electric Company's (IEC's) restoration performance during a major storm event in October 2015. Filed with the Israeli courts, his opinion addressed IEC's comparable position in restoration time, restoration rate, immediate response, restoration practices deployed, and overall prudence of its decisions in the events leading up and during the storm. He not only provided incontrovertible proof of prudence, but through comparisons with other major storm events in North America and Europe, he presented a compelling argument that IEC excelled in its performance.
- *FirstEnergy Pennsylvania Operating Companies:* The FirstEnergy Pennsylvania Operating Companies engaged UMS Group to conduct an independent review and assessment of its internal and external mutual assistance activities, including a review of the mutual assistance provided to and received from other electric distribution companies (EDCs) during 2011 and 2012. An initial list of 26 outages covering 13 storm events was developed, based on number of customers impacted (minimum of 5 percent), with due regard to including all four Operating Companies within Pennsylvania. We applied our standard multi-tiered diagnostic framework to:
  - Compare the FE PA OPCOs practices relating to Mutual Assistance with those in use at comparable electric distribution organizations, and
  - Assess execution of these practices, initially at a high level to address issues of equity in their application across the FE PA Operating Companies' service territories and electric utility industry, and then on a storm-by-storm / outage-by-outage basis to identify specific opportunities for improvement, either programmatic or event driven.

In order to establish context for the analyses and comparisons required to support the specific assessments and conclusions contained within this report, UMS Group reviewed (1) FirstEnergy's most current E-Plan, (2) specific service restoration information for the 26 outages contained within FirstEnergy's Outage Management System (OMS), and (3) all previously filed Major Event Reports (MERs) for these specific outages / storm events, and was afforded complete access to the Company's technical and management staff. UMS Group concluded that notwithstanding several opportunities to fine-tune / improve its practices that at the highest level, the FE PA Operating Companies' use of Mutual Assistance fell well within an industry-based range of reasonableness. Our review confirmed that plans were reasonably conceived, for the most part actions were properly executed (some exceptions were noted in the final report), and the results were generally appropriate (although with the benefit of hindsight, we did acknowledge that marginal improvement opportunities may have been possible). As with the above-mentioned Focused Reliability Audits, all findings and recommendations were accepted as presented by the respective Commission Staffs and FirstEnergy.

- *Jersey Central Power and Light:* In support of a 2011 Base Rate Case Filing, UMS Group was hired to provide an independent, third-party assessment of FirstEnergy's JCP&L Operating Company's investment and spending levels and reliability performance as compared against the other FirstEnergy electric utilities, other New Jersey electric utilities, and other peer group utilities. Our efforts objectively demonstrated that JCP&L's reported reliability had shown consistent improvement since 2004 and that its performance ranged between top quartile and median relative to two comparable peer groups. We were also successful in showing JCP&L's effectiveness in implementing asset management-related initiatives, and industry-leading service restoration processes; appropriately bridging the gap between reported reliability and the customer experience related to two extraordinary storm events in 2011 (Hurricane Irene and the October 31st Snowstorm). Further, his analyses illustrated that the capital investment and O&M spending levels were appropriate for the level of service required by the Regulator (BPU). In conjunction with filing written direct testimony, Mr. Cummings provided direct and rebuttal testimony at rate hearings conducted in October 2013 and supported JCP&Ls outside counsel in the preparation of final briefs. Related to this effort, he prepared a written report adjudging the prudence of decisions made during the 2011 extraordinary storm events and Super Storm Sandy, from which the utility received a favorable outcome.

- *Met-Ed, Cleveland Electric Illuminating, and Penelec:* UMS Group has also performed several detailed reliability assessments for other FirstEnergy Operating Companies (Met-Ed, CEI and Penelec). This work was conducted for FirstEnergy with the approval / concurrence of respective State Regulators to address concerns around reliability and included extensive interaction with commission staff. In each of these efforts, UMS Group assessed actual reliability performance, relevant O&M practices, spending and investment levels, and overall approaches to Asset Management against industry "best practices," and provided recommendations that were accepted by each utility and their respective Commission Staffs. The final deliverables included a comprehensive report and a formal presentation to the PA and OH Commission Staffs.

Appendix F – Peer Group Panel Survey

NOTE: In ensuring the readability of the various tables, we excluded columns for comments and a precursor question for unit costs that read as follows: Please enter number of units and total cost over the past 3 years, the percent of these costs attributable to labor, of this labor the percent outsourced, and whether the equipment was purchased in-house.

Unit Costs

Asset Category / Capital	Unit of Measure	Actual (Total, 3-YR Period)		Unit Cost	Percent of Cost Assigned to Labor	Percent of Labor Outsourced	In-House Purchase of Equipment (Yes/No)
		No. of Units	Sum of Cost				
Wood Poles Installed & Replaced	Each						
UG Cable Installed & Replaced	Meters / Feet						
Pole Top Transformers Installed & Replaced	Each						
Padmount Transformers Installed & Replaced	Each						
Vault Transformers Installed / Replaced	Each						
Network Transformers / Protectors Installed & Replaced	Each						
Breakers Installed & Replaced	Each						
Cable Chambers / Manholes Installed & Replaced	Each						

Maintenance Programs / OM&A	Unit of Measure	Actual (Total, 3-YR Period)		Unit Cost	Percent of Cost Assigned to Labor	Percent of Labor Outsourced	In-House Purchase of Equipment (Yes/No)
		No. of Units	Sum of Cost				
Vegetation Management (Inspected / Trimmed)	Kilometers / Miles						
Pole Test and Treat	Each						
Overhead Line Patrol	Kilometers / Miles						
Building Vault Inspections	Each						
Substation Maintenance (PM and CM, Collectively)	Total MVA						

Accounting

Question 1	Method	Answer
Which of the following methods do you use to determine unit rates for your asset categories and / or maintenance programs?	Divide total spent by number of units.	☐
	Average individual costs of separate work orders	☐
	Other (please specify in comments)	☐

Question 2	Method	Answer
In addition to Direct Labor and Material, which of the following costs are included in your unit costs for <u>In-House work</u>?	Design and permitting costs	☐
	Project management and supervisory costs	☐
	Other project-related costs (e.g. fleet and warehouse)	☐
	Other labor-related costs (e.g. training, conferences, and meetings)	☐
	Employee-related costs (e.g. vacation, sick time, insurance, and pension)	☐
	Administrative and general costs	☐
	AFUDC / CWIP	☐
	Other (please specify in comments)	☐

Question 3	Method	Answer
In addition to contractor costs, which of the following costs are included in your unit costs for contracted work?	Contractor management / supervision costs (please indicate in comments if these costs include overheads per question 2)	☐
	Permitting and design costs	☐
	Other (please specify in comments)	☐

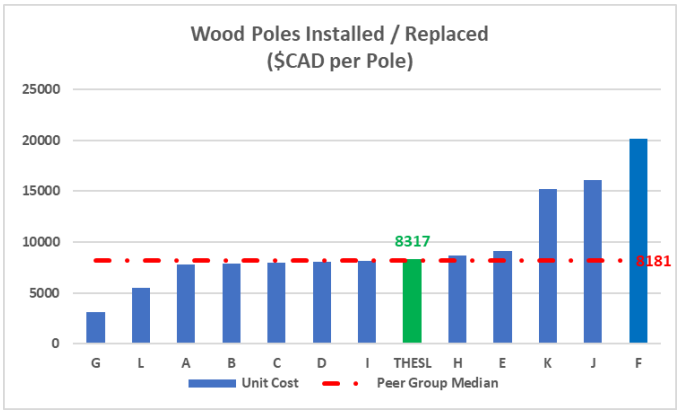
Question 4	Answer (Yes / No)
Do you "net out" customer contributions from your unit costs?	

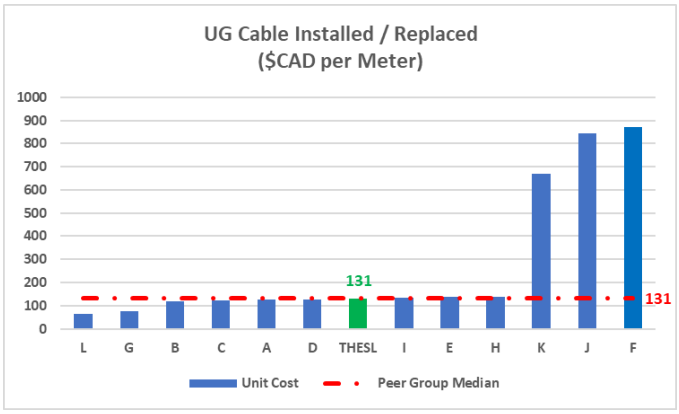
Local Factors

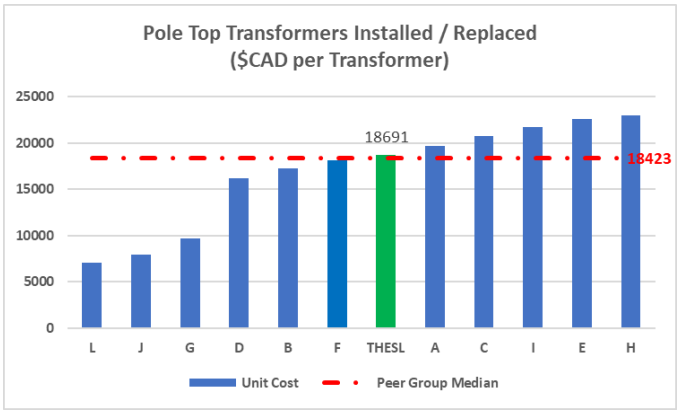
Question 1	Factor	Answer
Which of the following factors impact the cost of you performing inspections and replacement work?	Excessive travel time (over 30 mins)	☐
	Road restrictions which limit working hours	☐
	High water table	☐
	Working next to energized lines (requiring dedicated observer, gloves, etc.)	☐
	Requirements to perform work off hours (i.e. night / weekend)	☐
	Changed standards requiring rebuilds rather than like-for-like (i.e. clearances)	☐
	Excessive switching requirements (i.e. to isolate on dual radial construction)	☐
	Shoring requirements for UG work	☐
	Limitations on tree trimming (e.g. unusually tight clearances)	☐
	Prior use of lead cables	☐
	High fault currents (impacting equipment sourcing)	☐
	Paid duty for police presence on public roads	☐
	Extensive use of submersible transformers	☐
	Environmental regulations	☐
	Insufficient IT Enablement	☐
	Union Work Rules	☐
	City consent requirements (i.e. customer notification, restoration, progressive clean-up, etc.)	☐
	Other (please specify in comments)	☐

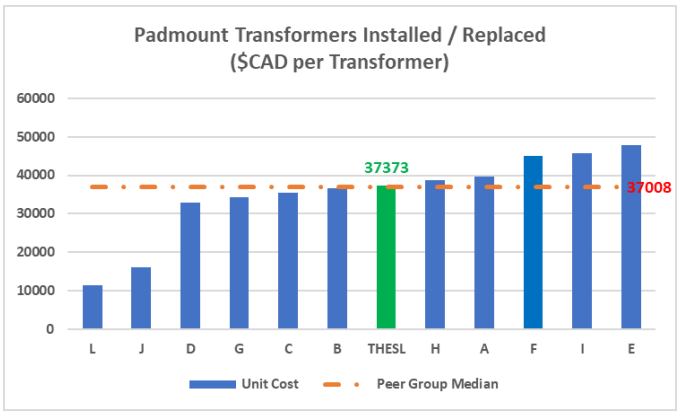
Appendix G – Detailed Benchmarking Results

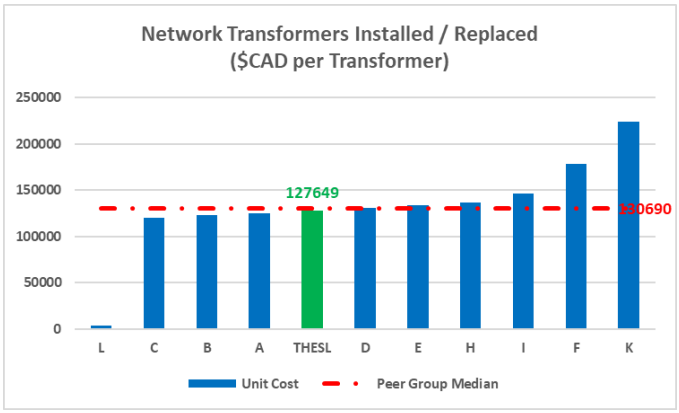
The following charts are provided, presenting the unit costs for each of the utilities (in ascending order), showing THESL's (Green) position relative to each of the electric utilities and the Peer Group Panel "normalized" median value (Red). Tables that detailed each step of the "normalization" process are presented in Appendix C.

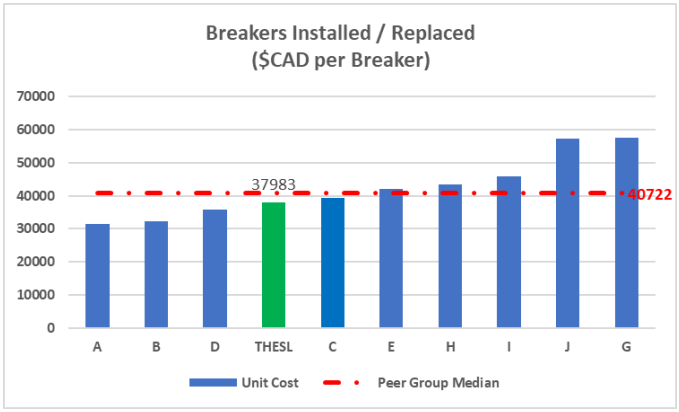


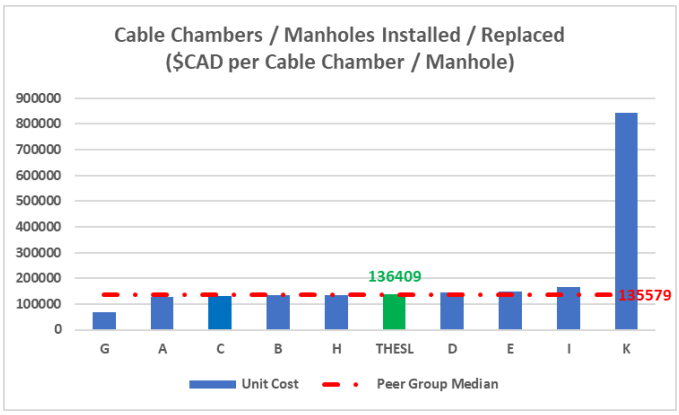


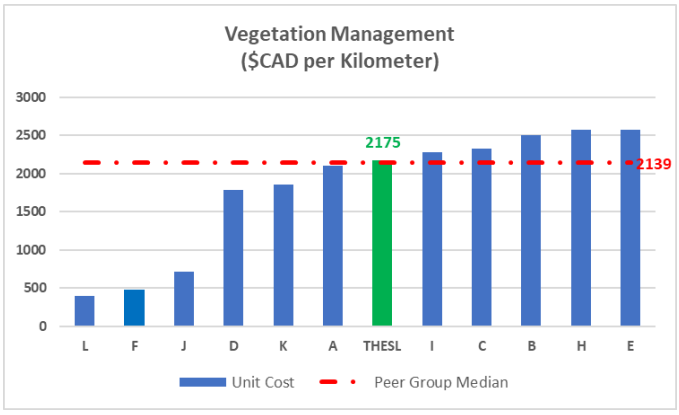


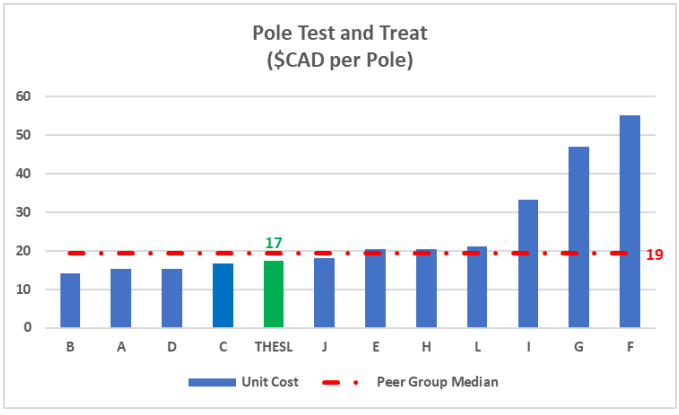

Padmount Transformers Installed / Replaced
($CAD per Transformer)
60000
50000
40000
30000
20000
10000
0
37373
37008
L
J
D
G
C
B
THESL
H
A
F
I
E
Unit Cost
Peer Group Median

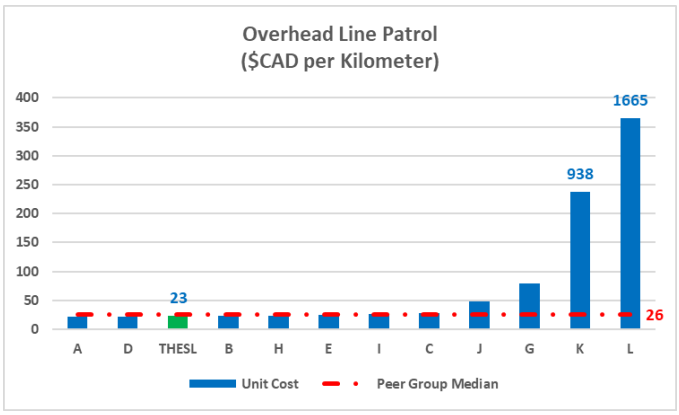

Network Transformers Installed / Replaced
($CAD per Transformer)
250000
200000
150000
100000
50000
0
127649
130690
L
C
B
A
THESL
D
E
H
I
F
K
Unit Cost
Peer Group Median

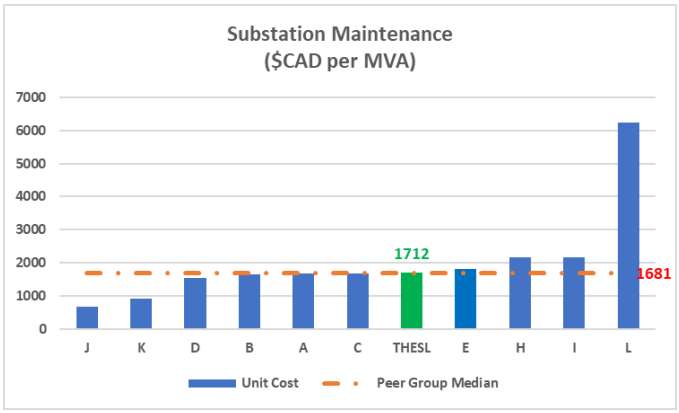

Breakers Installed / Replaced
($CAD per Breaker)
70000
60000
50000
40000
30000
20000
10000
0
37983
40722
A
B
D
THESL
C
E
H
I
J
G
Unit Cost
Peer Group Median

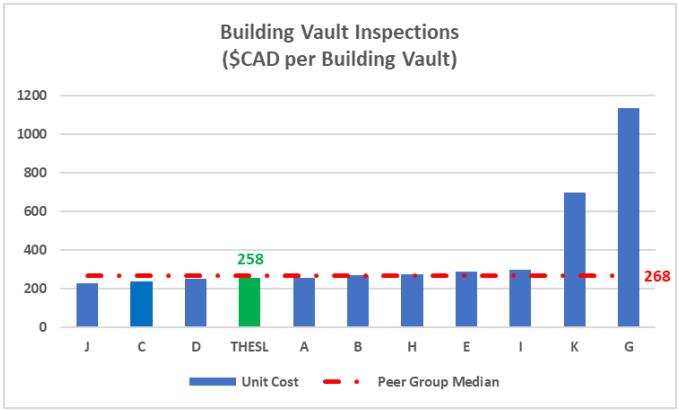

Cable Chambers / Manholes Installed / Replaced
($CAD per Cable Chamber / Manhole)
900000
800000
700000
600000
500000
400000
300000
200000
100000
0
136409
135579
G
A
C
B
H
THESL
D
E
I
K
Unit Cost
Peer Group Median


Vegetation Management
($CAD per Kilometer)
3000
2500
2000
1500
1000
500
0
2175
2139
L
F
J
D
K
A
THESL
I
C
B
H
E
Unit Cost
Peer Group Median


Pole Test and Treat
($CAD per Pole)
60
50
40
30
20
10
0
17
19
B
A
D
C
THESL
J
E
H
L
I
G
F
Unit Cost
Peer Group Median


Overhead Line Patrol
($CAD per Kilometer)
400
350
300
250
200
150
100
50
0
1665
938
23
26
A
D
THESL
B
H
E
I
C
J
G
K
L
Unit Cost
Peer Group Median


Substation Maintenance
($CAD per MVA)
7000
6000
5000
4000
3000
2000
1000
0
1712
1681
J
K
D
B
A
C
THESL
E
H
I
L
Unit Cost
Peer Group Median


Building Vault Inspections
($CAD per Building Vault)
1200
1000
800
600
400
200
0
258
268
J
C
D
THESL
A
B
H
E
I
K
G
Unit Cost
Peer Group Median

FACILITATING INNOVATION

Toronto Hydro's approach to innovation focuses on the deployment of new and advanced business strategies and technologies to enhance grid performance and operational processes, upskill the utility's workforce, and deliver incremental value to customers. In accordance with section 2.1.7 of the OEB's Filing Requirements, this schedule details Toronto Hydro's past achievements and future plans to advance innovation across the organization. With reference to key strategies, demonstrative examples and specific projects, this evidence describes how: (1) Toronto Hydro advanced innovation in the current 2020-2024 rate period, and (2) innovation shaped key components of the 2025-2029 investment plan and regulatory framework that underpin this application.

Toronto Hydro's innovation activities span many areas of the organization, including:

- fostering a culture of innovation and continuous improvement where employees are empowered to bring forward ideas for improvement through a Toronto Hydro-wide Innovation Sandbox;
- modernizing the grid by deploying new field technologies to enhance system observability and controllability, to enable a more modern, resilient, and efficient grid for the future;
- integrating Distributed Energy Resources ("DERs") onto the distribution system and developing capabilities to leverage new resource types such as Demand Response ("DR") and Energy Storage Systems ("ESSs") as tools to address system planning objectives;
- preparing for electrification by augmenting the capacity planning process with new scenarios-based modelling to gain a clearer view of the range of load growth trajectories;

- leveraging Information and Operational Technologies ("IT/OT") to enhance organizational systems and drive productivity through process automation;
- enhancing customer experience and service levels through digital tools that increase customer self-service capabilities and enable customers to receive more information;
- investing in workforce development and upskilling to acquire new skillsets such as digital skills and data analytics needed to run a modern utility; and,
- evolving regulatory frameworks to ensure that Toronto Hydro can deliver its investment plan while providing accountability and risk mitigation to ratepayers.

1. INNOVATION IN THE 2020-2024 RATE PERIOD

This section describes innovative strategies and initiatives undertaken by Toronto Hydro during the current 2020-2024 rate period across numerous dimensions of its business.

1.1 Innovation @ TH (Sandbox)

In 2021, Toronto Hydro launched an internal sandbox initiative referred to as "Innovation @ TH" to engage and encourage employees to bring forward ideas for proof of concept projects that are novel and provide value to customers across any area of the company's business and processes. This initiative empowers employees to embrace change and fosters a culture of innovation, meaning a solution-oriented mindset that obstacles can be overcome through creative problem-solving. Importantly, through the Innovation @ TH Sandbox, the utility has identified new strategies and technologies that can be scaled into its normal operations.

An example of an Innovation Sandbox project that is in the process of being scaled is the Virtual Reality ("VR") Training project. This project enables employees to receive an immersive field training experience in a virtual environment which enhances the quality of

training and improves safety outcomes by eliminating the physical risk of potential mistakes. In 2022, a VR module was integrated into Toronto Hydro's training program for Pad-Mounted Switchgear operations and repair.[1]

Another example of a project that is currently in progress and supported by the sandbox is the intelligent vegetation management project ("AiDash"). This proof of concept allows Toronto Hydro to leverage artificial intelligence ("AI") powered tools for analytics and asset management purposes. Specifically, the AiDash program applies system imagery technology to create a view of the overhead distribution system with an overlay of vegetation (e.g. tree branches) to conduct predictive maintenance analytics. If successful and scaled, this would allow for more efficient deployment of resources (e.g. prioritizing high-risk areas for trimming tree branches to avoid damage to overhead wires).

1.2 System Observability: Network Condition, Monitoring and Control (NCMC)

Toronto Hydro continues to implement Network Condition Monitoring and Control ("NCMC") technology to increase situational awareness of the low voltage secondary distribution network. This program includes investments in field technologies (i.e. sensors and alarms) that enable better system observability (e.g. monitoring water levels, vault and transformer operating temperature, oil level and tank pressure, and real-time loading data) and controllability (i.e. remote switching) within network vaults.[2]

Increased system observability, through vault sensors and alarms, enables Toronto Hydro to detect and intervene in fault triggers (e.g. water levels) preventing potentially catastrophic vault flooding and other failures, such as oil spills. As of June 2023, Toronto Hydro avoided over $120,000 by leveraging this technology to remotely check protectors (rather than

[1] Exhibit 4, Tab 4, Schedule 3.
[2] Exhibit 2B, Section E7.3.

dispatching trucks and crews). Furthermore, in multiple instances, Toronto Hydro's power system controllers leveraged real-time loading data during outage events to determine that the network could support multiple contingencies, allowing the failed equipment to be isolated without taking the network down.[3] The lessons learned, skills developed, and benefits realized through the NCMC program provide a robust foundation for the continued implementation of system observability technology as part of the Grid Modernization Strategy outlined in Exhibit 2B, Section D5 and summarized in section 2.1 below.

1.3 System Controllability: Reclosers Pilot

Reclosers are pole-mounted fault interrupting devices which will allow Toronto Hydro to reduce the impacts of momentary and sustained outages by preventing faults downstream of the recloser from impacting customers upstream of the recloser. For example, if a tree branch downstream of a recloser makes contact with a line, the recloser responds to the detected fault by temporarily opening the circuit to clear the fault and automatically closing to restore power, unless the fault persists. Reclosers can also serve as remotely-operated tie or sectionalizing points, helping to reduce switching (e.g. fault isolation and service restoration) times.

Toronto Hydro undertook engineering studies to assess the technical feasibility of reclosers on the distribution system, followed by pilot projects to test the correct operation of reclosers. One set of pilot projects was aimed at testing time-current coordination of reclosers with upstream protective devices (e.g. station circuit breakers). After successful results of one of the pilot projects, Toronto Hydro has started to deploy reclosers. These reclosers, once installed and operational, will not only provide immediate reliability benefits,

[3] *Ibid.*

but will also serve as building blocks for the deployment of the self-healing grid that Toronto Hydro intends to implement in the next decade per its Grid Modernization strategy.[4]

The second set of pilot projects was aimed at testing communication-based coordination of reclosers with upstream protective devices. Communication-based protective device coordination allows for more protective devices (such as reclosers) to be deployed on the distribution system, enhancing the flexibility and reliability of the system. This project was submitted and approved as part of the "Innovation @ TH" initiative described in section 1.1.The pilot is currently undergoing the iterative testing needed to set up and program the communication protocol between the reclosers and station circuit breakers. If the proof of concept is validated, it can be scaled and integrated into investment programs such as System Enhancements as a foundational technology for developing the self-healing grid.[5]

1.4 Etobicoke Demand Response Pilot

Toronto Hydro's Non-Wires Solutions ("NWS") program was established in the 2015-2019 Distribution System Plan to address capacity constraints through local demand response ("LDR").[6] For the 2020-2024 rate period, Toronto Hydro is deploying LDR to alleviate capacity constraints in the Etobicoke area at two transformer stations: Manby and Horner. As an additional layer to the program, Toronto Hydro also set out to test how demand-side resources can be dispatched to support both the local grid and the upstream bulk system (a strategy referred to as benefit stacking). To that end, in 2022, Toronto Hydro received joint approval from the OEB Innovation Sandbox and the Independent Electricity System Operator ("IESO") Grid Innovation Fund to launch a pilot project (known as the Etobicoke Demand

[4] Exhibit 2B, Section E7.1.
[5] *Ibid.*
[6] Exhibit 2B, Section E7.2.

Response pilot) in partnership with Power Advisory LLC and Toronto Metropolitan University Centre for Urban Energy.[7]

The Etobicoke Demand Response Pilot examines how Toronto Hydro can leverage local demand response capacity procured from third-party resources (including behind-the-meter customer resources) to address system peak demand, while also offering that same capacity into the IESO market (on a simulated basis for the purpose of the pilot) to test how additional revenue streams and system benefits can be unlocked for customers. This project is the first of its kind in Ontario to test how a distributor can enable IESO market participation on behalf of its customers as the Total Distribution System Operator ("DSO").

1.5 Battery Energy Storage Systems

Toronto Hydro owns and operates a grid-side 2 MW/2MWh Battery Energy Storage System ("BESS") located at the site of the former Bulwer MS.[8] Commissioned in 2020, the Bulwer BESS enables Toronto Hydro to test and explore how utility-owned energy storage systems can support the grid, and offers a hands-on opportunity to learn how to integrate energy storage technology with existing practices and procedures of managing and operating the grid. The Bulwer BESS is equipped with remote monitoring and controlling capabilities that are integrated into the Energy Centre as part of the utility's ongoing development of the DER management system ("DERMS").[9] Toronto Hydro uses the Energy Centre to remotely operate Bulwer BESS, and analyze the system impacts of different dispatch schedules. Other valuable experience gained from the Bulwer BESS project includes how to procure, design, construct and maintain grid-side BESS. These insights will be instructive as the utility

[7] *Ibid.*
[8] Exhibit 2B, Section E7.2.
[9] See Exhibit 2B, Section D5 for more information on DERMS.

continues to explore further use cases for grid-side BESS, particularly to enable the connection of renewable energy generation as outlined in Exhibit 2B, Section E7.2.[10]

1.6 Future Energy Scenarios Modelling Tool

In preparing for this application, Toronto Hydro complemented its capacity planning process with an innovative modelling tool called Future Energy Scenarios ("FES") – the first pathway study in Ontario to focus on the distribution-level impacts of the energy transition.[11] Using bottom-up consumer choice modelling (informed by data on technology cost and performance, policy, consumer attitudes, challenge factors (i.e. barriers to consumer adoption of new technologies), deployment levels, energy prices, etc.), this tool explores a range of possible changes to future peak demand based on the interplay of different policy, technology and consumer behaviour assumptions.

From this study, Toronto Hydro learned that while the nature of load changes on the distribution system varies considerably over the modelled time period, in this decade, electricity load growth is very similar across all scenario worlds. Load growth starts to diverge across the scenario worlds in the early part of the next decade (2030s), highlighting the need for early planning and capacity investments to ensure the distribution system is prepared for both near-term and long-term energy system changes.

The outputs of the Future Energy Scenario model are distinct from the System Peak Demand Forecast discussed in the capacity planning evidence in Exhibit 2B, Section D4. Rather than predict what the future holds through probabilistic methods, the Future Energy Scenarios enables the utility to explore the distribution system impacts of different plausible paths to Net Zero, and begin to quantify investments that would be required to reinforce the grid in

[10] Referred to as Renewable Enabling Battery Energy Storage System ("REBESS").
[11] Exhibit 2B, Section D4, Appendix A and Appendix B.

different scenarios. This capability supports Toronto Hydro's least regrets planning philosophy in that it allows the utility to stress test the 2025-2029 investment plan against plausible scenarios to ensure that it does not: (1) overbuild the system, or (2) become a barrier to enabling particular decarbonization pathways.

1.7 Electric Vehicles ("EV") Demand Response

To further facilitate electrification grid readiness, Toronto Hydro recently conducted an EV "smart charging" pilot with both Plug 'n' Drive and Elocity. The pilot recruited EV owners to install upgraded networked chargers (which include an internet connection for data communications) and provided them access to a mobile application which gives EV owners information about optimal charging schedules and an opportunity to participate in demand response events. The pilot also provided Toronto Hydro with a portal through which demand response events were conducted. Through this pilot, Toronto Hydro is gaining valuable insights into EV charging patterns and customer behaviour, while assisting EV owners to optimize their charging based on usage.

The next phase of the project is to understand how EVs can be leveraged to provide distribution system services. This entails reviewing technologies available for smart charging and testing them with technical control options, such as onboard vehicle telematics control systems that connect to applications from the vehicle's original equipment manufacturer's ("OEM"), in order to trigger demand response events. This phase also explores integration into Energy Centre and other metering systems to further real-time situational awareness in order to deploy EV DR assets to address specific network needs. Toronto Hydro intends to implement this next phase of the EV demand response pilot through the proposed Innovation Fund summarized in section 2.5.3 and detailed in Exhibit 1B, Tab 4, Schedule 2 and Appendix A.

1.8 Process Automation

Toronto Hydro's process automation strategy focuses on reducing the amount of manual labour required for routine tasks that do not require decision-making inputs. Over the 2020-2024 period, Toronto Hydro implemented over 80 different instances of automation using software tools such as "Wdesk" and "UiPath".

In 2022 Toronto Hydro rolled out the Wdesk – an application for automation in external reporting. This application streamlines the preparation and review of corporate financial statements, notes to the financial statements, and all relevant supporting documents by using structured templates that pull financial data directly from the appropriate sources. The application tracks and highlights changes, allowing for more efficient review of the documents by employees. Through the implementation of these automation programs Toronto Hydro's finance department has been able to save approximately 7,000 hours annually.

Toronto Hydro also implemented robotic process automation ("RPA") through an industry-leading platform known as UiPath, which is a general tool that provides a user-friendly platform for writing scripts to automate tasks across multiple applications. This tool does not require knowledge of technical programming language which allows for process automation to be implemented directly by business resources, with support from technical IT resources. Through UiPath, Toronto Hydro increased the number of process automation projects being deployed across the organization. For example, the Finance department has deployed UiPath in conjunction with another application to automate the daily preparation of project capitalization files by gathering data from multiple sources, preparing working files, and notifying responsible staff that action is required. Without this automation, each

analyst would have to run multiple, iterative queries to collect appropriate data and manually compile working papers by using large, complex spreadsheets.

1.9 Customer Experience and Service Tools

Providing customers with timely updates about power outages remains a priority for the utility. As a result, Toronto Hydro continues to build on its digital customer service offerings by improving existing tools and expanding customer channels in order to make it easier for customers to get near real-time information about power outages. Examples of recent enhancements are summarized below. Toronto Hydro notes that all of these new digital channels underwent extensive user and accessibility testing to help ensure they would serve all customers seamlessly.[12]

- The outage map now allows customers to track the progress of power outage restoration live – including informing customers when crews are on-site and providing an estimated restoration time;[13]
- Customers are able to chat online with a live agent to report outages;
- Customers are able to enroll in outage notification alerts via email and text messages.[14] These alerts notify customers when an outage occurs, provide an estimated time of restoration (when established), and notify customers when power is restored; and
- Toronto Hydro rolled out its mobile application in 2022. This application provides customers with access to outage and construction maps, online account information, and other self-service tools.

Toronto Hydro is also offering customers increased access to information and better service. For example, Toronto Hydro redesigned its Customer Self-Serve ("CSS") portal and

[12] *Ibid.*
[13] Exhibit 4, Tab 2, Schedule 14.
[14] *Ibid.*

mobile application with additional functionality that enables customers to review their consumption data and use tools to compare their bills under different pricing plans.[15] These functionalities allowed Toronto Hydro to be one of the first utilities in the province to make the new Ultra-Low Overnight rate available to customers. Going forward, Toronto Hydro plans to leverage AI-enabled tools to expand customer self-service capabilities through the use of chatbots and virtual assistants.[16]

1.10 Workforce Development and Upskilling

Toronto Hydro invests in its workforce by developing and nurturing talent, and by fostering a workplace culture that promotes change and innovation. Through advanced training programs, Toronto Hydro delivers upskilling opportunities to enhance employees' technical and professional abilities across all segments of the workforce. Between 2020-2022, Toronto Hydro delivered nearly 550 training and development programs tailored to the work requirements of different positions across the organization.[17] For example, after the implementation of the new Enterprise Resource Planning ("ERP") system, Toronto Hydro established a group of highly-trained and skilled employees, known as "enterprisers", to enable users throughout the company to unlock the full functionality of the new system.[18]

Furthermore, Toronto Hydro continually monitors trends to identify emerging skill requirements to support innovation. For example, in response to expected increases in data generated by new technologies such as the Advanced Metering Infrastructure ("AMI 2.0"), enhanced data analytics has been identified as a critical skill set for the future. Toronto Hydro is continuing to develop in-house training that focuses on building employees' future-ready skills, including fluency with data analytics programs to perform sophisticated

[15] *Ibid.*
[16] Exhibit 2B, Section D4.
[17] Exhibit 4, Tab 4, Schedule 3.
[18] *Ibid.*

research using modern software tools. These investments in upskilling the workforce are critical to developing advanced operational capabilities to intelligently manage a more complex and highly-utilized energy system.

Toronto Hydro has a long-standing history of partnerships with colleges and universities to develop new curricula and explore interdisciplinary learning opportunities that are aligned with the utility's short- and long-term workforce requirements. Collaborations with institutions such as George Brown College, Georgian College and Toronto Metropolitan University support academic programs that: (1) are aligned to entry level qualifications for key roles within the utility (i.e. Certified and Skilled Trades, and Designated and Technical professionals), and (2) advance skills sets for incoming talent. For example, in 2020, Toronto Hydro partnered with George Brown College to influence the curriculum development for a new three-year Electromechanical Engineering Technology – Power and Control Diploma Program.[19] Additionally, investments in experiential learning have resulted in 20 percent of co-op students finding employment at Toronto Hydro after graduation.

2. INNOVATION IN THE NEXT RATE PERIOD

Innovation shaped this application, and the 2025-2029 investment plan that underpins it in a number of ways, as detailed below.

2.1 Grid Modernization Strategy

The Grid Modernization strategy at Exhibit 2B, Section D5 identifies the operational and field technology investments necessary to ready the grid for decarbonization and the energy system transformation, while enhancing the value that the system provides to customers through improved reliability, resilience and efficiency outcomes.[20] Specifically, the strategy

[19] *Ibid.*
[20] Exhibit 2B, Section D5.

includes: (i) deploying field technologies onto the distribution system for better monitoring and controls; (ii) investments in resources (human capital) with enhanced skill sets to install and integrate field technology (and analyze the valuable data it provides) into day-to-day operations and system planning functions; and (iii) enabling IT/OT investments to facilitate connectivity, enable efficient data collection, improve management and analysis, and integrate multiple operating systems into centralized platforms such as the Distributed Energy Resource Management System ("DERMS").[21]

Through these investments, the Grid Modernization strategy aims to continue transforming existing infrastructure into a more technologically advanced distribution system and enable Toronto Hydro's journey towards a more integrated, intelligent, and self-healing grid that can provide: (i) greater resiliency in light of more frequent extreme weather events, (ii) enhanced grid capabilities to accommodate two-way power flows while maintaining safety and reliability, and (iii) long-term efficiency outcomes by reducing manual work efforts and improving asset analytics to enable grid optimization.

The success of the Grid Modernization Strategy hinges in part on a foundational investment in the Advanced Distribution Management System ("ADMS") – a multi-faceted software platform with various advanced capabilities and connected applications that integrate analytics, real-time data and control algorithms to optimize distribution network operations. The system provides a holistic view of the grid, and encompasses advanced applications (like Outage Management System ("OMS"), Fault Location Isolation and Service Restoration ("FLISR"), Volt/Var Optimization, etc.) which allow swift detection and response to outages and grid disturbances, and enable reliable and efficient DER management by optimizing

[21] Exhibit 4, Tab 2, Schedule 7.

voltage levels and reactive power flows throughout the distribution system. For more information on ADMS, please see the ADMS Business Case.[22]

2.2 Local Demand Response

Toronto Hydro's experience with LDR over the last two rate periods has led to a better understanding of how non-wires solutions can be used to complement traditional capacity planning functions and investments. In the optimal situation, LDR is successfully deployed to indefinitely avoid the need for a load transfer in a given area. Where this can be achieved, the capital work is no longer necessary resulting in significant long-term savings for ratepayers.[23] In other situations, where there is volatility or uncertainty with respect demand growth, LDR can be used to defer load transfers for a period of time until there is greater certainty that the load transfer will be needed. In these circumstances, although the net savings to customers may ultimately be lower, LDR provides value to the system as a flexibility tool to manage capacity. This is increasingly important since capacity is inherently complex and subject to external factors that are beyond the utility's control, and which are becoming more dynamic in the coming years as a result of changes in policy, technology and consumer preferences.

Building on its existing LDR program, Toronto Hydro identified further opportunities to use LDR in the 2025-2029 rate term to avoid and defer capital investments in load transfers, and set an ambitious goal to expand the reach of the LDR program in the next rate term.[24] Toronto Hydro intends to procure up to 30MW of flexible system capacity through the LDR program to displace and defer the need for load transfers in the Horseshoe North area

[22] Exhibit 2B, E8.4, Appendix A.
[23] Long term savings result from the avoidance of the revenue requirement related to the capital assets that would have been constructed through the load transfer project
[24] Exhibit 2B, Section E7.2.

during the 2025-2029 period.[25] Load transfers in this area are currently necessary to alleviate capacity constraints at a number of stations including Finch TS and Bathurst TS. The goal is to use LDR to defer or displace certain load transfers by procuring flexible system capacity from third-party or customer-owned DERs.

2.3 Renewable Enabling Investments

As of the end of 2022, Toronto Hydro connected 2,424 unique DER connections to its distribution grid. This represents over 304.9 MW of DER capacity across the various technology types. Renewables currently represent 116.2 MW of all DER capacity. Between 2023 and 2029, Toronto Hydro forecasts the connection of over 1700 additional renewables (totalling over 74 MW) to the distribution system, which would bring total installed capacity for renewable DERs to nearly 200 MW.[26,27]

Toronto Hydro's system capability to connect renewable DER facilities is subject to a number of constraints, including short-circuit capacity, the risk of islanding, and thermal limits. To address these constraints, Toronto Hydro continues to install real-time monitoring and control systems at every DER site that exceeds a certain size threshold.[28] This technology provides system planners and operators real-time visibility to ensure that the anti-islanding features of DER facilities operate in the event of a distribution system fault, and to inform system planning analyses. These field technologies are being integrated into Toronto Hydro's DERMS and SCADA-connected communication networks to enable the safe and reliable operation of the grid with bi-directional distribution grid flows.

[25] Exhibit 2B, Section E7.2.
[26] Exhibit 2B, Section E3.
[27] Exhibit 2B, Section E5.1
[28] Exhibit 2B, Section E5.5.

Additionally, Toronto Hydro plans to deploy nine energy storage systems, with an aggregate capacity of 10.2 MW, to enable the connection of forecasted renewable growth on nine high-priority feeders. The utility selected these feeders based on their existing high renewable DER penetration, low minimum load to generation ratios, and high forecasted renewable DER growth. Rather than restricting the connection of renewable DER facilities to feeders where minimum load is low, renewable enabling ESS can be deployed to increase the load to generation ratio to the recommended threshold and thereby enable the connection of renewable DER facilities.[29]

2.4 Enterprise Technology Portfolio

As noted throughout this schedule, Toronto Hydro relies on information technology ("IT") assets and systems to enable innovation across all areas of its business and operations. Robust planning and prioritization of IT projects is essential for the utility to advance innovation through technology. To that end, Toronto Hydro developed Enterprise Technology Portfolio ("ETP") roadmaps that identify and prioritize a number of enabling technology investments to advance innovation and efficiency outcomes while also ensuring optimal levels of IT system reliability and availability, and compliance with IT standards. The ETP roadmaps provide the utility with the necessary balance of certainty and precision for the implementation of near-term initiatives, and longer-term flexibility and agility to effectively respond to changes in requirements and availability of technological solutions.

For the 2025-2029 rate period, the ETP roadmaps include 55 software enhancement projects to implement the utility's modernization vision.[30] Specifically, to support grid modernization, Toronto Hydro intends to prioritize projects that enable monitoring and operational capabilities of its distribution system, including: (i) enhancing device communication and data acquisition capabilities (ii) introducing advanced grid configurations such as distribution

[29] Exhibit 2B, Section E7.2.
[30] See Exhibit 2B, Section E8.4 and the appendices thereto.

automation through manual FLISR, and (iii) enabling system monitoring and control capabilities, and asset analytics to optimize grid performance, and enhance day-to-day operational decisions and long-term system planning functions.

2.5 Regulatory Innovation

Innovation shaped both the investment plan and regulatory framework for this application. As noted in Exhibit 1B, Tab 2, Schedule 1, in developing the custom rate framework for this application, Toronto Hydro built upon the foundation of performance-based regulation in Ontario, rooted in the principles of the 2012 Renewed Regulatory Framework and OEB Handbook. The proposed 2025-2029 custom rate framework is comprised of several innovative elements that work together to create a balanced framework to enable the utility to deliver on outcomes that its customers need and value in the context of a changing energy landscape. These elements of regulatory innovation are summarized below.[31]

2.5.1 Performance Incentive Mechanism

A key enhancement and innovation within Toronto Hydro's 2025-2029 custom rate framework is the proposed Performance Incentives Mechanism ("PIM"). The PIM shifts cost and performance risk to the utility, ensuring greater accountability to customers for key outcomes in the areas of: (i) reliability and resilience, (ii) customer service and experience, (iii) environment, safety and governance, and importantly (iv) efficiency and financial performance. These performance outcomes are measured through twelve custom metrics with set targets on the utility's 2025-2029 Custom Scorecard. [32] Toronto Hydro carries the risk of achieving the performance outcomes since, if the targets are not achieved, Toronto Hydro cannot earn its approved return on equity ("ROE"). As such, the PIM is an

[31] See Exhibit 1B, Tab 2, Schedule 1 for Rate Framework; and Exhibit 1B, Tab 5 for Customer Engagement.
[32] See the Performance Outcomes Framework evidence at Exhibit 1B, Tab 3, Schedule 1 for more information on the performance targets and weighted metrics set out in the Custom Scorecard.

asymmetrical incentive to the benefit of customers that also safeguards the utility's financial integrity by providing it with the opportunity (not the guarantee) to earn its full ROE.[33]

The PIM is enabled by an evolution to the existing incentives within the rate framework. More specifically, the PIM complements the efficiency incentive within the X-factor (i.e. the stretch-factor that is based on empirical total cost benchmarking), with a proactive performance incentive factor of 0.6 percent that provides customers a significant upfront rate reduction benefit of approximately $65 million, which the utility can earn back if it meets the performance targets on its 2025-2029 custom scorecard. This innovation to the rate framework balances efficiency and other important performance outcomes, within a comprehensive incentive mechanism that places greater accountability risk on the utility and delivers financial benefits and service quality outcomes to customers.

2.5.2 Flexibility Mechanism

A flexibility mechanism, known as the Demand-Related Variance Account (the "DRVA") is another innovative element of Toronto Hydro's 2025-2029 custom rate framework. The DRVA is responsive to the practical reality that this five-year application is being filed during a time of change, as customers, communities and governments at all levels are actively embarking on an energy transition to mitigate the existential and economic impacts of climate change. This transition is creating new roles for electricity as an energy source, and while there is certainty that fundamental change is ahead, there are degrees of uncertainty about how that change will unfold in this decade. To address this uncertainty in the 2025-2029 rate period, Toronto Hydro proposes a symmetrical variance account that protects both ratepayers and the utility from structural unknowns in forecasted costs and revenues.[34]

[33] Toronto Hydro is proposing to finalize the targets once the rate proceeding commences. See Exhibit 1B, Tab 3, Schedule 1 for more information.
[34] Exhibit 1B, Tab 2, Schedule 1.

Utilizing existing regulatory tools (variance accounts) as purposeful flexibility mechanisms recognizes that in times of greater uncertainty, risk is best placed on performance outcomes that provide value to customers regardless of what happens, rather than on the accuracy of predictions models of what could happen. The DRVA empowers the utility to be more agile, and remain responsive to serving its customers even in the face of unforeseen changes or challenges to how customer demand manifests in this first chapter of the energy transition.

2.5.3 Innovation Fund

The last element of regulatory innovation in Toronto Hydro's framework is a proposal to establish an Innovation Fund to support the design and execution of pilot projects over the 2025-2029 rate period.[35] The pilot projects undertaken through the Innovation Fund would be focused on testing new technologies, advanced capabilities and alternative strategies that enable electrification grid readiness and are responsive to the OEB's expectations with respect to distributors facilitating DER integration, as expressed in the Framework for Energy Innovation ("FEI") report.[36] Toronto Hydro proposes to collect the amounts allocated to the Innovation Fund through a rate rider, rather than through base rates, in order to provide transparency to ratepayers on their bill and flexibility to the utility to determine how the funds should be allocated across capital and operational expenditures on the basis of the selected pilot projects.

The proposed fund is an innovative element of the 2025-2029 custom rate framework because it supports utility investment in innovation work that is more early stage, exploratory and developmental in nature, and therefore where the outcomes are less certain, but the potential benefits for the system and customers could be significant. While the benefits of individual projects may not be immediate or certain, and some initiatives

[35] Please refer to Exhibit 1B, Tab 4, Schedule 2 for more information about the Innovation Fund proposal.
[36] Ontario Energy Board, Framework for Energy Innovation: Setting a Path Forward for DER Integration (January 2023)

may prove to be more or less fruitful than others, this type of work is nevertheless critical to achieving real innovation during a time of change and transformation of the energy sector.

Furthermore, the Innovation Fund assists Toronto Hydro in overcoming the challenges of pursuing innovation in the context of a rate cycle that generally requires investment planning to be carried out far in advance and that requires spending to be classified either as a capital or operating expense. By providing Toronto Hydro with operational flexibility to identify and pursue the research, development and piloting of new technologies, capabilities and strategies throughout the rate period, and to determine the necessary types of expenditures in real time based on the specifics of each project or initiative, the Innovation Fund would enable the utility to be more responsive to emerging needs and technologies as they arise during the rate period, and to scope, design and implement pilot projects and other exploratory initiatives more effectively.

INNOVATION FUND PROPOSAL

1. OVERVIEW

In alignment with the Ontario Energy Board's ("OEB") statutory objective to facilitate innovation in the electricity sector, Toronto Hydro proposes to establish an Innovation Fund to support the design and execution of innovative pilot projects over the 2025-2029 rate period. The pilot projects to be deployed through the Innovation Fund would focus on testing new technologies, advanced capabilities, and alternative strategies that are responsive to the OEB's expectations expressed in the *Framework for Energy Innovation* ("FEI") report:[1]

> *The OEB expects distributors to modify their planning and operations to prepare for DER impacts on their systems, including integrating these resources cost-effectively, while maintaining reliable service for their customers. Distributors are also expected to consider DER solutions as NWAs when assessing options for meeting system needs.*

Toronto Hydro proposes to allocate approximately $16 million to the Innovation Fund to be collected through a rate rider, rather than through base rates, in order to provide greater transparency to ratepayers on the bill and flexibility to the utility to determine how the funds should be allocated across capital and operational expenditures on the basis of the selected projects. In addition, Toronto Hydro proposes to establish a new variance account to record variances between the amounts collected by the rate rider and the actual costs incurred to execute projects as part of the Innovation Fund.

[1] Ontario Energy Board, Framework for Energy Innovation: Setting a Path Forward for DER Integration (January 30, 2023).

Deployment of the Innovation Fund would target specific areas of innovation and be subject to the governance framework described herein.

a. **Section 2** describes the rationale for establishing the proposed Innovation Fund;
b. **Section 3** describes the areas of innovation that will be the focus of Toronto Hydro's pilot projects, including the rationale for their selection;
c. **Section 4** describes the governance framework Toronto Hydro will follow for deploying the Innovation Fund, including the processes for designing, implementing, and evaluating pilot projects relating to each of the areas of innovation; and
d. **Section 5** describes the proposed rate treatment, including the rationale for using a rate rider and the proposed variance account.

2. RATIONALE FOR THE PROPOSED INNOVATION FUND

The need for innovation in the electricity sector is well documented and has taken on increasing prominence within the regulatory framework applicable to Ontario's electricity distributors. For example, the OEB's electricity-related objectives under section 1 of the *Ontario Energy Board Act, 1998* now include a responsibility to facilitate innovation in the sector and the Letters of Direction that the OEB has received from the Minister of Energy in recent years have demonstrated a growing recognition of the importance of innovation to support rapid and transformative change in the sector, to enable the government's *"vision for the energy system in which Ontario leverages its clean energy grid to promote electrification and job creation while continually enhancing reliability, resiliency and customer choice."*[2]

[2] Ministry of Energy, Letter of Direction from the Minister of Energy to the Chair of the OEB Board of Directors (October 21, 2022), online: <https://www.oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20221021.pdf>

Consistent with the themes identified in the Minister's Letters of Direction,[3] and in other prominent expressions of federal, provincial, and municipal policy,[4] Toronto Hydro recognizes that the energy sector is on the cusp of transformation, driven by the imperatives of decarbonizing key sectors of the economy through electrification. This shift is expected to expand the role of clean electricity as a source of energy for transportation and heating. Toronto Hydro also recognizes that the pace and timing of these changes is driven by a complex interplay of policy, technological developments, and consumer choice. While there is certainty that fundamental change is ahead, there are degrees of uncertainty about how that change will unfold.[5] Innovation is key tool for managing within this uncertainty by building new capabilities to adapt to change and by leveraging technology to achieve expanded benefits for customers.

These trends and the need for innovation are not unique to Ontario, but the solutions will need to be designed to work in Ontario and, for Toronto Hydro, to meet the specific needs and challenges of a dense urban city with a diverse customer base. As customers increasingly adopt DERs, electrified transport, and heating at scale, Toronto Hydro will have to ensure sufficient distribution system capacity, often in densely populated and congested parts of the system, so that it can continue to fulfill its service obligations of connecting customers in a timely manner and providing electricity reliably. One of the proposed pilot project concepts – Flexible Connections,[6] would seek to explore new operational capabilities that

[3] *Supra* note 2.
[4] For examples of federal plans see Net-Zero by 2050, Emissions Reduction Plan 2030 (including Canadian Net-Zero Emissions Accountability Act, 2021), and Canada's Climate Actions for a Healthy Environment and a Healthy Economy, online: <https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview.html>. For an example of provincial plans see Minister's Letter referenced above in Footnote 2. For an example of municipal plans see TransformTO Net Zero Strategy, online:<https://www.toronto.ca/services-payments/water-environment/environmentally-friendly-city-initiatives/transformto/.>
[5] Exhibit 2B, Section D4.
[6] Exhibit 1B, Tab 4, Schedule 2, Appendix A.

could enable new DER customers to be connected to otherwise constrained parts of the grid without having to build costly infrastructure. If this pilot is successful, it could improve Toronto Hydro's DER hosting capabilities and avoid the need for more capital-intensive upgrades.

The proposed Innovation Fund is an important part of Toronto Hydro's approach to innovation because it addresses needs that are not adequately met by existing funding mechanisms. In this way, the Innovation Fund would be complementary to existing funding mechanisms insofar as they relate to innovation. For instance, whereas existing mechanisms tend to support spending where the beneficial outcomes are more proven or certain, the proposed Innovation Fund would be able to support work that is more early stage, exploratory and developmental in nature. While the benefits of individual projects may not be immediate or certain, and some initiatives may prove to be more or less fruitful than others, this type of work is nevertheless critical to achieving real innovation and unlocking new benefit streams for the system and its customers.

The proposed Innovation Fund would also assist Toronto Hydro in overcoming the challenges of pursuing innovation in the context of a rate cycle that generally requires investment planning to be carried out far in advance and that requires spending to be classified either as a capital or operating expense, with little flexibility to trade-off between these types of investment during the rate period. By providing Toronto Hydro with operational flexibility to identify and pursue the research, development, and piloting of new technologies, capabilities, and strategies throughout the rate period, and to determine the funding implications in real time based on the facts of each project or initiative, Toronto Hydro would be able to design and implement pilot projects and other exploratory initiatives more effectively.

Toronto Hydro's attention to the specific areas of innovation and application of the governance framework, each of which is discussed below, would help bring rigour, discipline, and focus in deploying the funding associated with the Innovation Fund. Given that the pilot projects and other initiative have yet to be designed or undertaken, it is on the basis of the framework for implementation and deployment of the Innovation Fund, as a component of its overall approach to innovation, that Toronto Hydro seeks approval for this proposal.

Toronto Hydro conducted research to inform the level of funding requested for this proposal. Toronto Hydro's research revealed that utility investments across comparable innovation initiatives and research and development activities range from 0.3 to 1 percent of revenues. Accordingly, the utility proposes to allocate 0.3 percent of its revenue requirement, or approximately $16 million, to the 2025-2029 Innovation Fund.[7] For example, in the United Kingdom, under Ofgem's performance-based regulatory framework known as RIIO 2 (Revenues = Incentives plus Innovation Opportunities), networks may recover 0.5 to 1 percent of base revenues for innovation that facilitates decarbonization while driving down costs for network customers and for projects with the potential to address consumer vulnerability or deliver longer-term financial or environmental benefits.[8][9] Similarly, pursuant to the Reforming Energy Visions ("REV") framework in New York, utilities can recover 0.5 percent of their total revenue requirement up to a maximum of $10 million per year for REV demonstration projects that advance the development of new utility and third-party service or business models or enable the integration of DERs without having an

[7] Exhibit 6, Tab 1, Schedule 1.
[8] Ofgem, RIIO-2 Network Innovation Allowance program: Governance Documents, online: <https://www.ofgem.gov.uk/publications/riio-2-nia-governance-document-update>;
[9] Ofgem, Electricity Network Innovation Competition, online: <https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/network-price-controls-2013-2023-riio-1/network-price-controls-2013-2023-riio-1-riio-1-network-innovation-funding/electricity-network-innovation-competition-riio-1>..

adverse impact on reliability.[10] Toronto Hydro also notes that most recently in Ontario, Enbridge Gas Inc. proposed an Energy Transition Technology Fund ("ETTF") to advance research, development, and commercialization of low-carbon technologies. The ETTF allocates $25 million, or approximately 0.4% of the test year revenue requirement, to the advancement of low-carbon technology innovation.[11]

3. AREAS OF INNOVATION

Toronto Hydro plans to test specific new distribution capabilities by deploying pilot projects that have the potential to be scaled into standard capital or operational work programs. Pilot projects are the most effective method for testing new distribution capabilities because they allow testing and evaluation to happen quickly and at a small enough scale to reduce technical, operational, and financial risk. This approach is further supported by the recognition that new distribution capabilities cannot be readily integrated with Toronto Hydro's unique distribution system characteristics without a thorough analysis and testing of impacts. This analysis must typically be undertaken as part of a pilot project to assess the following types of parameters: functional compatibility with existing core technology, feasibility of integration with existing control systems; compliance with minimum safety, operating, and cyber security standards; and financial viability and sustainability.

As Toronto Hydro develops pilot projects under the Innovation Fund, the utility intends to focus on areas of innovation that have the following characteristics:

[10] New York City State, *Reforming the Energy Vision* (March 2016) online: <https://www3.dps.ny.gov/W/PSCWeb.nsf/All/B2D9D834B0D307C685257F3F006FF1D9>.
[11] EB-2022-0200, Enbridge Gas Inc. Application, Exhibit 1, Tab 10, Schedule 7 (October 31, 2022).

1. The innovation project explores a distribution capability that is connected to adapting to fundamental change in the energy landscape as identified in or related to expectations set out by the OEB for DER integration in the FEI report,[12] mainly:
    - Evolving and enhancing load forecasting, considering DER adoption;
    - Making enabling investments such as system monitoring and data analytics;
    - Adjusting operational practices to incorporate and manage DERs on the system, including dispatching and use as non-wires-alternatives;
    - Modifying planning processes to identify, assess, and implement non-utility-owned DER solutions; and
    - Developing skills and knowledge, and acquiring talent.
2. The innovation project has potential to deploy an inventive solution, where the definition of innovation is aligned with section 2.1.7 ("Facilitating Innovation") of Chapter 2 of the OEB's Filing Requirements for Distribution Rate Applications:[13]
    - the use of new technology or new ways of using existing technology;
    - innovative business practices, including relationships with others to enhance services to customers and share costs; or
    - enhancing distribution services in a way that benefits customers, including facilitating customers' ability to innovate in how they receive distribution services.

Toronto Hydro undertakes a continuous process of developing pilot project candidates as part of its annual planning activities and regular engagements with customers, stakeholders, experts, and utility peers. The 2025-2029 Grid Modernization Strategy (Section D5),

[12] Ontario Energy Board, Framework for Energy Innovation: Setting a Path Forward for DER Integration (January 30, 2023) at page 3.
[13] Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications - Chapter 2 (December 15, 2022)

highlights four pilot project concepts that could be supported by the proposed Innovation Fund: Flexible Connections, Electric Vehicle ("EV") Commercial Fleet Charging, EV Demand Response, and Advanced Microgrids.[14] Toronto Hydro identified these project concepts through its distribution system and modernization planning processes.[15] In evaluating system needs, Toronto Hydro considered new solutions, including new technologies, business practices, and strategies being utilized by other organizations. However, adopting the innovative solutions implemented by utilities in other jurisdictions is not a "cut-and-paste" exercise; it requires further in-depth exploration and testing or piloting to assess the parameters identified above. As a result, upon closer consideration of potential innovative solutions as part of the planning and modernization processes, the four areas identified as pilot project concepts were considered to be too nascent to deploy as standard distribution system solutions. They were also identified as posing a funding risk because more developmental work is needed to test the technologies and prove related beneficial outcomes for Toronto Hydro's system.

4. GOVERNANCE FRAMEWORK

The governance framework outlined in this section guides the deployment of the proposed Innovation Fund with a view to providing transparency and accountability to ratepayers as to how the funds collected through rates would be allocated and used to facilitate innovation at Toronto Hydro. The framework outlines the activities that would be taken to design, execute, evaluate, and account for pilot projects to ensure that deployment of the Innovation Fund delivers on its principal aim of enabling Toronto Hydro to develop new distribution capabilities needed to adapt to transformative changes in the energy system related to the use of DERs and to enable decarbonization through electrification.

[14] *Supra* note 6.
[15] Exhibit 2B, Section A3.

A steering committee of senior utility leaders oversees the four-phase governance framework depicted in Figure 1 below. The committee is responsible for approving key decisions with respect to the project such as scope, budget, and timelines. To advance a particular project throughout the four phases of the framework, the steering committee designates a pilot project owner based on key business functions that correspond to the area of innovation.

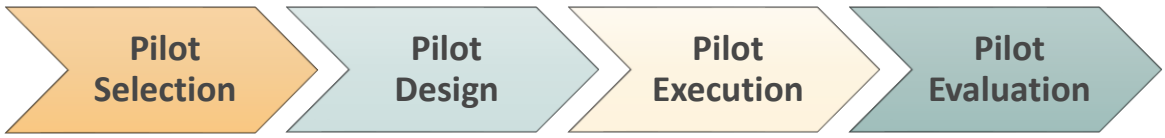


Figure 1: Innovation Fund Governance Framework

4.1 Pilot Selection and Design Phases

The initial phase of the governance framework involves engaging the internal leaders and pilot project owners who are responsible for the business functions that correspond to the areas of innovation. These individuals would collectively assess and select one or more of the areas of innovation to pursue through the implementation of one or more pilot projects. While the pilot projects have been flagged for interest due to their potential to develop into new distribution capabilities, further research and screening would be required to progress the projects from concepts into scoped-out proposals that fit within the timelines and budget available through the Innovation Fund. Toronto Hydro would select the pilot projects that would proceed to the next phase on the basis of the following key considerations:

a. **Potential Business Value** – informed by market readiness based on industry trends and technological advancements, as well as lessons learned from the implementation of similar projects and initiatives by Toronto Hydro or other entities.

b. **Feasibility** – selected pilot project(s) can be designed, executed, and completed by the end of the 2025-2029 rate period, as informed by primary research or reference to similar projects undertaken by other utilities.

c. **Opportunity for scalability** based on parameters such as functional compatibility with existing core technology; feasibility of integration with existing control systems; compliance with minimum safety, operating, and cyber security standards; and financial viability and sustainability.

d. **Opportunity to leverage external funding –** where possible Toronto Hydro would seek alignment with areas of research and development being funded by organizations such as Natural Resources Canada or other government agencies, including programs that are aimed at supporting the energy transition and climate policies.[16] For example, under the Investing in Canada: Green Infrastructure program, NRCan offered opportunities for demonstration projects in the areas of zero emissions vehicles, smart grids, building energy efficiency, and renewable power generation.[17] Any such external funding that Toronto Hydro is able to obtain would be tracked in the proposed variance account as an offset.

To inform the pilot project selection process, Toronto Hydro would engage with external stakeholders to present ideas and solutions that are being considered for the deployment of the Innovation Fund. These stakeholder engagements would help Toronto Hydro gain a better understanding of what is technically and financially feasible, and provide additional perspective with respect to the range of potential innovation needs and opportunities. External engagements would include industry stakeholders such as:

[16] Exhibit 1B, Tab 4, Schedule 2, Appendix B.
[17] Government of Canada, Green infrastructure programs (October 12, 2022) online: <https://natural-resources.canada.ca/climate-change/green-infrastructure-programs/19780>..

- provincial bodies such as the OEB and IESO, in particular their innovation teams;
- energy services companies and clean technology vendors and suppliers;
- government agencies such as Natural Resources Canada; and
- other regulated entities such as Ontario distributors and energy companies in other jurisdictions that have relevant experience with innovation projects.

After considering the feedback and information received at the stakeholder engagements, Toronto Hydro would prepare the pilot selection report identifying the selected projects and key details about the projects, including the rationale for selecting them. The team would then scope out a work plan for designing and implementing the selected pilot project(s) during the 2025-2029 rate period.

The next paragraphs describe the general objectives and activities of the design phase that would be undertaken for each pilot project independently, according to the work plan. The pilot project owners would be responsible for compiling and proposing pilot project scopes and a work plan to the steering committee. In turn, the steering committee would be responsible for approving the work plan, including pilot project scopes and budgets, and for providing strategic direction and guidance to the project owners. A key component of the design phase would be to maximize Toronto Hydro's ability to learn and develop new distribution capabilities from its pilot projects, which would be achieved as follows:

1. Designated responsible persons ("DRPs") for the pilot project set outcomes for each selected pilot project in the design phase, which are aimed at learning about how the selected pilot project's innovation can be developed into new distribution capabilities and integrated into business operations. Learning objectives may include:

a. **Developing an understanding of the business case:** The Pilot Selection process guides the selection of pilot projects that are rationally connected to and required for adaptation to fundamental change in the energy landscape. However, in order for new distribution capabilities to be developed and integrated in Toronto Hydro's planning and operational process, the utility may need to develop a more detailed understanding of the business case for investing in a particular technology, in order to test the financial sustainability of the proposed solution.

b. **Defining and testing a "theory of operation"**[18] for a new technological or operational solution to address, for example, a technical system need (e.g., peak loading or power quality issues on transformers, feeders, etc.) arising from changing network conditions driven by new behaviour, such as customers charging EVs and installing heat pumps, as well as new resources such as distributed generation.

c. **Further exploring use cases with a focus on ratepayer benefit**. This objective would effectively involve setting a hypothesis as to the benefits and impacts of technological or operational capabilities that are enabled by advances in underlying technology or business practices and further exploring the application of the underlying capability and its potential benefits.

2. Once the pilot outcomes and learning objectives have been set, project owners scope the pilot project(s) by identifying what activities and expenditures need to be undertaken to execute the pilot project in a manner that delivers the planned outcomes. This may include:

[18] CIGRE Canada, Integrating Distributed Resources into ENMAX's Secondary Network System, 2022 CIGRE Canada Conference & Expo (October 31 – November 3, 2022) online: <https://cigreconference.ca/papers/2022/paper_522.pdf>.

a. **Preparing materials** such as program rules, contracts, terms of reference, application forms, and technical designs and schematics;
b. **Procuring products and/or services** from vendors, energy services companies, or customers;
c. **Deploying or developing technology or equipment** on the system or into operational processes such as system communication;
d. **Modifying business practices** such as separate accounting of activities, installing protective equipment or taking protective measures to isolate testing from affecting system and customer reliability, or other technical and financial risk mitigation measures that may be appropriate;
e. **Gathering and analyzing internal data** such as metered generation and load data, forecasts of system loading or resource adoption (e.g., EVs, heat pumps, storage systems), financial information, and performance, etc.; and
f. **Identifying whether there are any regulatory obstacles** that may require Toronto Hydro to consult with or make an application to the OEB Innovation Sandbox for regulatory relief.

3. Pilot project owners set milestones for each pilot project to be monitored and tracked throughout the lifecycle of the pilot project. The milestones primarily set out the start and end dates for each pilot project and intermediate milestones may consist of monitoring identified indicators or required analysis and decisions to support meeting the learning outcomes initially set for each pilot project.
4. Pilot project owners document the work plan, final pilot project designs, and supporting materials.

4.2 Pilot Execution & Evaluation Phases

During the pilot execution phase, the pilot project owners would be responsible for executing the work plan and implementing each of the pilot projects in accordance with the activities, expenditures, and milestones contained in the project scopes. The milestones set out for each pilot project would play a vital role as they would provide a "gated" approach to controlling funding and expenditures. Mainly, the steering committee would be responsible for reviewing milestone reports created by the project owners, including the funding of activities that were completed in order to achieve the milestone.

This final phase of the governance framework would evaluate each executed pilot project on the basis of the outcomes, learning objectives, and milestones identified separately for each pilot project. The pilot project owners would document their evaluations and learnings to be presented to the steering committee for the committee's decisions on next steps.

Pilot evaluation would focus on whether the set outcomes (i.e. learning objectives) of the project have been achieved. This would be an open-ended evaluation where the pilot project DRPs would reflect on what happened during the implementation of a pilot project and comment on whether the outcomes have been achieved as set out in the project scope during the design phase. In commenting on the achievement of outcomes, the pilot project owner would elaborate on lessons learned and how the results of the pilot project contributed to the learning objectives. Additionally, the pilot project owners would assess the execution of the project, including whether there were material deviations in pilot execution from the approved project scopes, budgets, and timelines.

Finally, since pilot projects by nature are exploratory, it is conceivable that a pilot project may not meet the outcomes initially set out for it. This result may be attributed to external

factors that cause material deviations from the timeline and budget contained in the workplan. It would be incumbent on the Innovation Fund team to identify and comment on what learnings may have been gained even if the initial outcomes were not achieved as expected.

Pilot evaluation would also consider whether the pilot project should be continued, discontinued, repeated with modifications, or scaled into a new distribution capability fitting into an existing investment program. This is the key conclusion for a pilot project, where Toronto Hydro determines the future of the piloted technology, capability, or strategy-based on the outcomes achieved and learnings gained from implementing the pilot project. Depending on what the original outcomes were set for a given pilot project, an appropriate set of next steps would be determined. For illustrative purposes only, next steps could include the following, non-exhaustive possibilities:

- outcomes were achieved and sufficient information and data were gathered throughout the pilot to warrant scaling a pilot project into a new distribution capability in either an existing or new program;
- outcomes were achieved but further information or data is needed (perhaps use case was understood but a stronger business case needs to be created) to warrant continuation or repeating the pilot project with modifications as a next phase of the project;
- outcomes were achieved but learnings indicate that there it is no value in pursuing the pilot project further, warranting the pilot project to be discontinued; or
- outcomes were not achieved but learnings helped identify gaps and value in pursuing the pilot project further, warranting to repeat the pilot project with modifications.

In the pilot evaluation and learnings report, the steering committee, based on the evaluation provided by the pilot project owners, would document the next steps for the pilot. To maximize learnings gathered from implementing the selected pilot projects and contribute to broader knowledge sharing with the electricity sector, Toronto Hydro would share the report with the OEB Innovation Sandbox team, and through the Sandbox the learnings could be further shared with industry stakeholders as the OEB deems suitable.

5. PROPOSED RATE TREATMENT

Toronto Hydro proposes that the Innovation Fund receive total rate funding of approximately $16 million to execute innovative pilot projects over the 2025-2029 rate period in the manner described in this Schedule. Toronto Hydro proposes to recover this amount through an Innovation Fund rate rider.[19] The use of a rate rider gives Toronto Hydro funding certainty for prioritizing innovation investments and provides ratepayers with transparency by appearing as a separate and distinct line item. Furthermore, it enables the Innovation Fund to be created independently of Toronto Hydro's base revenue requirement, thereby providing the utility the necessary flexibility to determine whether the expenditures would be capital or operational in nature on the basis of the selected project(s).

Toronto Hydro proposes to establish a new variance account—the Innovation Fund Variance Account ("IFVA")—to record variances between the amounts collected by the rate rider and the actual costs incurred to deploy the selected pilot projects. The proposed variance account meets the OEB's three-part test for establishing a new account:[20]

a. **Causation:** As described above, the forecast amount to be recorded in the proposed variance account is clearly outside of base upon which rates are derived, as the

[19] Exhibit 9, Tab 1, Schedule 1.
[20] *Supra* note 13.

innovation pilot projects that Toronto Hydro would track in this account would not form part of the utility's base revenue requirement.

b. **Materiality:** The amounts to be recorded in the proposed variance account would depend on the actual expenditures incurred to execute the select pilot projects, which will be determined in accordance with the governance framework.

c. **Prudence:** Prudence is supported by the fact the forecast amount is based on reasonable spending comparable with utilities and regulators in other jurisdictions and by the governance framework described above which will provide rigour and focus in how the funds are used for driving innovation.

APPENDIX A TO INNOVATION FUND PROPOSAL: PILOT PROJECT CONCEPTS

The 2025-2029 Grid Modernization Strategy outlined in Exhibit 2B, Section D5 highlights four pilot project concepts that could be supported by the proposed Innovation Fund:

- Flexible Connections,
- Electric Vehicle ("EV") Commercial Fleet Charging,
- EV Demand Response, and
- Advanced Microgrids.

In sections that follow Toronto Hydro provides a brief description of each of these pilot project concepts and explains how they align with the following key considerations:

- Exploring a **distribution capability** that is connected to adapting to fundamental change in the energy landscape, or as identified in the OEB's expectations for DER integration in the FEI report;
- Having the **potential to deploy an innovative solution** meaning: a) the use of new technology or new ways of using existing technology; b) innovative business practices, including relationships with others to enhance services to customers and share costs; or c) enhancing distribution services in a way that benefits customers, including facilitating customers' ability to innovate in how they receive grid services.

Flexible Connections Pilot Project Concept

The rapid integration of Distributed Generation (DG) assets into the distribution network poses several technical constraints if not proactively managed and coordinated. These include reverse power flow (particularly in low load scenarios), compromised power quality, voltage violations, and elevated fault levels. Consequently, DG customers looking to connect to the network can be faced with financial and time-related burdens associated with network upgrades. It may also be the case that Toronto Hydro cannot reasonably accommodate additional DG on a feeder under the certain circumstances and must reject the application entirely.

In order to improve customers' ability to develop and connect their desired DG project at an affordable connection cost, Toronto Hydro is planning to explore and develop alternative solutions, capitalizing on innovative technological and commercial offerings. The Flexible Connections pilot project concept can accelerate the effort of developing and implementing a comprehensive framework to facilitate efficient and cost-effective integration of DG into constrained areas of the distribution network. This could be achieved through continued development of an advanced DERMS system, coupled with intelligent device installation utilized through a communications platform.

"Flexible" refers to real-time adaptability in managing constraints and DG access to network capacity without the need for expensive distribution system upgrades. DG customers would be offered an alternative to the standard fixed connection, where Toronto Hydro would have greater control of the output of the DG asset, with the goal of curtailing production in real- or near-real time (potentially in a fully automated manner), in coordination with real- or near-real-time conditions on the distribution grid. Such a solution would ultimately result in a faster and more cost-effective connection process for the DG customer. To enable this offering, Toronto Hydro would need to develop technical and operational protocol systems in a holistic manner.

Flexible Connections Pilot Project Concept
Distribution Capability
• **Making enabling investments such as system monitoring and data analytics:** Real-time awareness of system characteristics require sensors and smart devices installed on the network to monitor, as well as to control DERs. These investments are foundational to enabling faster, cheaper DG connections by avoiding the need for infrastructure upgrades. • **Adjusting operational practices to incorporate and manage DER on the system, including dispatching and using as NWA:** To undertake the modification of this business practice, a comprehensive framework that facilitates the efficient and cost-effective integration of DG assets as controllable, flexible resources into constrained areas of the distribution network needs to be developed, including modified connection agreements.
Potential to Deploy an Innovative Solution
• **The use of new technology or new ways of using existing technology:** The solution leverages some combination of existing technology (e.g. telecommunication system, digital relays, etc.), new DERMS capabilities, and new field technologies (e.g. smart inverters) to create an innovative monitoring and control solution that is tailored to Toronto Hydro's operational reality. • **Enhancing distribution services in a way that benefits customers, including facilitating customers' ability to innovate in how they receive distribution services:** A flexible connections process would support customer abilities to adopt DER technologies such as generation and energy storage more quickly and at a potentially cheaper cost compared to traditional approaches.

Electric Vehicle (EV) Commercial Fleets Pilot Project Concept
The Commercial EV Pilot would examine the impact of commercial EV fleet charging at commercial facilities and charging depots, and optimize charging schemes based on the flexibility requirements and preferences of Toronto Hydro and agreed upon by project partners. These tasks could offer insights into managing charging schemes for the most common charging locations, identifying methods for easy and cost-effective fleet electrification, and optimizing commercial fleet charging while considering flexibility services. Moreover, the project could assess the usefulness and benefits of flexibility services to Toronto Hydro. Additionally, demand forecasting and mitigation planning can be achieved once data is aggregated from the above studies.
Distribution Capability
Adjusting operational practices to incorporate and manage DER on the system, including dispatching and using as NWA: The project concept entails collaboration with major commercial fleet operators to assess the impact of their fleet's electrification on the distribution system. Various testing methods would be employed to gain insight into diverse charging options and develop an effective implementation strategy for fleet operators. The project encompasses quantifying and minimizing the network impact of commercial EVs through trialing different methods, exploring the total cost of ownership of smart solutions for EV fleets operators, and determining the necessary infrastructure to facilitate the EV transition. Technical solutions would be tested and implemented by fleet operators and Toronto Hydro, including flexibility services to grid (e.g. Vehicle-to-Grid, Demand Response, managed charging, etc.) from commercial EV fleets and planning tools for depot energy modeling and optimization.
Potential to Deploy an Innovative Solution
Business practices including relationships with others to enhance services to customers and share costs: The project would develop the ability to quantify and minimize the impact of commercial fleet electrification on the distribution network, investigate and quantify the total cost of ownership for intelligent scheduling and charging solutions for EV fleets, and identify the necessary infrastructure, including network, charging, and IT components, to facilitate the transition to EV fleets and enable effective load management and capacity optimization.

Electric Vehicle Demand Response (EVDR) Pilot Project Concept
EVDR would allow Toronto Hydro to manage EV charging in real-time based on the type of conditions occurring on the network. Currently, Phase 1 of an EV Smart Charing pilot is being trialed with Elocity which explores new hardware to convert simple chargers to "smart chargers" by adding a device to connect to the internet and enable on/off functions, and a customer application and utility portal to trigger DR events. In a subsequent phase, Toronto Hydro would like to review available technologies for smart charging, and test technical control options such as the Open Charge Point Protocol (OCPP) with electric vehicle supply equipment (EVSE) and onboard a vehicle telematics control to directly connect with vehicle original equipment manufacturer's (OEM) applications. Finally, Toronto Hydro would like to explore broader tool integration into the Energy Center and metering systems to further real-time situational awareness for EVDR.
Distribution Capability
Adjusting operational practices to incorporate and manage DER on the system, including dispatching and using as NWA: EVs particularly in high-concentration can pose network challenges, such as overloading secondary distribution transformers, exerting additional electrical stress on overhead conductors and underground cables, and increasing peak load at various levels. EV demand response could become a flexible and intelligent solution to maintain grid stability in areas of high-EV penetration by managing EV load as a non-wires solution rather than by expanding or enhancing grid infrastructure.
Potential to Deploy an Innovative Solution
• **The use of new technology or new ways of using existing technology:** Identify viable technical hardware and control models along with demand response (DR) events to facilitate coordinated charging and potential discharging of EV batteries to support network needs (also known as Vehicle-to-Grid). This would be achieved through development of applications, hardware integration, and mechanisms to identify and trigger EV DR events to support trials and roll-out with Toronto-based market participants.

Electric Vehicle Demand Response (EVDR) Pilot Project Concept
• **Enhancing distribution services in a way that benefits customers, including facilitating customers' ability to innovate in how they receive distribution services:** By participating in demand response offerings EV customers could have access to a wider range of choices with respect to charging times, including more incentives to manage their electricity use. • **Business practices including relationships with others to enhance services to customers and share costs:** The pilot would explore opportunities to build and expand on relationships with charge-point operators, demand side service providers, and electric vehicle supply equipment providers to identify best practices for market and utility led smart charging solutions with an outcome of maximizing benefits for the various project participants while minimizing/sharing costs.

Advanced Microgrids Pilot Project Concept
According to the Electric Power Research Institute, a microgrid is "a group of interconnected loads and distributed energy resources (DERs) within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from the grid to operate in both grid-connected and islanded modes." Toronto Hydro is uniquely positioned to trial a microgrid on its distribution system owing to the unique urban characteristics (e.g. Toronto Island where access is generally restricted to water transportation) and the dense service environment in which it operates, along with key customers with sensitive needs. Under this pilot, Toronto Hydro would explore the role of a regulated distributor operating a microgrid nested within the distribution grid, would be controlled by Toronto Hydro, would involve Toronto Hydro assets, and may involve customer-owned Distributed Energy Resources. Demonstration of a community microgrid on Toronto Hydro's system would be necessary to quantify the potential value of resiliency capabilities and optimizing microgrid assets to provide backup power in outage events. Insights would help support utility investment planning and customer engagement with smart communities.
Distribution Capability
• **Adjusting operational practices to incorporate and manage DER on the system, including dispatching and using as non-wires-alternatives:** Microgrids involve the control of DERs and management of system stability (e.g. Voltage and frequency), functions that historically have not been typical distribution operation activities but that will be necessary to enable a more interactive grid and decentralized generation. Capabilities need to be developed to operate microgrids and microgrid assets in a safe and reliable manner. These capabilities include processes, systems and field devices. This pilot would entail the development of such capabilities. • **Modifying planning processes to identify, assess, and implement non-utility-owned DER solutions:** Microgrids can offer **unique** benefits, and as such conventional grid planning needs to be evolved appropriately to integrate microgrids. This pilot would involve the development of a microgrid planning framework and the integration of the framework into Toronto Hydro's normal planning processes.

Advanced Microgrids Pilot Project Concept
Potential to Deploy an Innovative Solution
• **The use of new technology or new ways of using existing technology:** The pilot would involve the introduction and integration of microgrid controllers into the grid, and the operation of Toronto Hydro and/or customer assets through the microgrid controller. • **Enhancing distribution services in a way that benefits customers, including facilitating customers' ability to innovate in how they receive distribution services:** The project would involve customers in order to understand their needs and to explore the use of customer-owned DERs in a microgrid owned and operated by Toronto Hydro, thereby opening a new benefit stream for customers who own DERs or who are load customers in a microgrid. • **Business practices including relationships with others to enhance services to customers and share costs:** In pursuing opportunities to collaborate with customers such as key accounts, customers with critical loads, and DER customers, to plan, implement and operate the microgrid, Toronto Hydro would explore how it can leverage these relationships to maximize benefits (e.g. enhanced services such as reduced outage duration) and reduce costs. There is also an opportunity to partner with academic institutions to utilize new analytical tools and share knowledge about operating a microgrid on an urban utility network.

Natural Resources Canada | Ressources naturelles Canada

Toronto Hydro-Electric System Limited
EB-2023-0195
Exhibit 1B
Tab 4
Schedule 2
Appendix B
ORIGINAL
(8 Pages)

October 27, 2023

RE: Utility innovation to enable affordability and customer choice

Dear Ontario Energy Board,

The Office of Energy Research and Development (OERD) at Natural Resources Canada (NRCan) is providing this letter in response to Toronto Hydro's proposal **to fund utility innovation** as part of their Fall 2023 rate application.

OERD leads the Government of Canada's efforts in delivering energy research, development, and demonstration (RD&D) funding, accelerating efforts in energy innovation. OERD recognizes the role of the regulator in setting just and reasonable rates and in addressing innovation needs in its jurisdiction.

Please find attached OERD's summation of publicly available NRCan information on the value of utility innovation. The document, Experience and Evidence of Utility Innovation Benefits, contains the following information:

- The value of utility innovation in general;
- What OERD has heard from its stakeholders on utility innovation;
- What OERD has learned through our programs; and
- Examples of regulatory mechanisms that have successfully enabled utility innovation.

The document outlines the value for funding innovation to develop options to advance customer choice, reduce consumer costs and increase options for customer participation.

Thank you for your time and consideration.

Sincerely,

Handler, Cynthia

Digitally signed by Handler, Cynthia
Date: 2023.11.06 14:46:25 -05'00'

Cynthia Handler
(she/her/elle)
Acting Director General, Office of Energy Research and Development
Energy Efficiency and Technology Sector
Natural Resources Canada

Canada

Natural Resources Canada
Ressources naturelles Canada

Attachments (1): Experience and Evidence of Utility Innovation Benefits

Experience and Evidence of Utility Innovation Benefits

Natural Resources Canada (NRCan) - Office of Energy Research and Development (OERD)

Utility Innovation Benefits

Utility innovation plays a considerable role in enhancing affordability for customers by exploring cost-effective approaches in an evolving energy system.

Utility innovation promotes affordability. Utility innovation allows for the testing and demonstration of novel technologies, technical solutions, and business models that can deliver better and cost-effective service for customers. For example, grid optimization solutions and demand-side management can deliver reduced energy consumption and increased comfort for customers. These solutions maximize the use of existing assets, reducing the need for new grid investments that would otherwise put upwards pressure on rates.

Utility innovation delivers value to customers by responding to emerging customer needs and preferences. Electrification and the energy transition are changing expectations about the traditional relationship between customers and utilities. Customer needs and preferences are evolving with the rising adoption of distributed energy resources, smart grid technologies and devices, and electric vehicles. Through innovation in new technical solutions, technology adoption, and service delivery models, utilities have the potential to better meet customer needs and improve service for customers. Innovation in service delivery models includes scenarios where customers receive compensation for active participation in the provision of value-added services to the grid, creating new revenue streams for customers.

Utility innovation is a necessary part of an effective energy innovation ecosystem. Utilities have the potential to adopt and implement innovative technologies and solutions at the distribution level to the benefit of their customers. Utility innovation stimulates private sector innovation and improves the effectiveness and impact of government support for sector-wide innovation, ultimately resulting in the accelerated development and adoption of novel cost-effective solutions to the benefit of customers.

Utility innovation projects enable the collection of data and dissemination of information that further promote innovation. Data and information are required to evaluate the viability of business cases and use cases for novel solutions, while limiting ratepayer impacts. These insights can help utilities and decision-makers in other jurisdictions to consider the value of similar novel solutions deployed in their markets.

What We Heard: stakeholder perspectives on utility innovation

Stakeholders have communicated to NRCan the value of, and need for, utility innovation in supporting core utility business activities, improving customer choice and experience, and reducing costs.

The “What we heard” results from the NRCan Request for Information published in 2023 on electricity regulation and grid modernization regarding **enabling innovation and promoting innovation projects at the utility level.** (Source)

- Respondents identified that the current regulatory landscape poses challenges to utilities with respect to proposing innovative projects to their regulators. They also stated that the current regulatory landscape is challenged by evolving market conditions and ongoing revolutionary system changes in the energy sector.
- Respondents emphasized the importance of regulatory sandboxes and other mechanisms and processes to enable and promote piloting and experimentation.
- Respondents highlighted an ongoing need for research, development, and demonstration projects, especially for systems integration of new technologies and operations.

The "What we heard" results from the NRCan Request for Information published in 2022 on grid readiness for zero-emission vehicles regarding **innovation in enabling new technical solutions and applications to meet emerging needs of an evolving energy system.** (Source).

- Respondents identified the importance of encouraging interoperability, building out the infrastructure that is needed to accommodate transportation electrification, and enabling new capabilities for this infrastructure. This would involve establishing open-innovation approaches to facilitate interoperability and increase knowledge dissemination.
- To address concerns with infrastructure readiness and availability to meet higher loads, respondents identified the need for utilities and grid operators to develop new tools for meeting infrastructure needs. They also saw a need for programming to facilitate vehicle-to-grid transactional capabilities while ensuring safety and grid reliability.
- Respondents emphasized the importance of promoting the development and adoption of grid readiness technology at the distribution level, from the innovation phase to scaling and deployment.

What we See: OERD observations from its programs

Utility-led innovation projects have resulted in clear benefits with respect to customer choice and experience, affordability, and energy system benefits.

NRCan has funded grid innovation projects since 2003 and has observed meaningful outcomes that advance technological, social, environmental, and economic benefits for Canadians. **Providing support to adopters (such as utilities) and their providers to develop and demonstrate innovative solutions enhances their ability to drive change that realizes value for their business, the electricity system, ratepayers, and taxpayers**.

The Smart Grid Program (2018-2023) provided partial funding to 21 utility and adopter-led demonstration and deployment projects across eight jurisdictions. This program advanced technical solutions such as grid monitoring and automation, integration of distributed energy resources, microgrids, demand management (demand response and energy efficiency), new markets, and rate design. Broadly, these projects have resulted in several significant benefits, including:

- Improved utilization of existing electricity system assets;
- Increased penetration distributed energy resources, including renewable energy;
- Increased reliability, resiliency and flexibility of the power system;
- Maintained or enhanced cyber security;

- Enabled reductions in greenhouse gas emissions; and
- Economic benefits, including local job creation; new business models, market actors, and revenue opportunities; and net energy bill savings to customers.

The projects funded under the Smart Grid Program are now ending, and final public reports are becoming available (See Annex for project list). **These reports provide evidence that utility-led innovation projects can result in clear benefits to customer choice and experience, affordability, and to the electricity system.** For example:

- A microgrid that reduced congestion issues on a constrained transmission system, thereby deferring costly upgrades by increasing the utilization of existing assets while enhancing power quality and reliability. (Source)
- A microgrid with state-of-the-art capabilities that enables GHG emissions reductions and that has the potential to be replicated in remote locations that rely on fossil-based generation. This project will also help with local training and skills development and promotes public education and awareness through a public exhibition. (Source)
- A transactive energy market that leveraged customer assets to provide valuable grid services during peak demand periods, in exchange for credits to local businesses, thereby promoting grid efficiency while providing economic benefits to local merchants and promoting customer participation in energy markets. (Source)
- Controllable DERs paired with advanced telemetry and artificial intelligence, that optimize resource dispatch and reduce monthly peak demand, resulting in substantial cost savings to the utility, as well as system GHG reductions. (Source)
- A competitive market-based approach to secure energy, capacity, and reserve services from DERs to meet local, regional and province-wide electricity needs through transmission-distribution coordination. This demonstration project explores the potential of non-wires solutions to defer, reduce or avoid costs associated with traditional infrastructure. The project supports reliability and affordability to ratepayers, provides communities more options to address their local electricity needs, and provides new revenue opportunities to new market participants, such as commercial business. (Source)

Some Examples: Regulatory mechanisms that have successfully enabled utility innovation

OERD acknowledges the efforts of several jurisdictions in developing regulatory mechanisms that enable utility innovation that benefits customers. Enabling innovation under a regulatory framework may allow a utility to incorporate innovation into long-term planning and promote organizational culture change in a way that temporary government programs cannot typically afford.

- **FortisBC Energy Clean Growth Innovation Fund**: The British Columbia Utilities Commission rate-funded FortisBC Inc.'s Innovation Fund to promote investments in innovative emissions-reducing projects. FortisBC Energy Inc. justified the innovation fund by stating that it was required to accelerate the pace of clean energy innovation, to achieve performance breakthroughs and cost reductions, and to provide cost-effective, safe, and reliable solutions for customers. (Source)

- **Nova Scotia Utility and Review Board (NSUARB) Innovation Justification Criteria:** These criteria allow innovation projects to be justified on the basis that there is a reasonable expectation that they will provide customer value on 1) reducing upward pressure on revenue requirement, 2) reliability and grid stability, 3) environmental and other compliance, and 4) customer experience improvements. Projects can also be justified on the basis that they are reasonably expected to allow for testing before deploying at scale, provide valuable data and learnings, or aid in the development of business cases. (Source)
- **Ofgem Network Innovation Allowance:** This represents a set amount that RIIO network licensees receive as part of their price control allowance. This allows utilities to create innovation funds and to claim them as operations and maintenance expenditures. (Source)
- **Ontario Energy Board (OEB) Innovation Sandbox:** The first of its kind in Canada, the Innovation Sandbox supports pilot projects testing new activities, services, and business models. The OEB has also published an Innovation Handbook and has launched an Innovation Sandbox Challenge, all in the interest of promoting utility innovation to promote affordability and to create customer value. (Source)

Annex: List of projects funded by NRCan's Smart Grid Program

Table 1. List of projects funded by NRCan's Smart Grid Program

Number	Recipient	Project Title	Project Type	System category
1	Yukon Energy	Residential Demand Response Program (RDRP)	Demonstration	DERMS
2	EPCOR	EPCOR Smart Grid System (ESGS)	Deployment	DERMS, Microgrid, Distributed energy storage
3	EQUS REA	Canada's 1st Member-Owned Rural Smart Grid Project	Deployment	DERMS
4	ENMAX Power	Integrating Distributed Generation into Secondary Networks in Large Urban Centres	Demonstration	Grid monitoring and automation
5	FortisAlberta Inc.	FortisAlberta Waterton Energy Storage Project	Demonstration	Microgrid-connected
6	City of Lethbridge	Conservation Voltage Reduction (CVR) Deployment in Lethbridge	Demonstration	Grid monitoring and automation

		Electricity Utility (LEU) Distribution Network		
7	SaskPower	SaskPower Distribution Modernization Program	Deployment	Grid monitoring and automation
8	SSM PUC	Sault Smart Grid	Deployment	Grid monitoring and automation
9	Entegrus Powerlines Inc.	Conservation Voltage Reduction	Deployment	Grid monitoring and automation
10	Bracebridge	Smart, Proactive, Enabled, Energy Distribution; Intelligent, Efficiently, Responsive (SPEEDIER) Project	Hybrid	DERMS
11	London Hydro	West 5 Smart Grid Project	Hybrid	DERMS
12	Alectra Utilities	Power.House Hybrid: Minimizing GHGs and Maximizing Grid Benefits	Demonstration	DERMS
13	Alectra Utilities	GridExchange	Demonstration	DERMS
14	Independent Electricity System Operator (IESO)	York Region Non-Wires Alternatives Demonstration Project	Demonstration	New markets & rate options (NRO)
15	Lakefront Utilities	Digital Utility Platform	Deployment	Grid monitoring and automation
16	Hydro-Quebec	Smart Grid Deployment of Off-Grid Networks	Deployment	Microgrid off-grid, grid monitoring, automation and storage off-grid
17	Hydro-Quebec	Lac-Megantic Microgrid	Hybrid	Microgrid-connected
18	Saint John Energy	Integrated Dispatchable Resource Network for	Hybrid	DERMS

		Local Electric Distribution Utility		
19	New Brunswick Power	Collaborative Grid Innovation for Atlantic Smart Energy Communities	Hybrid	DERMS
20	Nova Scotia Power	Collaborative Grid Innovation for Atlantic Smart Energy Communities	Hybrid	DERMS
21	PEI Energy	Slemon Park Microgrid Project	Deployment	Microgrid, DERMS
Legend: DERMS– Distributed Energy Resource Management				

CUSTOMER ENGAGEMENT

Customer engagement is one of the key tools that Toronto Hydro uses to inform business planning and decision making. It helps the organization gather critical information, including to identify what is working and what is not working with regards to the programs and services it provides to customers. Customer engagement activities ensure customers' voices are being heard and enable Toronto Hydro to continue meeting evolving customer expectations.

The 2025-2029 investment plan that underpins this application is the product of an extensive application-specific customer engagement process, which garnered feedback from over 37,000 customers (approximately 4.7 percent of the utility's customer base) from start to finish. The plan is also informed by extensive ongoing customer and stakeholder engagement activities undertaken in the normal course of business as part of the utility's robust and sophisticated customer research and response model, as described below in section 3. This schedule describes each of these sources of customer feedback and how they informed the 2025-2029 investment plan that underpins the application.

1. CHANGING CUSTOMER LANDSCAPE

Toronto Hydro serves over three million residents, 28 million visitors annually, and approximately 100,000 businesses.[1] Toronto Hydro's customers include individual residential consumers, large industrial and commercial businesses and thousands of high-rise multi-residential condominium and apartment buildings, with hundreds of thousands of end-use sub-metered customers behind a Toronto Hydro "bulk meter."[2] The utility's service

[1] City of Toronto, *Toronto at a Glance*, "online", https://www.toronto.ca/city-government/data-research-maps/toronto-at-a-glance/>.
[2] Exhibit 1B, Tab 3, Schedule 3 at page 31.

territory is home to Canada's largest banks, stock exchange, major manufacturers, and other large organizations that are particularly sensitive to power interruptions, including dozens of hospitals, healthcare and long-term care facilities and hundreds of schools, colleges, and universities that rely on Toronto Hydro for their electricity needs. In addition, the utility serves the Provincial Legislature, City Hall and a range of government offices and work centres that plan, deliver and oversee a wide-range of community functions and matters of broad socio-economic significance. Finally, Toronto Hydro serves current and future transit lines in the City including the Yonge North Subway Extension, Scarborough Subway Extension, Eglinton Crosstown West Extension, and the Ontario Line.

Toronto Hydro has a robust customer research and response model that is effective at understanding and responding to customer needs and expectations. Ongoing and application-specific research reveals that customer behaviour and attitudes are evolving, and there is a shift in terms of customer needs and priorities. These include:

- Reliability and investment in new technology have become increasingly important to customers, and are almost on par with price.
- Customers are looking for information to improve their understanding of climate change, decarbonization and electrification, as well as an understanding of Toronto Hydro's role in these initiatives, while at the same time looking for opportunities to reduce their overall energy costs.
- Many customers have strong expectations for Toronto Hydro to commit to environmental initiatives and lessen environmental impact.
- Customers have evolving communication preferences – email is the preferred method of contact for all communications and younger Torontonians, in particular, have above-average preference for SMS communications.

- Customers have shown more concern for the future of the electricity system and the grid than in past years.

In addition, as key sectors of the economy electrify, previously non-electric energy usages (e.g. building heating and transportation systems), and as customers leverage technology to play a more active role in the production and management of the electricity they consume, Toronto Hydro expects that customer needs and expectations will continue to increase, driving the need for greater resiliency, and higher volumes and more complexity in customer inquires and interactions.

The utility's 2025-2029 investment plan, and in particular the operational investments within the plan summarized in Exhibit 4, Tab 1, is designed to ensure that the utility has the necessary level of resources with the right skills to maintain an agile and robust customer research and response model as the energy transition unfolds.[3] Similarly, the utility's *Grid Modernization Strategy* presented in Exhibit 2B, Section D5 lays the groundwork for building a more intelligent and self-healing grid that is able to deliver the future system resiliency that customers will increasingly expect as they become more reliant on clean electricity for their energy needs.

2. APPLICATION-SPECIFIC CUSTOMER ENGAGEMENT

Following the OEB's policy guidance, and building on the successful approach in its prior application, Toronto Hydro undertook a two-phased customer engagement approach to inform this application. First, prior to embarking on the business and investment planning process, it obtained a genuine understanding of its customers' needs and priorities, and used

[3] Exhibit 4, Tab 1, Schedule 1 and Section 5.1.6.

this feedback to set strategic direction for the investment priorities of its plan.[4] Second, after the 2025-2029 draft plan was prepared, Toronto Hydro went back to customers to obtain feedback on the draft plan. The utility considered this feedback in refining and finalizing its plan.

As illustrated in the Figure 1 below, Toronto Hydro's application-specific customer engagement process spanned over 18 months, between late 2021 and mid-2023. From start to finish, Toronto Hydro obtained feedback from nearly 37,000 customers, representing an increase of 190 percent compared to the customer engagement in its prior application, and approximately 4.7 percent of the utility's total customer base.[5] This gave Toronto Hydro a genuine understanding of its customers' needs, priorities and preferences and informed the development, refinement and finalization of Toronto Hydro's 2025-2029 investment plan.

[4] Exhibit 2B, Section E2.
[5] In the 2020-2024 Rate Application, approximately 12,500 customers participated in the application specific customer engagement.

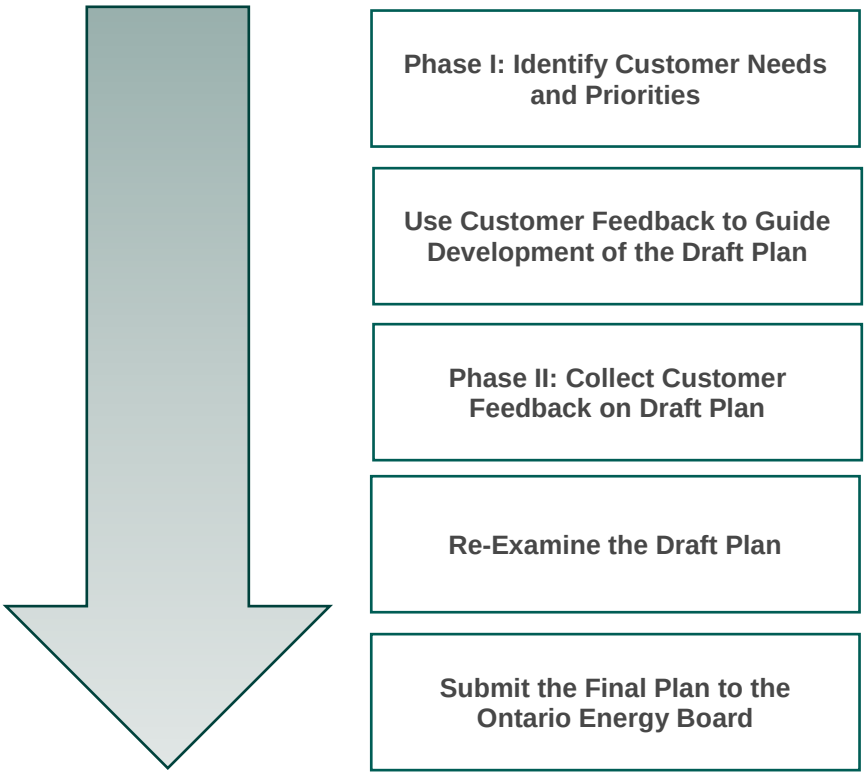


Figure 1: Customer Engagement Process

Toronto Hydro engaged Innovative Research Group ("Innovative"), a national consulting firm with expertise in public opinion research (and experience in energy policy in particular), to execute the utility's customer engagement process. The Innovative Report, found at Appendix A to this schedule, describes in detail the process, methodology and results of Toronto Hydro's application-specific customer engagement.

2.1 Phase 1

Phase 1 of the customer engagement process assessed customers' needs and preferences in relation to Toronto Hydro's programs and services for the 2025-2029 rate period. The results revealed that customers' core priorities are centered around three themes:

1. **Price and reliability are the top customer priorities:** Relative to price, reliability has become increasingly important to residential customers. When it comes to reliability, customers prioritize reducing the length of outages, with a particular focus on extreme weather events for residential and small business customers. Key Account customers are more sensitive to power interruptions and prioritize reducing the total number of outages.
2. **New Technology:** Almost as equally important to price and reliability, customers expect the utility to invest in new technologies that will reduce costs and make the system better, even if the benefits aren't immediate, as long as the costs and benefits are clear.
3. **System Capacity:** Customers expect Toronto Hydro to invest proactively in system capacity to ensure that high growth areas do not experience a decrease in service levels. The majority of Key Account customers surveyed have Net Zero goals to reduce their business' net greenhouse gas emissions to and expect Toronto Hydro to support them in meeting their climate action objectives by ensuring that the system has capacity for growth and by providing them advisory services.

Toronto Hydro applied this feedback as a front-end input into the development of the draft investment plan. Considering this feedback, and other inputs, Toronto Hydro organized its plan around the following investment priorities:

1. **Sustainment:** Investments to upkeep old equipment that is in poor condition and replace outdated equipment**.**
2. **Modernization:** Investments in technology to get more use out of existing equipment, and build a smarter, more efficient and reliable grid.
3. **Growth:** Investments in capacity to power the growing city and serve customers' growing and changing needs for electricity.

4. **General Plant:** Investments in vehicles, work centers and IT to keep the business running and reduce Toronto Hydro's emissions.

For each of these strategic priorities, Toronto Hydro set performance objectives that provide value for customers based on the feedback received, and are meaningful to its operations, including to:

- invest enough in the sustainment of asset health and other leading indicators of asset risk to maintain reliability performance;
- prioritize investments in technology to modernize the grid and develop advanced operational capabilities to make the system better for the future; and
- invest proactively in system capacity to ensure that the grid is able to support future growth without compromising other outcomes like safety and reliability.

Through an iterative process that spanned over a year, Toronto Hydro system planners and experts worked diligently to identify the minimum investments necessary to meet these objectives and balance near-and long-term service quality performance with price impacts for customers, as informed by the feedback in Phase 1. Achieving this important balance entailed both top-down direction with respect to price constraints and budget limits, and bottom-up analysis of system requirements and performance levels.[6]

To help Toronto Hydro integrate the customer feedback into its planning process, Innovative developed a placemat summarizing the findings of the Phase 1 Customer Engagement survey in an accessible format. Toronto Hydro shared this placemat with system planners and other subject matter experts involved in the planning process to ensure that customer feedback was considered in developing the plan from a bottom-up perspective. Employing

[6] *Supra* Note 4

this feedback and other business inputs such as asset condition and system performance, Toronto Hydro developed a $5.9 billion draft plan that was then taken back to customers during Phase 2 of the engagement.

2.2 Phase 2

Phase 2 solicited detailed customer feedback on the $5.9 billion draft plan and the associated price impacts, providing the utility additional insight about customers' preferences relative to the investment plan priorities, options and outcomes. This feedback: (i) confirmed that Toronto Hydro found a suitable balance between price and other key outcomes of its 2025-2029 investment plan, (ii) supported the refinement and finalization of the plan, and (iii) informed the development of the 2025-2029 custom scorecard presented in Exhibit 1B, Tab 3, Schedule 1.

To obtain this critical customer feedback, Innovative developed an interactive online workbook providing customers the opportunity to learn about Toronto Hydro's draft plan and express preferences with respect to key investment choices. Toronto Hydro distilled the 2025-2029 draft investment plan into seven investment areas:

1. **Modernization**: Investments to build a smarter, more efficient and resilient grid.
2. **Growth**: Investments to increase grid capacity to reliably serve customers' growing electricity needs.
3. **Sustainment – Reliability:** Investments to manage near-term reliability risk due to equipment failure.
4. **Sustainment – Stewardship:** Investments in the paced upkeep of equipment at or near end of life to manage longer-term reliability outcomes.
5. **Sustainment – Standardization**: Investments to replace outdated equipment with equipment meeting modern standards.

6. **General Plant**: Investments in fleet, facilities and IT infrastructure to keep the business running efficiently.
7. **Decarbonization**: Investments to reduce Toronto Hydro's greenhouse gas emissions from its own operations by electrifying fleet and facilities assets.

For each investment area, Toronto Hydro put forward the draft plan, along with pacing options to spend more or less, for faster or slower progress towards achieving performance across the following key outcomes: system health, reliability, customer service, efficiency and environment. After making their preliminary choices, customers were provided with the total price implications of those choices and invited to change their selections if desired. At the end of the workbook, customers were asked if they would be willing to support the rate increase associated with Toronto Hydro's draft plan – a question commonly referred to as *social permission*.

Through this interactive customer engagement process, Toronto Hydro obtained valuable feedback on the draft plan. At the top level, Toronto Hydro learned that on average, 84 percent of customers surveyed supported the draft plan and its associated rate impacts. Further, 18 percent of customers supported a plan that does even more to advance key outcomes. At a more granular level, this process provided the utility insights into customer prioritization between respective investment categories. In general, customer trade-offs between price and progress were: (a) in-line with the draft plan on Modernization, Stewardship and Standardization, and (b) slightly lower than the draft plan on Growth, Reliability, Running the Business and Decarbonization.

Toronto Hydro considered this feedback, and took it into account in order to refine and finalize its 2025-2029 investment plan presented in this application. In direct response to

customer feedback, Toronto Hydro challenged itself to reprioritize certain investment, and reduce the overall capital plan by approximately $70 million, as further described in Exhibit 2B, Section E2.

2.3 Responsive to OEB Guidance

In conducting the application-specific customer engagement process described above in section 2, Toronto Hydro considered the OEB's *Renewed Regulatory Framework for Electricity Distributors* ("RRF"), the *Filing Requirements for Electricity Distribution Rate Applications* ("Filing Requirements"), the *Handbook for Utility Rate Applications*, the EB-2018-0165 decision in respect of Toronto Hydro's 2020-2024 rate application, and OEB decisions in other utilities' rate applications. The OEB's guidance centres on two key considerations, which were thoroughly addressed by Toronto Hydro through its customer engagement process, as detailed in this schedule and in Exhibit 2B, Section E2.

1. A utility's business plan must be informed by and responsive to customer needs and preferences, in the context of broader considerations such as asset condition, system performance and other safety and regulatory requirements; and
2. A utility is expected to develop a genuine understanding of its customers' needs and preferences, and be able to demonstrate how the business plan was informed by customer feedback.

In addition to being responsive to this OEB guidance, Toronto Hydro specifically reflected on the OEB's feedback in the 2020-2024 Decision, which noted that *"[i]n future customer engagement initiatives, there may be an opportunity to build on the current level of customer understanding and focus on some areas of particular concern*."[7] The OEB also expressed some caution about customers' ability to understand the system investments requirements

[7] EB-2018-0165, Decision and Order (December 19, 2019) at Page 13.

or priorities in details. Reflecting on this feedback, Toronto Hydro enhanced its application-specific customer engagement process to be more focused, yet comprehensive and accessible, so that customers could meaningfully participate even without having in-depth knowledge of the electricity system.

For Phase 1, rather than conducting the low volume customer surveys solely via telephone, Toronto Hydro and Innovative were able to move these surveys to an online format, resulting in increased customer participation and more robust customer insights to inform the development of Toronto Hydro's 2025-2029 investment plan. In the Phase I engagement, Toronto Hydro saw a 546 percent increase in participation rates among residential customers, and a 293 percent increase among small business customers.

In Phase 2, mindful of the expanded investment priorities and rate impacts associated with its plan, Toronto Hydro put its entire draft plan to customers for feedback in an interactive survey that took customers through key investment areas of the plan. The investment choices presented in the workbook were grounded in the investment options developed and considered throughout the planning process.[8] Each choice was designed to solicit feedback about customers' preferences and trade-offs between price (i.e. rate impacts) and other key outcomes (i.e. system health, reliability, customer service, efficiency and environment). To enable customers to express their preferences, an interactive slider tool and outcomes table was developed for each area.

In an effort to increase customer participation rates, Toronto Hydro took a number of steps to bring visibility to the workbook including:

[8] To present the full rate impacts to customers, the utility allocated the cost of operational investments to each of the seven key areas of investment.

- Emailing over 440,000 customers with an invitation to complete the workbook;
- Notifying customers about the workbook through the utility's print newsletter (included with customer bills) and an electronic newsletter (delivered to nearly 200,000 customers);
- Inviting customers to participate in the Phase 2 engagement through the Toronto Hydro website and social media channels; and
- Using online display ads through social media which generated approximately 5.45 million impressions and over 17,000 clicks to the workbook.

These efforts were successful in increasing customer participation in the Phase 2 engagement. Nearly three times more customers completed the workbook compared to the 2018 survey conducted in the lead up to the 2020-2024 rate application. Table 2 below, compares the customer engagement results for the previous and the current rate application. Overall, customers were more supportive of the draft plan presented in this application compared to last time.

Table 1: Phase 2 Customer Engagement Comparison

Rate Class	2018		2023		2018 vs. 2023	
	Participation	Social Permission	Participation	Social Permission	Participation	Social Permission
Residential	10,765	71%	32,187	80%	199%	+9%
Small Business	396	55%	695	77%	76%	+22%
C&I	202	73%	264	82%	31%	+9%
Key Accounts	37	78%	52	96%	41%	+18%
Total	11,400	69%	33,198	84%	191%	+15%

3. ONGOING CUSTOMER ENGAGEMENT

Ongoing customer and stakeholder engagement activities occur in the normal course of business as part of Toronto Hydro's robust and sophisticated customer research and response model.[9] Insights collected by the utility through these ongoing activities were embedded in the development of this application, in addition to the results of the application-specific engagement detailed above in section 2.

Interactions with customers through various channels informed the utility's plans in a number of ways, including: (i) development of capital plans particular investments to expand and modernize the grid to meet the future load demands of customers; (ii) the continuous improvement of customer-interfacing functions and services; and (iii) specific performance outcomes and measures that relate to customer service and experience as detailed in Exhibit 1B, Tab 3, Schedule 1.

This section summarizes the ongoing customer research activities undertaken across different programs and functions that comprise the 2025-2029 investment plan detailed in Exhibit 2B (capital) and Exhibit 4, Tab 2 (operations), and summarizes key areas of Toronto Hydro's plan and rate application that have been informed by and are responsive to the evolving expectations and needs of the utility's diverse customer base.

3.1 Customer Services

Toronto Hydro's customer services, outlined in the Customer Care program, and in the Customer Operation Program respond to the needs of the utility's large and diverse customer base. [10,11]

[9] Exhibit 2B, Section B.
[10] Exhibit 4, Tab 2, Schedule 14.
[11] Exhibit 4, Tab 2, Schedule 8.

As noted in the Customer Care Program, an increasingly popular method of engagement continues to be Toronto Hydro's mobile and digital self-service portal, known as Customer Self-Serve (CSS) portal.[12] It offers customers 24/7 online access to their account, including ability to view and download bills and payment histories. It also provides access to additional features to help manage their account including automated move-in/move-out capability, register for electronic billing (i.e. eBills), pre-authorized debit enrolment and outage notifications, switch electricity price plan, and chat with Customer Care representative regarding any account-related inquiries. In addition, the "My Usage" page on the CSS portal provides customers the ability to track and compare their electricity usage and costs on an hourly, daily, monthly, and yearly basis. Furthermore, customers are able to access a price comparison tool to help make an informed decision when selecting between tiered, standard time of use, and the new Ultra-Low Overnight time of use electricity pricing plans.

In 2022, the Contact Centre received and addressed approximately 70,000 written (i.e. paper mail, fax, and email) inquiries and about 343,000 telephone calls. Customers engage with the Contact Centre to inquire about Toronto Hydro's business practices, available programs and service choices (such as pricing plan options), government incentives, payment options, electricity consumption and demand, moves, collections, financial assistance programs, and a variety of other topics. The Contact Centre is responsible for many activities that contribute to the service quality performance results tracked by the OEB through scorecards and annual reporting requirements.[13] Despite an increasing volume and complexity of customer interactions, the utility intends to maintain high service quality performance on over the 2025-2029 rate period and expand its accountability to other aspect of customer service and experience outcomes.[14]

[12] *Supra* note 13.
[13] Exhibit 1B, Tab 3, Schedule 2.
[14] Exhibit 1B, Tab 3, Schedule 1.

The Escalations and Special Investigations area resolves specific customer concerns that require complex or lengthy analysis. The most frequently occurring issues relate to energy and bill management, including high bill issues, energy management, payment challenges, and power quality requests pertaining to interruptions in power. With customers increasingly working from home since 2020, any interruption in power, including momentary and short duration outages, has become more impactful to customers. The Escalations and Special Investigations function intakes escalated matters through a variety of channels. For example, in 2022, this function processed approximately 1,900 escalations received through the Contact Centre. The Escalations and Special Investigations function is also responsible for Toronto Hydro's consumer complaint response process and the resolution of customer escalations forwarded through the OEB E-Portal. The function deploys field resources as necessary to investigate power quality, billing, or other issues. In 2022, Escalations and Special Investigations resolved 99 percent of escalated customer inquiries within 10 business days or less.

In recent years, the issues handled by the Escalations and Special Investigations function have become progressively more complex. The investigation and resolution of these issues typically involve internal stakeholders from multiple capital and OM&A programs, such as Customer Operations, Work Program Execution, or Public Legal & Regulatory, and sometimes external stakeholders such as provincial and municipal transit operators, various departments of the City of Toronto, or social assistance agencies. Toronto Hydro expects the complexity of issues addressed by this function to increase as more customers adopt DERs and EVs and those resources are integrated with distribution operations, and as public policy initiatives relating to major transit, telecom, or construction projects drive various activities in the utility's service territory in an impactful way for customers.

3.2 Key Accounts

Toronto Hydro's Key Account customers are those customers who have critical loads including customers who have electricity use greater than 1MW, priority loads (such as hospitals and financial institutions), essential public services, and developers. These customers often have distinct needs and priorities including:

- **High sensitivity to reliability issues** – for many Key Account customers any interruptions, even momentary ones, can cause high costs due to loss of product and health and safety concerns.
- **Complex connections and expansions –** connections and expansions for Key Account customers are often more complex, due to their sheer size and requirement for more sophisticated configurations.
- **Environmental Social & Governance (ESG) goals** – Approximately 64 percent of Key Account customers have plans to decarbonize and expect Toronto Hydro to support them in their journey as they consideration electrification solutions.

Toronto Hydro's Key Account's team manages the relationships and acts as a single point of contact for all work activities related to serving the distinct needs of Key Accounts customers, including matters such as: [15]

- facilitating and assisting with scheduling and planning for major capital and maintenance projects, operational requirements, and regulatory compliance;
- liaising with departments across Toronto Hydro including: engineering, design and construction, and operations;
- meeting with customers to resolve billing issues, coordinate planned outages, and provide business-specific updates during unplanned outages;
- resolving issues related to reliability and power quality;

[15] Exhibit 4, Tab 2, Schedule 8.

- discussing opportunities for reducing emissions and meeting decarbonization goals;
- partnering with the IESO to support the delivery of Local Incentive Programs;[16] and,
- providing account and sector specific information through various channels such as direct mail, newsletters, workshops, and association outreach.

As the needs of customers evolve, the Key Accounts function is keeping abreast of these evolutions by investing in more proactive engagement with Key Account customers, and by working closely with other parts of the organization to facilitate a positive customer connections experience for these customers.[17] To that end, there are currently over 30 Key Account customers actively pursuing large expansions and new connections greater than 1 MVA, totaling 57 connection and expansion projects.[18]

3.3 Media and Public Relations

Toronto Hydro's Media and Public Relations department engages customers and other stakeholders through a number of different channels, including: [19]

- Owned media channels (content that is published through channels that Toronto Hydro creates or controls), including its website, social media channels, print newsletters, email newsletters/blasts, bill inserts, customer bill, mobile app, media events, community events and, Interactive Voice Response system);
- Paid media channels (third-party channels that require payment from Toronto Hydro), e.g. newspaper advertising, radio advertising, direct mail, digital and social media advertising;

[16] Under previous Conservation and Demand Management frameworks, the Key Accounts function worked with large customers to access provincial funding for energy efficiency programs.
[17] In 2022, the Toronto Hydro undertook over 1,100 engagements with customers.
[18] *Supra* note 14.
[19] These channels are regularly reviewed and updated to reflect Customer feedback and preferences. For more information see Exhibit 4, Tab 2, Schedule 18.

- Earned media channels (content about Toronto Hydro that comes voluntarily from others) such as print, broadcast and online news outlets;
- Customer surveys, including the OEB's and Electricity Canada's customer satisfaction surveys (annual and bi-annual, respectively), the OEB's bi-annual *Public Awareness of Electrical Safety Survey*, and Toronto Hydro initiated surveys on brand trust and reputation and other one-off topics (e.g. billing) as needed for gathering relevant quantitative customer feedback
- Contact with local business improvement organizations, community groups and ratepayer associations;
- Proactive outreach to City Councillors, the Mayor's office and City staff; and
- Community events.

Toronto Hydro also considers direct customer feedback through its Customer Advisory Panel ("CAP"). The CAP is selected through a multi-step process to ensure representation from a diverse cross-section of customers. The utility engages its CAP to obtain ongoing feedback on a variety of topics using a mix of focus groups, surveys, user experience testing, targeted one-on-one interviews, and workshop sessions (inclusive of both residential and business customers). In recent years, Toronto Hydro used feedback from its CAP to help inform the redesign of its customer-facing website, the rollout of new digital tools such as the Toronto Hydro mobile app, updates to its service connections brochures, and development of rates communications, among other initiatives.

Additionally, the media serves as an important conduit between Toronto Hydro and its customers. Media and Public Relations proactively and reactively communicates accurate and timely information to the media about Toronto Hydro's programs, services and

operations, including power outages, electrical safety, rates, and investments in the distribution system.

Increasingly, digital channels, including social media, and online tools, such as mobile apps, SMS notifications and live online chat, are becoming the preferred source of information for customers experiencing an outage. Toronto Hydro's digital team focuses on engaging the public through these channels and actively communicates with those who engage Toronto Hydro via its social media channels (Toronto Hydro has over 121,000 followers on X (formerly known as Twitter) as of November 2023. Media outlets and journalists also rely on digital channels to collect information, increasing their importance and creating an opportunity for Toronto Hydro to use these channels as additional communications tools with the media.

Municipal Government Relations and the Office of the President manages relationships with key City stakeholders. Customer escalations for complex cases are managed through a multi-stage dispute resolution process. The Office of the President handles approximately 1,000 issues per year with approximately two-thirds directed to it from councillors and other elected and public officials. The remaining third is comprised of the second level in the customer dispute resolution process if customers are not satisfied with the outcome of an escalation handled by customer facing teams as described above. The Customer Advocate is the final step within Toronto Hydro's complaint process and reviews cases for customers unsatisfied with responses provided by Toronto Hydro. Of the approximately 1,000 issues managed through the Office of the President in 2022, over 98 percent were successfully resolved without a formal Customer Advocate review. This is further discussed in Exhibit 4, Tab 2, Schedule 18.

3.4 Community Relations

Through Community Relations, Toronto Hydro communicates regularly with customers regarding planned capital work projects and scheduled outages, in order to engage and help customers prepare for work at or near their property.[20] Toronto Hydro issues proactive communications to notify customers of planned work, and manages a customer inquiry line to address questions and concerns. Community Relations staff are dispatched on-site, when needed, to liaise with customers in a prompt and courteous manner. This process is critical for building brand trust and upholding Toronto Hydro's reputation within the communities it serves.

Toronto Hydro maintains productive relationships with public interest groups and agencies involved in commerce, environmental protection, and education. Stakeholder outreach commonly takes the form of one-on-one contact with customers, community town hall meetings, special information sessions, and a variety of online content. Using a variety of communication channels allows Toronto Hydro to engage customers with varying needs, concerns, and preferences, with the goal of giving appropriate attention to all customer segments**.**

When work has the potential to disrupt local neighbourhoods and property, typically, Toronto Hydro engages customers through three rounds of notifications:

- General notification of construction work is given to all affected residents;
- Letters are provided to all customers that will have equipment, such as poles or transformers, located on or adjacent to their property; and
- A pre-construction letter is issued approximately one week prior to work commencing.

[20] Exhibit 4, Tab 2, Schedule 18.

Community Relations is responsible for providing these notifications and for addressing or escalating customer concerns. For example, if customers are not satisfied with the scope or nature of planned work, Community Relations may investigate new design options or engage customers in-person or at utility-initiated community meetings.

More intensive and incremental engagement is used in relation to rear-lot projects, which can require significant work on Toronto Hydro's part to relocate electrical infrastructure and remove legacy assets from private property. Before work begins, Toronto Hydro proactively initiates an Open House in the community where work is expected to take place. At that forum, Toronto Hydro provides an overview of the scope and timelines of the work, an explanation of why the work is taking place and contact information for customers who wish to follow up for more information. The three-round notification process is then implemented.

3.5 System and Capacity Planning

Ongoing customer engagement also plays a role in various aspects of Toronto Hydro's capital planning process. For example, the utility uses the City of Toronto's development pipeline to engage large customers and developers with upcoming projects to understand their needs, determine their load requirements and timelines, provide technical guidance, explore innovation opportunities, and provide support in understanding the connection process. These engagements usually occur up to five to eight years before an intended connection materializes, enabling a smoother connection experience for customers and providing Toronto Hydro with valuable insight into emerging technologies that customers are adopting behind-the-meter, that can drive significant load growth or change in demand patterns in certain parts of the grid. Accordingly, these engagements enable Toronto Hydro to incorporate anticipated connections into its System Peak Demand Forecast with a higher

degree of confidence. Based on this forecast, Toronto Hydro determines investment needs in demand-driven program such Stations Expansion and Load Demand, to manage capacity and plan for future system peak load growth.[21]

Toronto Hydro's participation in Regional Planning is another channel of ongoing engagement that informs the development of the capital plan. The Regional Planning Process includes community and stakeholder engagement, including webinars, led by the IESO. The IESO invites the City of Toronto, First Nations, and Métis communities, stakeholders, community groups and the general public to provide input on the Scoping Assessment Outcome Report and development of the IRRP that is currently underway. The inaugural webinar occurred in March 2023, and coincided with the publication of the Scoping Assessment Outcome Report. For more information about the Regional Planning Process, see Exhibit 2B, Section B3 of the DSP.

Finally, Toronto Hydro's plans are responsive to the priorities of local government, and in particular the City's *TransformTO Strategy*, which identifies objectives to reduce greenhouse gas emissions, improve health, grow the economy, and improve social equity. In 2021, Toronto Hydro prepared an industry-leading Climate Action Plan to assess the utility's role in enabling and advancing the City's *TransformTO* objectives.[22] The Climate Action Plan revealed that most significant opportunity for Toronto Hydro to enhance its contributions to climate action is to substantially expand its existing, regulated, electricity distribution business to build a grid that is capable of supporting the realization of the City's *Net Zero Strategy*. The 2025-2029 Investment Plan that underpins this rate application is a critical step in that direction, with least regret investments in system capacity and modernization

[21] Exhibit 2B, Sections B and D4.
[22] Toronto Hydro, Climate Action Plan, "online", https://www.torontohydro.com/documents/20143/74105431/climate-action-plan.pdf/8fe4406c-7675-76a7-00c9-c0c4e58ae6df?t=1638298942821

initiatives that enable Toronto Hydro's grid and operations to be ready and equipped to serve an electrified future.[23]

[23] Exhibit 2B, Section D4. For more information on Toronto Hydro's alignment with city of Toronto priorities, see Section D2.1.4 of the DSP.

INNOVATIVE RESEARCH GROUP

CONFIDENTIAL

Toronto Hydro Customer Engagement

Executive Summary

2025-29 CIR Application

TORONTO HYDRO®

STRICTY CONFIDENTIAL

Customer Engagement

2025-29 CIR Application

November 2, 2023

Confidentiality

This Report and all of the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of Toronto Hydro Electric-System Ltd. (Toronto Hydro).

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro. The conclusions drawn and opinions expressed are those of the authors.

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Introduction

Toronto Hydro Electric-System Ltd. (**Toronto Hydro**) engaged Innovative Research Group Inc. (**INNOVATIVE**) to design, execute, and document the results of its customer engagement process under the Renewed Regulatory Framework for Electricity Distributors (RRFE) as part of its business planning process for the 2025-2029 Custom Incentive Rate-Setting Application.

Throughout the process of developing its 2025-2029 Custom Incentive Rate-Setting Application, Toronto Hydro set out to gather meaningful feedback from its customers, specifically when it came to their needs, preferences and trade-offs regarding the pacing and prioritization of specific investment and spending areas.

Findings from this customer engagement revealed that an average of 84% of customers, across all rate classes, provided *social permission* to proceed with Toronto Hydro's draft plan.

Social permission is the percentage of customers who responded to Toronto Hydro's draft plan by indicating either: (1) they think Toronto Hydro should accelerate spending beyond the level in the draft plan to deliver better system outcomes, (2) they support the proposed rate increase that is reflected in the draft plan, or (3) they feel that the proposed rate increase in the draft plan is necessary, even though they don't like the proposed increase.

Approach to Meaningful Customer Engagement

The Ontario Energy Board's (OEB) "consumer-centric" approach to rate applications contained in the *RRFE* requires Local Distribution Companies (LDCs) to demonstrate that their services are provided in a manner that responds to identified customer needs and preferences.[1] LDCs are required to provide an overview of customer engagement activities that they have undertaken with respect to their plans and how customer needs and preferences have been reflected in the LDCs' application. The Handbook for Utility Rate Applications notes the following: *"The OEB expects a utility's rate application to provide an overview of customer needs, preferences and expectations learned through the utility's customer engagement activities."*[2] These requirements have the effect of bringing customers feedback data to bear on utility planning.

The OEB does not specify how customer engagement should be conducted or how customer feedback should be received. However, it has encouraged utilities to use *"both existing and new processes."*[3] Toronto Hydro's customer engagement was designed with this in mind, where customer feedback was collected using multiple methodologies, including: an online customer feedback portal, focus groups, one-on-one interviews, telephone surveys and online surveys. Additional information on the approach is provided in subsequent sections of this executive summary and within the relevant appendices.

Between 2021 and 2023, INNOVATIVE gathered feedback from nearly 37,000 Toronto Hydro customers as part of the utility's application-specific customer engagement efforts. In context, this engagement represented Toronto Hydro's largest and most comprehensive customer engagement over the utility's history.

[1] OEB Renewed Regulatory Framework for Electricity Sections 2.4.2, 5.0, and 5.0.4.
[2] Handbook for Utility Rate Applications, p. 12 (October 13, 2016)
[3] Handbook for Utility Rate Applications, p. 12 (October 13, 2016)

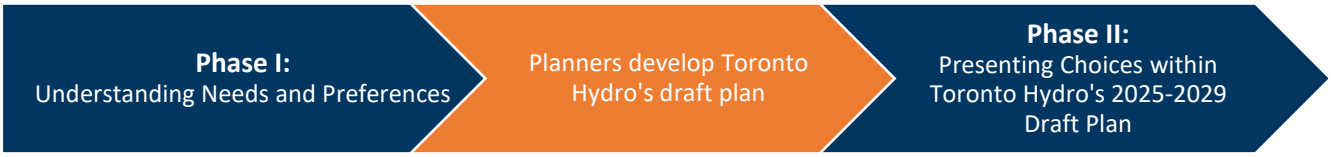
The key objectives of this customer engagement were to:

1. Obtain input as to customers' needs and preferences as they relate to the outcomes and goals that the utility should focus on over the 2025-2029 rate period.

2. Solicit customer feedback on key investment areas based on pacing and bill impact.

3. Assess overall social permission for the draft plan.

INNOVATIVE and Toronto Hydro developed a two-phased engagement approach to achieve these objectives. Following the customer engagement in Phase I, Toronto Hydro developed a draft plan to align with identified customer needs, preferences, and expectations. Afterwards, INNOVATIVE worked with Toronto Hydro to translate the draft plan into engagement materials that a typical customer could understand. INNOVATIVE developed a workbook survey and tested it through a series of focus groups and one-on-one interviews. The workbook was then made available to all customers. It mainly focused on obtaining customer feedback on key investment areas based on pacing and bill impact.



The way customers want to be engaged is evolving. Building off lessons learned from its 2020 rate application customer engagement, Toronto Hydro's approach employed enhanced methods of engagement to better meet evolving expectations. Details of the enhancements are documented at the end of this summary. Some of the key enhancements included:

- Descriptive video narratives to help explain complex themes such as the energy transition, electrification, and grid modernization.
- Providing customers with the *entire* draft plan – including capital expenditures and operating expenses – to get feedback on the trade-offs between prices and other outcomes such as system health, reliability, efficiency, customer services, and the environment.
- An online-centered approach served as the focal point of this customer engagement, which contributed to a successful participation rate and representative sample of customers.

This document contains the results of both phases of customer engagement, with a focus on the generalizable results of the representative customer samples from Phases I and II.

Customer Engagement Key Findings

Phase I: Understanding Needs and Preferences

Based on a review of the OEB Handbook for Utility Rate Applications and previous decisions, the first phase of Toronto Hydro's customer engagement focused on understanding customers' **needs** and **preferences**, defined as follow:

Needs	**Needs questions** focus on understanding the gap between the services and experience customers want and the services and experience customers are receiving.
Preferences	**Preferences questions** focus on customer views about the outcomes the utility should focus on, priorities among those outcomes, and trade-offs illustrated by choices on specific programs or the pacing and prioritization of investments.

The first phase of the customer engagement took place between **November 2021 and March 2022**. In addition to obtaining input as to customers' needs and preferences as they relate to the outcomes and goals that the utility should focus on over the 2025-2029 rate period, it also developed a detailed understanding of the demographic differences between customers with known email addresses (email sample) and the broader customer base (telephone sample). See **Appendix 2.0** for the findings of the comparison.

Customer Engagement Approach

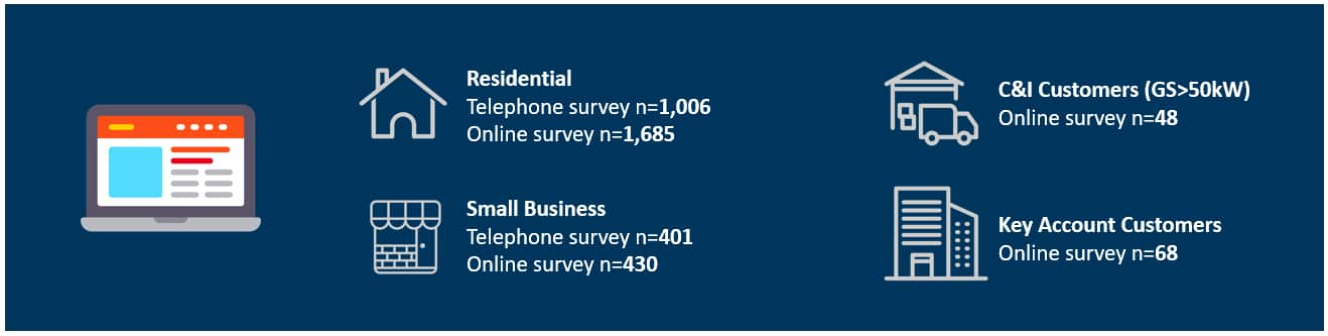
As one of the objectives of Phase I was to obtain input as to customers' needs and preferences, the customer engagement focused on understanding the range of views that exist within the customer base, how different types of customers perceive certain issues, and ultimately deliver a summary or "**Placemat**" that can be used by the planners in developing the draft plan.

This initial phase of engagement was conducted at the beginning of Toronto Hydro's planning cycle to ensure that the draft plan that was subsequently prepared took into consideration the needs and preferences of customers. Building on existing research, INNOVATIVE conducted a series of exploratory focus groups and in-depth interviews with customers.

Between November 2021 and January 2022, an initial round of exploratory qualitative research was conducted amongst residential, small business (GS<50 kW), commercial & industrial (GS 50-999 kW), and key account customers. Through discussing customers' expectations, today and into the future, these focus groups and interviews were able to identify key outcomes and the criteria customers use to measure success. This engagement also provided insights into what customers expect of Toronto Hydro, and what customers prioritize, both in the context of valued customer outcomes, and choices the utility was considering in its 2025-2029 rate application.

Toronto Hydro's customer engagement was an iterative process, wherein each phase and activity informed the next. The results of the exploratory qualitative research (see **Appendix 1.0** for summary) played an important role in informing the questions that were asked in a subsequent series of telephone and online surveys. Results from these subsequent surveys formed the bulk of the insights gathered in Phase I of the customer engagement.

The graphic below summarizes the sample sizes of the surveys conducted by rate class.



This section provides an overview of customer needs, preferences and expectations as gathered through the representative online surveys conducted in Phase I. Full results can be found in **Appendices 3.0 – 6.0.**

Customer Needs

Before understanding customer needs, the survey measured customer satisfaction with the services provided by Toronto Hydro. A large majority of the customers across rate class were satisfied with the services provided.

Overall Satisfaction with Toronto Hydro	Phase I Online Survey Results			
	Residential (n=1,600)	Small Business (n=430)	C&I* (n=48)	Key Accounts (n=68)
Satisfied	77%	76%	90%	76%
Neutral	15%	16%	10%	13%
Dissatisfied	8%	8%	0%	11%

* Interpret C&I results as directional due to the small sample size.

Comprehending customer needs means understanding the gap between the services and experience customers want and the services and experience customers are receiving. To uncover this gap, we asked what Toronto Hydro could do to improve its services.

Overall, the results indicated that Toronto Hydro is meeting its customers' needs. In addition to overall high levels of satisfaction with Toronto Hydro, most customers – across all rate classes – indicated they either *don't know* or *do not believe that there is anything specific* that the utility can do to improve services.

Top-5 Customer Needs (open-ended)	Phase I Online Survey Results			
	Residential (n=1,600)	Small Business (n=430)	C&I (n=48)	Key Accounts (n=68)
1st	**Don't know**	**Don't know**	**Don't know**	**Don't know**
2nd	Nothing	Costs	Reliability	Communications
3rd	Rates	Billing	Communication	Reliability
4th	Climate Action	Nothing	Billing	Customer Service
5th	Communications	Reliability	Customer Service	Billing

* Interpret C&I results as directional due to the small sample size.

Customer Preferences

Based on a preliminary review of Toronto Hydro's past and ongoing customer engagement efforts, as well as the initial exploratory qualitative research, a list of potential utility outcomes was identified as follows:

1. *Delivering electricity at reasonable distribution rates.*
2. *Enabling customers to access new electricity services.*
3. *Ensuring reliable electrical service.*
4. *Ensuring the safety of electricity infrastructure.*
5. *Expanding the electricity grid so that customers can reduce their impact on climate change by using electricity to replace fossil fuels.*
6. *Helping customers with conservation and cost savings.*
7. *Investing in new technology that could help either reduce costs or better help withstand the impacts of adverse weather.*
8. *Minimizing Toronto Hydro's impact on the environment.*
9. *Providing quality customer service and enhanced communications.*
10. *Replacing aging infrastructure that is beyond its useful life.*

General Priorities

Among competing outcomes, *price*, *reliability*, and *investing in new technology* were the top three priorities for both residential and small business customers. Commercial and industrial customers prioritized *rates, reliability,* and *grid capacity expansion.* For key account customers, *reliability, restoration times,* and *infrastructure safety* topped the list of service outcome priorities.

Prioritizing Outcomes	Phase I Online Survey Results			
	Residential (n=1,600)	**Small Business** (n=430)	**C&I** (n=48)	**Key Accounts** (n=68)
(%) indicates total percentage by rate class that place specific priority in their top 3 outcomes	**Reasonable rates (46%)**	**Reasonable rates (54%)**	**Reasonable rates (50%)**	**Reliable service including power quality (69%)**
	Reliable service (45%)	**Invest in new technology (40%)** Reduce costs Withstand adverse weather	**Reliable service (48%)**	**Outage restoration in extreme weather (52%)**
	Invest in new technology (45%) Reduce costs Withstand adverse weather	**Reliable service (36%)**	**Grid capacity expansion for climate action (33%)**	**Safety of infrastructure (39%)**

For <u>residential customers</u>, *rates*, *reliability*, and *investing in technology* were all tied as their top priorities. Traditionally, rates and reliability were the top priorities for the residential rate class. As for the interest in investing in technology to reduce costs and withstand adverse weather, many customers in this engagement expressed an interest in making long-term investments that not only could improve reliability and lower rates, but also address climate change.

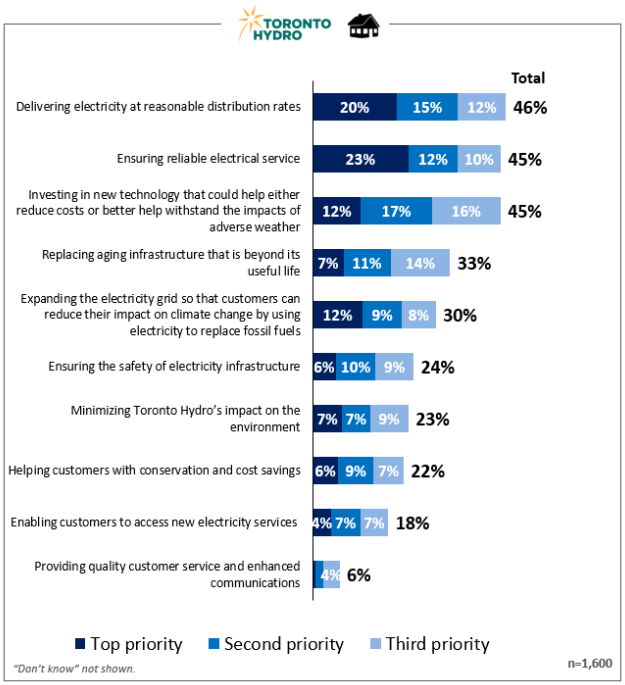
For <u>small business customers</u>, "reasonable rates" was cited as their top priority. Small business customers appeared to be more price-sensitive than residential customers. Reasonable rates stood out as the top priority by a considerable margin compared to other priorities. The next priority was investing in new technology to reduce costs and withstand adverse weather. Reliability was the third highest priority.

For <u>C&I customers</u>, rates and reliability were tied as their top priorities. C&I customers prioritized both rates and reliability, like residential customers. Other outcome priorities were substantially less important to this rate class.

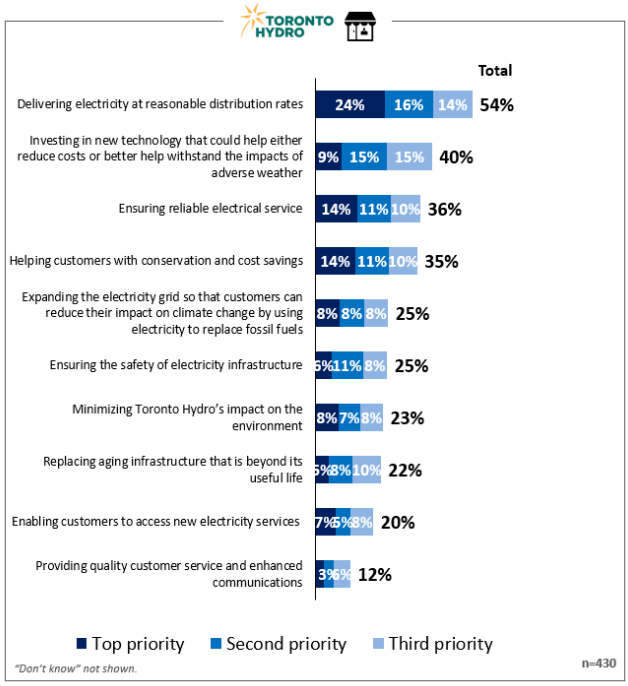
For <u>key account customers</u>, reliability was cited as their top priority. Key account customers prioritized reliability more than any other outcome priorities given their sensitivity to power quality issues. Without reliable electrical service, these customers cannot operate efficiently or safely. Other key outcomes these customers valued was Toronto Hydro's ability to prevent or reduce outage restoration time caused by extreme weather and ensuring safety of the infrastructure. The importance of these other outcome priorities appeared to be related to a need for reliable services so these customers can carry on their operations with minimal disruptions. Other priorities were substantially less important to Toronto Hydro's key account rate class.

The charts below detail outcome priorities across Toronto Hydro's rate classes.

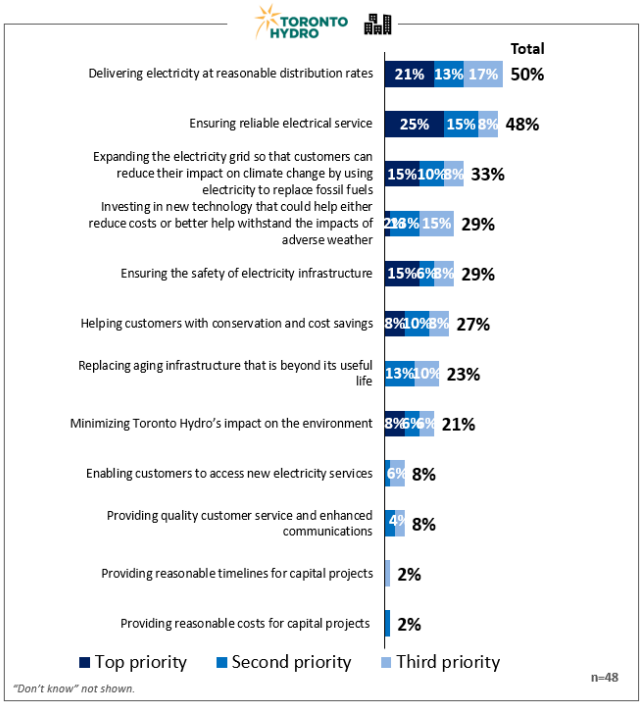
Residential



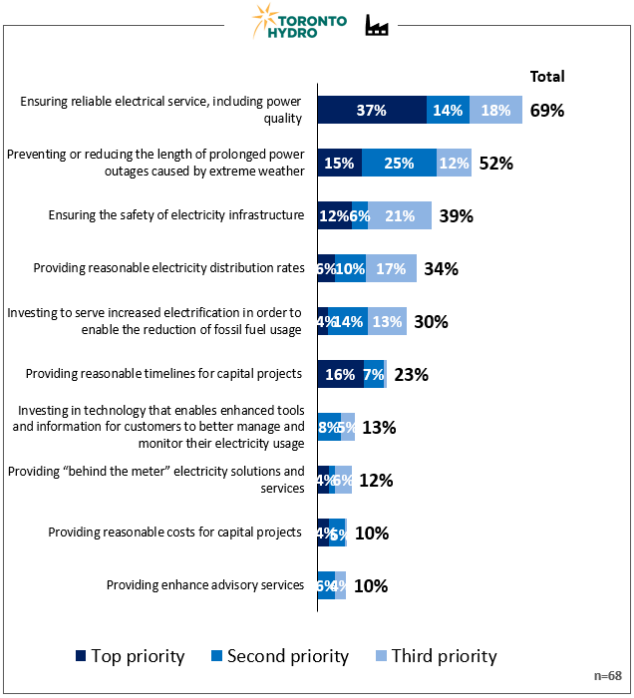
Small Business



Commercial & Industrial



Key Accounts



In addition to identifying top customer needs and general priorities, other preferences around **reliability**, **grid modernization**, **climate action** and **social equity** were measured.

Prioritizing Reliability Investments

In terms of prioritizing reliability investments, residential and small business customers were primarily interested in reducing both the length of time and number of power outages caused by extreme weather. C&I and key account customers were less concerned about outages caused by extreme weather and put a greater priority on investments that generally reduce the number and length of regular outages. Key account customers also put relatively high prioritization on improving power quality.

Reliability	Phase I Online Survey Results			
	Residential (n=1,600)	Small Business (n=430)	C&I (n=48)	Key Accounts (n=68)
(%) indicates total percentage by rate class that place specific priority in their top 3 outcomes	**Reduce restoration time in extreme weather (70%)**	**Reduce restoration time in extreme weather (60%)**	**Reduce restoration time (63%)**	**Reduce outages (78%)**
	Reduce outages in extreme weather (57%)	**Reduce outages (57%)**	**Reduce outages (56%)**	**Improve power quality (73%)**
	Reduce outages (56%)	**Reduce outages in extreme weather (56%)**	**Reduce outages in extreme weather (54%)**	**Reduce restoration time (59%)**

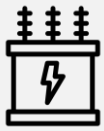
Prioritizing Technology Investments

In terms of prioritizing grid modernization, residential, small business, C&I customers all ranked investments in technologies that reduce customers costs highest, followed by investments in technologies that reduce the environmental impact of Toronto Hydro's operations. Key account customers were not asked these questions.

Grid Modernization	Phase I Online Survey Results			
	Residential (n=1,600)	Small Business (n=430)	C&I (n=48)	Key Accounts (n=68)
(%) indicates total percentage by rate class that place specific priority in their top 3 outcomes	**Find efficiencies and reduce customer costs (79%)**	**Find efficiencies and reduce customer costs (79%)**	**Find efficiencies and reduce customer costs (79%)**	n/a
	Reduce environmental impact of internal operations (56%)	**Reduce environmental impact of internal operations (51%)**	**Reduce environmental impact of internal operations (52%)**	n/a
	Reduce both length and number of outages (54%)	**Help customers better manage electricity usage (50%)**	**Reduce both length and number of outages (54%)**	n/a

Support for Core Investment Priorities

The Phase I customer engagement surveys revealed that a majority of customers support investments in core aspects of Toronto Hydro's distribution system, even if that meant electricity bills would need to increase.

Investment Trade-off (% total support)		**Residential** (n=1,600)	**Small Business** (n=430)	**C&I*** (n=48)	**Key Accounts** (n=68)
	**System Renewal** Toronto Hydro should invest what it takes to replace the system's aging infrastructure to maintain system reliability.	**76%**	**69%**	**79%**	**87%**
	**General Plant** Toronto Hydro should make the investments necessary to ensure its staff have the equipment and IT and computer systems they need.	**68%**	**59%**	**56%**	**68%**
	**System Capacity** Toronto Hydro should proactively invest in system capacity to ensure customers in high growth areas do not experience a decrease in reliability.	**66%**	**61%**	**73%**	**82%**

***** Interpret C&I results as directional due to small sample size.

Support for Grid Modernization

The **Canadian Net-Zero Emissions Accountability Act**, which became law on June 29, 2021, enshrines in legislation Canada's commitment to achieve net-zero emissions by 2050. Toronto Hydro's shareholder, the **City of Toronto**, has set even more ambitious targets to reduce community-wide greenhouse gas (GHG) emissions in Toronto to net zero by 2040 – 10 years earlier than initially proposed.

Overhauling the City of Toronto's energy infrastructure in a relatively short amount of time represents an unprecedented technical challenge that will cost billions of dollars over the coming decades.

As such, a key component of Toronto Hydro's Phase I customer engagement was to understand customer priorities as they pertain to the energy transition and electrification.

Across all rate classes, customers were supportive of Toronto Hydro exploring investments in new technologies that may increase rates, so long as the benefits of these investments are clearly articulated.

Furthermore, customers were supportive of the idea of Toronto Hydro exploring electrification investments today that help prepare for the future, even if the benefits might not be immediately realized.

Grid Modernization (% total support)		**Residential** (n=1,600)	**Small Business** (n=430)	**C&I*** (n=48)	**Key Accounts** (n=68)
	**System Enhancements** If Toronto Hydro is clear about the cost to customers and the potential benefits, they should explore new technologies that would make the system better, even if it could increase customer rates.	**63%**	**59%**	**75%**	**76%**
	**Future Benefits** If Toronto Hydro is clear about the cost to customers and the potential benefits, they should explore new technologies that might not provide immediate benefit but will in the future.	**71%**	**67%**	**73%**	**78%**

***** Interpret C&I results as directional due to the small sample size.

Support for Climate Action

A key part of the City of Toronto's "**TransformTO Net Zero Strategy**" requires switching from gasoline in the transportation system and natural gas in home/building heating to electricity-powered alternatives, adopting more distributed energy resources (DERs) and using energy storage systems.

These initiatives will require Toronto Hydro to expand and modernize its existing electricity distribution grid to ensure that it can help achieve the City's targets.

Another key component of Toronto Hydro's Phase I customer engagement was to understand customers' willingness to pay more to help meet future emission reduction targets and support financial assistance programs for low-income customers.

Nearly half of all Toronto Hydro customers (and a majority of key account customers) said they support a specific charge on their monthly bill to help Toronto meet its future emissions targets, even if their electricity bill grows by between 2.5% and 10% a year for the next 10 years (5% for C&I and key accounts).

Customers were split on whether they would be willing to pay more to provide financial assistance to make electricity bills more affordable for low-income customers.

It should be noted that an estimated 64% of Toronto Hydro's key account customers had "net zero" targets or carbon reduction initiatives in place at the time of this survey in early 2022.

Climate Action (% total support)		**Residential** (n=1,600)	**Small Business** (n=430)	**C&I*** (n=48)	**Key Accounts** (n=68)
	**Electrification** Support for a specific charge on monthly bill to help Toronto **meet its future emissions targets** if your electricity bill will grow by… *2.5% to 10% annually / 5% for C&I and key accounts*.	**48%**	**47%**	**44%**	**53%**
	**Social Equity** Would you be willing to **pay an extra few dollars per month** for Toronto Hydro to provide financial assistance to make electricity bills more affordable for low-income customers?	**41%**	**42%**	**52%**	**N/A**

* Interpret C&I results as directional due to the small sample size.

Delivery of Phase I Findings

The findings from these surveys are also summarized in the *"Customer Engagement: Needs and Preferences Planning Placemat"* (see **Appendix 7.0**) which was shared with Toronto Hydro planners, so that customer feedback could be considered by them as an input in the early stages of the planning process.

Phase II: Presenting Choices within the 2025-29 Draft Plan

Following the findings of Phase I, Toronto Hydro began developing a draft plan to align with identified customer needs, preferences, and expectations. Toronto Hydro engaged again with INNOVATIVE to design, execute, and document the results of a second customer engagement based on that plan.

The purpose this second phase of engagement was to:

1. Solicit customer feedback on key investment areas based on pacing and bill impact.
2. Assess overall social permission for the draft plan.

Customer Engagement Approach

INNOVATIVE worked with Toronto Hydro to understand the utility's draft plan, where there was optionality within the plan, and what implications these decisions would have for customers, including service levels and overall cost. In late 2022, the draft plan was then translated into engagement materials that a typical customer could understand. INNOVATIVE developed a workbook survey and tested it through a series of focus groups and one-on-one interviews. The survey was then made available to all customers in the spring of 2023.

Using workbook surveys, customers were re-engaged to solicit customer feedback on Toronto Hydro's draft plan and explore specific trade-offs in relation to seven key investment areas and the associated bill impacts, as well as the pacing and prioritization of investments.

The following section summarizes customer feedback from this online survey among residential, small business (GS<50 kW), commercial and industrial (GS 50-999 kW), and key account customers.

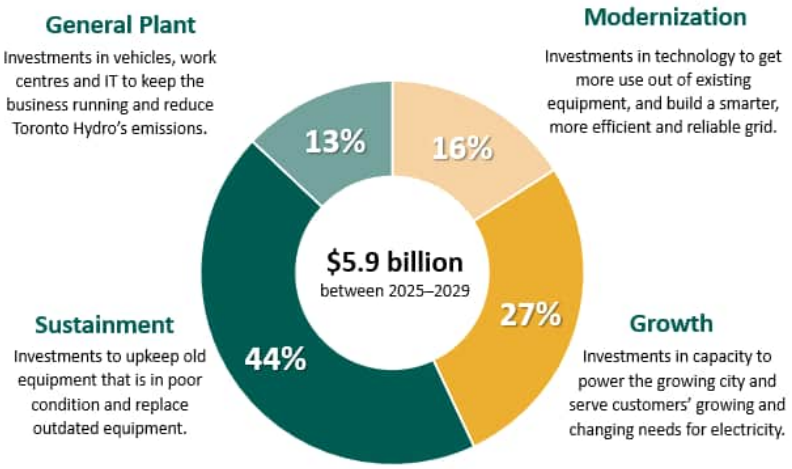
Key account customers consist of GS 1,000-4,999 kW customers with either a single account, or multiple accounts (which together constitute large load volume) and large use customers with demand of 5,000 kW+.

The graphic below summarizes the sample sizes of this engagement by rate class.



Core Investment Categories

Toronto Hydro's 2025–2029 draft plan was made up of four spending categories: *Modernization, Growth, Sustainment,* and *General Plant*.



Within these four categories, customers were asked to make choices on trade-offs consisting of seven key investment areas:

		Sustainment:	*General Plant:*
1. Modernization	**2. Growth**	**3. System Reliability**	**6. Running the Business**
		4. Grid Stewardship	**7. Decarbonization**
		5. Standardization	

Social Permission

An average of 84% of customers, across all rate classes, gave Toronto Hydro social permission to proceed with its draft plan.

These customers provided social permission by indicating either:

1. They think Toronto Hydro should accelerate spending beyond the level in the draft plan to deliver better system outcomes.
2. They support the proposed rate increase that is reflected in the draft plan, or
3. They feel that the proposed rate increase in the draft plan is necessary, even though they don't like the proposed increase.

Together, these three customer choices constitute what we define as "social permission".

Overall Social Permission by Rate Class

Rate Class	Residential	Small Business	C&I	Key Accounts*	Average across rate classes
Sample Size	n = 32,187	n = 695	n = 264	n = 52	
Proposed Rate Impact (increase by 2029)	$17.18	$50.88	$870.85	$7,480.60 (KA) / $39,221.50 (LU)	
Accelerate Spending	18%	14%	15%	26%	18%
Support Proposed Plan	24%	24%	23%	38%	27%
Necessary to Maintain Grid	38%	39%	44%	32%	38%
Scale Back Plan	14%	16%	11%	3%	11%
Don't Know	6%	7%	7%	2%	6%
Social Permission (Accelerate + Support + Necessary)	**80%**	**77%**	**82%**	**96%**	**84%**

* "**Key Accounts**" customers consist of GS 1,000-4,999 kW customers with either a single account, or multiple accounts (which together constitute large load volume) and large use customers with demand of 5,000 kW+.

In addition to assessing the level of social permission customers gave to Toronto Hydro's draft plan, the survey also gauged customer preferences on specific trade-offs within the seven key investment areas. Within each investment area, customers had a range of different preferences around the draft plan. To provide a general direction of customer preference for each investment area, customer responses were grouped to **three** categories depending on the degree to which they would like to dial the draft plan up or down. The three categories were: Above Plan, On Plan, and Below Plan. The definition of these categories is detailed in **Appendix 8.0**.

At a high-level, customer preferences on specific trade-offs can be summarized as follows:

- A majority of **key account customers** felt Toronto Hydro should spend on plan or above plan within each of the seven key investment areas. For **residential customers**, either a majority or near-majority felt Toronto Hydro should spend on plan or above plan within the seven key investment areas. The percentage of customers indicating Toronto Hydro should spend on plan or above plan, within the seven key investment areas, was somewhat lower among **commercial and industrial customers**, and lowest among **small business customers**.
- Customers were generally in-line with Toronto Hydro's draft plan (on plan), or in some instances preferred a higher level of spending (above plan), in the areas of **Modernization**, **Stewardship** and **Standardization**.
- Spending preferences were relatively lower in other areas: **Growth**, **Reliability**, and **General Plant** investments (including **Running the Business** and **Decarbonization**).

The detailed results by rate class can be found in **Appendices 9.0** to **12.0**.

While customers who opted for dialing the draft plan up were more likely to give social permission to the draft plan and vice versa, it is worth exploring the level of social permission from customers who opted for dialing the draft plan *down*.

The tables below show the level of social permission received from customers in the three categories (Above Plan, On Plan, and Below Plan) for each investment area. The results across rate class showed that:

- A vast majority of customers regardless of rate class who preferred dialing the draft plan up (in the above plan category) gave social permission to the draft plan.
- Similarly, a large majority of those who opted for the draft (in the on plan category) also gave social permission to the draft plan.
- While the level of social permission received among customers who preferred dialing the draft plan down (in the below plan category) was the lowest of the three categories, a majority of customers from this category nonetheless gave social permission for proceeding with the draft plan (in that they still felt the rate increase was necessary). This holds true across all rate classes.

Residential

Social Permission (%)	Three Categories of Customer Preference		
	Above Plan	On Plan	Below Plan
Overall Social Permission		**80%**	
Modernization	95%	91%	62%
Growth	96%	94%	69%
Reliability	95%	93%	69%
Stewardship	94%	90%	62%
Standardization	94%	92%	65%
Running the Business	96%	94%	69%
Decarbonization	94%	92%	68%

Small Business

Social Permission (%)	Three Categories of Customer Preference		
	Above Plan	On Plan	Below Plan
Overall Social Permission	**77%**		
Modernization	94%	89%	64%
Growth	96%	91%	69%
Reliability	95%	91%	69%
Stewardship	91%	89%	63%
Standardization	90%	91%	64%
Running the Business	88%	95%	68%
Decarbonization	90%	89%	68%

Commercial & Industrial

Social Permission (%)	Three Categories of Customer Preference		
	Above Plan	On Plan	Below Plan
Overall Social Permission	**82%**		
Modernization	91%	85%	75%
Growth	88%	93%	76%
Reliability	86%	92%	77%
Stewardship	89%	91%	73%
Standardization	93%	90%	73%
Running the Business	98%	92%	75%
Decarbonization	91%	95%	75%

Key Accounts

Due to the small sample size of key account customers as well as the high level of social permission to the draft plan, the study did not divide key account customers into segments based on their spending preferences to explore the connection with the level of social permission.

LEAP Qualified Residential Customers

While lower than the average residential customer, 72% of Low-income Energy Assistance Program (LEAP) qualified residential customers gave Toronto Hydro social permission to proceed with its draft plan.

The level of social permission was similar among customers who did not disclose their household income after tax and household size in the survey.

The level of social permission among residential customers whose household income after tax is less than $52,000 but who do not qualify for LEAP are on par with the residential customers overall.

Social Permission by Residential Rate Class

	Residential Overall	LEAP Qualification			
		LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
Accelerate Spending	18%	16%	14%	22%	11%
Support Proposed Plan	24%	18%	25%	28%	18%
Necessary to Maintain Grid	38%	38%	40%	36%	41%
Scale Back Plan	14%	16%	14%	11%	21%
Don't Know	6%	13%	7%	3%	9%
Social Permission (Accelerate + Support + Necessary)	**80%**	**72%**	**79%**	**86%**	**71%**

Delivery of Phase II Findings

Following Phase II, findings from this phase were provided to Toronto Hydro so they could be considered in finalizing the draft plan.

Customer Engagement Coverage & Enhancements

The following section provides details on the expanded coverage and enhancements applied in Phase I and Phase II of Toronto Hydro's customer engagement.

Comparing Coverage to Previous Customer Engagement

The number of completed workbooks tripled compared to the last customer engagement among residential and small business customers, resulting in approximately 33,000 completed workbooks.

C&I customers were not surveyed online in the last engagement. As such a comparison was not made.

While the number of completed workbooks might seem relatively low among key account customers (n=52), it represents 16% of the key account customer base. Both the number of completed key account workbooks and the response rate have increased over 40% compared to the last engagement.

Rate Class	Current Engagement	Change of Complete Rate from last Application	Last Engagement	
	Online		Online	Telephone
Residential	n=32,187	↑ 217%	n=10,165	n=600
Small Business	n=695	↑ 284%	n=181	n=215
C&I	n=264	n/a	n/a	n=202
Key Accounts	n=52 (16% response rate)	↑ 41%	n=37 (11% response rate)	n/a

Enhancements to Toronto Hydro's Customer Engagement

New elements in Toronto Hydro's customer engagement included:



Reference surveys: To prepare for a shift from a telephone-centric engagement with low-volume customers to an online methodology, INNOVATIVE introduced two concurrent surveys; one using a telephone and the other an online methodology. This exercise was to better understand the composition of the customer base and to ensure the results of online surveys were representative of the customers.



Video narratives: A series of overview videos were embedded in the online workbook to help explain complex subjects, such as electrification and investments in modernization.



Investment categories: Toronto Hydro organized its plan around four investment categories. Within these categories, the survey further specified seven key areas to help customers make choices. These investment areas were designed to solicit feedback about customer preferences and trade-offs between price and other key outcomes.



Total impact of investment categories: The seven investment areas presented the total 5-year draft plan including both capital expenditures and operating expenses. This way the engagement was able to connect the bill impact to each of the seven investment areas in a transparent fashion. Traditionally, the engagement focused on capital expenditures only.



Customer outcomes: When soliciting feedback about customer preferences, the survey laid out how the size of investments connected to outcomes in a grid format. Each of the seven key investment areas had a description of multiple outcomes. This grid layout allowed customers to better understand the trade-offs between price and the different outcomes in a clear and meaningful way.



Scaled responses: For each key investment area, the survey provided customers with a sliding scale that gave customers flexibility to dial the draft plan up or down to indicate their preference between price and outcomes.



Dynamic bill calculator: Customers were able to see changes to their bill in real-time based on their selections. This allowed customers to build a bill that better reflected their preferences and priorities relative to the draft plan.



Enhanced participation: A more extensive effort was made to increase participation in the online survey. These efforts included using the latest customer list and encouraging participation by having Toronto Hydro widely promote the survey through both internal and external communications channels. As part of the promotion of the survey, creative incentives were used to help increase response rates. This resulted in over 33,000 completed workbooks (over three times as many completed workbooks from the 2020 Rate Application customer engagement).

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro. The conclusions drawn and opinions expressed are those of the authors.

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CONFIDENTIAL

APPENDIX 01

Phase I

Customer Engagement

Qualitative Research

November 2, 2023

STRICTLY CONFIDENTIAL

Customer Engagement

2025-2029 CIR Application

November 2, 2023

Confidentiality

This Report and all of the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of Toronto Hydro Electric-System Ltd. (THESL).

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for THESL. The conclusions drawn and opinions expressed are those of the authors.

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1. Introduction

Innovative Research Group Inc. (INNOVATIVE) was engaged by Toronto Hydro in 2021 to design, execute, and document the results of its customer engagement, as part of Toronto Hydro's Rate Application to the Ontario Energy Board (OEB) for the years 2025 to 2029.

The primary goal of Phase I focus groups and the interviews was to explore customer needs and preferences with regards to the electricity service they receive from Toronto Hydro. This research also identified gaps in the services and experience customers want and the services they are currently receiving.

As part of this engagement, a series of focus groups was held among Toronto Hydro Low-Volume customers (e.g. residential and small business customers) in November 2021 and among commercial and industrial (C&I) customers in December 2021 via the Zoom videoconference platform. A series of in-depth interviews was also held among Toronto Hydro key account customers in December 2021 and January 2022, also via Zoom.



Focus Group Structure

The focus groups were facilitated by a trained moderator and followed a structured discussion guide. All groups began with a discussion about what Toronto Hydro does, Toronto Hydro's share of customers monthly electricity bill, and how Toronto Hydro fits into Ontario's electricity system. To aid in that discussion, a handout was used and displayed to customers through screensharing (see *Section 5: Focus Group Stimulus*).

Customers were then asked about their level of satisfaction with Toronto Hydro's services, and what Toronto Hydro could do to better serve them as their electricity distributor. The groups went on to discuss what it means for Toronto Hydro to be doing a good or bad job.

Customers from the first two nights were asked to think about future challenges that will face Toronto Hydro. A list of planning challenges was also shown to customers. However, given there was a significant overlap between this discussion and the following one about outcomes, this discussion was subsumed as part of the outcomes discussion with the remaining groups.

The groups then moved on to discussing key outcomes they expect from a utility. A list of outcomes was provided to facilitate the discussion. This led into a discussion of trade-offs, including whether

customers would be willing to pay more to help Toronto Hydro prepare for future needs and challenges.

This report summarizes key findings and offers observations. Respondent verbatim responses are in italics. In general, our approach in reporting is to allow the respondents to be heard as much as possible, utilizing representative verbatim comments, offering interpretation and comment where necessary.

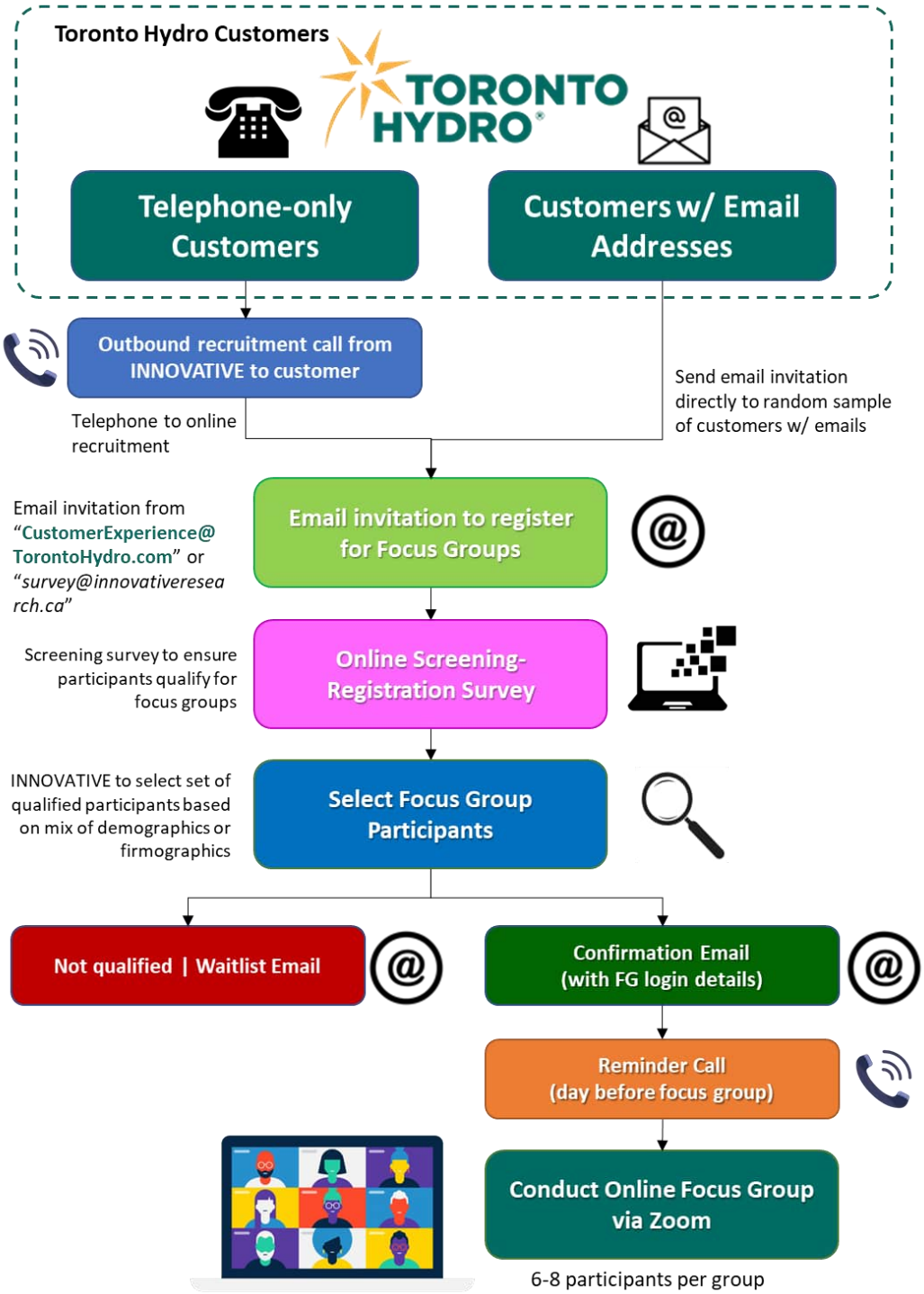
Interpreting Focus Groups and Interview Findings

Qualitative research does not hold the same statistical reliability or representativeness of quantitative research. It is an exploratory research technique that should be used for strategic direction only.

In focus group research, the value of the findings lies in the *depth* and *range* of information provided by the customers, rather than in the *number* of individuals holding each view. References in this report such as "most" or "some" customers cannot be projected to the full population. Only a large sample, quantitative survey would be accurately projectable to the full population.

Qualitative Research Customer Recruitment Process

Low-volume and C&I customers were randomly recruited to participate in the focus groups using both telephone and email methodologies as illustrated in the diagram below. Key account customers were recruited exclusively via email invitations from a list of customers provided by Toronto Hydro.



2. Low-Volume Customer Focus Groups

2.1 Methodology

Eight focus groups were held with low-volume customers (residential and small business customers) from each of the following areas below.

Date	Focus Group Times	Number of Participants	Customer Type	Service Area
November 18th, 2021	5:00 pm – 7:00 pm	6 participants	Small business	Etobicoke/ York
	7:00 pm – 9:00 pm	7 participants	Residential	
November 22nd, 2021	5:00 pm – 7:00 pm	6 participants	Small business	North York
	7:00 pm – 9:00 pm	9 participants	Residential	
November 23rd, 2021	5:00 pm – 7:00 pm	8 participants	Small business	Scarborough
	7:00 pm – 9:00 pm	7 participants	Residential	
November 24th, 2021	5:00 pm – 7:00 pm	6 participants	Small business	Toronto/ East York
	7:00 pm – 9:00 pm	6 participants	Residential	

Participants were recruited randomly over the phone and by e-mail, using customer lists provided by Toronto Hydro. Small business participants received a $150 cash incentive as compensation for their time, while residential customers received $100.

2.2 Key Findings

Customers were vaguely familiar with the role Toronto Hydro plays in Ontario's electricity system.

Most customers were able to identify that Toronto Hydro is responsible for electricity distribution. As part of operating the distribution system, maintenance of infrastructure was mentioned in most groups. Only a few customers had a more detailed understanding of Toronto Hydro's role within Ontario's electricity system.

Furthermore, customers were unfamiliar with the Ontario Energy Board (OEB), and the rate application process that regulated utilities must go through. Most were not aware that the OEB regulates electricity prices in Ontario, including Toronto Hydro's rates.

Most customers expect reliable electricity first and foremost.

When asked about their current needs and expectations regarding their electricity service, the main topic that arose unaided was reliability. Furthermore, customers mentioned a desire for lower electricity bills, followed by improved customer service.

Customers who are more dependent on electricity were not willing to sacrifice their service; these customers prefer Toronto Hydro to be focused on maintaining infrastructure in order to sustain or improve reliability, regardless of a rate increase. Only a few were willing to have less reliable service in exchange for a rate reduction.

Most customers are supportive of additional measures to support electrification and fight climate change.

When talking specifically about measures to prepare for electrification, most were willing to pay more on their bill, although there were also those who were less willing to pay more for this purpose. Small business customers were more likely to say they shouldn't be the ones paying more.

2.3 Detailed Findings

2.3.1 General Awareness

Most participants were aware that Toronto Hydro delivers electricity. As part of operating the distribution system, maintenance of the distribution infrastructure was explicitly mentioned in most groups. Only a few were also aware that Toronto Hydro is not responsible for producing electricity and how Ontario's electricity system works at a high level.

> *"So essentially, it's ensuring delivery of electricity to homes. It's billing its service and maintenance of those lines."*

> *"I don't think Toronto Hydro produces electricity. I'm not totally sure on the structure. But I know, there's like the Bruce Power, the people who generate the power, and then it flows through lines by maybe Hydro One, and then all the individual utilities distribute the power amongst whatever regions they have."*

However, there was some confusion among participants with respect to the specific role Toronto Hydro plays in Ontario's electricity system. Some participants were unsure if Toronto Hydro is also responsible for the generation of electricity.

> *"I don't think that Toronto Hydro generates. I'm not sure, I have no idea about that. They could or they could not, I have no idea."*

Having explained how Toronto Hydro fits into the electricity system in Ontario and shown how the payments they make to Toronto Hydro are allocated to the electricity system (see Section 5 for the information shared), there was still confusion over Toronto Hydro's ownership structure and revenue expectations. Concerns were raised about how much profit the utility could make and where it was being allocated.

> *"The whole Toronto Hydro system, is it a private company or something or is it government funded?"*

Furthermore, most participants were unfamiliar with the Ontario Energy Board (OEB), and the rate application process that regulated utilities must go through. Most were not aware that the OEB regulates electricity prices in Ontario, including Toronto Hydro's rates.

> *"Who regulates Toronto Hydro? Hydro One? OPG?"*

2.3.2 Needs and Expectations

Satisfaction levels

Having discussed the role Toronto Hydro plays in the electricity system and what they pay for to the electricity system, participants were asked about their current satisfaction level regarding their electricity service. Most participants were satisfied with the services. They were generally satisfied with reliability and customer services.

> *"Just like having said my lights turn on when I turn on the switch, I haven't had any issues. I've had to deal with them on the phone. They are okay. They're pleasant. No problem so far."*

However, some participants had concerns with reliability, communication related to outages, customer service more broadly, and cost.

Reliability

Reliability was the top need that came up unaided across all groups. Generally, participants were satisfied with reliability, and expected that to continue or be improved. Some also pointed out that they had noticed improvements in reliability and restoration times recently.

> *"I think the diminishing frequency of [outages] makes us more satisfied. And seeing when there are outages, even if it's not in my own neighborhood, seeing how dedicated the teams are to get everyone online… I think that increases satisfaction as well showing that you're valued as a client."*

Having said that, some participants noted specific problems with reliability, especially in particular neighbourhoods compared to others.

> *"I have to say that I'm not happy at all. Over here, where we are right now, the quality of the service has been awful, right from the start. And I find that almost everything of importance in this place is running on a battery backup because otherwise, it's just not good."*

> *"I feel like on a big kind of winter storm, windstorm, [the electricity] kind of flicks in and out. Especially working from home the last couple of years, I just want to make sure that we could really rely on it, but the power in my neighborhood flicks on like in the last month, three or four times."*

Communication

On the outage front, participants expressed a range of satisfaction levels. Many were quite happy with the speed at which outages were resolved. Some participants also found the outage map on Toronto Hydro's website useful. It provides key information and updates about restoration times during outages.

> *"I really like that online, you could just look at the map, like the outage map, and it's pretty accurate."*

However, a significant portion of the customers were dissatisfied with the level of communication on updates during outages, especially by phone. Difficulty getting in touch with Toronto Hydro during outages was a common issue.

> *"When we immediately called, at first there was no knowledge of what happened, which is understandable. Yeah, and it took probably about half an hour before we got any satisfaction in terms of yes, the power in your particular block is gone."*

Customer Service

Some participants mentioned concerns with long response or wait times to receive services and the right information. This was a particular concern for small business customers.

> *"Getting a new connection is a really big headache, especially if it has to be a high voltage service. We waited almost five, six weeks to get a new connection, which is I think, very slow… also, for a business like us where we are trying to compete with other businesses, time delay is gonna cost us a lot. I mean, we pretty much lost a client… I don't understand why we had to wait for three weeks to get 20 minutes [of work]."*

Cost

The other top issue mentioned was the cost of electricity. Many were concerned about the rising electricity bill. For some participants, the priority was to keep cost as low as possible, even if that would mean lowering expectations for power quality and reliability.

> *"You know, I've watched my bill climb steadily over the last years. This is something that I find alarming."*

> *"They could probably cut costs. I live in an area where I've never had an issue with any power outages or anything of that nature. [When asked if they would be willing to have an outage or two if they could reduce their bills] Yeah, I don't see it being the end of the world. That wouldn't be an issue for me. I don't spend a lot of time using a lot of electricity. I'm not on a computer. I don't work from home. I don't have kids. I wouldn't see it as a problem… If you're gonna have an outage in January, February, when it's freezing, it probably wouldn't be ideal. But I'm sure there's way that they can cut costs."*

2.3.3 How Toronto Hydro can serve its customers better

When asked how Toronto Hydro could serve them better, participants tended to follow up on issues that they first mentioned when asked whether they were satisfied or dissatisfied, especially on cost and customer service. The topic of reliability was mentioned by fewer participants relative to cost and customer service.

New issues such as billing and concern for the environment emerged in this discussion. Some customers expected a better billing experience and Toronto Hydro to help customers make more environmentally conscious choices.

Cost

Reducing the cost of electricity was mentioned in most of groups. Some felt Toronto Hydro can help them find efficiencies, provide tools to monitor their usage, and provide information to compare different billing methods to keep their costs low.

> *"As a business owner, or as even if a consumer it comes down to the bottom line, how can we reduce that number on our bill. There's many ways about it. There's both responsibility of the user, the consumer, and also, hopefully, programs and campaigns on Toronto Hydro's side, for example recommendation on how to reduce your energy consumption."*

> *"I think if they were more transparent about how individual families could cut costs, I think that's particularly important in like going through COVID, and people working from home where I'm sure people's electricity bills have gone up, because of increased daytime usage, etc.*

So, if there were more transparent ways [to see] what your usage is and how you could do things, I think that could make a big difference."

"I can suggest that given that there's an option for time of use and tiered rates, why doesn't Hydro just come out and do a comparison from each of us. Tell us which is more beneficial, as opposed to making us do all the work. My suspicion is that we've been using less electricity as a result of the efficiencies, the bulbs, the awareness of when time of use is cheaper, but at the same time, the bills are still going up higher. And that doesn't seem to make a lot of sense."

While suggestions to cut costs were made, one participant expressed appreciation of how Toronto Hydro helped their customers manage their bills during the pandemic by providing different pricing options.

"I like how they provided us a means of, either you can choose a flat rate that's higher and just stick to that, or during the COVID they came up with some innovative billing methods."

Customer Service

Participants mentioned concerns with customer service in terms of response times and the information they received.

"I think they need to have a better communication, because whenever we try to reach out for anything, it was hard to get response… As a business owner, we have other things to take care of. At the same time, we should not be spending more time trying to reach out and it's not easy to reach out to somebody over the phone when they are working from home. My operations manager, she spent at least easily every day, almost two to three hours on the phone, trying to get answers. So that's a lot of our spending on something which we should not."

Many small business customers also expressed a desire for Toronto Hydro to communicate with them more proactively and more transparently. They felt the conversations can help Toronto Hydro better understand their customer needs and the neighbourhoods they serve.

"Toronto Hydro could build something where they get to understand us as customers more. There should be a [method] where it will help them decide when to shut an area down to upgrade. So, you're not hurting the people that are paying the bills."

Reliability

Only some participants mentioned reliability as an area for improvement. To protect themselves from service interruption, some small business customers would be willing to pay more to trade reliability. One participant even reported a desire to pay into a plan that could mitigate loss during outages.

"I'd love to be able to pay into an insurance plan. I don't mind it being on my electric bill, if there were a possibility… that they were allowed to start a fund [that would help businesses in unexpected times of need]. I have no problem with that as a business person."

Billing

A few customers mentioned a need to improve their billing experiences, from the ease of accessing their bills to paying their bills online.

> *"Alternative methods of payment would be great. Instead of the sort of direct debit they have currently... You don't have to [use credit card] if you don't want to, and if you do you pay the cost."*

> *"I know for preauthorized debit, you still have to fax that form in, which is, given the fact it's 2021, you know, not the most ideal thing."*

Environment

There were several mentions of expecting Toronto Hydro to help customers make more environmentally conscious choices.

> *"Toronto Hydro should encourage people to use natural gas less either by marketing, or just like giving affordable services."*

> *"I know some people that want to get an electric vehicle, but they don't have a driveway. And they don't have a garage so they can't charge at home. I'd love to see them do what city of London does, where they have charging stations in the neighborhoods, maybe every fifth or sixth home, and then people can, you know, reserve that spot and charge once a week."*

2.3.4 Outcome Priorities

When asked what outcomes would determine whether Toronto Hydro was doing a good versus bad job, main topics that came up unaided were reliable electricity services, keeping cost low, good customer service, efforts to prepare for climate change, and a transparent billing system.

Reliability

Reliability was the top outcome that came up unaided across all groups. Generally, participants were expecting continued or improved reliability. This includes an expectation of fewer outages and faster response times when an outage does occur.

> *"There [are] no power outages, especially here. We need the fridges on all the time. And if there is any power glitches or anything that is resolved right away."*

> *"If they're reliable, that is half the game. I have to say Toronto Hydro is pretty reliable."*

Cost

The other top issue mentioned in all groups was the cost of electricity. Some participants had also suggested looking for Toronto Hydro to provide tools and information to help customers better manage their energy usage and find efficiencies.

> *"I'm just looking for information on ways we can reduce the bill, everything comes back to the bill as a consumer."*

> *"I think, in line with affordability. I would like to see more incentives offered to allow people to find ways of paying less. I think at one point, there were some monitoring devices that were given to households, so that we can monitor usage throughout the day. Also, to measure some of the appliance usage… I think more of that would be known."*

Customer Service

Although participants mentioned customer service less frequently than reliability and affordability, it was still cited as a desirable outcome, especially among those that had experienced issues in the past.

> *"[Good customer service for me means that Toronto Hydro would] actually have a solution for the issue, or if not, if, like, if they didn't have a solution then to have like a clear timeline of how to resolve the situation or when they would be able to get an answer."*

Environment

There were several mentions of expecting Toronto Hydro to consider the impact of, and prepare for, climate change and extreme weather events.

> *"The drive towards sustainability, energy conservation. That's important. Their continuous effort and sense of not just building the infrastructure maintaining but also future thinking in terms of what could potentially be an issue over the next coming years as far as what's we're seeing in BC and all these disasters around the world, the ability to at least prepare for such events."*

Several participants mentioned focusing on incentives and rebates for upgrading their buildings and equipment to be more sustainable.

> *"[I would like to see] incentives for business clients who want to switch to solar energy, or some kind of other alternative sources and whatnot. And I want to see better kinds of plans…to help people to shoulder those expenses."*

When asked if participants were willing to pay more to focus on climate action, most participants were open to the idea with the hope that this will improve the electricity system as a whole and lower the costs for customers in the long run.

> *"Absolutely. I would be willing to pay more. Because I believe that there's long term gain. So, if multiple companies or buildings put solar panels in and collected electricity in the walls, and that was distributed, I think that would help small businesses, or even residents."*

Billing

A few participants expressed an interest in learning more about where their money is going. They would like to receive more education on their billing. Some felt the reduction in usage but an increase in their bill left them feeling Toronto Hydro was not transparent about their operation.

> *"I like transparency. Where is my money actually going? I know that you showed us that pie chart. But I didn't really know that before. I don't think It's on my bill. I see, like, all these explanations of things I don't understand. And then my little graph of how much I spent last year versus this year, I'm like, oh, I've gotten better, but my bills are still high. So, what am I actually paying for?"*

Enabling New Technology

When prompted with a list of possible outcomes Toronto Hydro can focus on (see Appendix 4 for the information shown), many participants expressed that upgrading general equipment and enabling new technologies were outcome priorities. This was most commonly expressed as a long-

term goal that would help with not only reliability and affordability, but also with climate change and the energy transition.

> *"I would put [my number one choice] into enabling new technology, because I think it feeds back into both reliability and affordability."*

> *"Enabling new technology, I feel like it's… a long-term goal, especially with our current climate."*

Helping to address social issues

Many participants expressed the preference for addressing social issues, such as to provide subsidies for lower income families and struggling businesses.

> *"Especially with the pandemic, where small businesses were given a chance to apply for subsidies, I think that that model, I think could totally work if let's say somebody or household had a certain amount of income."*

When asked how such a rate relief program should be executed, many had a preference for Toronto Hydro running such a relief program, but a sizable group of participants felt this responsibility lies within the government and Toronto Hydro should focus on distributing electricity.

> *"I'm a little bit on the fence about the last one helping to address social issues. From my point of view, these are social issues, that's why we have the Government of Ontario."*

> *"I think Toronto Hydro should mainly concentrate on working, getting reliable connections."*

2.3.5 Trade-offs: Reliability vs. Cost

After prompting participants with possible outcomes, the discussion led to two major trade-offs. One of the two trade-offs is between reliability and cost. It's about whether customers are willing to pay more for reliable electricity or not.

Some participants raised the importance of reliability over lower cost unprompted. They would rather pay more to get reliable power.

> *"For me, I think reliability is the major one. Because having power supply continuously makes more difference than whether it's cheap or not. I mean, even if I end up paying a little more, if I have 100 percent electricity, that's what I look for."*

When asked if participants would trade lower rates for reliability, most were unwilling to trade less reliability for lower rates; only some participants expressed a desire for lower rates.

> *"For me, reliability is number one, and affordability is number two. Because this is coming in store. And if there's no power, that's a big issue for me. I lose business or even losing money directly from something melting."*

> *"I mean if you can have uninterrupted connection then I don't mind paying a little bit more. Because if power goes down, my entire business goes down. So, if I'm losing money on something I'd rather pay upfront and be 100% secure."*

> *"Affordability. You know what, in this time with everything, the inflation rate, everything going up. Trying to try to keep the business going and to keep the bottom dollar in check."*

When further probed on whether Toronto Hydro's equipment should be run 'to failure' more often, or regularly maintained, even if there is nothing wrong with it, most customers opted either for

preventative maintenance or for finding a balance between being preventative/safe and keeping costs low.

> *"For me, reliability is key. So [being] proactive, that preventative maintenance angle is critical for me."*

> *"…don't run it to failure. But don't just replace it too early and spend tons of money on it. Find that optimal [point] where there might be a little bit less reliability, but the chances are pretty low and you'll save a good chunk of money."*

2.3.6 Trade-offs: Investing in the Future vs. Lower Costs Today

The second trade-off is between investing in the future and having a lower bill today. Investing in the future would mean a higher electricity bill today to finance those investment projects. This discussion explored which one is more important to participants.

Some participants raised the importance of investing to prepare for the future unprompted. One small business participant also discussed the importance of pacing the investments to minimize bill impact.

> *"I'm going to go back to the fact that they have under invested in capital hardware… They've tried to put a plan together in the past. I don't know if they have a specific capital plan where they're going to replace 6% of the wires every year for the next decade, whatever. I would like to see a plan where they have targets. We've got a million miles wires in Toronto, and we're going to do 50,000 or 100,000 wires a year or something… Because if they don't, you're gonna wind up having to do 600,000 wires one year, and have a massive extra cost… We're gonna pay one way or the other, I would rather pay a few cents more now than dollars later."*

When asked if Toronto Hydro should think ahead and make investments to prepare for the future even if that means customers will have to pay more today, there was a general consensus that Toronto Hydro should, with some citing innovating and preparing for the future as reasons. Some also envisioned that investing in the future can lead to a host of benefits such as lower rates and shifting to cleaner energy sources.

> *"I think we have no choice. Again, if you want to talk about reliability. Well, without keeping up to date with the infrastructure, you lose reliability."*

> *"Enabling the new technology is the most important because if you allow for that, you're going to enable energy transition, you're going to create a system where hopefully, it'll be reliable. And it also leads to affordability. Because with a reduction for the more efficient and effective use of your resources should lower the price, and at the same time, it enables economic growth, it provides safety, and maybe we could even address social issues such as a carbon footprint."*

Despite this general consensus, some participants still identified maintaining lower costs and sticking to reliability in the shorter term as more important.

> *"I think we need to be practical about things and keep costs low and be reliable. And that's really where it's at."*

When talking specifically about measures to reduce climate change, most customers were willing to pay more.

> *"I'm absolutely in favor of paying more, I think there's a responsibility, I do support, lowering our emissions, encouraging more renewable sources of energy and trying to reduce our carbon footprint and help climate change. I think we have an obligation being Canadian in Toronto being in Ontario to be thought leaders on this."*

However, compared to residential customers, some small business customers are more hesitant when it comes to paying more for climate change measures.

> *"I definitely don't think that something that this is something that I should pay for… there has to be an incentive… and there's no incentive for me."*

3. Commercial & Industrial Focus Groups

3.1 Methodology

Four focus groups were held across two evenings with C&I customers from each of the following areas below.

Date	Focus Group Times	Number of Participants	Customer Type	Service Area
December 1st, 2021	5:30 pm – 7:30 pm	5 participants	C&I	Etobicoke/ York
	7:30 pm – 9:30 pm	4 participants	C&I	North York
December 2nd, 2021	5:30 pm – 7:30 pm	4 participants	C&I	Scarborough
	7:30 pm – 9:30 pm	5 participants	C&I	Toronto/ East York

Participants were recruited randomly over the phone and by e-mail, using customer lists provided by Toronto Hydro. Commercial and industrial participants received a $200 incentive as compensation for their time.

3.2 Key Findings

Most customers are satisfied with the service they receive from Toronto Hydro.

Most customers were generally satisfied with the reliability of the electricity service they receive. However, some experienced an increase in outages over the past few years. Some customers expressed concerns with billing; in particular, the complexity of rates and how they might reduce their bills. In general, customers were satisfied with the customer service they receive.

Most customers expect reliable electricity first and foremost.

The most frequently mentioned priority was reliability. This was also often the first outcome mentioned when customers were asked how to determine whether Toronto Hydro is doing a good job. Customers referred to reliability both in terms of minimizing disruptions but also in terms of getting power back again when there is an issue. One aspect of reliability that was stressed was upgrading equipment to improve reliability and reduce outages. Overall, reliability was prioritized above affordability, with some customers stating they would pay more to have fewer outages.

When it comes to climate change measures, most customers were supportive of shifting to using more electricity.

Most customers were supportive of shifting to using more electricity, although there were some hesitations regarding the cost of their electricity bill. A few customers also expressed concern about the safety and reliability of an electricity system with higher demands than today.

3.3 Detailed Findings

3.3.1 General Awareness

Most participants were somewhat aware that Toronto Hydro delivers electricity and is not responsible for electricity generation, although some were not entirely sure of the specific role Toronto Hydro plays in Ontario's electricity system.

> *"What I see on the bill is delivery. They're not actually the producer, right?"*
>
> *"They're kind of like the middleman. I know a lot of our electricity sometimes is bought from the states wholesale. And then they'll take that and then they'll run it through their systems to power the other homes and businesses around the area that they're servicing. That's their job and to make sure we have a reliable connection and to provide us with any support that we need or anything that goes down to make sure that that's all being repaired."*

Understanding of how their payments to the electricity bills are allocated is limited. However, one participant was aware that Toronto Hydro collects payment for the entire electricity system unaided.

> *"I know you guys basically distributing the [electricity], managing the infrastructure so that you can distribute electricity from the generator to the end users. So more, you manage and maintain the infrastructure, but you do not generate electricity. And you basically pass along the cost of the customer, but you don't technically make a profit when you're selling electricity."*

Having shared how Toronto Hydro fits into Ontario's electricity system and how their payments are allocated to the electricity system (see Section 5), a few participants felt there is an opportunity to learn more.

> *"I had no idea that only 6% of the bill goes to Hydro. A hydro bill is all so big to begin with. And there's no like a formal education process that can advise us as consumers, what are we actually paying for?"*
>
> *"I was surprised that the 6%. I didn't think it was such a low percentile that they took as far as covering their costs. And maybe, as well as similar education, where something like that could be passed on to the board and the directors… then they'll have a better understanding instead of just why did the bill go up so high? How are we gonna budget for this, so on and so forth?"*

3.3.2 Needs and Expectations

Satisfaction levels

Apart from a few isolated incidents, participants were generally satisfied with the service they received from Toronto Hydro.

Reliability

Participants were generally satisfied with the reliability of the electricity service they received.

> *"Reliability has never been questioned."*
>
> *"We haven't had many issues. And we've been in business for over 25 years now… In terms of power outages, if we have any, I can't even recall the last time we've had one at our place."*

However, some expressed an increase in outages over the past few years, as well as issues with a transformer.

> *"We are now finding that over the last two, three years, there have been a lot of blackouts…every five minutes, I'm saving my files, because I don't know when there's gonna be a surge or blackout or whatever, because it's happening a little bit more frequently than before."*
>
> *"Just recently, in this year, we had power outages two times… and it caused us roughly half a day to restore the power. It's happened quite often, in my opinion."*
>
> *"It's probably increased over the past few years. Like we used to get a two to three times. And we have like a transformer actually in front of our building itself, that sometimes will blow and it'll have an issue… It has increased over the times where we've had to send people home early, just because we can't do anything that day."*

Participants expressed a range of views in terms of how long it usually takes for the power to come back on after experiencing an outage. While some outages were short, a few participants expressed that despite the short durations, they still caused large disruptions for their business.

> *"These one, two second outages happen, I would say on average maybe every two to three weeks. Sometimes more often, sometimes less. And that is disruptive."*
>
> *"We have about 50 security cameras in the building. So then they have to restart. The same thing with computers, we have to reboot them, and sometimes there are problems with rebooting."*
>
> *"As a food manufacturer, the biggest thing for us is when the power goes out, and sometimes we are not aware about it… how much of our inventory is going to be lost?"*

Billing

Some participants expressed concerns with billing; in particular, the complexity of rates. This left them wondering about ways in which they can reduce their bills.

> *"They have numerous delivery items on the bill. It's not just one, but it's multiple. So that's the only question that you know, I've never had answered."*
>
> *"I guess for us, we don't understand the bills. I engaged… a third party to say, okay, how can you knock my bill down, because I have no idea how to do this… It kind of bothers me why*

certain people know about this and yet you know, the ordinary Joe, which I was for years, why I didn't know. Why was I so stupid to pay the high rates?"

"For years, I've been debating switching over to tiered or time of use, but they can't really comment on whether or not you should do it. Because they don't want to assume it because it might cost more, it might cost less. They weren't great at helping me."

Customer Service

In general, participants were satisfied with the customer service they had received. Some participants expressed that it was easy to get hold of customer service when they had an issue that needed resolving.

"I think they have one of the better customer services. I can get through almost immediately. And, their menu system is quite easy to get a hold of them."

Other positive experiences mentioned included the way Toronto Hydro has dealt with an incident involving a transformer explosion.

"At one point in time… we actually had an explosion. Hydro, to their credit, they kind of came by and with our contractors worked through the night to kind of get up and going so that it happened on a Sunday afternoon, we were wiped out for good 12 hours, [and] the next morning was Monday morning, production was there and no one even knew that we had an explosion or anything."

However, some expressed dissatisfaction with the way Toronto Hydro deals with issues related to their transformers.

"I have complained about how they inspect and notify me. [They] say we were in your vault room today, and you have these deficiencies. Please call this phone number for more information… The person who answers the phone at the number doesn't have the information, you have to send an email if you want to get more information about it. And I've repeatedly asked when the person is on site, could they please come and talk to me."

Others expressed dissatisfaction with communication and specifically communication relating to their bills.

"The only one glitch we had was one month, for some reason our bill had doubled. And when I tried to call Toronto Hydro about the reasoning for this, the only answer I got was that's what the meter says."

"If you asked me personally, how is Toronto Hydro doing, I would say in terms of communication pretty bad."

3.3.3 How Toronto Hydro can serve its customers better

When asked how Toronto Hydro could serve them better, many participants mentioned better communication and customer service in general, others hoped to see more reliable power with less interruptions and more education on how customers can keep their bills low.

Better Communication

Many participants indicated a desire for better communication and ease of contacting people at Toronto Hydro, particularly for discussing billing issues.

"I would just like a way to communicate with them directly when there's an issue."

"It would just be nice to have a human being to talk to. And it would be even nicer if when they were on site, they would introduce themselves and say I'm here, I've just looked at this. This is what the situation is."

Many also expressed the desire for better communication in the case of an outage.

"A lot of organizations are also switching to SMS text alerts, I guess, again, because everyone's on their phones. So that would be really helpful and even a chat function, because we can't stay on the phone for a long time, [during outages]."

Transparency was also mentioned in terms of accurate communication regarding how long outages and disruptions last. This was especially important for businesses that deal with food products, as they need to make decisions about how to deal with their refrigerated or frozen inventory.

"I think in terms of power outrage … like Toronto Hydro to inform the area who has a problem… So give us … roughly how long the [problem would be] so we'll be better prepared for our company. We process food. We don't have any [power], will be spoiled. But what's the timeframe?"

Reliability

A few participants mentioned reducing the number of outages – momentary outages included.

"These short outages that I spoke about, I understand that it's easier said than done to, to rectify this issue. Whether these short outages can be eliminated? I don't know."

Keeping Cost Low

Many participants expressed the desire for Toronto Hydro to do more in helping them reduce their bills, including assistance navigating which type of billing system they should use based on their usage.

"It would have been nice if somebody had come to me and said 'Hey, you could be saving money a lot of money by doing this.'"

"[We would like] a better recommendation of what would work better for us because obviously we want to pay less."

Some participants also suggested incentive programs for those with multiple accounts, where they could "bundle" their accounts and save more. Other incentive programs mentioned included incentives for upgrades, such as switching to LED lights.

"If they could be a little more proactive in helping us like, finding better ways to save because we have different sites… Is there a way to bundle everything together? … If you have more, the more you save, so there's nothing like that, right?"

"More incentives, if you change to LEDs, or you upgrade stuff a condominium or even at home."

3.3.4 Outcome Priorities

When asked what outcomes would determine whether Toronto Hydro was doing a good versus bad job, the main topics that came up unaided were reliable electricity services, followed by keeping costs low and good customer service. Other outcomes customers mentioned included a transparent billing system and efforts to prepare for climate change.

Reliability

The most frequently mentioned priority was reliability. This was also often the first outcome mentioned when participants were asked how they would know whether Toronto Hydro is doing a good or a bad job. Participants referred to reliability both in terms of minimizing disruptions but also in terms of getting power back again when there is an issue, such as an exploded transformer.

> *"If, you know, we go to work one day, and nothing's working, if that were to happen often I could say they're not doing a good job."*

> *"When I think about the 'good job, bad job' it's are my lights on every day? And the answer is generally, yes."*

One aspect of reliability that was stressed was the need to upgrade Toronto Hydro's equipment to improve reliability and reduce outages.

> *"[They need to] improve their infrastructure to avoid power fluctuation or more momentary power outages. That's number one."*

Some participants also expressed the need to focus on reliability in neighbourhoods that have more businesses, as opposed to residential areas.

> *"[I'd like to see them] working on maybe fixing outages faster, especially neighborhoods that might need more… if it's purely residential, maybe the residential people don't care as much as if it's strictly a business center area."*

Overall, reliability was preferred above affordability, with some participants stating they would pay more to have fewer outages.

> *"To keep the power on, and not to have outages, I would pay more because in the long run, it would be very expensive for us anyway if the power's out."*

Keeping Cost Low

Several participants also mentioned affordability when asked about how to know whether Toronto Hydro is doing a good or bad job.

> *"On a per dollar basis of this many hours I ran last year, this many hours I ran this year, is it higher or lower. That's the way I guess I judge the utility bill."*

Many participants indicated that energy saving programs, incentives, and education were priorities to help businesses reduce their bills. This included the potential for Toronto Hydro to conduct energy audits for large buildings. Another idea mentioned was a reimbursement or credit for businesses who are affected by outages.

> *"[With a reimbursement or credit], as a business, you feel more happy that someone's actually looking after you and taking care of you. And that they do value us."*

When comparing affordability with other outcomes, there were a few participants who prioritized affordability over everything.

> *"At the end of the day, residential customers, commercial customers, they really just care about their hydro bill… I think affordability at the end of the day is the most important outcome for anybody."*

Customer Service

Another top outcome was customer service. As with reliability and keeping cost low, it was often mentioned right away as an indicator of whether Toronto Hydro is doing a good or a bad job.

> *"The only way I can personally know what's good or bad is if there's ever an issue, and I have to call in, the type of service that I get, and getting the problem resolved."*

Transparency in Billing

Several participants felt that they would like to see more accountability and transparency in their billing as an outcome priority.

> *"I'd like to see some accountability in terms of where exactly the money goes, the bulk of it,… [and] how they justify what they charge us."*

Environment

A few participants mentioned a focus on the environment as a priority without being prompted. Specifically, some participants would like to see Toronto Hydro being more involved in building charging stations for electric vehicle.

> *"We are at the very beginning stages of installing electric vehicle charging stations. And it would be great if there was some, you know, reliable source of information, [or] if they could be involved in that process."*

Assisting Low-Income Populations

When prompted with a list of possible outcomes Toronto Hydro can focus on (see Section 5 for the information shown), many participants' attention was drawn to helping to address social issues, specifically providing financial assistance to low-income populations, and enabling new technology. These issues were not brought up as an outcome Toronto Hydro should focus on prior to showing the list of possible outcomes to participants.

Helping to address social issues was not brought up unaided. Once it was shown in a list of outcomes and the moderator provided helping low- or fixed-income customers as an example of addressing social issues, most participants agreed that it is an important priority for Toronto Hydro to make sure bills are affordable for vulnerable members of the population. One participant also recalled some form of ongoing support programs for low-income people.

> *"I actually do think it should be on the list. I'm assuming social issues kind of ties in with, a lot of neighborhoods within Toronto, or within the Ontario region that are like… below middle-class families. And so, for those families, or even businesses in that area, it might not be easy to pay those monthly bills or to keep up with the monthly bills. So, affordability kind of ties in with that."*

> *"It's quite visible with some condominium residents that they cannot afford the bills. And then I remember there was there was a program, I'm not sure if it's still alive that the program that was targeting low-income families. Some residents applied for health. I'm not sure."*

Enabling new technology

The list of possible outcomes also prompted a few participants stating that there is a need to invest in research and development that help Toronto Hydro find energy efficiencies and develop green energy.

> *"There are a lot of countries that we can mimic that are doing a lot of great things with energy efficiency and green energy. So just to have like a dedicated unit within Toronto Hydro to focus on research, R&D, would be good."*

3.3.5 Climate change and electrification

The groups then discussed if they think net-zero commitments in Toronto or in the country will have an impact on their businesses and on Toronto Hydro's operations. Participants were shown an image of what energy transition might mean (see Section 5 for the information shown) and asked for their reaction to the shift.

For most participants, the main incentive for reducing their carbon footprint is cost savings, through financial rewards such as energy efficiency measures and rebates. Other participants have more general goals to be sustainable.

Some participants expressed an expectation from their clients to install electric charging stations and solar panels. However, most participants said that cost is still a barrier to more rigorous electrification measures, and very few participants indicated that their clients expect them to reduce their carbon footprint.

3.3.6 Trade-offs: Preparing for the energy transition vs. Lower short-term costs

In general, although most participants were concerned about the cost of electrification and preparing for energy transition, they were largely supportive of moving forward with it.

> *"I think the world is going towards this new world. It's going to happen. It's just a matter of time."*
>
> *"I would say it's a benefit more than a problem. But there are costs associated with it."*
>
> *"It would be good for business. I don't see it in the near future, but maybe down the road."*

A few participants expressed concern about the safety and reliability of the new system because there is room for improvement when it comes to reliability as the electricity system stands right now. Moving to a new system left them feeling worried if the system will be even less reliable than today.

> *"I feel that was dangerous? Because we don't have that capacity, or the technology to link those power generators into the system. I don't think [it's] reliable right now at least I haven't experienced this. I don't think they're reliable."*

When prompted as to whether Toronto Hydro should act now to anticipate demand for electricity, or wait until they have a firmer indication of growing demand, there were mixed responses. Some participants favoured acting slowly and waiting until demand firms up.

> *"Wait until the demand firms up or do it slowly in stages and see how it works. Let's say phase one and wait a year and see how it goes."*

"I don't agree with the concept that if you build it, they will come."

Others preferred acting now to prepare for the future, even if that meant taking on the risk that demand won't be there.

"I would be more future focused, to get more reliable service."

"I don't think that you can risk stability. I think you have to pay into it what you have to pay into it to make it a stable, reliable system."

Several participants expressed concern about the high costs of preparing for the future on vulnerable populations, even if they were in favour of moving quickly, in general.

"I'd rather see the higher costs and moving forward. However, the vulnerable groups should be protected somehow."

In some groups, participants were asked if they would be willing to pay 5% more on their bill to help tackle climate change. There were a mix of responses to this. Although some participants expressed some hesitation with spending more, having information on exactly how the money would be spent was seen as something that would leave them more willing to pay extra.

"What I think is how the thing is sold. If we can say, we're doing A, B, C, D, E, and it can be clearly related to helping and bettering the environment, I think it's something that that is palatable and can be swallowed."

4. Key Account Interviews

4.1 Methodology

INNOVATIVE conducted 14 interviews with key accounts between December 6, 2021 and January 12, 2022. Participants were randomly recruited by e-mail from a list of key accounts provided by Toronto Hydro. Interviews were approximately 60 minutes in length and followed a structured interview guide, similar to that of the focus groups with residential, small business, and C&I customers.

In appreciation of their time, INNOVATIVE made a $100 donation to a charity of each participating key account customers' choice.

4.2 Key Findings

Reliability appears to be paramount for most Key Accounts.

Good reliability appears to be seen as "table stakes" for most key accounts. Without reliable electrical service, this rate class cannot operate efficiently or in some cases safely (in the case of public institutions such as hospitals, colleges, and universities). Among large industrial customers, power quality continues to be an issue for key accounts with sensitive machinery and equipment. Improving reliability appears to far outweigh any concern about increases in the distribution portion of this rate classes' electricity bills.

Increased capacity is largely seen as a key requirement to successfully navigating the energy transition.

Key accounts expressed a need to know where the electrical grid capacity is today and where it will be tomorrow. Almost all key accounts interviewed have net zero targets or at least have carbon reduction initiatives in the works. Most key accounts customers suggested that without increased electrical capacity, their net zero initiatives will be significantly hampered.

Furthermore, almost all key accounts are acutely aware that electrification will have a significant impact on the price they pay for electricity. However, for many, this appears to be viewed as a cost of doing business.

Almost all key accounts customers cited a need from Toronto Hydro for accurate capacity and cost forecasts so they can better plan for the energy transition and electrification.

Key Accounts customers expressed a desire for enhanced customer service.

While all key accounts customers stated that they are satisfied with the services they receive from Toronto Hydro, many also conveyed the need for enhanced services. To many, this meant going beyond the traditional *Key Account-LDC* relationship and providing additional advisory services to help navigate the challenges presented by the energy transition and electrification. A number suggested that they want to work with Toronto Hydro as a partner, not just a utility, to overcome

these challenges. This included interests in timely, proactive engagement to help solve problems, identify opportunities, improve efficiencies, and better manage energy costs. Some went as far as to suggest interests in behind-the-meter solutions delivered through Toronto Hydro, and in some cases, financing options to help overcome immediate investment hurdles.

4.3 Detailed Findings

4.3.1 Customer Experience

Key account participants generally had a positive experience with Toronto Hydro. Praises were centred around the quality of **customer service** and **power reliability**.

Customer service: This came up again when asked more specifically, what Toronto Hydro did well. The positive impact of having direct contact with Toronto Hydro and their key account managers was a recurring theme that emerged in almost all the interviews. They were very satisfied with the service they received. Those who had worked with other utilities even mentioned that other utilities didn't seem as committed to keeping them happy or working closely with them through their key account management team.

Power reliability: Many key account customers also expressed contentment with the limited frequency of outages that they experienced, despite concerns about aging infrastructure.

Areas for Improvement

When asked what, if anything, Toronto Hydro could do better to serve their organizations, various companies had differing suggestions centering around **communications**, **power reliability**, and **business partnership** regarding the enhancement of Toronto Hydro's services.

- **Communications**: The theme of improved communications was voiced among several key account participants. Some wished to have a more meaningful say in Toronto Hydro's investment plans that could address their future needs. Others stressed the importance of clearer communication during scheduled power outages to prevent miscommunication.
- **Power reliability**: Hospitals, given the critical nature of their work, particularly emphasized the necessity for a reliable power supply to ensure the safety of patients during periods of voltage fluctuations or power outages. This applied to other businesses where they expected a certain standard of power quality to assure the quality of their products, for example, which needed a temperature-controlled environment.
- **Business partnership**: Some key account participants expected a more streamlined approach for new service connections or system upgrade projects, as these projects had posed challenges for them in the past. They believed that simplifying this process would be beneficial. Other companies wanted a more streamlined process for obtaining quotes as their organizations changing energy needs (e.g. when fuel switching to electricity to meet net-zero emission goals).

4.3.2 Needs and Preferences

Needs and preferences of key account customers centred on three key areas.

1. **Power reliability:** Generally speaking, almost all key account participants had high expectations for reliability in their electricity services. While reliability is considered relatively good by key accounts who participated in these interviews, even a few annual power outages or power quality issues can be very disruptive and costly for this rate class.
2. **Customer service/Business partnership:** As mentioned earlier, many customers felt that having a key account manager they could reach out made it easier for them to do business with Toronto Hydro, compared to other utilities they either currently or previously have worked with. While most key account participants are satisfied with their existing dedicated key account managers at Toronto Hydro, many also expressed a desire for enhanced services including advisory support and even behind-the-meter solutions to help them navigate the energy transitions and meet their net zero commitments.
3. **Infrastructure Investments/Enabling Climate Action:** Some key account participants expressed concerns about Toronto Hydro's aging grid infrastructure and limited capacity to meet future electricity demand. Not only was this deemed as a potential barrier to their own net zero comments and growth, but it could also pose a barrier to broader economic growth and the energy transition across the City of Toronto. Ensuring reliable power is available to customers when they need it is very important to almost all key account participants.

4.3.3 Emerging Challenges

Customers saw **capacity for reliable power** and **climate action** as the main areas Toronto Hydro will need to focus on over the next decade.

- **Capacity for reliable power**: Customers were concerned about how aging infrastructure, increased frequency of extreme weather events, and cyber security threats might affect the reliability of the grid. With the need to have a reliable supply of electricity, many key account participants expect upgrades to the electricity system that would lead to an expansion of the grid to increase capacity, a stronger economy, and a lower carbon future.
- **Climate Action:** As mentioned above, almost all key account participants have net zero targets or carbon reduction initiatives in the works, but few know how they are going to reach these targets. Many key account participants shared their hopes that Toronto Hydro would increase their support in helping them transition to lower or non-emitting carbon energy sources, building out more distributed energy resources (including battery storage), and enabling grid modernization, such as microgrids technologies.

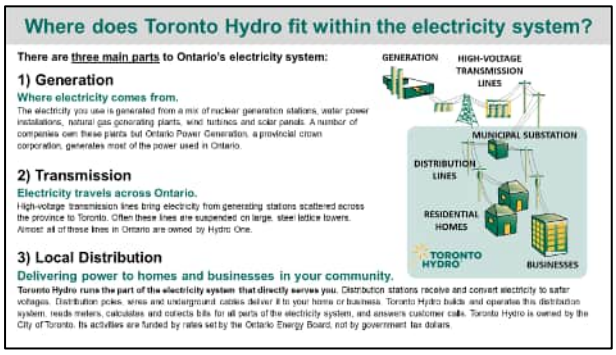
5. Focus Groups Stimulus

In all focus group sessions with residential, small business, and C&I customers, a series of stimulus was used to help guide the conversation. The stimulus focused on the following 5 themes:

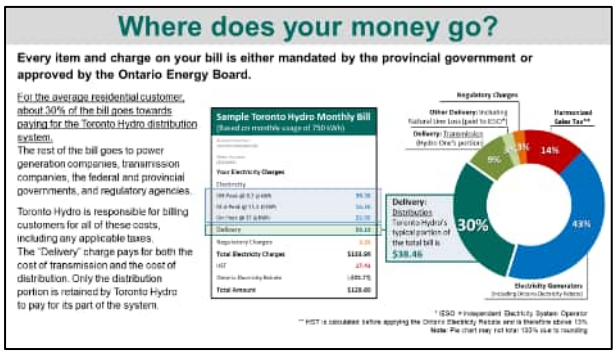
1. Where does Toronto Hydro fit within the electricity system?
2. Information on "Where does your money go?"
3. Planning Challenges
4. Outcome Prioritization
5. Changing World of Electricity

The complete stimulus used in each group can be found below.

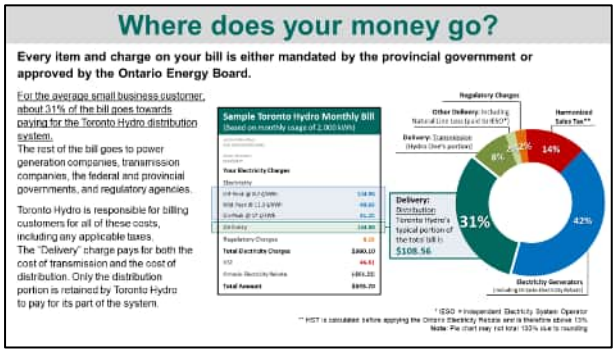
Where does Toronto Hydro fit within the electricity system?



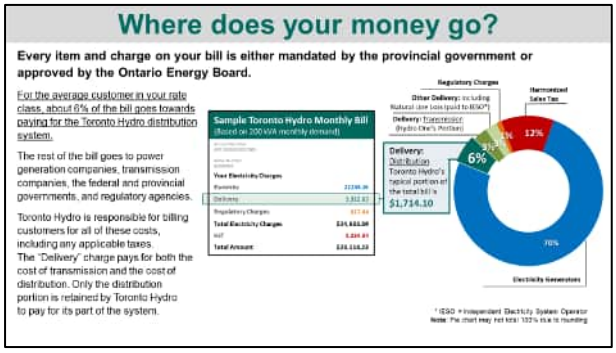
"Where does your money go?" Residential version



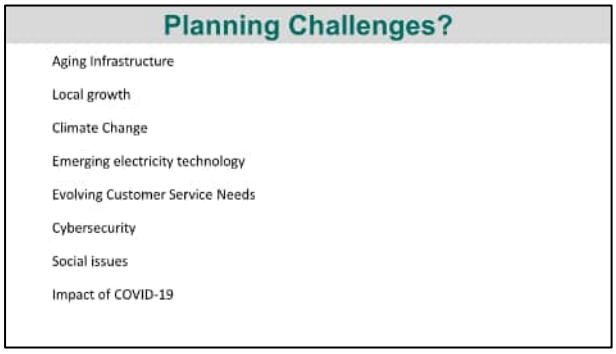
“Where does your money go?” Small Business version



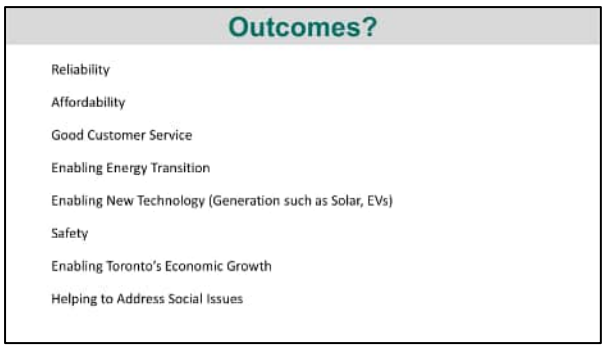
“Where does your money go?” C&I version



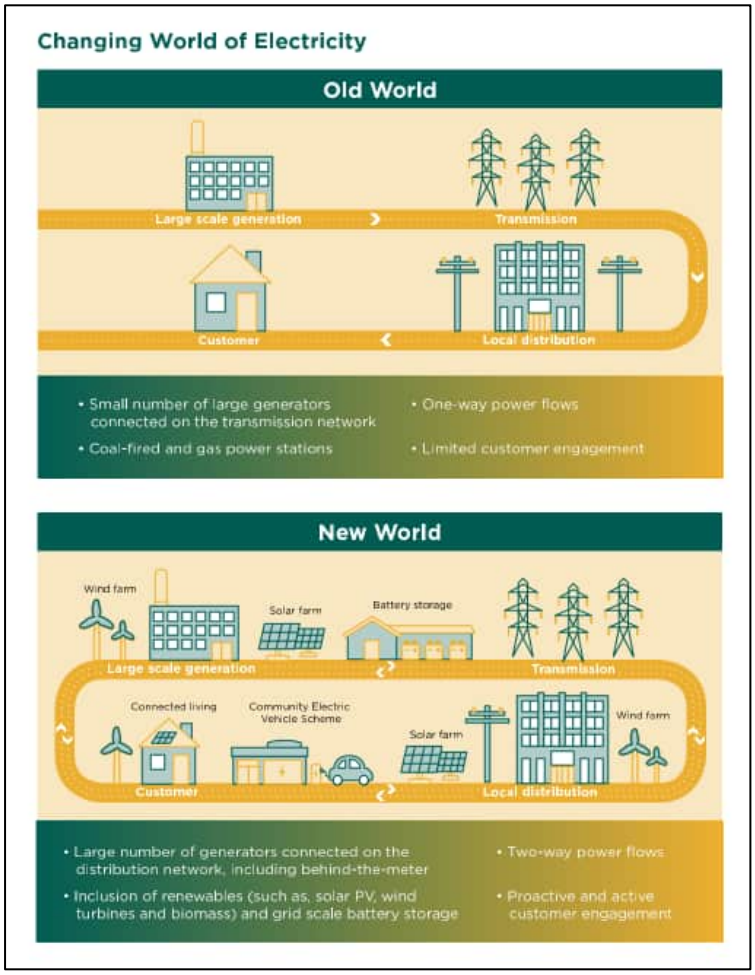
Planning Challenges



Outcomes



"Changing World of Electricity"



Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro. The conclusions drawn and opinions expressed are those of the authors.

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CONFIDENTIAL

APPENDIX 02

Reference Survey Report

Customer Sample Validation

November 2, 2023

STRICTLY CONFIDENTIAL

2025 – 2029 Rate Application

Report Navigation

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Reference Survey Overview

Research Objective

As part of the Phase I Customer Engagement, Toronto Hydro commissioned Innovative Research Group (INNOVATIVE) to survey its customers across rate classes. Among low-volume customers, which consist of residential and small business rate classes, INNOVATIVE conducted parallel telephone and online surveys.

Running parallel telephone and online surveys served two primary purposes:

1. **To gather feedback and insights on preferences and needs from low-volume customers.**
   Feedback from these surveys helped Toronto Hydro's planners and engineers inform the design of the utility's business plan, which was shared in draft with customers in Phase II of this engagement.

2. **To establish baselines and develop weights that allow Toronto Hydro to move to an online methodology for its low-volume customer engagement program**.
   Establishing a baseline and understanding the difference between customers with known email addresses (email sample) and the broader customer base is a critical step for utilities that wish to migrate to representative online survey methodologies in the second phase of their customer engagement. Where significant differences exist between the email sample and the broader customer base (e.g. demographics, firmographics, attitudes, and opinions), the insights gained from these parallel surveys can be used to develop weights, which can minimize these differences.

Benefits of Moving to an Online Methodology

The benefits of migrating from a generalizable pure-telephone methodology to a generalizable pure-online methodology was realized in Phase II of Toronto Hydro's customer engagement when its draft plan was presented to customers in an interactive workbook format. These benefits included:

- Better presentation of information through the use of visuals (e.g. diagrams, pictures, videos).
- Ability to ask more questions, as respondents are more likely to spend a longer time participating in an online survey than on the phone.
- Reduced costs as online surveys are less costly than telephone surveys.

This report documents the results of four surveys conducted by INNOVATIVE among Toronto Hydro's low-volume customers (small business and residential) and provides recommendations on appropriate weighting for future Toronto Hydro online survey methodologies.

Sample Validation

Email Sample vs. Total Customer Accounts

Overall Customer Email Coverage

The information below compares the sample of each rate class with email addresses to the total customer accounts of that rate class.

- For **Residential** accounts, 49% has an email address on file. Removing duplicate email addresses leaves 46% unique email addresses.
- For **Small Business** accounts, 35% has an email address. Removing duplicate email addresses leaves 19% unique email addresses.
- For **C&I** accounts, 64% has an email address. Removing duplicate email addresses leaves 26% unique email addresses.

Rate Class	Total Accounts	Email Sample	Email Coverage (out of Total Accounts)	Unique Emails	Unique Email Coverage (out of Total Accounts)
Residential	627,729 records	310,696	**49%**	291,869	**46%**
Small Business	65,514 records	23,150	**35%**	12,191	**19%**
C&I	8,716 records	5,573	**64%**	2,268	**26%**

- Toronto Hydro provided a list of the most up-to-date **Key Account** representative contact information at the time. At the time, the list contained 204 unique emails.

Sample Validation

Email Sample vs. Total Customer Accounts

Sample Validation

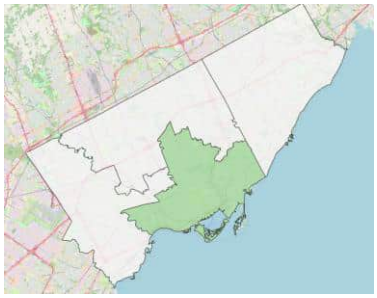
The information below compares the sample of each rate class with email addresses to the total customer accounts of that rate class across two known variables – distributions of (1) region and (2) consumption quartile.

(1) Regional Distribution by Rate Class

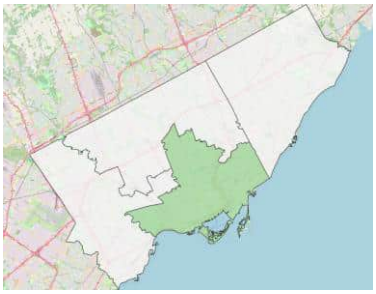
Using the first three digits of postal codes (FSAs), customers are grouped into four unique regions within Toronto Hydro's service territory.

For most regions, the distributions are comparable (within a difference of +/-4%) between the full set of customer records and those with an email account on file. The exception was residential customers in Toronto/East York, who were +5% overrepresented among customers with an email address compared to the full set of customer records.

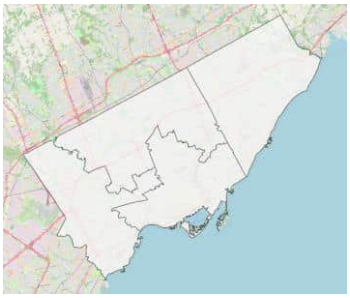
Residential



Small Business



C&I



Legend: Difference*
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

(2) Distribution of Consumption Quartile by Rate Class

For most consumption quartiles, the distributions are comparable (also within a difference of +/-4%) between the email sample and the total accounts. In the Fourth quartile among small business customers, there are +7% more of the email samples than the total accounts.

Quartiles	Email Sample	Difference*	Email Sample	Difference*	Email Sample	Difference*
Rate Class	***Residential***		***Small Business***		***C&I***	
First	28%	**+3%**	22%	**-3%**	21%	**-4%**
Second	25%	**0%**	21%	**-4%**	25%	**0%**
Third	23%	**-2%**	24%	**-1%**	26%	**1%**
Fourth	24%	**-1%**	32%	**+7%**	28%	**+3%**

Note: * The difference is the distribution in the email sample *minus* the distribution among total customer accounts.

Sample Validation

Email Sample vs. Total Customer Accounts

Survey Sample

For the most part, responses from the telephone and online surveys were very similar within both customer types. However, there were a few distinct difference that are worth noting. The table below documents the differences between the *email* and *telephone* samples. These differences below are from the weighted samples, unless specified.

Areas	Residential	Small Business
Demographics / Firmographics	**Age:** *Before weighting*, online respondents were older than telephone respondents.	None
Environmental Controls	None	**Bill impact:** Online respondents were more likely to report that their bill has an impact on the bottom line of their organizations than telephone respondents (65% vs 56%).
Customer Perceptions	**Familiarity with Toronto Hydro**: Online respondents were more likely to say they are familiar with Toronto Hydro than telephone respondents (76% vs 66%). **Reliability experience**: Online respondents were more likely report having experienced an outage (67% vs 57%).	**Familiarity with Toronto Hydro**: Online respondents were more likely to say they are familiar with Toronto Hydro than telephone respondents (67% vs 59%). **Familiarity with Toronto Hydro's share of bill**: Online respondents were more likely to say they are familiar with the amount of their bill going to Toronto Hydro (39% vs 25%). **Reliability experience**: Online respondents were more likely report having experienced an outage (55% vs 45%).

Weighting Scheme

Given the similarities in known account characteristics (average consumption and region), Toronto Hydro's email sample appeared to be a good representation of the broader customer base. The online and telephone surveys returned similar results on most demographics and firmographics, as well as environmental controls.

While there were some differences on customer perceptions between online and telephone surveys, the *direction* of the results was comparable. For example, although online residential respondents were more likely to say they are familiar with Toronto Hydro than telephone respondents, more respondents say they were familiar than unfamiliar regardless of the survey mode.

Even though the online sample skewed towards certain customers, weighting the samples by consumption and region ensured the final samples were representative of the customers by the two known variables. As such, no one area or no one consumption quartile was over or underrepresented in the survey samples.

To further account for the skew in age among residential customers, the online residential survey was also weighted by age to more closely reflect the age distribution that was captured in the telephone survey.

INNOVATIVE RESEARCH GROUP

Methodology and Respondent Profiles

Section 1



Reference Survey
Methodology

Survey Design

This report documents the results of four surveys conducted by INNOVATIVE among Toronto Hydro's low-volume customers (residential and small business).



The **residential telephone survey** was fielded from **December 3rd to 20th, 2021** amongst a random sample of **n=1,000** (unweighted n=1,006) residential customers.

The **small business telephone survey** was fielded from **December 7th to 22nd, 2021** amongst a random sample of **n=400** (unweighted n=401) small business customers.

Both telephone surveys were weighted by region and consumption quartiles within their respective rate classes to produce a representative sample of Toronto Hydro's customer base.



The **residential online survey** was fielded from **December 7th, 2021 to January 10th, 2022** amongst **n=1600** (unweighted n=1685) residential customers.

The **small business online survey** was fielded from **December 9th, 2021 to January 9th, 2022** amongst **n=430** (unweighted n=430) small business customers.

As discussed earlier, because the telephone survey generally had a younger age demographic than the online survey, in addition to weighting the residential online survey by region and consumption quartiles, it was weighted by age to more closely reflect the age distribution that was captured in the telephone survey.

The small business online survey was weighted by region and consumption quartiles to report on a representative sample of the customer base.

Sample Design



Toronto Hydro provided INNOVATIVE with confidential access to its customer lists in order to conduct this research. The customer list included information on region and electricity consumption, as well as all available telephone numbers and email addresses. The four surveys followed a random sample methodology. Random samples were then surveyed.

Since only a subset of the customers on the lists have email addresses on file, INNOVATIVE conducted a baseline analysis to see how customers with email addresses differ from the broader customer base, followed by a detailed comparison between online and telephone survey results. The following pages detail the sampling methodology used for this research.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

INNOVATIVE RESEARCH GROUP

Residential Sample

Sample Validation

Telephone Residential Sample

Targets were set based on region and annual electricity usage in the residential telephone survey. Weights were also applied to ensure the sample is representative of the residential customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region.

Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
Etobicoke/York	44 (44)	49 (49)	52 (52)	50 (50)	195 (195)
North York	58 (57)	53 (53)	52 (52)	59 (59)	222 (220)
Scarborough	22 (22)	58 (58)	67 (66)	53 (53)	200 (200)
Toronto/E. York	129 (127)	91 (91)	80 (79)	89 (88)	389 (385)
Total	253 (250)	251 (250)	251 (250)	251 (250)	1006 (1000)

Online Residential Sample

Similar to the telephone residential sample, targets were set based on region and annual electricity usage in the residential online survey.

As discussed earlier, because the telephone survey generally had a younger age demographic than the online survey, in addition to weighting the residential online survey by region and consumption quartiles, it was weighted by age to more closely reflect the age distribution that was captured in the telephone survey.

The online residential sample has been weighted by age, region and consumption.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region, as well as age against the telephone reference survey.

Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
Etobicoke/York	63 (71)	83 (78)	87 (83)	88 (81)	321 (312)
North York	54 (90)	81 (84)	81 (84)	86 (94)	302 (352)
Scarborough	37 (35)	91 (94)	105 (106)	74 (85)	307 (321)
Toronto/E. York	218 (203)	213 (145)	162 (127)	162 (140)	755 (615)
Total	372 (400)	468 (400)	435 (400)	410 (400)	1685 (1600)

Age	Total
18-34	88 (242)
35-54	515 (616)
55+	1082 (741)
Total	1685 (1600)

Small Business Sample

Sample Validation

Telephone Small Business Sample

Targets were set based on region and annual electricity usage in the small business telephone survey. Weights were also applied to ensure the sample is representative of the small business customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region.

Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
Etobicoke/York	15 (15)	19 (18)	19 (19)	18 (18)	71 (70)
North York	22 (22)	24 (24)	23 (23)	23 (23)	92 (91)
Scarborough	19 (19)	23 (23)	21 (20)	21 (21)	84 (84)
Toronto/E. York	44 (44)	35 (35)	38 (37)	37 (37)	154 (153)
Total	100 (100)	101 (100)	101 (100)	99 (100)	401 (400)

Online Small Business Sample

Similar to the telephone small business sample, targets were set based on region and annual electricity usage in the small business online survey. Weights were also applied to ensure the sample is representative of the small business customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region.

Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
Etobicoke/York	14 (17)	14 (19)	17 (20)	23 (20)	68 (76)
North York	17 (23)	24 (25)	23 (25)	18 (25)	82 (98)
Scarborough	15 (21)	25 (25)	23 (22)	18 (23)	81 (91)
Toronto/E. York	60 (47)	55 (38)	52 (40)	32 (40)	199 (165)
Total	106 (107)	118 (108)	115 (108)	91 (107)	430 (430)

Telephone versus Online

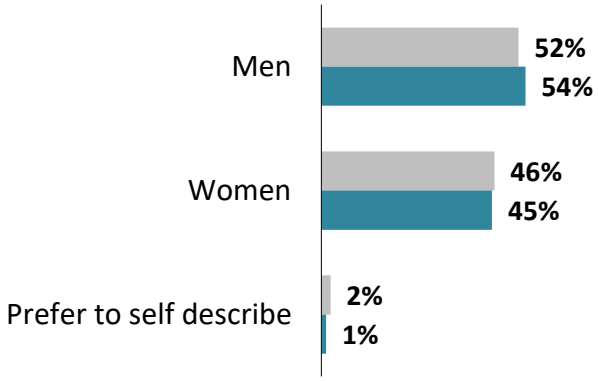
Demographics

Residential

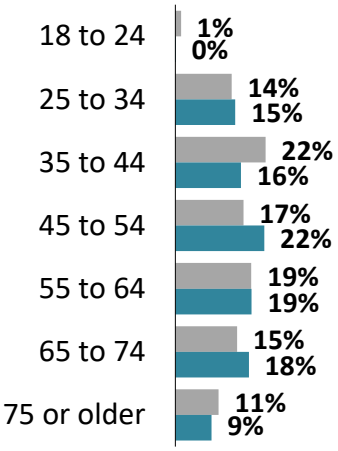
Telephone

Online

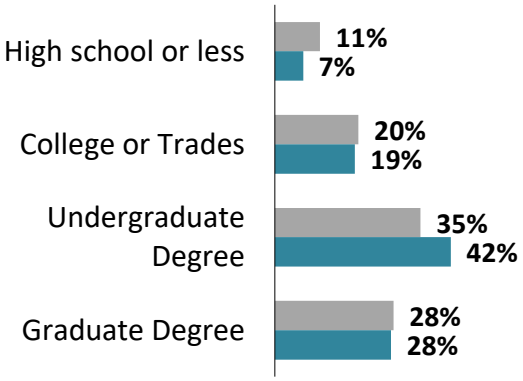
Gender



Age

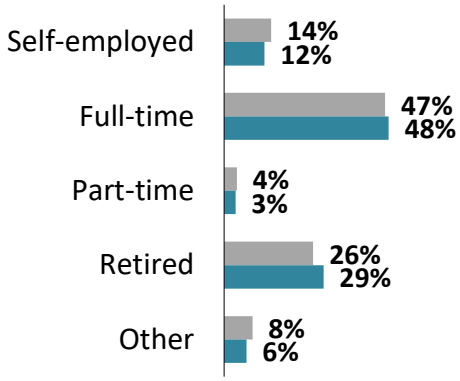


Education



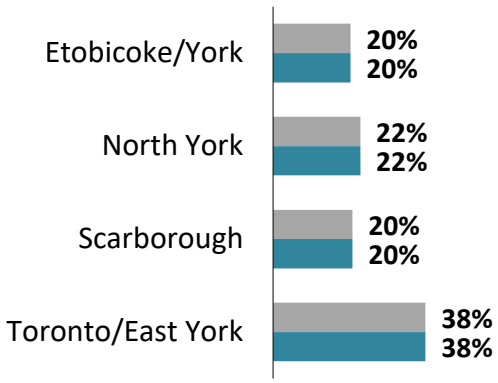
Note: 'Other/Prefer not say' (T: 6%; O: 5%) not shown

Employment



Note: 'Prefer not say' (T: 2%; O: 2%) not shown

Region



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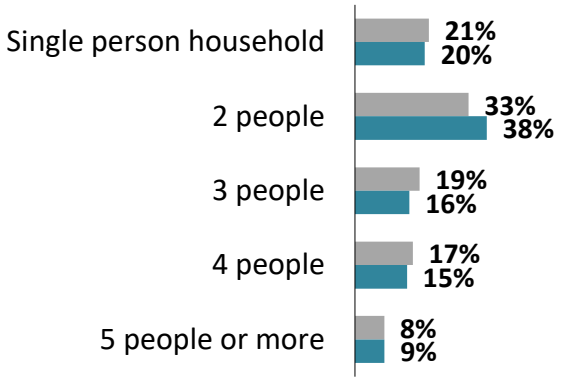
Telephone versus Online
Demographics

Residential

Telephone

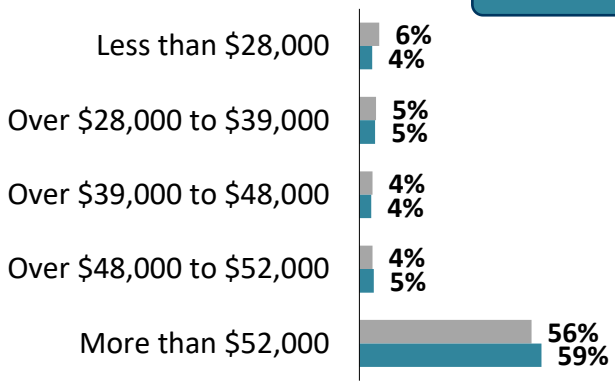
Online

Household Size



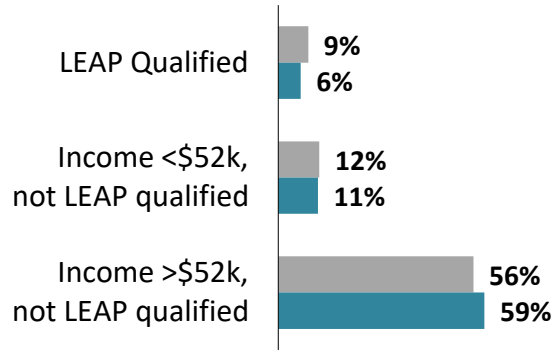
Note: 'Prefer not to say' (T: 2%; O: 3%) not shown

Household Income (after-tax)



Note: 'Prefer not say' (T: 24%; O: 23%) not shown

LEAP Qualification (calculated based on household size and after-tax income)



Note: 'Refused' (T: 24%; O: 23%) not shown

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Telephone versus Online

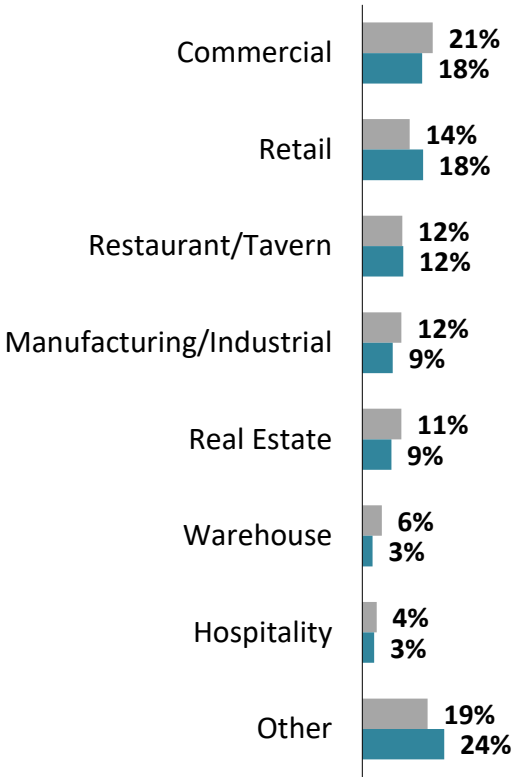
Firmographics

Small Business

Telephone

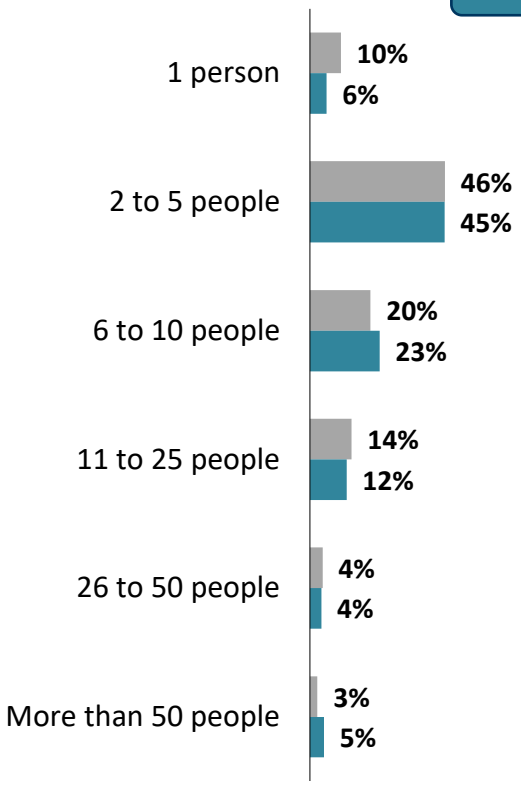
Online

Industry



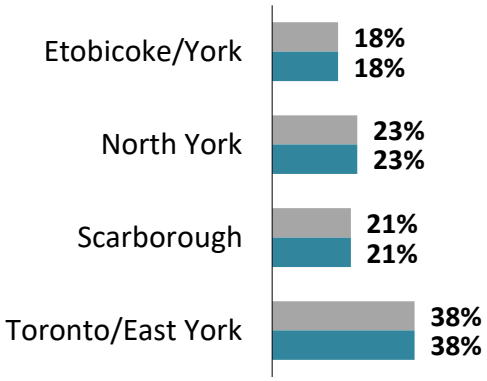
Note: Ranked in order by telephone responses.
'Prefer not to say/Don't know' (T: 2%; O: 4%) not shown

Number of Employees



Note: 'Prefer not say/Don't know' (T: 3%; O: 4%) not shown

Region



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Environmental Controls

Section 2



Telephone versus Online

Environmental Controls

It is important to distinguish between what is within, and what is outside of Toronto Hydro's influence or control when it comes to drivers of customer opinion.

Perceptions of distributors often tend to move with general perceptions of ***Ontario's electricity sector*** rather than in response to the local utility.

To prepare for the energy transition, perceptions of distributors are now more tied to ***attitudes towards phasing out fossil fuels*** than ever before.

Perceptions of utilities are also strongly correlated with ***financial circumstances***. In tough times perception and preference can change because customers are struggling with their bills, not because of anything the company has, or has not, done.

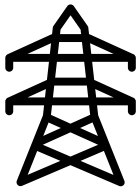
Control questions help distributors distinguish between:

a) utility driven programs that impact customer opinion; and

b) uncontrollable external drivers that impact customer opinion.

When conducting research in the energy sector, INNOVATIVE often tests multiple environmental controls to assess what role predispositions (customer values and beliefs – which can be difficult and costly to change) play in the formation of an opinion towards a utility.

In this study, our environmental controls focus on three key questions to help capture external phenomena:



General perceptions of Ontario's electricity sector: *Customers are well served by the electricity system in Ontario.*



Attitudes towards phasing out fossil fuels: *Fossil fuels should be phased out as quickly as possible to speed up the shift to a lower-carbon future.*



Financial Circumstances: *The cost of my electricity bill has a major impact on [Residential: my finances / Small Business: the bottom line of my organization] and requires I do without some other important priorities.*

Telephone versus Online

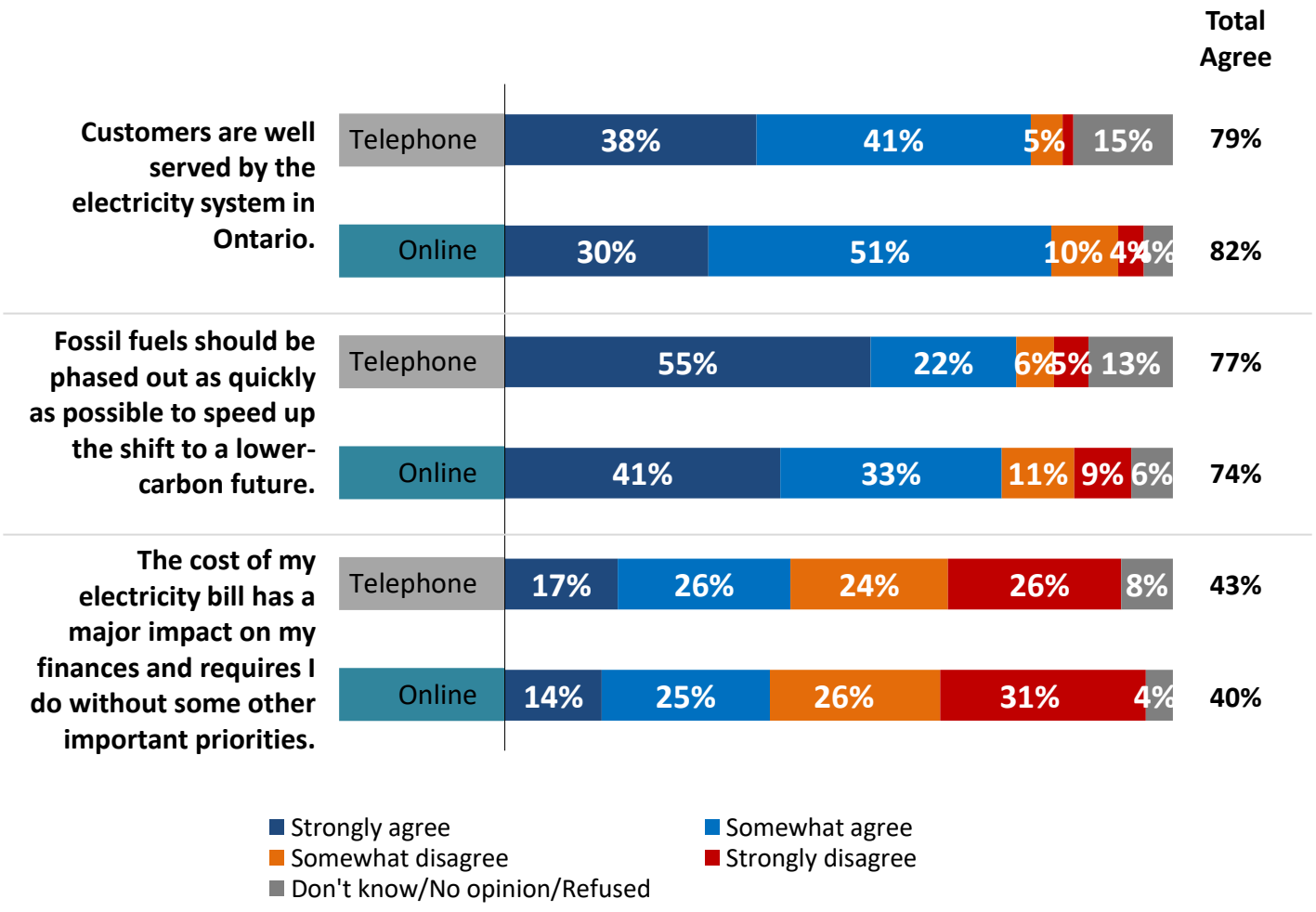
Environmental Controls

Residential

[Telephone] Lastly, I'd like to ask you some general questions about the electricity system in Ontario.

For each statement, please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

[Online] To what extent do you agree or disagree with the following statements?



Note: sums added before rounding.

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Telephone versus Online

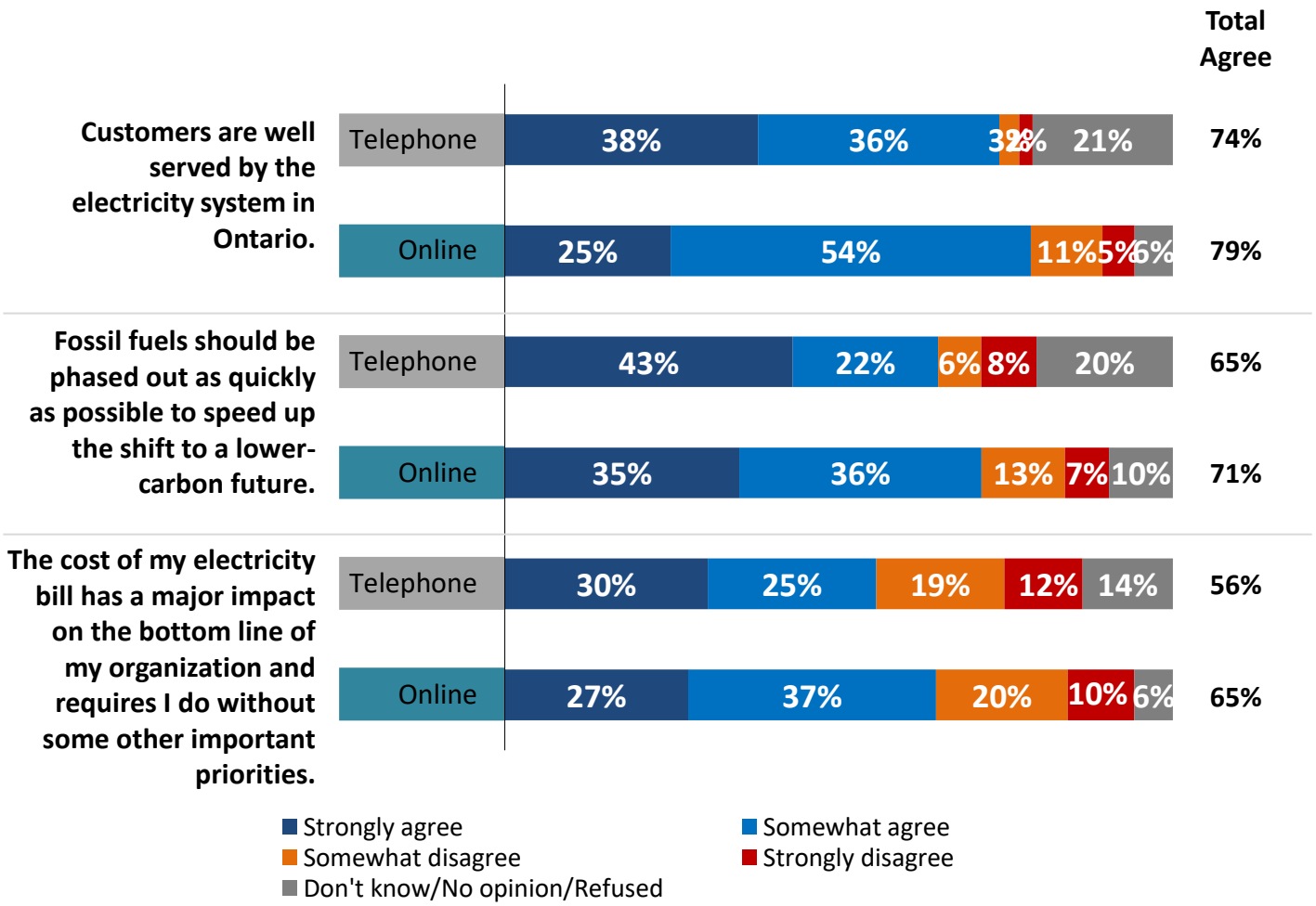
Environmental Controls

Small Business

[Telephone] Lastly, I'd like to ask you some general questions about the electricity system in Ontario.

For each statement, please tell me if you would strongly agree, somewhat agree, somewhat disagree or strongly disagree. If you don't know enough to say or don't have an opinion just let me know.

[Online] To what extent do you agree or disagree with the following statements?



Note: sums added before rounding.

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INNOVATIVE RESEARCH GROUP

Customer Perceptions

Section 3



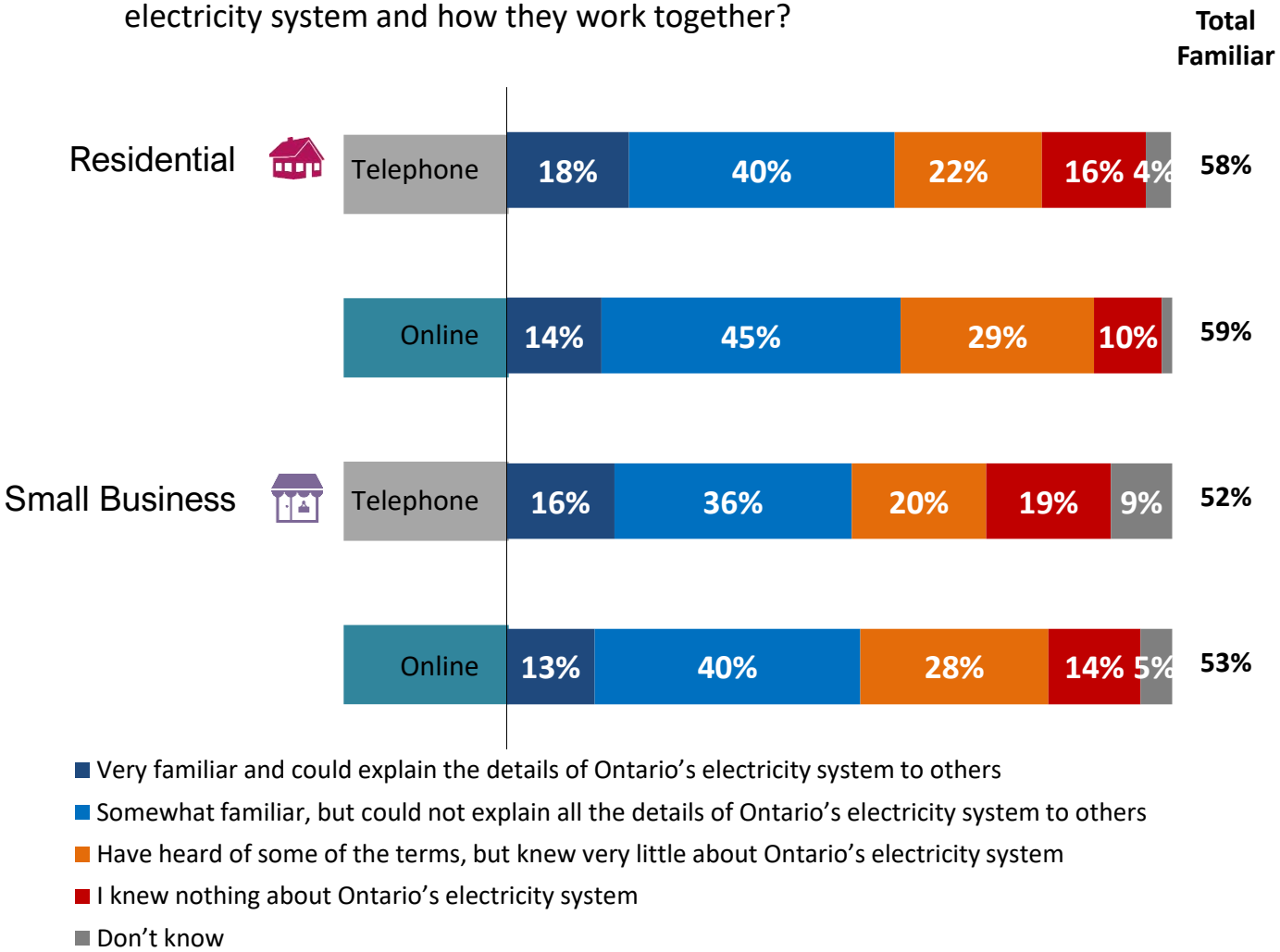
Familiarity with Ontario's Electricity System

Q

As you may know, Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province
- **Local distribution networks** take the electricity from provincial transmission lines and bring it to your home through a network of wires, poles and other equipment.

Before this survey, how familiar were you with the various parts of the electricity system and how they work together?



Note: sums added before rounding.

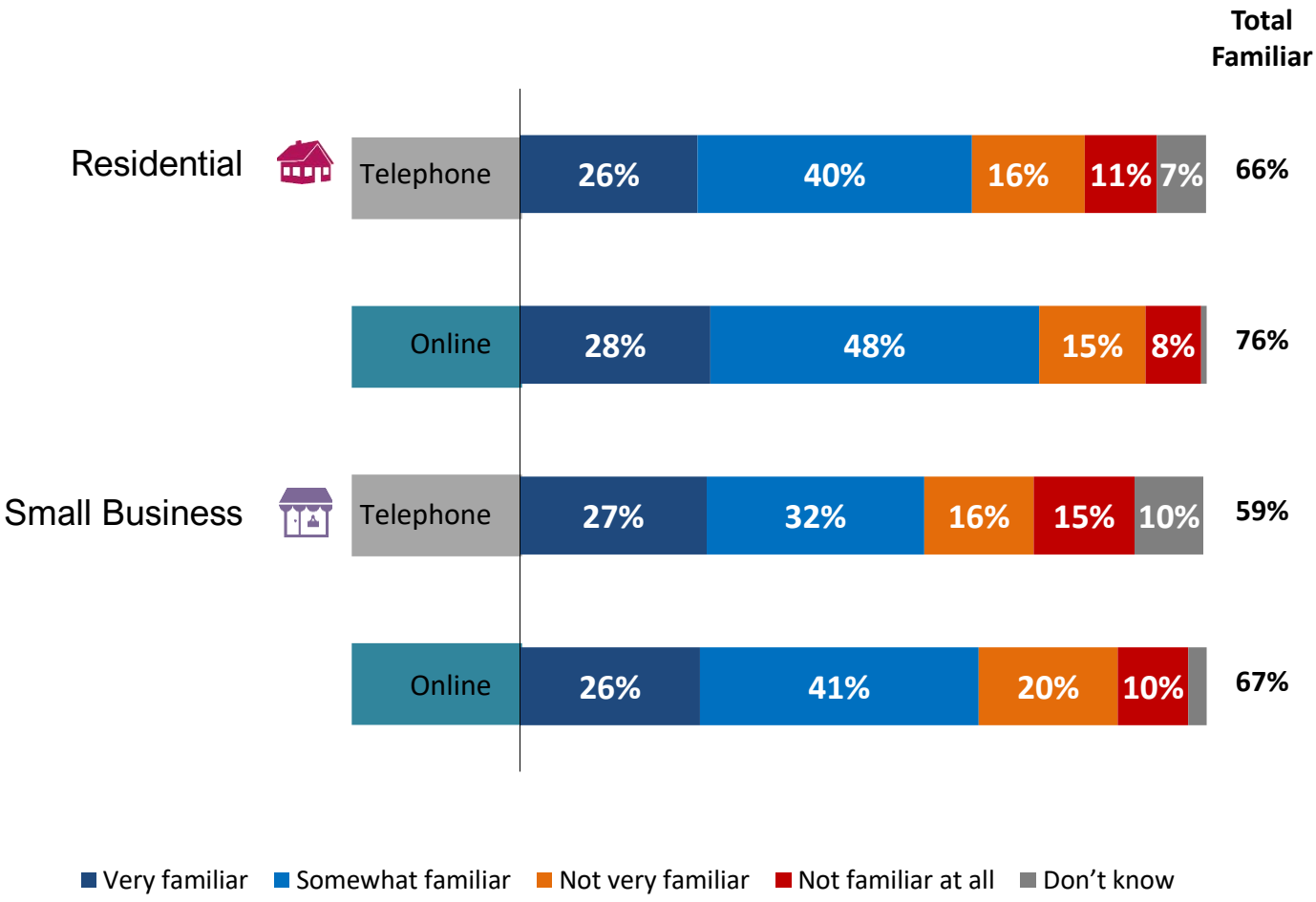
INNOVATIVE RESEARCH GROUP

Familiarity with Toronto Hydro

Q

Toronto Hydro owns and operates Toronto's distribution network. This is the network that takes the electricity from high-voltage transmission towers and brings it to your home through a network of wires, poles and other equipment.

Before this survey, how familiar were you with **Toronto Hydro**, which operates the electricity distribution system in your community?



Note: sums added before rounding.

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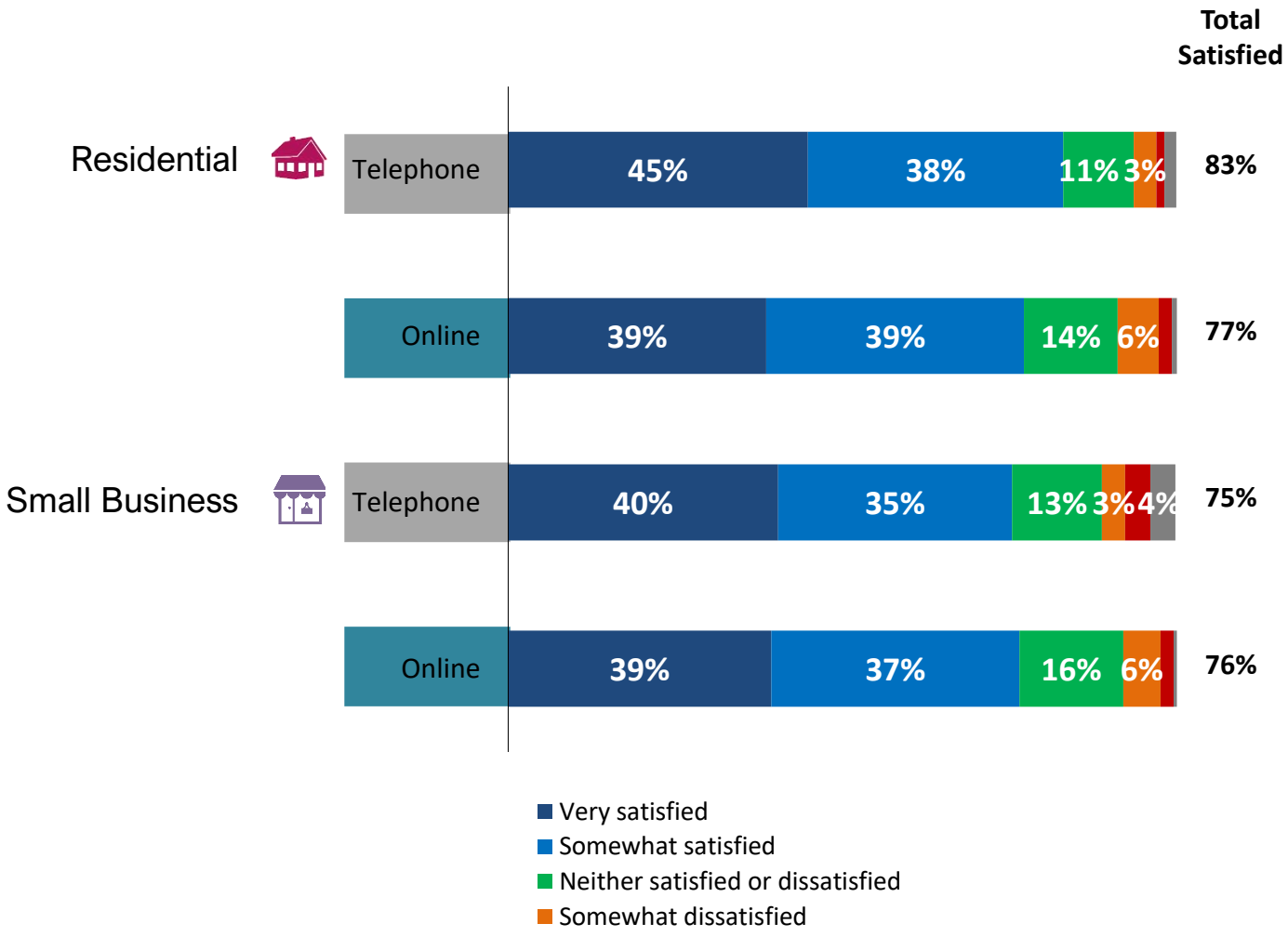
Satisfaction with Toronto Hydro

Q Thinking specifically about the services provided to you and your community by **Toronto Hydro**, overall, how satisfied or dissatisfied are you with the services that you receive?



Note: sums added before rounding.

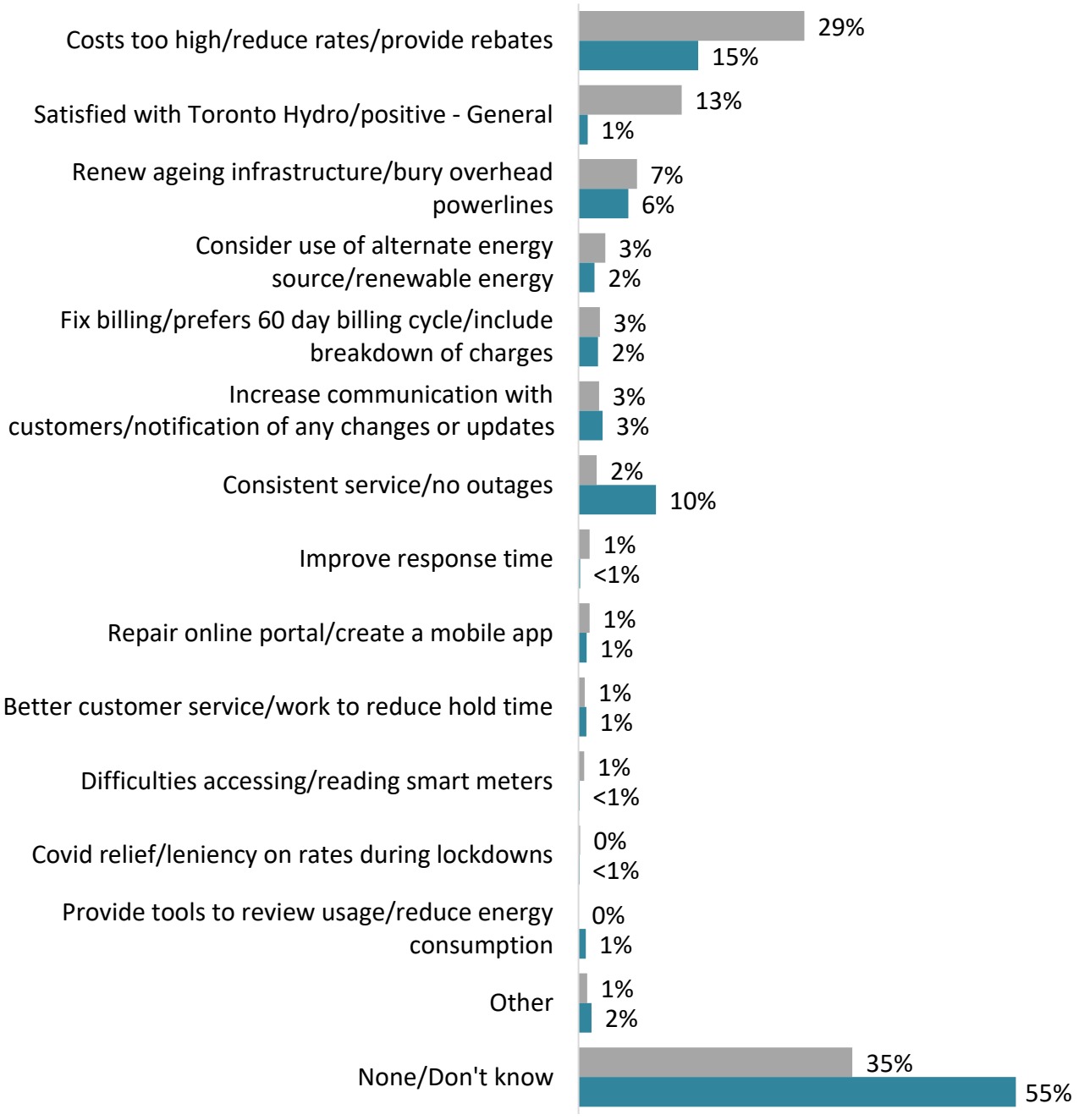
Residential

Suggestions for Improvement

Q Is there anything in particular you would like Toronto Hydro to do to improve its services to you?

Telephone

Online



Ranked in order by telephone responses. “Other” represents responses codes <1%.

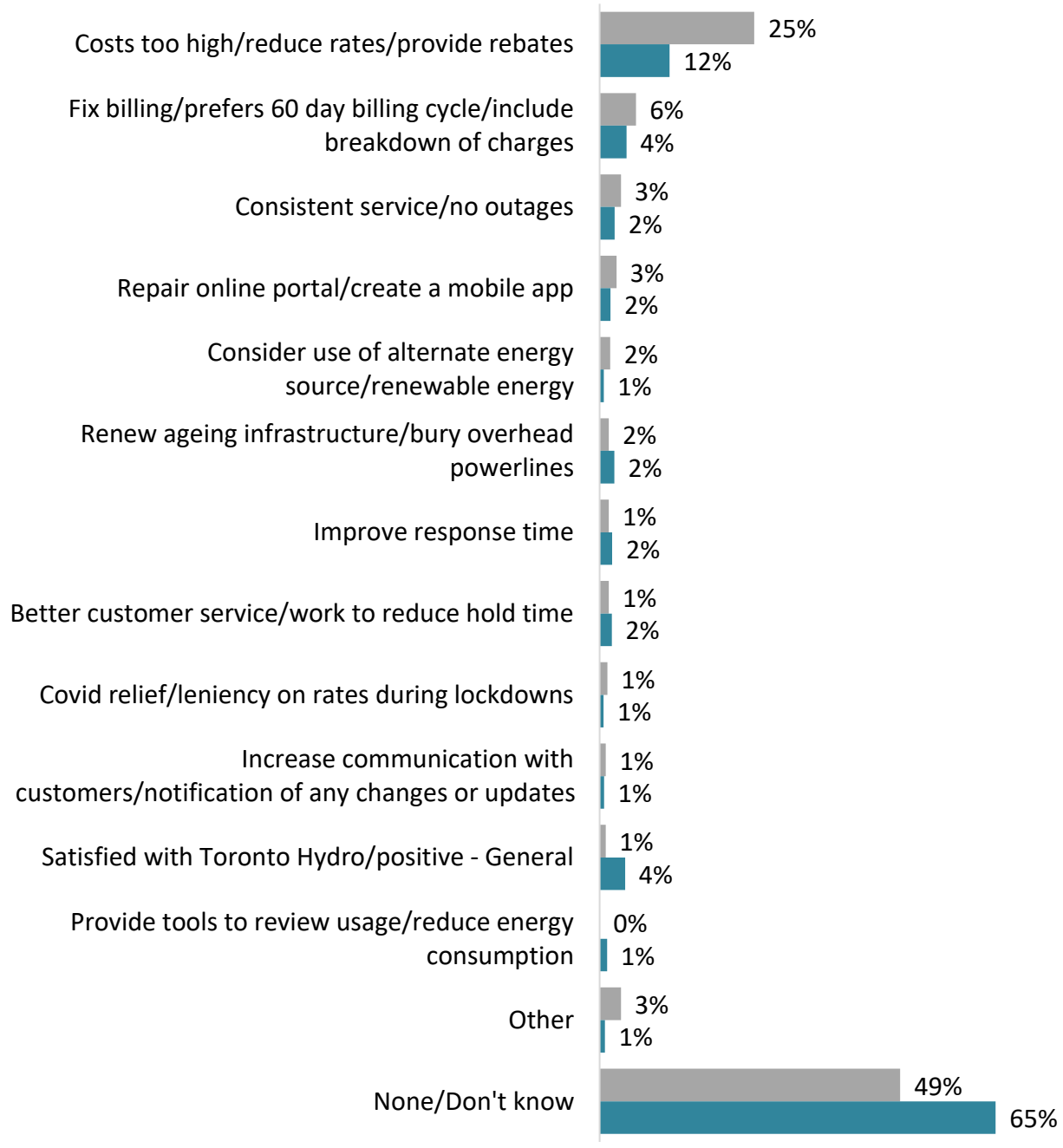
INNOVATIVE RESEARCH GROUP

Suggestions for Improvement

Q Is there anything in particular you would like Toronto Hydro to do to improve its services to you?

Telephone

Online



Ranked in order by telephone responses. “Other” represents responses codes <1%.

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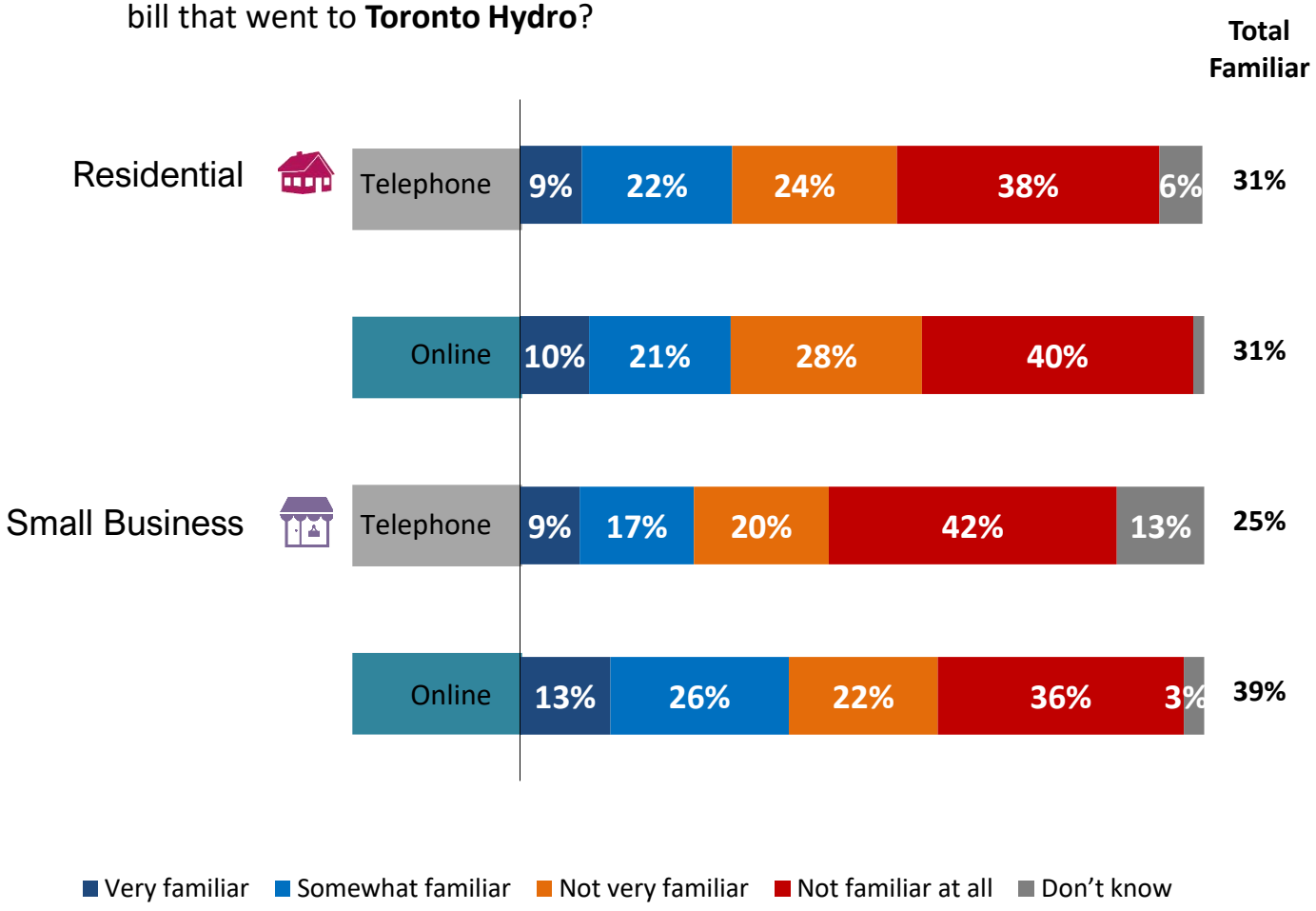
Familiarity Toronto Hydro's Share of the Bill

While **Toronto Hydro** is only responsible for the distribution portion of the system, to make it easier for customers, they are responsible for collecting payment for the entire electricity system.

Toronto Hydro keeps about [Residential: **30%** / Small Business: **31%**] of the average residential customer's bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of your electricity bill that went to **Toronto Hydro**?



Note: sums added before rounding.

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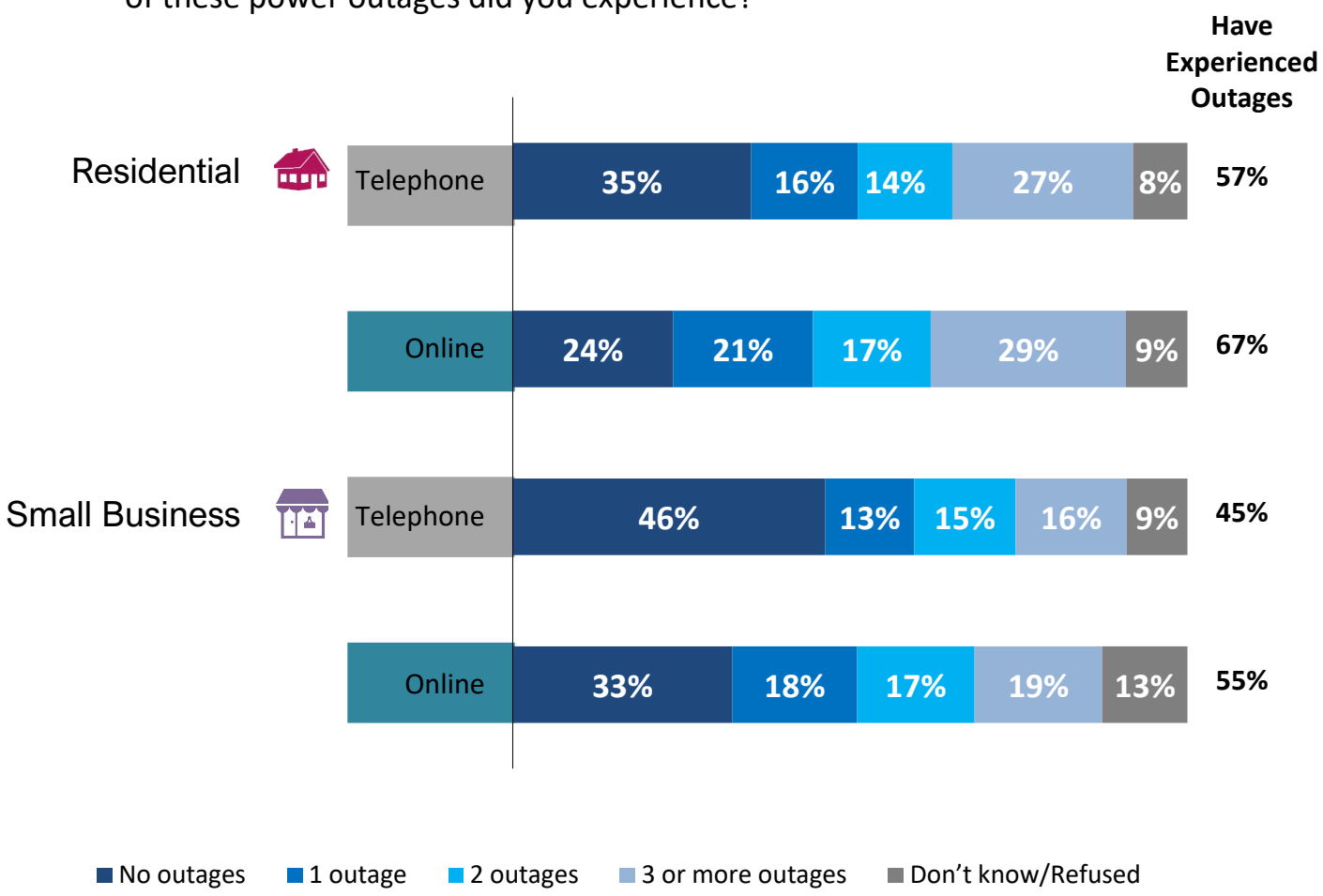
Reliability Experience

Q **[Residential]** Now, let's talk about the reliability of electricity service you receive.

Have you experienced any power outages at **home in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?

[Small Business] Now, let's talk about the reliability of electricity service your organization receives.

Have you experienced any power outages at **your organization in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?



Note: sums added before rounding.

INNOVATIVE RESEARCH GROUP

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro. The conclusions drawn and opinions expressed are those of the authors.

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CONFIDENTIAL

APPENDIX 03

Residential
Needs and Preferences Survey

November 2, 2023

2025 – 2029 Rate Application

Report Navigation

APPENDICIES

PHASE I

- APPENDIX.01 – Customer Engagement Focus Groups
- APPENDIX.02 – Customer Sample Validation
- APPENDIX.03 – Residential Needs and Preferences Survey
- APPENDIX.04 – Small Business Needs and Preferences Survey
- APPENDIX.05 – Commercial & Industrial Needs and Preferences Survey
- APPENDIX.06 – Key Accounts Needs and Preferences Survey
- APPENDIX.07 – Needs and Preferences Planning Placemat

PHASE II

- APPENDIX.08 – Customer Engagement Workbook Overview
- APPENDIX.09 – Residential Workbook Report
- APPENDIX.10 – Small Business Workbook Report
- APPENDIX.11 – Commercial & Industrial Workbook Report
- APPENDIX.12 – Key Accounts Workbook Report
- APPENDIX.13 – Customer Engagement Workbook (Residential Version)

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Residential Customers

Online Survey Results

Section 3.1



Online Survey

Survey Design & Methodology

Residential

INNOVATIVE was engaged by Toronto Hydro to gather customer input to assess the importance of the outcomes and priorities identified in the qualitative components of Phase I of the customer engagement.

Field Dates

The **Residential Online Survey** was sent to a random selection of Toronto Hydro residential customers who provided the utility with an email address. Customers had an opportunity to complete the survey between **December 7th, 2021, and January 10th, 2022**.

Each customer received a unique URL that could be linked back to their annual consumption, region and rate class.

In total, the residential survey was sent to **40,094** customers from *customerexperience@torontohydro.com*. A reminder email was sent 6 days after the initial invitation to those who had not yet completed the survey.

Residential Online Survey Completes

A total of **1,685** (unweighted) Toronto Hydro residential customers completed the online survey via unique URL.

Sample Weighting

The residential online survey sample was weighted proportionately by age, consumption quartiles and region in order to be representative of the broader Toronto Hydro customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region, as well as age against the telephone reference survey.

Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
Etobicoke/York	63 (71)	83 (78)	87 (83)	88 (81)	321 (312)
North York	54 (90)	81 (84)	81 (84)	86 (94)	302 (352)
Scarborough	37 (35)	91 (94)	94 (105)	74 (85)	307 (321)
Toronto/E. York	218 (203)	213 (145)	145 (162)	162 (140)	755 (615)
Total	372 (400)	468 (400)	435 (400)	410 (400)	1685 (1600)

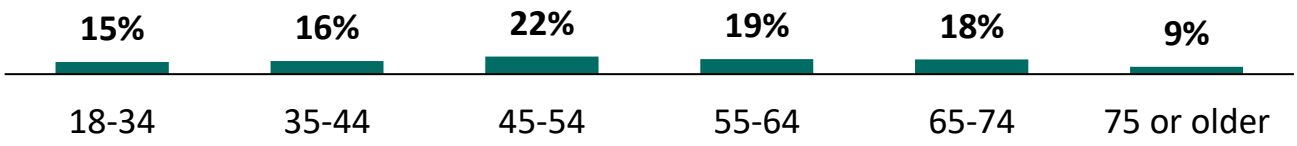
Age	Total
18-34	88 (242)
35-54	515 (616)
55+	1082 (741)
Total	1685 (1600)

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Online Survey
Demographic breakdown

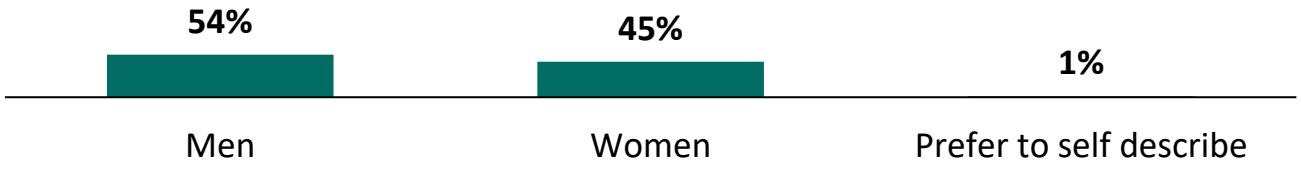
Residential

Q Age



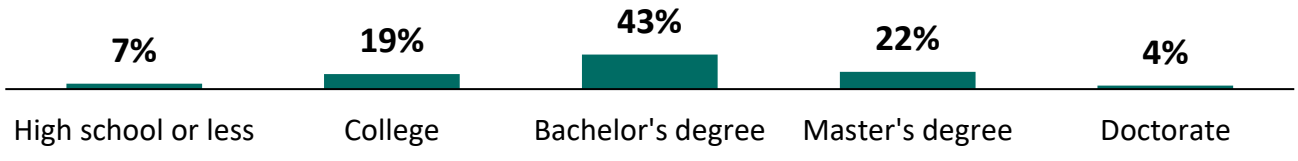
n=1,600

Q Gender



n=1,600

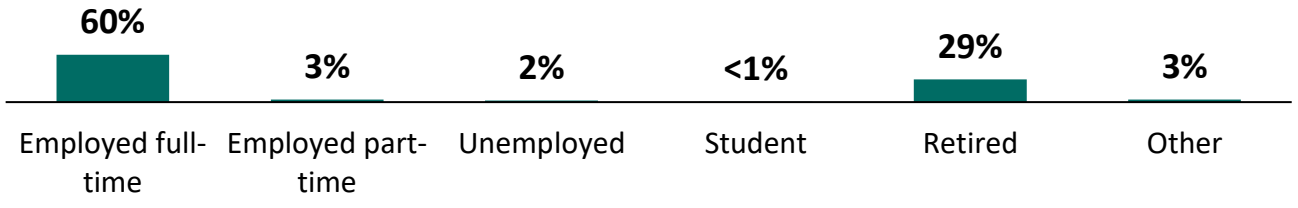
Q Education



"Prefer not to say" (5%) not shown.

n=1,600

Q Employment Status



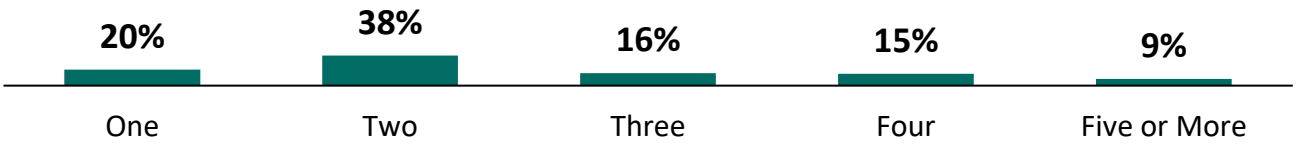
"Prefer not to say" (2%) not shown.

n=1,600

Online Survey
Demographic breakdown

Residential

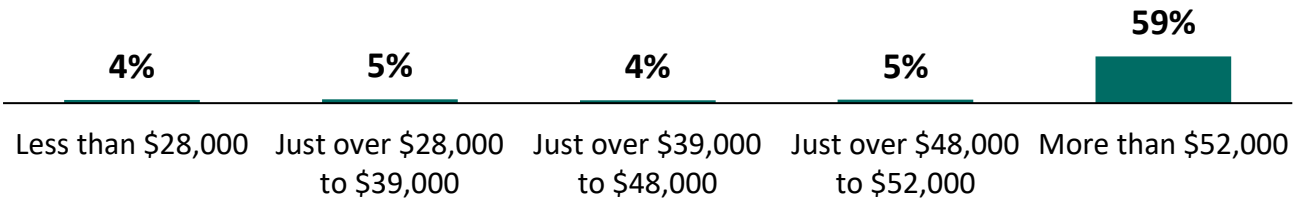
Q Household Size



"Prefer not to say" (3%) not shown.

n=1,600

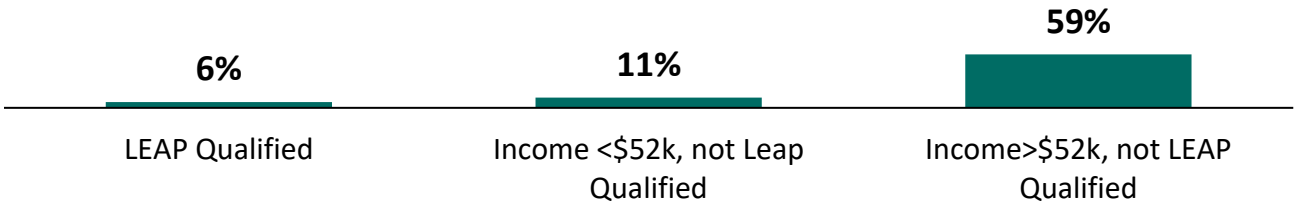
Q After Tax Household Income



"Prefer not to say" (23%) not shown.

n=1,600

Q LEAP Qualification (calculated based on household size and income)



"Prefer not to say" (23%) not shown.

n=1,600

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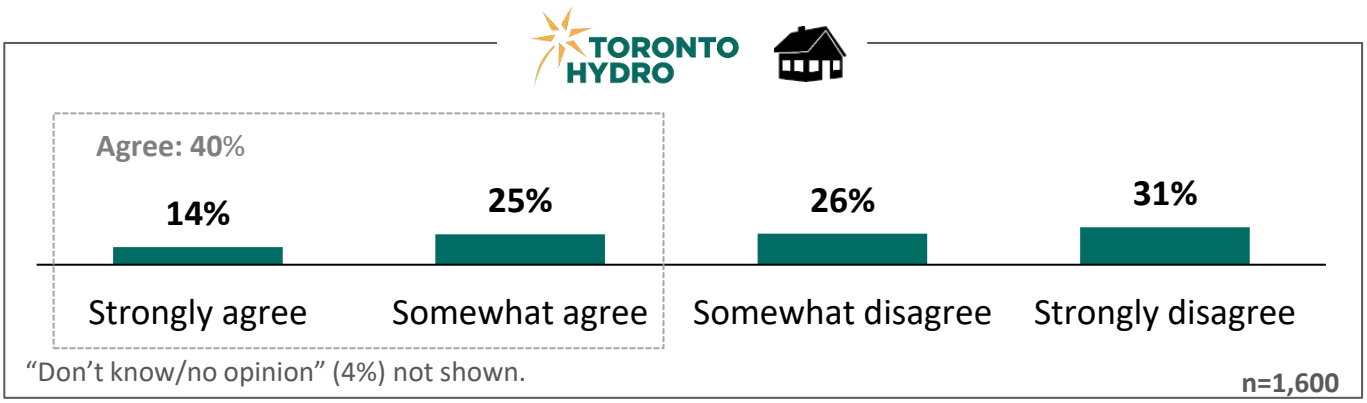
Online Survey
Environmental Controls

Residential

To what extent do you agree or disagree with the following statements?

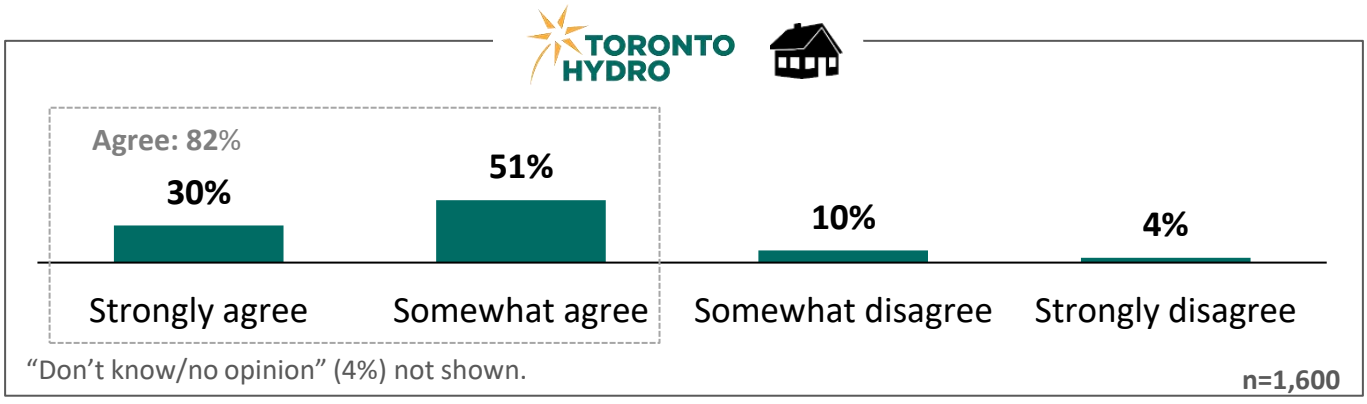
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know/no opinion" (4%) not shown.

n=1,600

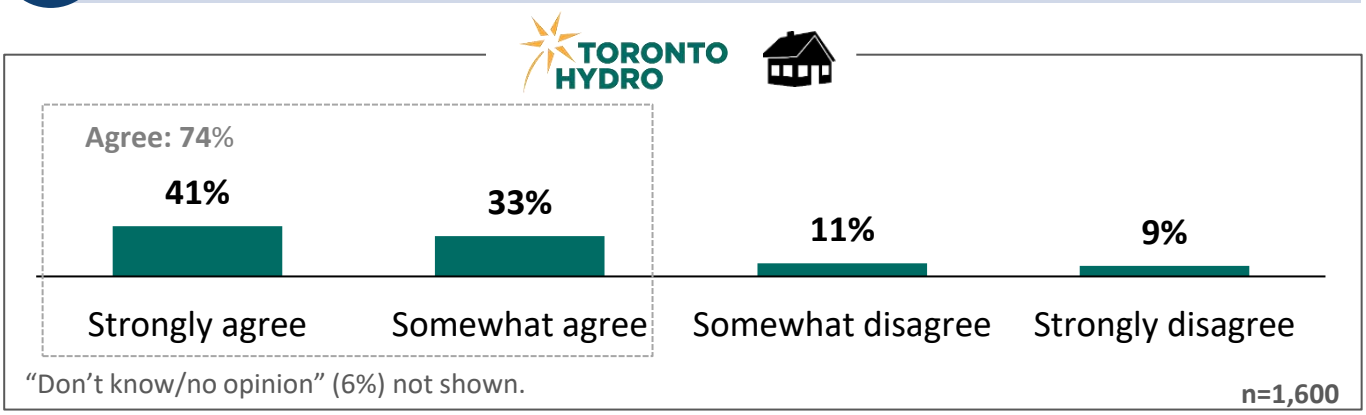
Q Customers are well-served by the electricity system in Ontario.



"Don't know/no opinion" (4%) not shown.

n=1,600

Q Fossil fuels should be phased out as quickly as possible to speed up the shift to a lower-carbon future.



"Don't know/no opinion" (6%) not shown.

n=1,600

Online Survey

Familiarity with Ontario's Electricity System

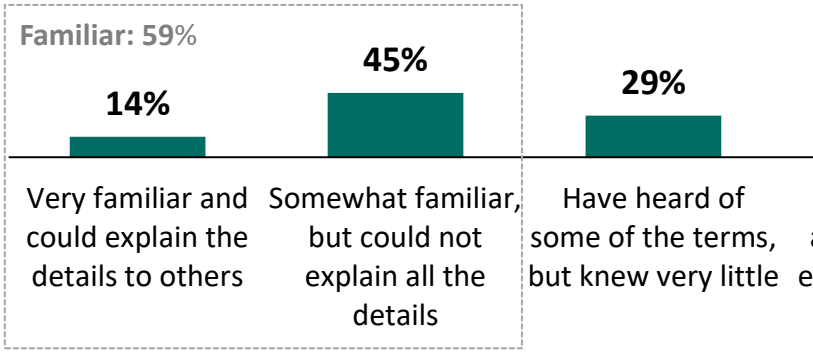
Residential

As you may know, Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province
- **Local distribution networks** take the electricity from provincial transmission lines and bring it to your home through a network of wires, poles and other equipment.

Q Before this survey, how familiar were you with the various parts of the electricity system and how they work together?

TORONTO HYDRO



	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Very familiar	17%	15%	14%	12%	12%	13%	15%
Somewhat familiar	48%	40%	45%	46%	42%	47%	45%
Knew very little	24%	30%	30%	31%	29%	27%	30%
Knew nothing	8%	13%	9%	10%	15%	11%	9%
Don't know	2%	2%	2%	1%	2%	2%	2%
Familiar (Very + Somewhat)	**66%**	**55%**	**59%**	**59%**	**54%**	**60%**	**60%**

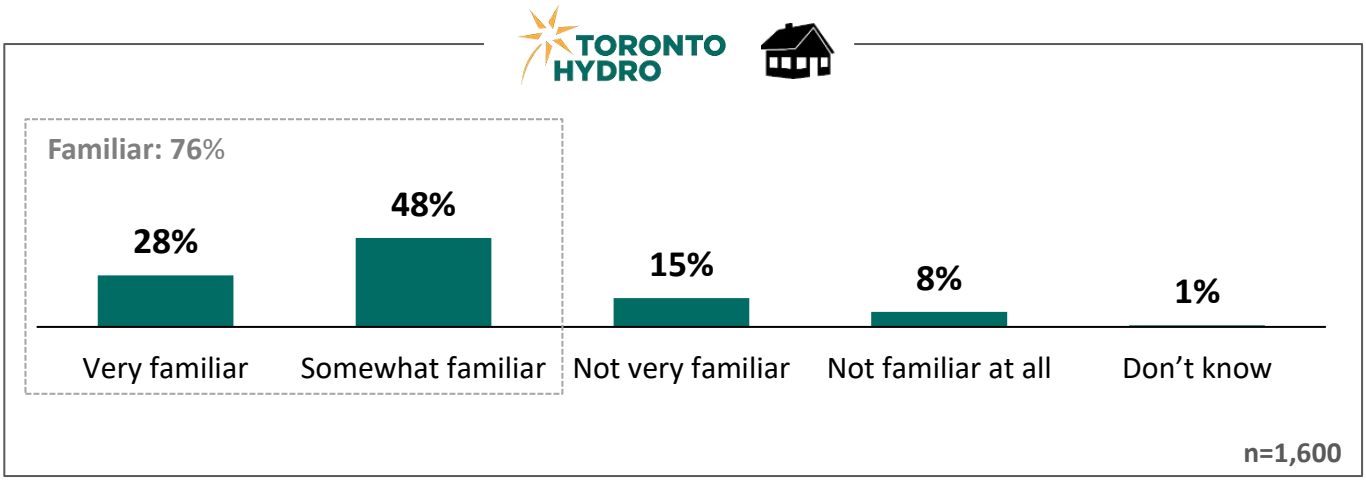
Online Survey

Familiarity with Toronto Hydro

Residential

Toronto Hydro owns and operates Toronto's distribution network. This is the network that takes the electricity from high-voltage transmission towers and brings it to your home through a network of wires, poles and other equipment.

Q Before this survey, how familiar were you with **Toronto Hydro**, which operates the electricity distribution system in your community?



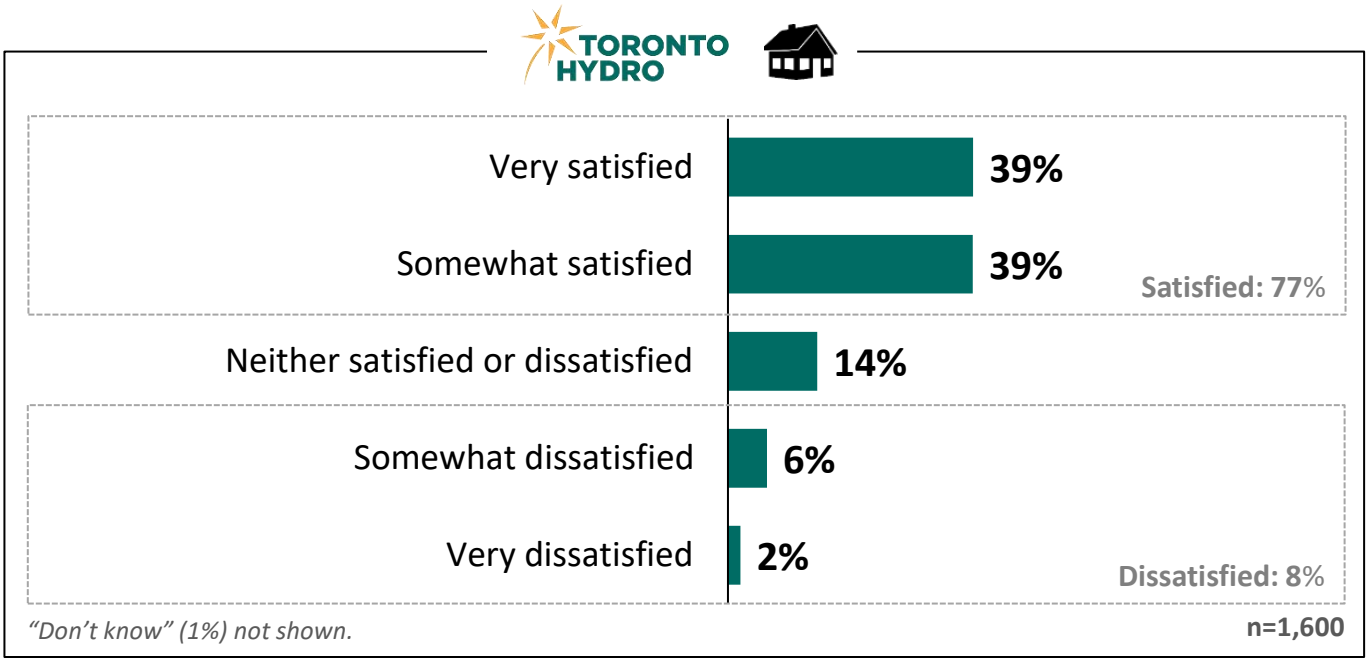
		Region			Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Very familiar	31%	27%	32%	24%	32%	25%	28%
Somewhat familiar	50%	46%	45%	50%	41%	48%	50%
Not very familiar	11%	15%	16%	18%	16%	15%	15%
Not familiar at all	7%	11%	6%	8%	10%	11%	7%
Don't know	1%	1%	<1%	1%	1%	1%	1%
Familiar (Very + Somewhat)	**81%**	**73%**	**77%**	**74%**	**73%**	**73%**	**77%**

Online Survey

Overall Satisfaction with Toronto Hydro

Residential

Q Thinking specifically about the services provided to you and your community by **Toronto Hydro**, overall, how satisfied or dissatisfied are you with the services that you receive?



"Don't know" (1%) not shown.

n=1,600

	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Very satisfied	38%	38%	39%	39%	32%	33%	42%
Somewhat satisfied	33%	42%	41%	38%	36%	39%	39%
Neither satisfied or dissatisfied	16%	11%	13%	15%	19%	14%	13%
Somewhat dissatisfied	8%	6%	6%	6%	7%	11%	4%
Very dissatisfied	4%	2%	1%	1%	6%	3%	1%
Satisfied (Very + Somewhat)	**71%**	**80%**	**81%**	**77%**	**68%**	**72%**	**81%**
Dissatisfied (Very + Somewhat)	**11%**	**8%**	**7%**	**7%**	**12%**	**13%**	**5%**

Online Survey

Residential

How Toronto Hydro can Improve Services to Customers

Q Is there anything in particular you would like Toronto Hydro to do to improve its services to you?

Response	%
Costs too high/reduce rates/provide rebates	15.1%
Consistent service/no outages	9.8%
Renew ageing infrastructure/bury overhead powerlines	6.3%
Increase communication with customers/notification of any changes or updates	3.0%
Fix billing/prefers 60-day billing cycle/include breakdown of charges	2.5%
Consider use of alternate energy source/renewable energy	2.0%
Satisfied with Toronto Hydro/positive - General	1.2%
Repair online portal/create a mobile app	1.0%
Better customer service/work to reduce hold time	1.0%
Provide tools to review usage/reduce energy consumption	0.9%
Improve response time	0.2%
Difficulties accessing/reading smart meters	0.1%
Covid relief/leniency on rates during lockdowns	0.1%
Other	1.6%
None/Don’t know	55.2%

Note: Only responses >0.1% shown

Online Survey

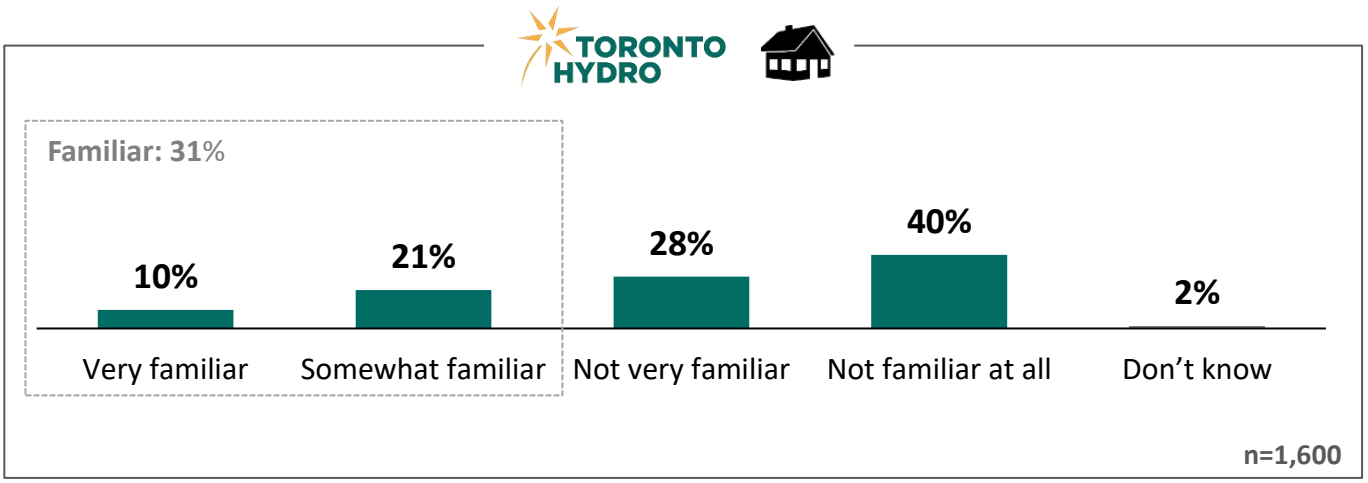
Familiarity with Bill Remittance to Toronto Hydro

Residential

While **Toronto Hydro** is only responsible for the distribution portion of the system, to make it easier for customers, they are responsible for collecting payment for the entire electricity system.

Toronto Hydro keeps about **30%** of the average residential customer's bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Q Before this survey, how familiar were you with the amount of your electricity bill that went to **Toronto Hydro**?



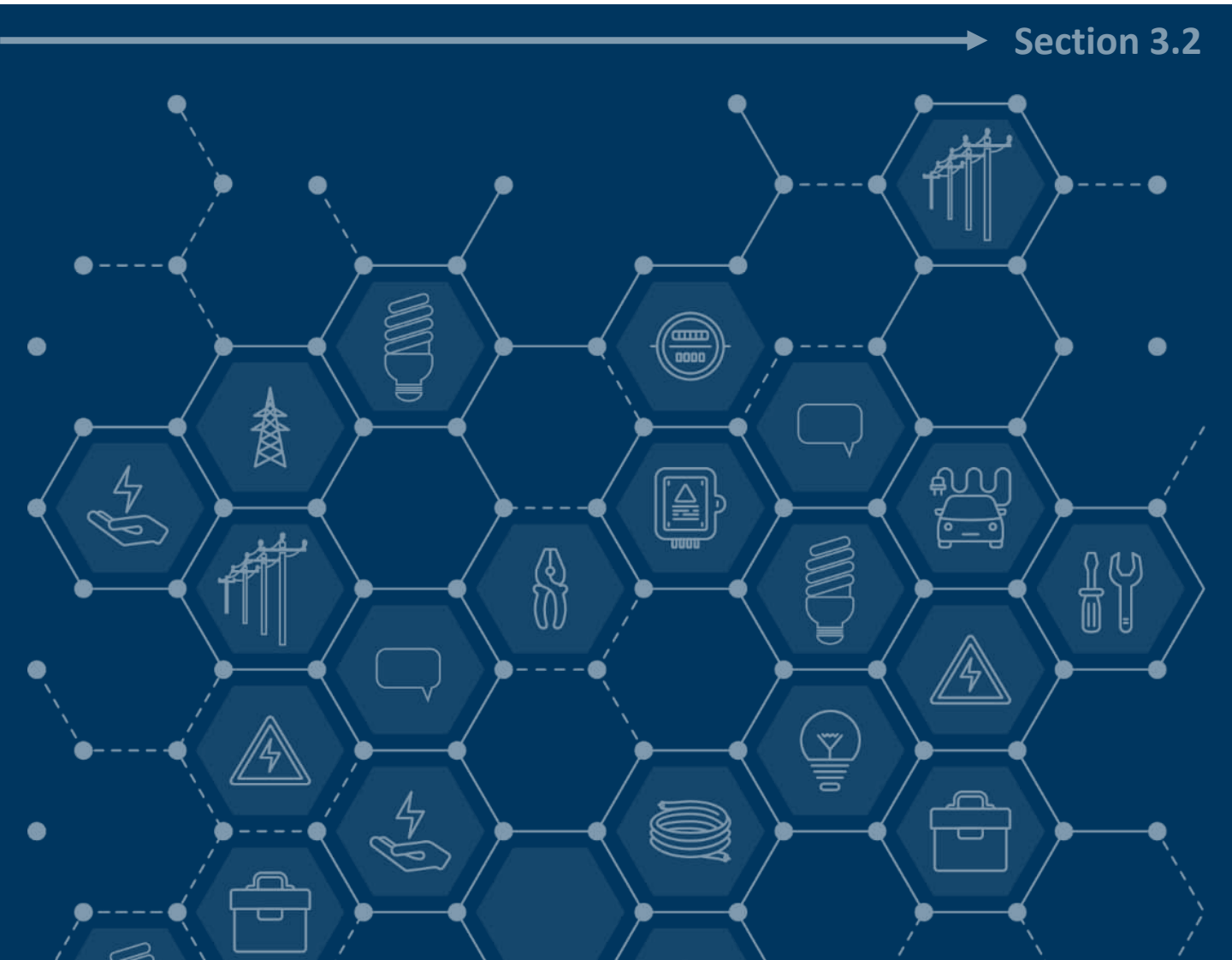
	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Very familiar	15%	9%	10%	8%	9%	10%	10%
Somewhat familiar	22%	23%	23%	18%	21%	30%	17%
Not very familiar	25%	26%	33%	28%	27%	26%	29%
Not familiar at all	36%	39%	33%	46%	40%	31%	43%
Don't know	2%	3%	1%	1%	3%	2%	1%
Familiar (Very + Somewhat)	**37%**	**33%**	**33%**	**25%**	**30%**	**41%**	**27%**

INNOVATIVE RESEARCH GROUP

Residential Customers

Consumer Priorities

Section 3.2



Online Survey

Importance of Customer Priorities

Residential

Now, let's talk about our second topic – outcomes.

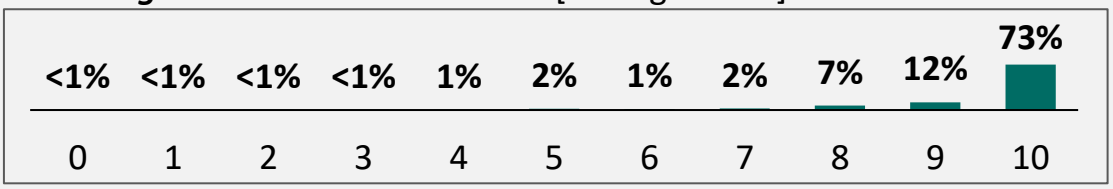
Everyday **Toronto Hydro** interacts with hundreds of its customers through multiple channels and touchpoints, including surveys, the call centre and social media.

In a recent series of customer focus groups, a number of company goals were identified as priorities for **Toronto Hydro**.

Q

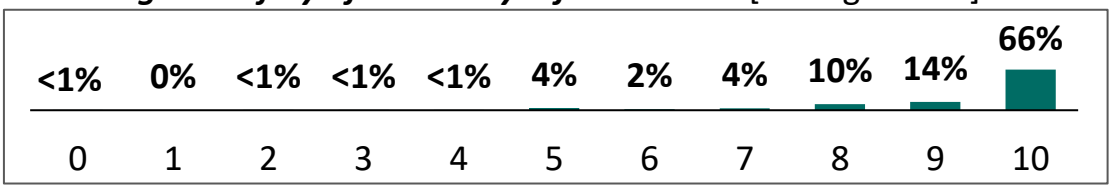
Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Toronto Hydro** priorities to you as a customer?

Ensuring reliable electrical service [average = **9.5**]



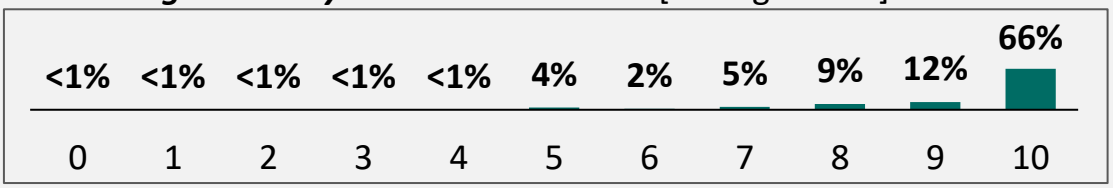
Not at all important — Extremely important

Ensuring the safety of electricity infrastructure [average = **9.2**]



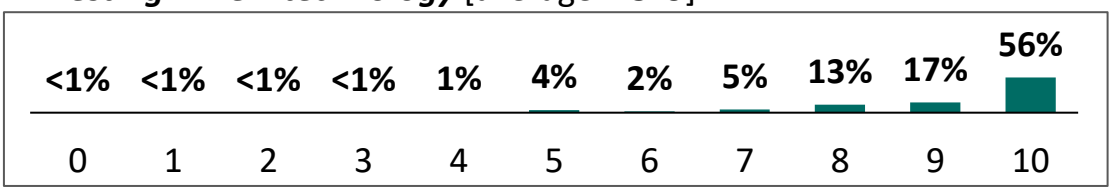
Not at all important — Extremely important

Delivering electricity at reasonable rates [average = **9.2**]



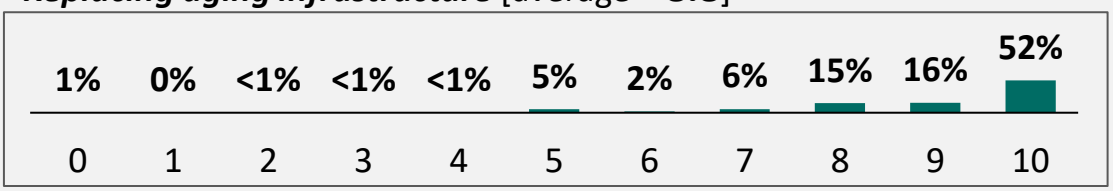
Not at all important — Extremely important

Investing in new technology [average = **9.0**]



Not at all important — Extremely important

Replacing aging infrastructure [average = **8.8**]



Not at all important — Extremely important

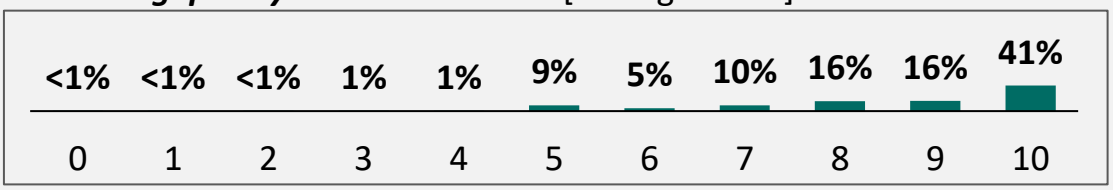
Online Survey

Importance of Customer Priorities (Cont'd)

Residential

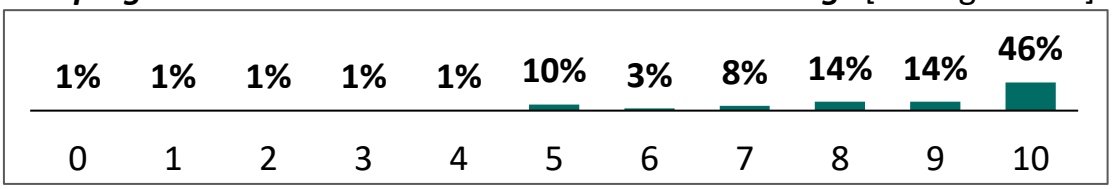
Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Toronto Hydro** priorities to you as a customer?

Providing quality customer service [average = **8.4**]



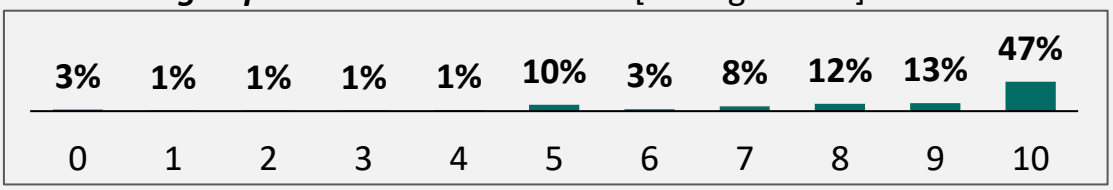
Not at all important — Extremely important

Helping customers with conservation and cost savings [average = **8.4**]



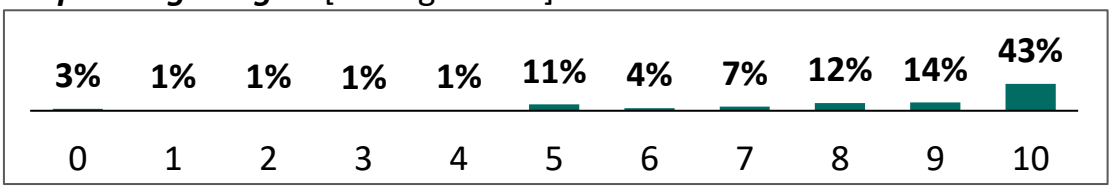
Not at all important — Extremely important

Minimizing impact on the environment [average = **8.2**]



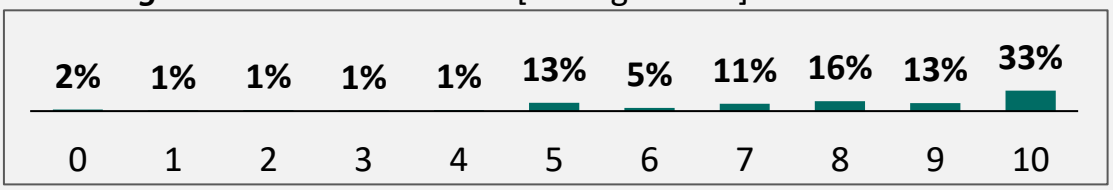
Not at all important — Extremely important

Expanding the grid [average = **8.0**]



Not at all important — Extremely important

Enabling access to new services [average = **7.7**]



Not at all important — Extremely important

INNOVATIVE RESEARCH GROUP

Online Survey

Importance of Customer Priorities | Summary Scores

Residential

Q

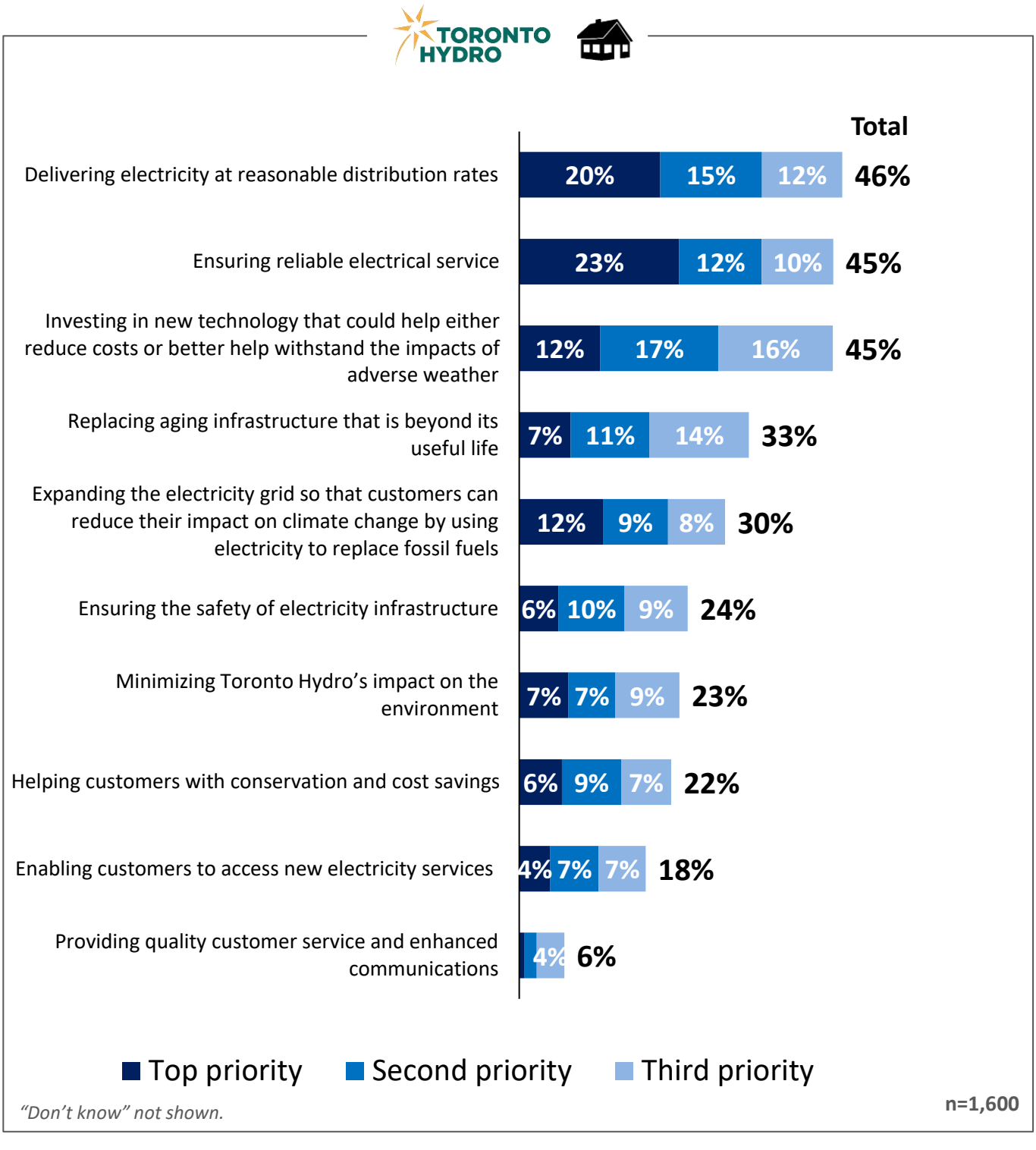
Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Toronto Hydro** priorities to you as a customer?

	Region				Bill impact on finances		
Average Score	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Ensuring reliable service	9.4	9.5	9.5	9.4	9.4	9.4	9.5
Ensuring safety of infrastructure	9.1	9.3	9.3	9.2	9.1	9.1	9.3
Delivering electricity at reasonable rates	9.3	9.3	9.3	9.1	9.7	9.3	9.1
Investing in new technology	8.9	9.1	8.9	9.0	8.8	9.0	9.0
Replacing aging infrastructure	8.9	8.9	8.6	8.9	8.5	8.8	9.0
Providing quality customer service	8.4	8.5	8.6	8.2	8.6	8.5	8.2
Helping customers with conservation	8.3	8.4	8.5	8.3	8.7	8.6	8.2
Minimizing impact on the environment	8.0	8.0	8.1	8.6	7.5	8.3	8.4
Expanding the grid	7.8	7.8	7.7	8.4	7.1	8.0	8.3
Enabling access to new services	7.9	7.6	7.8	7.7	7.8	7.8	7.7

Online Survey
Ranking Customer Priorities

Residential

Q Thinking of the priorities on the previous page, which would you say is the **most** important? What is the next most important priority you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?



"Don't know" not shown.

n=1,600

Online Survey

Ranking Customer Priorities | Summary Scores

Residential

Q Thinking of the priorities on the previous page, which would you say is the **most** important? What is the next most important priority you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?

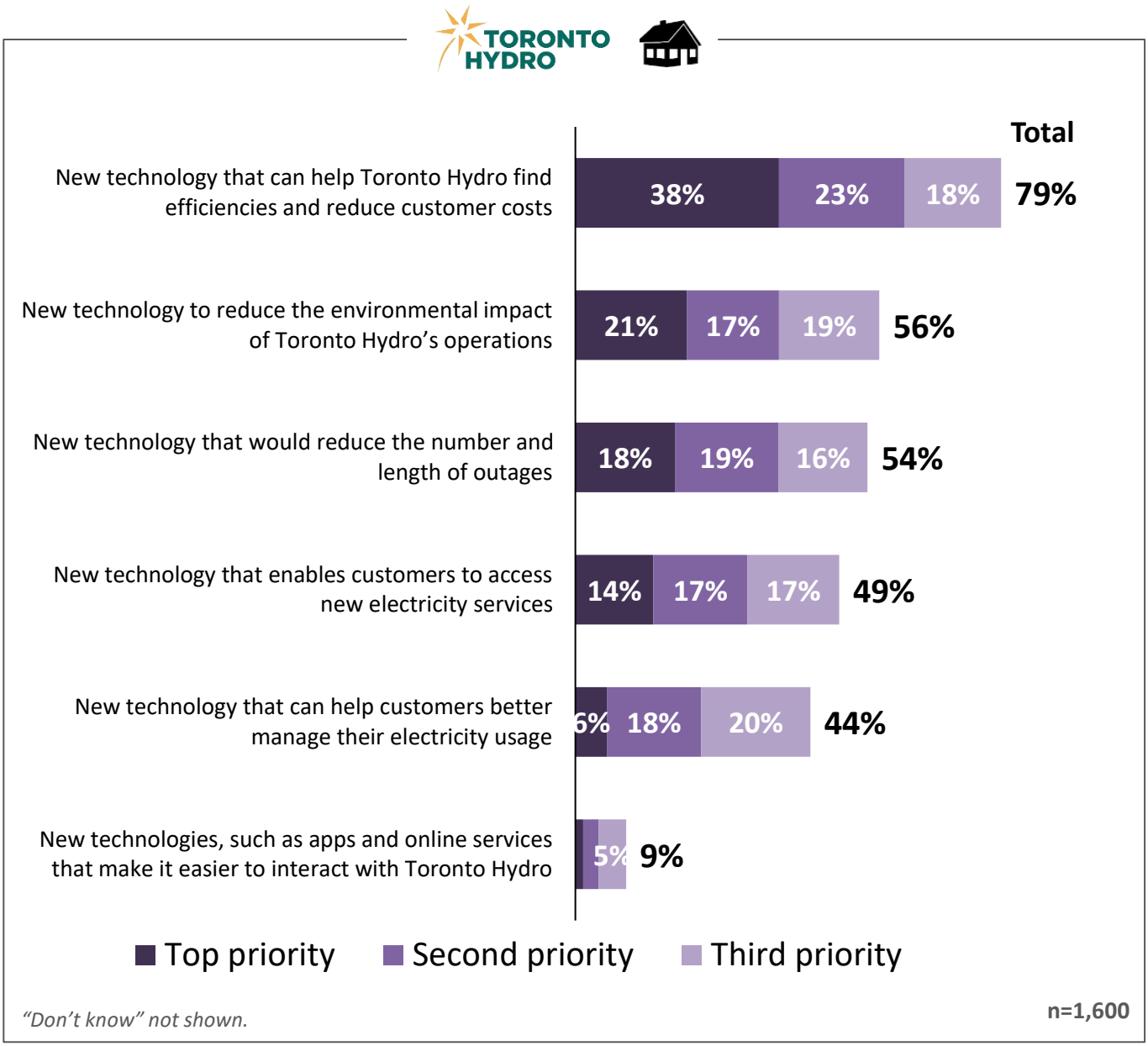
	Region				Bill impact on finances		
% who select as top 3 priority	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Delivering electricity at reasonable rates	50%	49%	52%	40%	74%	56%	36%
Ensuring reliable service	47%	50%	42%	43%	37%	44%	48%
Investing in new technology	46%	45%	46%	44%	38%	49%	45%
Replacing aging infrastructure	33%	33%	32%	33%	23%	30%	37%
Expanding the grid	26%	23%	24%	38%	14%	26%	35%
Ensuring safety of infrastructure	21%	28%	24%	24%	19%	21%	27%
Minimizing impact on environment	19%	20%	18%	29%	12%	22%	26%
Helping customers with conservation	24%	20%	32%	16%	47%	25%	15%
Enabling access to new services	18%	19%	16%	19%	14%	18%	20%
Providing quality customer service	8%	8%	7%	5%	12%	8%	5%

Online Survey
Ranking Technology Priorities

Residential

Investments in new technology can help Toronto Hydro address a range of issues. These include reliability, efficiency, customer service, Toronto Hydro's impact on the environment, new service offerings and tools to manage electricity usage.

Q Among the following potential investments in new technology, which would you say is the **most** important? What is the next most important new technology priority you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?



"Don't know" not shown.

n=1,600

Online Survey

Ranking Technology Priorities | Summary Scores

Residential

Q Among the following potential investments in new technology, which would you say is the **most** important? What is the next most important new technology priority you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?

	Region				Bill impact on finances		
% who select as top 3 priority	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
New tech that make it easier to interact with Toronto Hydro	78%	84%	84%	74%	92%	81%	75%
New technology to reduce the environmental impact of Toronto Hydro's operations	52%	51%	51%	64%	36%	55%	62%
New technology that would reduce the number and length of outages.	55%	62%	52%	51%	48%	54%	56%
New tech that enables customers to access new services	52%	41%	47%	53%	42%	45%	52%
New tech that can help customers better manage usage	41%	44%	49%	42%	56%	45%	40%
New technologies, such as apps and online services that make it easier to interact with Toronto Hydro.	10%	12%	11%	7%	20%	9%	7%

Online Survey
Additional Priorities

Q Can you think of any other important priorities that **Toronto Hydro** should be focusing on?

Response	%
Lowering rates	5.0%
Reducing carbon footprint/assessing environmental impact	4.0%
Improving reliability/safety/efficiency in power delivery	3.4%
Finding efficiencies/reducing operating costs	2.0%
Improving customer service/communication/transparency	1.9%
Offering renewable energy options	1.8%
Upgrading infrastructure/burying lines	1.3%
Allowing for greater demand due to electric vehicles	0.6%
Cyber Security/Grid Security	0.5%
Improve billing/provide more information on bill/usage	0.3%
Survey biased	0.1%
Other	1.5%
None	5.7%
Don't know	72.0%

Note: Only responses >0.1% shown

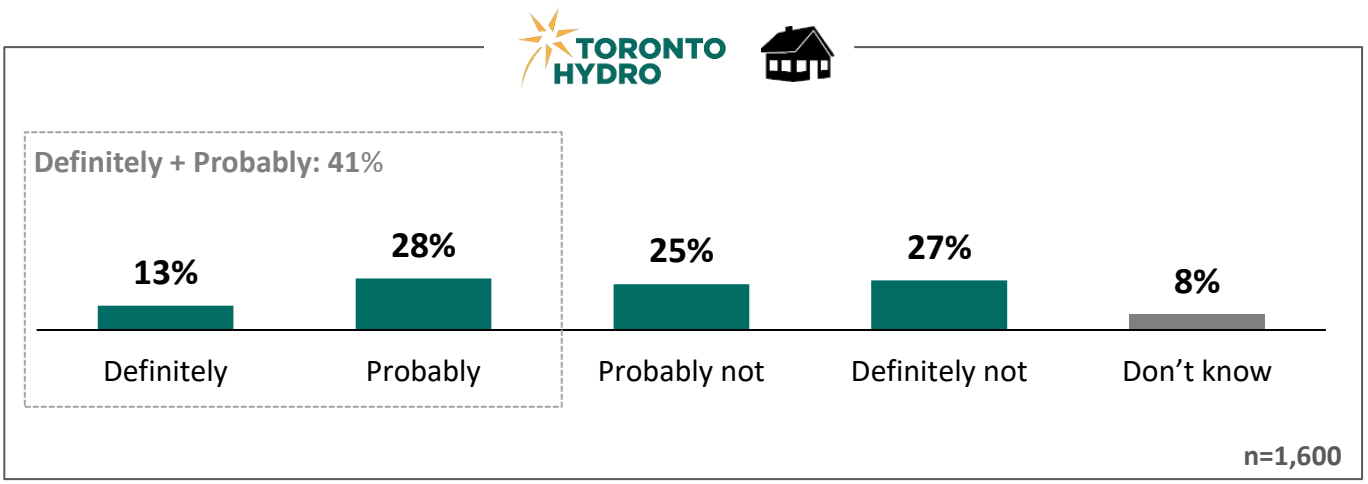
Online Survey

Support for Low-Income Customers

Residential

In recent interactions with customers, a number of customers identified assisting low-income Torontonians with their electricity bills.

Q In addition to the amount that you currently pay on your electricity bill, would you be willing to pay an extra few dollars per month in order for Toronto Hydro to provide financial assistance to make electricity bills more affordable for low-income customers?



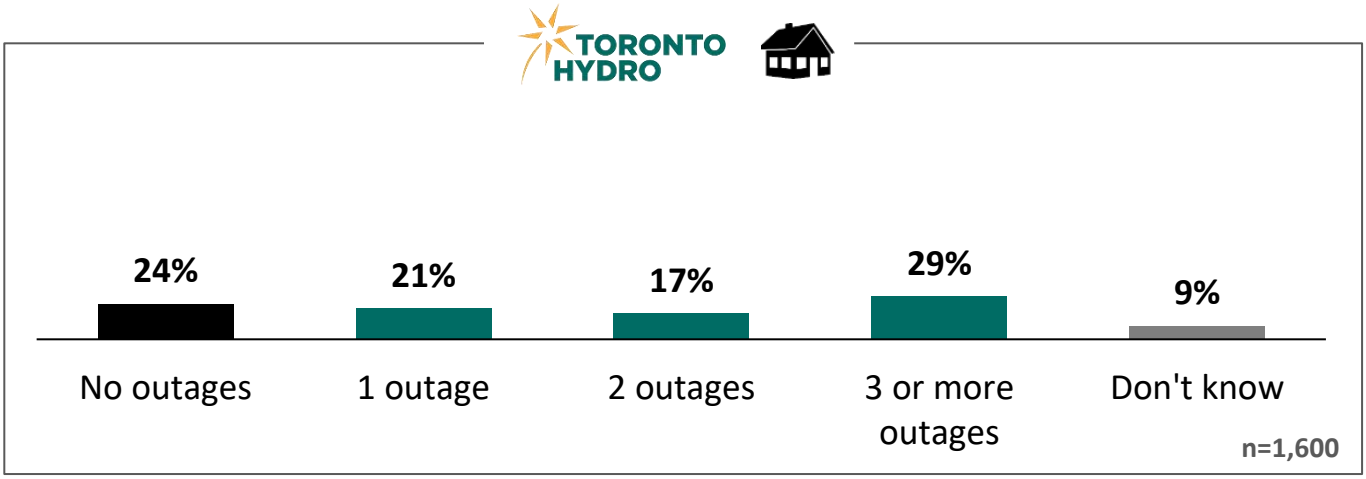
		Region			Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Definitely	9%	10%	11%	18%	6%	9%	17%
Probably	28%	22%	20%	34%	9%	23%	34%
Probably not	28%	23%	30%	20%	19%	30%	24%
Definitely not	27%	34%	31%	20%	61%	28%	18%
Don't know	8%	10%	7%	8%	6%	10%	8%
Definitely + Probably	37%	33%	32%	52%	14%	32%	51%

Online Survey

Number of Outages Experienced

Residential

Q Now, let's talk about the reliability of electricity service you receive. Have you experienced any power outages at **home in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?



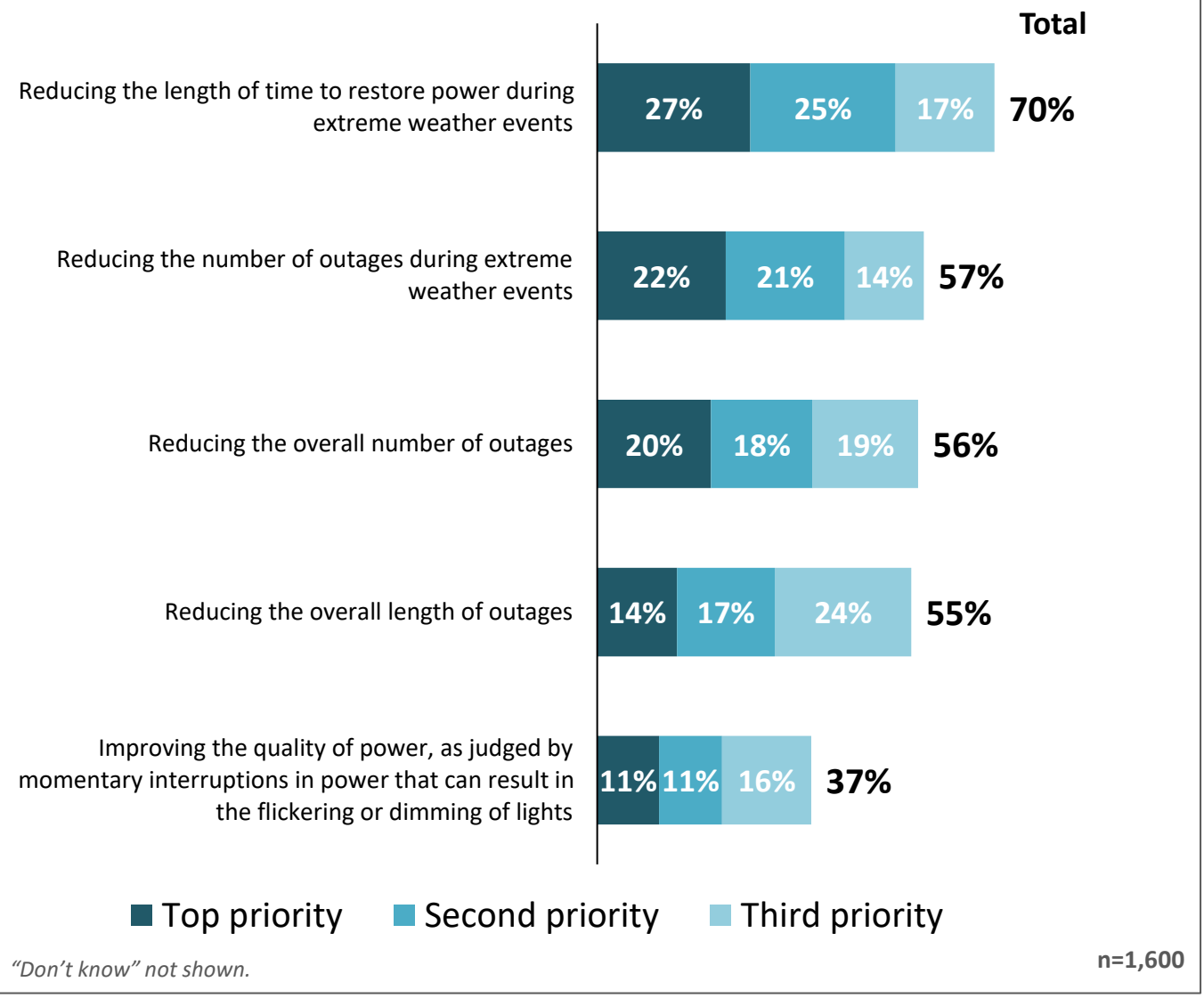
		Region			Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
No outages	16%	22%	16%	33%	20%	21%	26%
1 outage	21%	15%	24%	22%	17%	19%	22%
2 outages	20%	20%	19%	14%	21%	20%	16%
3 or more outages	35%	31%	33%	23%	35%	30%	27%
Don't know	8%	12%	7%	9%	7%	10%	9%

Online Survey
Ranking Reliability Priorities

Residential

When it comes to reliability, there are a number of areas that **Toronto Hydro** could focus on.

Q Among the following reliability outcomes, which would you say is the **most** important? What is the next most important reliability outcome you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?



"Don't know" not shown.

n=1,600

Online Survey

Ranking Reliability Priorities | Summary Scores

Residential

Q Among the following reliability outcomes, which would you say is the **most** important? What is the next most important reliability outcome you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?

	Region				Bill impact on finances		
% who select as top 3 priority	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Reducing the length of time to restore power during extreme weather events	63%	74%	66%	72%	67%	66%	72%
Reducing the number of outages during extreme weather events	53%	59%	55%	60%	59%	57%	57%
Reducing the overall number of outages	57%	55%	56%	57%	53%	58%	56%
Reducing the overall length of outages	58%	55%	58%	52%	56%	51%	56%
Improving the quality of power, as judged by momentary interruptions	43%	38%	45%	31%	45%	43%	33%

INNOVATIVE RESEARCH GROUP

Residential Customers

Investment Trade-Offs

Section 3.3



Online Survey
System Renewal

Residential

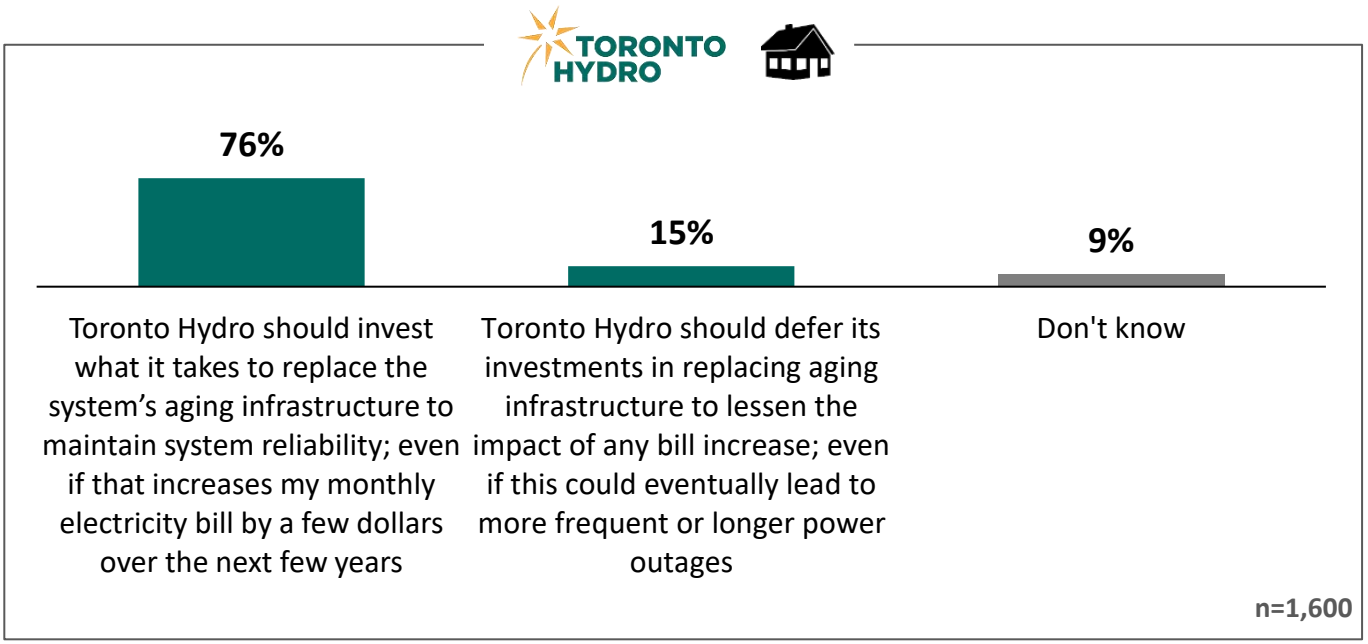
Now let's turn to our final topic – investment trade-offs.

Toronto Hydro is in the early stages of developing its investment plan for the next five years. While conversations with customers will continue over the next several months, the utility wants to know your preferences when it comes to finding the right balance between costs and other outcomes.

There are four investment categories that we would like to discuss.

The first category focuses on projects that replace and restore aging electrical infrastructure, like overhead poles and underground cables.

Q Regarding investments in aging infrastructure, which of the following statements best represents your point of view?



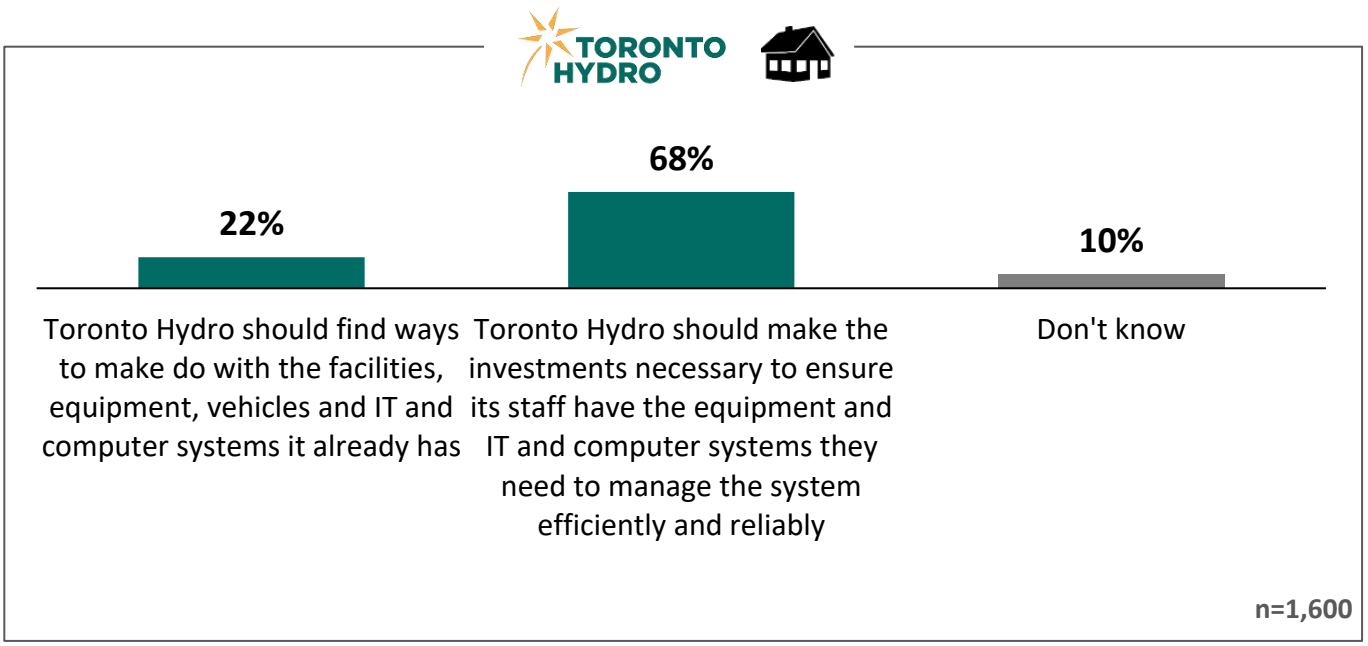
	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Invest what it takes	73%	76%	70%	82%	47%	67%	88%
Defer investments	17%	15%	20%	10%	41%	19%	6%
Don't know	10%	9%	10%	8%	12%	14%	6%

Online Survey
General Plant

Residential

The second category focuses on keeping **Toronto Hydro's** business running. This includes facilities to house staff and equipment, vehicles and tools to service equipment and IT systems to manage the system and other information.

Q Regarding these types of investments, which of the following best represents your point of view?



	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Make do with what it already has	24%	26%	25%	17%	43%	22%	17%
Make the necessary investments	65%	66%	63%	73%	48%	65%	74%
Don't know	12%	8%	12%	10%	9%	13%	9%

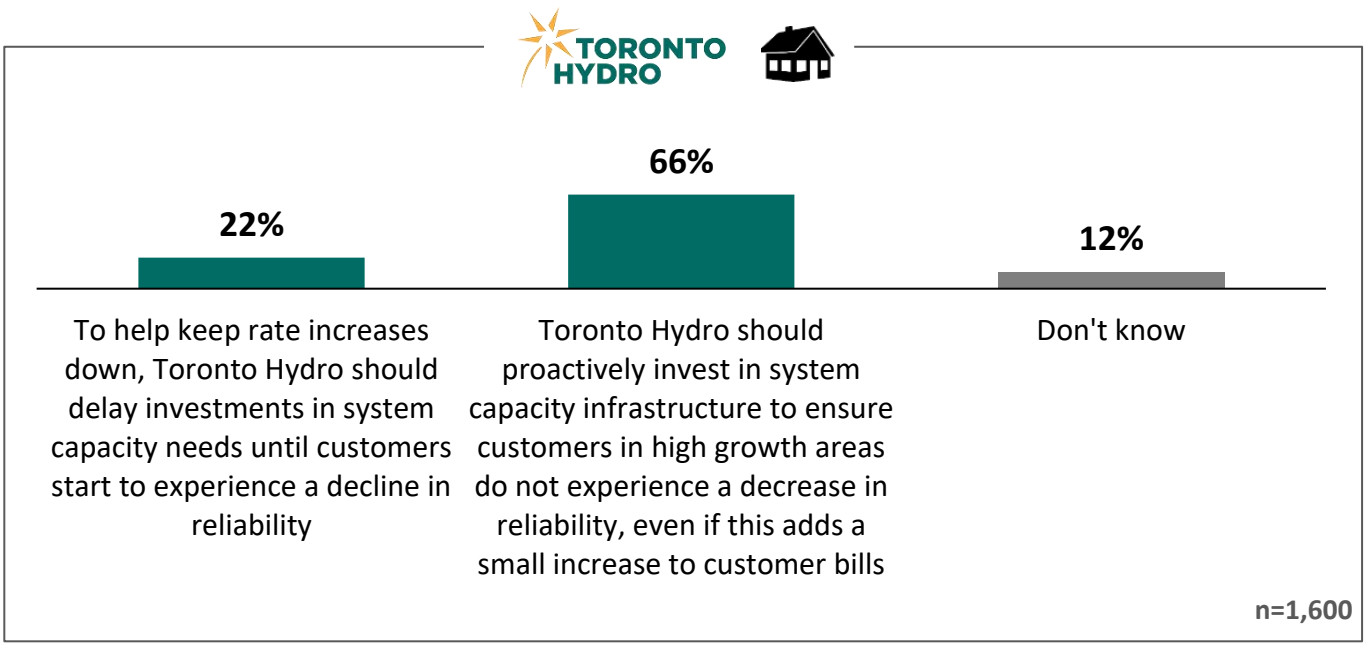
Online Survey
System Service

Residential

The third investment category focuses on growth and greater demand for electricity in various parts of **Toronto Hydro's** service territory.

Increased demand for electricity puts pressure on existing electrical infrastructure. Eventually, further infrastructure investments are required to support increased demand for electricity.

Q With this in mind, which of the following statements best represents your point of view?



	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Delay investments	21%	27%	31%	15%	49%	24%	15%
Proactively invest	65%	60%	59%	75%	35%	61%	76%
Don't know	14%	13%	11%	10%	16%	15%	9%

Online Survey
Grid Modernization

Residential

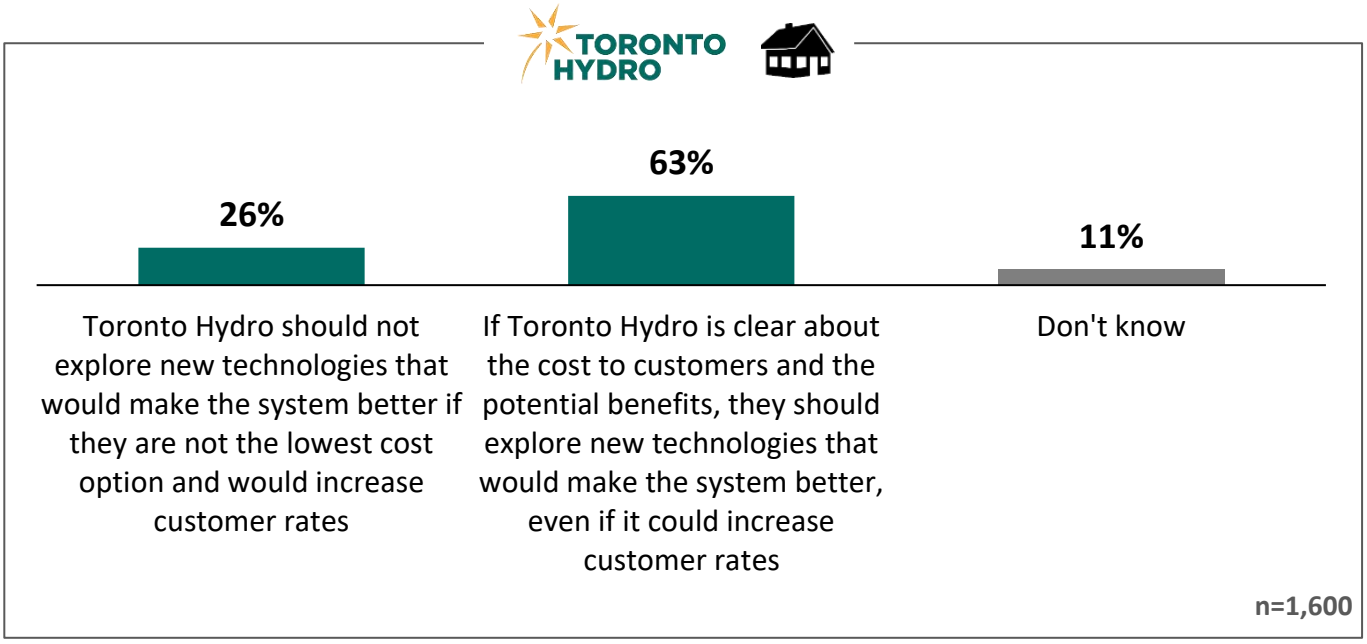
Toronto Hydro can invest in technology than can lead to a wide range of benefits including reliability, efficiency, customer service, and reducing environmental impacts.

When deemed the lowest cost option that will provide equal or improved service, Toronto Hydro will, in most cases, invest in technology.

However, there are two other scenarios where Toronto Hydro needs your feedback.

First, there are times when Toronto Hydro identifies new technology that can improve reliability or provide other benefits, but it will cost customers more. For instance, advanced customer meters that can measure when different home appliances are running, allowing Toronto Hydro to provide customers with better advice on how to reduce their energy consumption and costs.

Q Regarding these types of investments, which of the following best represents your view?



	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Should not explore new tech	29%	31%	31%	20%	47%	33%	18%
Should explore new tech	60%	57%	59%	69%	39%	54%	72%
Don't know	11%	12%	10%	11%	14%	13%	9%

Online Survey
Grid Modernization (Con't)

Residential

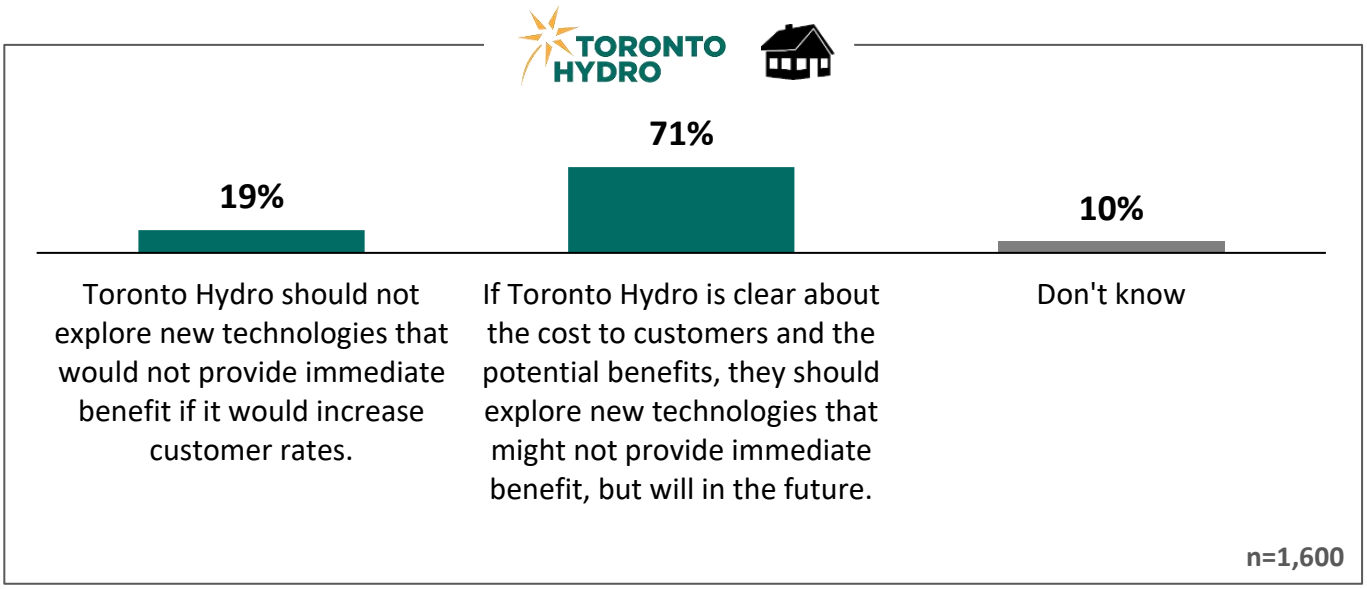
The second scenario is where Toronto Hydro identifies new technology that is needed to improve the system in the future and would increase costs now, but the benefit might not be felt until later.

This includes accommodating emerging technologies like solar power, battery storage and electric vehicles.

Regardless of whether you are considering new energy choices like an electric vehicle for yourself today, Toronto Hydro must be prepared as adoption becomes more widespread over the next 5-10 years.

For instance, charging each electric vehicle draws as much energy as two average homes. If a dozen or so people come home and start changing their vehicles at a period of peak demand, it could overload the grid in that neighbourhood. While Toronto Hydro cannot predict the exact rate of electric vehicle adoption in the City of Toronto, the utility must make certain investments today that will allow it to manage electric vehicle demand in the future.

Q Which of the following best represents your view?



	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Should not explore new tech	19%	19%	27%	15%	38%	26%	12%
Should explore new tech	69%	71%	63%	77%	47%	61%	81%
Don't know	12%	10%	10%	8%	14%	13%	7%

Online Survey

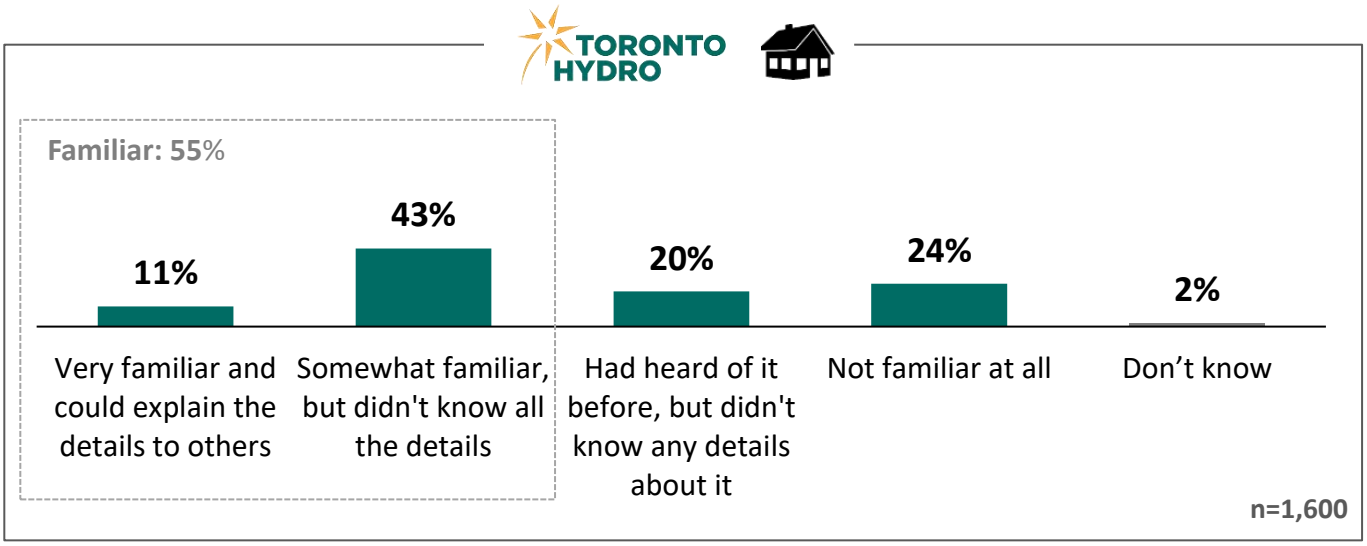
Familiarity with Sources of GHG Emissions

Residential

In November 2021, the City of Toronto released its 2019 Greenhouse Gas (GHG) Inventory, which tracks Toronto's progress towards GHG reduction targets and identifies key emissions sources. GHG emissions have a wide variety of environmental impacts that lead to climate change and global warming.

This report notes that the two **primary sources of GHG emissions** in Toronto are: energy use in buildings (natural gas and electricity) and transportation fuels (primarily gasoline) – accounting for 93% of all emissions in the city.

Q Before this survey, how familiar would you say you were with the primary sources of GHG emissions in Toronto?



	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Very familiar	14%	12%	11%	9%	14%	8%	12%
Somewhat familiar	45%	45%	38%	44%	33%	45%	45%
Had heard of it	19%	16%	21%	21%	18%	23%	18%
Not familiar at all	20%	24%	26%	24%	32%	21%	23%
Don't know	1%	3%	3%	1%	2%	3%	1%
Familiar (Very + Somewhat)	**59%**	**57%**	**50%**	**54%**	**47%**	**53%**	**57%**

Online Survey

Familiarity with the City's Plan

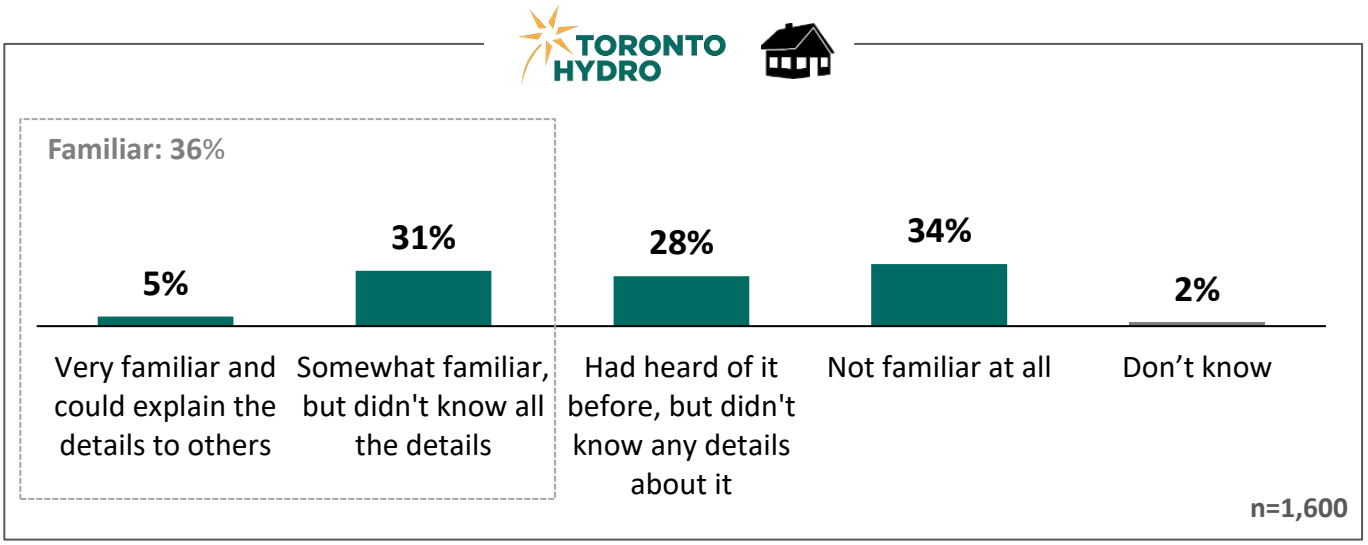
Residential

In October 2019, Toronto City Council voted to accelerate its efforts to mitigate and adapt to climate change and adopt a stronger emissions target for Toronto: **net zero emissions by 2040.**

A key part of the City's "Net Zero Strategy" requires switching from gasoline in the transportation system and natural gas in home/building heating to electricity-powered alternatives, adopting renewable generators and using energy storage systems.

These initiatives will require Toronto Hydro to expand and modernize its existing electricity distribution grid to ensure that it is capable of helping achieve the City's targets.

Q Before this survey, how familiar were you with the City of Toronto's plan to use an expanded and modernized grid to reduce GHG emissions in Toronto to help address climate change?



		Region			Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Very familiar	7%	6%	6%	4%	7%	5%	5%
Somewhat familiar	30%	29%	30%	32%	25%	35%	30%
Had heard of it	31%	26%	30%	26%	31%	27%	27%
Not familiar at all	30%	36%	32%	37%	36%	29%	36%
Don't know	2%	4%	2%	1%	1%	4%	1%
Familiar (Very + Somewhat)	**36%**	**35%**	**36%**	**36%**	**31%**	**40%**	**35%**

Online Survey

Support for Bill Increase to Meet Emissions Targets

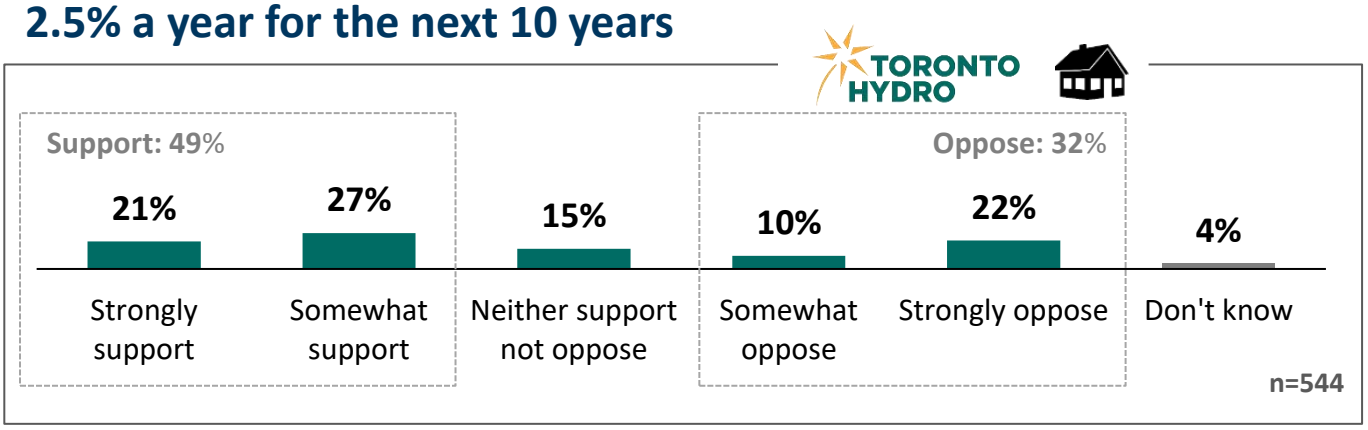
Residential

As Toronto Hydro is 100% funded through the rates its customers pay, investing in an expanded and modernized electricity grid would mean that customers, like yourself, would pay more.

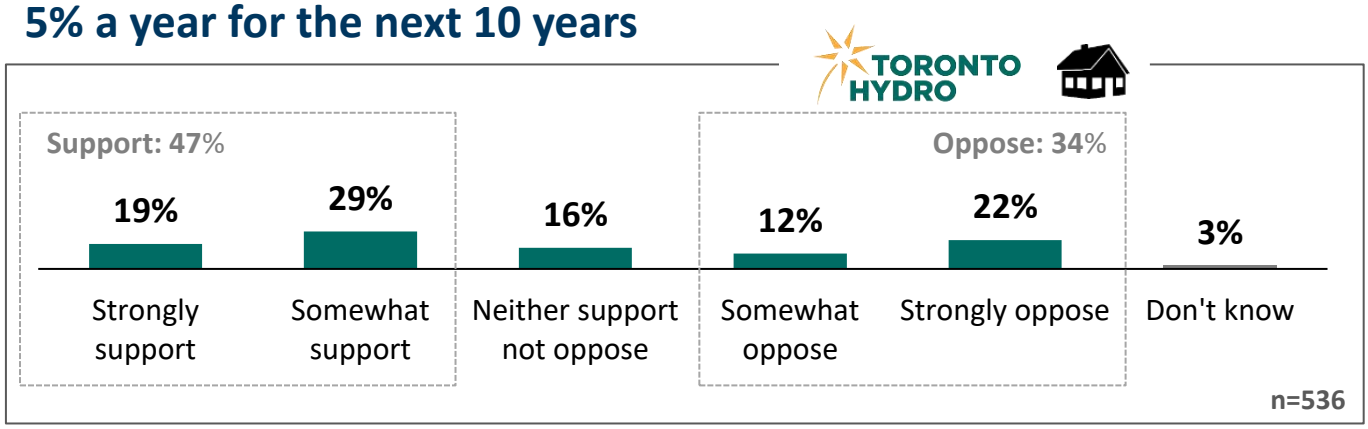
The sooner that Toronto Hydro expands and modernizes the grid, the sooner Toronto can reach its climate change goals.

Q Would you support or oppose a specific charge on your monthly bill to help Toronto meet its future emissions targets if your electricity bill will grow by **[COST]**?

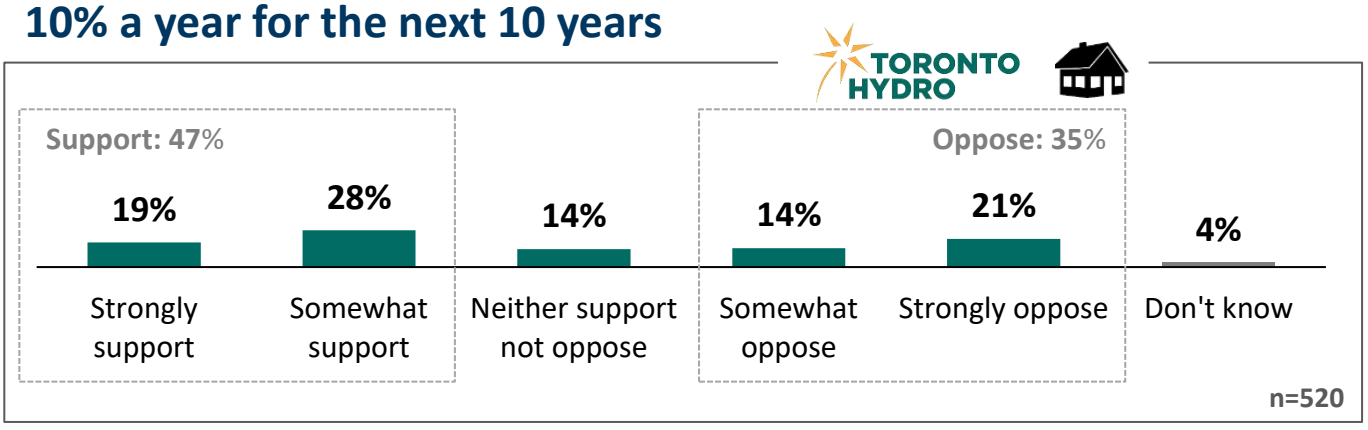
2.5% a year for the next 10 years



5% a year for the next 10 years



10% a year for the next 10 years



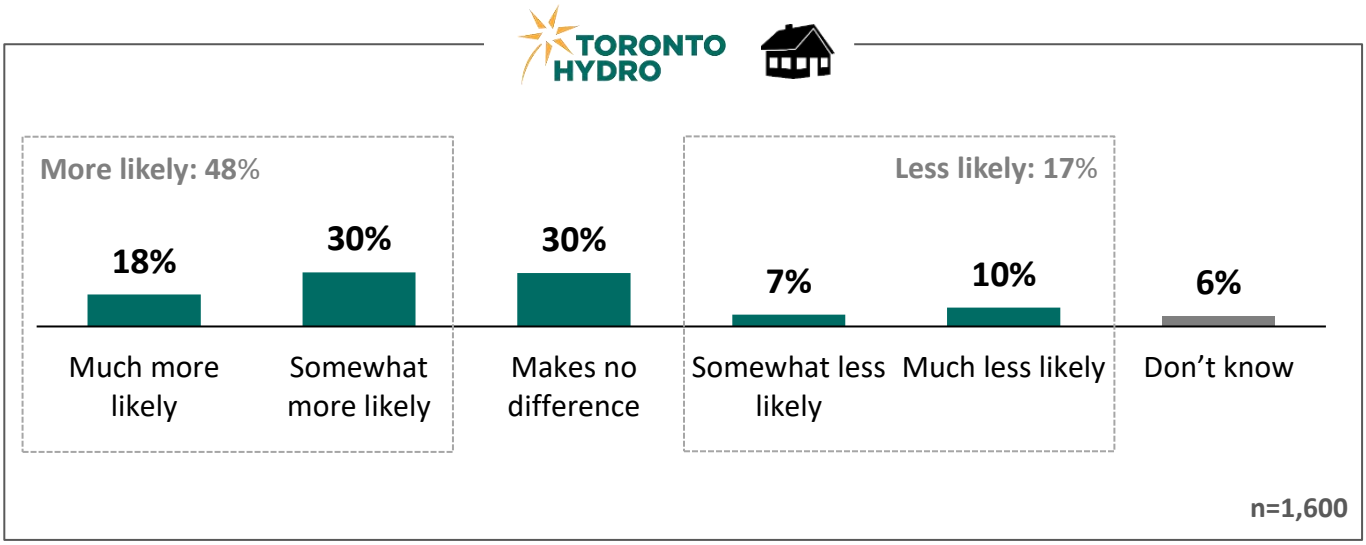
Online Survey

Potential for Rate Increase Offset

Residential

Some studies have indicated that increasing customer bills to specifically help meet emissions targets could be offset in later years because of reductions in other types of energy bills. For example, as fuel-switching to electricity becomes more widespread, customers may experience cost reductions for gasoline and natural gas.

Q Does knowing these types of rate increases could be offset in later years because of reduction in other types of energy bills make you more or less likely to support a specific charge on your monthly bill to help Toronto meet its future emissions targets?



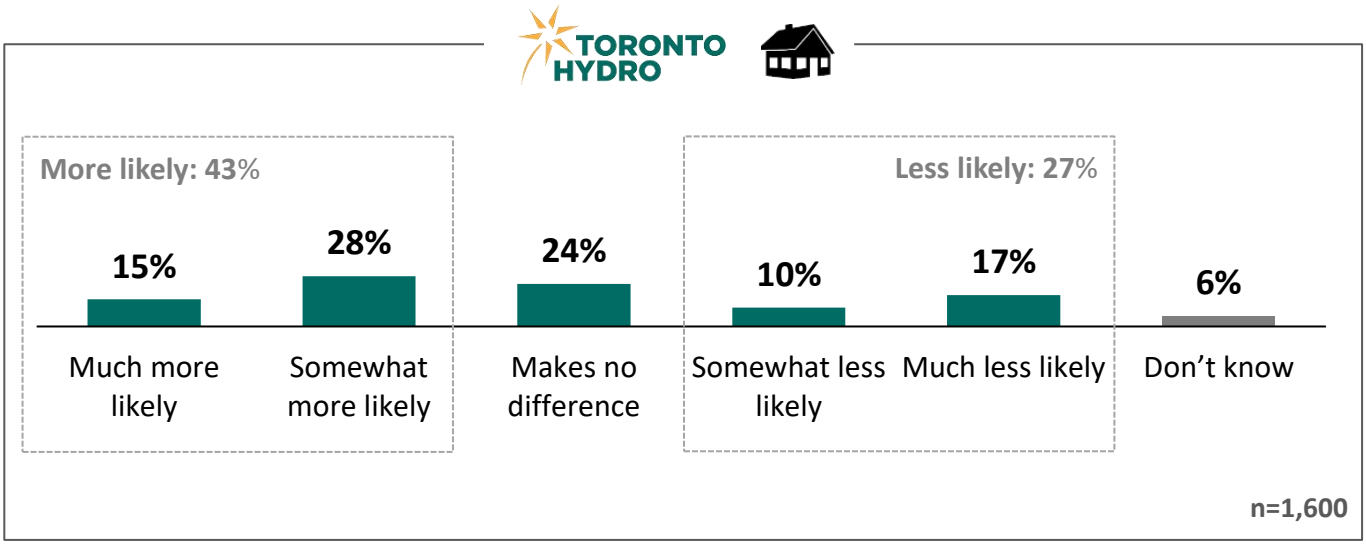
	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Much more likely	19%	12%	16%	21%	9%	12%	22%
Somewhat more likely	26%	33%	29%	31%	17%	32%	32%
No difference	26%	29%	23%	35%	25%	26%	32%
Somewhat less likely	7%	10%	10%	2%	12%	10%	4%
Much less likely	15%	9%	14%	7%	32%	12%	5%
More likely (Very + Somewhat)	**45%**	**44%**	**45%**	**52%**	**26%**	**43%**	**55%**
Less likely (Very + Somewhat)	**22%**	**19%**	**24%**	**10%**	**44%**	**22%**	**9%**

Online Survey
Inclusion of Rate Relief

Residential

Some customers have said that they would be willing to spend more in order to help Toronto meet its future emissions targets, however, feel that lower-income Torontonians should receive rate relief in order to offset any associated price increase.

Q Would the inclusion of "rate relief" for low-income customers make you **more or less likely to support** a specific charge on your monthly bill to help Toronto meet its future emissions targets?



	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Much more likely	11%	9%	15%	20%	14%	9%	18%
Somewhat more likely	27%	25%	25%	31%	14%	28%	31%
No difference	24%	26%	20%	25%	15%	23%	26%
Somewhat less likely	10%	11%	15%	8%	10%	13%	9%
Much less likely	22%	21%	18%	12%	43%	19%	11%
More likely (Very + Somewhat)	**39%**	**35%**	**40%**	**51%**	**28%**	**37%**	**49%**
Less likely (Very + Somewhat)	**32%**	**32%**	**34%**	**20%**	**52%**	**33%**	**20%**

Online Survey

Residential

Do future offset rates and rate relief increase or decrease support?

Does knowing these types of rate increases could be offset in later years because of reduction in other types of energy bills make you more or less likely to support a specific charge on your monthly bill to help Toronto meet its future emissions targets?

	Would you support or oppose a specific charge on your monthly bill to help Toronto meet its future emissions targets if your electricity bill will grow by [COST]?						
	Total	Strongly support	Somewhat support	Neither support nor oppose	Somewhat oppose	Strongly oppose	Don't know
Much more likely	18%	58%	16%	7%	2%	1%	3%
Somewhat more likely	30%	22%	53%	36%	27%	9%	8%
Makes no difference	30%	18%	26%	41%	40%	34%	10%
Somewhat less likely	7%	1%	2%	7%	19%	10%	9%
Much less likely	10%	0%	1%	3%	7%	40%	6%
Don't know	6%	1%	1%	8%	5%	6%	65%
Net "More Likely"	**+31%**	**+79%**	**+66%**	**+33%**	**+2%**	**-39%**	**-4%**

Would the inclusion of "rate relief" for low-income customers make you more or less likely to support a specific charge on your monthly bill to help Toronto meet its future emissions targets?

	Would you support or oppose a specific charge on your monthly bill to help Toronto meet its future emissions targets if your electricity bill will grow by [COST]?						
	Total	Strongly support	Somewhat support	Neither support nor oppose	Somewhat oppose	Strongly oppose	Don't know
Much more likely	15%	44%	13%	5%	2%	6%	5%
Somewhat more likely	28%	28%	47%	37%	15%	5%	14%
Makes no difference	24%	18%	24%	28%	33%	21%	18%
Somewhat less likely	10%	3%	10%	13%	20%	11%	3%
Much less likely	17%	5%	4%	11%	19%	52%	7%
Don't know	6%	2%	2%	6%	10%	5%	54%
Net "More Likely"	**+15%**	**+64%**	**+47%**	**+17%**	**-22%**	**-51%**	**+9%**

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro. The conclusions drawn and opinions expressed are those of the authors.

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CONFIDENTIAL

APPENDIX 04

Small Business
Needs and Preferences Survey

TORONTO HYDRO

November 2, 2023

STRICTLY CONFIDENTIAL

2025 – 2029 Rate Application

Report Navigation

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- APPENDIX.01 – Customer Engagement Focus Groups
- APPENDIX.02 – Customer Sample Validation
- APPENDIX.03 – Residential Needs and Preferences Survey
- APPENDIX.04 – Small Business Needs and Preferences Survey
- APPENDIX.05 – Commercial & Industrial Needs and Preferences Survey
- APPENDIX.06 – Key Accounts Needs and Preferences Survey
- APPENDIX.07 – Needs and Preferences Planning Placemat

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INNOVATIVE RESEARCH GROUP

Small Business Customers

Online Survey Results

Section 4.1



Online Survey

Survey Design & Methodology

INNOVATIVE was engaged by Toronto Hydro to gather customer input to assess the importance of the outcomes and priorities identified in the qualitative components of Phase I of the customer engagement.

Field Dates

The **Small Business Online Survey** was sent to all Toronto Hydro small business customers who provided the utility with an email address. Customers had an opportunity to complete the survey between **December 9th, 2021, and January 9th, 2022**.

Each customer received a unique URL that could be linked back to their annual consumption, region and rate class.

In total, the small business survey was sent to **11,212** customers from *customerexperience@torontohydro.com*. A reminder email was sent 6 days after the initial invitation to those who had not yet completed the survey. Two additional reminder emails were sent weekly afterwards.

Small Business Online Survey Completes

A total of **430** (unweighted) Toronto Hydro small business customers completed the online survey via a unique URL.

Sample Weighting

The small business sample has been weighted proportionately by consumption quartiles and region in order to be representative of the broader Toronto Hydro service territory.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region.

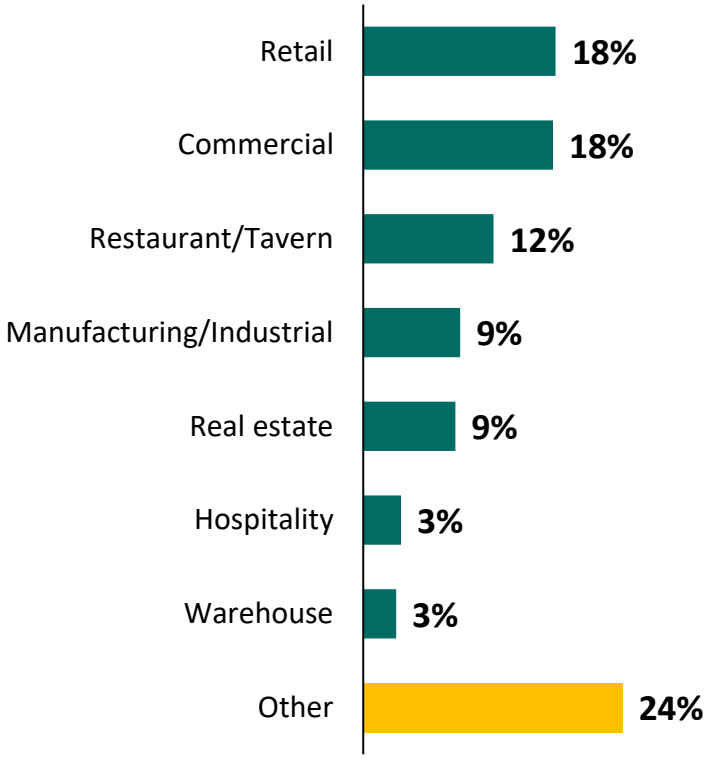
Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
Etobicoke/York	14 (17)	14 (19)	17 (20)	23 (20)	68 (76)
North York	17 (23)	24 (25)	23 (25)	18 (25)	82 (98)
Scarborough	15 (21)	25 (25)	23 (22)	18 (23)	81 (91)
Toronto/E. York	60 (47)	55 (38)	52 (40)	32 (40)	199 (165)
Total	106 (107)	118 (108)	115 (108)	91 (107)	430 (430)

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Online Survey
Demographic breakdown

Small Business

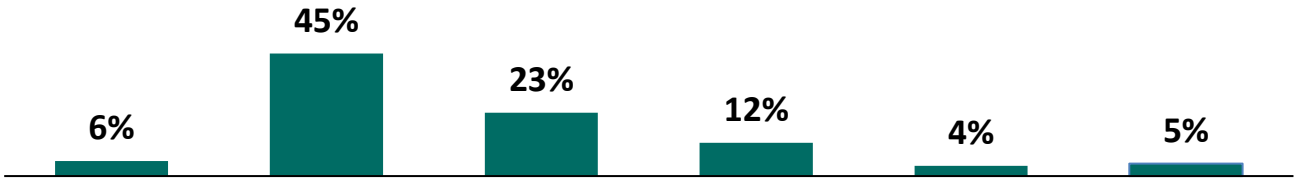
Q Which of the following best describes the sector in which your business operates?



"Don't know" (1%) and "Prefer not to say" (4%) not shown.

n=430

Q Including yourself, how many people work at your organization?



"Don't know" (<1%) and "Prefer not to say" (4%) not shown.

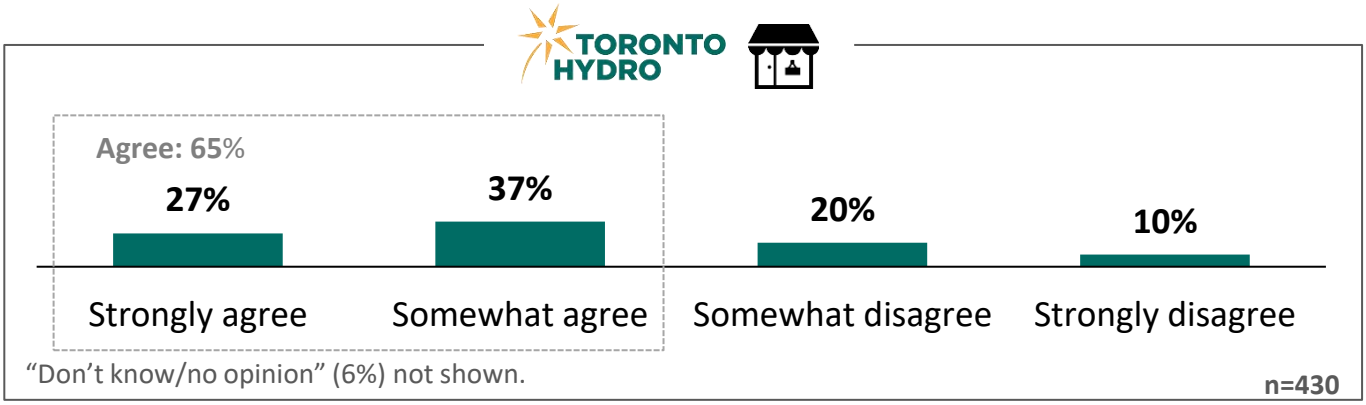
n=430

Online Survey
Environmental Controls

Small Business

To what extent do you agree or disagree with the following statements?

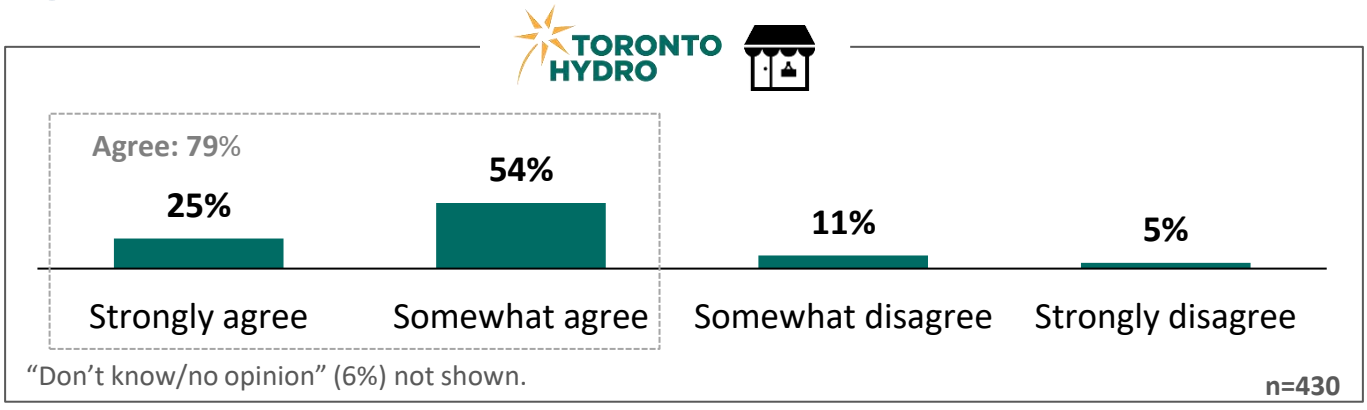
Q The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know/no opinion" (6%) not shown.

n=430

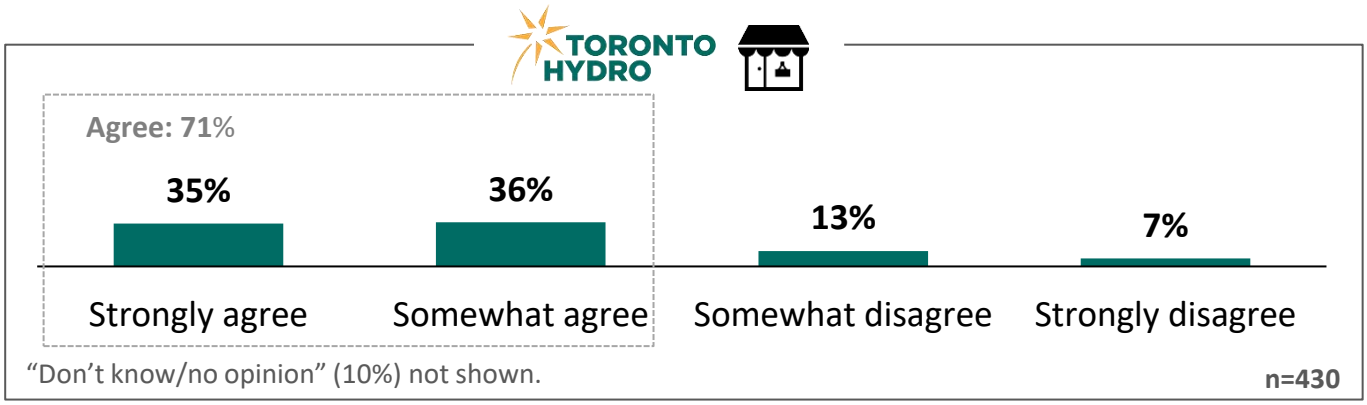
Q Customers are well-served by the electricity system in Ontario.



"Don't know/no opinion" (6%) not shown.

n=430

Q Fossil fuels should be phased out as quickly as possible to speed up the shift to a lower-carbon future.



"Don't know/no opinion" (10%) not shown.

n=430

Online Survey

Familiarity with Ontario's Electricity System

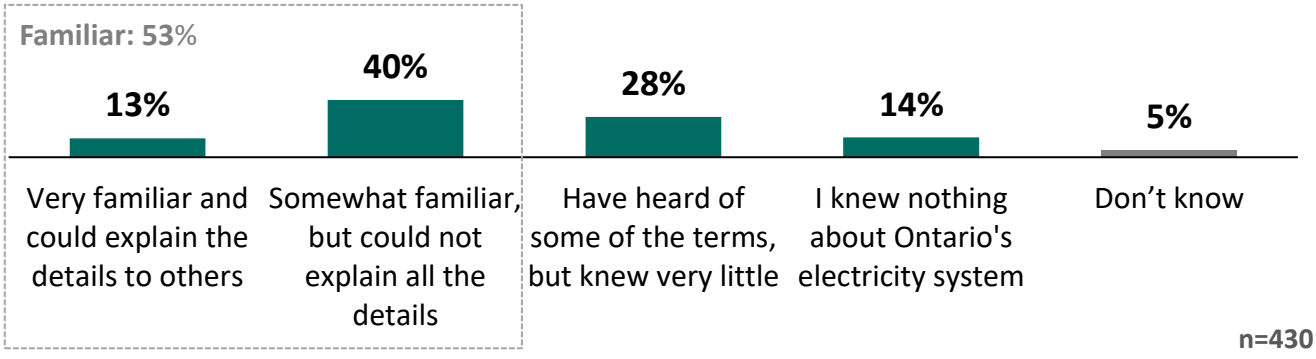
Small Business

As you may know, Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province
- **Local distribution networks** take the electricity from provincial transmission lines and bring it to your home through a network of wires, poles and other equipment.

Q Before this survey, how familiar were you with the various parts of the electricity system and how they work together?

TORONTO HYDRO



	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Very familiar	14%	15%	14%	12%	17%	15%	8%
Somewhat familiar	42%	39%	35%	42%	34%	41%	44%
Knew very little	30%	24%	28%	30%	30%	25%	30%
Knew nothing	11%	19%	15%	11%	12%	15%	14%
Don't know	3%	3%	7%	5%	7%	3%	5%
Familiar (Very + Somewhat)	**55%**	**54%**	**49%**	**54%**	**51%**	**56%**	**52%**

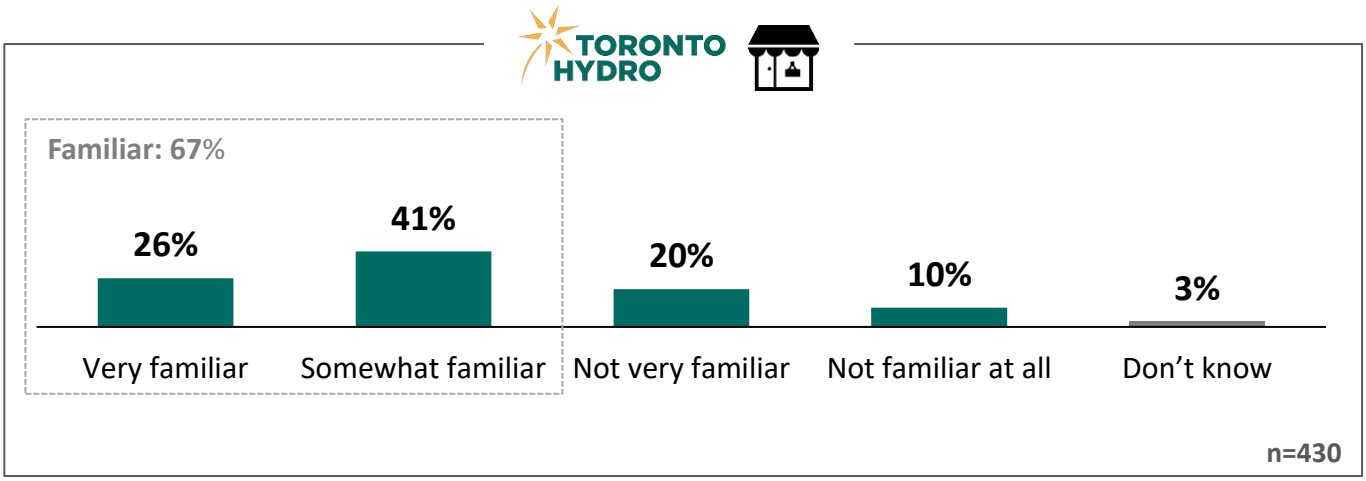
Online Survey

Familiarity with Toronto Hydro

Small Business

Toronto Hydro owns and operates Toronto's distribution network. This is the network that takes the electricity from high-voltage transmission towers and brings it to your business through a network of wires, poles and other equipment.

Q Before this survey, how familiar were you with **Toronto Hydro**, which operates the electricity distribution system in your community?



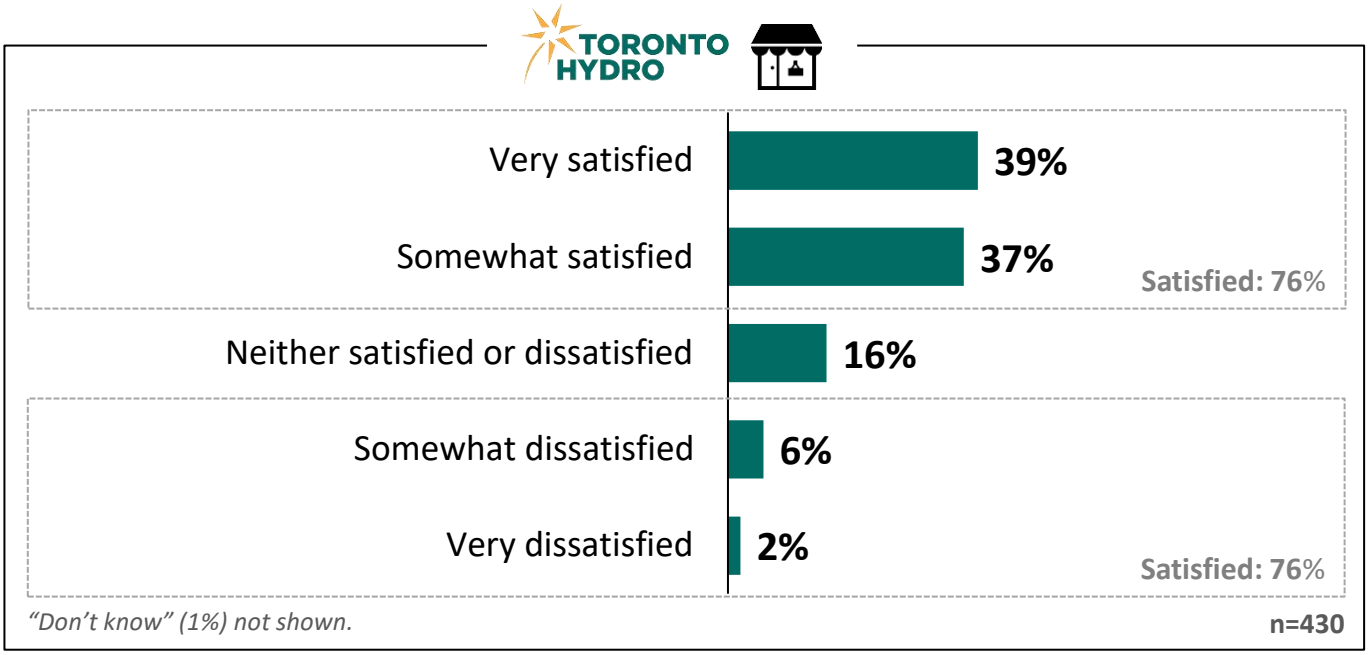
	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Very familiar	26%	27%	24%	28%	29%	25%	25%
Somewhat familiar	48%	37%	37%	41%	39%	42%	41%
Not very familiar	15%	25%	22%	19%	16%	23%	21%
Not familiar at all	8%	10%	12%	10%	14%	8%	9%
Don't know	4%	1%	5%	2%	1%	2%	4%
Familiar (Very + Somewhat)	**73%**	**63%**	**61%**	**69%**	**68%**	**67%**	**66%**

Online Survey

Overall Satisfaction with Toronto Hydro

Small Business

Q Thinking specifically about the services provided to you and your community by **Toronto Hydro**, overall, how satisfied or dissatisfied are you with the services that your organization receives?



"Don't know" (1%) not shown.

n=430

	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Very satisfied	42%	36%	48%	35%	33%	37%	47%
Somewhat satisfied	43%	42%	28%	37%	38%	43%	30%
Neither satisfied or dissatisfied	10%	17%	9%	21%	19%	13%	15%
Somewhat dissatisfied	3%	2%	10%	6%	8%	4%	5%
Very dissatisfied	2%	3%	2%	1%	2%	2%	1%
Satisfied (Very + Somewhat)	**85%**	**78%**	**76%**	**72%**	**70%**	**80%**	**78%**
Dissatisfied (Very + Somewhat)	**5%**	**5%**	**12%**	**8%**	**11%**	**6%**	**6%**

Online Survey

Small Business

How Toronto Hydro can Improve Services to Customers

Q Is there anything in particular you would like Toronto Hydro to do to improve its services to you?

Response	%
Costs too high/reduce rates/provide rebates	11.5%
Fix billing/prefers 60 day billing cycle/include breakdown of charges	4.4%
Satisfied with Toronto Hydro/positive - General	4.2%
Consistent service/no outages	2.4%
Renew ageing infrastructure/bury overhead powerlines	2.4%
Improve response time	2.1%
Better customer service/work to reduce hold time	2.0%
Repair online portal/create a mobile app	1.8%
Provide tools to review usage/reduce energy consumption	1.2%
Increase communication with customers/notification of any changes or updates	0.7%
Consider use of alternate energy source/renewable energy	0.7%
Covid relief/leniency on rates during lockdowns	0.6%
Other	0.9%
None/Don't know	65.1%

Note: Only responses >0.1% shown

Online Survey

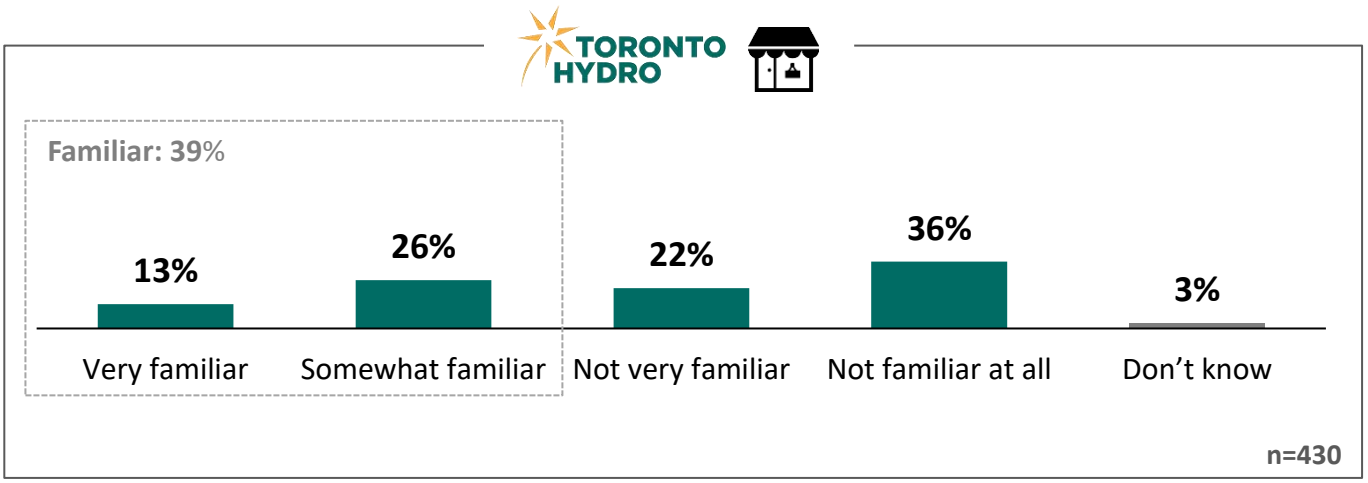
Familiarity with Bill Remittance to Toronto Hydro

Small Business

While **Toronto Hydro** is only responsible for the distribution portion of the system, to make it easier for customers, they are responsible for collecting payment for the entire electricity system.

Toronto Hydro keeps about **31%** of the average small business customer's bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to **Toronto Hydro**?



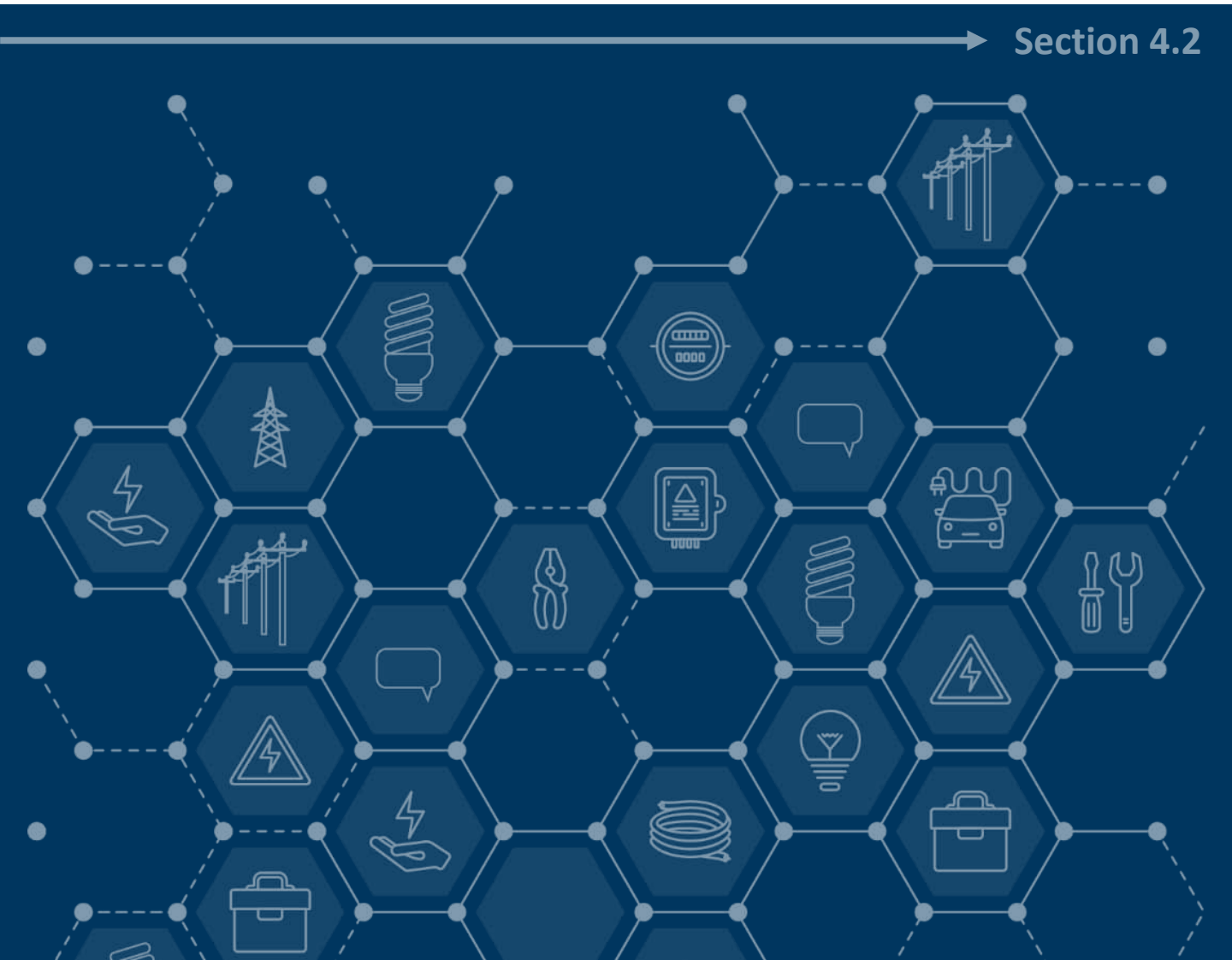
	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Very familiar	15%	12%	10%	15%	19%	12%	10%
Somewhat familiar	27%	21%	35%	24%	28%	32%	19%
Not very familiar	19%	24%	20%	22%	21%	20%	25%
Not familiar at all	35%	41%	30%	37%	30%	34%	43%
Don't know	3%	1%	5%	3%	2%	3%	4%
Familiar (Very + Somewhat)	**42%**	**33%**	**45%**	**39%**	**47%**	**44%**	**29%**

INNOVATIVE RESEARCH GROUP

Small Business Customers

Customer Priorities

Section 4.2



Online Survey

Importance of Customer Priorities

Small Business

Now, let's talk about our second topic – outcomes.

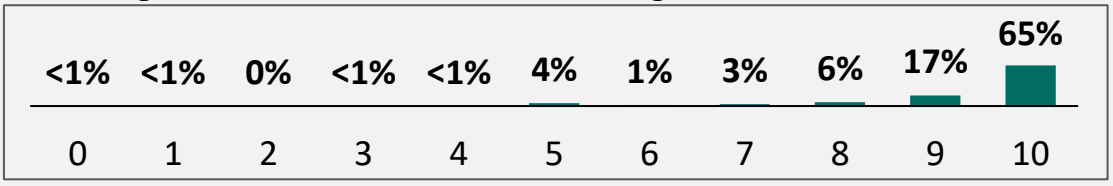
Everyday **Toronto Hydro** interacts with hundreds of its customers through multiple channels and touchpoints, including surveys, the call centre and social media.

In a recent series of customer focus groups, a number of company goals were identified as priorities for **Toronto Hydro**.

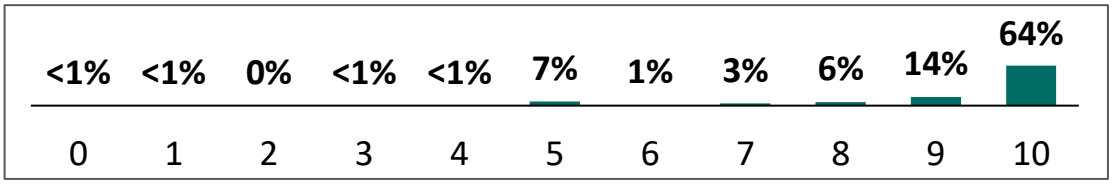
Q

Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Toronto Hydro** priorities to you as a customer?

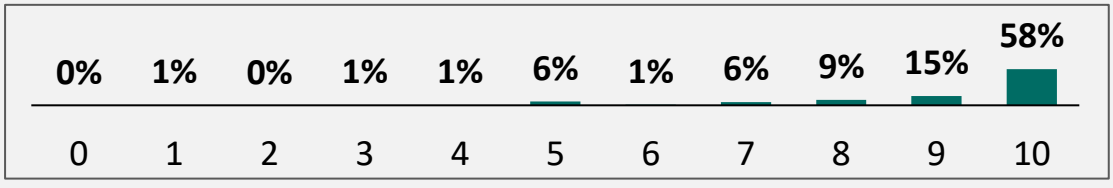
Ensuring reliable electrical service [average = **9.2**]



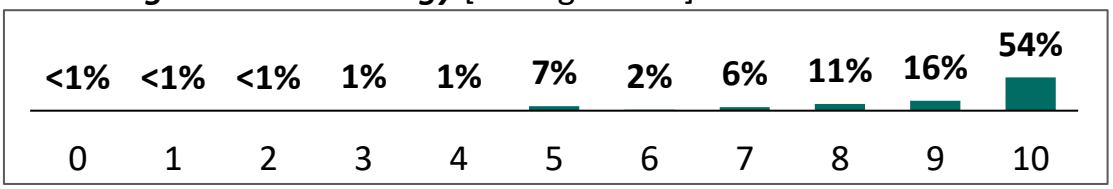
Delivering electricity at reasonable rates [average = **9.1**]



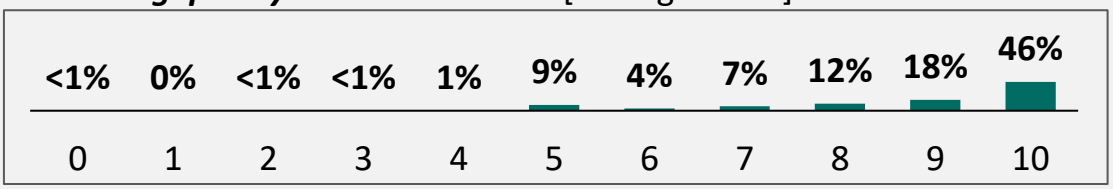
Ensuring the safety of electricity infrastructure [average = **9.0**]



Investing in new technology [average = **8.8**]



Providing quality customer service [average = **8.6**]



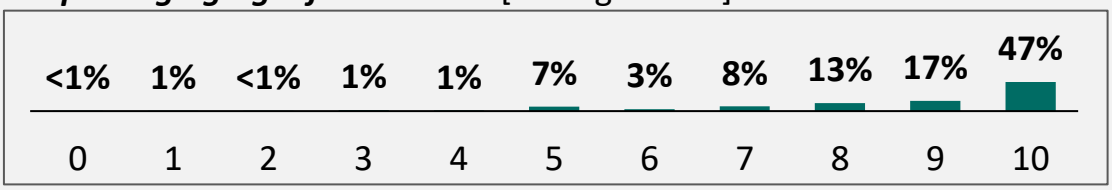
Online Survey

Importance of Customer Priorities (Cont'd)

Small Business

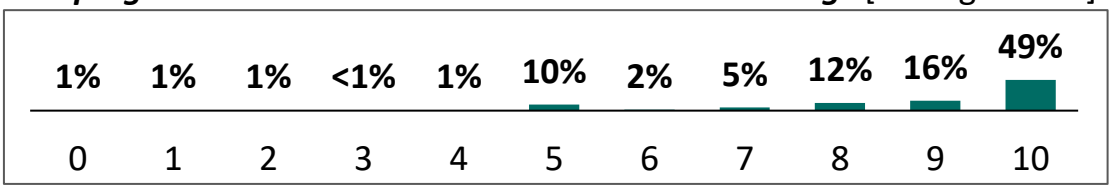
Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Toronto Hydro** priorities to you as a customer?

Replacing aging infrastructure [average = **8.5**]



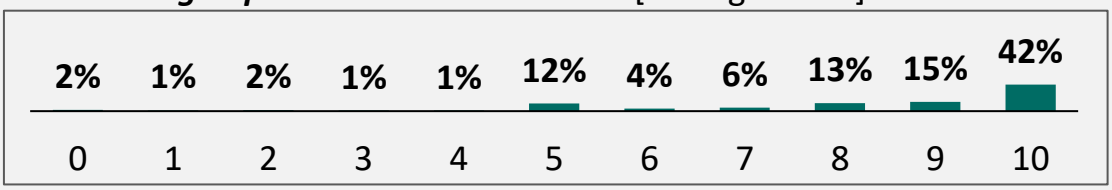
Not at all important — Extremely important

Helping customers with conservation and cost savings [average = **8.5**]



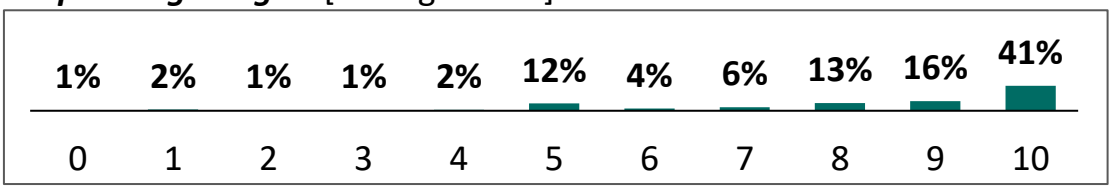
Not at all important — Extremely important

Minimizing impact on the environment [average = **8.1**]



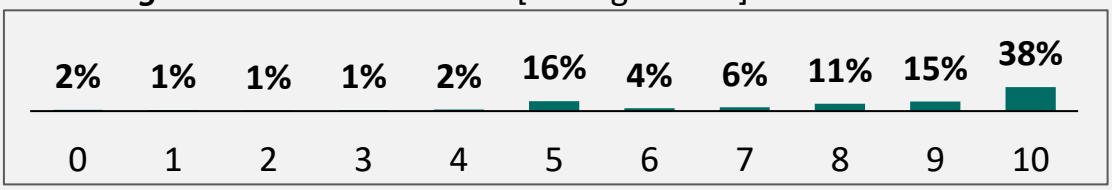
Not at all important — Extremely important

Expanding the grid [average = **8.0**]



Not at all important — Extremely important

Enabling access to new services [average = **7.8**]



Not at all important — Extremely important

Online Survey

Small Business

Importance of Customer Priorities | Summary Scores

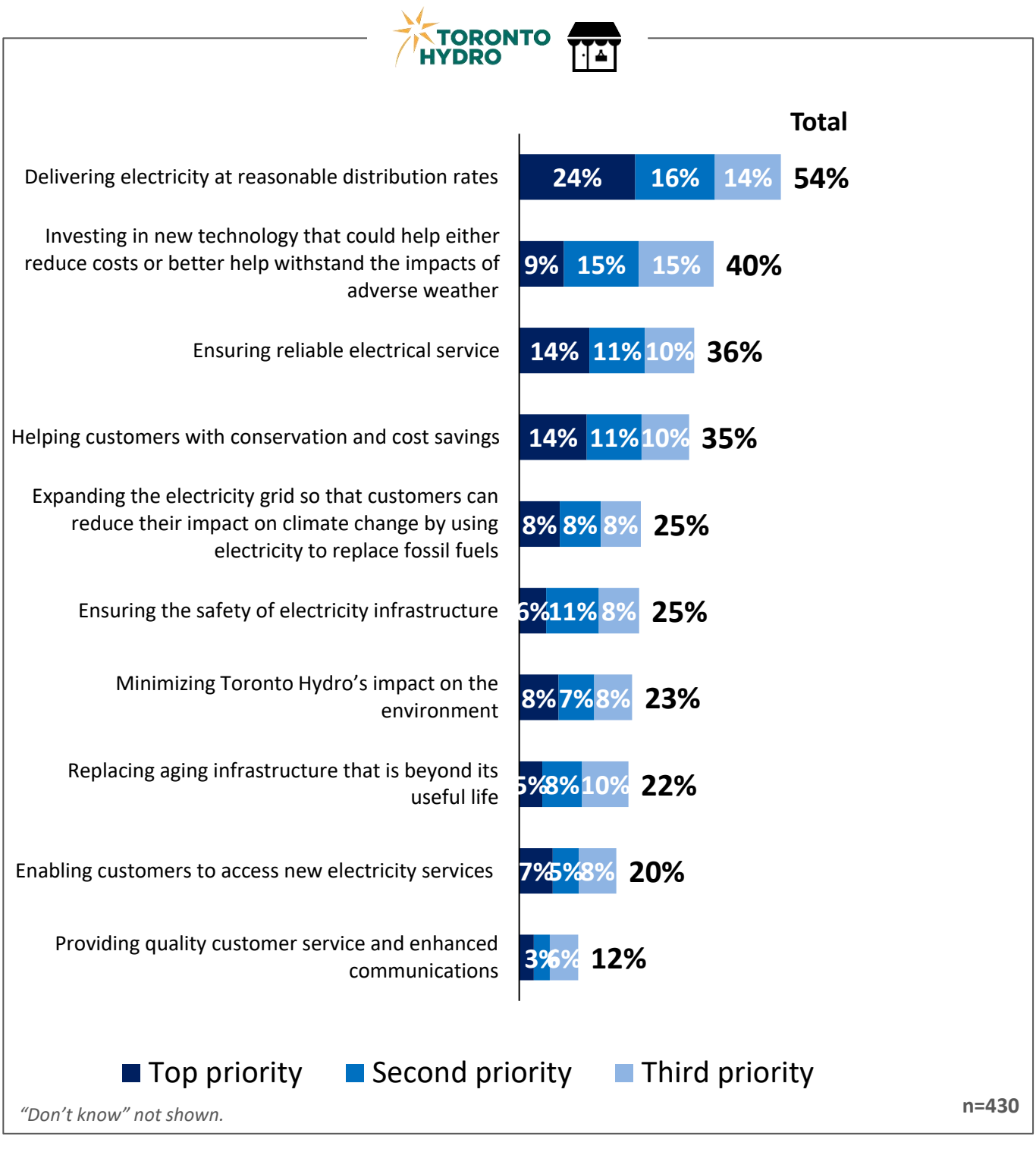
Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Toronto Hydro** priorities to you as a customer?

	Region				Bill impact on finances		
Average Score	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Ensuring reliable service	9.6	9.3	8.7	9.3	9.2	9.3	9.2
Delivering electricity at reasonable rates	9.2	9.3	8.8	9.2	9.4	9.2	8.9
Ensuring safety of infrastructure	9.1	9.1	8.7	9.0	8.9	9.0	9.0
Investing in new technology	9.1	8.8	8.6	8.6	8.6	8.9	8.8
Providing quality customer service	8.5	8.9	8.6	8.5	8.8	8.6	8.5
Replacing aging infrastructure	8.8	8.6	8.2	8.6	8.3	8.6	8.6
Helping customers with conservation	8.5	8.8	8.2	8.5	8.9	8.6	8.2
Minimizing impact on environment	8.0	8.1	8.2	8.1	7.9	8.0	8.4
Expanding the grid	8.2	7.8	7.9	8.1	7.9	7.9	8.2
Enabling access to new services	7.8	7.6	8.1	7.9	8.0	7.7	7.9

Online Survey
Ranking Customer Priorities

Small Business

Q Thinking of the priorities on the previous page, which would you say is the **most** important? What is the next most important priority you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?



"Don't know" not shown.

n=430

Online Survey

Ranking Customer Priorities | Summary Scores

Small Business

Q Thinking of the priorities on the previous page, which would you say is the **most** important? What is the next most important priority you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?

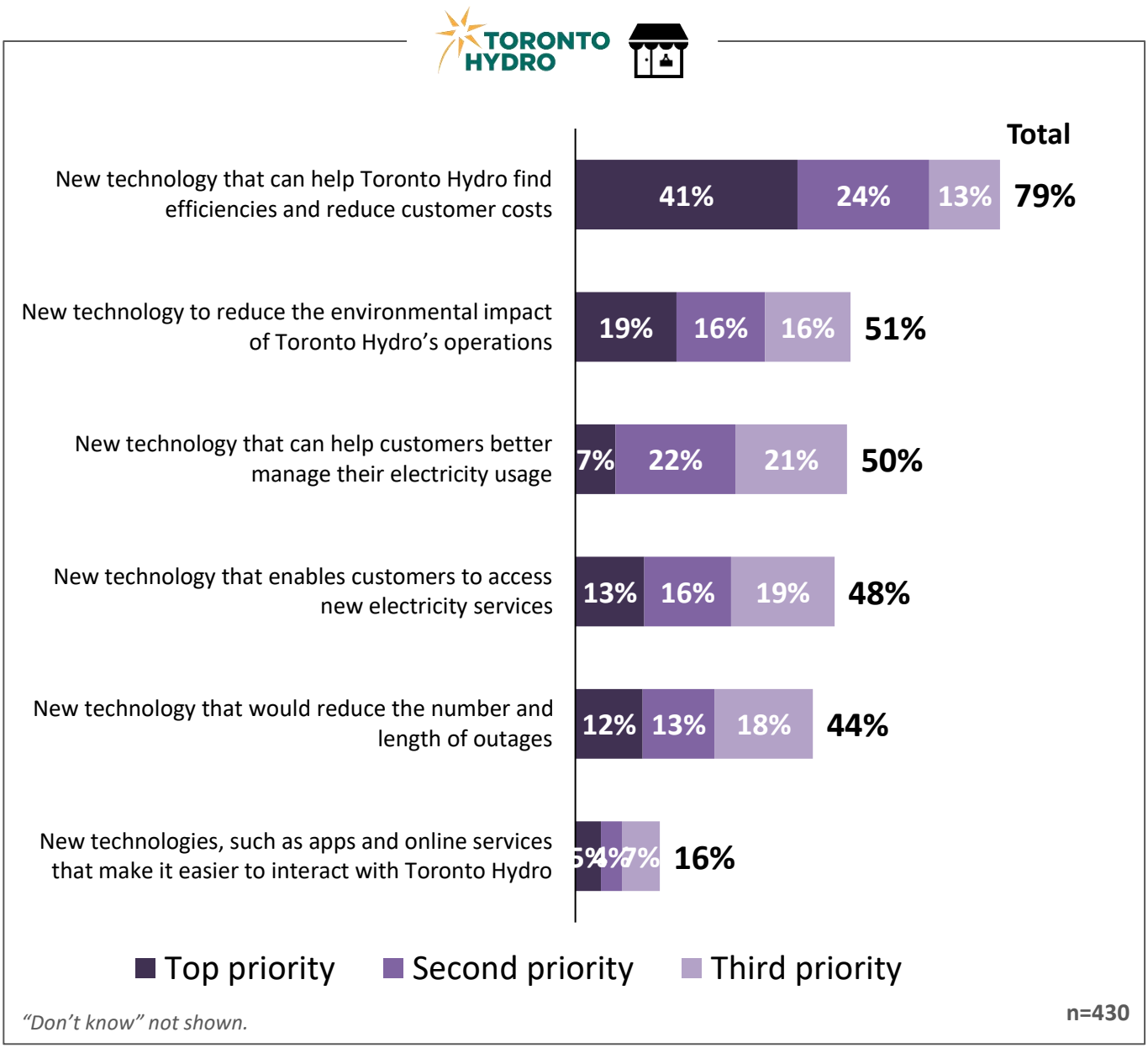
	Region				Bill impact on finances		
% who select as top 3 priority	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Delivering electricity at reasonable rates	61%	55%	51%	51%	60%	59%	44%
Investing in new technology	43%	46%	33%	39%	35%	41%	42%
Ensuring reliable service	39%	33%	29%	40%	30%	39%	37%
Helping customers with conservation	29%	34%	45%	33%	43%	35%	28%
Expanding the grid	21%	25%	20%	30%	19%	24%	31%
Ensuring safety of infrastructure	29%	22%	23%	24%	29%	24%	22%
Minimizing impact on environment	22%	27%	22%	22%	23%	22%	25%
Replacing aging infrastructure	26%	23%	21%	21%	15%	24%	26%
Enabling access to new services	15%	20%	22%	21%	20%	19%	20%
Providing quality customer service	9%	14%	16%	10%	20%	8%	11%

Online Survey
Ranking Technology Priorities

Small Business

Investments in new technology can help Toronto Hydro address a range of issues. These include reliability, efficiency, customer service, Toronto Hydro's impact on the environment, new service offerings and tools to manage electricity usage.

Q Among the following potential investments in new technology, which would you say is the **most** important? What is the next most important new technology priority you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?



"Don't know" not shown.

n=430

Online Survey

Ranking Technology Priorities | Summary Scores

Small Business

Q Among the following potential investments in new technology, which would you say is the **most** important? What is the next most important new technology priority you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?

	Region				Bill impact on finances		
% who select as top 3 priority	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
New tech that can help Toronto Hydro find efficiencies and reduce costs	86%	80%	71%	79%	77%	83%	75%
New tech to reduce environmental impact	43%	51%	52%	54%	42%	49%	60%
New tech that can help customers better manage usage	49%	46%	54%	51%	57%	54%	42%
New tech that enables customers to access new services	57%	47%	34%	52%	46%	48%	50%
New tech that would help reduce number and length of outages	45%	50%	44%	40%	45%	43%	44%
New tech that make it easier to interact with Toronto Hydro	13%	18%	18%	14%	21%	13%	14%

Online Survey
Additional Priorities

Q Can you think of any other important priorities that **Toronto Hydro** should be focusing on?

Response	%
Offering renewable energy options	2.8%
Lowering rates	2.6%
Finding efficiencies/reducing operating costs	2.5%
Improving reliability/safety/efficiency in power delivery	2.4%
Providing programs and incentives/cost savings for consumers	2.3%
Upgrading infrastructure/burying lines	2.2%
Improving customer service/communication/transparency	2.0%
Reducing carbon footprint/assessing environmental impact	2.0%
Improve billing/provide more information on bill/usage	1.2%
Allowing for greater demand due to electric vehicles	1.2%
Other	0.5%
None	7.2%
Don't know	71.1%

Note: Only responses >0.1% shown

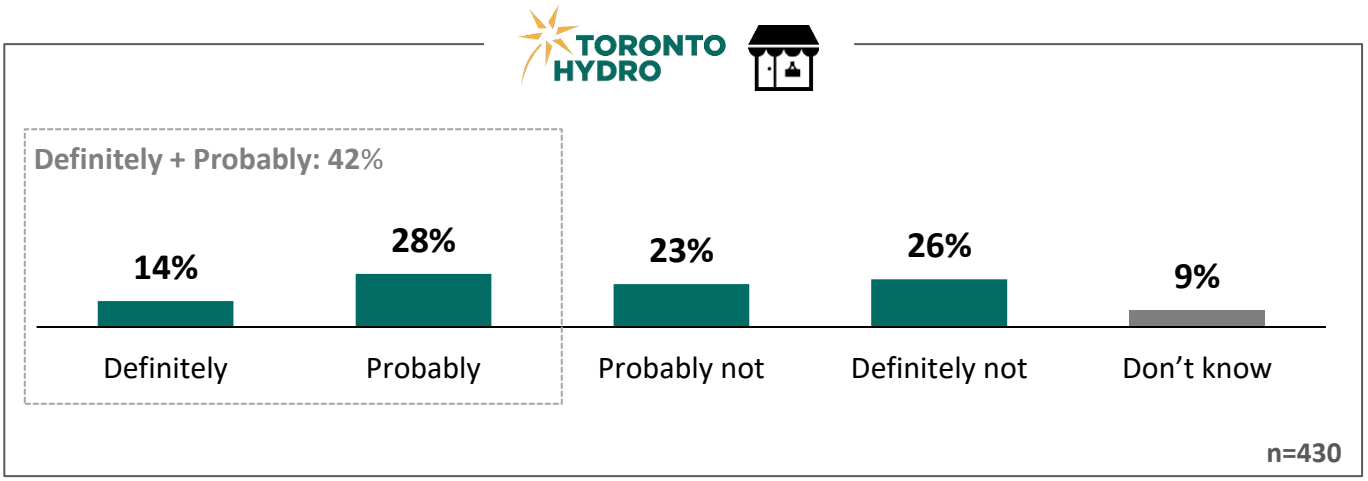
Online Survey

Support for Low-Income Customers

Small Business

In recent interactions with customers, a number of customers identified assisting low-income Torontonians with their electricity bills.

Q In addition to the amount that you currently pay on your electricity bill, would you be willing to pay an extra few dollars per month in order for Toronto Hydro to provide financial assistance to make electricity bills more affordable for low-income customers?



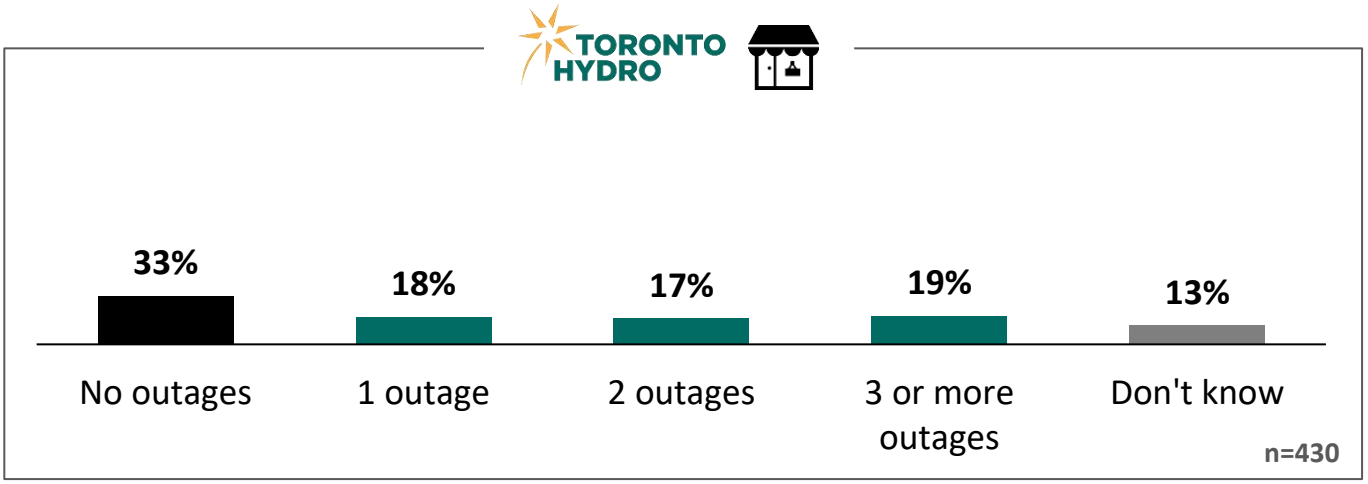
		Region			Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Definitely	17%	14%	13%	14%	15%	10%	18%
Probably	21%	26%	32%	31%	17%	25%	40%
Probably not	21%	32%	17%	22%	23%	28%	17%
Definitely not	32%	23%	27%	23%	34%	29%	16%
Don't know	9%	5%	11%	10%	10%	8%	9%
Definitely + Probably	38%	40%	45%	45%	33%	35%	58%

Online Survey

Number of Outages Experienced

Small Business

Q Now, let's talk about the reliability of electricity service your organization receives. Have you experienced any power outages at **your organization in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?



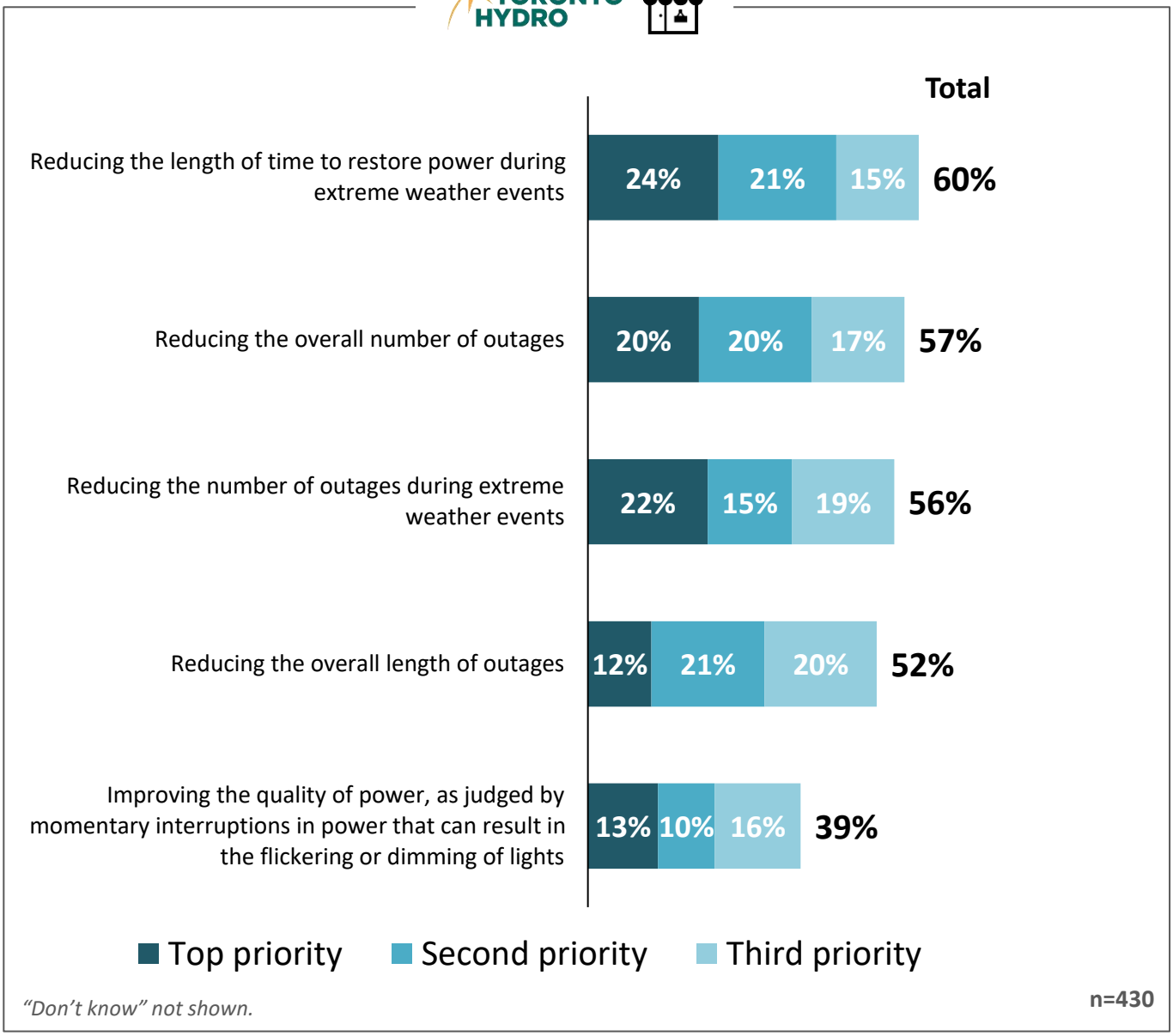
		Region			Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
No outages	21%	33%	30%	39%	36%	29%	34%
1 outage	24%	6%	26%	19%	20%	19%	17%
2 outages	22%	25%	16%	12%	13%	17%	21%
3 or more outages	17%	25%	15%	18%	21%	20%	16%
Don't know	16%	11%	14%	12%	9%	16%	12%

Online Survey
Ranking Reliability Priorities

Small Business

When it comes to reliability, there are a number of areas that **Toronto Hydro** could focus on.

Q Among the following reliability outcomes, which would you say is the **most** important? What is the next most important reliability outcome you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?



"Don't know" not shown.

n=430

Online Survey

Ranking Reliability Priorities | Summary Scores

Small Business

Q Among the following reliability outcomes, which would you say is the **most** important? What is the next most important reliability outcome you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?

	Region				Bill impact on finances		
% who select as top 3 priority	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Reducing the length of time to restore power during extreme weather events	60%	61%	56%	61%	65%	55%	61%
Reducing the overall number of outages	58%	60%	56%	56%	49%	59%	62%
Reducing the number of outages during extreme weather events	50%	63%	52%	56%	52%	61%	52%
Reducing the overall length of outages	56%	49%	52%	54%	53%	52%	52%
Improving the quality of power, as judged by momentary interruptions	41%	38%	42%	36%	48%	39%	31%

INNOVATIVE RESEARCH GROUP

Small Business Customers

Investment Trade-Offs

Section 4.3



Online Survey
System Renewal

Small Business

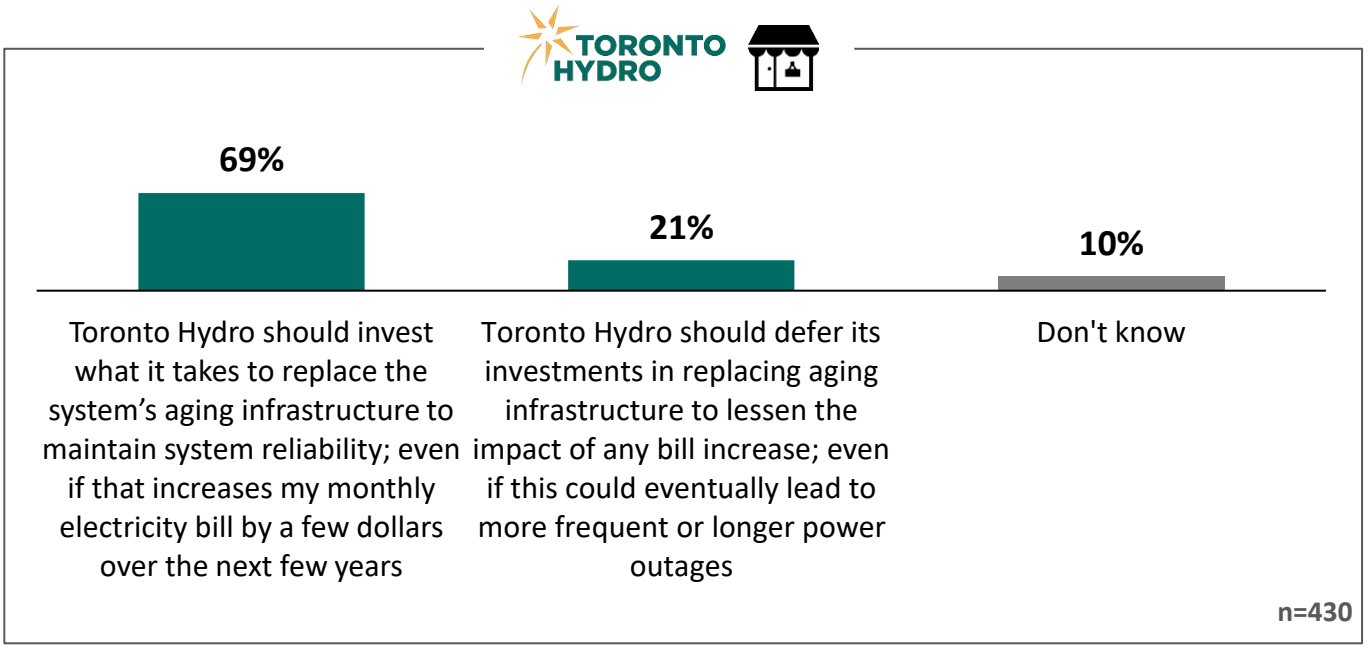
Now let's turn to our final topic – investment trade-offs.

Toronto Hydro is in the early stages of developing its investment plan for the next five years. While conversations with customers will continue over the next several months, the utility wants to know your preferences when it comes to finding the right balance between costs and other outcomes.

There are four investment categories that we would like to discuss.

The first category focuses on projects that replace and restore aging electrical infrastructure, like overhead poles and underground cables.

Q Regarding investments in aging infrastructure, which of the following statements best represents your point of view?



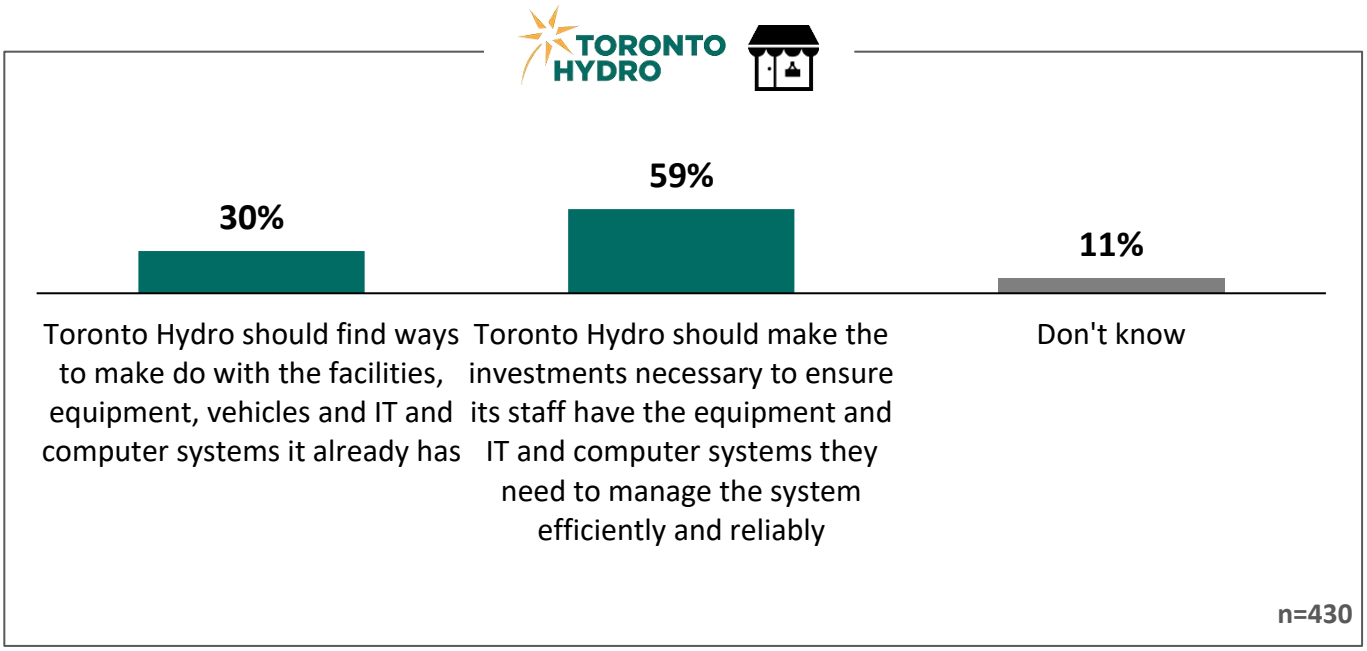
	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Invest what it takes	64%	73%	67%	69%	62%	65%	78%
Defer investments	21%	19%	22%	22%	29%	22%	15%
Don't know	15%	8%	10%	8%	9%	13%	7%

Online Survey
General Plant

Small Business

The second category focuses on keeping **Toronto Hydro's** business running. This includes facilities to house staff and equipment, vehicles and tools to service equipment and IT systems to manage the system and other information.

Q Regarding these types of investments, which of the following best represents your point of view?



	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Make do with what it already has	33%	27%	27%	31%	35%	32%	24%
Make the necessary investments	52%	63%	56%	62%	57%	58%	62%
Don't know	14%	10%	17%	7%	8%	10%	14%

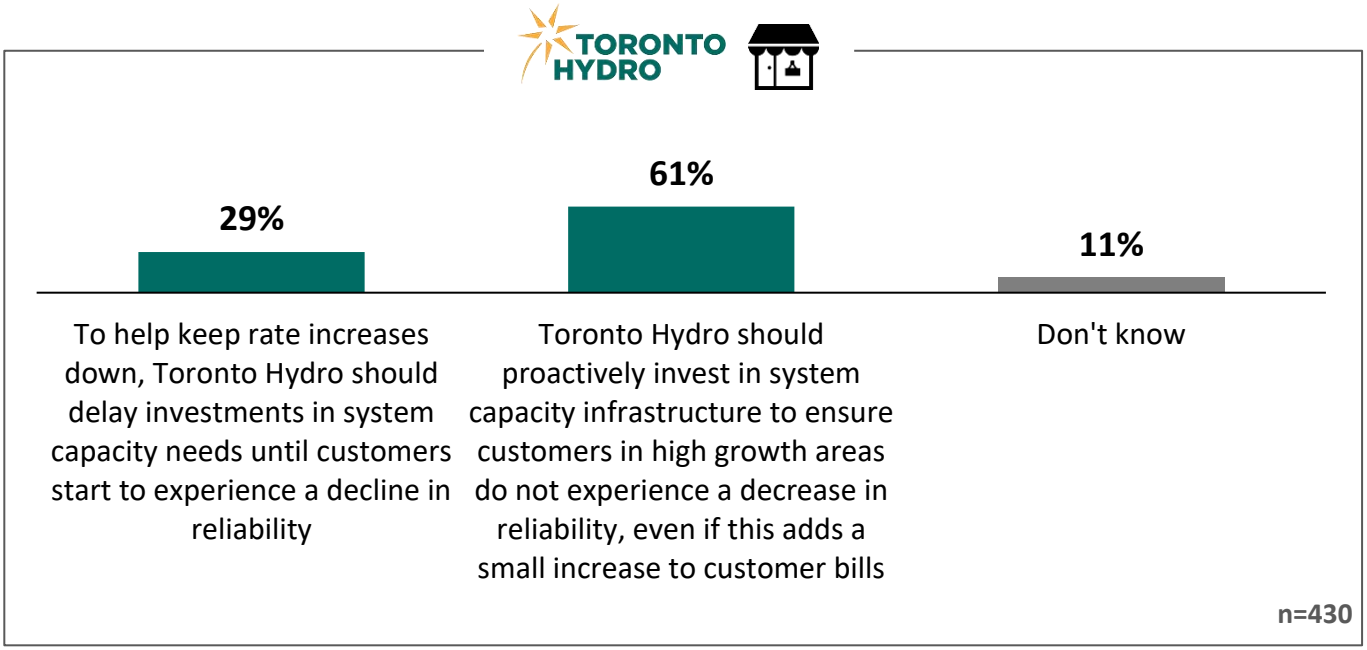
Online Survey
System Service

Small Business

The third investment category focuses on growth and greater demand for electricity in various parts of **Toronto Hydro's** service territory.

Increased demand for electricity puts pressure on existing electrical infrastructure. Eventually, further infrastructure investments are required to support increased demand for electricity.

Q With this in mind, which of the following statements best represents your point of view?



	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Delay investments	23%	27%	31%	31%	35%	33%	19%
Proactively invest	63%	67%	57%	58%	52%	58%	70%
Don't know	14%	6%	12%	11%	13%	9%	11%

Online Survey
Grid Modernization

Small Business

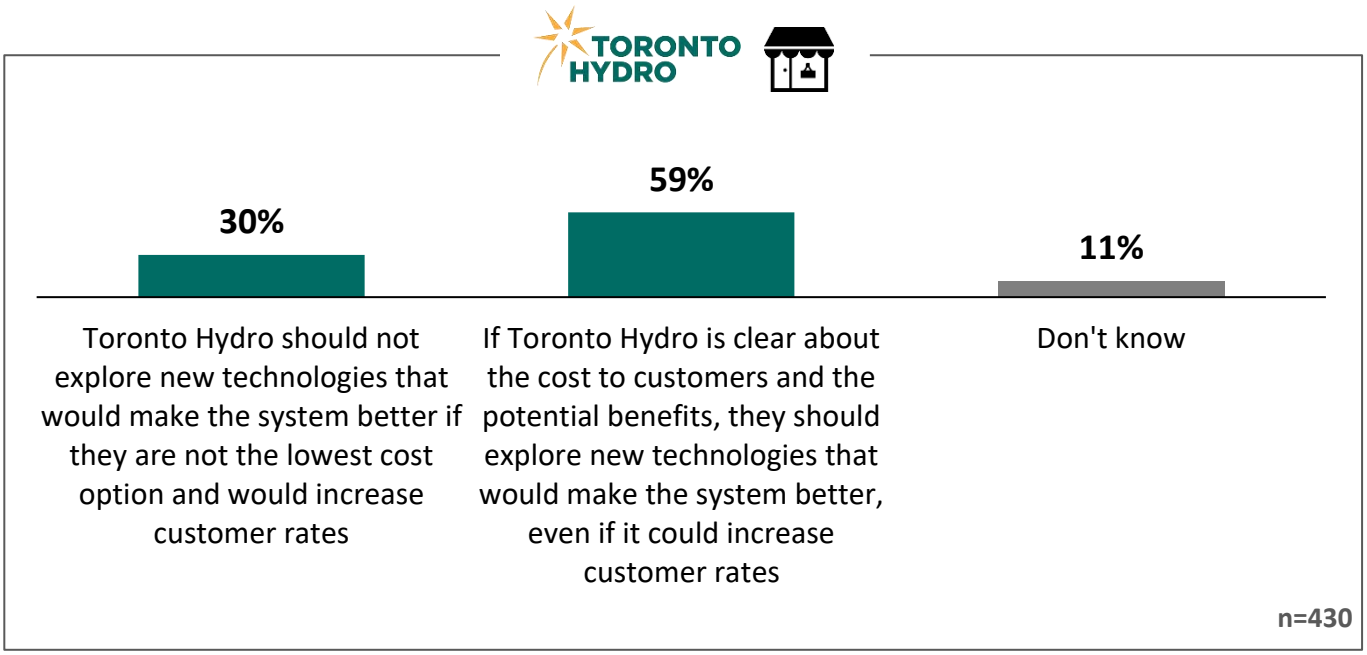
Toronto Hydro can invest in technology than can lead to a wide range of benefits including reliability, efficiency, customer service, and reducing environmental impacts.

When deemed the lowest cost option that will provide equal or improved service, Toronto Hydro will, in most cases, invest in technology.

However, there are two other scenarios where Toronto Hydro needs your feedback.

First, there are times when Toronto Hydro identifies new technology that can improve reliability or provide other benefits, but it will cost customers more. For instance, advanced customer meters that can measure when different home appliances are running, allowing Toronto Hydro to provide customers with better advice on how to reduce their energy consumption and costs.

Q Regarding these types of investments, which of the following best represents your view?



	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Should not explore new tech	39%	32%	24%	27%	37%	34%	19%
Should explore new tech	48%	61%	61%	63%	54%	56%	68%
Don't know	13%	7%	14%	11%	9%	10%	13%

Online Survey
Grid Modernization (Con't)

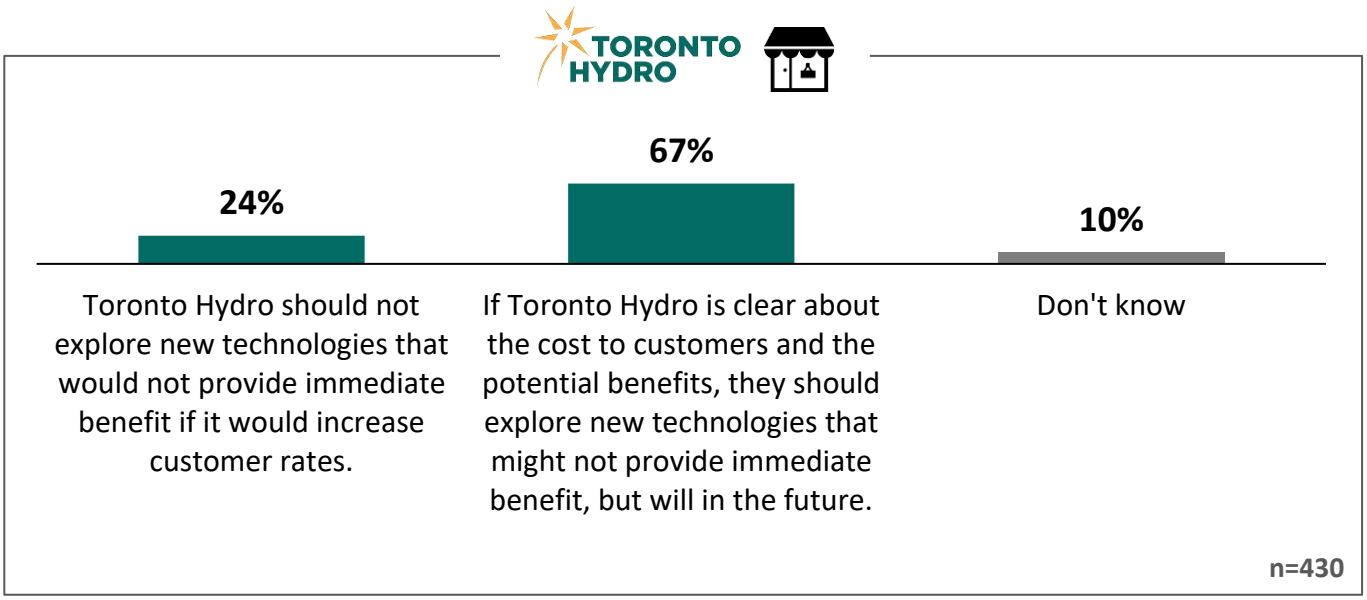
The second scenario is where Toronto Hydro identifies new technology that is needed to improve the system in the future and would increase costs now, but the benefit might not be felt until later.

This includes accommodating emerging technologies like solar power, battery storage and electric vehicles.

Regardless of whether you are considering new energy choices like an electric vehicle for yourself today, Toronto Hydro must be prepared as adoption becomes more widespread over the next 5-10 years.

For instance, charging each electric vehicle draws as much energy as two average homes. If a dozen or so people come home and start changing their vehicles at a period of peak demand, it could overload the grid in that neighbourhood. While Toronto Hydro cannot predict the exact rate of electric vehicle adoption in the City of Toronto, the utility must make certain investments today that will allow it to manage electric vehicle demand in the future.

Q Which of the following best represents your view?



	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Should not explore new tech	26%	33%	21%	18%	26%	26%	19%
Should explore new tech	62%	63%	67%	71%	62%	66%	72%
Don't know	12%	4%	12%	11%	12%	8%	10%

Online Survey

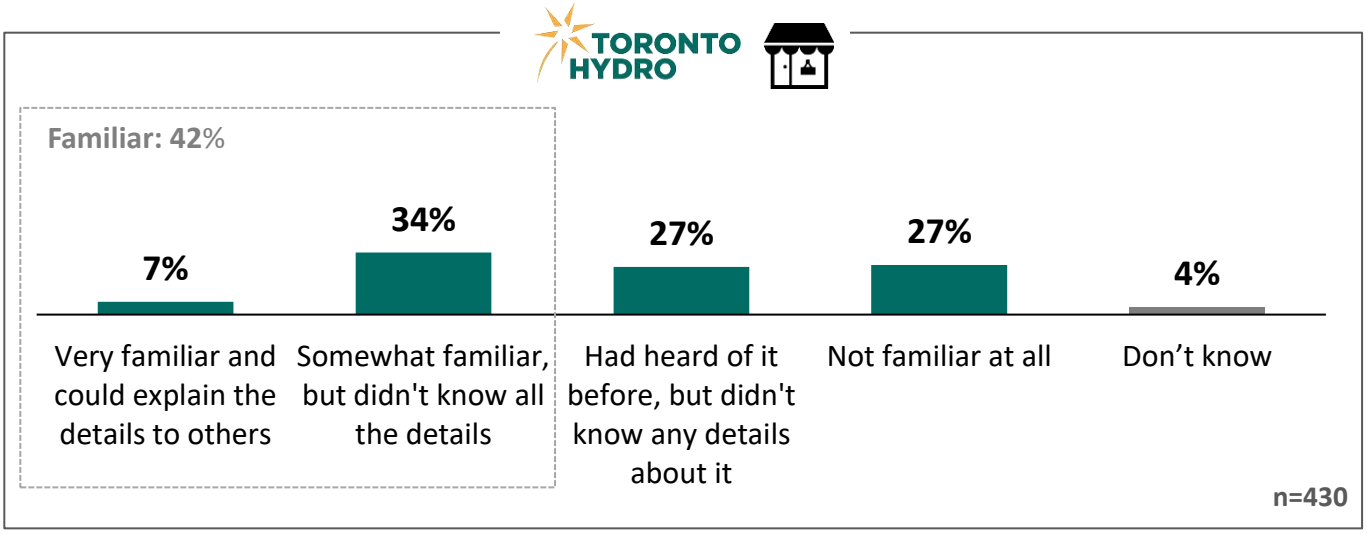
Familiarity with Sources of GHG Emissions

Small Business

In November 2021, the City of Toronto released its 2019 Greenhouse Gas (GHG) Inventory, which tracks Toronto's progress towards GHG reduction targets and identifies key emissions sources. GHG emissions have a wide variety of environmental impacts that lead to climate change and global warming.

This report notes that the two **primary sources of GHG emissions** in Toronto are: energy use in buildings (natural gas and electricity) and transportation fuels (primarily gasoline) – accounting for 93% of all emissions in the city.

Q Before this survey, how familiar would you say you were with the primary sources of GHG emissions in Toronto?



	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Very familiar	9%	11%	7%	4%	10%	7%	5%
Somewhat familiar	27%	34%	31%	40%	31%	33%	39%
Had heard of it	31%	21%	27%	28%	30%	25%	25%
Not familiar at all	26%	29%	31%	25%	26%	30%	26%
Don't know	8%	5%	4%	3%	3%	5%	5%
Familiar (Very + Somewhat)	**35%**	**45%**	**38%**	**44%**	**42%**	**40%**	**44%**

Online Survey

Familiarity with the City's Plan

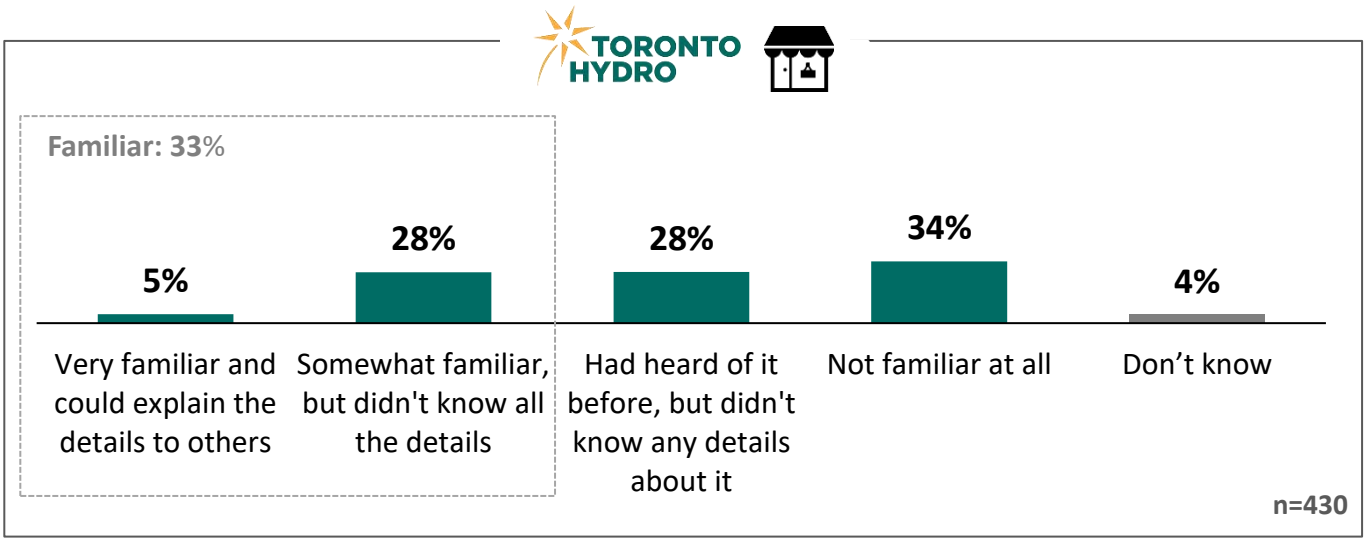
Small Business

In October 2019, Toronto City Council voted to accelerate its efforts to mitigate and adapt to climate change and adopt a stronger emissions target for Toronto: **net zero emissions by 2040.**

A key part of the City's "Net Zero Strategy" requires switching from gasoline in the transportation system and natural gas in home/building heating to electricity-powered alternatives, adopting renewable generators and using energy storage systems.

These initiatives will require Toronto Hydro to expand and modernize its existing electricity distribution grid to ensure that it is capable of helping achieve the City's targets.

Q Before this survey, how familiar were you with the City of Toronto's plan to use an expanded and modernized grid to reduce GHG emissions in Toronto to help address climate change?



		Region			Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Very familiar	5%	7%	6%	2%	7%	4%	4%
Somewhat familiar	24%	24%	33%	30%	25%	31%	27%
Had heard of it	28%	26%	28%	30%	32%	26%	28%
Not familiar at all	35%	37%	30%	35%	32%	34%	36%
Don't know	8%	6%	2%	4%	3%	5%	5%
Familiar (Very + Somewhat)	**30%**	**32%**	**39%**	**32%**	**32%**	**36%**	**31%**

Online Survey

Support for Bill Increase to Meet Emissions Targets

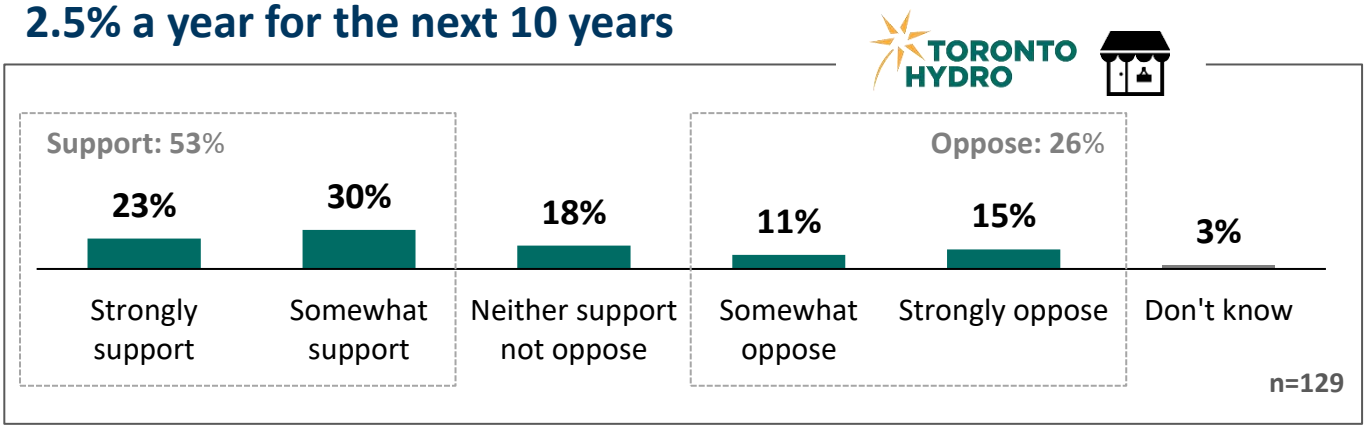
Small Business

As Toronto Hydro is 100% funded through the rates its customers pay, investing in an expanded and modernized electricity grid would mean that customers, like yourself, would pay more.

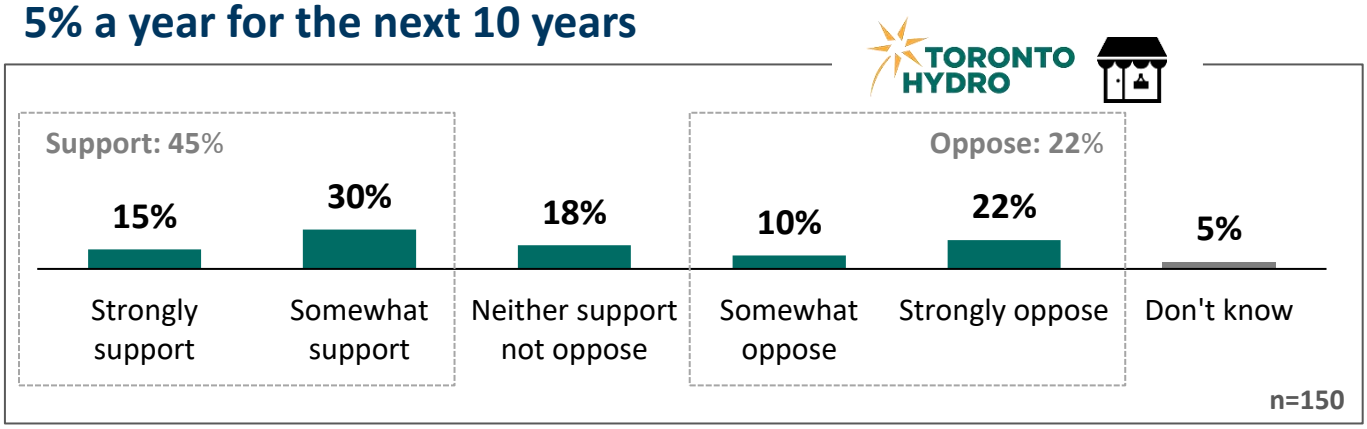
The sooner that Toronto Hydro expands and modernizes the grid, the sooner Toronto can reach its climate change goals.

Q Would you support or oppose a specific charge on your monthly bill to help Toronto meet its future emissions targets if your electricity bill will grow by **[COST]**?

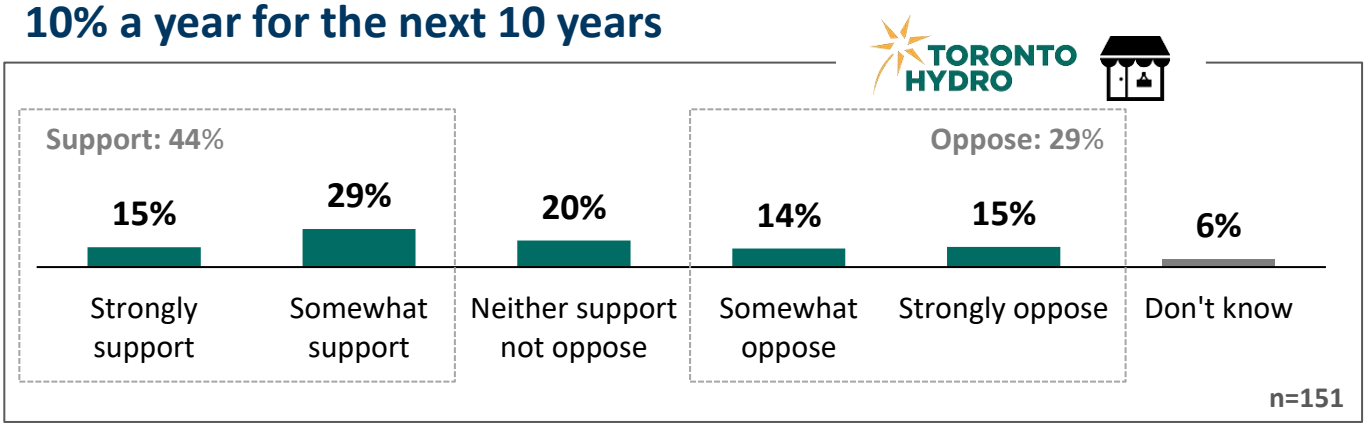
2.5% a year for the next 10 years



5% a year for the next 10 years



10% a year for the next 10 years



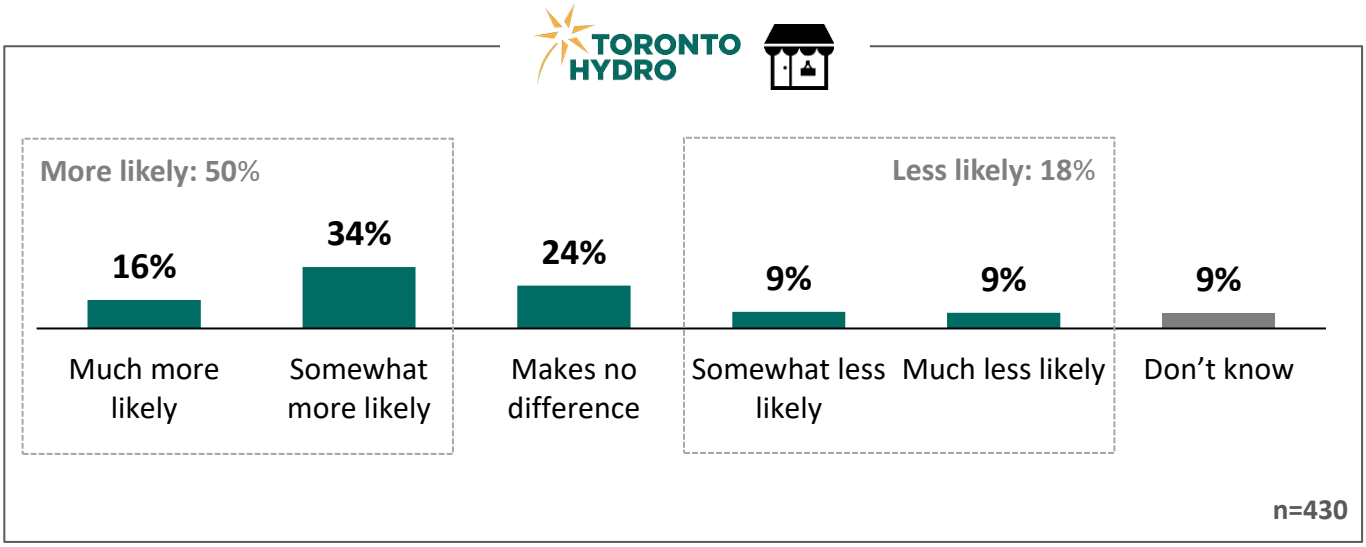
Online Survey

Potential for Rate Increase Offset

Small Business

Some studies have indicated that increasing customer bills to specifically help meet emissions targets could be offset in later years because of reductions in other types of energy bills. For example, as fuel-switching to electricity becomes more widespread, customers may experience cost reductions for gasoline and natural gas.

Q Does knowing these types of rate increases could be offset in later years because of reduction in other types of energy bills make you more or less likely to support a specific charge on your monthly bill to help Toronto meet its future emissions targets?



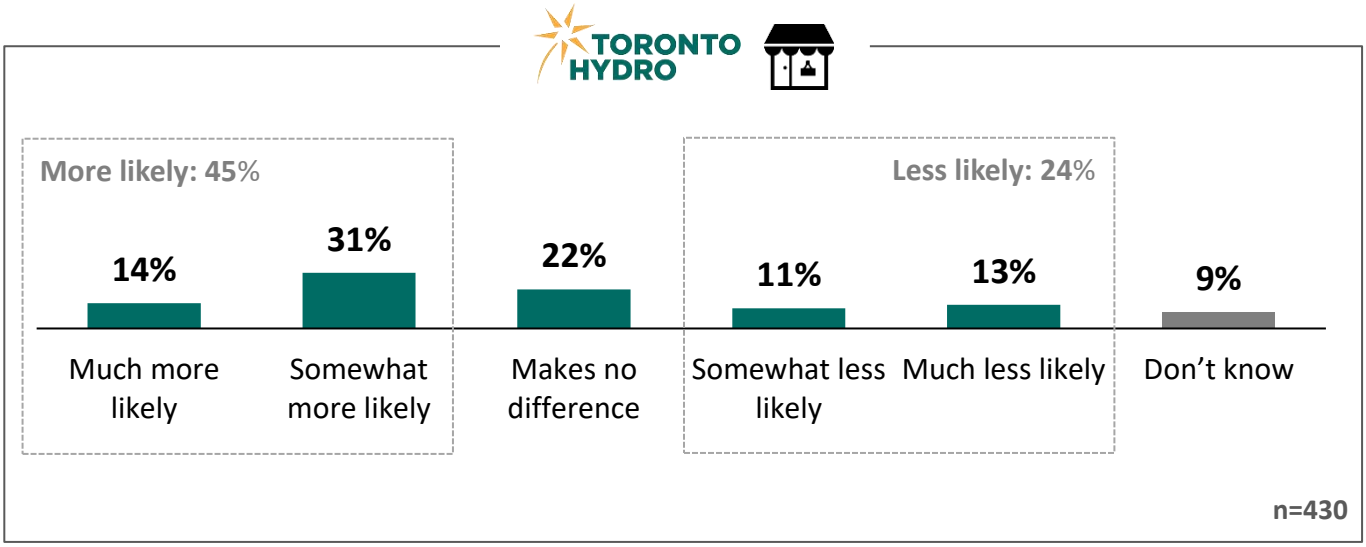
	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Much more likely	18%	11%	17%	17%	14%	10%	24%
Somewhat more likely	29%	38%	39%	31%	31%	38%	32%
No difference	30%	21%	14%	27%	24%	25%	23%
Somewhat less likely	8%	11%	13%	6%	10%	11%	8%
Much less likely	6%	10%	9%	9%	13%	10%	4%
More likely (Very + Somewhat)	**47%**	**50%**	**56%**	**48%**	**45%**	**48%**	**56%**
Less likely (Very + Somewhat)	**14%**	**22%**	**23%**	**15%**	**23%**	**21%**	**11%**

Online Survey
Inclusion of Rate Relief

Small Business

Some customers have said that they would be willing to spend more in order to help Toronto meet its future emissions targets, however, feel that lower-income Torontonians should receive rate relief in order to offset any associated price increase.

Q Would the inclusion of "rate relief" for low-income customers make you **more or less likely to support** a specific charge on your monthly bill to help Toronto meet its future emissions targets?



	Region				Bill impact on finances		
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	Significant impact	Impact	No Impact
Much more likely	12%	15%	17%	13%	18%	8%	17%
Somewhat more likely	27%	28%	32%	34%	20%	36%	34%
No difference	23%	21%	21%	22%	22%	23%	20%
Somewhat less likely	9%	12%	15%	10%	15%	11%	9%
Much less likely	15%	17%	8%	13%	18%	15%	7%
More likely (Very + Somewhat)	**40%**	**43%**	**49%**	**47%**	**38%**	**43%**	**52%**
Less likely (Very + Somewhat)	**24%**	**29%**	**23%**	**23%**	**33%**	**26%**	**16%**

Online Survey

Small Business

Do future offset rates and rate relief increase or decrease support?

Does knowing these types of rate increases could be offset in later years because of reduction in other types of energy bills make you more or less likely to support a specific charge on your monthly bill to help Toronto meet its future emissions targets?

	Would you support or oppose a specific charge on your monthly bill to help Toronto meet its future emissions targets if your electricity bill will grow by [COST]?						
	Total	Strongly support	Somewhat support	Neither support nor oppose	Somewhat oppose	Strongly oppose	Don't know
Much more likely	16%	51%	17%	4%	5%	1%	7%
Somewhat more likely	34%	22%	61%	38%	22%	10%	13%
Makes no difference	24%	18%	13%	35%	36%	33%	0%
Somewhat less likely	9%	5%	5%	6%	25%	16%	0%
Much less likely	9%	0%	1%	8%	10%	31%	4%
Don't know	9%	4%	2%	10%	2%	8%	76%
Net "More Likely"	**+32%**	**+69%**	**+72%**	**+27%**	**-9%**	**-37%**	**+16%**

Would the inclusion of "rate relief" for low-income customers make you more or less likely to support a specific charge on your monthly bill to help Toronto meet its future emissions targets?

	Would you support or oppose a specific charge on your monthly bill to help Toronto meet its future emissions targets if your electricity bill will grow by [COST]?						
	Total	Strongly support	Somewhat support	Neither support nor oppose	Somewhat oppose	Strongly oppose	Don't know
Much more likely	14%	35%	18%	7%	4%	1%	10%
Somewhat more likely	31%	31%	49%	31%	19%	14%	10%
Makes no difference	22%	18%	19%	31%	27%	22%	3%
Somewhat less likely	11%	10%	12%	7%	23%	11%	0%
Much less likely	13%	3%	1%	14%	22%	40%	4%
Don't know	9%	3%	2%	9%	5%	12%	73%
Net "More Likely"	**+21%**	**+53%**	**+54%**	**+17%**	**-22%**	**-36%**	**+16%**

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro. The conclusions drawn and opinions expressed are those of the authors.

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CONFIDENTIAL

APPENDIX 05

Commercial & Industrial
Needs and Preferences Survey

November 2, 2023

STRICTLY CONFIDENTIAL

2025 – 2029 Rate Application

Report Navigation

APPENDICIES

PHASE I

- APPENDIX.01 – Customer Engagement Focus Groups
- APPENDIX.02 – Customer Sample Validation
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- APPENDIX.04 – Small Business Needs and Preferences Survey
- APPENDIX.05 – Commercial & Industrial Needs and Preferences Survey
- APPENDIX.06 – Key Accounts Needs and Preferences Survey
- APPENDIX.07 – Needs and Preferences Planning Placemat

PHASE II

- APPENDIX.08 – Customer Engagement Workbook Overview
- APPENDIX.09 – Residential Workbook Report
- APPENDIX.10 – Small Business Workbook Report
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- APPENDIX.12 – Key Accounts Workbook Report
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INNOVATIVE RESEARCH GROUP

Commercial & Industrial Customers

Online Survey Results

Section 5.1



Online Survey

Survey Design & Methodology



INNOVATIVE was engaged by Toronto Hydro to gather customer input to assess the importance of the outcomes and priorities identified in the qualitative components of Phase I of the customer engagement.

Field Dates

The **C&I Online Survey** was sent to all Toronto Hydro C&I customers who provided the utility with an email address. Customers had an opportunity to complete the survey between **January 17th and 31st, 2022**.

Each customer received a unique URL that could be linked back to their annual consumption, region and rate class.

In total, the C&I survey was sent to **2,382** customers via e-blast from *customerexperience@torontohydro.com*. A reminder email was sent 2 days after the initial invitation to those who had not yet completed the survey. An additional reminder email was sent 2 days later, and a final reminder email was sent a week later.

C&I Online Survey Completes

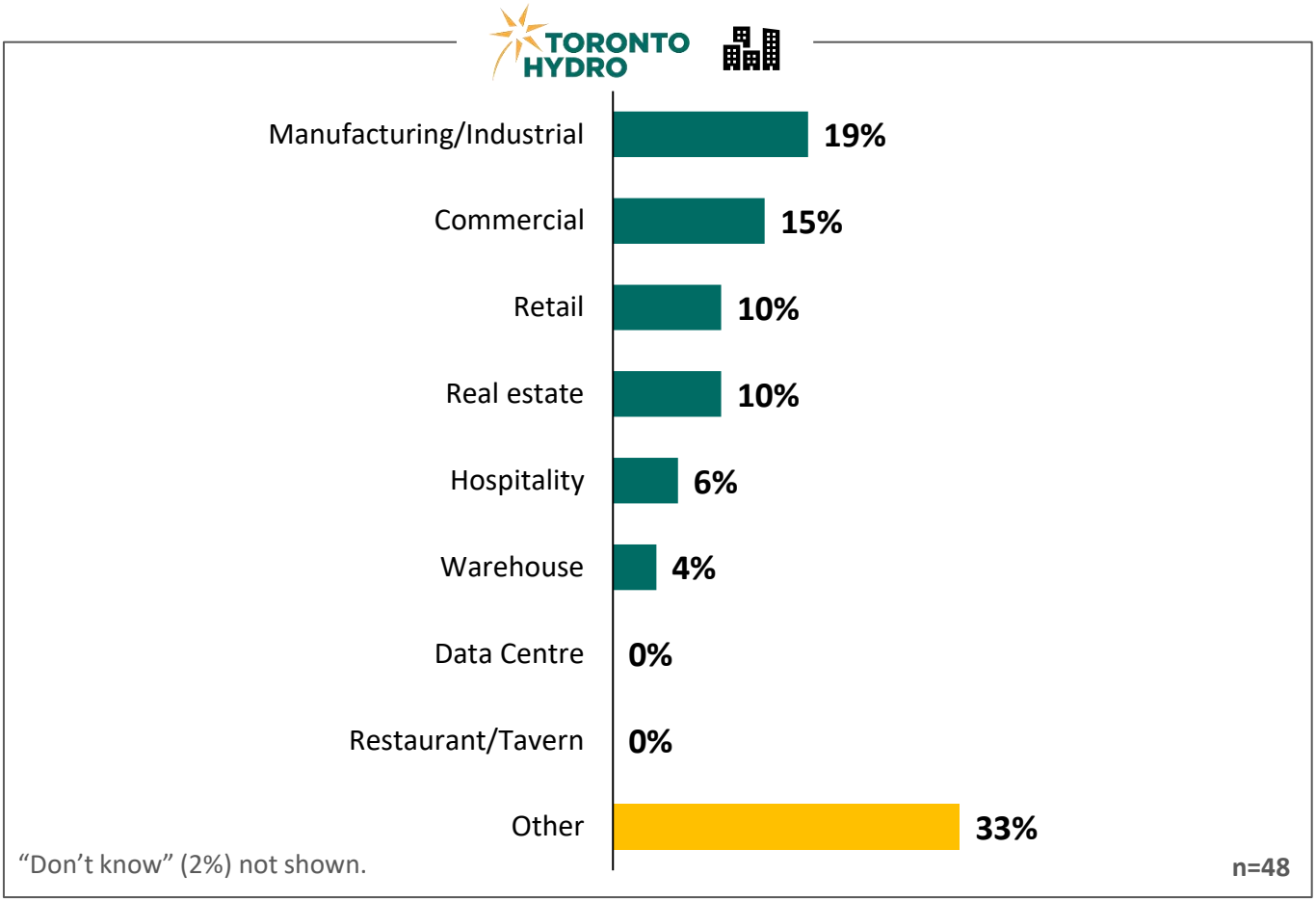
A total of **48** (unweighted) Toronto Hydro C&I customers completed the online survey via a unique URL.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Online Survey
Demographic breakdown

Commercial & Industrial

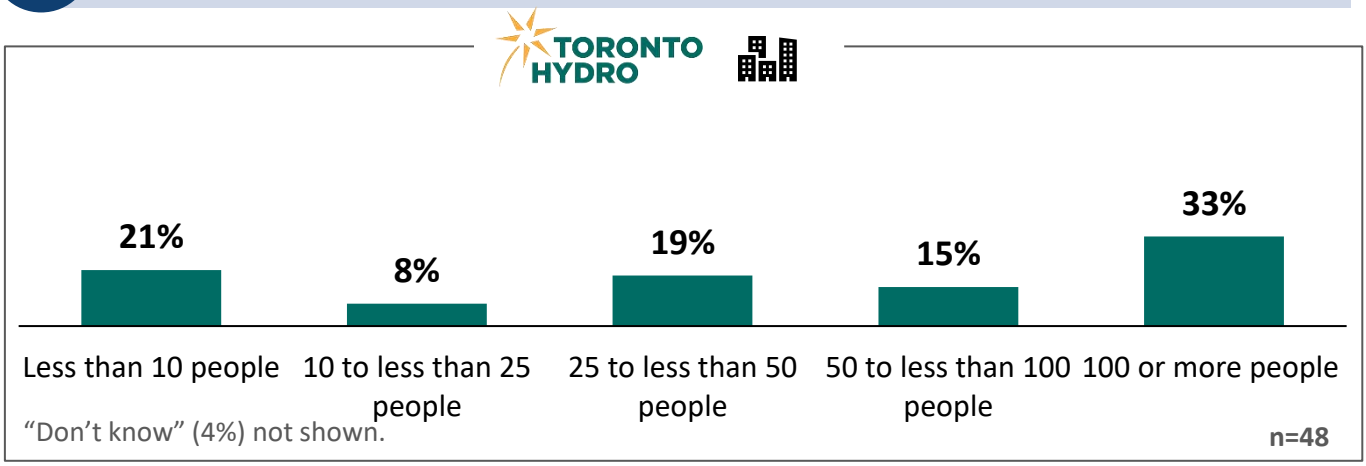
Q Which of the following best describes the sector in which your business operates?



"Don't know" (2%) not shown.

n=48

Q Including yourself, how many people work at your organization?



"Don't know" (4%) not shown.

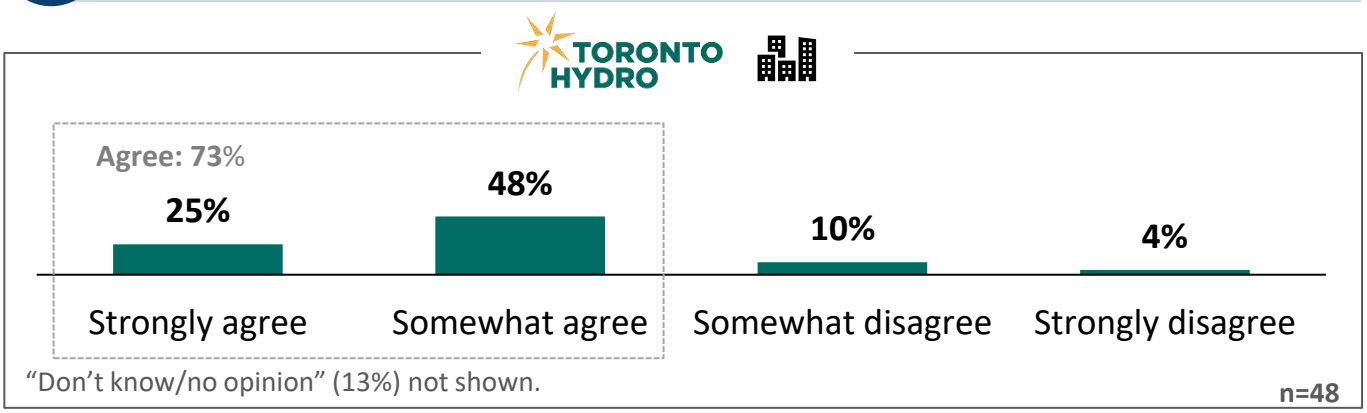
n=48

Online Survey
Environmental Controls

Commercial & Industrial

To what extent do you agree or disagree with the following statements?

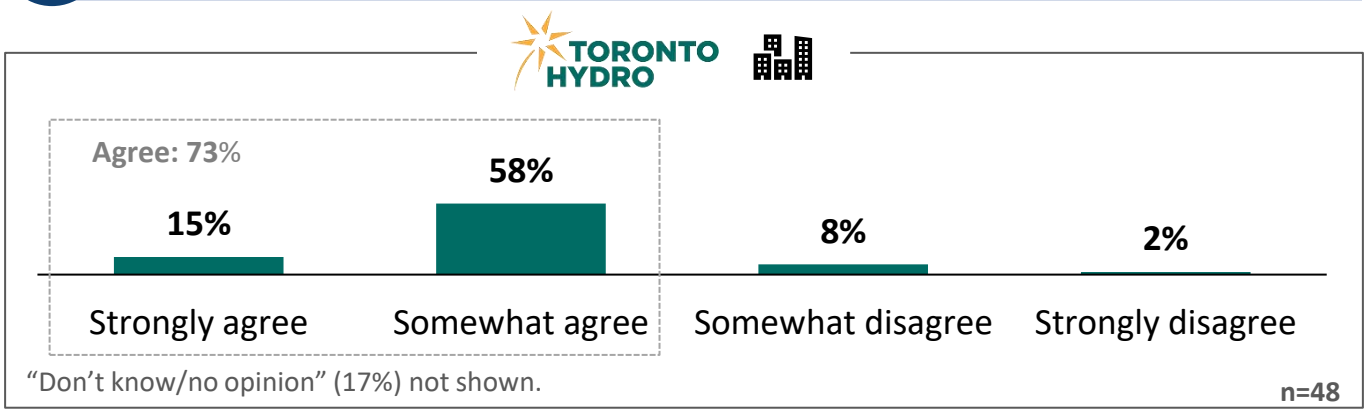
Q The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know/no opinion" (13%) not shown.

n=48

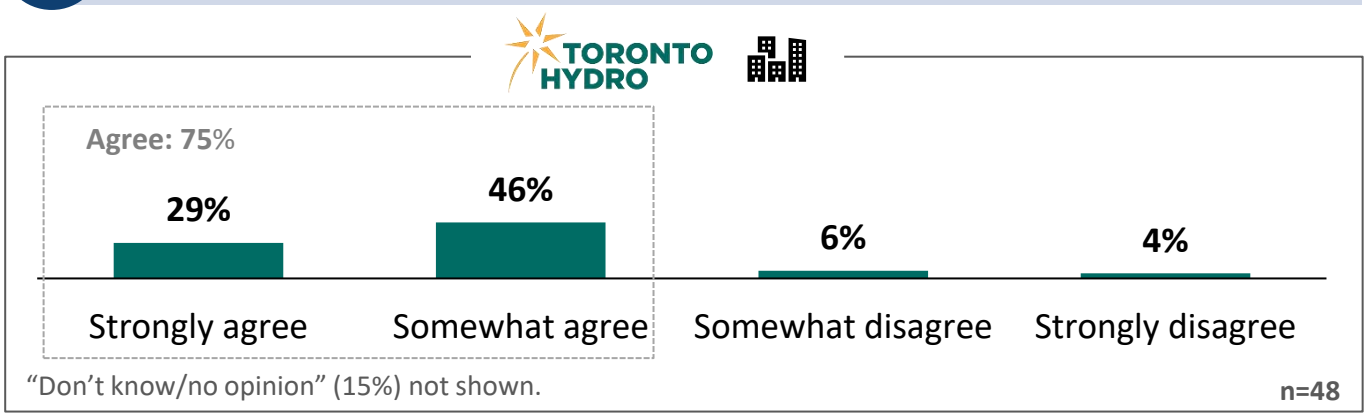
Q Customers are well-served by the electricity system in Ontario.



"Don't know/no opinion" (17%) not shown.

n=48

Q Fossil fuels should be phased out as quickly as possible to speed up the shift to a lower-carbon future.



"Don't know/no opinion" (15%) not shown.

n=48

Online Survey

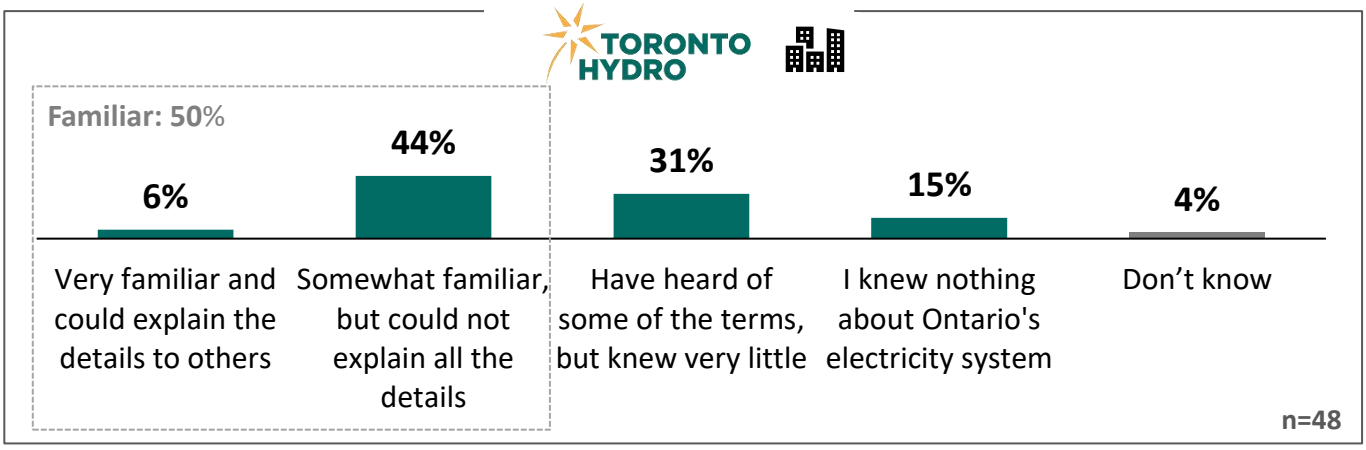
Familiarity with Ontario's Electricity System

Commercial & Industrial

As you may know, Ontario's electricity system has three key components: **generation**, **transmission** and **distribution**.

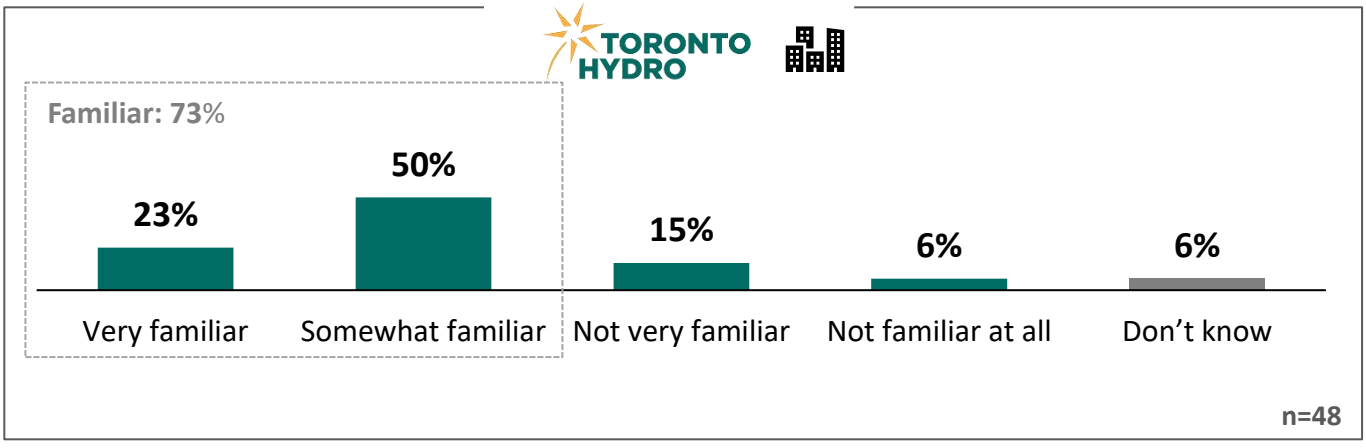
- **Generating stations** convert various forms of energy into electric power
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province
- **Local distribution networks** take the electricity from provincial transmission lines and bring it to your home through a network of wires, poles and other equipment.

Q Before this survey, how familiar were you with the various parts of the electricity system and how they work together?



Toronto Hydro owns and operates Toronto's distribution network. This is the network that takes the electricity from high-voltage transmission towers and brings it to your business through a network of wires, poles and other equipment.

Q Before this survey, how familiar were you with **Toronto Hydro**, which operates the electricity distribution system in your community?

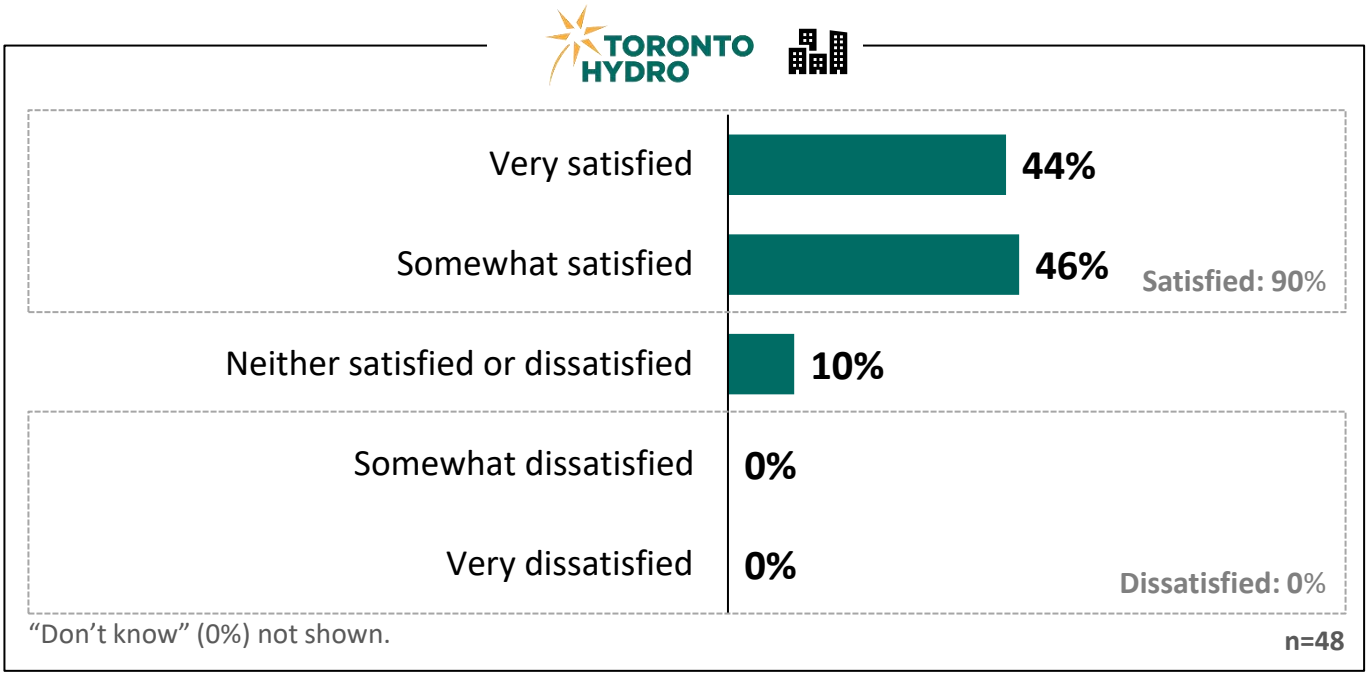


Online Survey

Satisfaction & Improvement with Toronto Hydro

Commercial & Industrial

Q Thinking specifically about the services provided to you and your community by **Toronto Hydro**, overall, how satisfied or dissatisfied are you with the services that your organization receives?



"Don't know" (0%) not shown.

n=48

Q Is there anything in particular you would like Toronto Hydro to do to improve its services to you?

Response	%
Reliability	10%
Communication	8%
Billing	8%
Service	4%
Costs	4%
None	6%
Don't Know	58%

Online Survey

Commercial & Industrial

How Toronto Hydro can Improve Services to Customers

Q Is there anything in particular you would like Toronto Hydro to do to improve its services to you?

Reliability
"Consistent hydro - there are a lot of power failures in the area which cause problems for security, computer and building systems."
"Either in summer and winter, power outage is a hassle. In winter it will be worst. Although it is not often (can't imagine what will be if that happens), yet it's ideal to have zero power outage."
"Eliminate power outages."
"Preventative Maintenance on distribution lines to prevent auto-reclosure events especially in spring time, overgrowth and animal activity that cause disruptions."
"Spikes in power that are causing damage to equipment."
Communication
"Better communications."
"Community communications on efficiency improvement plans."
"It seems that Toronto Hydro has my email address attached to numerous accounts within our organization that I am not responsible for."
"We want to be informed once a power outrage happens."
Billing
"As far as e-billings are concerned Toronto Hydro is quite excellent in providing us this service."
"Find a way to make the billing less complicated..."
"Help clarify why power usage on bill jumps up on occasion without any change in operational practice."
"When in the accounts (particularly for multiple accounts) page it would definitely help if there was a column to show due date as well for payments, next to the current balance. that would be better to view the bills as per due dates."
Service
"Response times when we plan a shutdown for private hydro-station maintenance; waited 4+ hours for vehicles to arrive despite being told they were coming. Had to PM Toronto Hydro on Twitter to get a response. Have experienced this a few times. Random power "blips" (not too frequent fortunately) but with no explanation or reason. Our restart and inspection of equipment can take up to 2 hours depending if we have personnel on site at the time."
"Maybe to provide updates from time to time to consumer. re: upgrade."
Costs
"If the rates can be reduced - that will be great."
"Lower rates."

Online Survey

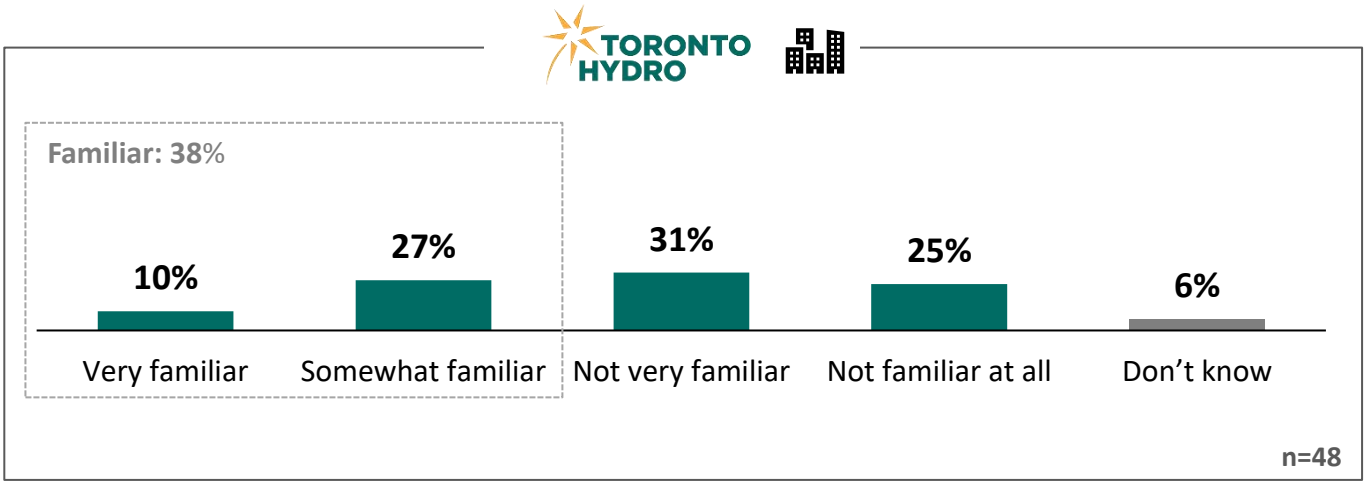
Commercial & Industrial

Familiarity with Bill Remittance to Toronto Hydro

While **Toronto Hydro** is only responsible for the distribution portion of the system, to make it easier for customers, they are responsible for collecting payment for the entire electricity system.

Toronto Hydro keeps about **6%** of the average mid-sized business customer's bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to **Toronto Hydro**?

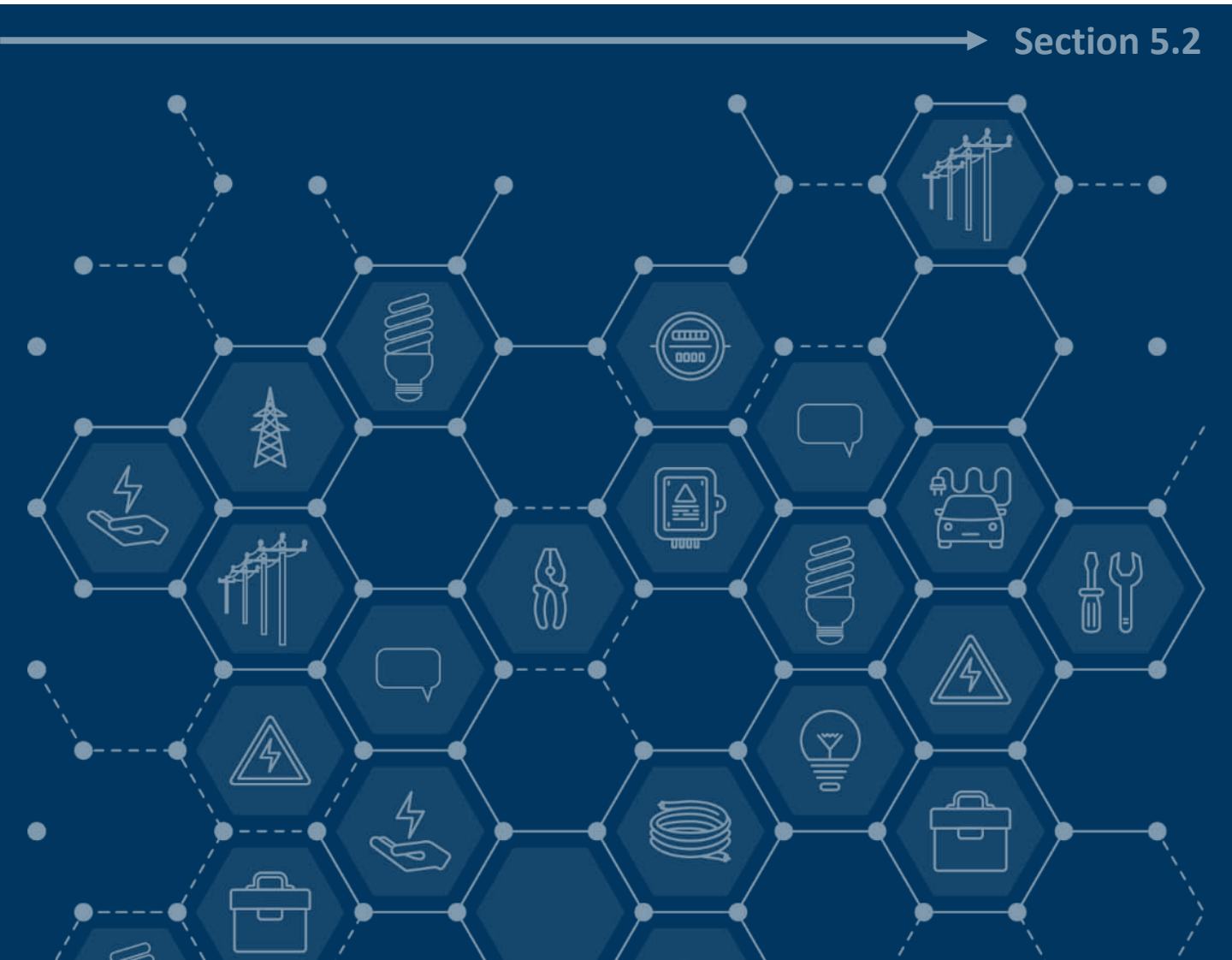


INNOVATIVE RESEARCH GROUP

Commercial & Industrial Customers

Customer Priorities

Section 5.2



Online Survey
Importance of Customer Priorities

Commercial & Industrial

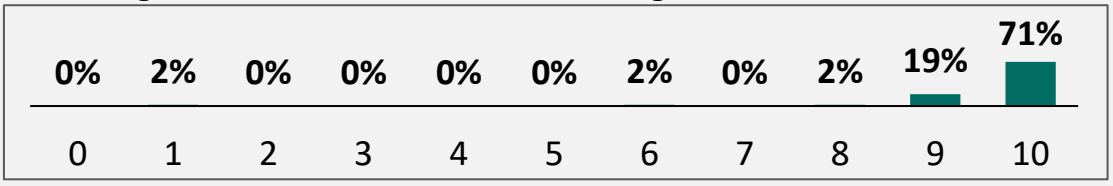
Now, let's talk about our second topic – outcomes.

Everyday **Toronto Hydro** interacts with hundreds of its customers through multiple channels and touchpoints, including surveys, the call centre and social media.

In a recent series of customer focus groups, a number of company goals were identified as priorities for **Toronto Hydro**.

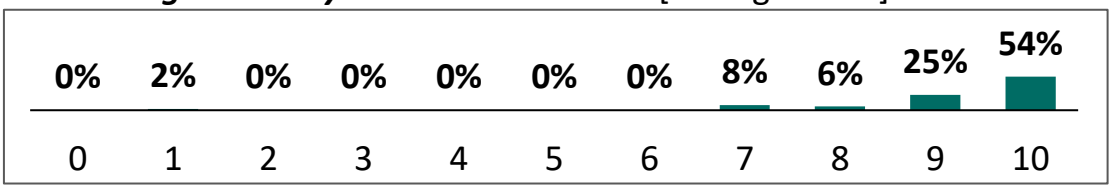
Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Toronto Hydro** priorities to you as a customer?

Ensuring reliable electrical service [average = **9.5**]



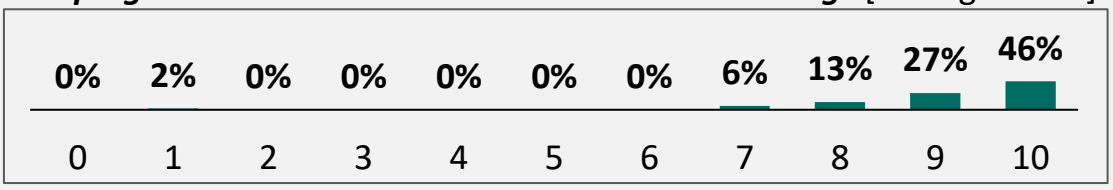
Not at all important — Extremely important

Delivering electricity at reasonable rates [average = **9.2**]



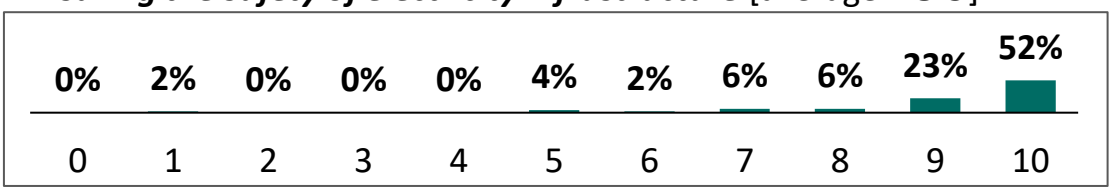
Not at all important — Extremely important

Helping customers with conservation and cost savings [average = **9.0**]



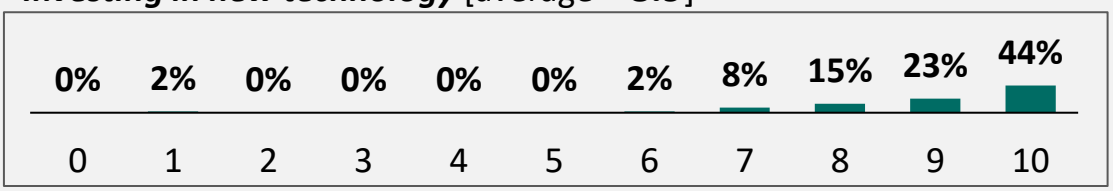
Not at all important — Extremely important

Ensuring the safety of electricity infrastructure [average = **8.9**]



Not at all important — Extremely important

Investing in new technology [average = **8.9**]



Not at all important — Extremely important

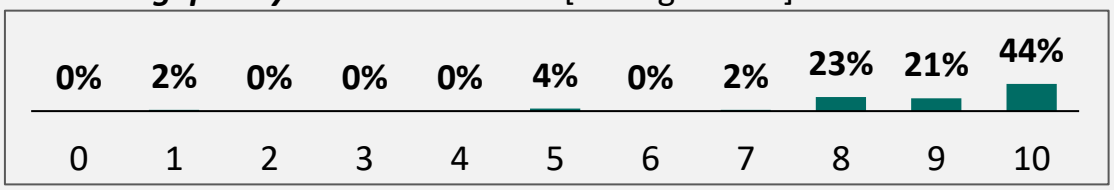
Online Survey

Importance of Customer Priorities (Cont'd)

Commercial & Industrial

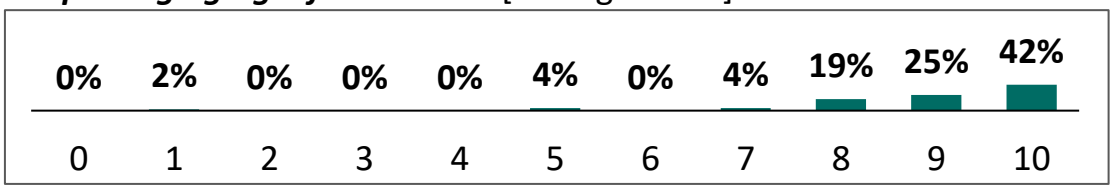
Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Toronto Hydro** priorities to you as a customer?

Providing quality customer service [average = **8.8**]



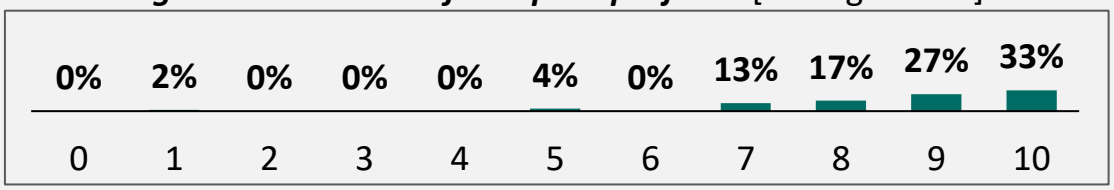
Not at all important — Extremely important

Replacing aging infrastructure [average = **8.8**]



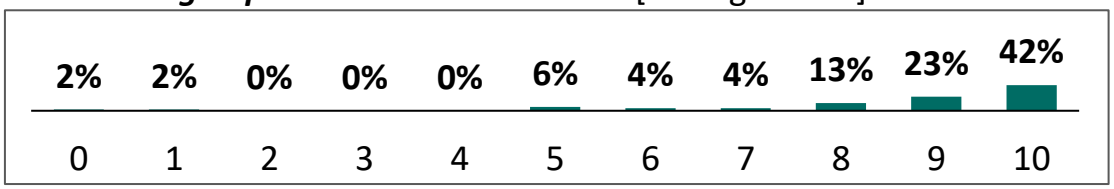
Not at all important — Extremely important

Providing reasonable costs for capital projects [average = **8.6**]



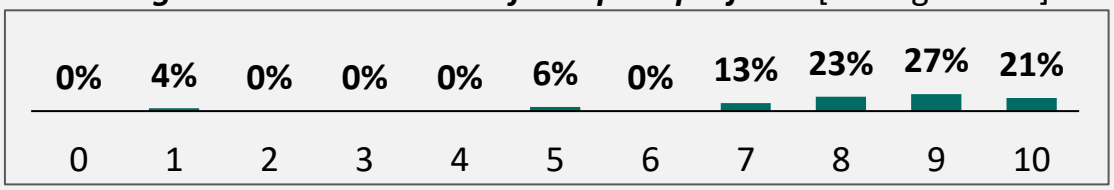
Not at all important — Extremely important

Minimizing impact on the environment [average = **8.5**]



Not at all important — Extremely important

Providing reasonable timelines for capital projects [average = **8.1**]

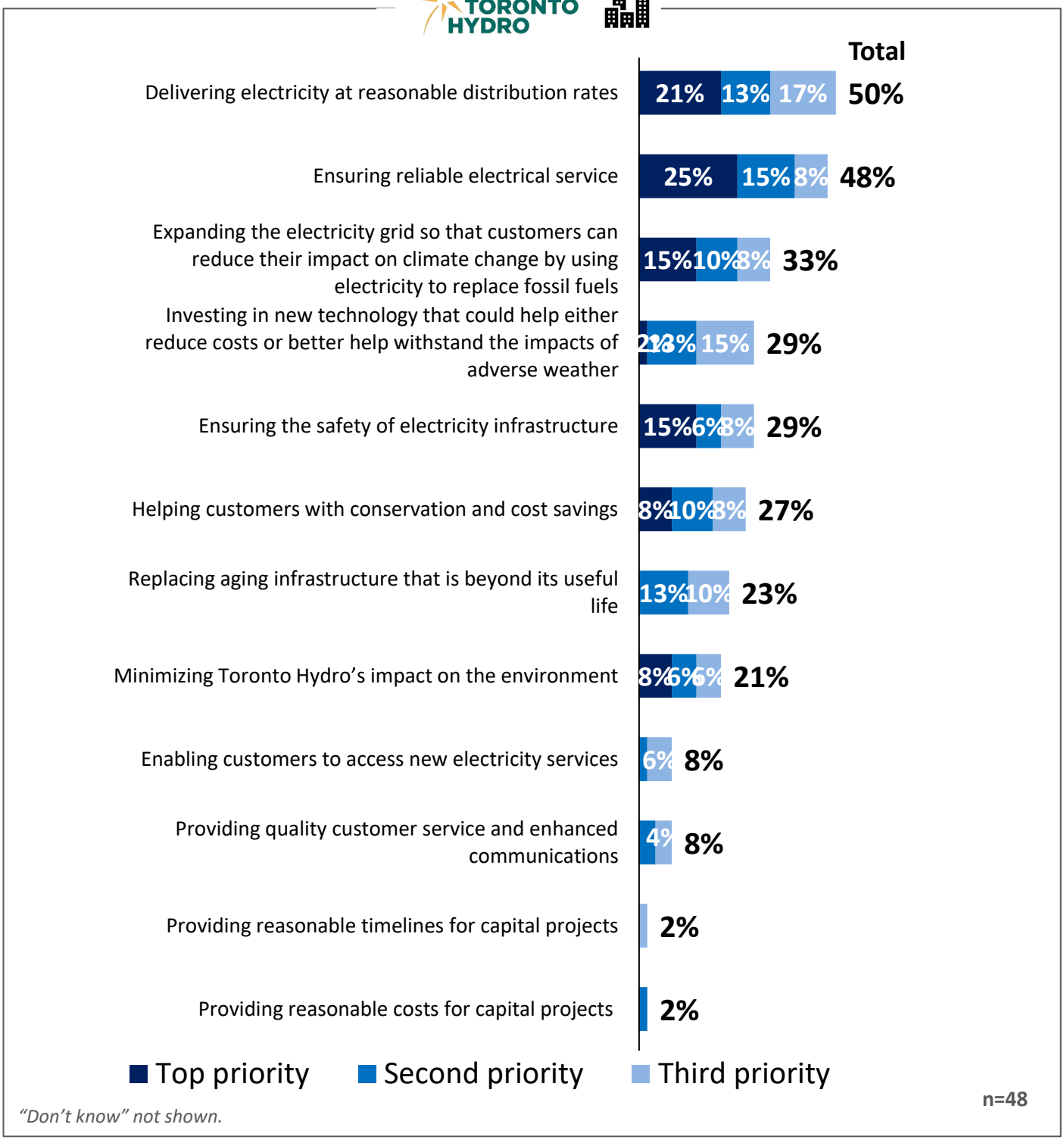


Not at all important — Extremely important

Online Survey
Ranking Customer Priorities

Commercial & Industrial

Q Thinking of the priorities on the previous page, which would you say is the **most** important? What is the next most important priority you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?



n=48

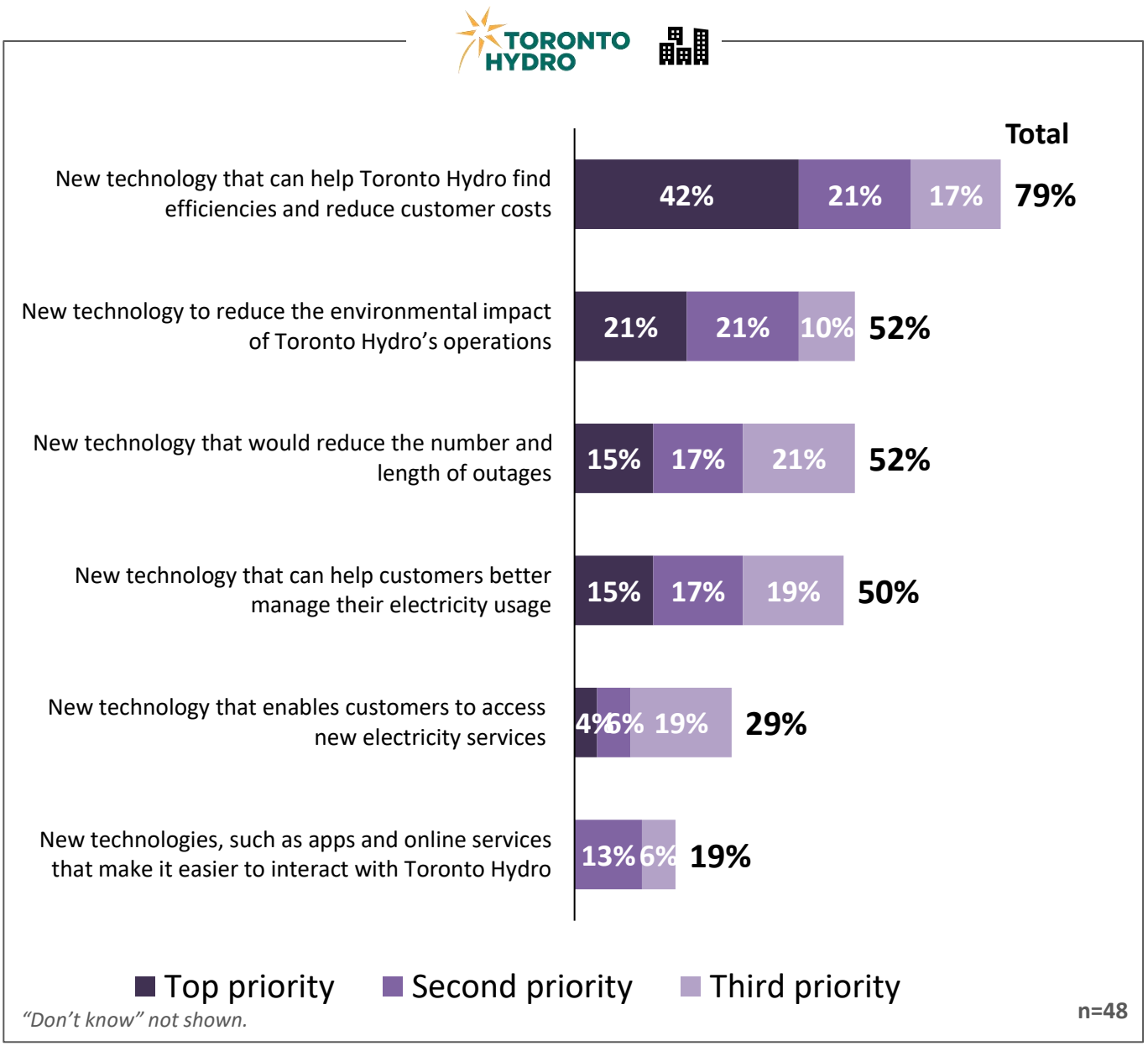
"Don't know" not shown.

Online Survey
Ranking Technology Priorities

Commercial & Industrial

Investments in new technology can help Toronto Hydro address a range of issues. These include reliability, efficiency, customer service, Toronto Hydro's impact on the environment, new service offerings and tools to manage electricity usage.

Q Among the following potential investments in new technology, which would you say is the **most** important? What is the next most important new technology priority you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?



"Don't know" not shown.

n=48

Online Survey
Additional Priorities

Commercial & Industrial

Q Can you think of any other important priorities that **Toronto Hydro** should be focusing on?

Response	%
Fighting Climate Change	4%
Communication	2%
Costs	2%
Reliability	2%
Other	4%
None	4%
Don't Know	81%

Fighting Climate Change
"Reducing their negative effect on the environment."
"Replacing fossil fuels!"
Communication
"Easy phone communication."
Costs
"For me focus on cost savings especially to consumers."
Reliability
"Preventative maintenance."
Other
"Public education."
"Focus on long-term benefits to the customers, not just short-term."

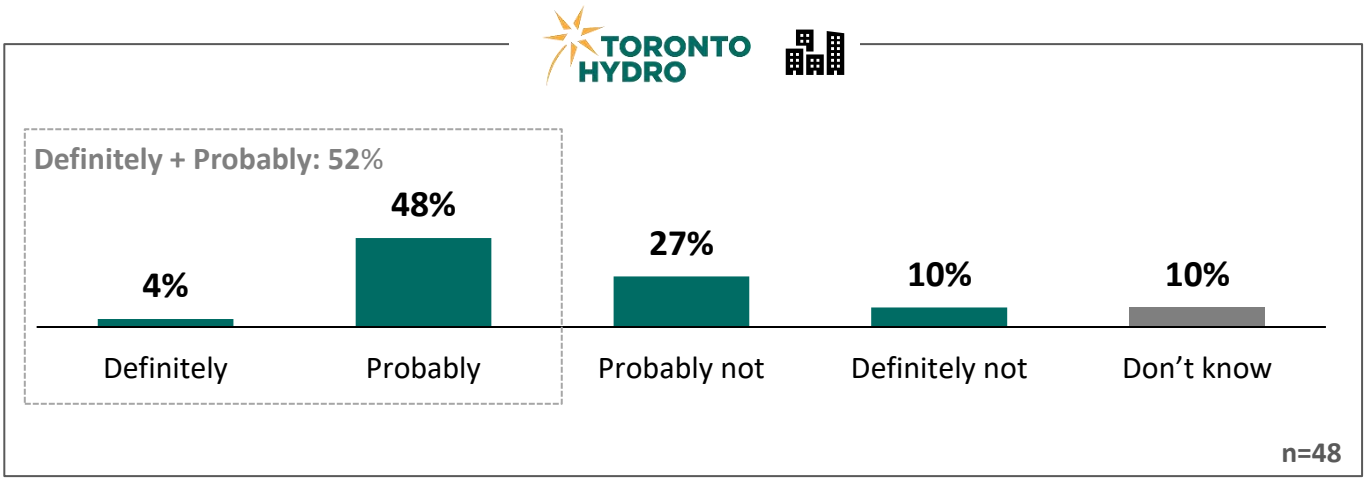
Online Survey

Commercial & Industrial

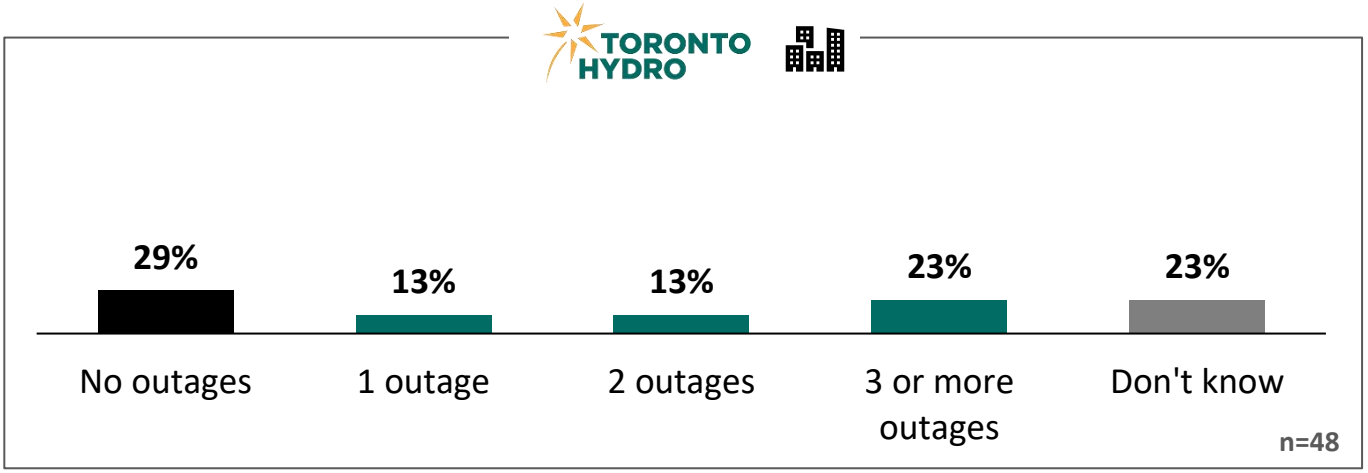
Support for Low-Income Customers & Outages Experienced

In recent interactions with customers, a number of customers identified assisting low-income Torontonians with their electricity bills.

Q In addition to the amount that you currently pay on your electricity bill, would you be willing to pay an extra few dollars per month in order for Toronto Hydro to provide financial assistance to make electricity bills more affordable for low-income customers?



Q Now, let's talk about the reliability of electricity service your organization receives. Have you experienced any power outages at **your organization in the past 12 months** which *lasted longer than one minute*? If so, approximately how many of these power outages did you experience?

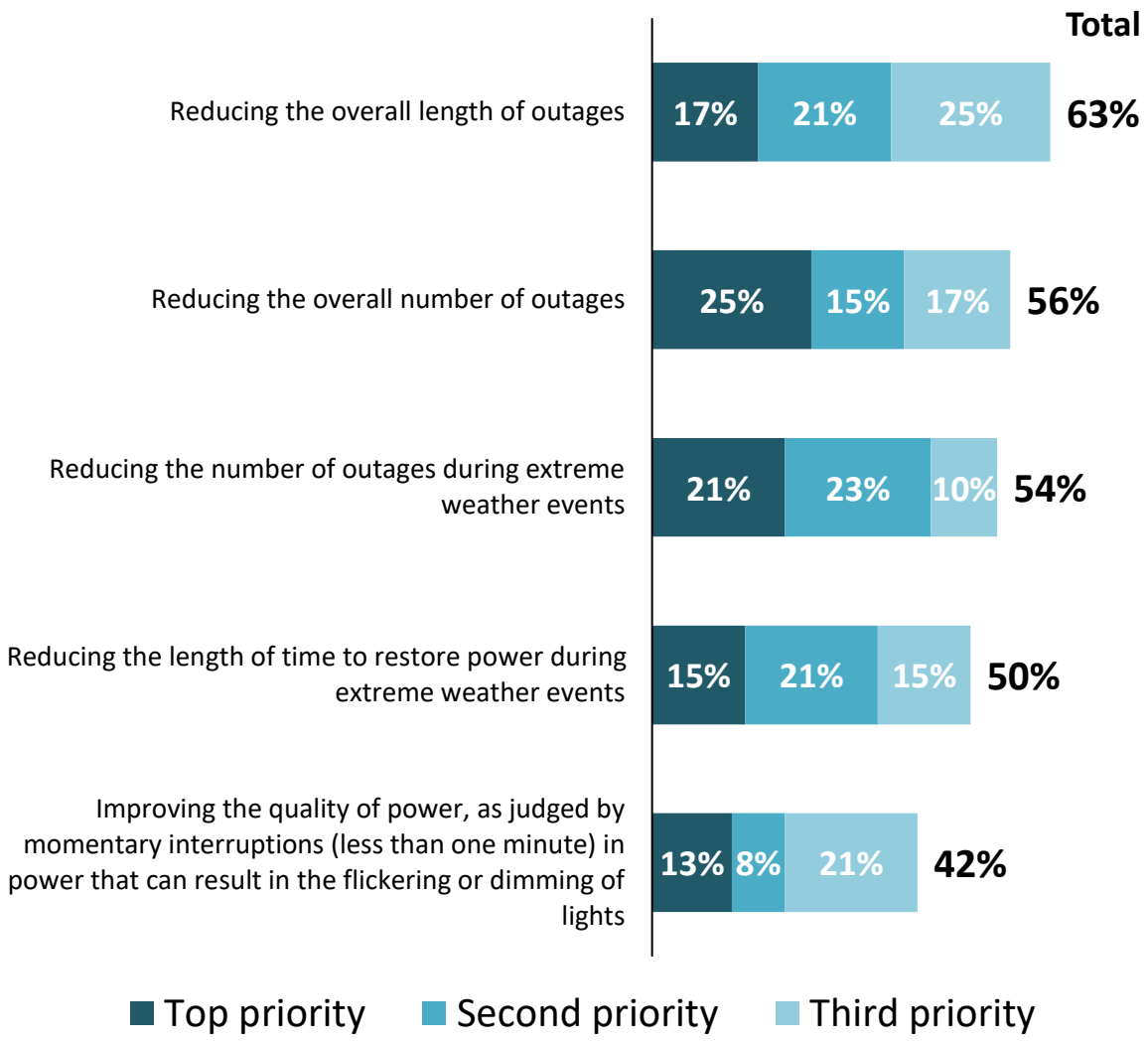


Online Survey
Ranking Reliability Priorities

Commercial & Industrial

When it comes to reliability, there are a number of areas that **Toronto Hydro** could focus on.

Q Among the following reliability outcomes, which would you say is the **most** important? What is the next most important reliability outcome you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?



"Don't know" not shown.

n=48

INNOVATIVE RESEARCH GROUP

Commercial & Industrial Customers

Investment Trade-Offs

Section 5.3



Online Survey
System Renewal

Commercial & Industrial

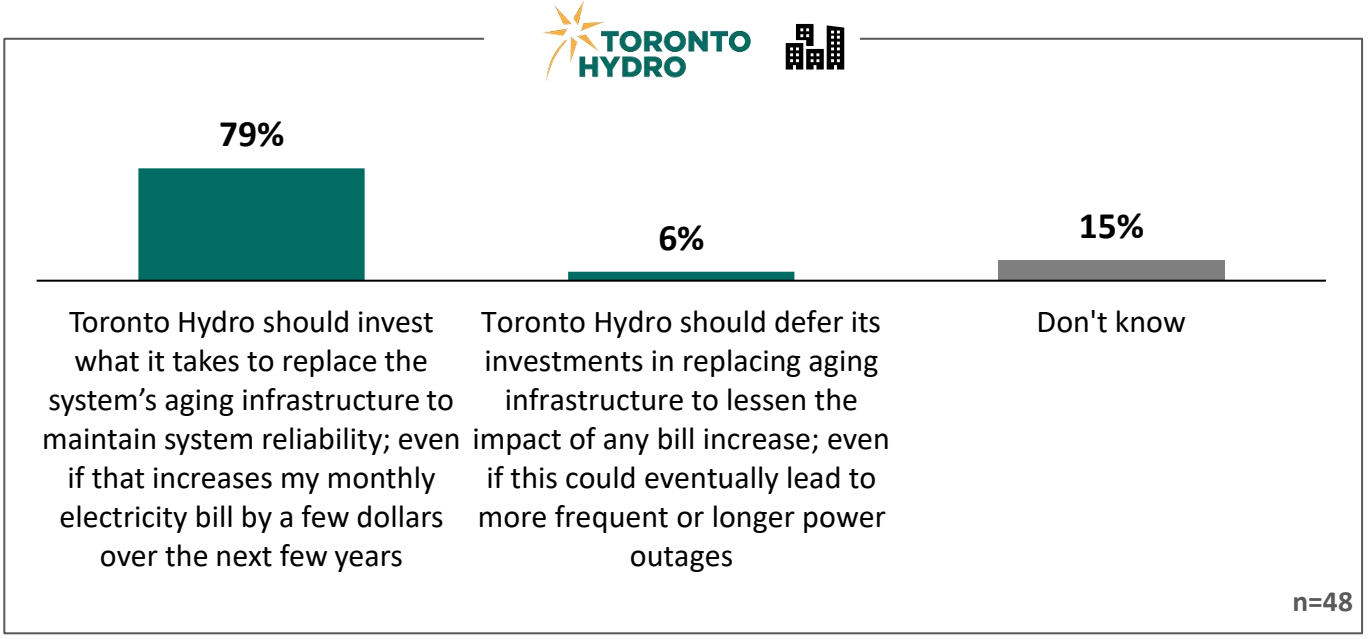
Now let's turn to our final topic – investment trade-offs.

Toronto Hydro is in the early stages of developing its investment plan for the next five years. While conversations with customers will continue over the next several months, the utility wants to know your preferences when it comes to finding the right balance between costs and other outcomes.

There are four investment categories that we would like to discuss.

The first category focuses on projects that replace and restore aging electrical infrastructure, like overhead poles and underground cables.

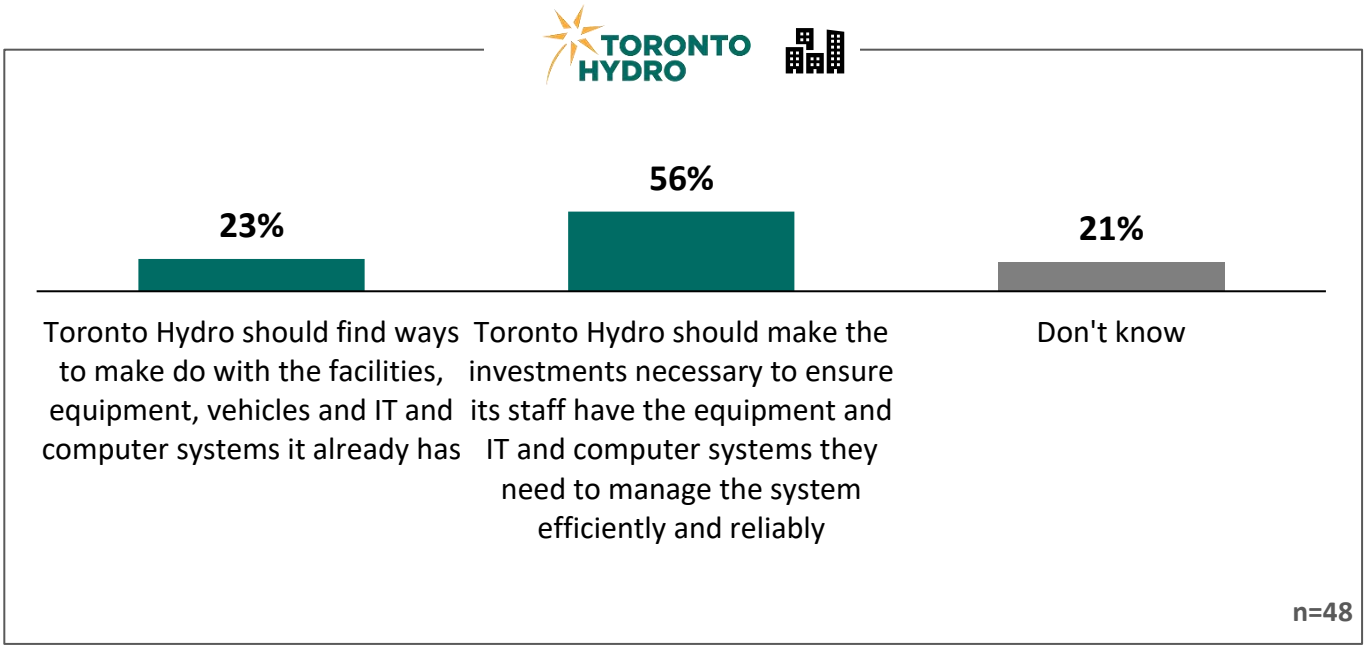
Q Regarding investments in aging infrastructure, which of the following statements best represents your point of view?



Online Survey
General Plant

The second category focuses on keeping **Toronto Hydro's** business running. This includes facilities to house staff and equipment, vehicles and tools to service equipment and IT systems to manage the system and customer information.

Q Regarding these types of investments, which of the following best represents your point of view?



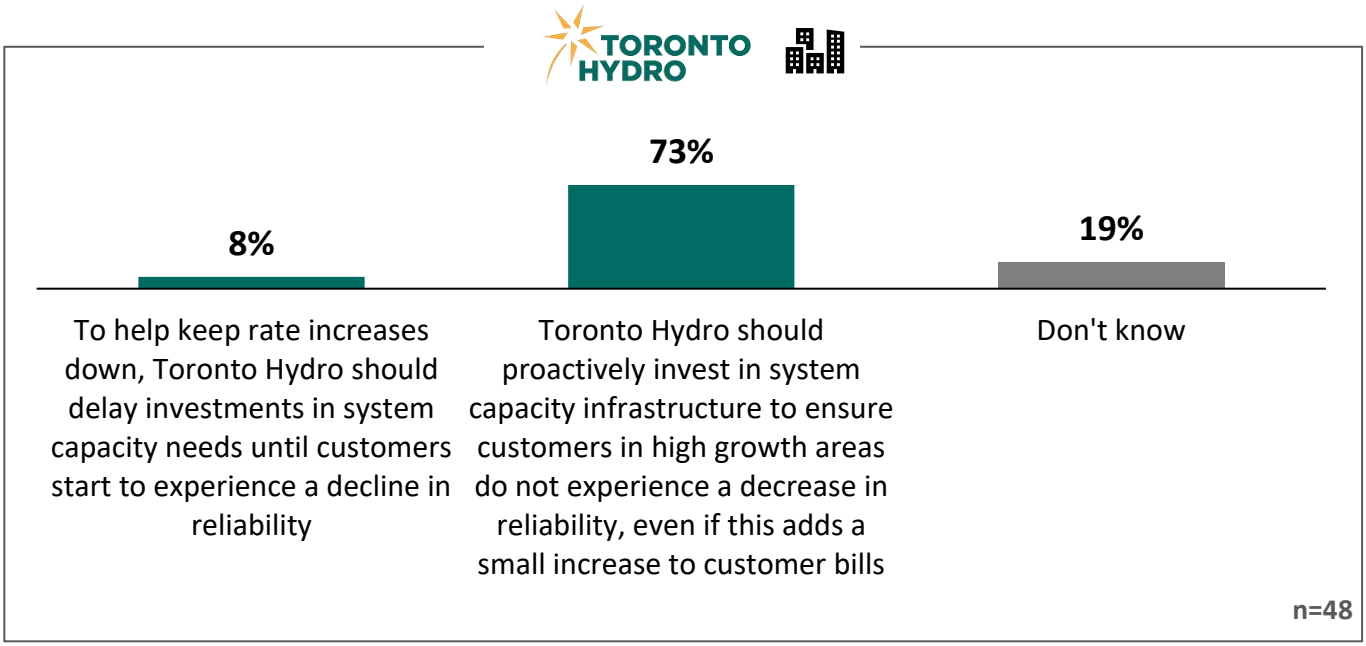
Online Survey
System Service

Commercial & Industrial

The third investment category focuses on growth and greater demand for electricity in various parts of **Toronto Hydro's** service territory.

Increased demand for electricity puts pressure on existing electrical infrastructure. Eventually, further infrastructure investments are required to support increased demand for electricity.

Q With this in mind, which of the following statements best represents your point of view?



Online Survey
Grid Modernization

Commercial & Industrial

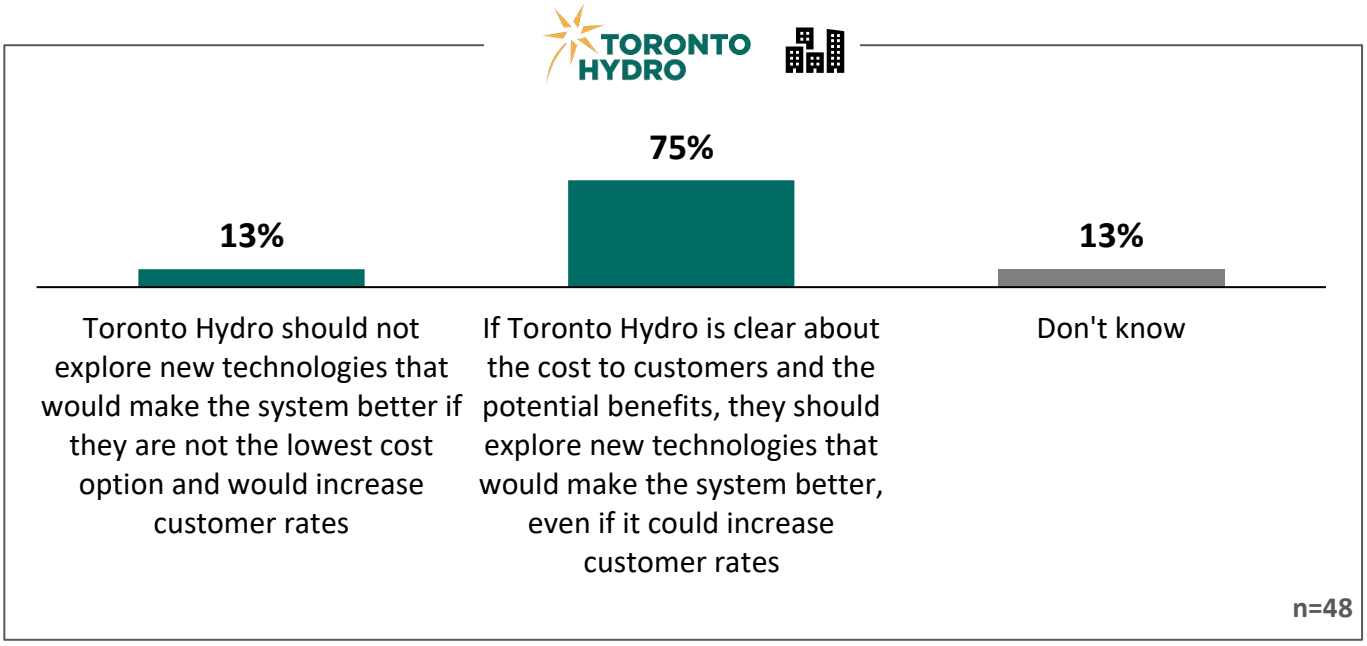
Toronto Hydro can invest in technology than can lead to a wide range of benefits including reliability, efficiency, customer service, and reducing environmental impacts.

When deemed the lowest cost option that will provide equal or improved service, Toronto Hydro will, in most cases, invest in technology.

However, there are two other scenarios where Toronto Hydro needs your feedback.

First, there are times when Toronto Hydro identifies new technology that can improve reliability or provide other benefits, but it will cost customers more. For instance, advanced customer meters that can measure when different home appliances are running, allowing Toronto Hydro to provide customers with better advice on how to reduce their energy consumption and costs.

Q Regarding these types of investments, which of the following best represents your view?



Online Survey
Grid Modernization (Con't)

The second scenario is where Toronto Hydro identifies new technology that is needed to improve the system in the future and would increase costs now, but the benefit might not be felt until later.

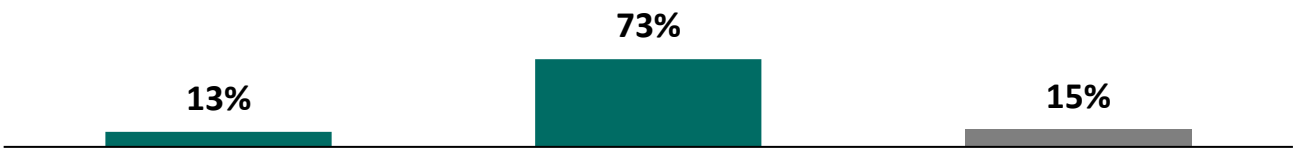
This includes accommodating emerging technologies like solar power, battery storage and electric vehicles.

Regardless of whether you are considering new energy choices like an electric vehicle for yourself today, Toronto Hydro must be prepared as adoption becomes more widespread over the next 5-10 years.

For instance, charging each electric vehicle draws as much energy as two average homes. If a dozen or so people come home and start changing their vehicles at a period of peak demand, it could overload the grid in that neighbourhood. While Toronto Hydro cannot predict the exact rate of electric vehicle adoption in the City of Toronto, the utility must make certain investments today that will allow it to manage electric vehicle demand in the future.

Q Which of the following best represents your view?

TORONTO HYDRO



Toronto Hydro should not explore new technologies that would not provide immediate benefit if it would increase customer rates.	If Toronto Hydro is clear about the cost to customers and the potential benefits, they should explore new technologies that might not provide immediate benefit, but will in the future.	Don't know

n=48

Online Survey

Familiarity with Sources of GHG Emissions

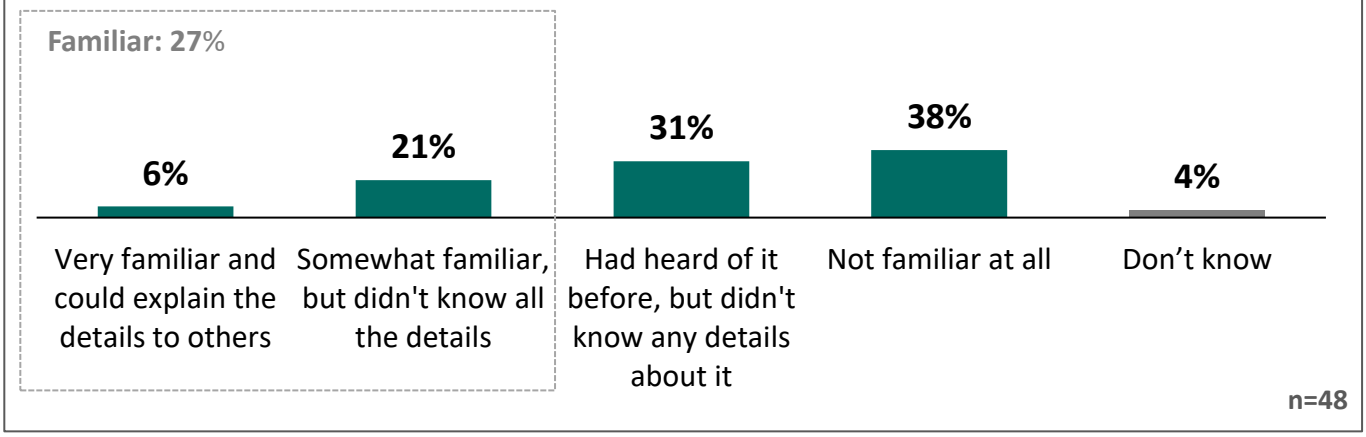
Commercial & Industrial

In November 2021, the City of Toronto released its 2019 Greenhouse Gas (GHG) Inventory, which tracks Toronto's progress towards GHG reduction targets and identifies key emissions sources. GHG emissions have a wide variety of environmental impacts that lead to climate change and global warming.

This report notes that the two **primary sources of GHG emissions** in Toronto are: energy use in buildings (natural gas and electricity) and transportation fuels (primarily gasoline) – accounting for 93% of all emissions in the city.

Q Before this survey, how familiar would you say you were with the primary sources of GHG emissions in Toronto?

TORONTO HYDRO



INNOVATIVE RESEARCH GROUP

Online Survey

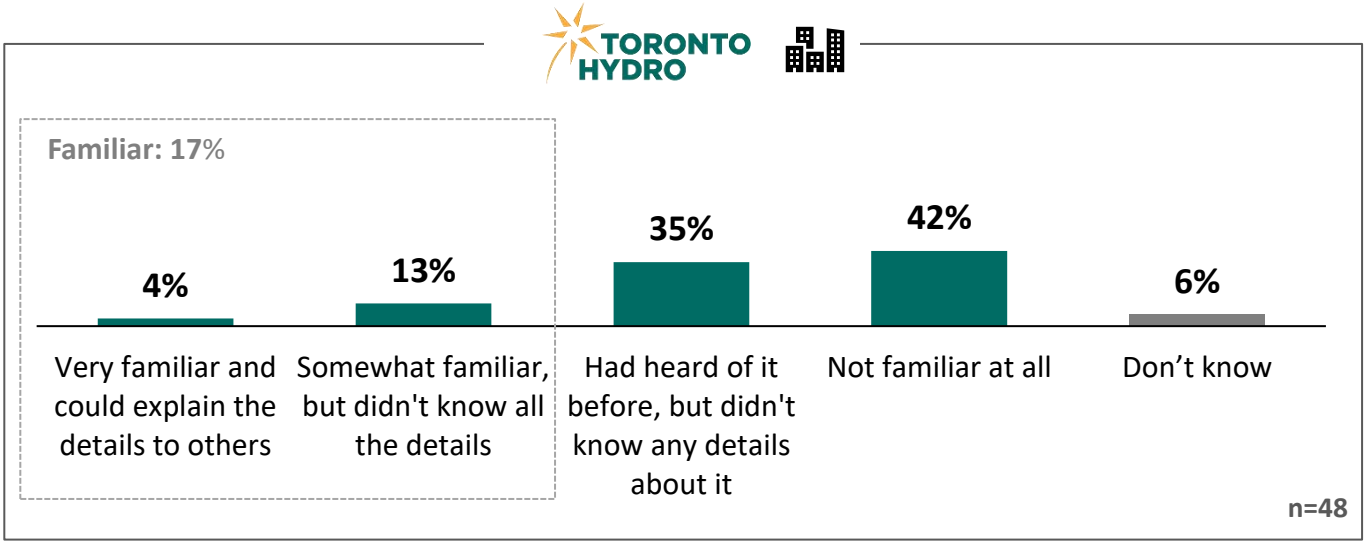
Familiarity with the City's Plan

In October 2019, Toronto City Council voted to accelerate its efforts to mitigate and adapt to climate change and adopt a stronger emissions target for Toronto: **net zero emissions by 2040**.

A key part of the City's "Net Zero Strategy" requires switching from gasoline in the transportation system and natural gas in home/building heating to electricity-powered alternatives, adopting renewable generators and using energy storage systems.

These initiatives will require Toronto Hydro to expand and modernize its existing electricity distribution grid to ensure that it is capable of helping achieve the City's targets.

Q Before this survey, how familiar were you with the City of Toronto's plan to use an expanded and modernized grid to reduce GHG emissions in Toronto to help address climate change?



Online Survey

Commercial & Industrial

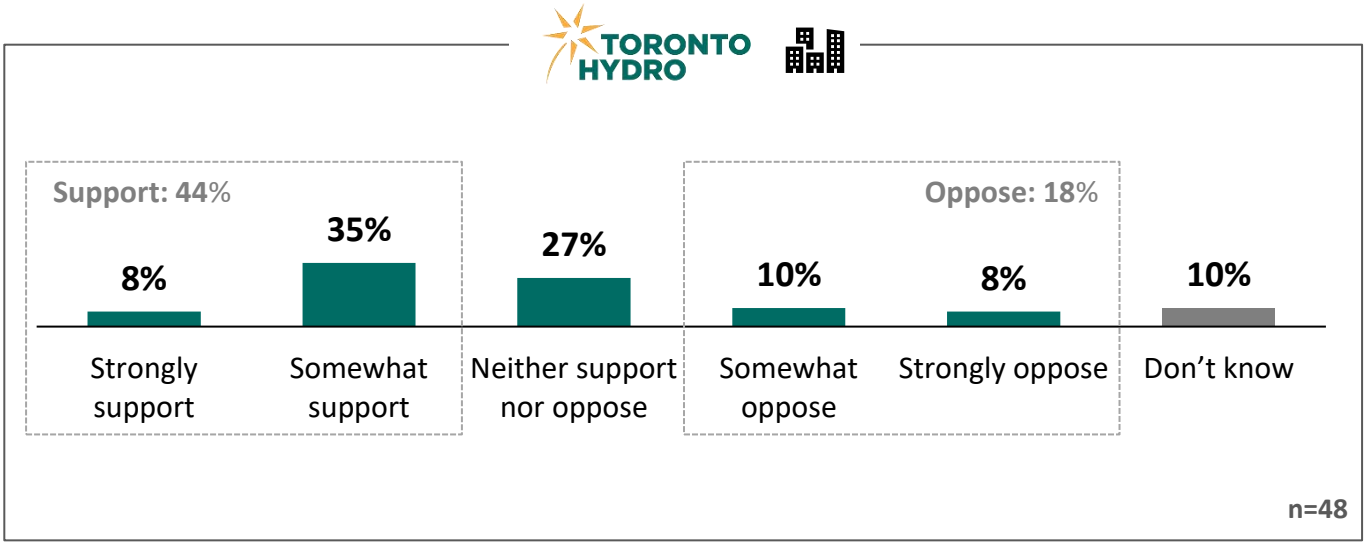
Support for Bill Increase to Meet Emissions Targets

As Toronto Hydro is 100% funded through the rates its customers pay, investing in an expanded and modernized electricity grid would mean that customers, like yourself, would pay more.

The sooner that Toronto Hydro expands and modernizes the grid, the sooner Toronto can reach its climate change goals.

Q Would you support or oppose a specific charge on the distribution portion of your monthly bill to help Toronto meet its future emissions targets if your electricity bill will increase by **5% a year for the next 10 years**?

*Recall, the distribution portion of your monthly bill is approximately **6%** of your total electricity bill.*



Online Survey

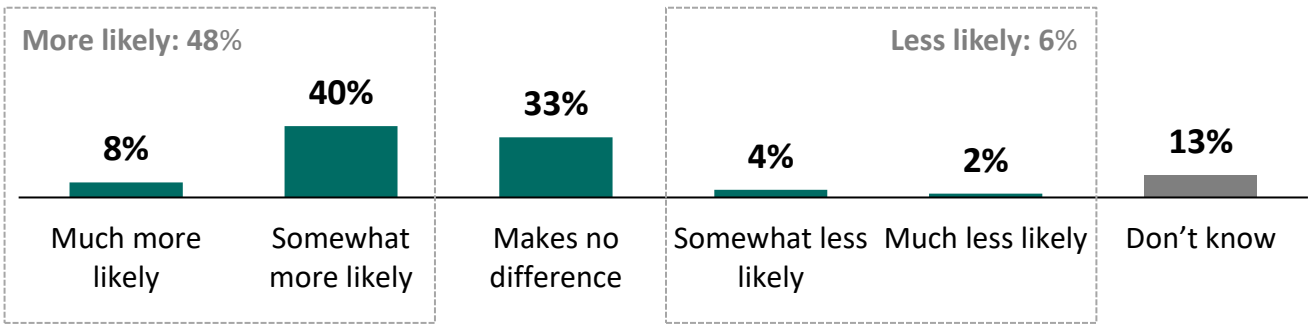
Potential for Rate Increase Offset

Commercial & Industrial

Some studies have indicated that increasing customer bills to specifically help meet emissions targets could be offset in later years because of reductions in other types of energy bills. For example, as fuel-switching to electricity becomes more widespread, customers may experience cost reductions for gasoline and natural gas.

Q Does knowing that these rate increases could be offset in later years because of reduction in other types of energy bills make you more or less likely to support a specific charge on your monthly bill to help Toronto meet its future emissions targets?

TORONTO HYDRO



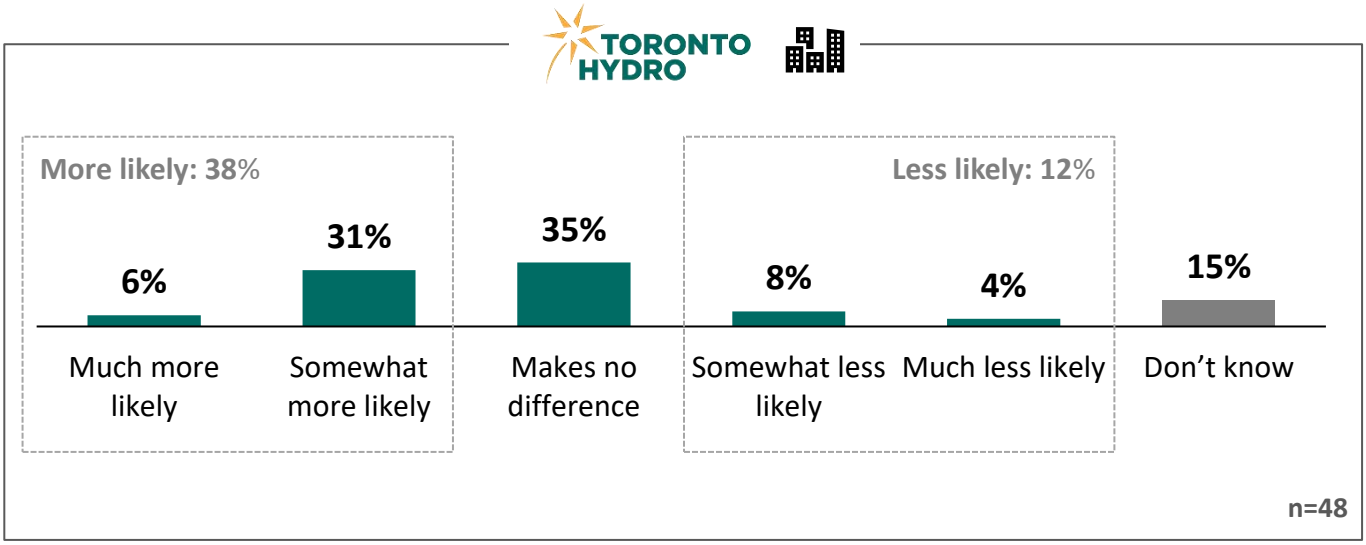
n=48

Online Survey
Inclusion of Rate Relief

Commercial & Industrial

Some customers have said that they would be willing to spend more in order to help Toronto meet its future emissions targets, however, feel that lower-income Torontonians should receive rate relief in order to offset any associated price increase.

Q Would the inclusion of "rate relief" for low-income customers make you **more or less likely to support** a specific charge on your monthly bill to help Toronto meet its future emissions targets?



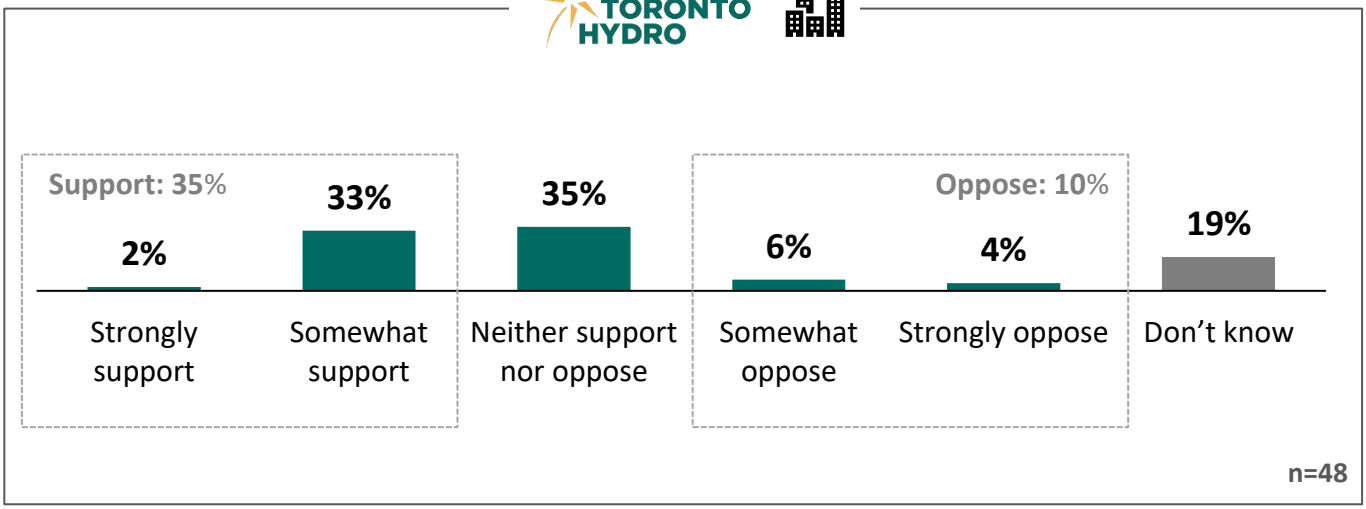
Online Survey

Support for Project Financing

Commercial & Industrial

In a recent series of interview with business customer, the idea of project financing was discussed.

Q Should Toronto Hydro help finance capital costs of energy transition projects through your monthly bills (i.e. finance behind-the-meter solutions and new equipment over an extended period to time through your organization's operating costs)?



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Commercial and Industrial Customers

Account Assessment

Section 5.4

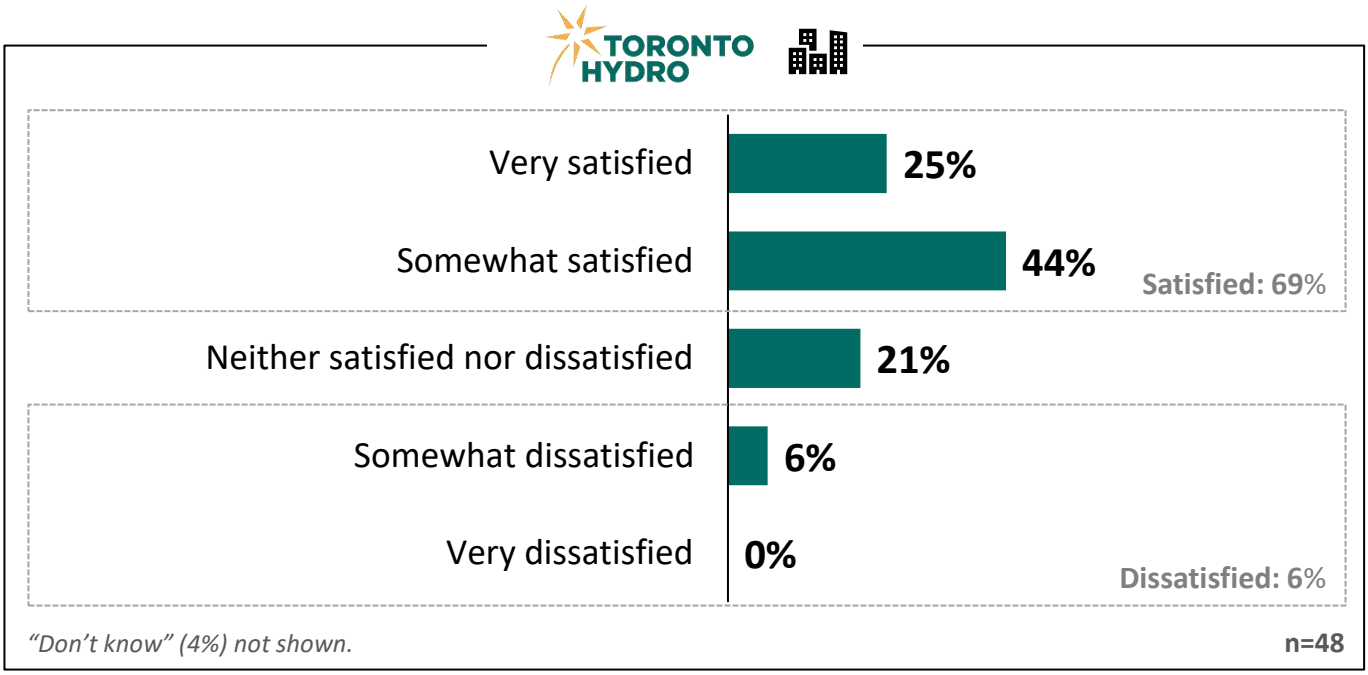


Online Survey

Overall Satisfaction with Customer Care

Commercial & Industrial

Q Overall, how satisfied are you with Toronto Hydro's customer care services?



"Don't know" (4%) not shown.

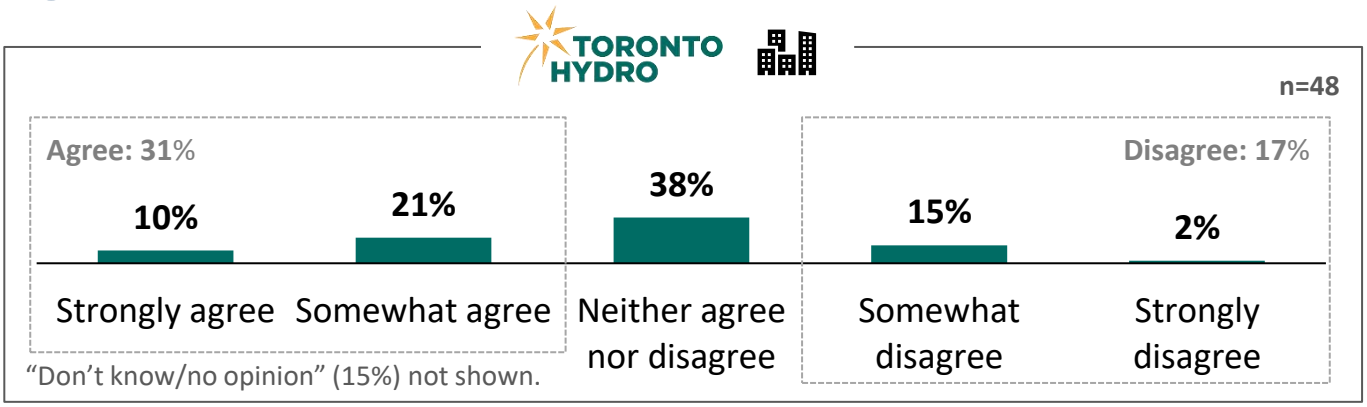
n=48

Online Survey
Account Assessment

Commercial & Industrial

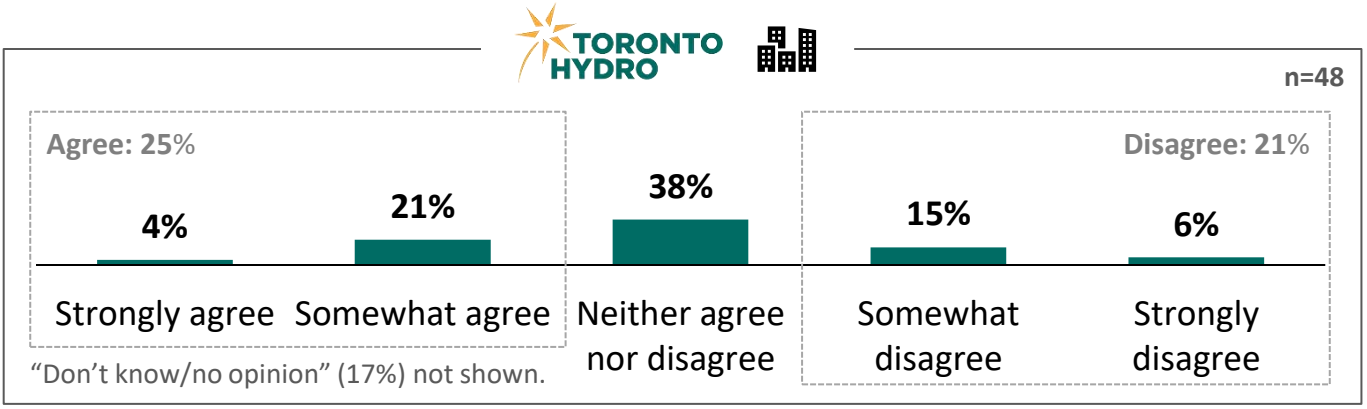
Please indicate if you agree or disagree with the following statements.

Q Toronto Hydro understands my organization and its challenges.



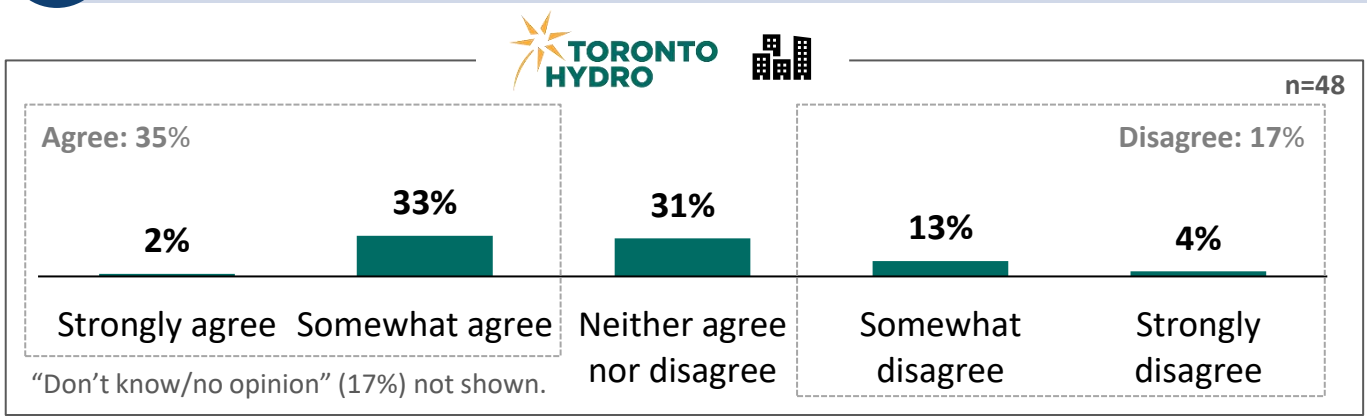
"Don't know/no opinion" (15%) not shown.

Q Toronto Hydro proactively provides my organization with business solutions.



"Don't know/no opinion" (17%) not shown.

Q Toronto Hydro is more than an electricity distributor, it is a business partner to my organization.



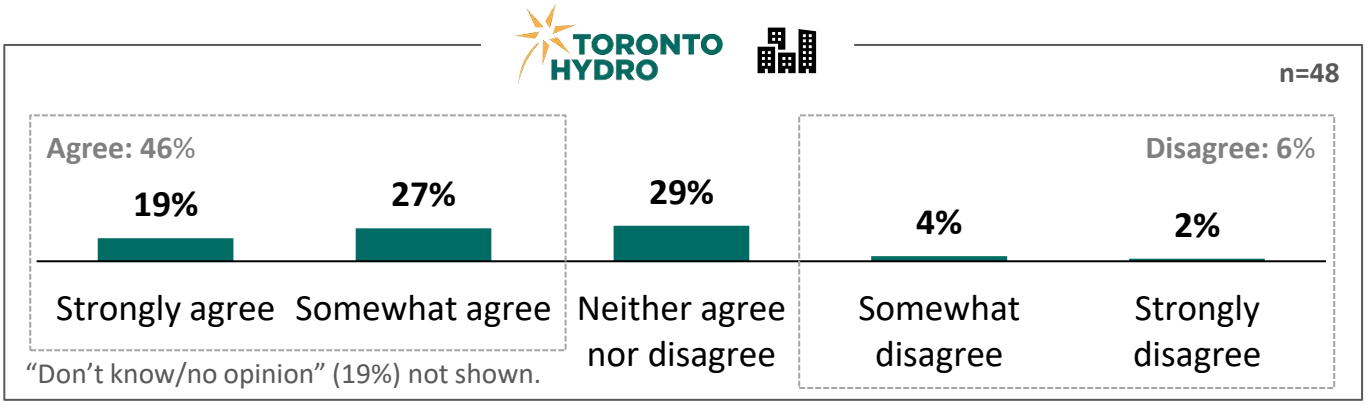
"Don't know/no opinion" (17%) not shown.

Online Survey
Account Assessment

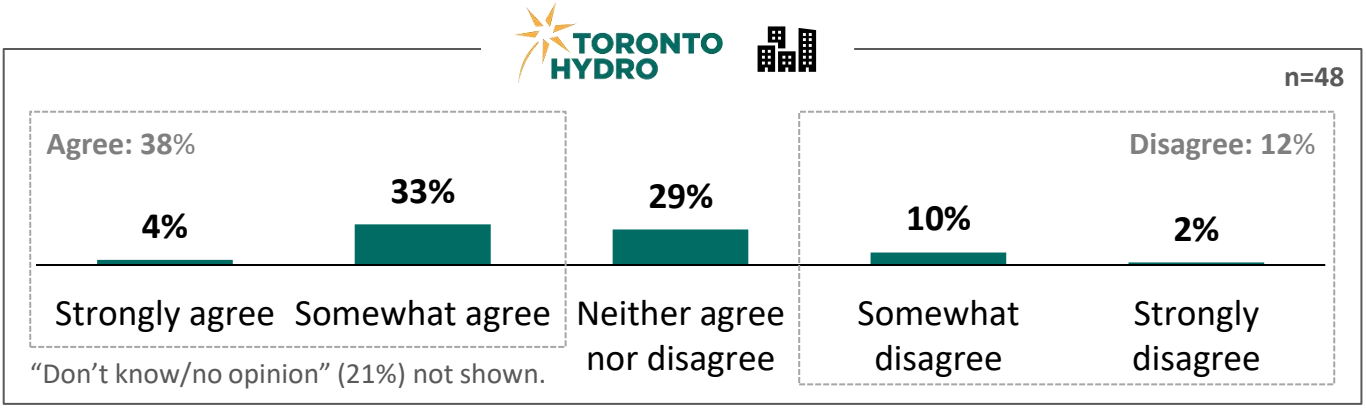
Commercial & Industrial

Please indicate if you agree or disagree with the following statements.

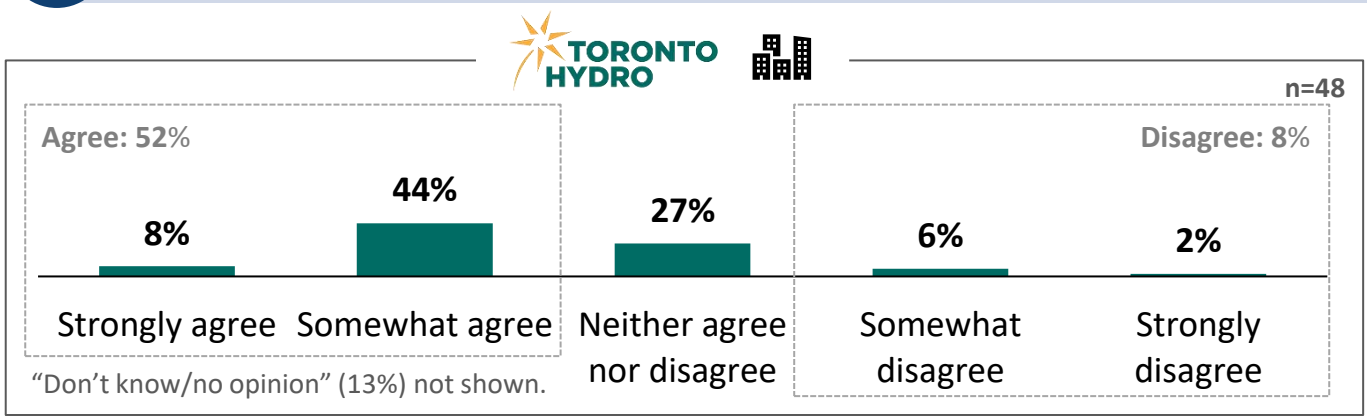
Q Toronto Hydro staff are easily accessible to my organization.



Q Toronto Hydro staff provide my organization with quality advice and guidance when I have questions about my service.



Q Toronto Hydro provides my organization with good value for money.



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Commercial & Industrial Customers

Additional Services

Section 5.5

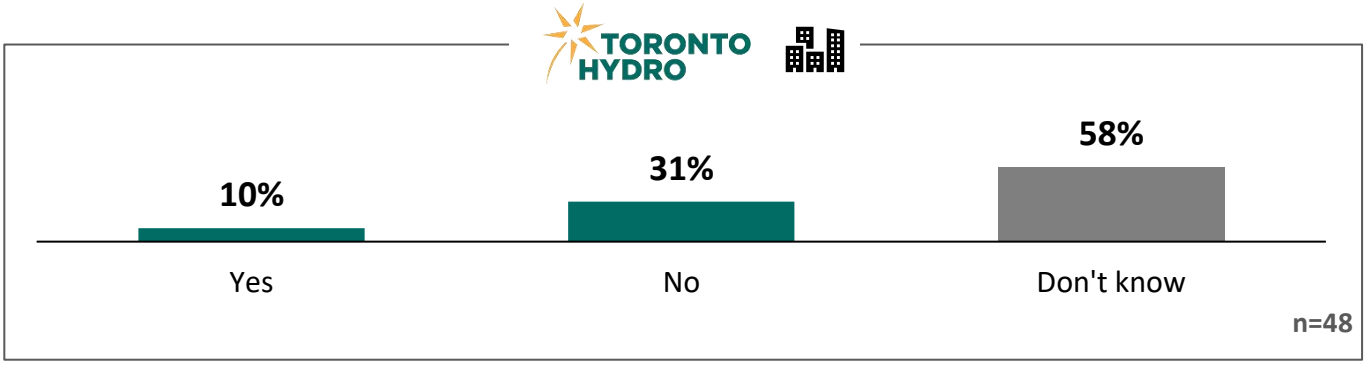


Online Survey

Service Offered by Toronto Hydro's Customer Care Team

Commercial & Industrial

Q Are there services that are currently offered by Toronto Hydro's **customer care team** that could be done differently to better fit your needs?



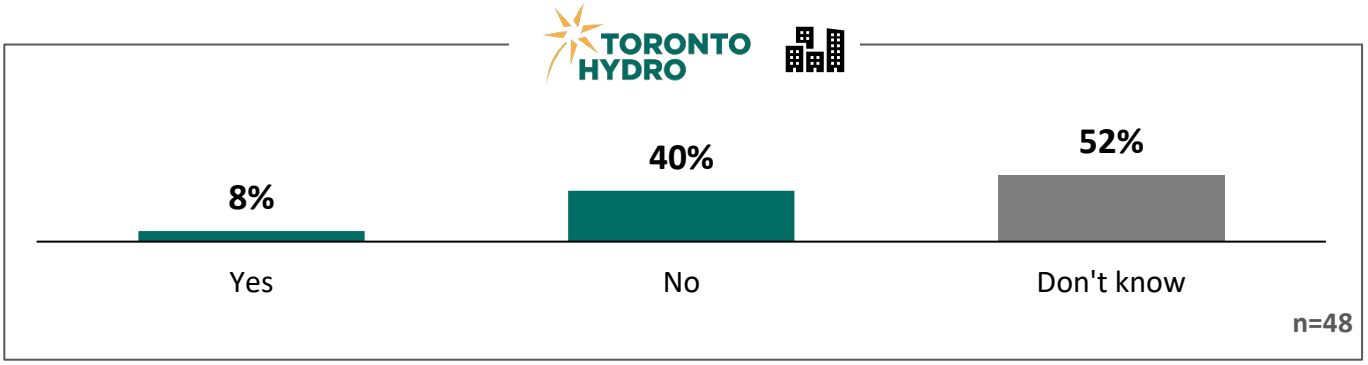
Responses from those who say "Yes"
Communication (6%)
"Email the customer about the power outages."
"It is very difficult to reach you out by phone."
"It would be great to have an assigned rep to business accounts."
Efficiency/Conservation Tips (2%)
"Proactive support in energy management / reduction strategies."
Service (2%)
"Reduce wait times."

Online Survey

Commercial & Industrial

Additional Services by Toronto Hydro's Customer Care Team

Q Are there any additional services that you would look to Toronto Hydro's **customer care team** to provide and would be willing to pay for?



Responses from those who say "Yes"
Communication (4%)
"Mobile app."
"Possibly, virtual metering."
Service (2%)
"If customers qualify for rebate, it should be done automatically without having to complete forms."
Efficiency/Conservation Tips (2%)
"Saving energy solutions."

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro. The conclusions drawn and opinions expressed are those of the authors.

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CONFIDENTIAL

APPENDIX 06

Key Accounts
Needs and Preferences Survey

TORONTO HYDRO

November 2, 2023

STRICTLY CONFIDENTIAL

2025 – 2029 Rate Application

Report Navigation

APPENDICIES

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- APPENDIX.01 – Customer Engagement Focus Groups
- APPENDIX.02 – Customer Sample Validation
- APPENDIX.03 – Residential Needs and Preferences Survey
- APPENDIX.04 – Small Business Needs and Preferences Survey
- APPENDIX.05 – Commercial & Industrial Needs and Preferences Survey
- APPENDIX.06 – Key Accounts Needs and Preferences Survey
- APPENDIX.07 – Needs and Preferences Planning Placemat

PHASE II

- APPENDIX.08 – Customer Engagement Workbook Overview
- APPENDIX.09 – Residential Workbook Report
- APPENDIX.10 – Small Business Workbook Report
- APPENDIX.11 – Commercial & Industrial Workbook Report
- APPENDIX.12 – Key Accounts Workbook Report
- APPENDIX.13 – Customer Engagement Workbook (Residential Version)

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Key Account Customers

Online Survey Results

Section 6.1



Online Survey

Survey Design & Methodology

Key Accounts

INNOVATIVE was engaged by Toronto Hydro to gather customer input to assess the importance of the outcomes and priorities identified in the qualitative components of Phase I of the customer engagement.

Field Dates

The **Key Accounts Online Survey** was sent to all Toronto Hydro key accounts customers who have provided the utility with an email address. Customers had an opportunity to complete the survey between **January 18th and February 4th, 2022**.

Each customer received a unique URL that could be linked back to their annual consumption, region and rate class.

In total, the key accounts online survey was sent to **362** customers via e-blast from *customerexperience@torontohydro.com*. A reminder email was sent 2 days after the initial invitation to those who had not yet completed the survey. An additional reminder email was sent a week after the first reminder.

Key Account Online Survey Completes

A total of **68** (unweighted) Toronto Hydro key accounts customers completed the online survey via unique URL.

Sample Weighting

The key accounts online survey sample has been weighted proportionately by sector in order to be representative of the broader key accounts customers within the Toronto Hydro service territory.

The table below summarizes the distribution, unweighted and weighted sample breakdown by sectors.

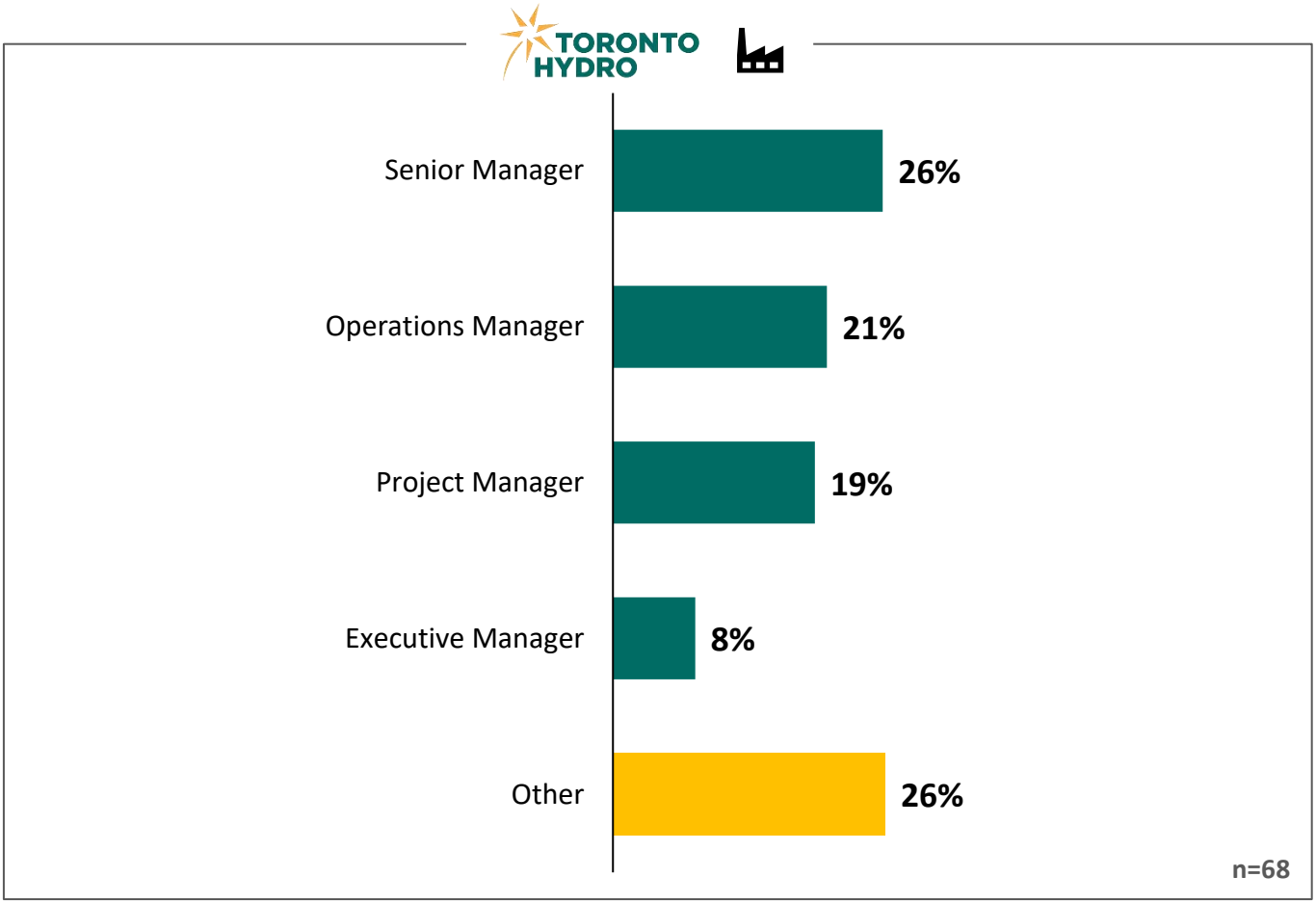
Category	Distribution		Survey Sample		Diff.	Weighted Sample	
	#	%	#	%	%	#	%
Commercial	115	32%	17	25%	-7%	21	32%
Industrial	93	26%	27	40%	+14%	17	26%
MASH	51	14%	15	22%	+8%	10	14%
MURB	105	29%	9	13%	-16%	20	29%
Total	**364**	**100%**	**68**	**100%**	--	**68**	**100%**

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

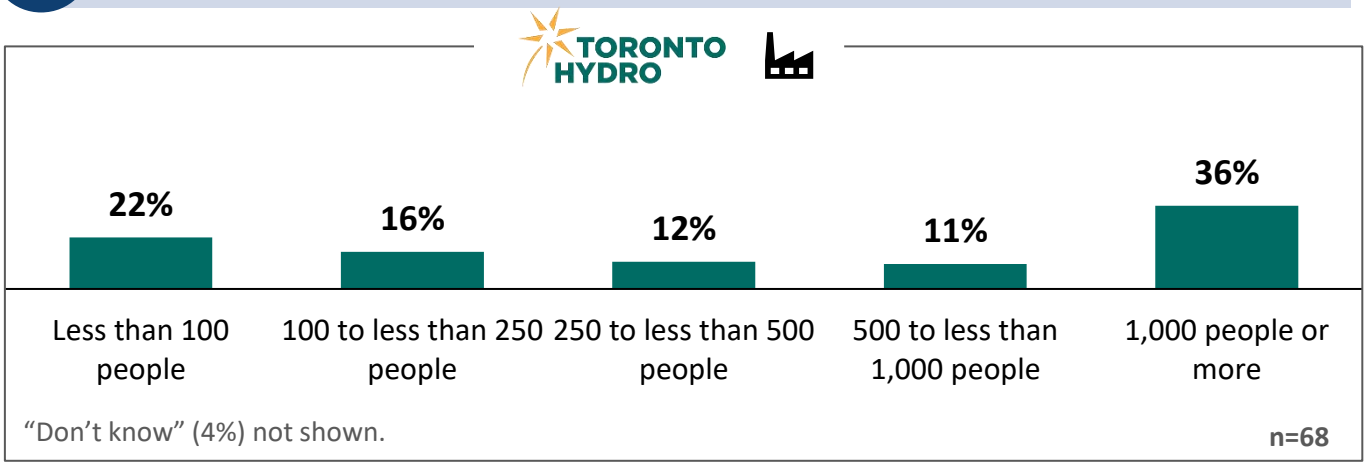
Online Survey
Demographic breakdown

Key Accounts

Q What occupation or position best describes your role at your organization?



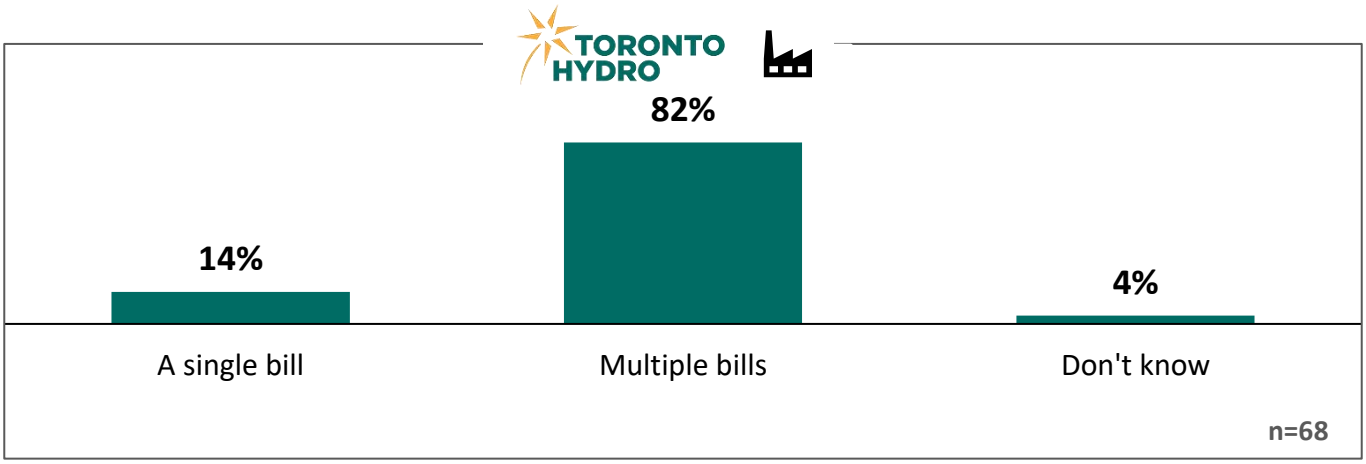
Q Approximately, how many people work at your organization in Toronto?



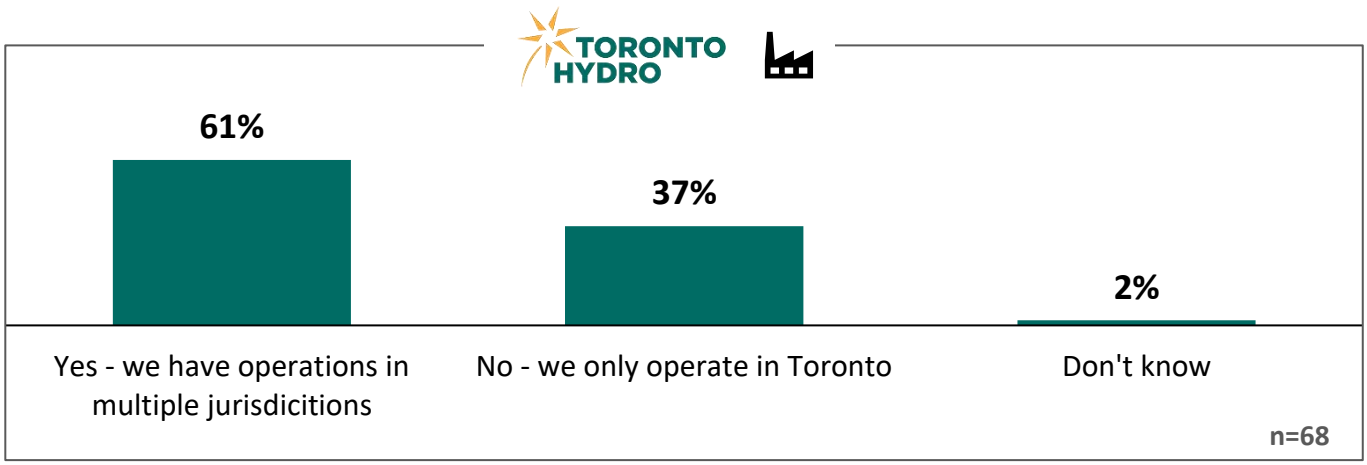
Online Survey
Demographic breakdown

Key Accounts

Q Does your organization receive a single bill or multiple bills from **Toronto Hydro**?



Q Does your organization receive electrical bills from utilities other than Toronto Hydro?



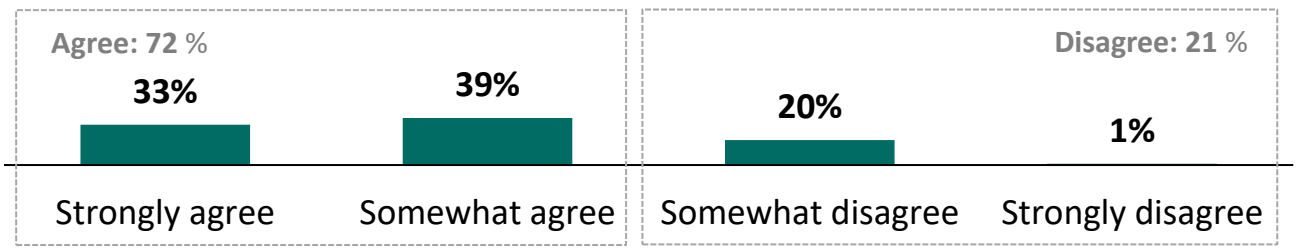
Online Survey
Environmental Controls

Key Accounts

To what extent do you agree or disagree with the following statements?

Q The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

TORONTO HYDRO

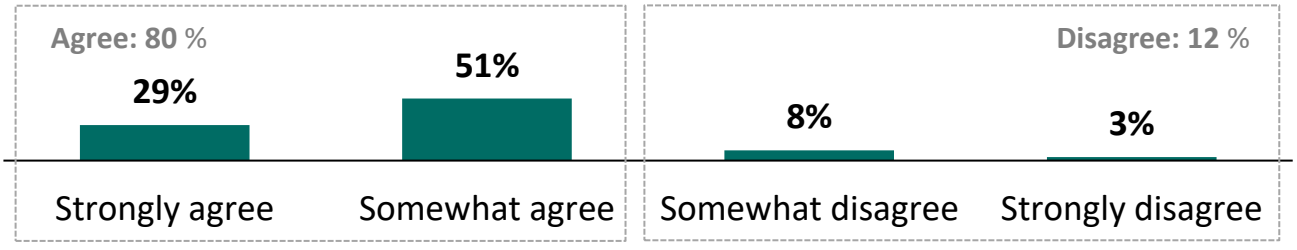


"Don't know/no opinion" (7%) not shown.

n=68

Q Customers are well-served by the electricity system in Ontario.

TORONTO HYDRO

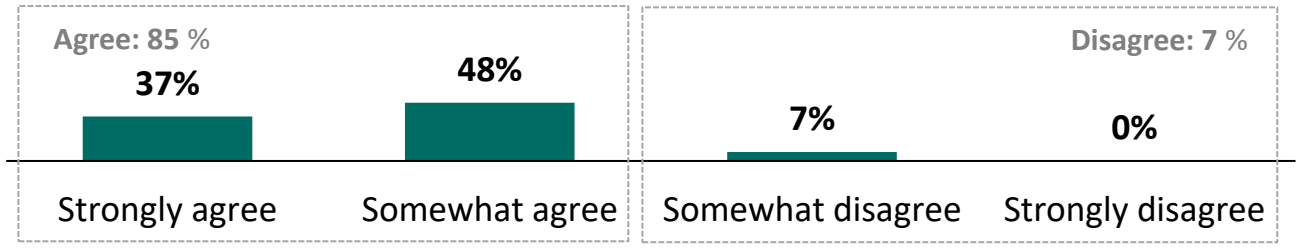


"Don't know/no opinion" (8%) not shown.

n=68

Q Fossil fuels should be phased out as quickly as possible to speed up the shift to a lower-carbon future.

TORONTO HYDRO



"Don't know/no opinion" (8%) not shown.

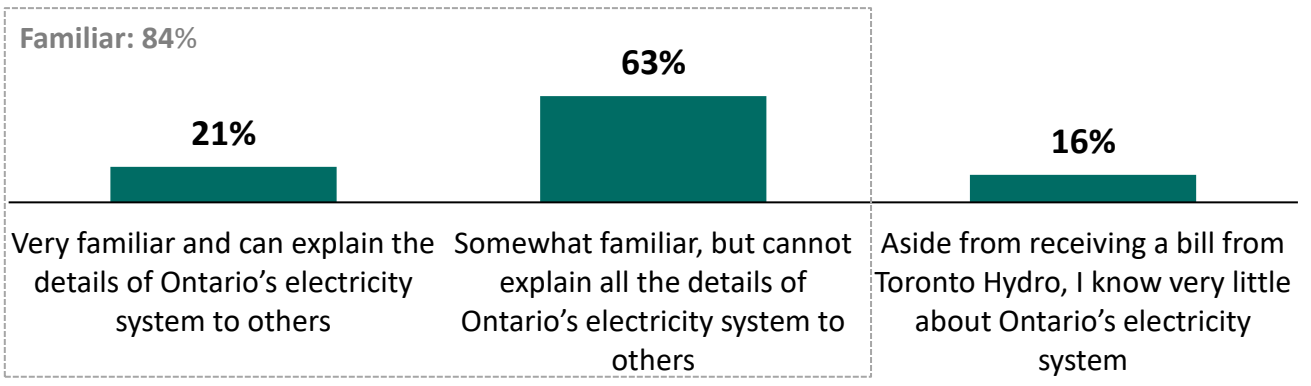
n=68

Online Survey

Familiarity & Satisfaction with Ontario's Electricity System

Key Accounts

Q How familiar are you with the various parts of Ontario's electricity system, how they work together, and which parts Toronto Hydro is responsible for?

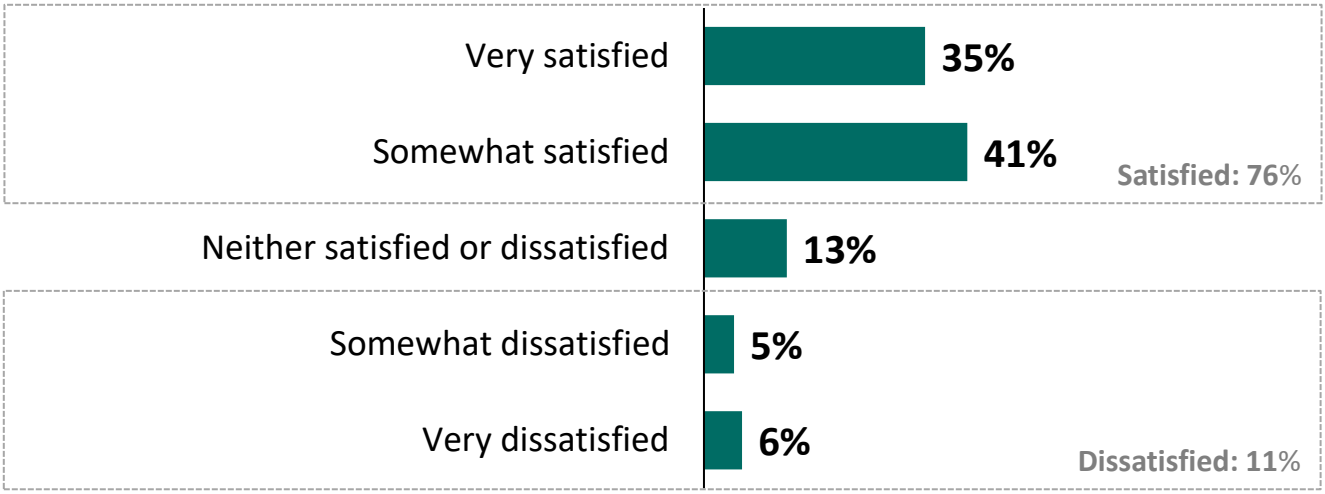


"Don't know" (0%) not shown.

n=68

As you may know, Toronto Hydro operates and maintains the local electricity distribution system, reads meters, calculates your charges, answers your calls, responds during outages and clears trees and brush from power lines. Toronto Hydro does not set the commodity price of electricity or the Global Adjustment charge.

Q Generally, how satisfied are you with the service your organization receives from Toronto Hydro?



"Don't know" (0%) not shown.

n=68

Online Survey

How Toronto Hydro can Improve Services to Customers

Key Accounts

Q Is there anything in particular you would like Toronto Hydro to do to improve its services to you?

Response	%
Communication	25%
Reliability	18%
Service	8%
Billing	6%
Efficiency/Behind the Meter	4%
Costs	1%
Other	3%
None	3%
Don't know	32%

Online Survey

How Toronto Hydro can Improve Services to Customers

Key Accounts

Q Is there anything in particular you would like Toronto Hydro to do to improve its services to you?

Communication
"No issues with the service received. Communication is good and your team is response whenever we do have issues."
"It would be good to have a regular discussion with the customers on a regular basis."
"Keep close communication and deliver required service according to the agreed timeline."
"Send notifications about upcoming scheduled power interruptions."
"More dialogue between account reps ad end customers. We are a large consumer and there is a partnership here. Other providers such as Alectra do a better job in this area. - thanks."
"We operate multiple commercial towers and are accountable to many different people. We need to ensure that our communication to these individuals are timely and accurate. we also need advance notice of any capital work that would affect our operations so that we can plan accordingly."
"Understand costumers needs better. Prompt response when outages occur rather then looking at Toronto outage map. Key account reps and improve communication with us as large complex managers. More flexible and firm commitments for maintenance at our sites."
"More communication with each construction team will be helpful."
"Working with newly appointed [Toronto Hydro employee] to help bilateral communications has help make the process with Hydro easier, especially the connection of new buildings."
"Service for when power needs to be shut off for PM / Maintenance work could be improved. Last summer we had Last minute cancel causing a lot of headaches and the information was know and could have been communicated sooner."
"Ensure that when you sub out services make sure the customer is aware who the sub is."
"A yearly meeting with the plant may be beneficial."
"Assign designers to project files. Have them act as liaison from inception into construction. Having a client sub out design to a third party creates issues. it is tough to track projects and get information back in a reasonable amount of time using the existing process."
"Stop changing key account managers often."

Online Survey

How Toronto Hydro can Improve Services to Customers

Key Accounts

Q Is there anything in particular you would like Toronto Hydro to do to improve its services to you?

Reliability
"Improve reliability."
"Reliability of hydro service at [our organization], we have had 6 prolonged outages since summer 2019."
"We consume in the range of 3 - 4 MW annually yet in recent years have lost our client service rep. we would like to get a client service rep to help guide us and respond to certain reliability issues we experience."
"My company operates a data center in Toronto and Toronto Hydro provides the least reliable electrical service of any facility in our portfolio (over 10 facilities). Our service in Toronto has gone down more times in 12 months than our entire portfolio combined in the last 10 years."
"Provide and maintain redundant capacity for the Copeland transformer that feeds our site."
"It will definitely help us to improve on micro-cut/power glitch which occurs. We experienced 2 times in the year 2021."
"Would like more frequent updates on what improvements or upgrades are being made to the electrical infrastructure. Our plants experience outages on a regular basis and it would be great if we can determine what is the root cause and how to prevent them."
"Toronto Hydro should improve the stability of the voltage in South Etobicoke in the area of Islington/Queensway area as we are prone to power blips, while not full power outages they affect our equipment negatively."
"Reduce the number of power outages / blips."
"1. Improve the power quality of critical vulnerable locations. For [us], these are [first branch location mentioned], [second branch location mentioned], both located in Scarborough. We also recently experienced power quality issues at [third brand location mentioned] in Etobicoke. 2, Customer outreach and training - particularly relating to permit approval."
"Reduce power failures."
"We experience a lots of short power outages which results a lots loss for our continuous operations. equipment and product losses."
"Power blips in our area are a huge concern leading to extensive financial losses."
"Delay for disconnection and connection again extremely long."

Online Survey

Key Accounts

How Toronto Hydro can Improve Services to Customers

Q Is there anything in particular you would like Toronto Hydro to do to improve its services to you?

Service
"Improve response time and status communication to disconnect and reconnect high voltage supply at the pole ie we have experienced delays in getting a crew to disconnect our incoming supply from the road ... and then to reconnect the supply."
"Reaching out to get information is difficult. Hard to get power shutdown support."
"The only concern I have with Toronto Hydro is the response times for concerns especially the outside lighting posts that are connected to the T.H. lighting grid."
"All good for services at this time."
"Our site suffered from multiple momentary power outage events last year, specially in the last quarter. We were informed that the maintenance around feeders was not up to date due to COVID. We would benefit a great deal from more frequent feeder maintenance, tree cutting, animal traps, any other preventive measures to provide reliable power supply. Maybe this tool already exists, but being able to track the maintenance schedule would give our organization a forewarning on possible issues due to delays, allowing us to pursue solutions before the issue gets out of hand. In addition, our site would benefit from receiving semi-annual records of voltage sags and momentary interruptions."
"Maintenance shutdown schedule should be more flexible with the operations of the customer's property."
Billing
"The bills to be more clear."
"When new chargers are added to bills, an explanation letter to accompany those new charges would help save time on both our end and Toronto Hydro's end investigating these charges. As an example, in January 2021 a new charge labelled 2019 Rate Rider Adjustment was added to our bill totaling roughly $17,000. We did not receive an explanation for this charge until February 2021, which led to billing confusion, bills being cancelled and reissued, and logistical headaches for our accounting department. A second example is the repayment of the GA Deferral which was built-in to the GA total rather than added as a separate line item. We had to go through significant challenges to ensure that our accruals were accurate so expenses incurred over two fiscal years were expensed in the appropriate fiscal years as the billing happened over two different fiscal years."
"Provide a consolidated bill where there are multiple unmetered services on one account. - Provide a central contact for all account related inquiries for large businesses that have thousands of accounts and often need expedient Service."
"As a large organization, we take time to process and approve invoices as they go through multiple departments, and approvals before a physical payment cheque is cut. As a result, we sometimes incur multiple late fees on our monthly bills if our review and approvals don't line up with our cheque cutting dates (which only happen every 2 weeks). The delayed payments are not due any prolonged inaction on our part, which makes it frustrating as a customer with every intent to pay. More flexibility on the late penalties or more time before they are incurred for us as large institutional organization would be very helpful."

Online Survey

How Toronto Hydro can Improve Services to Customers

Key Accounts

Q Is there anything in particular you would like Toronto Hydro to do to improve its services to you?

Efficiency/Behind the Meter
"Our organization wanted to put in a co-gen power plant but the age of the power distribution system in our area prevents us from doing this. Something to do with micro harmonic voltages."
"Energy reduction incentives tend to grease the investment skids on our side. It provides credibility to our investment and helps build the support from our senior leadership team."
"A more meaningful commitment to low carbon energy and incorporation of distributed energy resources into the Toronto and Ontario grid."
Costs
"Cost reduction."
Other
"I would like to be able to apply for PAP online."
"Support Utilities in Place, issue OTC's when paper work is ready, regardless of when the project is due."

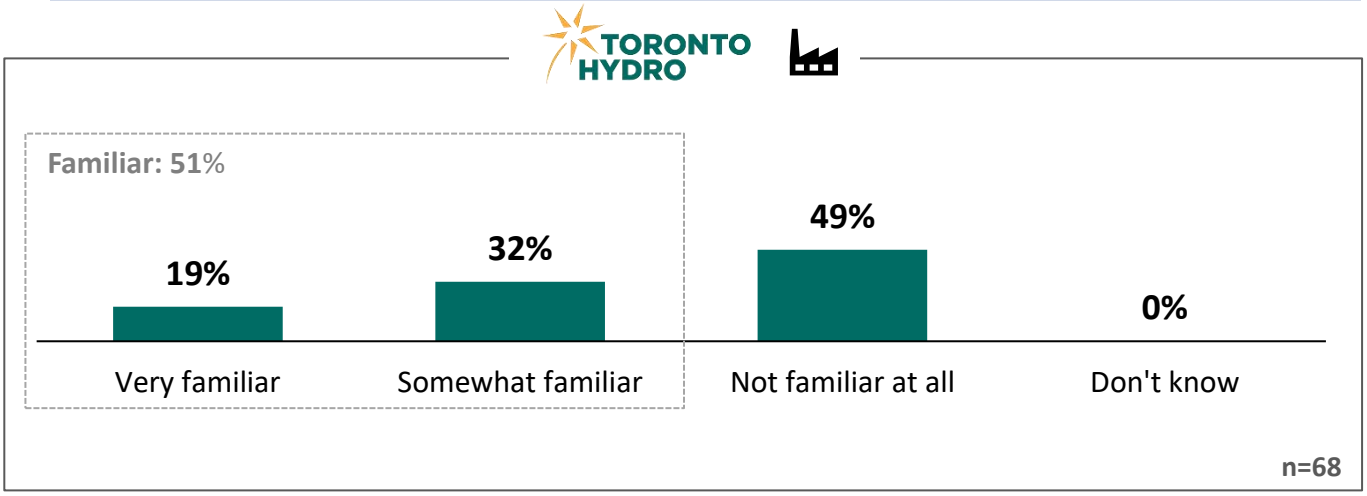
Online Survey

Familiarity with Bill Remittance to Toronto Hydro

Key Accounts

While **Toronto Hydro** is responsible for collecting payment for the entire electricity bill, it retains anywhere from **5% to 6%** of the average Key Account's bill – depending on customer load and type of customer account. The rest of the bill goes to power generation companies, transmission companies (mainly Hydro One), the provincial government and regulatory agencies.

Q Before this survey, how familiar were you with the percentage of your organization's electricity bill that went to **Toronto Hydro**?



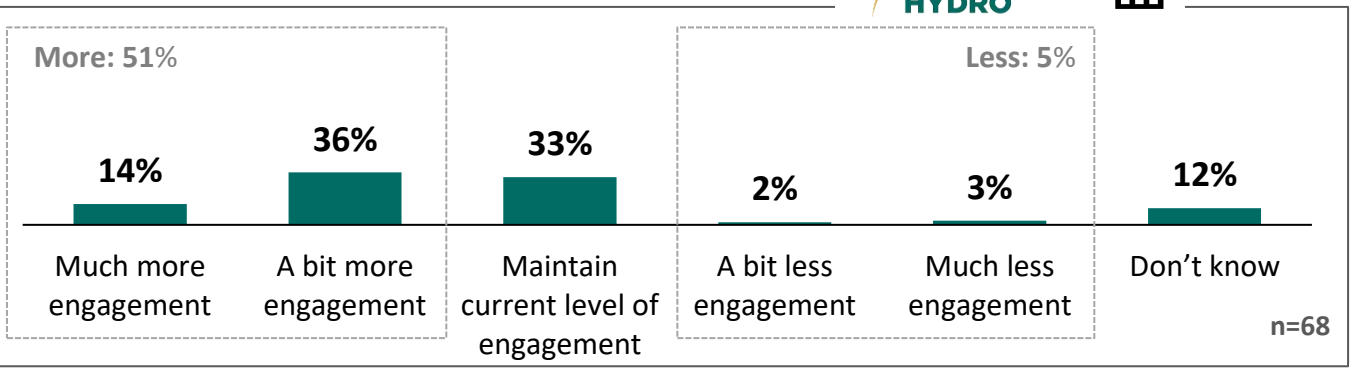
Online Survey

Engagement with Levels of Management

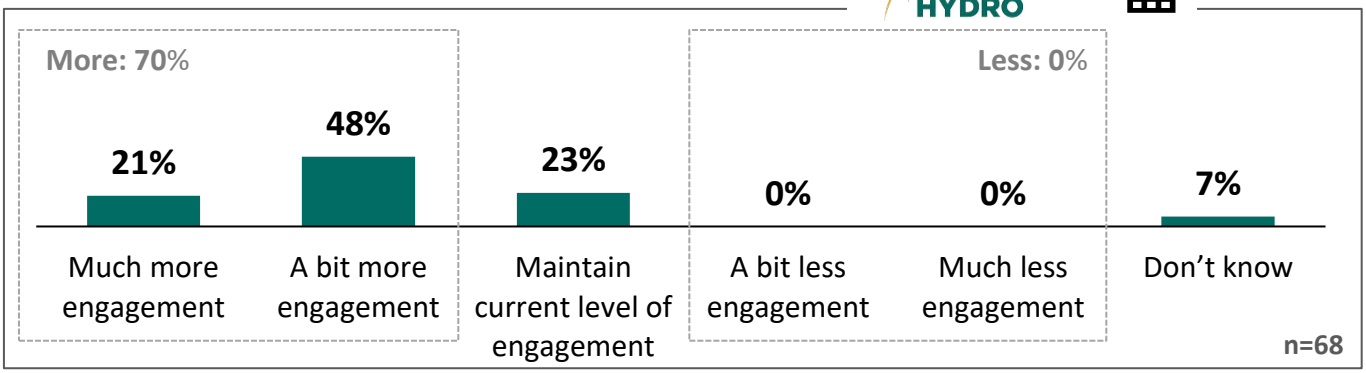
Key Accounts

Q Do you think **Toronto Hydro** staff should be making more or less effort to engage with the following levels of management at your organization?

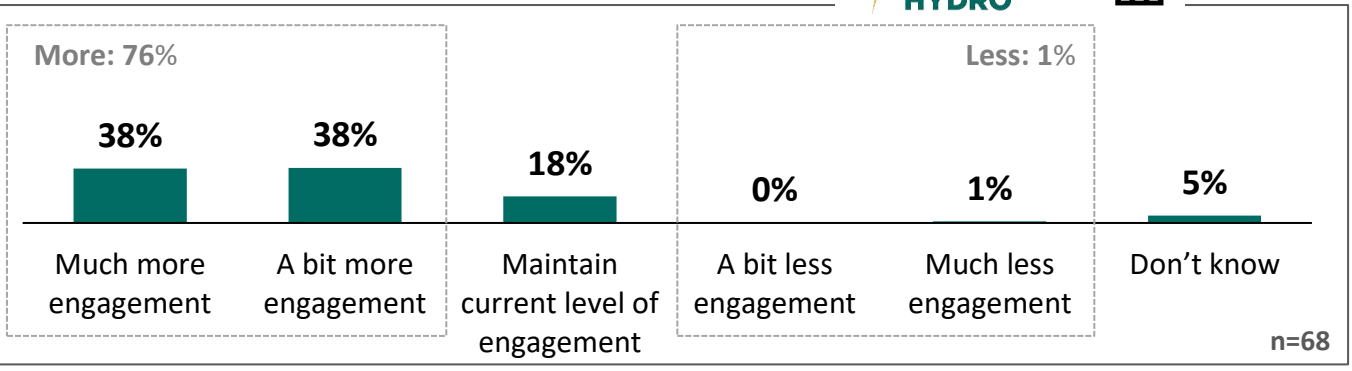
Executive Management Team



Senior Managers



Operations Team



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Key Accounts Customers

Customer Priorities

Section 6.2



Online Survey

Importance of Customer Priorities

Key Accounts

Now, let's talk about our second topic – outcomes.

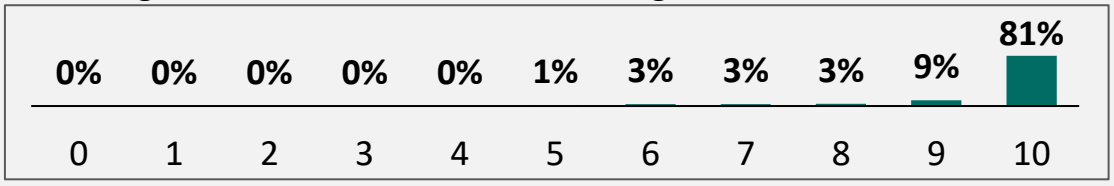
Toronto Hydro regularly holds discussions with its customers to better understand how it should set spending priorities with ratepayer dollars.

In a recent series of Key Account interviews**, several areas were identified as priorities** for Toronto Hydro.

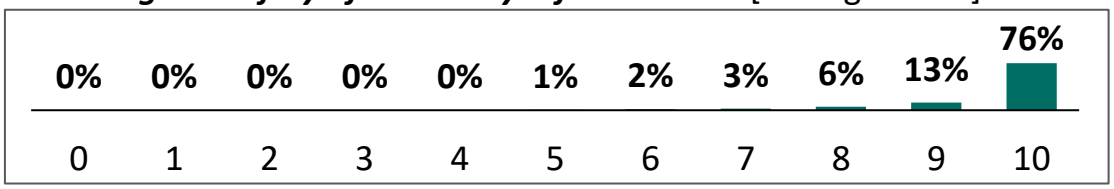
Q

Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Toronto Hydro** priorities to you as a customer?

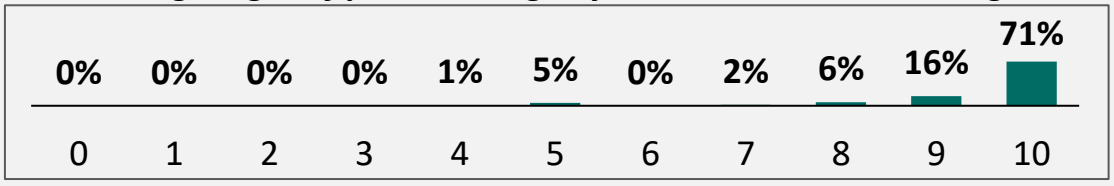
Ensuring reliable electrical service [average = **9.6**]



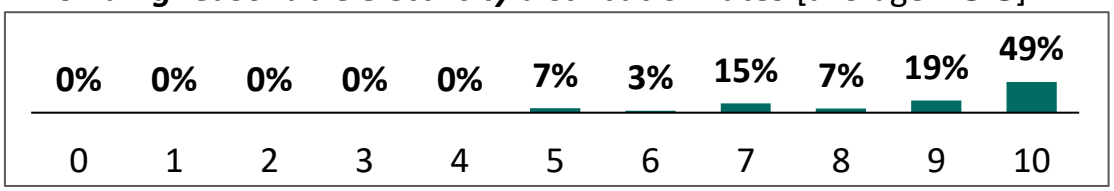
Ensuring the safety of electricity infrastructure [average = **9.5**]



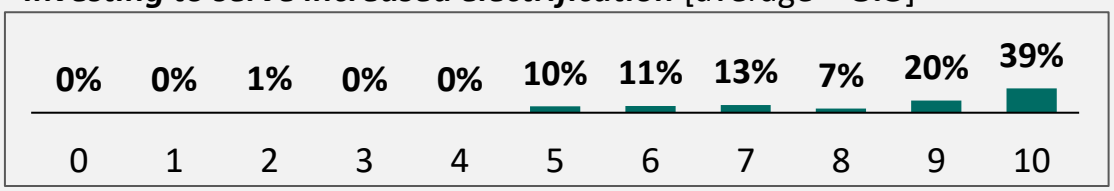
Preventing length of power outage by extreme weather [average = **9.4**]



Providing reasonable electricity distribution rates [average = **8.8**]



Investing to serve increased electrification [average = **8.3**]

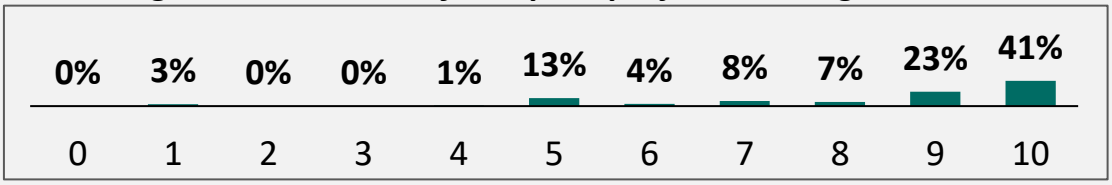


Online Survey

Importance of Customer Priorities (Cont'd)

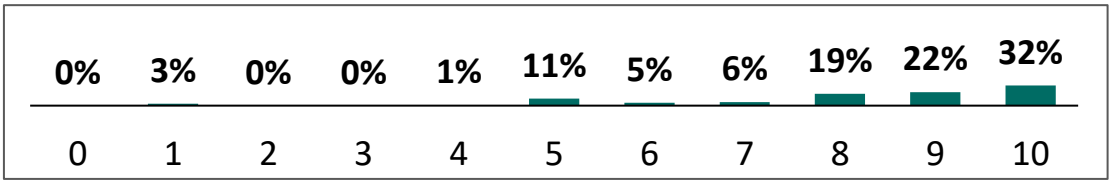
Q Using a scale from 0 to 10, where *0 means not important at all* and *10 means extremely important*, how important are each of the following **Toronto Hydro** priorities to you as a customer?

Providing reasonable costs for capital projects [average = **8.2**]



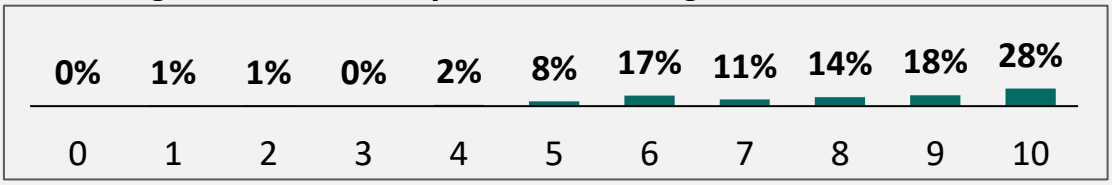
Not at all important — Extremely important

Providing reasonable timelines for capital projects [average = **8.1**]



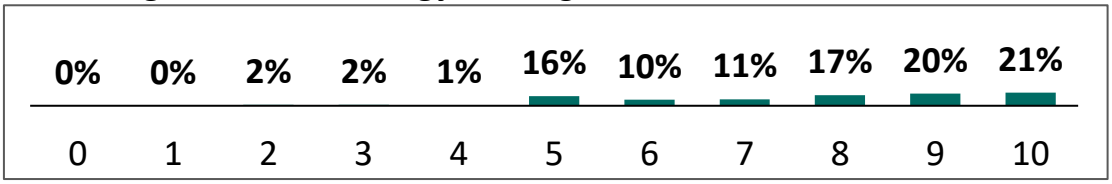
Not at all important — Extremely important

Providing enhance advisory services [average = **7.9**]



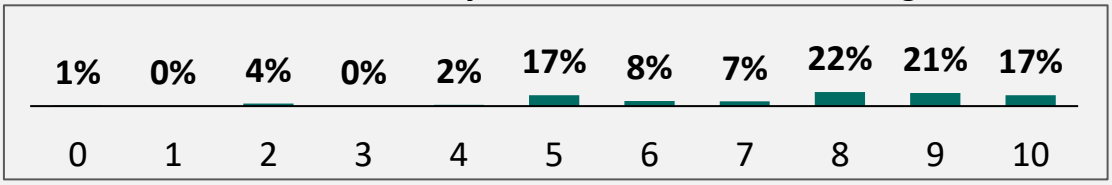
Not at all important — Extremely important

Investing in new technology [average = **7.6**]



Not at all important — Extremely important

"Behind the meter" electricity solutions & services [average = **7.4**]

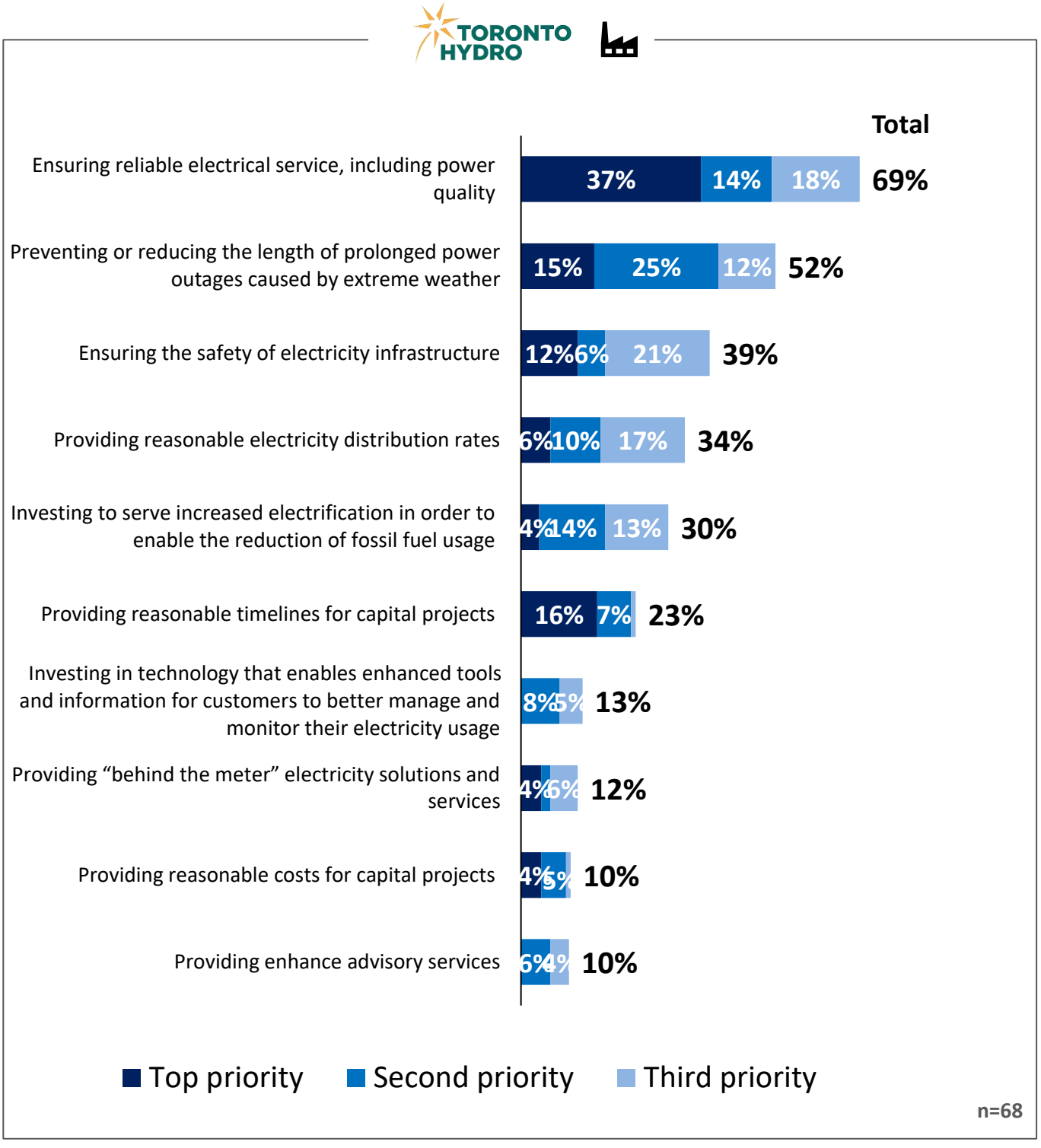


Not at all important — Extremely important

Online Survey
Ranking Customer Priorities

Key Accounts

Q Thinking of the priorities on the previous page, which would you say is the **most** important? What is the next most important priority you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?



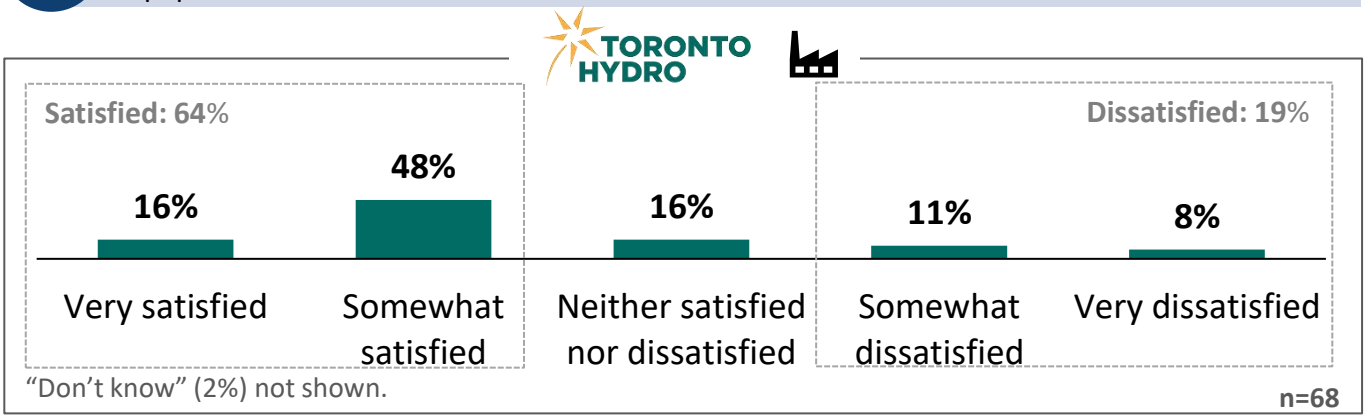
Online Survey

Power Quality and Reliability Outcomes

Key Accounts

The following statements are about the electrical service that your organization receives from Toronto Hydro. For each statement, please indicate your level of satisfaction or dissatisfaction.

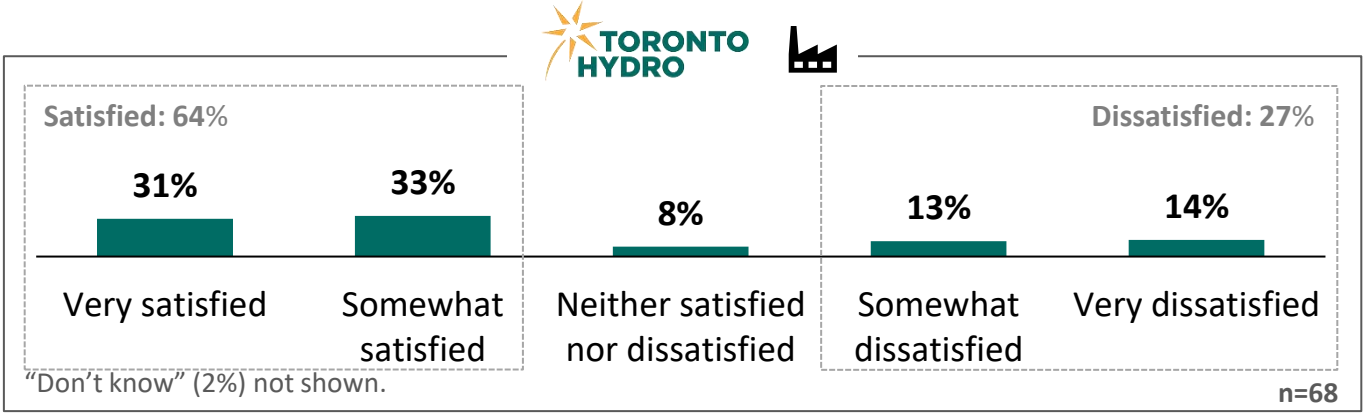
Q **Power quality** as judged by the absence of voltage fluctuations that may affect your equipment.



"Don't know" (2%) not shown.

n=68

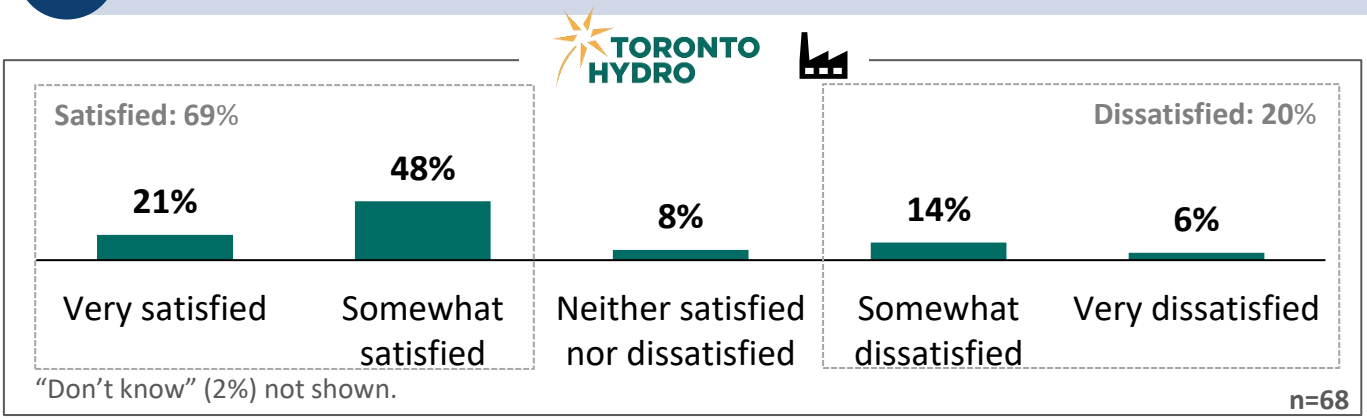
Q The **reliability of your electricity service** as judged by the number of power outages you experience.



"Don't know" (2%) not shown.

n=68

Q The amount of **time it takes to restore power** when unscheduled outages occur.



"Don't know" (2%) not shown.

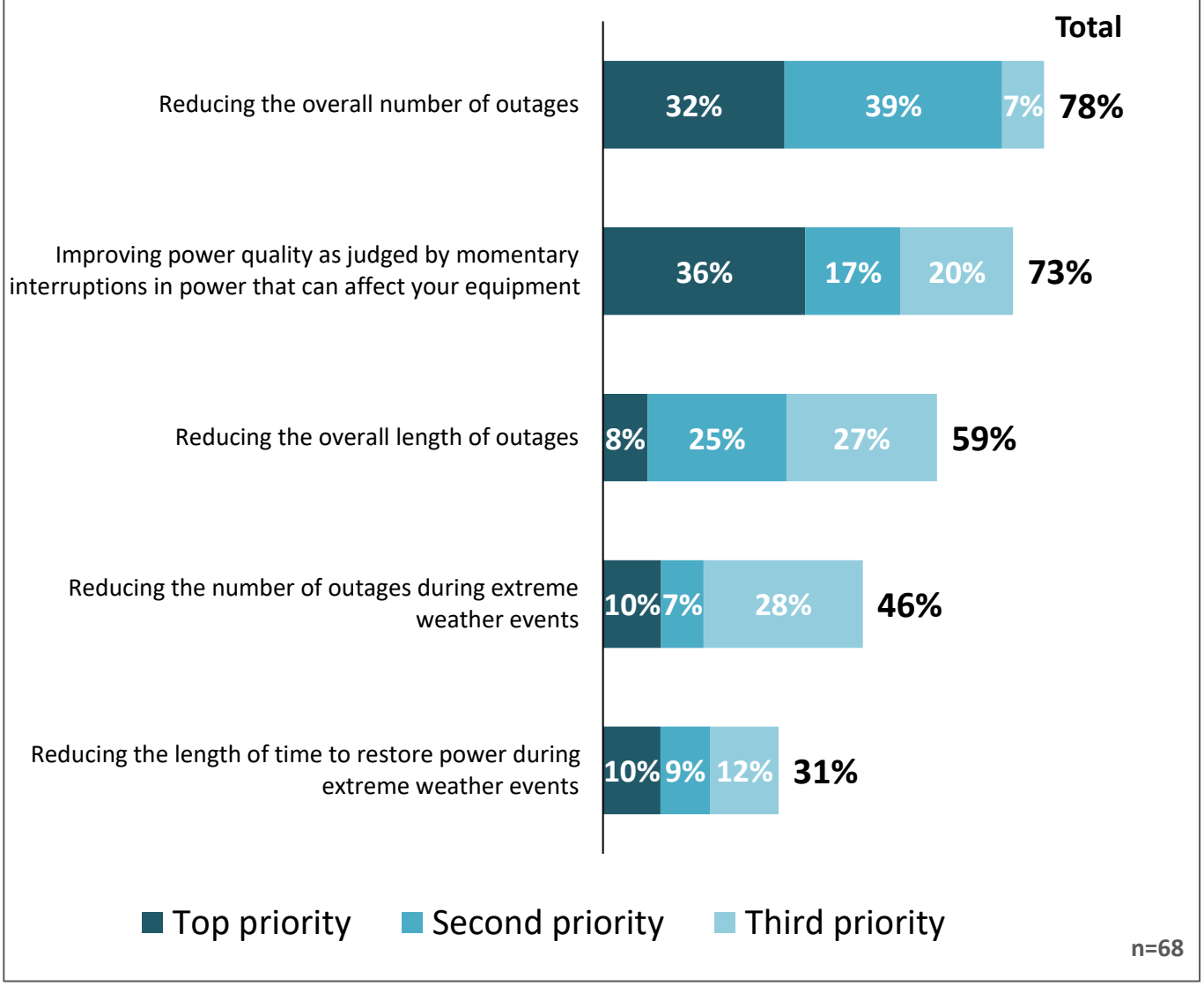
n=68

Online Survey
Ranking Reliability Priorities

Key Accounts

When it comes to reliability, there are a number of areas that **Toronto Hydro** could focus on.

Q Among the following reliability outcomes, which would you say is the **most** important? What is the next most important reliability outcome you think **Toronto Hydro** should focus on? And what do you consider the third most important priority?



Online Survey
Additional Priorities

Q Can you think of any other important priorities that **Toronto Hydro** should be focusing on, not listed on the previous pages?

Response	%
Communication	8%
Reliability	6%
Efficiency/Behind the Meter	6%
Billing	2%
Costs	2%
Other	4%
None	10%
Don't Know	62%

Online Survey
Additional Priorities

Q Can you think of any other important priorities that **Toronto Hydro** should be focusing on, not listed on the previous pages?

Communication
"Providing notices of power outages for large consumption customers ahead of outage occurrence and overall trying to eliminate any power outage incidents. Also, essential service should be prioritized to not experience any outages 24/7."
"Perhaps an automated messaging system to key account holders when the system has experienced a blip that impacts these accounts. That would serve to provide us with the information that we require and free up your resources by not having us call for an update."
"Transparency and clarity on design/approval procedure and breakdown of billing/quotations."
"They are mostly included. The sub-metering portal user friendliness could be improved generally."
Reliability
"The fluctuations in power have had a negative impact on down time to our facility and increase cost of repairs to motors and drives."
"Minimizing power outages and the duration of power outages is the highest priority for us"
"Assist customers with understanding what is the reliability of their electrical supply, specifically if there is a need to upgrade their transformer."
"Although we have two supply lines they're fed from same breaker. So, the plan was put down several times until the defect was isolated. Unacceptable to have power on/off for 5 times into a short interval maybe 2 hours. Injection molding machines were impacted and decided to let them down although the power was back to protect for an outage every 15 minutes."
Efficiency/Behind the Meter
"From our understanding, in parts of the city, it is difficult to request new power for new large construction developments because the feeders are maxed out. If the city continues to redevelop, will Hydro be able to absorb the new power demands?"
"Aiding with incentive programs to reduce energy profile."
"Investing in the equipment necessary to allow large businesses to use co-generation to power their business. This is an important element in keeping businesses competitive that call Toronto home. Decreasing costs to industrial customers utilizing automation and streamlining business processes."
"Educational seminars on customer owned transformer."

Online Survey
Additional Priorities

Q Can you think of any other important priorities that **Toronto Hydro** should be focusing on, not listed on the previous pages?

Costs
"Lower Rates."
Billing
"As mentioned earlier, consolidation of unmetered services on bills, to just provide summary information in the same manner as streetlighting."
"Understanding and working with clients to support their business back charges."
Other
"Work with University / industry tie up for better energy usage."
"Toronto Hydro is behind-the-times when it comes to data centers, which are one of the most important pieces of infrastructure in the post-pandemic world. The process to evaluate options efficiently and communicate with the client is horrendous."
"Decarbonization of electricity grid."

INNOVATIVE RESEARCH GROUP

Key Account Customers

Investment Trade-Offs

Section 6.3



Online Survey
System Renewal

Key Accounts

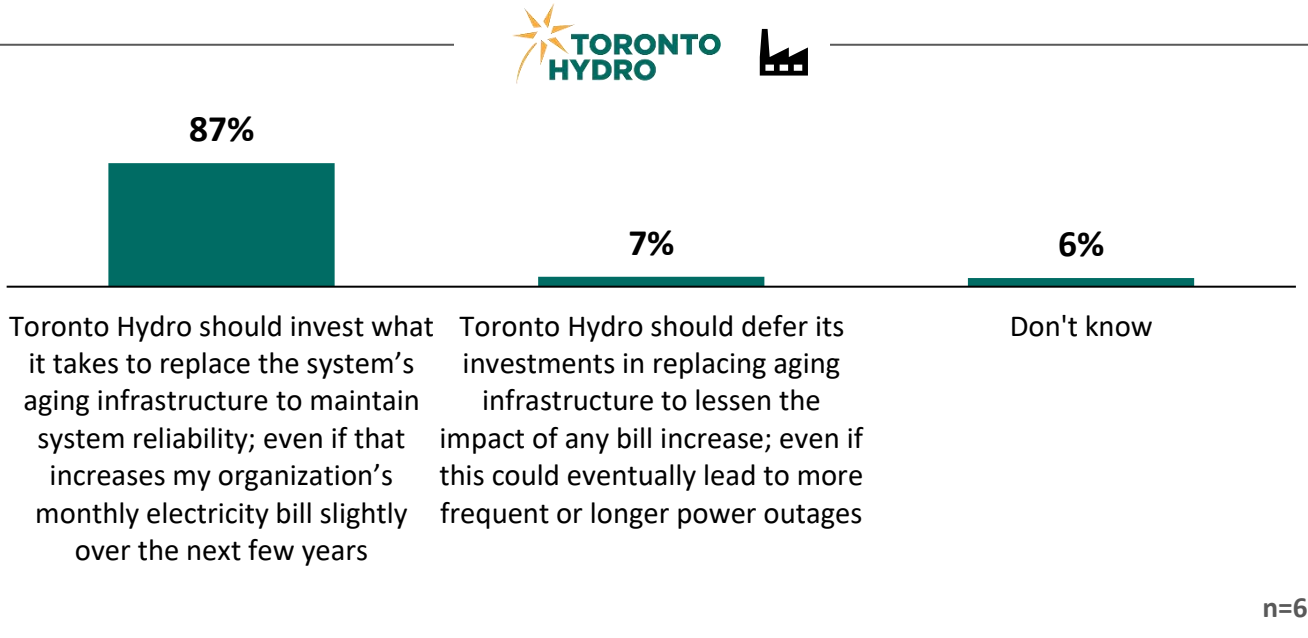
Now let's turn to our final topic – investment trade-offs.

Toronto Hydro is in the early stages of developing its investment plan for the five-year period between 2025 and 2029. While conversations with customers will continue over the next year, the utility wants to know your preferences when it comes to finding the right balance between costs and other outcomes.

There are four investment categories that we would like to discuss.

The first category focuses on projects that replace and restore aging electrical infrastructure, like overhead poles and underground cables.

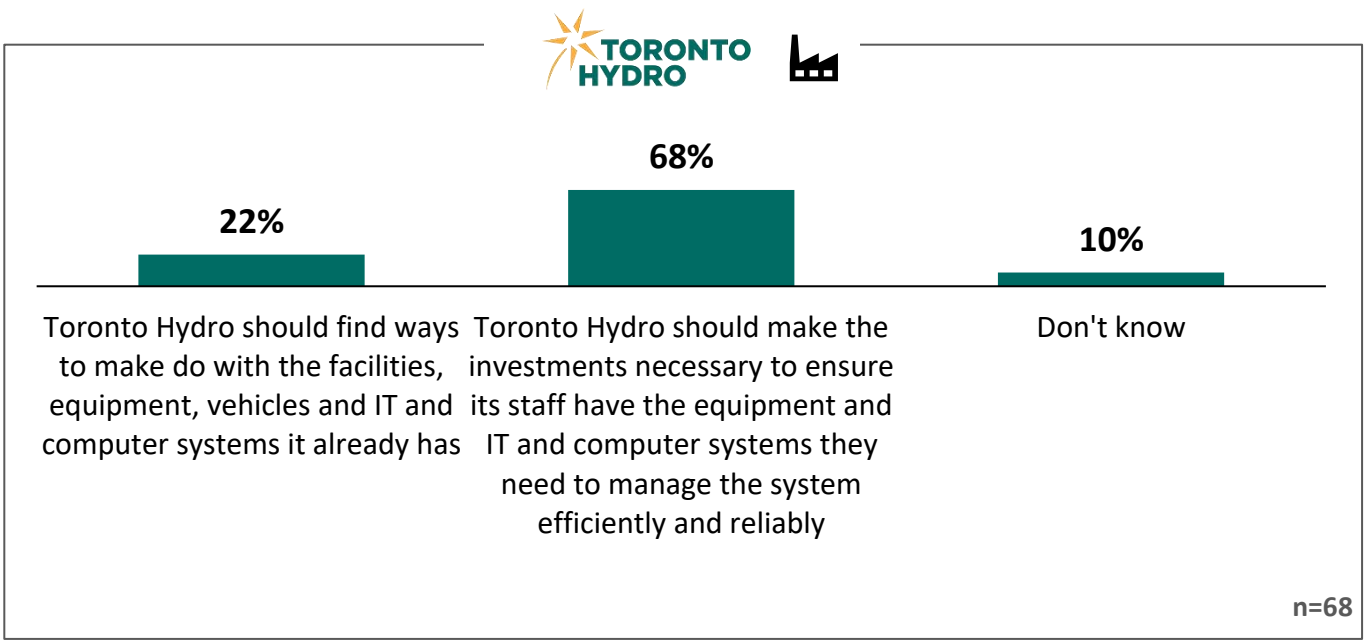
Q Regarding investments in aging infrastructure, which of the following statements best represents your point of view?



Online Survey
General Plant

The second category focuses on keeping **Toronto Hydro's** business running. This includes facilities to house staff and equipment, vehicles and tools to service equipment and IT systems to manage the system and customer information.

Q Regarding these types of investments, which of the following best represents your point of view?



Online Survey
System Service

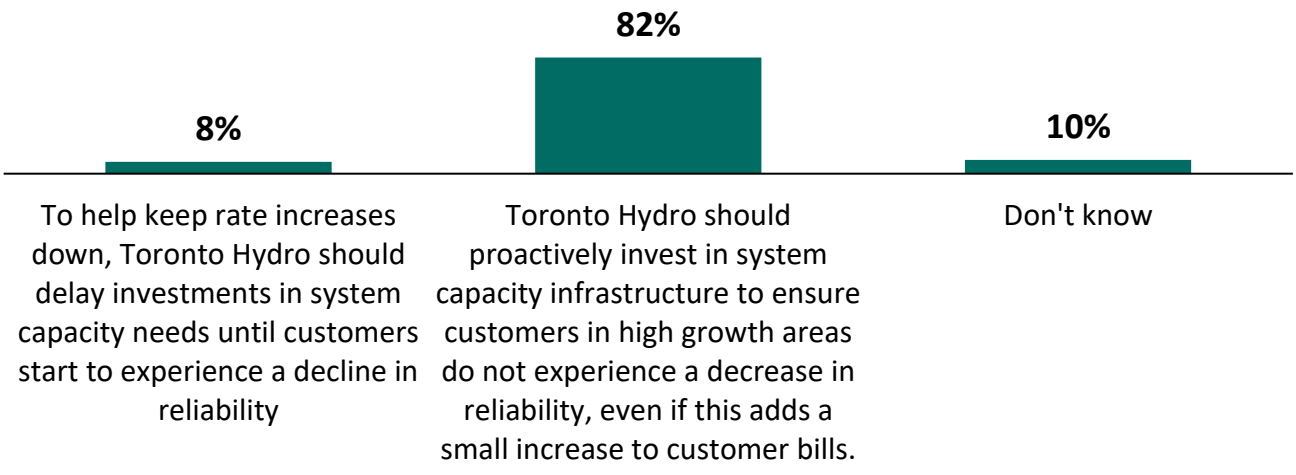
Key Accounts

The third investment category focuses on growth and greater demand for electricity in various parts of **Toronto Hydro's** service territory.

Increased demand for electricity puts pressure on existing electrical infrastructure. Eventually, further infrastructure investments are required to support increased demand for electricity.

Q With this in mind, which of the following statements best represents your point of view?

TORONTO HYDRO



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Online Survey
Grid Modernization

Key Accounts

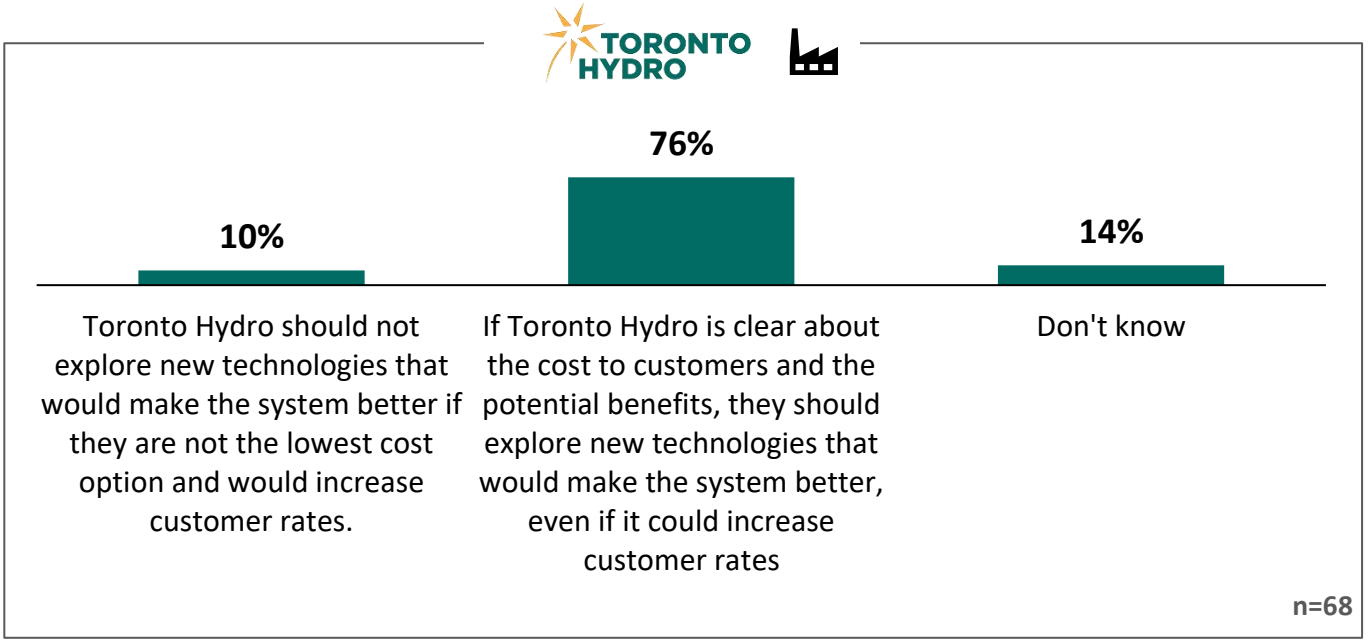
Toronto Hydro can invest in technology than can lead to a wide range of benefits including reliability, efficiency, customer service, and reducing environmental impacts.

When deemed the lowest cost option that will provide equal or improved service, Toronto Hydro will, in most cases, invest in technology.

However, there are two other scenarios where Toronto Hydro needs your feedback.

First, there are times when Toronto Hydro identifies new technology that can improve reliability or provide other benefits, but it will cost customers more. For instance, advanced customer meters that can measure when different home appliances or facility equipment is running, allowing Toronto Hydro to provide customers with better advice on how to manage their electricity usage and costs.

Q Regarding these types of investments, which of the following best represents your view?



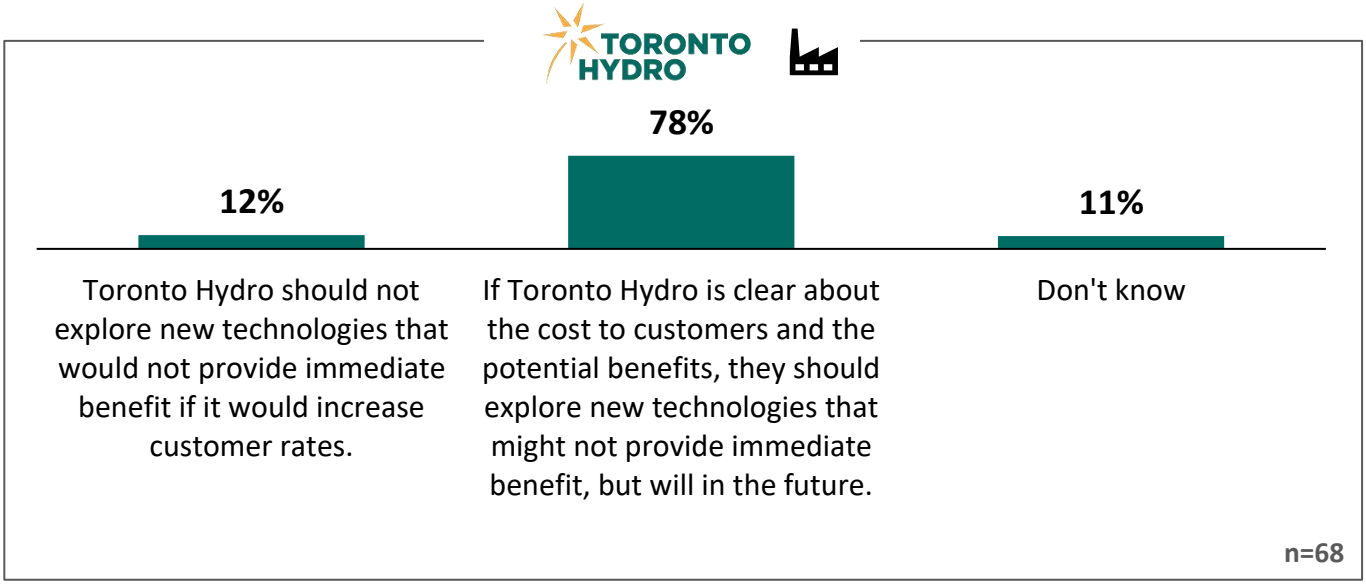
Online Survey
Grid Modernization (Con't)

The **second scenario** is where **Toronto Hydro** identifies new technology that is needed to improve the system in the future and would increase costs now, but the benefit might not be felt until later. This includes accommodating emerging technologies like solar power, battery storage, and electric vehicles.

Regardless of whether you are considering new energy choices like a battery storage, distributed energy resources (e.g. solar power), or onsite EV charging stations today, Toronto Hydro must be prepared as adoption becomes more widespread over the next 5-10 years.

For instance, charging each electric vehicle draws as much energy as two average homes. If a dozen or so people come home and start changing their vehicles at a period of peak demand, it could overload the grid in that neighbourhood. While Toronto Hydro cannot predict the exact rate of electric vehicle adoption in the City of Toronto, the utility must make certain investments today that will allow it to manage electric vehicle demand in the future.

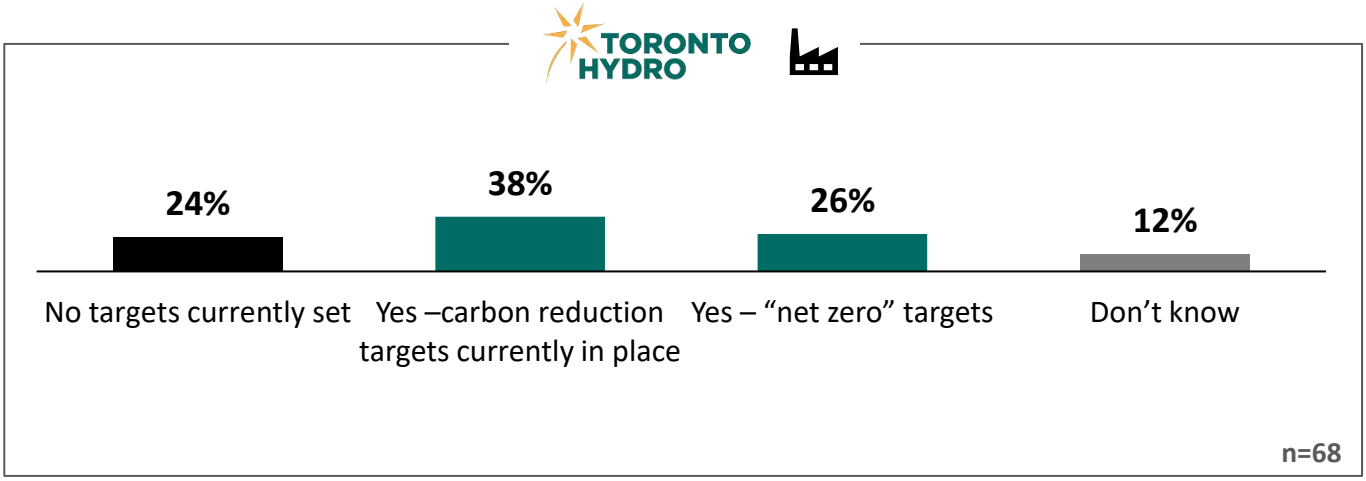
Q Which of the following best represents your view?



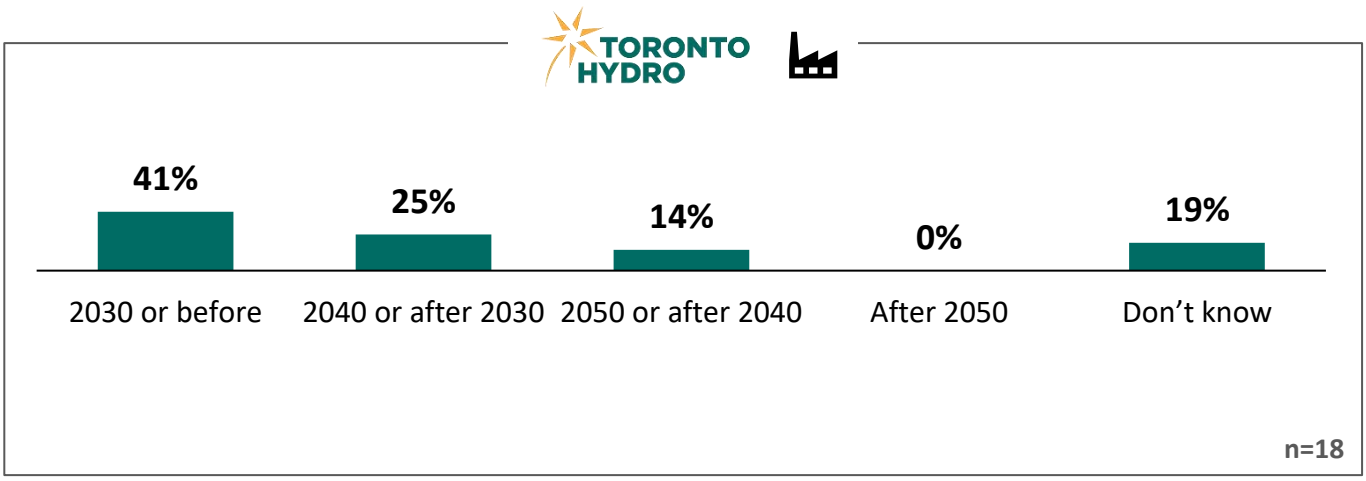
Online Survey
Carbon Reduction Initiatives

Key Accounts

Q Does your organization have a carbon reduction program in place?



Q What is your organization's "net zero" target date?



Online Survey

Familiarity with Sources of GHG Emissions

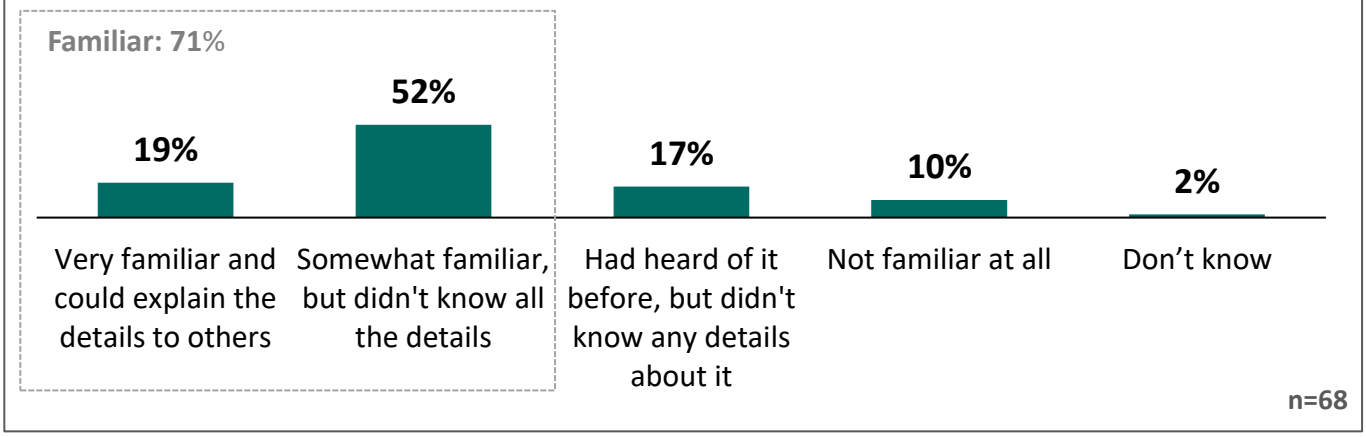
Key Accounts

In November 2021, the City of Toronto released its 2019 Greenhouse Gas (GHG) Inventory, which tracks Toronto's progress towards GHG reduction targets and identifies key emissions sources. GHG emissions have a wide variety of environmental impacts that lead to climate change and global warming.

This report notes that the **two primary sources of GHG emissions** in Toronto are: energy use in buildings (natural gas and electricity) and transportation fuels (primarily gasoline) – accounting for 93% of all emissions in the city.

Q Before this survey, how familiar would you say you were the primary sources of GHG emissions in Toronto?

TORONTO HYDRO



INNOVATIVE RESEARCH GROUP

Online Survey

Familiarity with the City's Plan

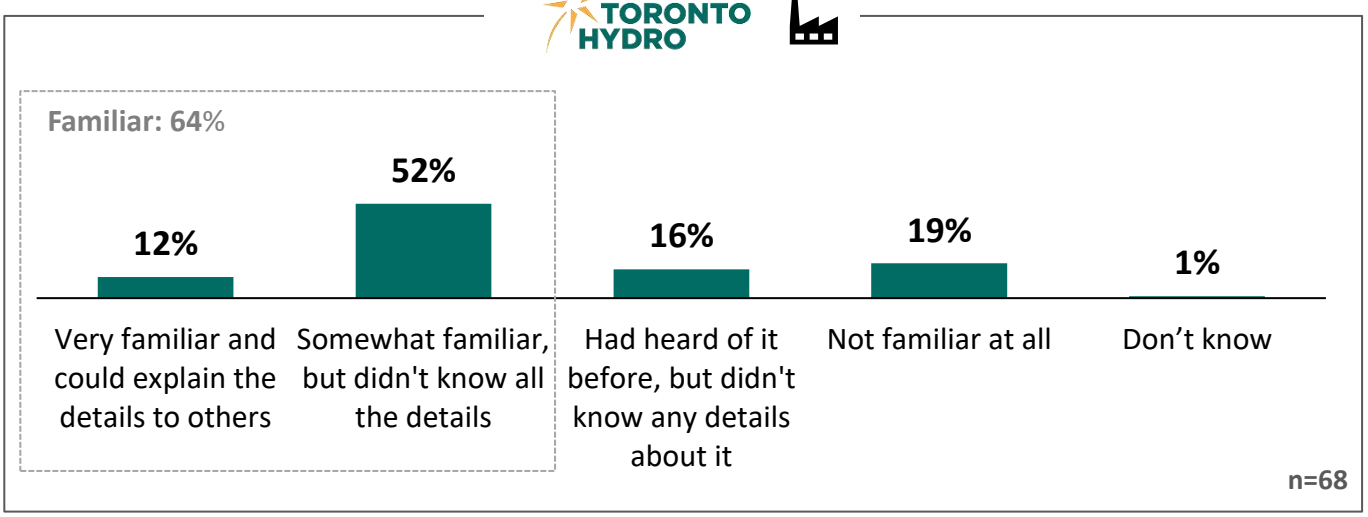
Key Accounts

In October 2019, Toronto City Council voted to accelerate its efforts to mitigate and adapt to climate change and adopt a stronger emissions target for Toronto: **net zero emissions by 2040.**

A key part of the City's "Net Zero Strategy" requires switching from gasoline in the transportation system and natural gas in home/building heating to electricity-powered alternatives, adopting renewable generation and using energy storage systems.

These initiatives will require Toronto Hydro to expand and modernize its existing electricity distribution grid to ensure that it is capable of helping achieve the City's targets.

Q Before this survey, how familiar were you with the City of Toronto's plan to use an expanded and modernized grid to reduce GHG emissions in Toronto to help address climate change?



Online Survey

Support for Bill Increase to Meet Emissions Targets

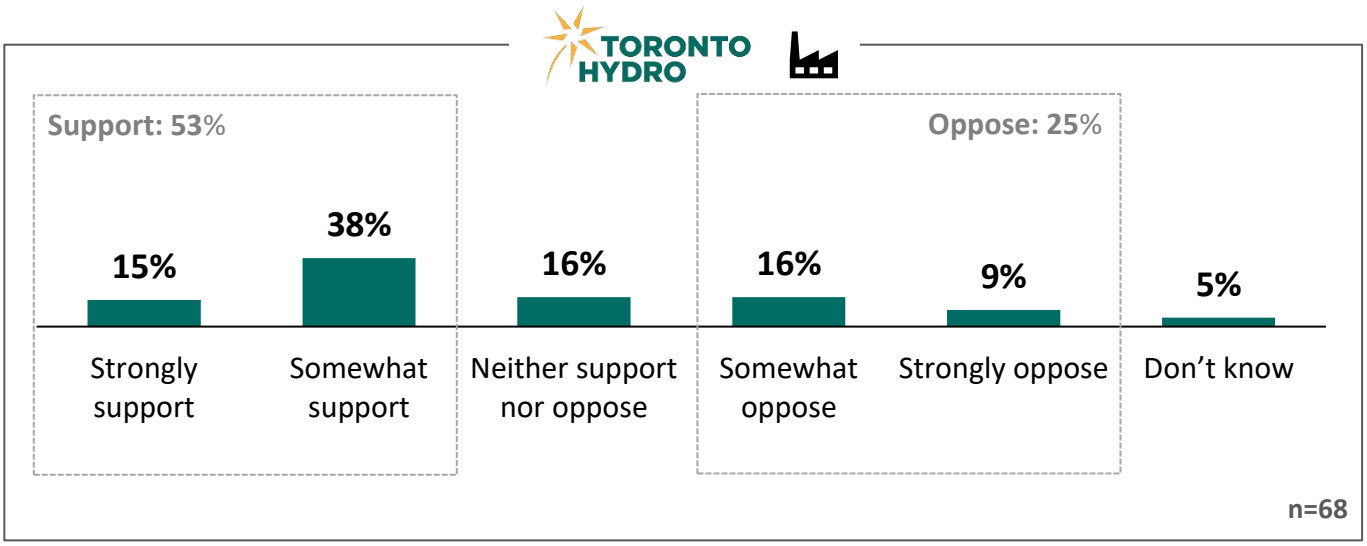
Key Accounts

As Toronto Hydro is 100% funded through the rates its customers pay, investing in an expanded and modernized electricity grid would mean that customers, like your organization, would pay more.

The sooner that Toronto Hydro expands and modernizes the grid, the sooner Toronto can reach its climate action goals.

Q Would you support or oppose a specific charge on the distribution portion of your monthly bill to help Toronto meet its future emissions targets if your electricity bill will increase by **5% a year for the next 10 years**?

*Recall, the distribution portion of your monthly bill is approximately **5-6%** of your total electricity bill.*



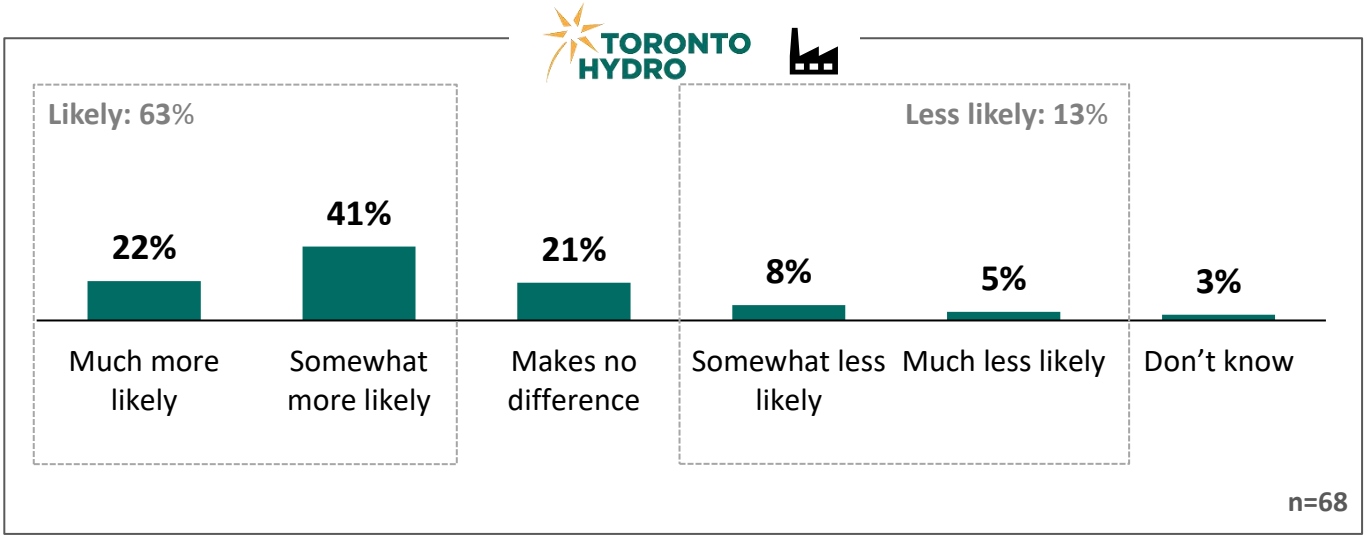
Online Survey

Potential for Rate Increase Offset

Key Accounts

Some studies have indicated that increasing customer bills to specifically help meet emissions targets could be offset in later years because of reductions in other types of energy bills. For example, as fuel-switching to electricity becomes more widespread, customers may experience cost reductions for fossil fuels, such as gasoline and natural gas.

Q Does knowing that these rate increases could be offset in later years because of reduction in other types of energy bills make you more or less likely to support a specific charge on your monthly bill to help Toronto meet its future emissions targets?



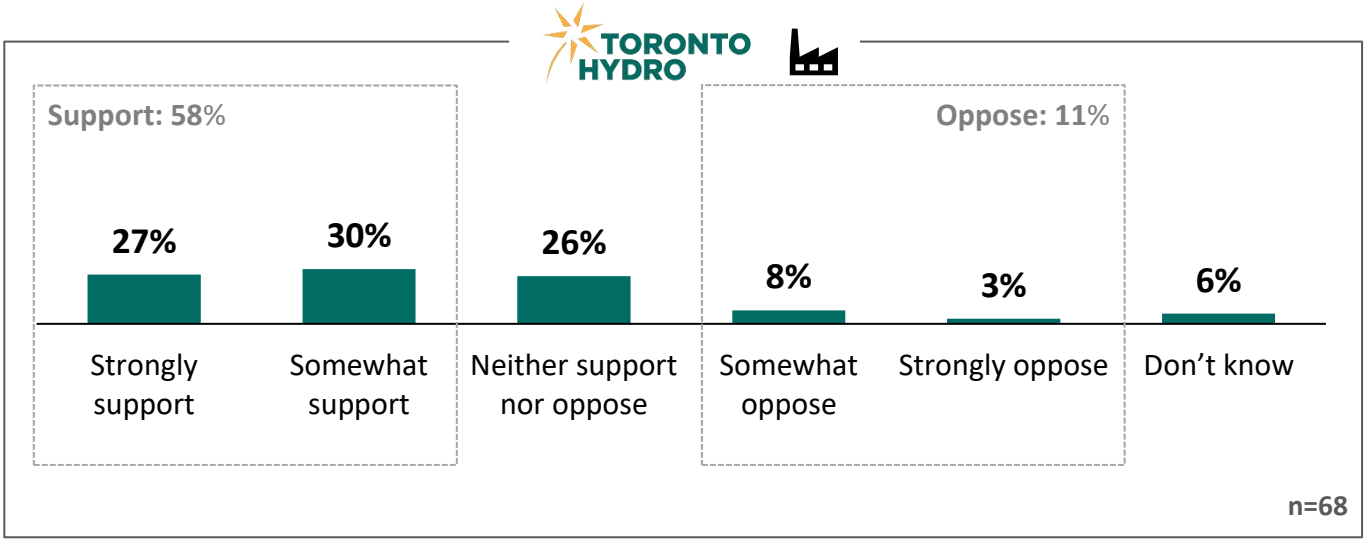
Online Survey

Support for Project Financing

Key Accounts

In a recent series of interviews with Key Account customers, the idea of **project financing** was discussed.

Q Should Toronto Hydro help finance capital costs of energy transition projects through your monthly bills (i.e. finance behind-the-meter solutions and new equipment over an extended period to time through your organization's operating costs)?



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Key Account Customers

Key Account Assessment

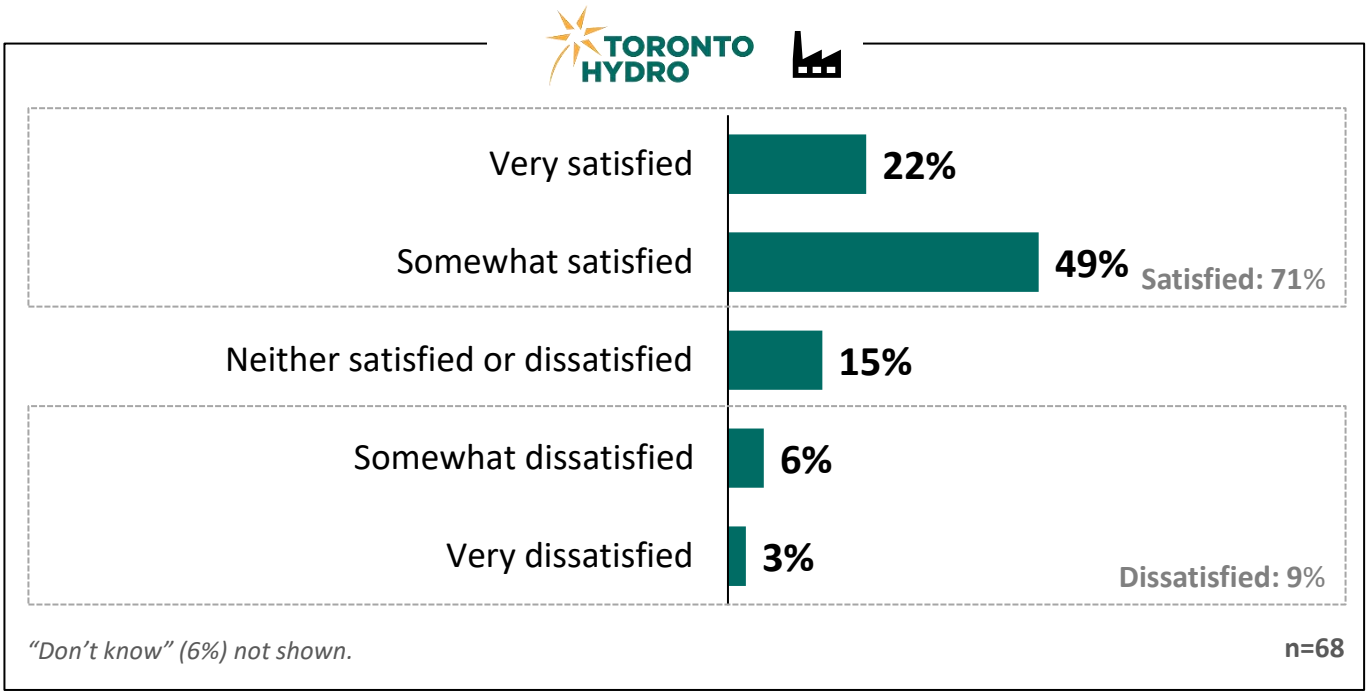
Section 6.4



Online Survey

Overall Satisfaction with Key Account Management Services

Q Overall, how satisfied are you with **Toronto Hydro's** Key Account management services?



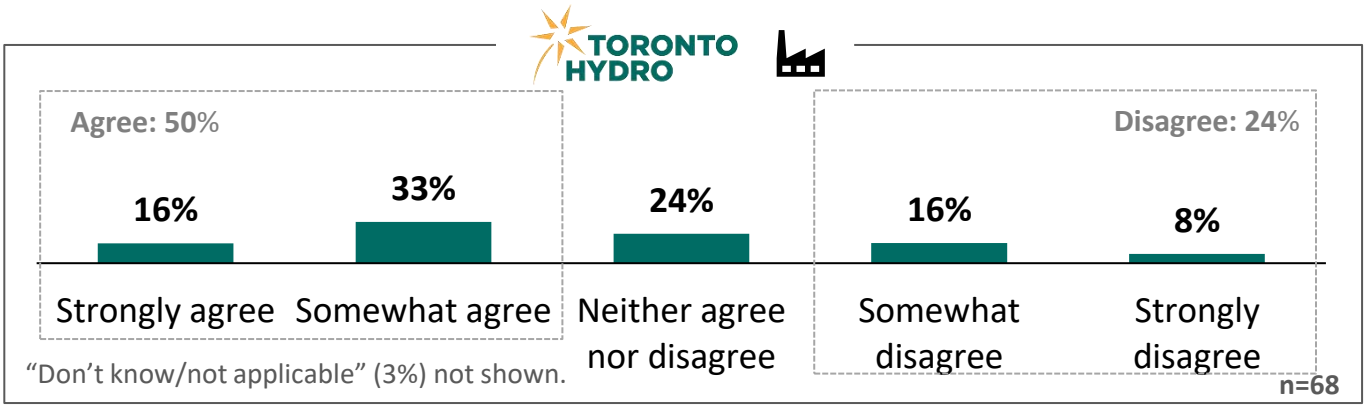
"Don't know" (6%) not shown.

n=68

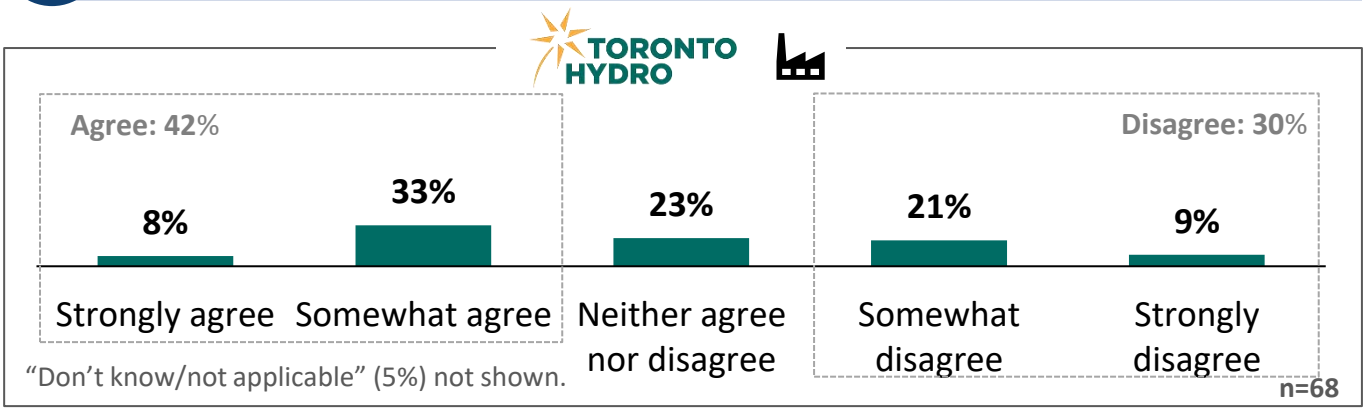
Online Survey
Key Account Assessment

Please indicate if you agree or disagree with the following statements.

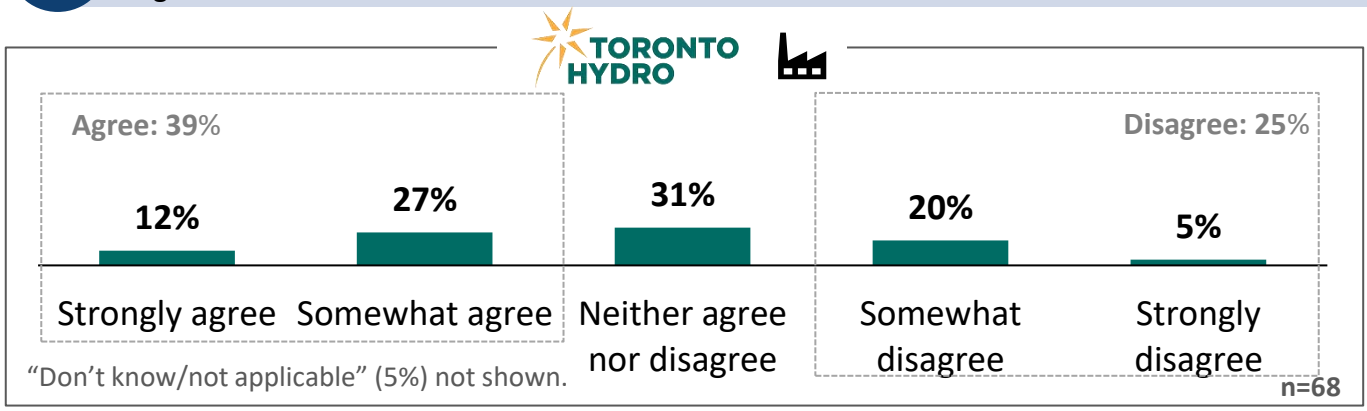
Q Toronto Hydro understands my organization and its challenges.



Q Toronto Hydro proactively provides my organization with business solutions.



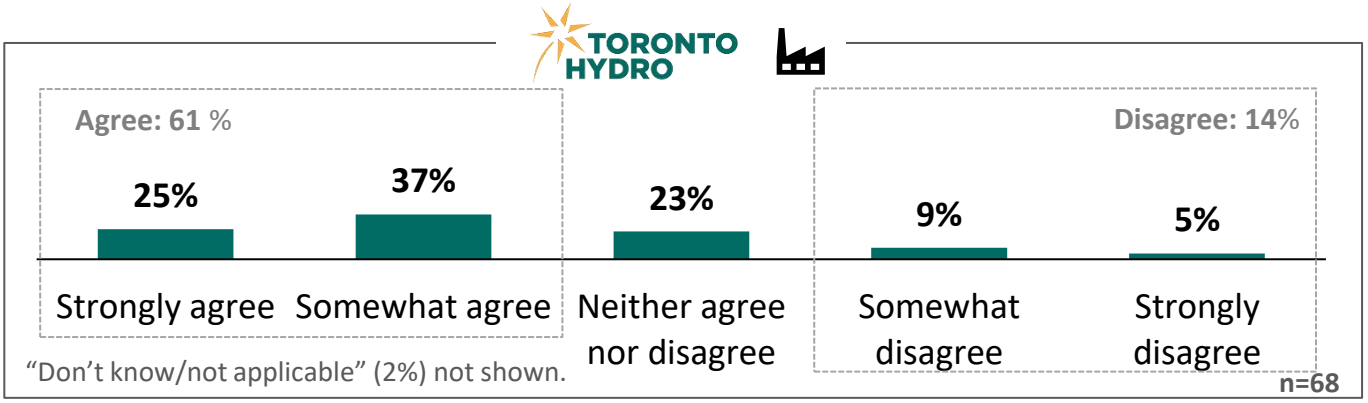
Q Toronto Hydro is more than an electricity distributor, it is a business partner to my organization.



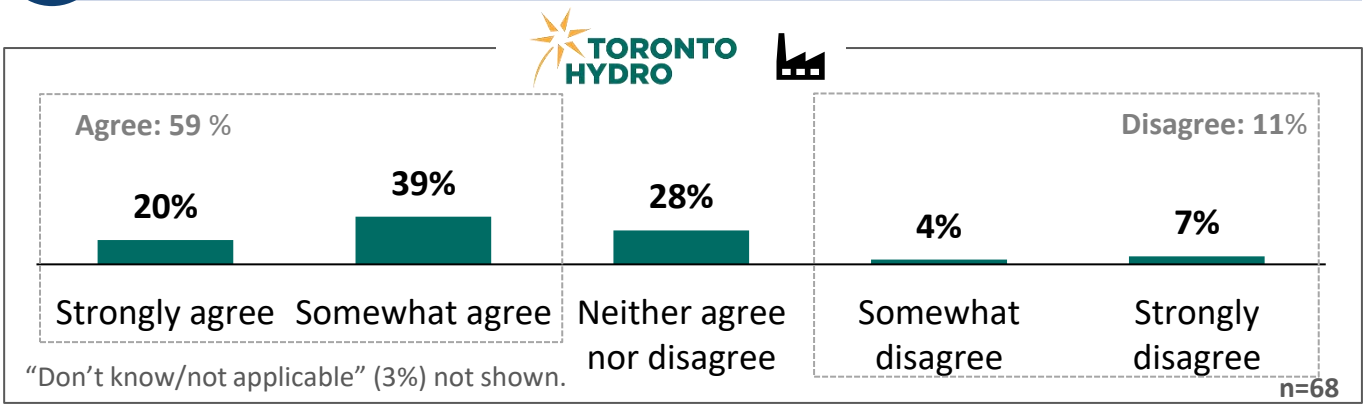
Online Survey
Key Account Assessment

Please indicate if you agree or disagree with the following statements.

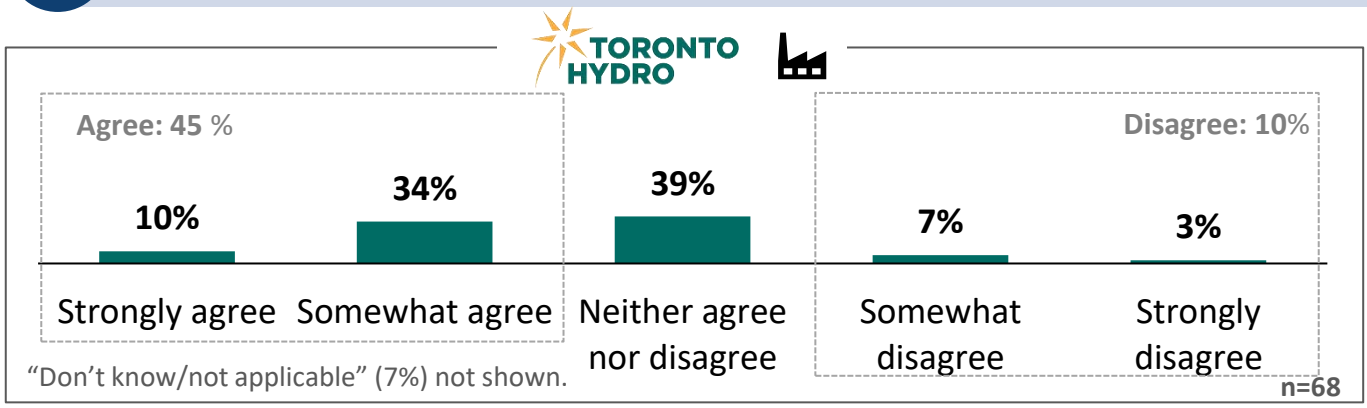
Q Toronto Hydro staff are easily accessible to my organization.



Q Toronto Hydro staff provide my organization with quality advice and guidance when I have questions about my service.



Q Toronto Hydro provides my organization with good value for money.



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Key Accounts Customers

Additional Services

Section 6.5

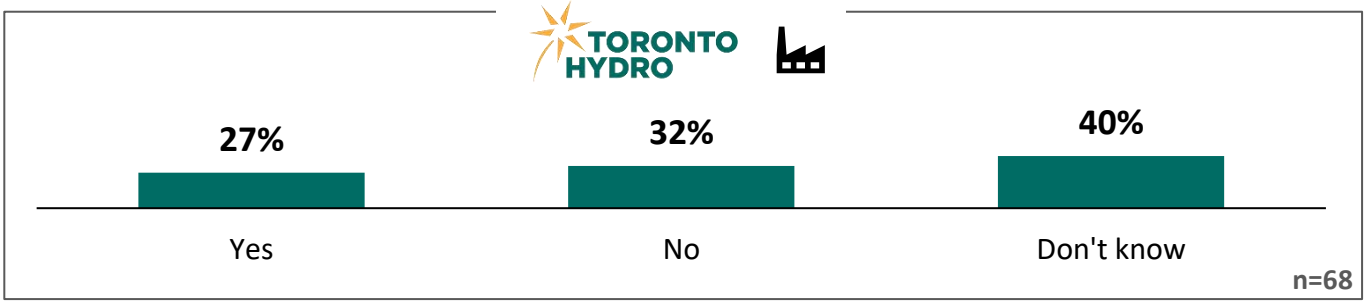


Online Survey

Service Offered by Toronto Hydro's Key Account Team

Key Accounts

Q Are there services that are currently offered by Toronto Hydro's **Key Account Team** that could be done differently to better fit your needs?



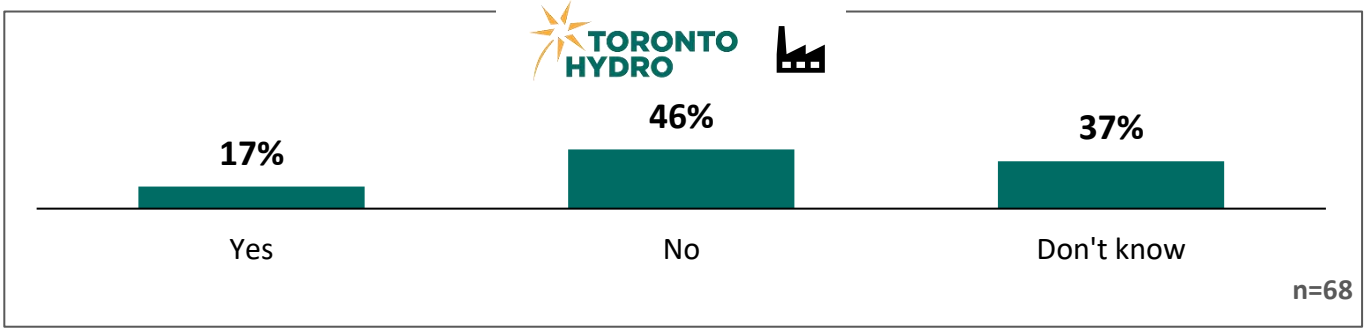
Responses from those who say "Yes"
Communication (13%)
"The communication with key accounts. I have never met anyone from the team, so not sure who they are."
"Communicate with me about my necessary support."
"Additional engagement with the plant to advise of upcoming initiatives/projects."
"A quicker response to metering issues is always good."
"Develop partnerships to understand your customer and their needs."
"Better interaction."
"Better customer support/management."
"A more pro-active approach."
"Our organization is not familiar with services offered by the Key Account Team so more could be done to push information about these services to our organization."
One Point of Contact (7%)
"One account manager/project manager for each project who can assist on all Hydro and Hydro Streetlighting related business throughout the course of the project."
"Singular Point of contact would be nice, I converse with relocation, OTC, all for the same project."
"Contact name"
Energy Conservation (5%)
"Incentives for energy conservation measures in commercial/industrial facilities."
"Provide more info on future energy projects and technology."
"Energy supported incentive programs."
Other (3%)
"New service process is slow and expensive."
"Make an arrangement for dedicated team for our Annual sub station shutdown in short notice."

Online Survey

Additional Services by Toronto Hydro's Key Account Team

Key Accounts

Q Are there any additional services that you would look to Toronto Hydro's **Key Account Team** to provide and would be willing to pay for?



Responses from those who say "Yes"
Service (5%)
"Project specific designers that are with project from start to finish."
"Customer audits."
"Provide engineering services at reasonable cost for adding second feed to the building."
Efficiency/Behind the Meter (3%)
"Facilities energy and conservation training."
"Help with battery storage solutions, or solar panels."
"Behind the meter solutions."
Communication (3%)
"Peak demand notification for Class A customers."
One Point of Contact (3%)
"Please refer to above comment." -- "One account manager/project manager for each project who can assist on all Hydro and Hydro Streetlighting related business throughout the course of the project."
Cost (1%)
"Power cost forecasts... forecasted rate changes and escalations (including GA and HOEP)."
Reliability (1%)
"Reduce power blips in our area leading to financial losses."
Other (1%)
"Possibly.....Would need to think about it."

Online Survey

Service Offered by Toronto Hydro's Key Account Team

Q Before this survey concludes, do you have any additional comments or feedback you'd like to share with Toronto Hydro?

Note: all feedback is anonymous and you will not be identified to Toronto Hydro without your expressed permission.

Response	%
Electrification/Reaching Net-Zero	6%
Communication	1%
Other	5%
None	88%

Electrification/Reaching Net-Zero
"Toronto Hydro historically and to this day does not seem like a willing partner in the move to decarbonize and distributed energy resources. They are a publicly owned utility, but does not act like one."
"I believe that T.H. should speed up their transition to LED lighting street lighting through the Toronto area this will go a long way to diminish the electrical consumption on the existing system and provide better lighting and diminish the costs of maintenance. With T.H. incentives my organization has realized good savings over the years with the IESO incentive programs for various projects."
"Fossil fuel does need to be phased out, but we need to do it in a way that allows businesses to compete internationally. Our business spends over $1M on electricity annually. It is a semi-major item on our cost breakdown. A 5 % increase in hydro rates for 10 years in a row would be very hurtful and if out of step with our business environment outside of Ontario could result in closure. It's delicate and must come with a balanced sensitive view."
"Most of the organizations are trying to reduce the energy and go to net zero in the near future. Hydro will be a key player. May need more technical support staff for further team work and also give guidance for the customers. Also there is a trend to move to Electricity from all sides, with all switching to electricity the load will shift from natural gas to electricity in all industry. May need to balance the same"
"Additional service (power requirements) to help us reach our zero carbon mandates set by our Company. This I will be connecting with Toronto Hydro in the short term to discuss."
Communication
"Email responses from directors would be nice."
Other
"The questions of this survey read as if there is another option to Toronto Hydro. What alternative do we have working in the city? Who are we to sway how you spend your funds? It's not like we can switch to geothermal, gas, or solar to circumvent or replace our dependency of this utility."
"The electricity service provided by Toronto Hydro is quite good. Impacts to our property due to electricity outages are minimal."

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro. The conclusions drawn and opinions expressed are those of the authors.

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APPENDIX 07

Phase I Customer Engagement

Needs and Preferences Planning Placemat

November 2, 2023

TORONTO HYDRO

STRICTLY CONFIDENTIAL

2025 – 2029 Rate Application

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- APPENDIX.04 – Small Business Needs and Preferences Survey
- APPENDIX.05 – Commercial & Industrial Needs and Preferences Survey
- APPENDIX.06 – Key Accounts Needs and Preferences Survey
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Phase I Customer Engagement

Toronto Hydro's 2025 Rate Application

Needs and Preferences Planning Placemat (March 2022)

INNOVATIVE RESEARCH GROUP

Rate Class Sample Size (Unweighted n)	Residential (n=1,685)	Small Business (n=430)	C&I* (n=48) *interpret as directional due to small 'n'	Key Accounts (n=68)
Needs				
What are customer needs? Most customers are generally satisfied with the service they receive from Toronto Hydro. When asked how Toronto Hydro can improve service, customers were not wedded to any specific needs or wants. Overall, the top customer needs continue to be "lower or reduce rates" and "ensure reliability" followed by "investing new technology" and "reducing restoration time".				
Top Customer Needs	Rates Reliability	Rates Invest in new technology	Rates Reliability	Reliability Reduce restoration time
Preferences				
Prioritizing Outcomes				
General Priorities (%) indicates total percentage by rate class that place specific priority in their top 3 outcomes	Reasonable rates (46%) Reliable service (45%) Invest in new technology (45%) Reduce costs Withstand adverse weather	Reasonable rates (54%) Invest in new technology (40%) Reduce costs Withstand adverse weather Reliable service (36%)	Reasonable rates (50%) Reliable service (48%) Grid capacity expansion for climate action (33%)	Reliable service including power quality (69%) Outage restoration in extreme weather (52%) Safety of infrastructure (39%)
Prioritizing Reliability Investments				
Reliability (%) indicates total percentage by rate class that place specific priority in their top 3 outcomes	Reduce restoration time in extreme weather (70%) Reduce outages in extreme weather (57%) Reduce outages (56%)	Reduce restoration time in extreme weather (60%) Reduce outages (57%) Reduce outages in extreme weather(56%)	Reduce restoration time (63%) Reduce outages (56%) Reduce outages in extreme weather (54%)	Reduce outages (78%) Improve power quality (73%) Reduce restoration time (59%)
Prioritizing Technology Investments				
Grid Modernization (%) indicate total percentage by rate class that place specific priority in their top 3 outcomes	Find efficiencies and reduce customer costs (79%) Reduce environmental impact of internal operations (56%) Reduce both length and number of outages (54%)	Find efficiencies and reduce customer costs (79%) Reduce environmental impact of internal operations (51%) Help customers better manage electricity usage (50%)	Find efficiencies and reduce customer costs (79%) Reduce environmental impact of internal operations (52%) Reduce both length and number of outages (54%)	N/A
INVESTMENT TRADE-OFFS			*% Total Support*	
System Renewal Necessary investments in aging infrastructure to maintain system reliability.	76%	69%	79%	87%
General Plant Necessary investments to ensure staff have reliable equipment and IT systems.	68%	59%	56%	68%
System Capacity Proactive investments to ensure customers in high growth areas do not experience a decrease in reliability.	66%	61%	73%	82%
GRID MODERNIZATION			*% Total Support*	
System Enhancements Explore new technologies that would make the system better even if they are not the lowest cost option.	63%	59%	75%	76%
Future Benefits Explore new technologies that will provide future (rather than immediate) benefits if the costs and benefits are clearly articulated.	71%	67%	73%	78%
CLIMATE ACTION			*% Total Support*	
Electrification Willingness to pay extra to help the City of Toronto meet its future emissions targets.	48%	47%	44%	53%
Social Equity Willingness to pay extra to provide financial assistance to low-income customers.	41%	42%	52%	N/A

An estimated 64% of key accounts have "net zero" targets or carbon reduction initiatives currently in place.

For more information about this document or the Phase I customer engagement results please contact the Regulatory Applications and Business Support team.

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APPENDIX 08

Phase II Customer Engagement
Online Workbook Overview

November 2, 2023

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2025 – 2029 Rate Application

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- APPENDIX.13 – Customer Engagement Workbook (Residential Version)

Introduction

Phase II 2025-2029 Rate Application Customer Engagement

The *Renewed Regulatory Framework for Electricity Distributors*

Toronto Hydro Electric-System Ltd. (**Toronto Hydro**) engaged Innovative Research Group Inc. (**INNOVATIVE**) to design, execute, and document the results of its customer engagement process under the Renewed Regulatory Framework for Electricity Distributors (RRFE) as part of its business planning process for the 2025-2029 Custom Incentive Rate-Setting Application.

The key objectives of this customer engagement were to:

1. Solicit customer feedback on key investment areas based on pacing and bill impact.

2. Assess overall social permission for the draft plan.

INNOVATIVE and Toronto Hydro developed a two-phased engagement approach to achieve these objectives. Following the customer engagement in Phase I, Toronto Hydro developed a draft plan to align with identified customer needs, preferences, and expectations. Afterwards, INNOVATIVE worked with Toronto Hydro to translate the draft plan into engagement materials that a typical customer could understand. INNOVATIVE developed a workbook survey and tested it through a series of focus groups and one-on-one interviews. The workbook was then made available to all customers. It mainly focused on obtaining customer feedback on key investment areas based on pacing and bill impact.

Each participating customer received a workbook with bill impacts that reflected the circumstances of their rate class. Five workbooks were created. Since the number of key accounts and large use customers within Toronto Hydro's customer base was lower than the other rate classes, responses from these two rate classes were aggregated for reporting purposes. The table below summarizes the field dates and the sample sizes of each rate class.

Rate Class	Field Dates	Sample Size (Unweighted n)
Residential	March 22nd – May 1st, 2023	n=32,187
GS<50 kW (Small Business)	March 23rd – May 1st, 2023	n=695
GS 50-999 kW (Commercial & Industrial)	April 3rd – May 22nd, 2023	n=264
GS 1,000-4,999 kW (Key Accounts)	April 3rd – June 2nd, 2023	n=52
Large Use		

Workbook Pages

Pages with a watermark in Appendices 09 to 12 are the original workbook pages. Please note that some of these pages include graphs and charts which are used to explain concepts to customers. They do not represent the survey data. By way of example, the original residential workbook pages can be found in Appendix 13 to provide context.

Introduction

Phase II 2025-2029 Rate Application Customer Engagement

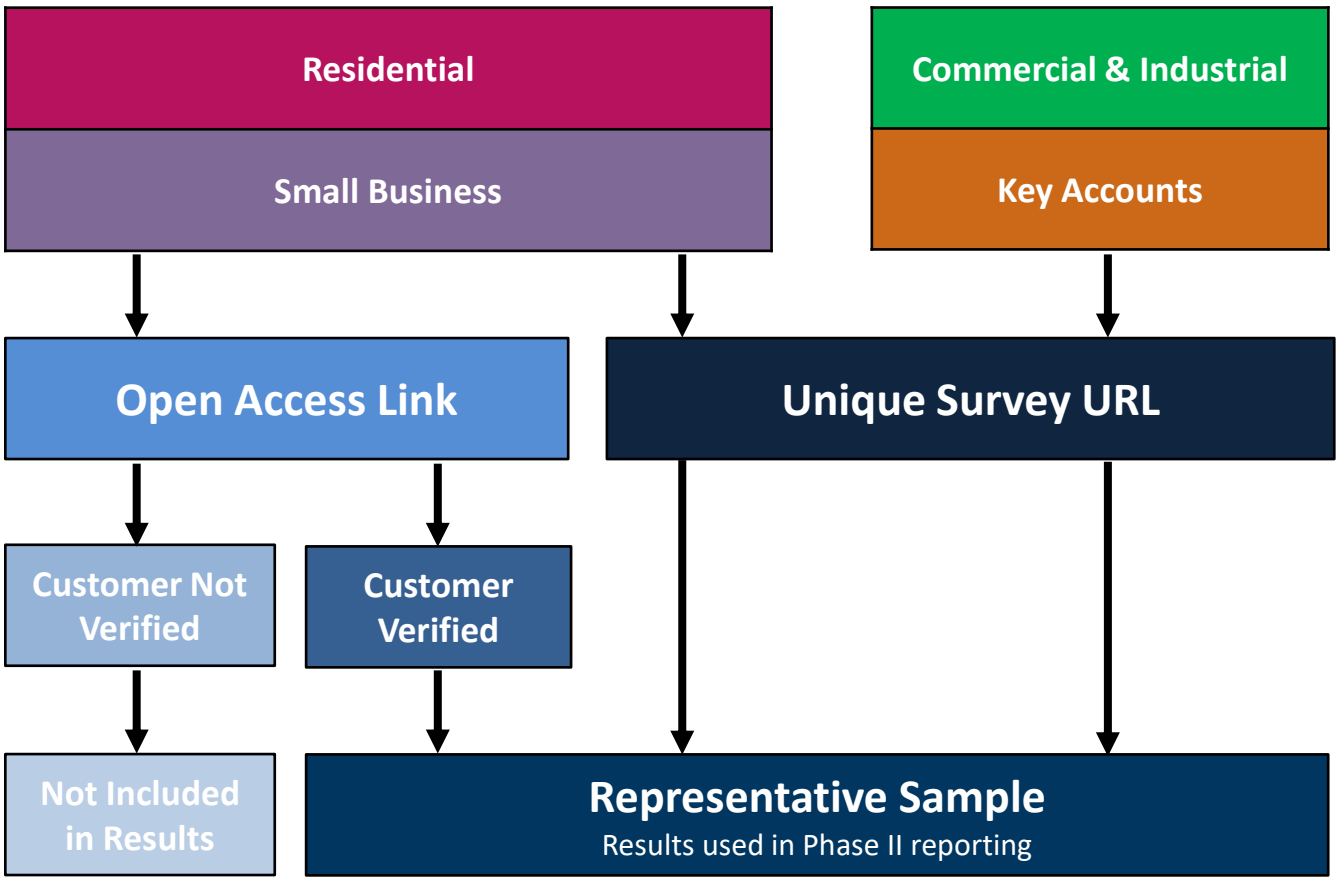
Customer Engagement

Customers with an email address on file received an email invitation. It included a **unique survey URL** that linked back to their annual consumption, region and rate class. INNOVATIVE administered all email invitations using a Toronto Hydro email address.

For residential and small business customers, an **open access link** was promoted through bill inserts, social and traditional media, as well as Toronto Hydro's website. This ensured all customers from these rate classes had the opportunity to participate in the survey. The open access link asked customers to enter their Toronto Hydro account number and the first three characters of the corresponding postal code (FSA) to verify their account information and direct them to the correct workbook version.

There are two main reasons why an open access link was only provided to the residential and small business customers. Firstly, these customers are a majority of the customer base. Secondly, based on our experience in engaging with electricity customers, it is more cost effective to invite C&I and key account customers through an email invite than providing an open access link to these customers.

The diagram below illustrates how residential and small business customers were verified in the open access link. It also illustrates how customers with an email address on file received an email invitation to enter the survey.



Sample Validation

Phase II 2025-2029 Rate Application Customer Engagement

Overall Coverage – Email Sample vs. Total Customer Accounts

64% of residential customers had an email address on file. 48% of small business customers had an email address on file. Both residential and small business customers were sent one survey invite (per account) regardless of whether they had more than one email address on file.

Rate Class	Total Accounts	Email Sample	Email Coverage (out of Total Accounts)	Unique Emails
Residential	802,645 records	510,227	**64%**	448,737
Small Business	80,538 records	38,819	**48%**	21,036
C&I	8,716 records	5,573	**64%**	2,841
Key Accounts	499 records	453	**91%**	311

Nearly all key account customers have an email contact on file. Toronto Hydro provided INNOVATIVE a list of the most up-to-date key account representative contact information. Based on this list, invites were sent to 311 unique key account customer emails.

Sample Validation

Phase II 2025-2029 Rate Application Customer Engagement

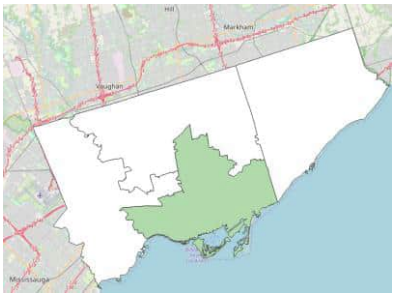
To ensure the residential and small business samples were representative of the customer base, attention was given to the distributions by (1) region and (2) consumption quartile between the full set of customer records and those with an email account on file.

(1) Regional Distribution by Rate Class

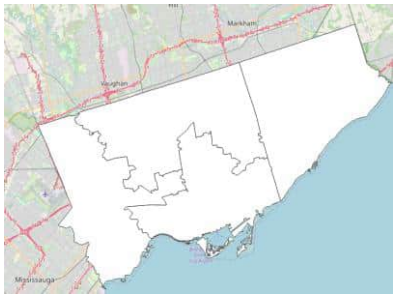
Using the first three characters of customer's postal codes (FSAs), the study grouped the customers into four unique regions within Toronto Hydro's service territory.

Across rate classes, the regional distribution between the full customer sample and those with an email address on file were within +/-4%. The exception was residential customers in Toronto/East York, who were +5% overrepresented among customers with an email address compared to the full set of customer records.

Residential



Small Business



Legend: Difference*
More than -10%
-10% to -5%
-4% to +4%
+5% to +10%
More than +10%

(2) Distribution of Consumption Quartile by Each Rate Class

Across consumption quartiles, the distribution of consumption between the full customer sample and those with an email address on file were within +/-4%. The exception was small business customers in the fourth quartile, who were +5% overrepresented among customers with an email address compared to the full set of customer records.

Quartiles	Total Accounts	Email Sample	Difference *	Total Accounts	Email Sample	Difference *
Rate Class	***Residential***			***Small Business***		
First	25%	28%	**+3%**	25%	24%	**-1%**
Second	25%	25%	**0%**	25%	22%	**-3%**
Third	25%	23%	**-2%**	25%	24%	**-1%**
Fourth	25%	24%	**-1%**	25%	30%	**+5%**

Survey Sample

To ensure the residential and small business samples were representative of the customer base, the samples were weighted proportionately by consumption quartiles and region. As such, no one area or consumption quartile was over or underrepresented in the survey samples.

For details of the sampling methodology of each rate class, please refer to the Survey Design & Methodology sections of Appendices 09 to 12.

Note: * The difference is the distribution in the email sample *minus* the distribution among total customer accounts.

Seven Key Investment Areas

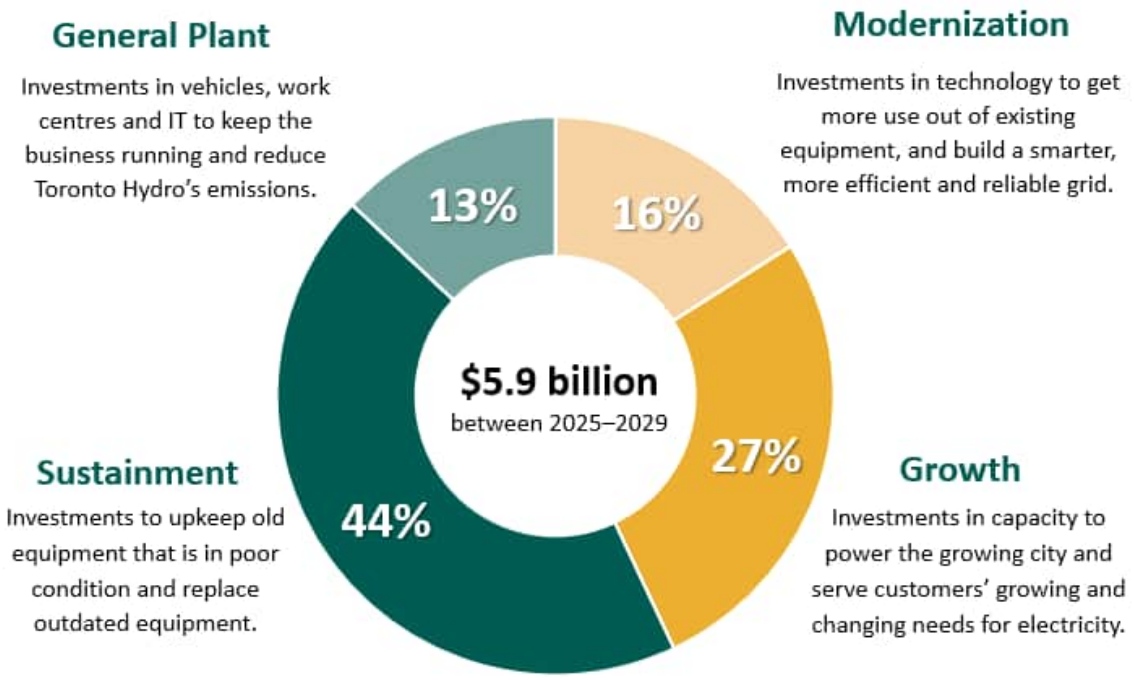
Phase II 2025-2029 Rate Application Customer Engagement

Workbook Design

The workbook first explained to customers what Toronto Hydro does and summarized some key planning considerations that Toronto Hydro's draft plan addresses. The workbook then presented customers with the impact of the draft plan on 2025-2029 rates. Finally, the workbook asked customers for input on seven key investment areas. Once customers were finished giving feedback – they were provided an opportunity to review and change their responses to find the right balance between price and other outcomes.

Core Investment Categories

Toronto Hydro's 2025–2029 draft plan was made up of four spending categories: *Modernization, Growth, Sustainment,* and *General Plant*.



Within these four categories, customers were asked to make choices on trade-offs consisting of seven key investment areas:

		Sustainment:	*General Plant*:
1. Modernization	**2. Growth**	**3. System Reliability**	**6. Running the Business**
		4. Grid Stewardship	**7. Decarbonization**
		5. Standardization	

Seven Key Investment Areas

Phase II 2025-2029 Rate Application Customer Engagement

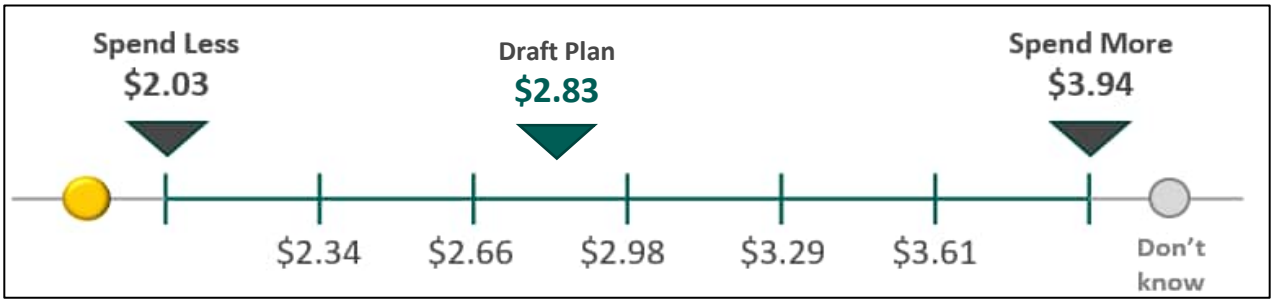
Data Collection: Understanding the Sliding Scale

For each of the seven key investment areas, after providing a detailed explanation of potential investments and expected outcomes, the survey provided customers with a **sliding scale** that gave customers flexibility to dial the draft plan up or down to indicate their **preference** between price and other outcomes. INNOVATIVE chose to use a dollar amount for customers to indicate their preference.

An image of the sliding scale from the **modernization** investment area (**residential** customers) is shown below as an example. This example is used in the next few pages for illustration purposes.

How much do you think Toronto Hydro should spend on its modernization plan?

Sliding scale:



Data Presentation Overview

As will be further discussed in the next section, INNOVATIVE used **two** analyses to present the survey responses.

1. Showing the **range of customer views**.
2. Providing a **general direction of customer preference**.

These analyses were done for each of the seven key investment areas.

Seven Key Investment Areas

Phase II 2025-2029 Rate Application Customer Engagement

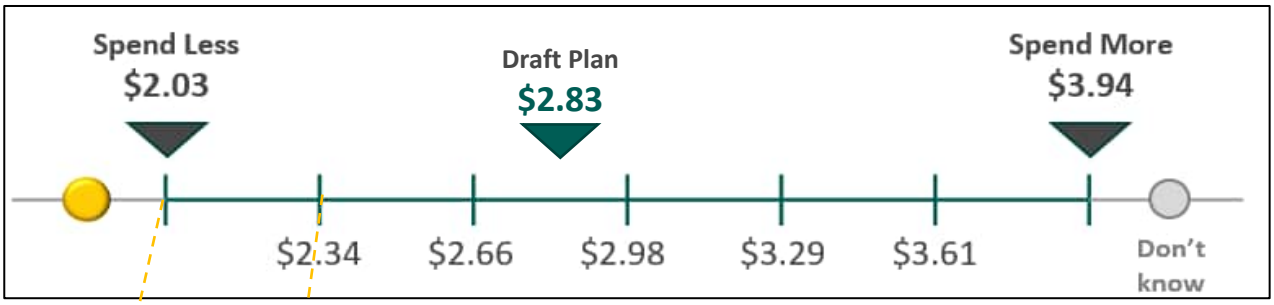
The Range of Customer Views

This analysis uses a **histogram** to show the distribution of customer preferences along the sliding scale and around the draft plan.

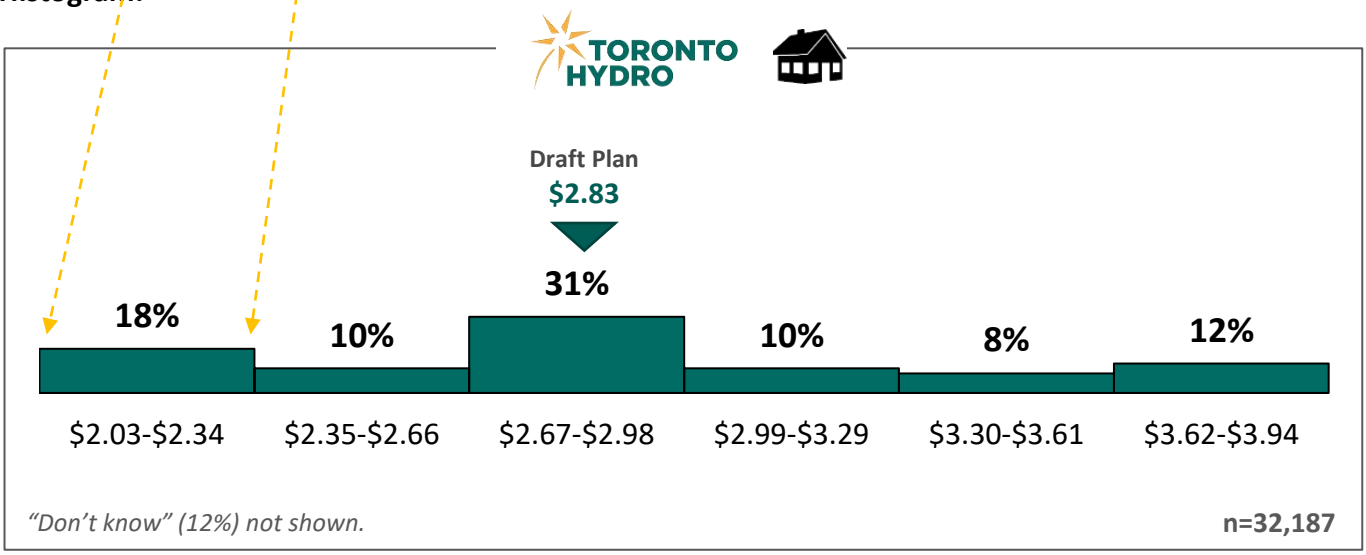
For this analysis, the sliding scale was divided into 6 equal divisions. Responses were then grouped into each division and presented in a bar.

How much do you think Toronto Hydro should spend on its modernization plan?

Sliding scale:



Histogram:



Seven Key Investment Areas

Phase II 2025-2029 Rate Application Customer Engagement

General Direction of Customer Preference

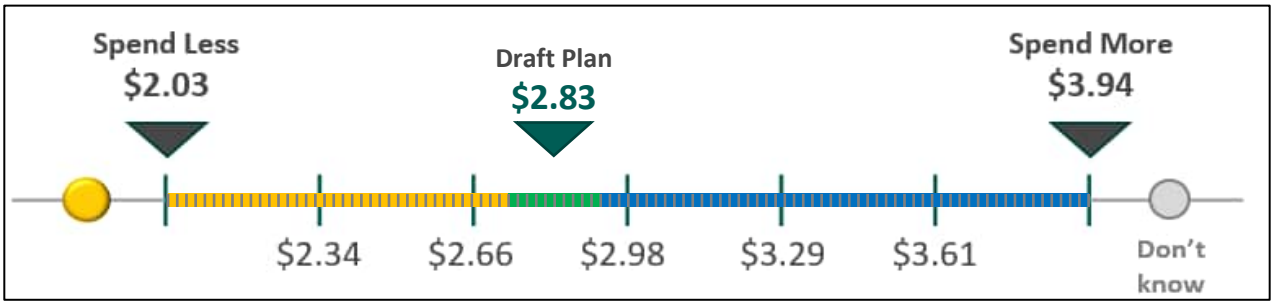
This analysis allowed Toronto Hydro to understand the direction of customer preferences on spending in order to inform decisions about finalizing the draft plan.

The sliding scale was divided into 100 equal divisions. Customers' responses were categorized as follows:

- **On Plan**: The study considered On Plan as responses that are within 5 divisions above (which corresponds to 5 percentage points above) or 5 divisions below (which corresponds to 5 percentage points below) the draft plan. For illustrative purposes, to put this in dollar terms, among residential customers, if the draft plan amount was $2.83, then selections between $2.73 and $2.93 (inclusive) were considered On Plan on the **modernization** investment area.
- **Below Plan**: The study considered Below Plan as responses that are more than 5 divisions (or percentage points) below the draft plan. This corresponds to values between $2.72 and $2.03 (inclusive) in the example below.
- **Above Plan**: The study considered Above Plan as responses that are more than 5 divisions (or percentage points) above the draft plan. This corresponds to values between $2.94 and $3.94 (inclusive) in the example below.

See the three colours on the sliding scale below for illustration.

How much do you think Toronto Hydro should spend on its modernization plan?



Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro. The conclusions drawn and opinions expressed are those of the authors.

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INNOVATIVE RESEARCH GROUP

CONFIDENTIAL

APPENDIX 09

Residential

Workbook Report

TORONTO HYDRO

November 2, 2023

STRICTLY CONFIDENTIAL

2025 – 2029 Rate Application

Report Navigation

APPENDICIES

PHASE I

- APPENDIX.01 – Customer Engagement Focus Groups
- APPENDIX.02 – Customer Sample Validation
- APPENDIX.03 – Residential Needs and Preferences Survey
- APPENDIX.04 – Small Business Needs and Preferences Survey
- APPENDIX.05 – Commercial & Industrial Needs and Preferences Survey
- APPENDIX.06 – Key Accounts Needs and Preferences Survey
- APPENDIX.07 – Needs and Preferences Planning Placemat

PHASE II

- APPENDIX.08 – Customer Engagement Workbook Overview
- APPENDIX.09 – Residential Workbook Report
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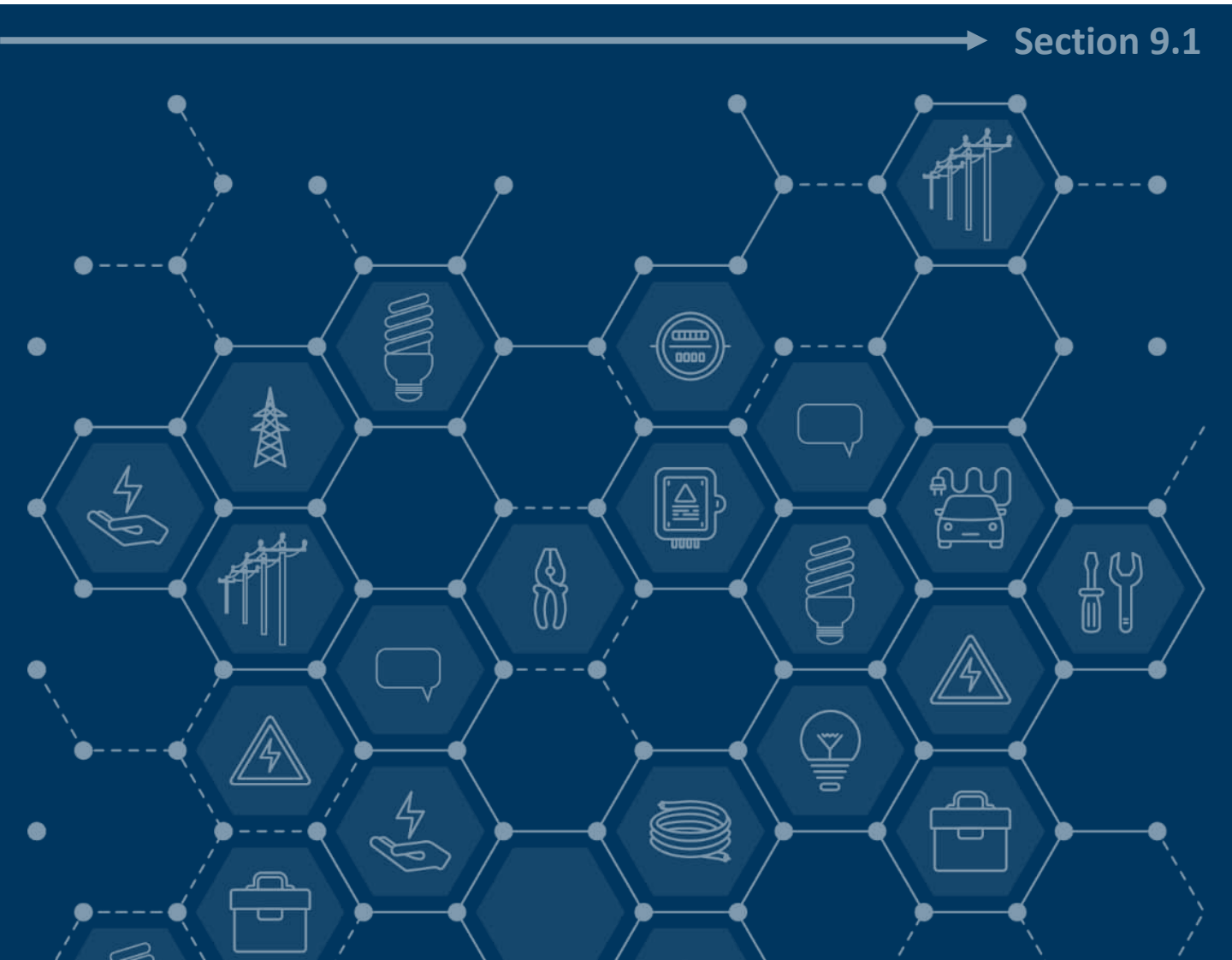
- APPENDIX.12 – Key Accounts Workbook Report
- APPENDIX.13 – Customer Engagement Workbook (Residential Version)

INNOVATIVE RESEARCH GROUP

Residential Customers

Online Workbook Report

Section 9.1



Online Survey

Survey Design & Methodology



Toronto Hydro Electric-System Ltd. (THESL) engaged Innovative Research Group (INNOVATIVE) to design, execute and document the results of THESL's customer engagement process as part of the development of its 2025–2029 business plan.

Field Dates

All Toronto Hydro residential customers with an email address on Toronto Hydro's file received the **Residential Online Workbook**. Customers had the opportunity to complete the survey between **March 22nd and May 1st, 2023**.

Incentives

Customers who completed the survey between March 23rd and May 1st were invited to enter a draw to win free electricity for a year, which was provided as a one-time, lump-sum credit valued at $1,500 to be applied to the winning customer's account. The incentive as it appeared to customers in the workbook is on pg.8 of this appendix.

Residential Online Survey Completes

A total of **32,187** (unweighted) Toronto Hydro residential customers completed the online survey. A total of 309 (unweighted) customers entered the survey through the open access link. All other remaining completes (31,878 (unweighted)) entered it via the unique URL.

Customers could complete the survey either via a unique URL sent to their emails or an open access link promoted by THESL. Customers with email addresses on file received an email invitation. It included a unique survey URL that linked back to their annual consumption, region and rate class.

Customers without email addresses on file received a paper bill insert that invited them to participate via an open access link. The open access link asked customers to enter their Toronto Hydro account number and the first three characters of the corresponding postal code. Once their account information was verified, their answers were linked back to their annual consumption, region and rate class.

Each customer was only permitted to complete the survey once, either through the unique URL or the open access link.

Online Survey
Survey Design & Methodology

Sample Weighting

The residential online survey sample was weighted proportionately by consumption quartile and region in order to be representative of the broader Toronto Hydro service territory.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region.

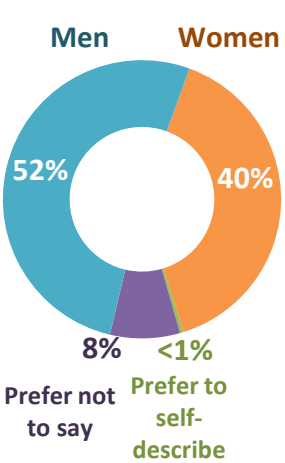
Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
Etobicoke/York	1,078 (1,346)	1,395 (1,422)	1,646 (1,621)	1,501 (1,608)	5,620 (5,997)
North York	1,646 (1,756)	1,757 (1,716)	1,632 (1,653)	1,641 (1,832)	6,676 (6,956)
Scarborough	379 (454)	1,581 (1,467)	2,193 (2,018)	1,846 (1,739)	5,999 (5,678)
Toronto/East York	4,187 (4,491)	3,921 (3,441)	3,125 (2,755)	2,659 (2,869)	13,892 (13,556)
Total	7,290 (8,047)	8,654 (8,047)	8,596 (8,047)	7,647 (8,047)	32,187 (32,187)

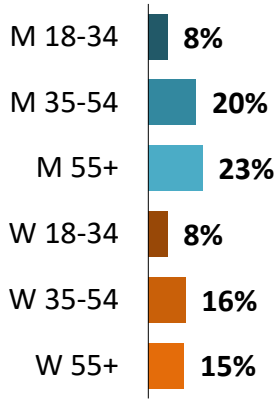
Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.

Online Survey
Demographic breakdown

Residential

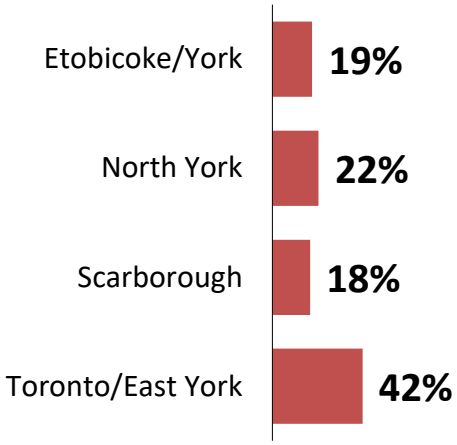
Gender & Age



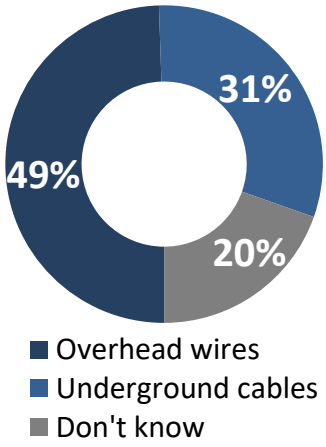


"Prefer not to say"/ "Prefer to self-describe" (10%) not shown.

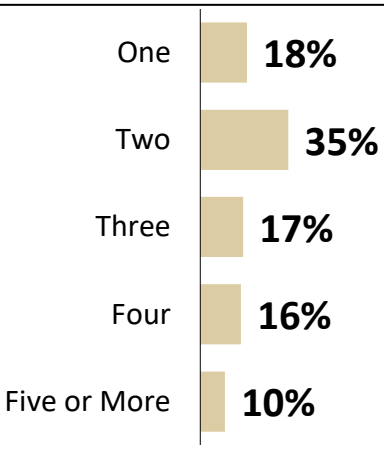
Region



Overhead Wires vs Underground Cables

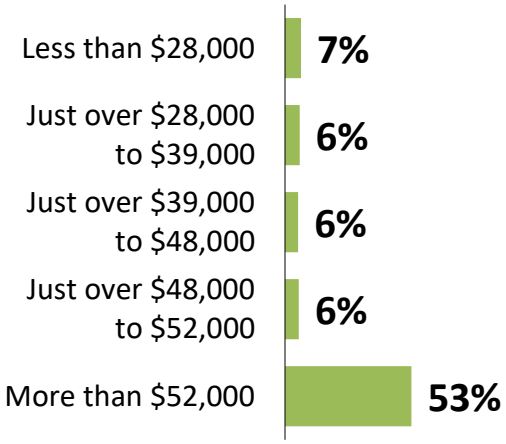


Household Size



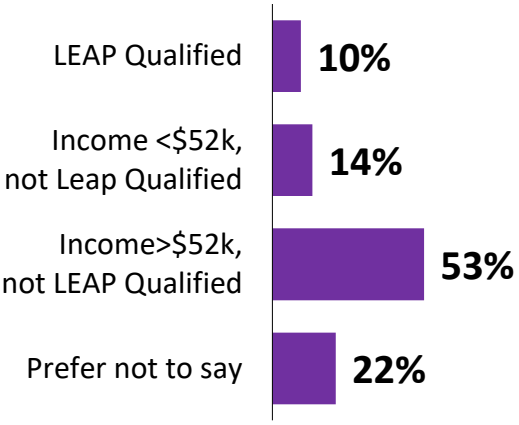
"Prefer not to say" (4%) not shown.

After Tax Household Income



"Prefer not to say" (22%) not shown.

LEAP Qualification*



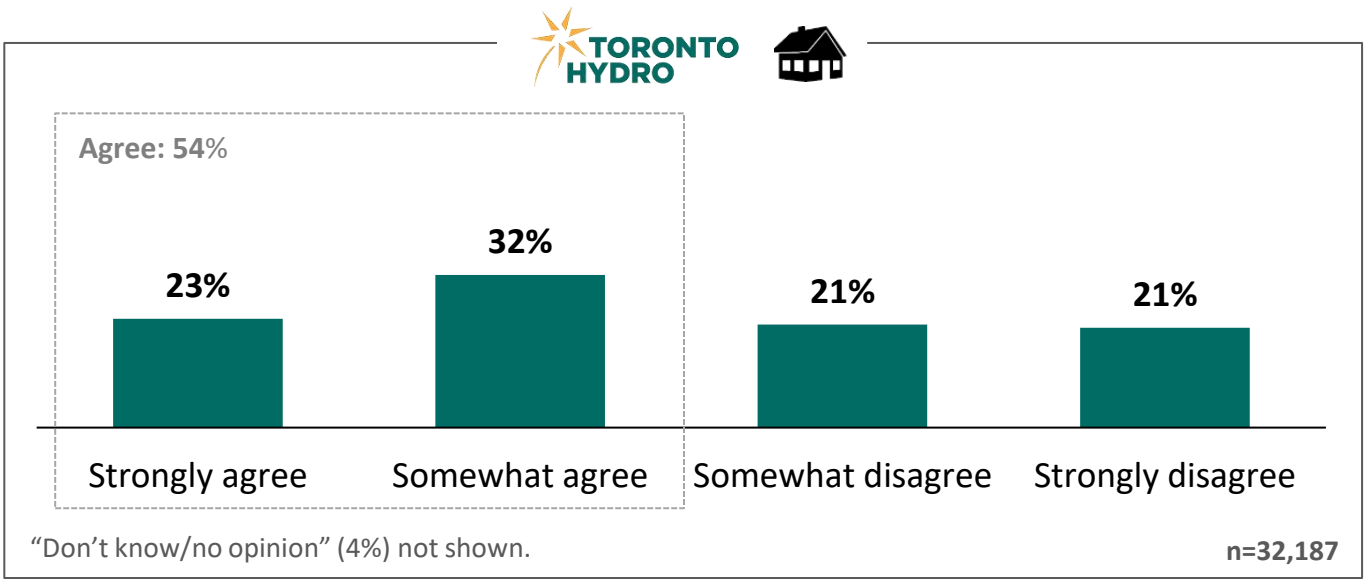
*Calculation based on household size and after-tax income.

Online Survey
Environmental Controls

Residential

To what extent do you agree or disagree with the following statements?

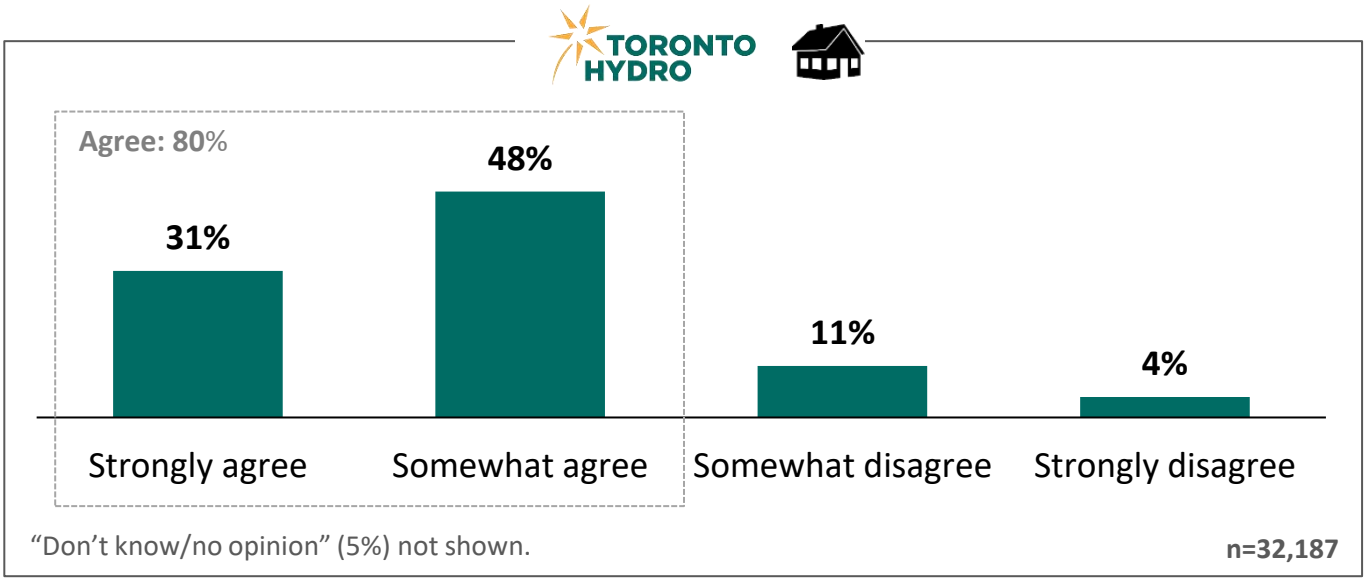
Q The cost of my electricity bill has a major impact on my household finances and requires that I do without some other important priorities.



"Don't know/no opinion" (4%) not shown.

n=32,187

Q Customers are well-served by the electricity system in Ontario.



"Don't know/no opinion" (5%) not shown.

n=32,187

INNOVATIVE RESEARCH GROUP

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Residential

Welcome to Toronto Hydro's customer feedback survey!

Toronto Hydro needs your input to find the right balance between the services you receive and the price you pay.



Land Acknowledgement: Toronto Hydro's grid is located on the traditional territory of many nations including the Mississaugas of the Credit, the Anishnabeg, the Chippewa, the Haudenosaunee and the Wendat peoples and is now home to many diverse First Nations, Inuit and Métis peoples.

The purpose of this survey is to get your feedback on the draft 2025–2029 business plan. Your feedback will help Toronto Hydro align this plan with what you need and want.

1. Your electricity rates pay for this plan, so your views must be considered.
2. You don't need to be an electricity expert to participate. The survey is focused on basic choices and provides the background information you need to answer the questions.
3. Recognizing that people absorb information in different ways, Toronto Hydro and its research partner have designed this survey to include diagrams, charts, images and videos to help explain Toronto Hydro's draft plan and what it means for you. If you prefer to skip the videos, the content is also explained in the body of the survey.
4. Depending on how much feedback you wish to provide and the number of videos watched, this survey should take approximately **20-30 minutes** to complete. If you need to pause and return later to finish the survey, your completed answers will be saved.
5. Some of the survey content may not display correctly on a mobile browser. It is strongly recommended that you complete this workbook on a desktop or laptop computer.

Those who complete the survey will be invited to enter a draw to win one of 10 "*free electricity for a year*" prizes!

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Toronto Hydro to gather your feedback, while protecting your confidentiality. Your individual answers will not be shared with Toronto Hydro in any identifiable way.

INNOVATIVE RESEARCH GROUP

WORKBOOK PREVIEW

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Residential

What is this customer engagement about?

The goal of this engagement is to share Toronto Hydro's draft five-year business plan for the future of the city's electrical grid and collect your feedback. This will help Toronto Hydro align its plans with your needs and preferences.

Click on the video below to learn about Toronto Hydro's customer engagement.



Every five years, Toronto Hydro is required to submit a plan for its proposed prices (rates) and spending to the Ontario Energy Board (OEB) for approval.

- **In 2021 and 2022, thousands of its customers told Toronto Hydro about what they need and want** to help Toronto Hydro prepare the draft 2025–2029 business plan.
- **Toronto Hydro is now looking for your input on this draft business plan** to align its investments and spending decisions with what matters to you as its customers.
- **Later this year, Toronto Hydro will present its updated business plan to the independent regulator,** the OEB. Toronto Hydro is accountable to the OEB for considering your feedback.

How will this customer engagement work?



1. The workbook explains what Toronto Hydro does and summarizes the key planning considerations that Toronto Hydro's draft plan needs to address.



2. The workbook explains how much of your electricity bill goes to Toronto Hydro, how that money is spent, and the impact of the draft plan on your 2025–2029 prices.
3. The workbook asks for your input on seven key choices that will affect the services you receive and the price you pay from 2025–2029.



Once you have finished giving feedback on the key choices, **you will have an opportunity to review and change your responses** until you feel you have found the right balance.



Want to know more about Toronto Hydro's customer engagement process? Click here.

WORKBOOK PREVIEW

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Residential

How will your feedback impact Toronto Hydro's plan and prices?

Toronto Hydro has a five-step approach to customer feedback.

✓ **1. Identify Customer Needs, Preferences, and Priorities**

In 2022, Toronto Hydro asked many types of customers from across the city about their needs and priorities for electricity distribution service.

✓ **2. Use Customer Feedback to Guide Development of Draft Plan**

Toronto Hydro planners were given summaries of the key findings from the initial customer engagement to consider as they began building their plans.

We are here

3. Collect Customer Feedback on the Draft Plan

Toronto Hydro is returning to customers to get feedback on the draft plan and ask customers how the draft plan could better meet their needs and preferences.

4. Use Customer Feedback to Finalize the Plan

Toronto Hydro will re-examine and make appropriate changes to the plan based on the feedback provided by customers in this engagement.

5. Submit the Plan to the Ontario Energy Board (OEB)

Toronto Hydro will file the plan with the OEB along with a report summarizing the results of this engagement. The OEB, consumer advocates and other interested groups will examine the plan in an open and transparent public process known as a rate application.

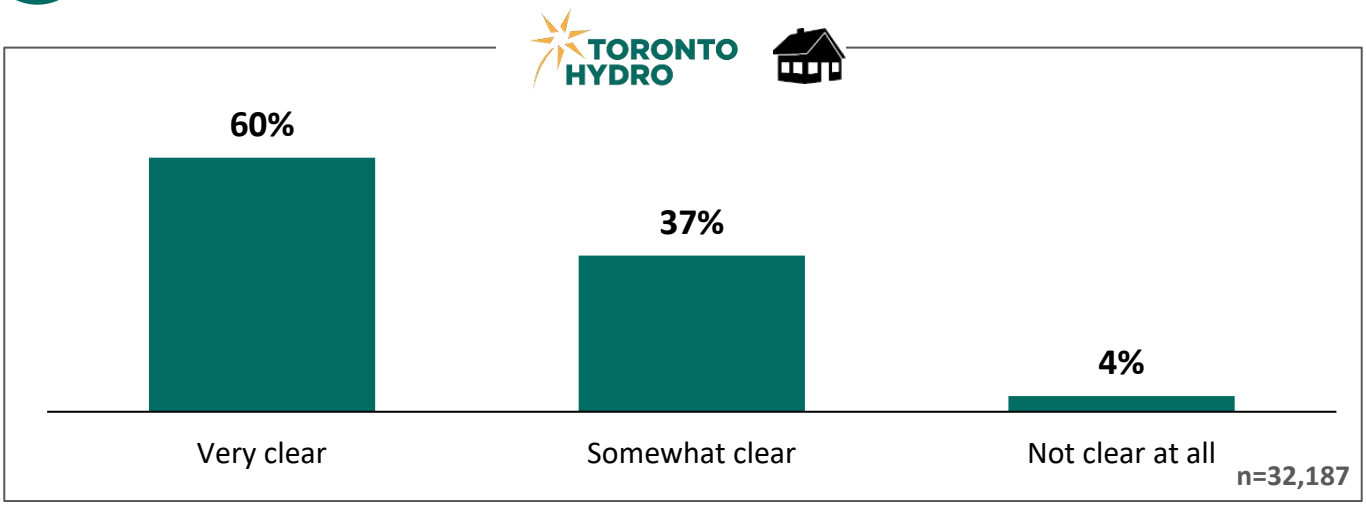
WORKBOOK PAGE

Online Workbook

Residential

Understanding the Purpose of the Customer Engagement

Q Do you feel that the purpose of Toronto Hydro's customer engagement is clear?



	Region			
	Etobicoke/York	North York	Scarborough	Toronto/East York
Very clear	60%	58%	59%	61%
Somewhat clear	36%	38%	38%	36%
Not clear at all	4%	4%	4%	4%

	LEAP Qualification			
	LEAP Qualified	Income <$52k, not Leap Qualified	Income >$52k, not LEAP Qualified	Prefer not to say
Very clear	59%	58%	64%	51%
Somewhat clear	37%	38%	34%	43%
Not clear at all	4%	4%	3%	5%

	Consumption Quartiles			
	First	Second	Third	Fourth
Very clear	60%	59%	60%	59%
Somewhat clear	37%	37%	36%	36%
Not clear at all	3%	3%	4%	4%

Electricity 101

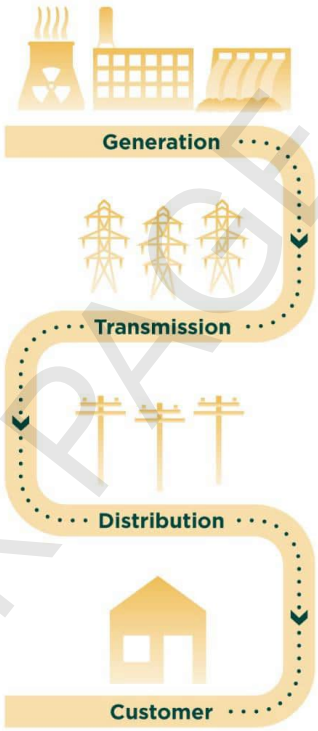
Toronto Hydro's role in Ontario's electricity system

Ontario's electricity system is made up of three parts: **generation**, **transmission** and **distribution**.

Generation

How electricity is made

About half of the electricity used in Ontario comes from nuclear power. The rest comes from a mix of hydroelectric, natural gas, wind and solar sources. Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from other generators contracted by the grid operator.



Transmission

How electricity travels across Ontario

Once electricity is made, it must be sent to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. Ontario has approximately 30,000 kilometers of transmission lines, mostly owned and operated by Hydro One.

Distribution

How electricity is delivered to you

Toronto Hydro is responsible for the last step of the journey: distributing electricity locally to end-use customers.

- Toronto Hydro does not generate or transmit electricity — it owns and operates the local electricity system made up of approximately 183,620 poles, 61,300 distribution transformers, 17,060 primary switches, 15,393 kilometers of overhead wires and 13,765 kilometers of underground cables.
- Toronto Hydro is wholly owned by the City of Toronto, but it does not receive taxpayer money — it is entirely funded by the distribution rates that you pay on your electricity bill.
- Toronto Hydro provides power to roughly 2.8 million people across the city of Toronto.

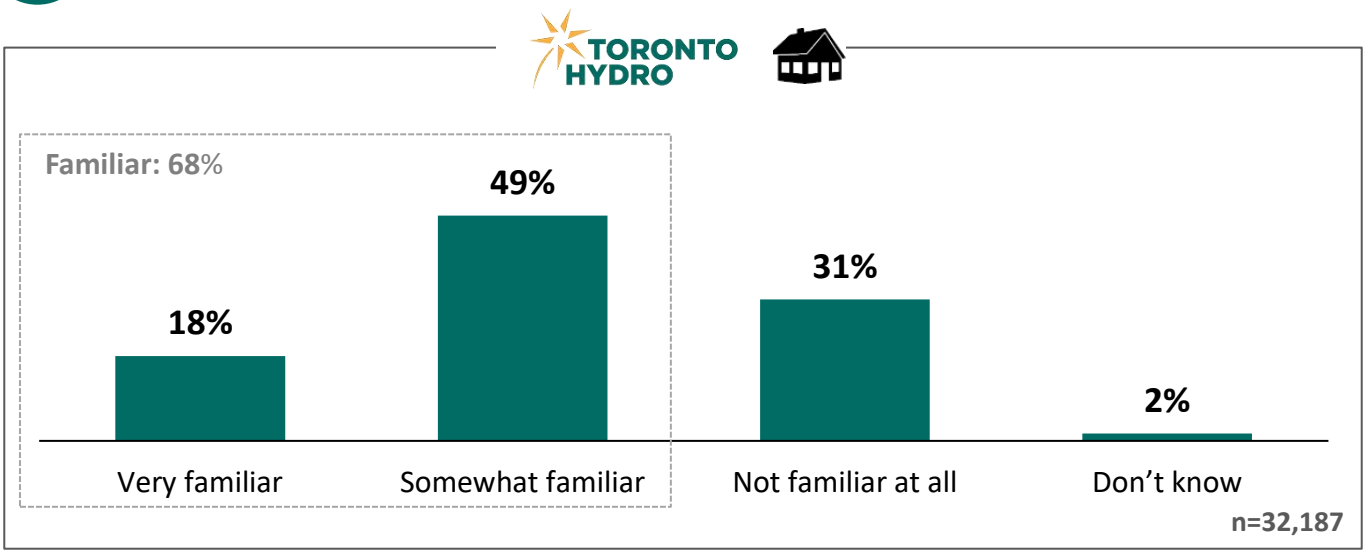
WORKBOOK PAGE

Online Workbook

Familiarity with Ontario's Electricity System

Residential

Q Before this engagement, how familiar were you with the various parts of the electricity system, how they work together and for which services Toronto Hydro is responsible?



	Region			
	Etobicoke/York	North York	Scarborough	Toronto/East York
Very familiar	20%	19%	21%	16%
Somewhat familiar	48%	50%	51%	48%
Not familiar at all	30%	29%	26%	34%
Don't know	2%	2%	2%	1%
Familiar (Very + Somewhat)	**69%**	**69%**	**72%**	**65%**

Online Workbook

Familiarity with Ontario's Electricity System

Residential

Q Before this engagement, how familiar were you with the various parts of the electricity system, how they work together and for which services Toronto Hydro is responsible?

	LEAP Qualification			
	LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
Very familiar	20%	17%	19%	17%
Somewhat familiar	46%	49%	49%	49%
Not familiar at all	30%	31%	30%	32%
Don't know	4%	2%	1%	2%
Familiar (Very + Somewhat)	**66%**	**67%**	**69%**	**66%**

	Consumption Quartiles			
	First	Second	Third	Fourth
Very familiar	15%	17%	20%	22%
Somewhat familiar	47%	50%	50%	49%
Not familiar at all	37%	31%	28%	27%
Don't know	2%	2%	1%	1%
Familiar (Very + Somewhat)	**61%**	**67%**	**71%**	**71%**

Toronto Hydro's Draft Plan

Planning Considerations

In preparing its plan, Toronto Hydro must consider many existing and emerging challenges of delivering safe, reliable and clean electricity at a reasonable price.

To learn more about what Toronto Hydro must consider in preparing its draft plan, click on the topics below.

Key challenges that Toronto Hydro's 2025–2029 draft plan addresses:



Keeping prices reasonable

- Many customers are concerned about the rising cost of living.
- Toronto Hydro must find the right balance between the investment needs of the local grid and the financial needs of its customers.



Responding to rising costs

- Like many companies, Toronto Hydro faces rising costs in purchasing equipment for the grid and doing construction work in the city.
- For example, from 2021 to 2022, the cost of buying electrical equipment increased by 9.9% while the cost of non-residential construction in the city of Toronto rose by 15.6%.



Powering a growing urban city

- Toronto is not just the largest city in Canada and an engine of the Canadian economy, it is also one of the fastest growing cities in North America.
- As the city continues to grow, the grid needs to be ready to power new condo towers, residential communities and businesses.



Fixing and replacing equipment in poor condition

- Much of Toronto Hydro's grid was installed in the 1950s and 1960s and needs to be replaced or upgraded.
- To keep the grid safe and reliable now and in the future, Toronto Hydro monitors the condition of its grid and uses this information to upgrade the equipment most at risk.



Reducing emissions from its own operations

- Toronto Hydro is committed to decarbonizing the company's footprint by 2040. To meet this goal, it must invest in reducing emissions from its vehicles and work centres.
- Toronto Hydro is expected to reduce its emissions by switching from oil and natural gas to clean electricity for powering its own operations.



Keeping up with the way customers use electricity

- Customers are using more electricity for their day-to-day energy needs, such as for transportation and electric heat pumps for home heating. They are also choosing new technologies such as solar panels and battery storage to manage their electricity usage and sell electricity to the local grid.
- To ensure customers can connect new technologies to the grid safely and reliably, Toronto Hydro needs to upgrade its equipment and modernize its systems.

WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Rate Application

Residential



Responding to extreme weather and cyber security attacks

- Extreme weather such as high heat, high winds, flooding and ice storms is increasingly straining and damaging to electricity grids.
- Cybercrime is on the rise across Canada. For example, Toronto Hydro is the target of around one million attempted cyber attacks each year, with attempts going over one million in 2022 (successfully deflected).
- Toronto Hydro needs to make the grid more resilient against extreme weather and cyber security attacks that could compromise reliability and put customers at risk.



Protecting public and employee safety

- Toronto Hydro and its customers have a strong safety record, but electricity is dangerous and safety cannot be taken for granted.
- As homes and businesses add new technologies that increase the amount of electricity flowing around us, Toronto Hydro must ensure that the grid remains safe for its employees and the public.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Residential

How much of my electricity bill goes to Toronto Hydro?

Every item on your bill is required by provincial regulation.

- Toronto Hydro collects payment for the entire electricity system, but only keeps the distribution portion of the "**Delivery**" charge. This charge pays for both Toronto Hydro's **distribution** system and Hydro One's **transmission** system, as well as line losses (power that is lost when electricity travels across the wires).
- **About 30% of the electricity bill goes to Toronto Hydro** to pay for the local distribution grid. The **remaining 70%** of the bill goes to generation companies, transmission companies, the federal and provincial governments, and regulatory agencies.

Typical Residential Bill

Sample Toronto Hydro Monthly Bill
(based on consumption of 750 kWh as of Jan. 1, 2023)

Account Number:
0000000000

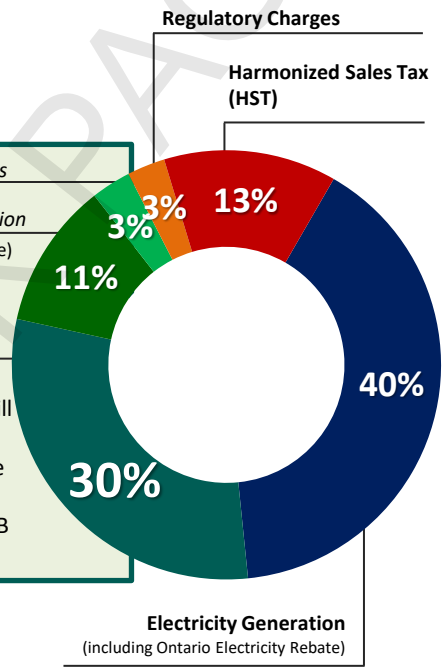
Meter Number:
00000000

Your Electricity Charges	
Electricity	
On-Peak (highest price) @ 15.1 c/kWh	20.39
Mid-Peak (mid price) @ 10.2 c/kWh	13.77
Off-Peak (lowest price) @ 7.4 c/kWh	35.52
Delivery	60.05
Regulatory Charges	4.27
Total Electricity Charges	$134.00
HST	17.42
Ontario Electricity Rebate	(-$15.68)
Total Amount	$135.74

Delivery: *Line Losses*
$4.75

Delivery: *Transmission*
(varies based on usage)
$14.60

Delivery:
Distribution
Toronto Hydro's part of the total bill is **$40.70**. This charge is the same for all residential customers per OEB requirements.



Note: For time of use Off-/Mid-/On-peak split 64%/18%/18% according to the OEB rate model. The Sample Bill is based on the OEB rates effective January 1, 2023.

Who holds Toronto Hydro accountable?

ONTARIO ENERGY BOARD

The **Ontario Energy Board (OEB)** is the public interest regulator responsible for setting electricity distribution rates (prices) and for protecting customers in Ontario.

The OEB holds Toronto Hydro accountable for:

- How it spends your money in current and future plans.
- Reporting on key outcomes (reliability) through an annual scorecard.
- Finding savings and efficiencies to absorb rising costs.

Want to know more about what Toronto Hydro has done to become more efficient? Click here.

WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Rate Application

Residential

What has Toronto Hydro done to become more efficient?

- Reduced the total number of facilities and gave back roughly $158 million to customers, resulting in a total credit of $104.66 on the average residential customer's bill from 2016 to 2021.
- Delivered approximately $10 million in reduced or avoided costs in this current 2020–2024 period by replacing outdated information systems with consolidated programs, enabling automation and lowering maintenance costs.
- Implemented new technology to automate crew scheduling, enabling Toronto Hydro to maximize crew working hours and respond to power outages quicker.

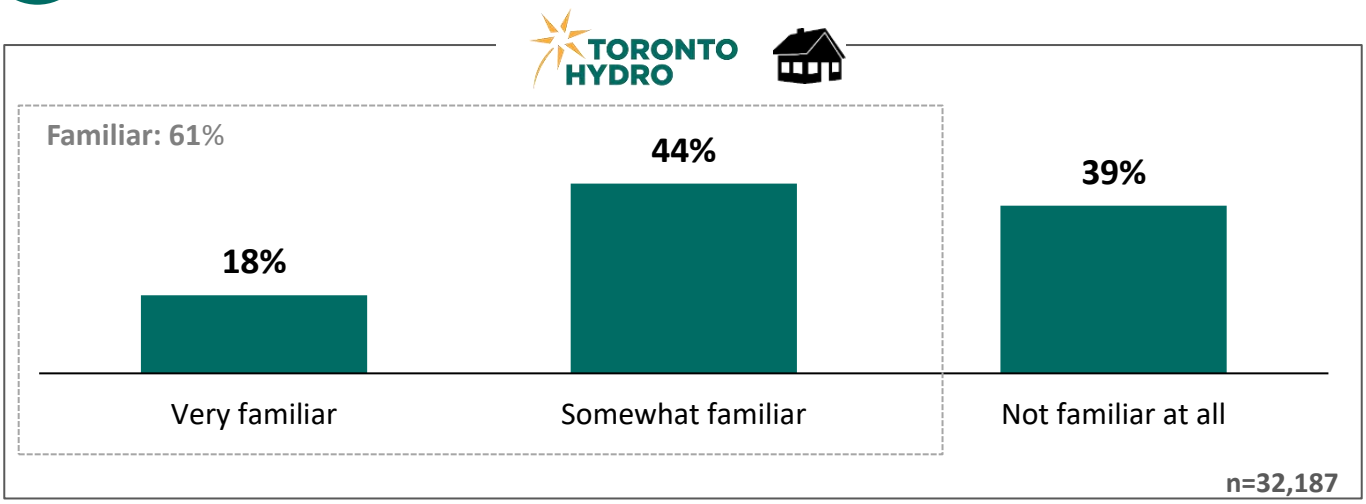
WORKBOOK PAGE

Online Workbook

Residential

Familiarity with the Percentage of Bill Remitted to Toronto Hydro

Q Before this customer engagement, how familiar were you with the amount of your electricity bill that went to Toronto Hydro?



	Region			
	Etobicoke/York	North York	Scarborough	Toronto/East York
Very familiar	19%	20%	22%	15%
Somewhat familiar	44%	46%	45%	41%
Not familiar at all	37%	34%	33%	44%
Familiar (Very + Somewhat)	**63%**	**66%**	**67%**	**56%**

	LEAP Qualification			
	LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
Very familiar	24%	20%	17%	16%
Somewhat familiar	44%	45%	42%	46%
Not familiar at all	32%	35%	41%	38%
Familiar (Very + Somewhat)	**68%**	**65%**	**59%**	**62%**

	Consumption Quartiles			
	First	Second	Third	Fourth
Very familiar	17%	18%	18%	19%
Somewhat familiar	41%	43%	45%	45%
Not familiar at all	42%	39%	37%	36%
Familiar (Very + Somewhat)	**58%**	**61%**	**63%**	**64%**

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Residential

How does Toronto Hydro propose to spend the money?

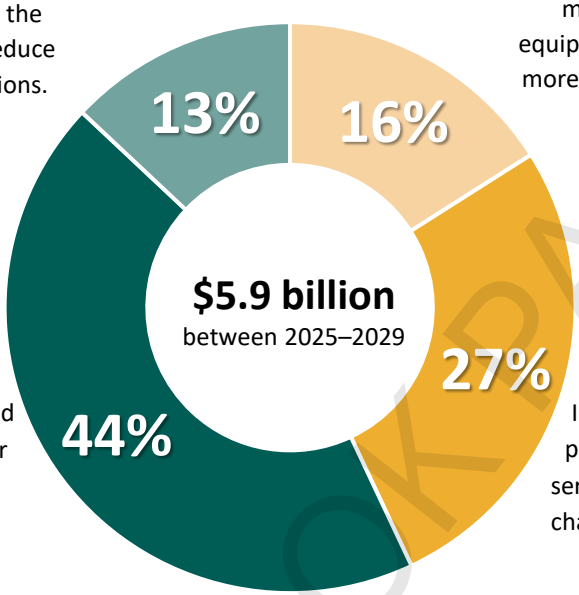
Toronto Hydro's five-year 2025–2029 draft plan is made up of four spending categories.

General Plant

Investments in vehicles, work centres and IT to keep the business running and reduce Toronto Hydro's emissions.

Modernization

Investments in technology to get more use out of existing equipment, and build a smarter, more efficient and reliable grid.



Sustainment

Investments to upkeep old equipment that is in poor condition and replace outdated equipment.

Growth

Investments in capacity to power the growing city and serve customers' growing and changing needs for electricity.

Want to know more about Toronto Hydro's current and future budgets? Click here.

How much will Toronto Hydro's draft plan cost me?

At the end of the five-year plan (2029), the typical residential customer would see the distribution portion of their electricity bill increase by **$17.18**: from an estimated rate (price) of $42.36 in 2024 to a proposed rate (price) of **$59.54 by 2029**.

Rate Period	Year	Avg. Monthly Bill	Toronto Hydro Portion	Toronto Hydro's Portion: Annual Increase (%)	Toronto Hydro's Portion: Annual Increase ($)
	2023	$135.74	$40.70	n/a	n/a
	2024	$135.11	$42.36	4%	$1.66
	2025	$139.55	$46.76	10%	$4.40
	2026	$142.10	$49.28	5%	$2.52
	2027	$145.26	$52.39	6%	$3.11
	2028	$150.04	$57.11	9%	$4.72
	2029	$152.51	$59.54	4%	$2.43
	5-yr impact		**$17.18**	**41%**	**$17.18**

Note: These estimated rate increases are preliminary and are subject to change based on customer feedback and other factors. A typical residential customer is assumed to use 750 kWh per month and enrolled under Time-of-use Regulated Price Plan. Bill projections assume that other aspects of the electricity bill that are outside of Toronto Hydro's control (commodity, transmission, government, regulatory fees) remain constant.

WORKBOOK PAGE

Toronto Hydro Background

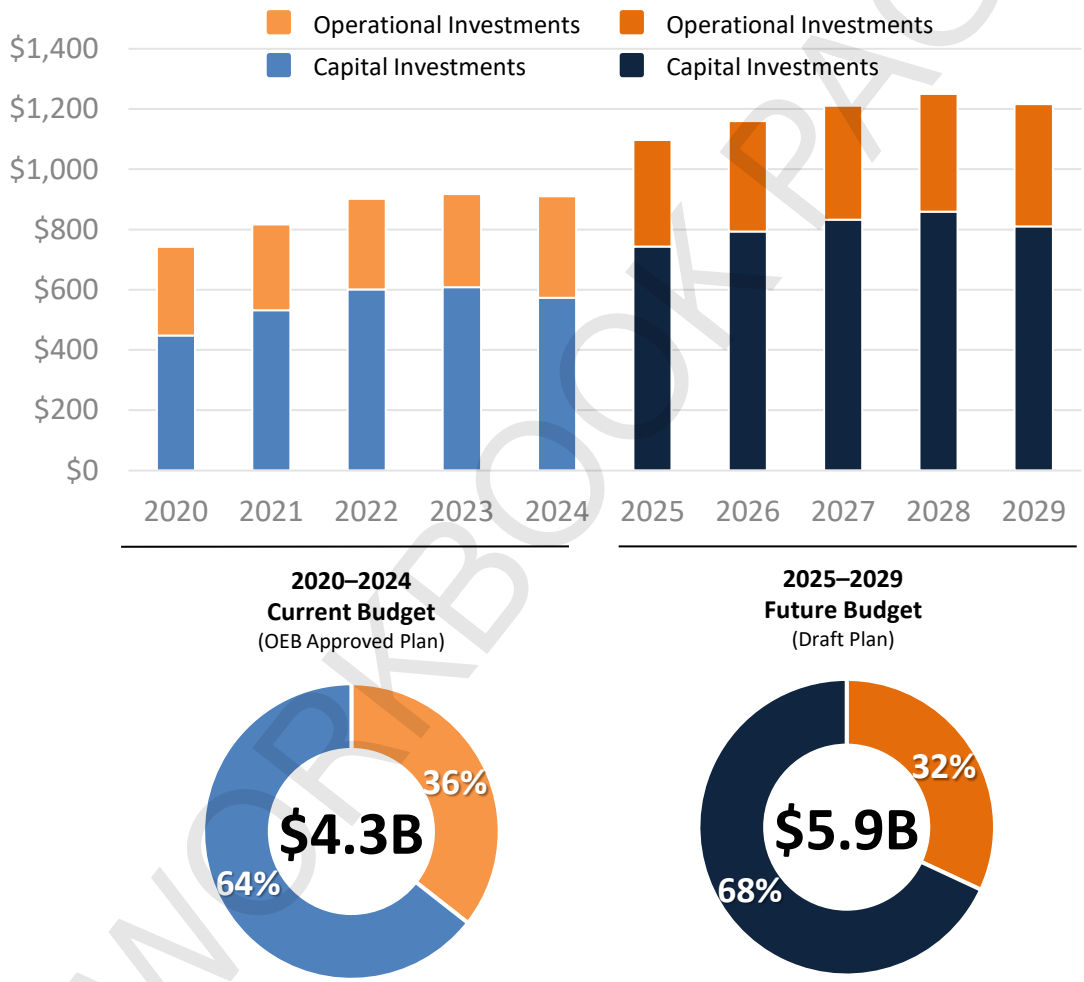
How much does it cost to run the local grid?

To run the local grid and serve customers, Toronto Hydro manages two budgets:

1. A **capital investment** budget which pays for the cost of buying and constructing physical infrastructure such as poles, wires, transformers, facilities, trucks and computers.

2. An **operational investment** budget which pays for maintenance and operation of the equipment, as well as the staff needed to manage the grid and serve customers daily.

Current and Future Budgets per year ($ millions)



WORKBOOK PAGE

The current five-year budget of **$4.3 billion** is based on the 2020–2024 plan approved by the OEB in a previous rate application. As mentioned earlier, this amount is funded by your 2020–2024 distribution rates.

The future five-year budget of **$5.9 billion** is based on the 2025–2029 draft plan presented in this customer feedback survey. The final budget for this next rate period will be adjusted to reflect customer feedback collected through this engagement and will be subject to extensive OEB review before rates are set for 2025–2029.

How does the survey work?

The next sections are about 7 key choices that Toronto Hydro needs to make to finalize its plan.

Each section provides some key background information. We encourage you to take the time to learn about your local electricity grid and where your money is going.

We also understand that life is busy. Many people find this information interesting — but if you would prefer to skip over the videos or the background information, you can jump right to the key choices.

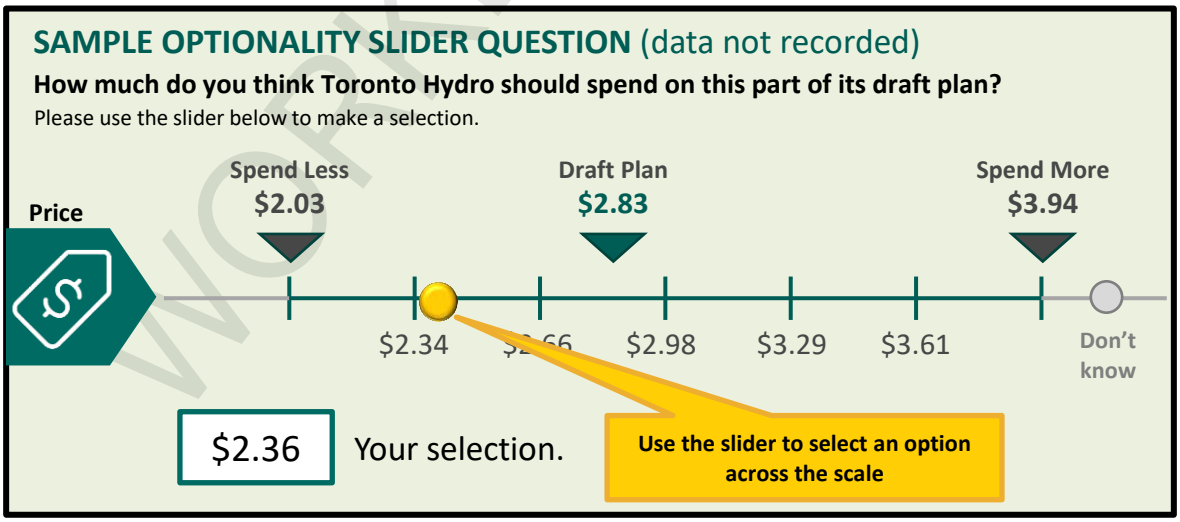
How do I make choices?

Each choice has a summary of three options that Toronto Hydro considered:

- **Spend Less:** A minimum spending option that keeps prices lower and meets the basic performance requirements but may entail some trade-offs on key outcomes, such as reliability.
- **Toronto Hydro's Draft Plan:** An option currently in the draft plan which makes additional progress toward key outcomes but delays some important work.
- **Spend More:** A faster paced spending option that makes additional progress towards better outcomes while recognizing practical limits due to resources and construction issues.

In each option, there is a sliding scale that enables you to dial the draft plan up or down. While Toronto Hydro's technical experts can tell us the maximum and minimum amounts we can practically spend, the balance of how much Toronto Hydro spends on the spectrum is up to customers like you.

At the end of the survey, you will get a summary of your choices and you will have the opportunity to change your answers to find the right balance for you.



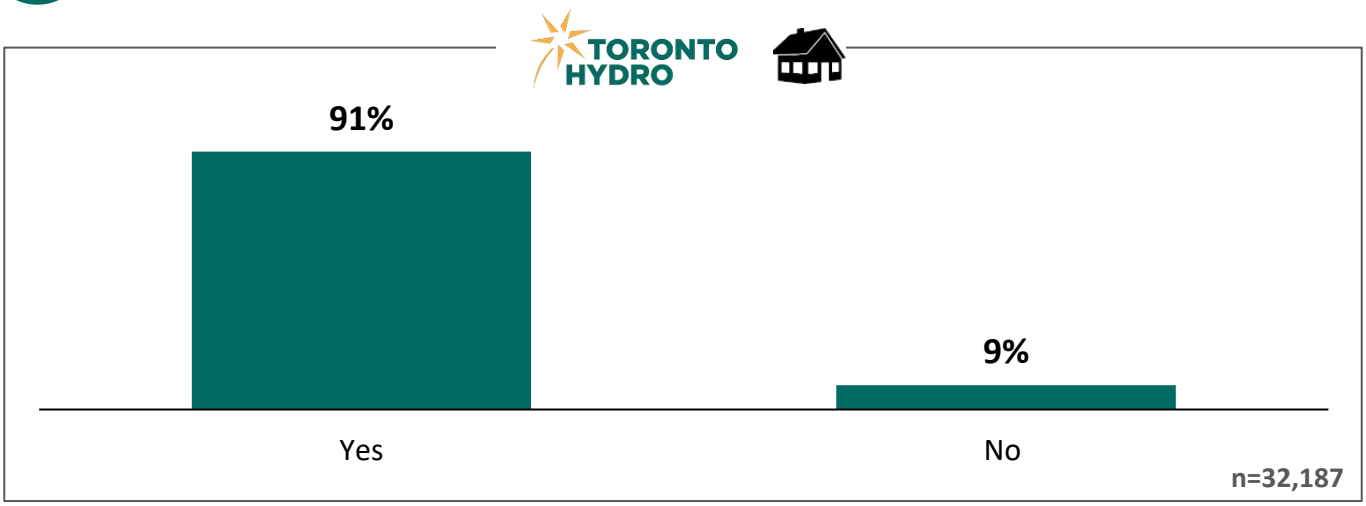
WORKBOOK PAGE

Online Workbook

Understanding the Slider

Residential

Q Is it clear that you can move the slider to any amount you feel best reflects your personal view of the best balance between lower costs and faster improvements?



	Region			
	Etobicoke/York	North York	Scarborough	Toronto/East York
Yes	91%	90%	90%	93%
No	9%	10%	10%	7%

	LEAP Qualification			
	LEAP Qualified	Income <$52k, not Leap Qualified	Income >$52k, not LEAP Qualified	Prefer not to say
Yes	86%	91%	94%	88%
No	14%	9%	6%	12%

	Consumption Quartiles			
	First	Second	Third	Fourth
Yes	90%	91%	92%	92%
No	10%	9%	8%	8%

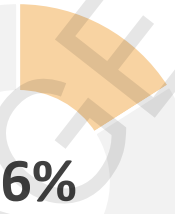
Draft Modernization Plan

Build a Smarter, More Efficient and Resilient Grid

What is this section about?

- This section explains how technology is changing the way customers use electricity and how Toronto Hydro operates and manages the grid to make it smarter, more efficient and resilient for customers.

  Want to learn more about how grid modernization benefits you? Click on the topics below.



- **Toronto Hydro's draft modernization plan enables:**
  - Faster and cheaper power restoration
  - More efficient use of existing equipment
  - Customer choice to adopt new technologies
  - Resilience against weather and cyber attacks

- This spending category makes up **16% of the draft plan** and would add **$2.83** on the average residential customer's monthly bill by 2029.

*Click on the video below to learn about Toronto Hydro's **draft modernization plan**.*



WORKBOOK PAGE

Modernization Plan

Building a Smarter, more Efficient and Reliable Grid

Toronto Hydro's Modernization Plan has four main objectives:

Faster and cheaper power restoration



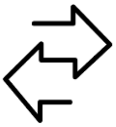
- Through automation, the smart grid can achieve self-healing capabilities. This means that the distribution grid on your street will be able to locate outages and restore power automatically.
- The smart grid enables Toronto Hydro to reduce the number and length of outages customers experience. It also reduces manual costs (trucks and crews) of responding to power outage events.

More efficient use of existing equipment



- As customers use more electricity, some equipment will reach its limits. Sensors and meters detect when and where these limits are approaching, enabling Toronto Hydro to make better decisions.
- The smart grid enables Toronto Hydro to get more use out of the existing equipment so that it can serve a greater customer need for electricity without having to build as much new infrastructure.

Customer choice to adopt new technologies



- Sensors, switches and software enable Toronto Hydro to monitor and control the flow of electricity so that customers can choose technologies to produce, store and sell power to the grid.
- The smart grid is designed to allow safe and reliable two-way power flow — from the grid to the customers and from customers to the grid. This system can reduce costs and makes the local grid more resilient to outages.

Resilience against weather and cyber attacks



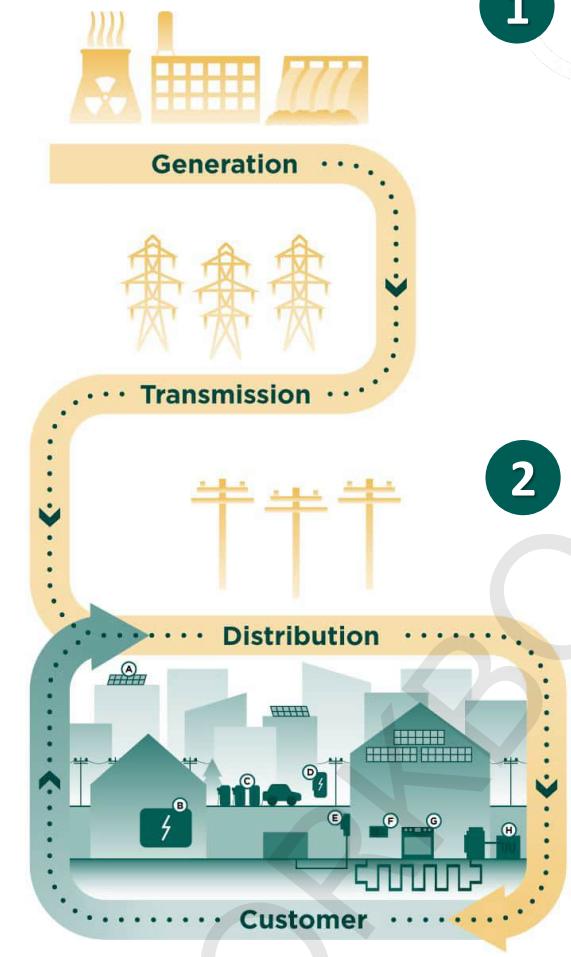
- Cyber attacks are increasing and getting more complex. Toronto Hydro must be prepared to respond to these threats to maintain reliable service and protect customer information.
- In addition to being able to restore power quicker, the smart grid can sense when environmental conditions like flooding pose a risk. This enables grid operators to strengthen the grid.

WORKBOOK PAGE

Modernization: Changing Technology, Changing Needs

For more than 100 years, things changed relatively slowly in terms of grid technology. Electricity was generated in large power stations and transmitted from around the province to Toronto Hydro's grid, and ultimately to homes and businesses. That is all changing, and because of technological advancement, the pace of change could be fast.

Toronto Hydro's 2025–2029 plan is shaped by two key changes in technology:



A. Solar panel
B. Battery storage
C. Public electric vehicle charging station
D. On-site backup generation
E. Smart meter
F. Home energy manager
G. Energy-efficient appliances
H. Heat pump

1 **Technologies that change how customers use electricity.** These include:

- Electricity products like electric vehicles, heat pumps and electric stoves that enable customers to use less fossil fuels (oil and gas), which contribute to climate change.
- Technologies like solar panels and battery energy storage that allow customers to produce and manage their electricity as well as sell it back onto the grid.

2 **Technologies that change how Toronto Hydro operates the grid**. These key changes are:

- The grid must shift from a **one-way system** that only sends electricity to customers to a **two-way system** that allows customers to generate and sell electricity to the grid.
- **Smart grid technology like sensors and automation** enables Toronto Hydro to monitor key equipment to prevent outages and get better use out of existing equipment. When outages do occur, this technology can re-route the grid to restore power much more quickly and at a lower cost than today.

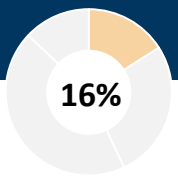
WORKBOOK PAGE

How much electricity does it take to charge an Electric Vehicle (EV)?

Did you know that when an EV is charging it can use as much electricity as two average homes? If everyone in a neighbourhood came home from work or school and started charging their EVs at the same time, the electricity demand could overload the grid.

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Modernization Plan

Residential



Making Choices: **Modernization**

By 2029, Toronto Hydro's draft **modernization plan** would cost the typical residential customer **$2.83** more per month on their monthly electricity bill. Toronto Hydro could spend more to increase the pace of modernizing the grid to get better reliability sooner, or it could spend less and slow down the progress.

	Spend Less	Draft Plan	Spend More
Reliability	Being ready to automate the grid by 2035 means that better reliability won't happen until the end of the next decade or beyond.	Being ready to automate the grid by 2030 means that better reliability will happen in the earlier part of the next decade.	Faster progress towards grid automation means better reliability earlier and improved reliability for critical loads located in the downtown area.
Customer Service	May reduce service levels (longer waits and higher costs) for some customers connecting new services. May reduce customer choice for new technologies.	Maintains service levels for customers connecting new services to the grid. Enables customer choice for new technologies such as solar panels.	Same as draft plan.
Efficiency	It will take longer for the grid to become more efficient. This may lead to higher costs in the next decade.	The grid will become more efficient in the next decade, which will help reduce costs.	Same as draft plan.

Choice 1 of 7:

Price

Spend Less **$2.03** | Draft Plan **$2.83** | Spend More **$3.94**

$2.34 | $2.66 | $2.98 | $3.29 | $3.61 | Don't know

$-.-- Your selection.

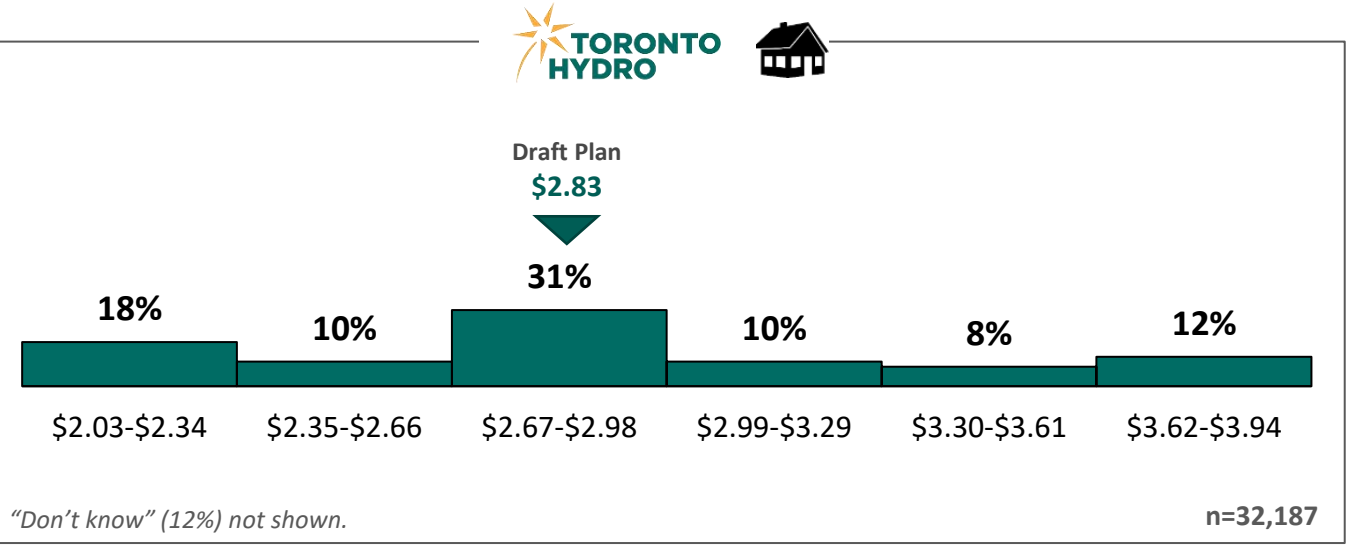
WORKBOOK PAGE

Online Workbook

Amount Spent on the Modernization Plan

Residential

Q How much do you think Toronto Hydro should spend on its modernization plan?



"Don't know" (12%) not shown.

n=32,187

	Overall	Region			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York
Below Plan	30%	31%	33%	35%	27%
On Plan	26%	26%	25%	24%	27%
Above Plan	32%	31%	26%	26%	38%
Don't Know	12%	11%	16%	15%	8%
TOTAL On Plan + Above Plan	58%	57%	51%	50%	65%

Online Workbook

Amount Spent on the Modernization Plan

Residential

Q How much do you think Toronto Hydro should spend on its modernization plan?

	Overall	LEAP Qualification			
		LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
Below Plan	30%	37%	34%	26%	37%
On Plan	26%	20%	23%	28%	26%
Above Plan	32%	19%	26%	39%	25%
Don't Know	12%	25%	16%	7%	13%
TOTAL On Plan + Above Plan	58%	38%	50%	67%	51%

	Overall	Consumption Quartiles			
		First	Second	Third	Fourth
Below Plan	30%	33%	31%	30%	28%
On Plan	26%	26%	26%	26%	25%
Above Plan	32%	28%	31%	33%	36%
Don't Know	12%	13%	12%	11%	11%
TOTAL On Plan + Above Plan	58%	54%	58%	60%	61%

Online Workbook

Additional Feedback on the Modernization Plan

Residential

Q Do you have additional feedback on Toronto Hydro's draft modernization plan?

Response	%
Modernize, be proactive, invest for the long term	2.7%
Prioritize renewables, solar/wind, and electric vehicles	1.7%
Prevent outages, stable power, system reliability	1.4%
Find efficiencies, cut wasteful spending, lower salaries	1.2%
Costs are too high already, cost of living, struggling to pay bills	1.1%
Need more information	1.0%
Support the increase (general)	0.9%
Oppose the increase, increase is too high (general)	0.8%
Cost shouldn't be borne by all customers	0.6%
Support developing new technology and innovation	0.3%
Should be funded by tax dollars/government	0.3%
Address equity, protect low-income customers	0.2%
Should be funded by developers	0.1%
Other	0.6%
No response	87.2%

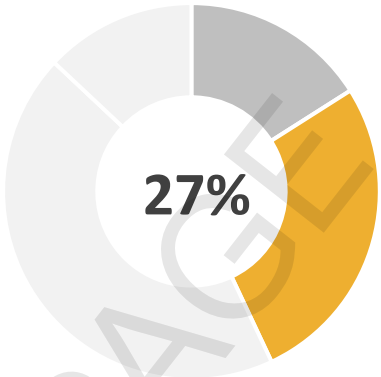
Note: Responses were optional. Only responses > 0.1% are shown.

Draft Growth Plan

Increase Capacity to Serve Customers

What is this section about?

- This section explains how fast the city of Toronto is growing and what it takes for the grid to serve customers' needs for more electricity.
- Toronto Hydro's draft growth plan is about increasing grid capacity to serve customers reliably now and in the future.



- This spending category makes up **27% of the draft plan** and would add **$4.62** on the average residential customer's monthly bill by 2029.

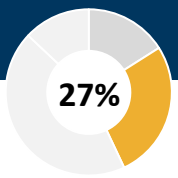
*Click on the video below to learn about Toronto Hydro's **draft growth plan**.*



WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Growth Plan

Residential



Growing City, Growing Needs

1 Toronto is growing, fast.

Toronto is one of the fastest growing cities in North America. A growing city means that we need a bigger local grid so that homes and businesses can get the power they need, when they need it.



Population Growth

Toronto will add approximately 500,000 more people this decade. To put this into context, Toronto is growing five times faster than Los Angeles.



230 Cranes
Toronto has led the crane count in North America since 2015.



2,114 Projects
including residential and non-residential in development in the city of Toronto.



+$1B in Construction
work planned for city infrastructure in Toronto annually (transportation and water).

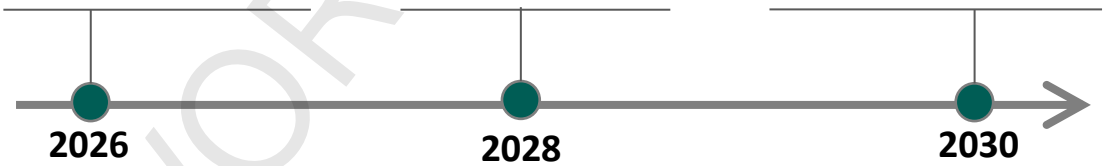
2 Individual customers will use more electricity than ever before.

The average customer will use more electricity in the next 10–15 years, as governments encourage businesses and communities to use less fossil fuels (oil and gas) to address climate change. Here are the key government policies that drive the need for more electricity in Toronto:

The Government of Canada may require 20% of all new car sales to be zero emission and is working towards a target of 60% by 2030.

The City of Toronto Green Building Standard requires all new mid- and high-rise buildings to be near zero GHG emissions.

The carbon tax may increase 161% by 2030 so customers use less oil and gas, and switch to clean electricity for cooking, heating and transportation.



23% **Forecasted increase in customers' need for electricity by the year 2030.**

Conservation and energy efficiency has helped manage electricity use over the past 20 years and will continue to play an important role in the future. But conservation alone is not enough. We need a bigger grid to serve customers in the long term.

WORKBOOK PAGE

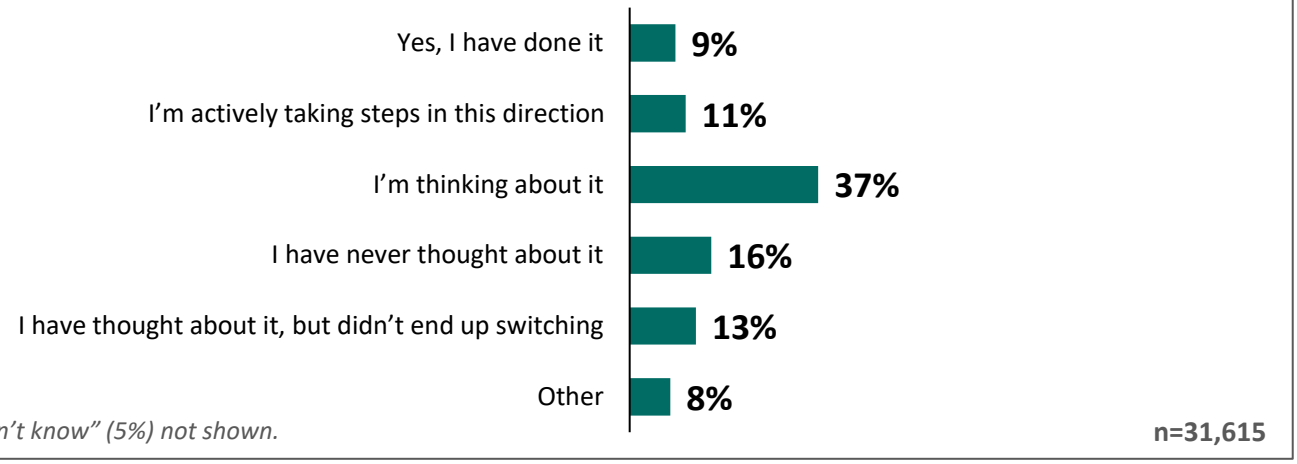
Online Workbook

Amount Spent on Growth Plan

Residential

Q When you think about all your energy bills, has your household ever considered shifting from one energy source to another to save money or reduce your impact on the environment?

For example, changing from a natural gas-fuelled furnace to an electric heat pump, or from a gas-fuelled vehicle to an electric vehicle?



	Region			
	Etobicoke/York	North York	Scarborough	Toronto/East York
Yes, I have done it	9%	9%	9%	10%
Actively taking steps	10%	11%	11%	11%
I'm thinking about it	38%	38%	40%	36%
I have never thought about it	16%	17%	17%	15%
I didn't end up switching	14%	14%	15%	12%
Other	8%	6%	4%	11%

Note: Responses were optional.

Online Workbook

Amount Spent on Growth Plan

Residential

Q When you think about all your energy bills, has your household ever considered shifting from one energy source to another to save money or reduce your impact on the environment?

For example, changing from a natural gas-fuelled furnace to an electric heat pump, or from a gas-fuelled vehicle to an electric vehicle?

	LEAP Qualification			
	LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
Yes, I have done it	11%	9%	10%	8%
Actively taking steps	12%	11%	11%	8%
I'm thinking about it	33%	34%	40%	36%
I have never thought about it	18%	18%	15%	17%
I didn't end up switching	10%	12%	14%	16%
Other	7%	11%	8%	9%

	Consumption Quartiles			
	First	Second	Third	Fourth
Yes, I have done it	8%	8%	9%	13%
Actively taking steps	10%	11%	11%	11%
I'm thinking about it	32%	38%	41%	38%
I have never thought about it	19%	17%	15%	14%
I didn't end up switching	10%	14%	15%	15%
Other	14%	8%	6%	5%

Note: Responses were optional.

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Growth Plan

Building a bigger grid takes time

It's easy to say Toronto needs more electricity, but meeting this need requires Toronto Hydro to make major investments in the grid, including:



Expand Transformer Stations

Bring more power into the city from the provincial grid to serve growing communities along the new transit corridors (Eglinton LRT, Finch LRT, Ontario Line) and the redevelopment of areas like Downsview Park and the Portlands.



Upgrade and Reconfigure the Grid

Make more space on the grid to enable customers to plug in. Upgrade equipment like cables and transformers and reconfigure how the existing system serves customers to make more space on the grid to accommodate new services like electric vehicle charging stations and solar panels.



Major Infrastructure Developments

Connect major projects like the Finch Light Rail Transit system and the Ontario Line, and relocate Toronto Hydro's grid equipment to enable these and other major infrastructure developments to be constructed in the city.

This work cannot happen quickly. Toronto is densely populated and congested. **Building new power lines and stations takes years of planning and construction.** There are also equipment and resource constraints that limit how quickly Toronto Hydro can build a bigger grid.

Managing Uncertainty

Toronto Hydro develops its forecast from information such as building permits and projected electric vehicle sales. However, customer adoption of new technology is uncertain due to:

Supply chain issues such as equipment and resource shortages can affect the availability of customer technologies.

Technological advancements can lead to fast cost reductions. For example, the price of lithium ion batteries (EVs) decreased by 79% from 2013 to 2022.

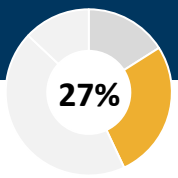
Government policies such as rebates for electric vehicles and solar panels drive customers and suppliers to make certain choices.

If Toronto Hydro invests too quickly to build a bigger grid, it means customers' rates will go up to pay for equipment that will not be used for some time. On the other hand, if it doesn't do enough to expand the grid for higher use of electricity, customers could experience less reliability (brownouts) and delays when they want to connect to the grid or plug in new technologies. Toronto Hydro needs your input on the pace for these investments.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Growth Plan

Residential



Making Choices: **Growth**

By 2029, Toronto Hydro's draft **growth plan** would cost the typical residential customer **$4.62** more per month on their monthly electricity bill. Toronto Hydro could spend more to better prepare the grid to serve customers' changing needs, or could spend less and wait and see if customers adopt new technologies over the 2025–2029 plan.

	Spend Less	Draft Plan	Spend More
Reliability	May lead to less reliability for customers in high-growth neighbourhoods. Increases reliability risk for the next decade.	Maintains reliability for customers in high-growth neighbourhoods. Manages reliability risk for the next decade.	Maintains reliability for customers in high-growth neighbourhoods. Improves reliability risk for the next decade.
Customer Service	May reduce service levels (longer waits and higher costs) for some customers connecting new services. May reduce customer choice for new technologies.	Maintains service levels for customers connecting new services to the grid. Enables customer choice for new technologies such as solar panels.	May improve service levels (shorter waits and lower costs) for some customers connecting new services to the grid. Improves customer choice for new technologies.
Efficiency	May lead to less efficient work if Toronto Hydro has to build a bigger grid reactively to serve customers.	Supports the ability to serve customers efficiently in the five-year plan based on the projected demand.	Supports the ability to serve customers efficiently in the five-year plan and beyond in the next decade.

Choice 2 of 7:

Price

Spend Less **$3.40** | Draft Plan **$4.62** | Spend More **$5.81**

$3.79 | $4.19 | $4.60 | $5.00 | $5.40 | Don't know

$-.-- Your selection.

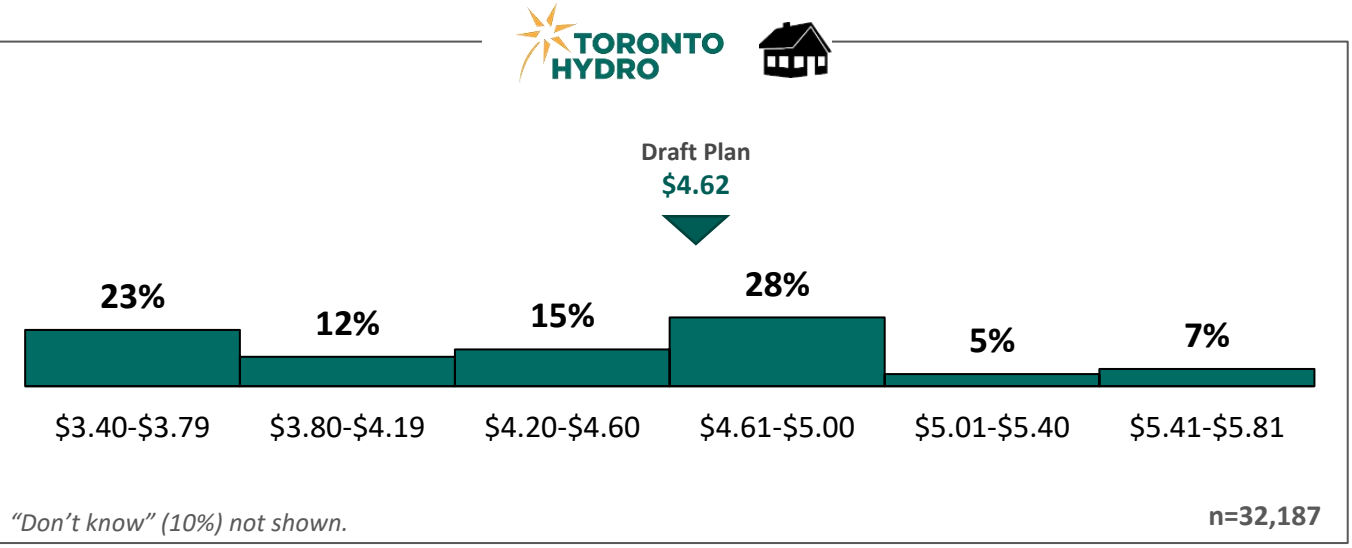
WORKBOOK PAGE

Online Workbook

Amount Spent on the Growth Plan

Residential

Q How much do you think Toronto Hydro should spend on its growth plan?



"Don't know" (10%) not shown.

n=32,187

	Overall	Region			
		Etobicoke/York	North York	Scarborough	Toronto/East York
Below Plan	42%	43%	45%	45%	39%
On Plan	28%	27%	25%	24%	31%
Above Plan	20%	19%	16%	17%	23%
Don't Know	10%	10%	14%	14%	7%
TOTAL On Plan + Above Plan	47%	47%	40%	41%	54%

Online Workbook

Amount Spent on Growth Plan

Residential

Q How much do you think Toronto Hydro should spend on its growth plan?

	Overall	LEAP Qualification			
		LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
Below Plan	42%	47%	45%	38%	48%
On Plan	28%	18%	24%	31%	26%
Above Plan	20%	12%	16%	25%	14%
Don't Know	10%	23%	15%	6%	12%
TOTAL On Plan + Above Plan	47%	30%	40%	56%	40%

	Overall	Consumption Quartiles			
		First	Second	Third	Fourth
Below Plan	42%	46%	42%	41%	40%
On Plan	28%	25%	28%	28%	28%
Above Plan	20%	17%	19%	21%	22%
Don't Know	10%	12%	11%	10%	10%
TOTAL On Plan + Above Plan	47%	43%	47%	49%	50%

Online Workbook

Additional Feedback on the Growth Plan

Residential

Q Do you have additional feedback on Toronto Hydro's draft growth plan?

Response	%
Modernize, be proactive, invest for the long term	1.5%
Prioritize renewables, solar/wind, and electric vehicles	1.0%
Find efficiencies, cut wasteful spending, lower salaries	0.9%
Should be funded by developers	0.9%
Costs are too high already, cost of living, struggling to pay bills	0.8%
Need more information	0.7%
Oppose the increase, increase is too high (general)	0.7%
Prevent outages, stable power, system reliability	0.7%
Cost shouldn't be borne by all customers	0.5%
Support the increase (general)	0.5%
Should be funded by tax dollars/government	0.3%
Support developing new technology and innovation	0.2%
Address equity, protect low-income customers	0.1%
Other	0.5%
No response	90.7%

Note: Responses were optional. Only responses > 0.1% are shown.

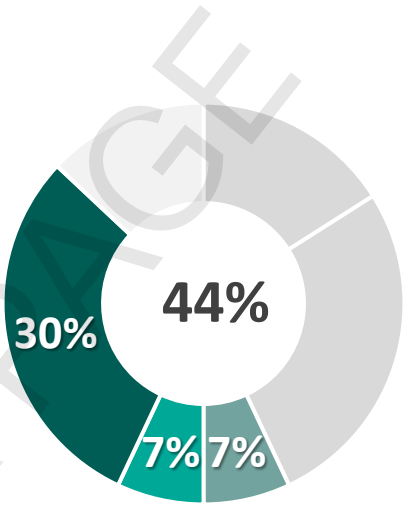
Draft Sustainment Plan

Replacing and Updating Equipment

What is this section about?

- This section is about upkeeping the grid to manage reliability and maintain safe and efficient operations.
- Toronto Hydro's draft sustainment plan section seeks your input in three areas:

1. Managing equipment in very poor condition with a high risk of failure.
2. Pacing the upkeep of equipment near the end of its expected life.
3. Standardizing outdated equipment.



- This spending category makes up **44% of the draft plan** and would add **$7.52** on the average residential customer's monthly bill by 2029.

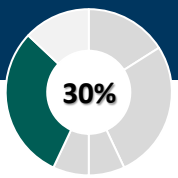
*Click on the video below to learn about Toronto Hydro's **draft sustainment plan**.*



WORK BOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Sustainment Plan

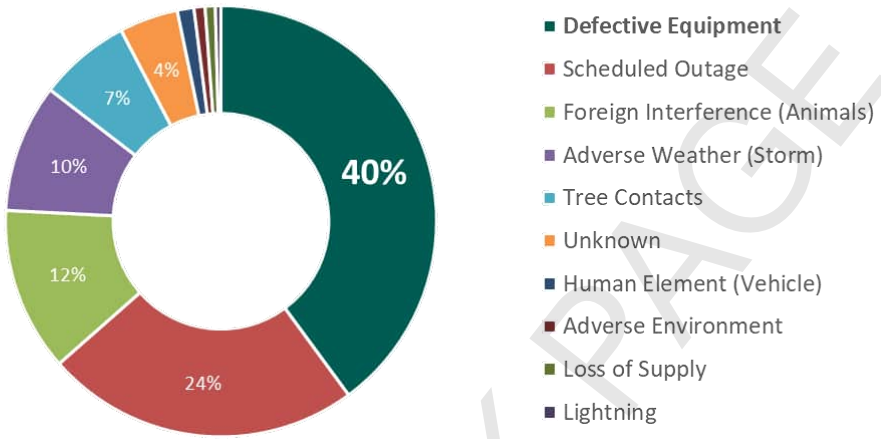
Residential



1 Reliability: Managing Equipment Failure Risk

While many power outages are caused by external events such as weather and falling trees, roughly **40%** of customer outages are caused by equipment failure. This is the largest single cause of outages, and customers look to Toronto Hydro to manage this risk.

Customer Outage Duration (Hours) by Cause 2018-2022



Toronto Hydro manages failure risk by:

- Inspecting equipment condition regularly, so that maintenance or replacement can be done before the equipment fails.
- Replacing and repairing equipment that is in bad condition or performing poorly. This includes replacing lines with a high number of outages or replacing transformers with visible signs of wear and tear such as rust.

Since 2014, Toronto Hydro's work to upkeep the grid has delivered a 13% reduction in the average number of outages experienced by customers and a 25% reduction in the length of those outages. Toronto Hydro's draft plan is to maintain these reliability results for customers.

Want to learn more about grid reliability and what causes power outages? Click here.

What type of work is Toronto Hydro doing to manage equipment failure risk?

Below is an example of a key investment that Toronto Hydro needs to make to prevent increased outages due to equipment failure.



Replacing Direct-Buried Cable

In parts of the grid that were built a long time ago, cables are laid directly in underground trenches without any protective barrier. **Underground equipment failures contribute to 57% of defective equipment failures, the large majority of which (75%) are due to cables.** Toronto Hydro's draft plan intends to replace 182 kilometers of direct buried cables by 2029 to manage the risk of power outages caused by this equipment.

WORKBOOK PAGE

System reliability

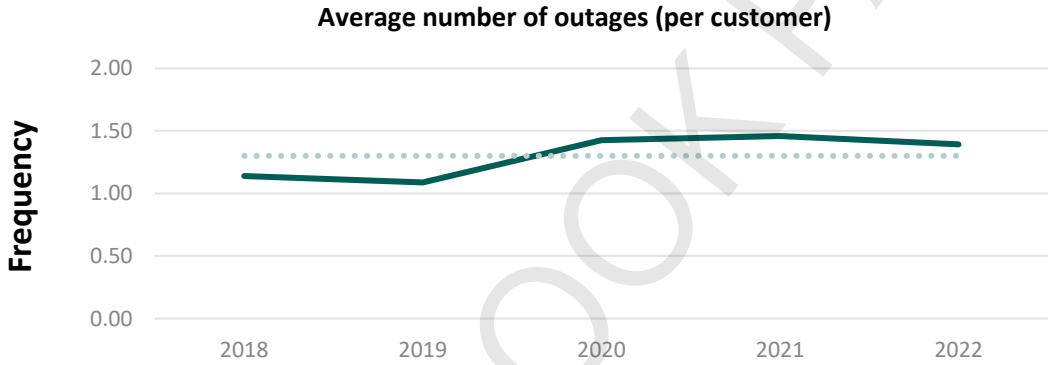
In order to provide feedback on Toronto Hydro's plans, it's important to understand how the distribution system has performed in the past, as well as what's expected in the future.

A core objective of Toronto Hydro's plan is to maintain current levels of reliability over the 2025–2029 plan period, while making foundational technology investments to reduce the length of power outages in the long-term.

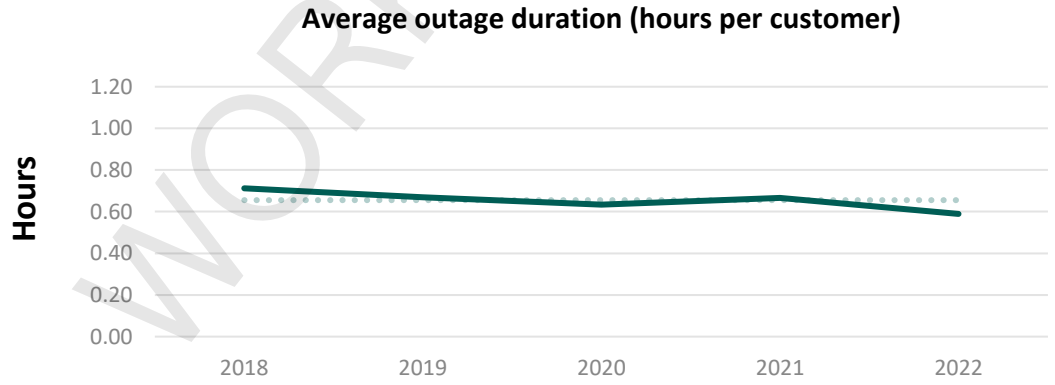
Toronto Hydro recognizes that power interruptions are inconvenient for residential customers and can be very costly for commercial and industrial customers.

Toronto Hydro tracks both the average number of power outages per customer and how long those interruptions last.

Between 2018 and 2022, the typical Toronto Hydro customer has experienced about two outages per year (*or 1.3 outages per customer to be exact*).



Over the same period, the average **duration** of an outage has been about 0.62 hours. Meaning, when the power does go out, Toronto Hydro is typically able to restore power in about 35 minutes.



It's important to keep in mind that these are system averages, and that your actual experience may be different. Some customers connected to newer lines may not experience any outages, while others are experiencing more than the average number of outages each year.

WORKBOOK PAGE

What is most likely to cause an outage?

Although both the number and length of outages have decreased compared to the previous five-year average, equipment failure remains the top cause of outages within Toronto Hydro's control.

That said, in 2022, severe weather presented a unique set of challenges for Toronto Hydro's distribution system.

Causes of Unscheduled Power Outages (five-year average: 2018 to 2022)



12%

Animal Contact: Outages caused by animals such as racoons, squirrels and birds coming in contact with overhead powerlines or transformers.



40%

Equipment Failure: Unscheduled power outages from equipment failure usually occur with distribution equipment that's beyond or approaching the end of their expected useful lives.



10%

Weather-Related Events: Adverse weather such as heavy rain, lightning strikes, ice, snow, wind, extreme temperatures, and freezing rain can disrupt the distribution system.



14%

Other: Includes tree contact (7%) and human interference (1%), such as construction workers accidentally cutting powerlines or motor vehicle accidents involving contact with distribution equipment. 4% of outages are unknown, but most are likely caused by animal contact.

Note: *statistics do not include loss of supply from Hydro One.*

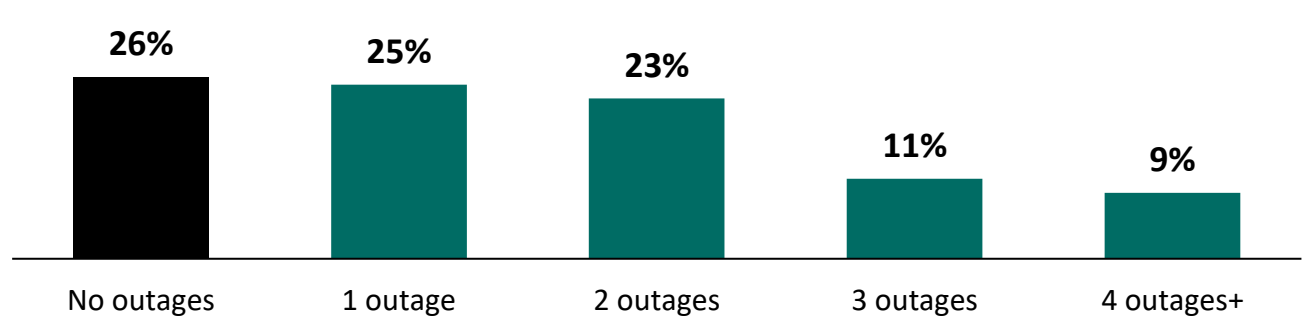
WORKBOOK PAGE

Online Workbook

Amount Spent on the Grid Reliability Plan

Residential

Q Over the past 12 months, have you experienced any power outages at your home which lasted longer than one minute?



"Don't know" (7%) not shown.

n=31,963

	Region			
	Etobicoke/York	North York	Scarborough	Toronto/East York
No outages	19%	21%	19%	34%
1 outage	24%	25%	22%	26%
2 outages	26%	24%	24%	20%
3 outages	14%	13%	14%	8%
4 outages+	12%	10%	14%	6%

Note: Responses were optional.

Online Workbook

Amount Spent on the Grid Reliability Plan

Residential

Q Over the past 12 months, have you experienced any power outages at your home which lasted longer than one minute?

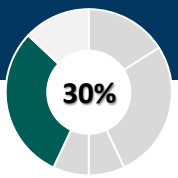
	LEAP Qualification			
	LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
No outages	31%	28%	26%	21%
1 outage	23%	25%	26%	22%
2 outages	20%	21%	23%	23%
3 outages	11%	11%	11%	12%
4 outages+	7%	8%	9%	12%

	Consumption Quartiles			
	First	Second	Third	Fourth
No outages	35%	27%	22%	20%
1 outage	24%	25%	25%	24%
2 outages	20%	22%	24%	25%
3 outages	9%	11%	12%	13%
4 outages+	6%	9%	11%	13%

Note: Responses were optional.

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Sustainment Plan

Residential



Making Choices: **Managing Equipment Failure Risk**

By 2029, Toronto Hydro's draft plan to manage equipment failure risk would cost the typical residential customer **$5.20** more per month on their monthly electricity bill. Toronto Hydro could spend more to improve reliability, or it could spend less and take on more risk of outages.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of the grid by 2029.	Maintains the overall health (age and condition) of the grid by 2029.	Improves the overall health (age and condition) of the grid by 2029.
Reliability	Reduces reliability compared to current levels. This means more power outages due to equipment failure.	Maintains reliability at current levels. This means holding steady on power outages due to equipment failure.	Improves reliability compared to current levels. This means less power outages due to equipment failure.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work. Increases work volumes and costs for the next decade.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work. Reduces work volumes and costs for the next decade.

Choice 3 of 7:

Price

Spend Less **$3.53** | Draft Plan **$5.20** | Spend More **$6.50**

$4.02 | $4.51 | $5.01 | $5.50 | $6.00 | Don't know

$-.-- Your selection.

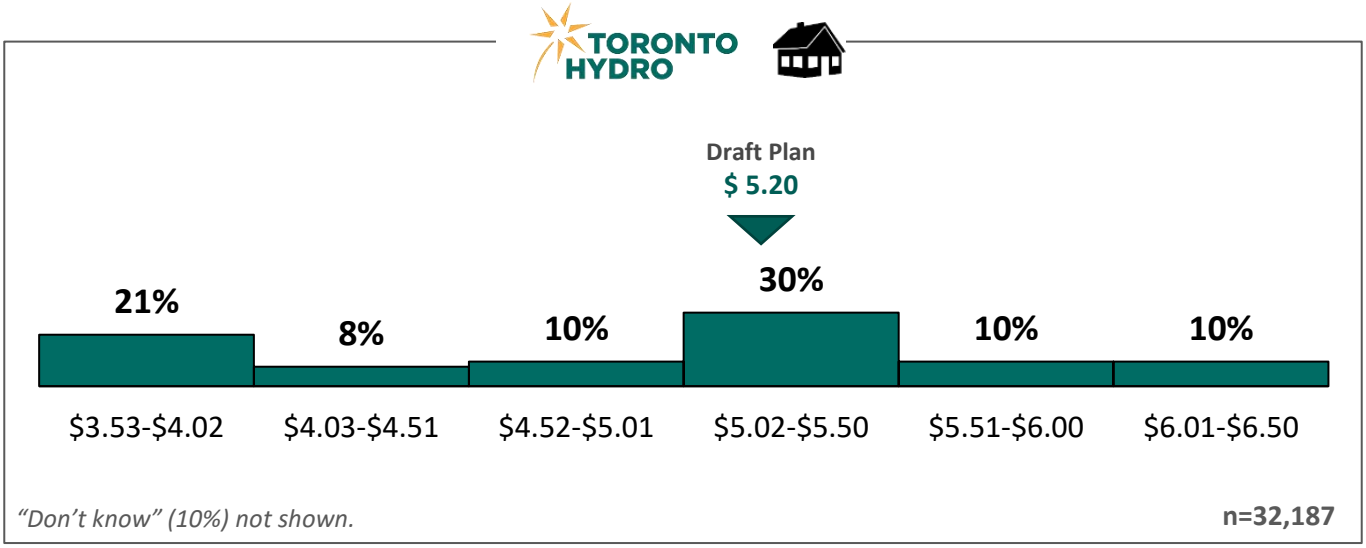
WORKBOOK PAGE

Online Workbook

Amount Spent on the Grid Reliability Plan

Residential

Q How much do you think Toronto Hydro should spend on its grid reliability plan?



"Don't know" (10%) not shown.

n=32,187

	Overall	Region			
		Etobicoke/York	North York	Scarborough	Toronto/East York
Below Plan	41%	41%	44%	45%	37%
On Plan	25%	24%	22%	21%	28%
Above Plan	24%	25%	20%	20%	27%
Don't Know	10%	10%	14%	14%	7%
TOTAL On Plan + Above Plan	49%	49%	42%	41%	56%

Online Workbook

Amount Spent on the Grid Reliability Plan

Residential

Q How much do you think Toronto Hydro should spend on its grid reliability plan?

	Overall	LEAP Qualification			
		LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
Below Plan	41%	48%	46%	36%	46%
On Plan	25%	17%	22%	28%	24%
Above Plan	24%	13%	18%	30%	19%
Don't Know	10%	22%	14%	6%	12%
TOTAL On Plan + Above Plan	49%	30%	40%	57%	42%

	Overall	Consumption Quartiles			
		First	Second	Third	Fourth
Below Plan	41%	44%	42%	39%	38%
On Plan	25%	23%	25%	26%	25%
Above Plan	24%	20%	23%	25%	27%
Don't Know	10%	12%	10%	10%	10%
TOTAL On Plan + Above Plan	49%	44%	48%	51%	52%

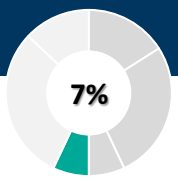
Online Workbook

Additional Feedback on the Grid Reliability Plan

Q Do you have additional feedback on Toronto Hydro's draft grid reliability plan?

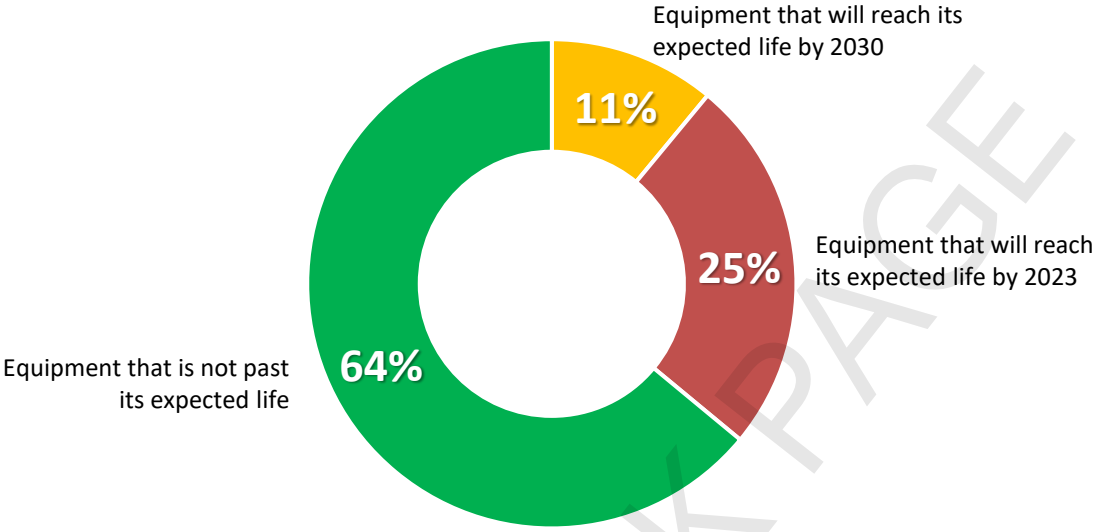
Response	%
Prevent outages, stable power, system reliability	2.8%
Modernize, be proactive, invest for the long term	1.2%
Find efficiencies, cut wasteful spending, lower salaries	0.8%
Need more information	0.4%
Support the increase (general)	0.4%
Costs are too high already, cost of living, struggling to pay bills	0.4%
Oppose the increase, increase is too high (general)	0.3%
Prioritize renewables, solar/wind, and electric vehicles	0.2%
Cost shouldn't be borne by all customers	0.2%
Make use of existing infrastructure, past spending	0.1%
Should be funded by tax dollars/government	0.1%
Other	0.4%
No response	92.6%

Note: Responses were optional. Only responses > 0.1% are shown.



2 Paced Upkeep of the Grid

About 25% of Toronto Hydro's equipment is operating past its expected life and an additional 11% is estimated to reach that point by 2030.



In this part of the plan, the key question is whether Toronto Hydro should wait until there are clear signs of equipment failure risk (such as rust or oil leaks), or whether it should get ahead of the problem by replacing old equipment proactively.

If Toronto Hydro waits, it can keep prices lower in the short term. However, this could create a surge of work in future years that will spike prices in the 2030s. There is also a risk that Toronto Hydro will not be able to do the amount of work required to deal with this equipment in the future, which could lead to more outages and higher safety risks due to equipment failures.

Want to learn more about Toronto Hydro's distribution grid? Click here.

What type of work is Toronto Hydro doing to upkeep the grid?

Below is an example of key investments that Toronto Hydro needs to make in a paced way to upkeep the grid and prevent a surge of work to address equipment failure risk in the future.



Paced Replacement of Network Vaults

This equipment is located in underground vaults in the downtown area, which serves many critical customers, such as hospitals and financial institutions. A very large portion of this equipment is going to be in poor condition and past its expected life in the 2030-34 period. To manage this risk, Toronto Hydro's draft plan intends to replace network vaults in a paced manner.

WORKBOOK PAGE

Renewing and replacing infrastructure

Toronto Hydro's grid is a mix of overhead, underground, network and station infrastructure. It operates at three different voltages (27.6kV, 13.8kV, and 4.16kV) and includes approximately:

- 61,300 distribution transformers
- 17,060 primary switches
- 15,393 km of overhead wires
- 13,765 km of underground wires
- 37 transformer stations



Overhead Infrastructure

The overhead system is made up of poles, wires, transformers, switches and other equipment. They are easier to replace, repair and inspect.

However, they are also more prone to foreign interference such as vehicles, trees, animals and weather-related outages.

This system consists of three different types of configurations two of which are outdated configurations from the 1950s and 1960s, making them more challenging to replace and restore particularly after a weather-related outage.



Underground Infrastructure

Toronto Hydro's underground system consists of cables, transformers, switches and civil infrastructures (like manholes). They can be placed either at ground level (green box above ground in your neighbourhood), underground, or inside building vaults (typical for multi-storey buildings). This system is made up of two different types of configurations where the downtown Toronto area consists of lead-covered cable, an outdated equipment with little to no suppliers.

While underground equipment is more resilient during weather-related events, it is more susceptible to flooding and at risk of faster deterioration due to moisture build-up.



Network Infrastructure

Toronto Hydro's network system, predominantly found in the downtown Toronto area, was installed in the early-to-mid 1900s to improve reliability (service levels) for critical loads (like financial institutions) and serves medium-sized loads in high-density areas, and areas with small and narrow sidewalks. It consists of interconnected low-voltage cables, vaults and network units.

While this system is better at handling normal equipment failures, proactive replacement and maintenance of this equipment are critical to avoid vault fires from occurring.



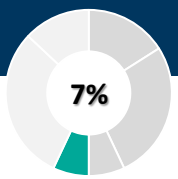
Station Infrastructure

Toronto Hydro's distribution stations receive the transmission supply from Hydro One at very high voltages. Station infrastructure consists of switchgear, power transformers, circuit breakers, remote terminal units (station computers) and battery systems. Toronto Hydro proactively replaces this equipment, as failure at the station level can cause widespread and lengthy power outages.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Sustainment Plan

Residential



Making Choices: **Paced Upkeep of the Grid**

By 2029, Toronto Hydro's draft plan to ensure paced upkeep of the grid would cost the typical residential customer **$1.15** more on their monthly electricity bill. Toronto Hydro could spend more to get ahead of future equipment failure risk, or it could spend less and defer some of this work at the risk of managing more power outages due to equipment failure in the next decade.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of the grid by 2029.	Maintains the overall health (age and condition) of the grid by 2029.	Improves the overall health (age and condition) of the grid by 2029.
Reliability	Higher risk of power outages due to equipment failure in the next decade.	Manages the risk of power outages due to equipment failure in the next decade.	Reduces the risk of power outages due to equipment failure in the next decade.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work. Increases work volumes and costs for the next decade.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work. Reduces work volumes and costs for the next decade.

Choice 4 of 7:



$-.--

Your selection.

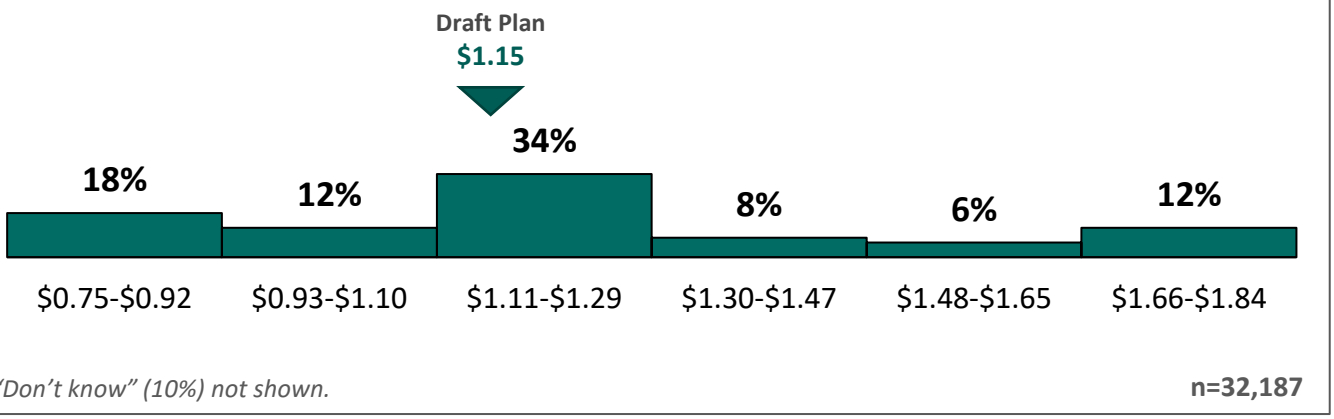
WORKBOOK PAGE

Online Workbook

Amount Spent on the Grid Stewardship Plan

Residential

Q How much do you think Toronto Hydro should spend on its grid stewardship plan?



"Don't know" (10%) not shown.

n=32,187

	Overall	Region			
		Etobicoke/York	North York	Scarborough	Toronto/East York
Below Plan	29%	30%	32%	33%	26%
On Plan	30%	29%	29%	27%	32%
Above Plan	31%	31%	25%	27%	35%
Don't Know	10%	10%	14%	13%	7%
TOTAL On Plan + Above Plan	61%	61%	54%	54%	68%

Online Workbook

Amount Spent on the Grid Stewardship Plan

Residential

Q How much do you think Toronto Hydro should spend on its grid stewardship plan?

	Overall	LEAP Qualification			
		LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
Below Plan	29%	34%	32%	25%	35%
On Plan	30%	23%	27%	32%	29%
Above Plan	31%	21%	27%	36%	24%
Don't Know	10%	22%	14%	6%	11%
TOTAL On Plan + Above Plan	61%	44%	54%	69%	54%

	Overall	Consumption Quartiles			
		First	Second	Third	Fourth
Below Plan	29%	32%	29%	28%	28%
On Plan	30%	29%	31%	31%	29%
Above Plan	31%	27%	30%	32%	34%
Don't Know	10%	12%	10%	9%	9%
TOTAL On Plan + Above Plan	61%	56%	61%	63%	63%

Online Workbook

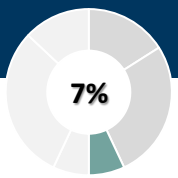
Additional Feedback on the Grid Stewardship Plan

Residential

Q Do you have additional feedback on Toronto Hydro's draft grid stewardship plan?

Response	%
Modernize, be proactive, invest for the long term	1.2%
Find efficiencies, cut wasteful spending, lower salaries	0.6%
Prevent outages, stable power, system reliability	0.6%
Need more information	0.4%
Support the increase (general)	0.4%
Oppose the increase, increase is too high (general)	0.3%
Costs are too high already, cost of living, struggling to pay bills	0.3%
Cost shouldn't be borne by all customers	0.2%
Make use of existing infrastructure, past spending	0.2%
Other	0.6%
No response	95.3%

Note: Responses were optional. Only responses > 0.1% are shown.

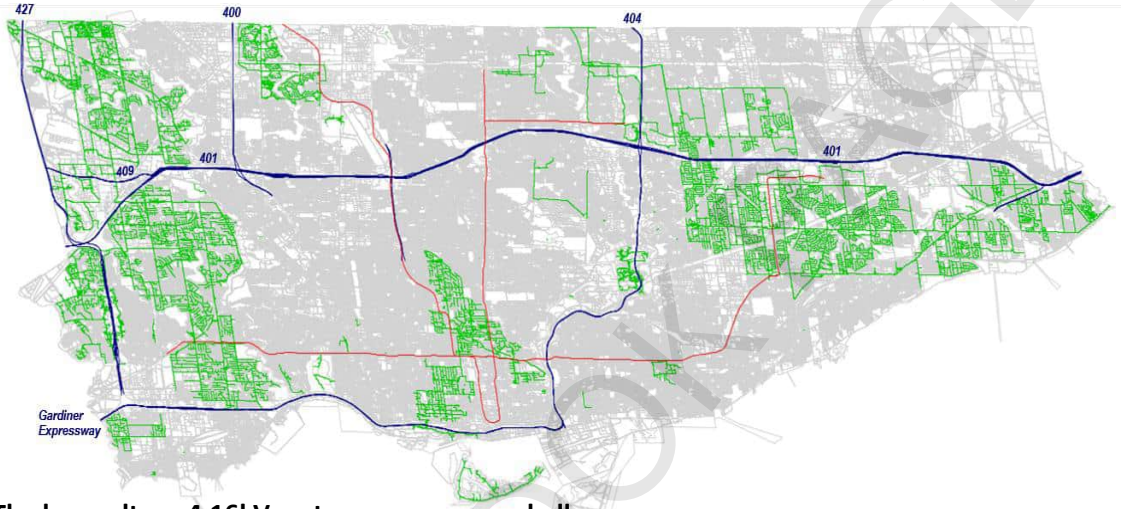


3 Standardize the Grid

Because of its history, Toronto Hydro has an old and diverse grid. Toronto Hydro is made up of 6 municipal utilities that were joined in 1998 when the City of Toronto was formed. Each utility owned and operated different types of equipment. As a result, Toronto Hydro's grid has three different voltage levels: 4.16kV, 13.8kV and 27.6kV.

The 27.6kV voltage level is the current standard for local grids. However, a large part of Toronto Hydro's grid is served at 4.16kV and 13.8kV.

Location of Outdated Voltage Lines



The low voltage 4.16kV system poses many challenges:

- Long outages for customers and higher cost to restore power – in 2022, the longest outage on the 4.16 kV system was 80 hours.
- Less efficient at carrying power over long distances, which means more electricity is lost as it travels from point A to point B (line losses).
- Less capacity to serve customers' growing electricity needs, which means longer waits and higher costs to connect new services such as electric vehicles and solar panels.
- Risk of supply chain and labour shortages as manufacturers stop making this equipment and technicians trained on this equipment retire.

What type of work is Toronto Hydro doing to standardize the grid?

Below is an example of a key investment to replace outdated equipment.



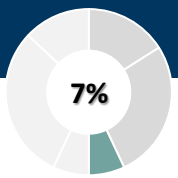
Voltage Conversion from 4.16kV/13.8kV to 27.6kV

Voltage conversion entails a full rebuild of outdated equipment such as rear lot construction (poles and wires in customers' backyards). This work improves reliability, safety and makes the grid more efficient. Toronto Hydro's draft plan intends to convert 1400 customers from rear lot service and works to eliminate rear lot construction from the grid by the late 2040s.

WORKBOOK ONLY

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Sustainment Plan

Residential



Making Choices: **Standardize the Grid**

By 2029, Toronto Hydro's draft **plan to standardize the grid** would cost the typical residential customer **$1.17** more on their monthly electricity bill. Toronto Hydro could spend more to speed up the pace of replacing outdated equipment or it could spend less to slow down the pace and delay the benefits of this work. For example, under spend more Toronto Hydro would convert all rear lot customers by the early 2040s, and under spend less by the 2050s.

	Spend Less	Draft Plan	Spend More
Reliability	Slower progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.	Steady progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.	Faster progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.
Customer Service	Less progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels.	Steady progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels	Faster progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels.
Efficiency	Slower progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.	Steady progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.	Faster progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.

Choice 5 of 7:

Price

Spend Less $0.89 | Draft Plan $1.17 | Spend More $1.52

$0.99 | $1.09 | $1.20 | $1.30 | $1.41 | Don't know

$-.-- Your selection.

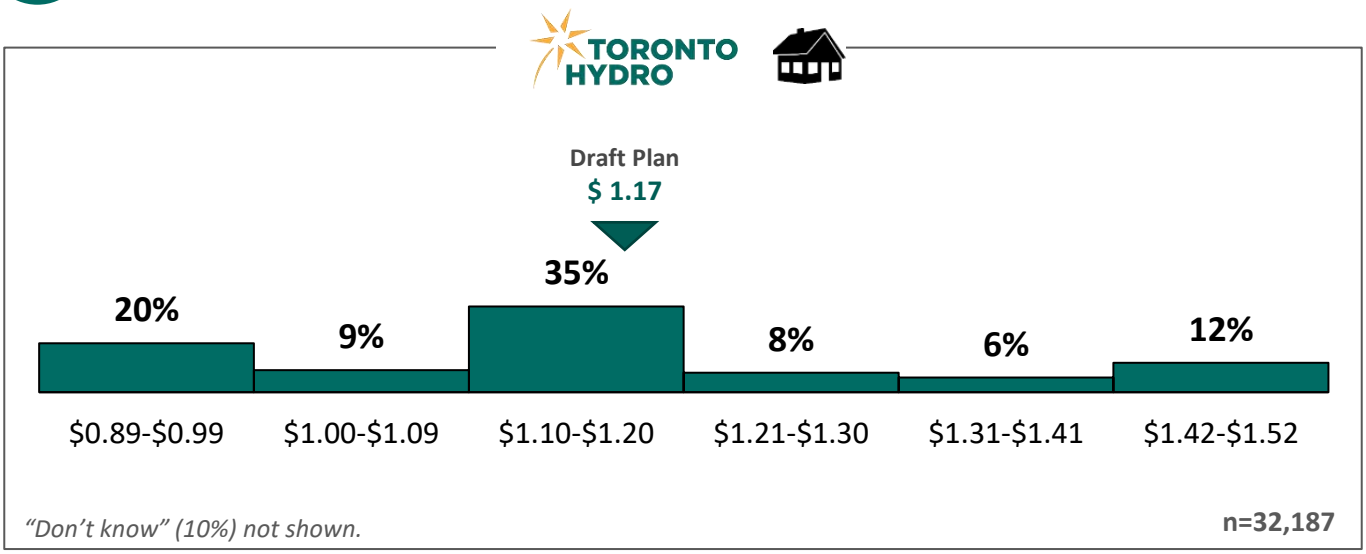
WORKBOOK PAGE

Online Workbook

Residential

Amount Spent on the Equipment Standardization Plan

Q How much do you think Toronto Hydro should spend on its equipment standardization plan?



"Don't know" (10%) not shown.

n=32,187

	Overall	Region			
		Etobicoke/York	North York	Scarborough	Toronto/East York
Below Plan	34%	34%	37%	36%	31%
On Plan	30%	29%	27%	27%	32%
Above Plan	27%	28%	22%	24%	30%
Don't Know	10%	9%	14%	13%	7%
TOTAL On Plan + Above Plan	57%	57%	49%	51%	63%

Online Workbook

Residential

Amount Spent on the Equipment Standardization Plan

Q How much do you think Toronto Hydro should spend on its equipment standardization plan?

	Overall	LEAP Qualification			
		LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
Below Plan	34%	38%	36%	30%	40%
On Plan	30%	21%	27%	32%	28%
Above Plan	27%	19%	24%	32%	21%
Don't Know	10%	22%	13%	6%	11%
TOTAL On Plan + Above Plan	57%	40%	50%	65%	49%

	Overall	Consumption Quartiles			
		First	Second	Third	Fourth
Below Plan	34%	37%	33%	32%	32%
On Plan	30%	28%	30%	30%	29%
Above Plan	27%	24%	26%	29%	29%
Don't Know	10%	11%	10%	9%	9%
TOTAL On Plan + Above Plan	57%	52%	57%	59%	59%

Online Workbook

Residential

Additional Feedback on the Equipment Standardization Plan

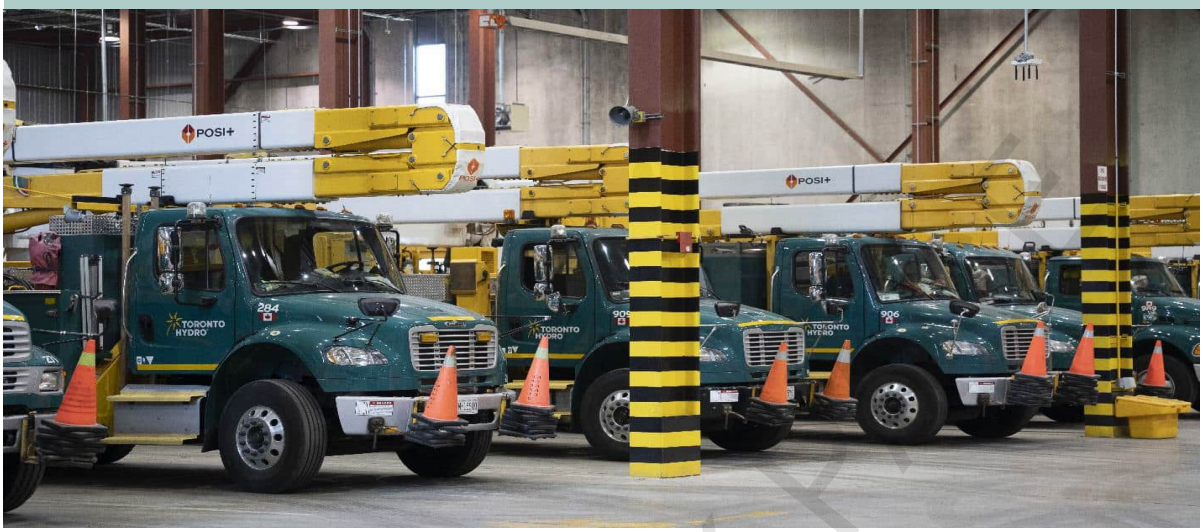
Q Do you have additional feedback on Toronto Hydro's draft equipment standardization plan?

Response	%
Modernize, be proactive, invest for the long term	1.2%
Prevent outages, stable power, system reliability	0.7%
Find efficiencies, cut wasteful spending, lower salaries	0.5%
Need more information	0.4%
Support the increase (general)	0.4%
Oppose the increase, increase is too high (general)	0.4%
Cost shouldn't be borne by all customers	0.2%
Costs are too high already, cost of living, struggling to pay bills	0.2%
Prioritize renewables, solar/wind, and electric vehicles	0.2%
Should be funded by tax dollars/government	0.2%
Make use of existing infrastructure, past spending	0.1%
Other	0.4%
No response	95.1%

Note: Responses were optional. Only responses > 0.1% are shown.

Draft General Plant Plan

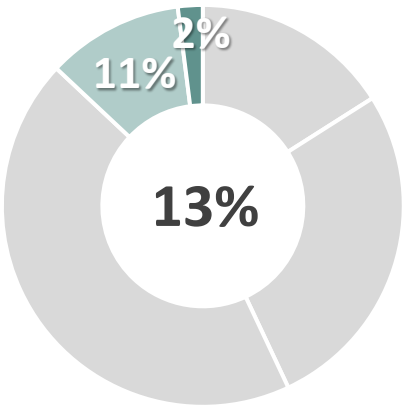
Keeping the Business Running



What is this section about?

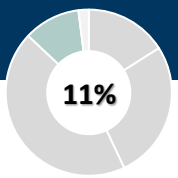
- This section is about the vehicles, work centres and IT systems that keep Toronto Hydro's business running efficiently.
- Toronto Hydro seeks your input on two choices within this part of the plan:

1. The pace of replacing the equipment needed to keep the business running.
2. The pace of reducing Toronto Hydro's emissions from its own operations.



- This spending category makes up **13% of the draft plan** and would add **$2.21** on the average residential customer's monthly bill by 2029.

WORKBOOK



1 Keep the Business Running

Work centres, vehicles and information technology systems are the backbone of Toronto Hydro's day-to-day operations. This equipment must be maintained in good working condition for efficient and reliable operations so that crews can restore power and customers can access key services like their online account and the outage restoration map.

- As with grid equipment, Toronto Hydro uses information such as age and condition data from inspections to decide which equipment should be replaced versus repaired.
- Toronto Hydro repairs equipment in poor condition such as leaking roofs, failed furnaces and worn-out vehicle braking systems. It also replaces equipment like software programs and hardware servers that are past expected useful life.

What type of work is Toronto Hydro doing to manage failure risk?

Below is an example of a key investment that Toronto Hydro needs to make to keep the business running and manage the risk of equipment failure.



Station Buildings

Toronto Hydro has approximately 250 properties that either house distribution stations equipment such as cables and transformers or support the distribution system.

Over 80% of station buildings are older than 40 years and require repairs and investments to address the following types of problems:

- Structural damage to the building (cracked foundations, leaking roofs)
- Mechanical, electrical and plumbing equipment in poor condition
- Compliance with building and fire code requirements

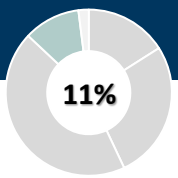
This work ensures safe and efficient operations and minimizes the risk of outages that can affect many customers. For example, structural damage to a station building poses a direct risk to distribution equipment such as power transformers.

So, how much and how quickly Toronto Hydro decides to invest in keeping their business running has a direct impact on customers. While this equipment may remain in service for a long time, when they unexpectedly fail, the costs incurred usually far exceed proactive investments (repairs and replacements) and can have a significant impact on system reliability and customer service.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft General Plant Plan

Residential



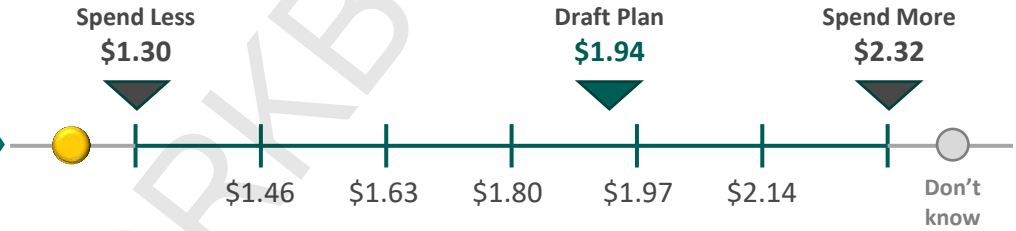
Making Choices: **Keep the Business Running**

By 2029, Toronto Hydro's draft plan to keep the business running would cost the typical residential customer **$1.94** more on their monthly electricity bill. Toronto Hydro could spend more to improve equipment health (age and condition) and functionality (better safety features) or spend less and take on more risk of equipment downtime.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of general plant equipment by 2029.	Maintains the overall health (age and condition) of general plant equipment by 2029.	Improves the overall health (age and condition) of general plant equipment by 2029.
Reliability & Service	Reduces equipment availability, which could mean longer outages or lower levels of customer service.	Maintains equipment availability consistent with current levels.	Improves equipment availability and functionality, which could mean better reliability and customer service levels.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work, which is more costly and increases equipment downtime.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work, and better equipment functionality.

Choice 6 of 7:

Price



$-.--

Your selection.

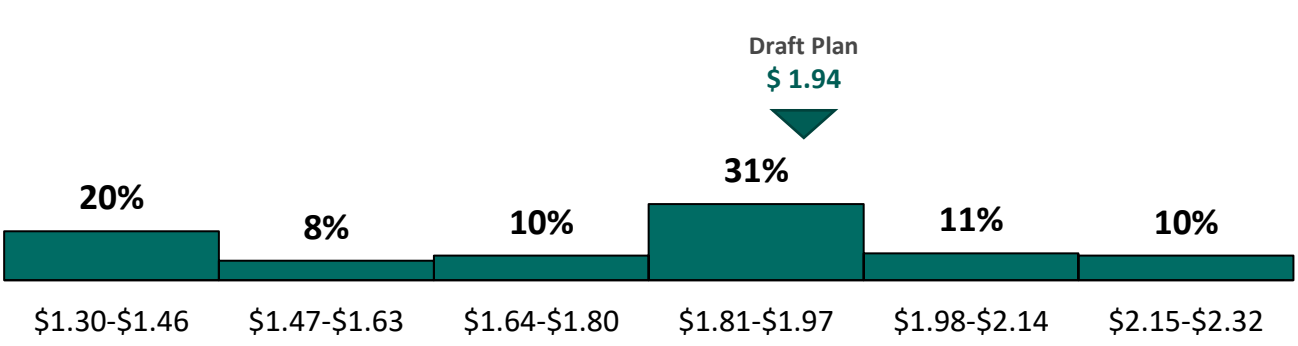
WORKBOOK PAGE

Online Workbook

Amount Spent on Keeping the Business Running

Residential

Q How much do you think Toronto Hydro should spend to keep the business running?



"Don't know" (10%) not shown.

n=32,187

	Overall	Region			
		Etobicoke/York	North York	Scarborough	Toronto/East York
Below Plan	43%	43%	46%	47%	40%
On Plan	29%	29%	25%	24%	32%
Above Plan	19%	19%	15%	17%	21%
Don't Know	10%	9%	13%	13%	7%
TOTAL On Plan + Above Plan	47%	47%	40%	40%	54%

Online Workbook

Amount Spent on the Keeping the Business Running

Residential

Q How much do you think Toronto Hydro should spend to keep the business running?

	Overall	LEAP Qualification			
		LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
Below Plan	43%	47%	47%	39%	49%
On Plan	29%	18%	24%	33%	26%
Above Plan	19%	13%	16%	22%	14%
Don't Know	10%	22%	13%	6%	11%
TOTAL On Plan + Above Plan	47%	31%	40%	55%	40%

	Overall	Consumption Quartiles			
		First	Second	Third	Fourth
Below Plan	43%	46%	43%	41%	41%
On Plan	29%	26%	28%	30%	29%
Above Plan	19%	16%	18%	19%	21%
Don't Know	10%	11%	10%	9%	9%
TOTAL On Plan + Above Plan	47%	43%	47%	50%	50%

Online Workbook

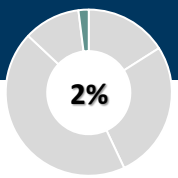
Residential

Additional Feedback on Keeping the Business Running

Q Do you have additional feedback on Toronto Hydro's draft for keeping the business running?

Response	%
Find efficiencies, cut wasteful spending, lower salaries	1.2%
Modernize, be proactive, invest for the long term	0.7%
Prevent outages, stable power, system reliability	0.4%
Support the increase (general)	0.4%
Need more information	0.3%
Oppose the increase, increase is too high (general)	0.3%
Costs are too high already, cost of living, struggling to pay bills	0.3%
Cost shouldn't be borne by all customers	0.2%
Should be funded by tax dollars/government	0.2%
Make use of existing infrastructure, past spending	0.1%
Prioritize renewables, solar/wind, and electric vehicles	0.1%
Other	0.4%
No response	95.4%

Note: Responses were optional. Only responses > 0.1% are shown.



2 Reducing Toronto Hydro's Emissions

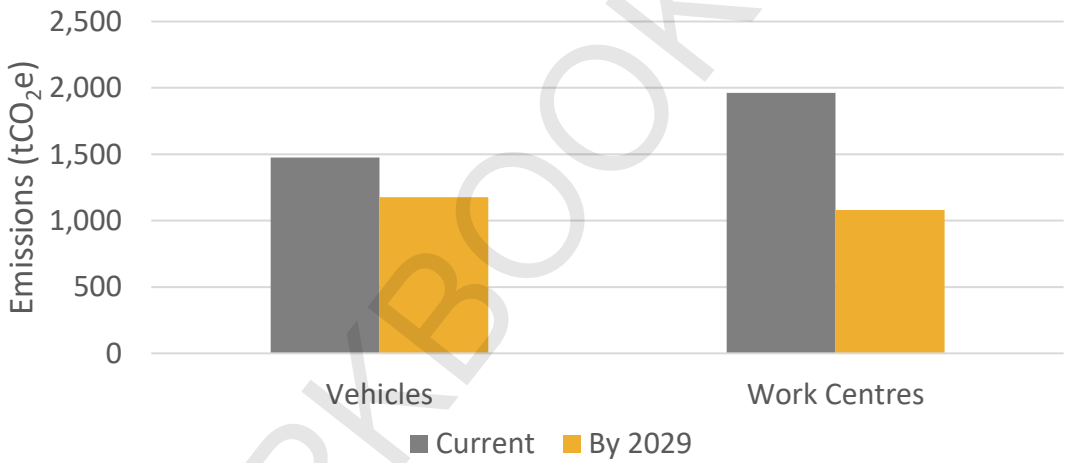
To address climate change, companies around the world are setting targets to reduce greenhouse gas (GHG) emissions from fossil fuels — a pledge commonly known as Net Zero.

Moving toward Net Zero has increasingly become the expectation of governments, financial markets, stakeholders and customers. For example, in October 2019, Toronto City Council unanimously voted to accelerate efforts to reduce emissions across the city.

To do its part in addressing climate change, Toronto Hydro is committed to reducing emissions from its vehicles and work centres by:

- Replacing gasoline and diesel power vehicles with hybrid and electric vehicles
- Converting natural gas boilers and heaters in its work centres to electric ones.

Toronto Hydro's Draft Plan to Reduce Emissions



Carbon Tax Savings

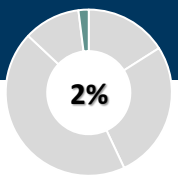
Reducing carbon emissions from vehicles and work centres could help Toronto Hydro manage rising costs due to the carbon tax (recall that the carbon tax may increase by 161% from 2023 to 2030). **Over the 2025–2029 period, Toronto Hydro's draft plan could reduce carbon tax payments by roughly half a million dollars.**

With your feedback, Toronto Hydro needs to decide how quickly to transition to cleaner sources of energy for its operations. In the next section, you will be presented these options.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft General Plant Plan

Residential

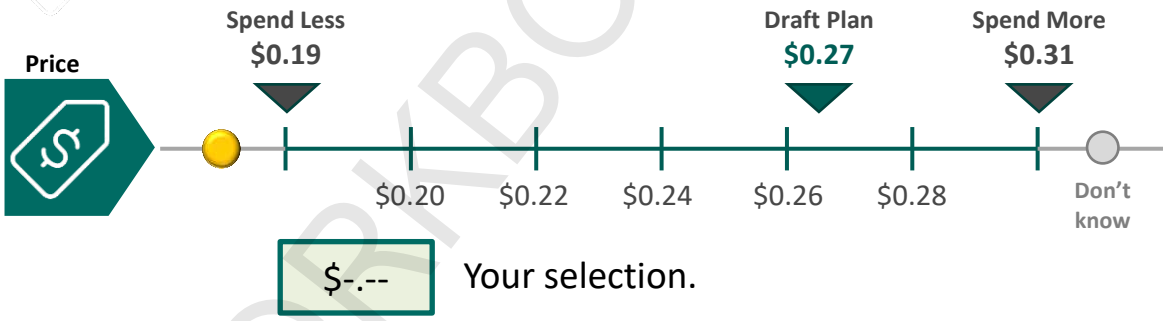


Making Choices: **Reducing Toronto Hydro's Emissions**

By 2029, Toronto Hydro's draft plan to reduce emissions would cost the typical residential customer **$0.27** more on their monthly electricity bill. Toronto Hydro could spend more for faster progress towards reducing its emissions, or spend less to slow down the progress.

	Spend Less	Draft Plan	Spend More
Environment	Less progress to reduce emissions — about 27% reduction by the end of the decade.	Steady progress to reduce emissions — about 35% reduction by the end of the decade.	Faster progress to reduce emissions — about 36% reduction by the end of the decade.
Efficiency	Higher exposure to rising energy costs (oil and gas) due to the carbon taxes and other pressures.	Managed exposure to rising energy costs (oil and gas) due to the carbon tax and other pressures.	Less exposure to rising energy costs (oil and gas) due to carbon taxes and other pressures.

Choice 7 of 7:



$-.-- Your selection.

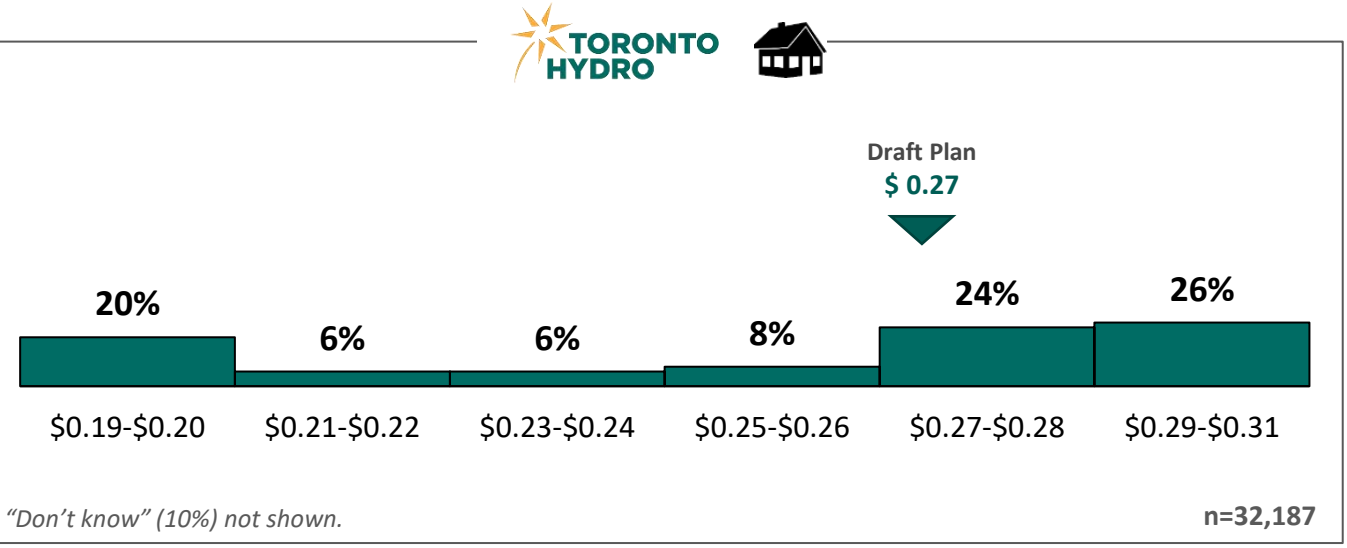
WORKBOOK PAGE

Online Workbook

Amount Spent on Decarbonization

Residential

Q How much do you think Toronto Hydro should spend to reduce its own emissions?



"Don't know" (10%) not shown.

n=32,187

	Overall	Region			
		Etobicoke/York	North York	Scarborough	Toronto/East York
Below Plan	37%	39%	43%	42%	32%
On Plan	27%	27%	25%	26%	28%
Above Plan	26%	24%	18%	18%	34%
Don't Know	10%	9%	14%	13%	7%
TOTAL On Plan + Above Plan	53%	52%	43%	45%	62%

Online Workbook

Amount Spent on Decarbonization

Residential

Q How much do you think Toronto Hydro should spend to reduce its own emissions?

	Overall	LEAP Qualification			
		LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
Below Plan	37%	40%	39%	34%	44%
On Plan	27%	22%	27%	29%	26%
Above Plan	26%	16%	21%	32%	19%
Don't Know	10%	21%	13%	6%	11%
TOTAL On Plan + Above Plan	53%	38%	47%	60%	45%

	Overall	Consumption Quartiles			
		First	Second	Third	Fourth
Below Plan	37%	38%	37%	36%	38%
On Plan	27%	26%	27%	28%	27%
Above Plan	26%	25%	26%	27%	26%
Don't Know	10%	11%	10%	9%	9%
TOTAL On Plan + Above Plan	53%	51%	53%	54%	53%

Online Workbook

Additional Feedback on Decarbonization

Residential

Q Do you have additional feedback on Toronto Hydro's draft decarbonization plan?

Response	%
Prioritize renewables, solar/wind, and electric vehicles	1.9%
Oppose the increase, increase is too high (general)	0.8%
Support the increase (general)	0.6%
Modernize, be proactive, invest for the long term	0.5%
Find efficiencies, cut wasteful spending, lower salaries	0.5%
Need more information	0.3%
Should be funded by tax dollars/government	0.3%
Cost shouldn't be borne by all customers	0.2%
Costs are too high already, cost of living, struggling to pay bills	0.2%
Other	0.6%
No response	94.1%

Note: Responses were optional. Only responses > 0.1% are shown.

Online Workbook

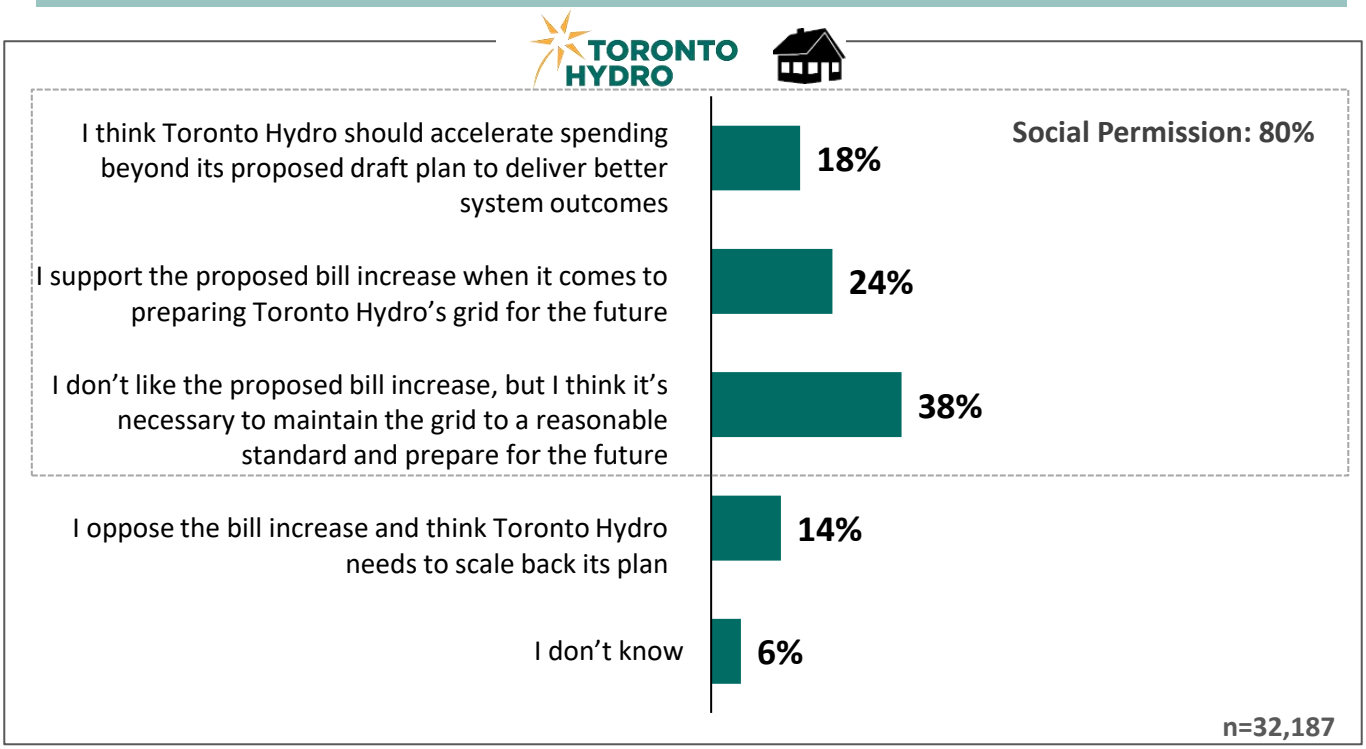
Social Permission

Residential

Q

Toronto Hydro has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Toronto Hydro would like to know how you feel about the total rate impact of its current draft plan.

Considering what you have learned about Toronto Hydro's 2025–2029 draft plan and that this may result in a **$17.18 increase** in the distribution portion of your monthly electricity bill by 2029, which of the following best represents your point of view?



	Region			
	Etobicoke/York	North York	Scarborough	Toronto/East York
Accelerate spending	16%	16%	16%	20%
Support proposed bill	24%	23%	24%	26%
Necessary to maintain grid	39%	40%	41%	36%
Oppose the bill increase	15%	15%	13%	13%
I don't know	6%	7%	6%	5%
Social Permission	**79%**	**78%**	**80%**	**82%**

Online Workbook

Social Permission

Residential

Q

Toronto Hydro has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Toronto Hydro would like to know how you feel about the total rate impact of its current draft plan.

Considering what you have learned about Toronto Hydro's 2025–2029 draft plan and that this may result in a **$17.18 increase** in the distribution portion of your monthly electricity bill by 2029, which of the following best represents your point of view?

	Region			
	LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
Accelerate spending	16%	14%	22%	11%
Support proposed bill	18%	25%	28%	18%
Necessary to maintain grid	38%	40%	36%	41%
Oppose the bill increase	16%	14%	11%	21%
I don't know	13%	7%	3%	9%
Social Permission	**72%**	**79%**	**86%**	**71%**

	Consumption Quartiles			
	First	Second	Third	Fourth
Accelerate spending	15%	17%	19%	21%
Support proposed bill	24%	25%	25%	23%
Necessary to maintain grid	39%	39%	38%	36%
Oppose the bill increase	16%	13%	13%	14%
I don't know	7%	6%	6%	5%
Social Permission	**77%**	**81%**	**81%**	**81%**

Online Workbook

Residential

Final Comments for the Draft Plan & Proposed Rate Increase

Q Do you have any final comments regarding Toronto Hydro's draft plan for 2025–2029 and the proposed rate increase?

Response	%
Find efficiencies, cut wasteful spending, lower salaries	2.1%
Costs are too high already, cost of living, struggling to pay bills	2.0%
Modernize, be proactive, invest for the long term	1.8%
Support the increase (general)	0.9%
Prioritize renewables, solar/wind, and electric vehicles	0.9%
Need more information	0.8%
Oppose the increase, increase is too high (general)	0.7%
Prevent outages, stable power, system reliability	0.6%
Should be funded by tax dollars/government	0.6%
Cost shouldn't be borne by all customers	0.5%
Address equity, protect low-income customers	0.4%
Should be funded by developers	0.2%
Good information	0.2%
Other	0.6%
No response	87.9%

Note: Responses were optional. Only responses > 0.1% are shown.

INNOVATIVE RESEARCH GROUP

Residential Customers

Online Workbook Diagnostics

Section 9.2

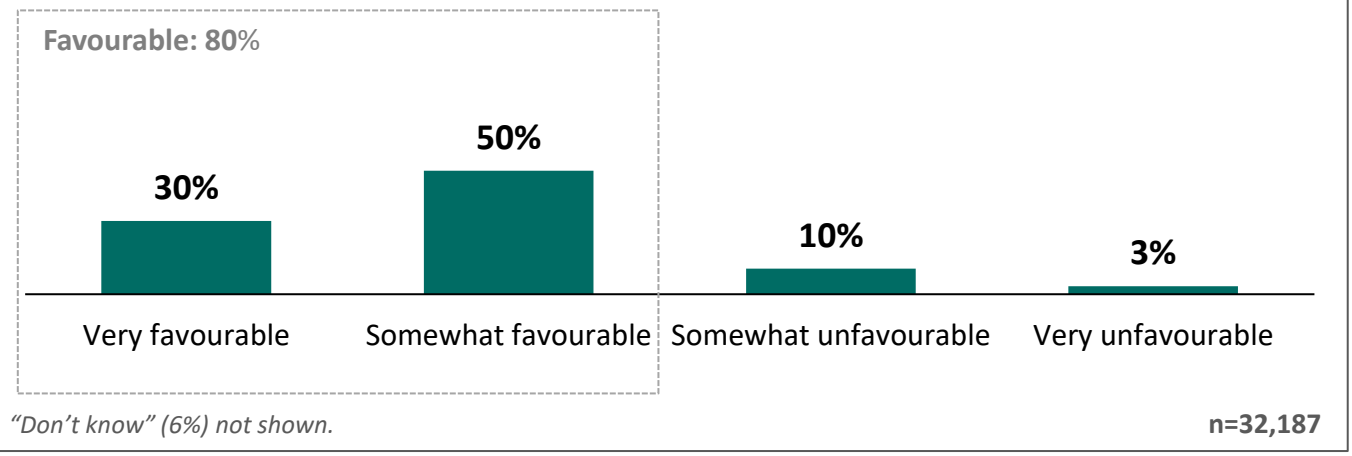


Online Workbook

Workbook Impression

Residential

Q Overall, what is your impression of the survey you just completed?



"Don't know" (6%) not shown.

n=32,187

	Region			
	Etobicoke/York	**North York**	**Scarborough**	**Toronto/East York**
Very favourable	31%	28%	30%	30%
Somewhat favourable	49%	52%	51%	50%
Somewhat unfavourable	11%	10%	9%	11%
Very unfavourable	4%	3%	3%	3%
Don't know	6%	7%	7%	5%
Favourable (Very + Somewhat)	**80%**	**80%**	**82%**	**80%**
Unfavourable (Very + Somewhat)	**14%**	**13%**	**12%**	**15%**

Online Workbook

Workbook Impression

Q Overall, what is your impression of the survey you just completed?

	Region			
	LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
Very favourable	28%	30%	34%	22%
Somewhat favourable	48%	52%	51%	49%
Somewhat unfavourable	11%	10%	9%	13%
Very unfavourable	3%	3%	2%	5%
Don't know	9%	6%	4%	10%
Favourable (Very + Somewhat)	**77%**	**81%**	**85%**	**71%**
Unfavourable (Very + Somewhat)	**14%**	**13%**	**12%**	**19%**

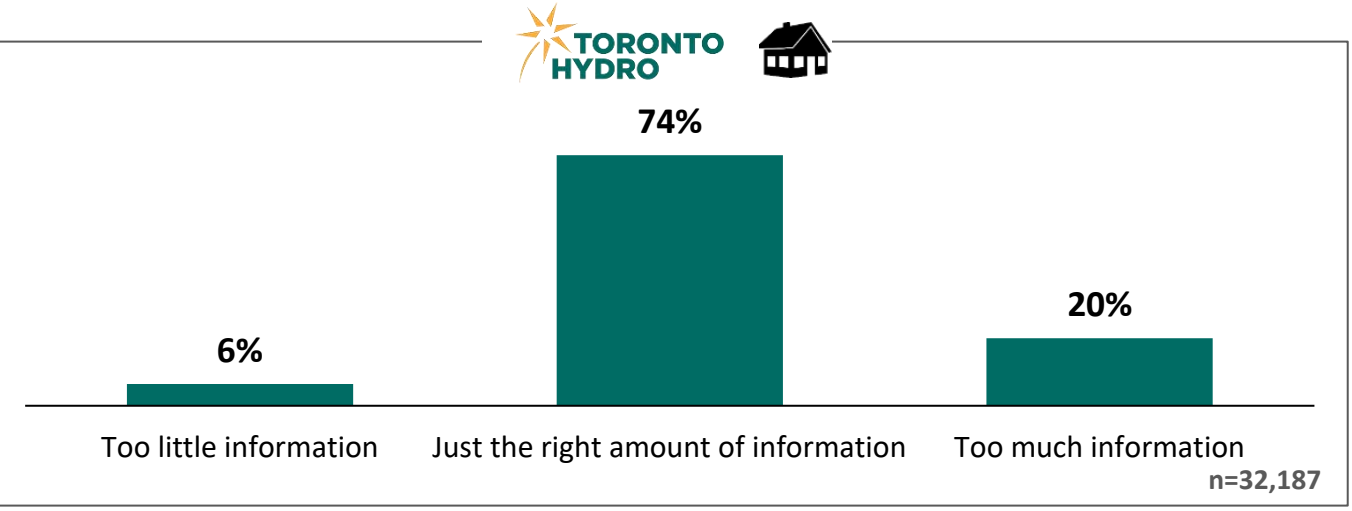
	Consumption Quartiles			
	First	Second	Third	Fourth
Very favourable	28%	29%	31%	31%
Somewhat favourable	50%	51%	51%	50%
Somewhat unfavourable	11%	10%	10%	10%
Very unfavourable	3%	3%	3%	4%
Don't know	7%	6%	6%	6%
Favourable (Very + Somewhat)	**79%**	**80%**	**81%**	**81%**
Unfavourable (Very + Somewhat)	**15%**	**13%**	**13%**	**14%**

Online Workbook

Amount of Information

Residential

Q In this survey, do you feel that Toronto Hydro provided too much information, not enough, or just the right amount?



	Region			
	Etobicoke/York	North York	Scarborough	Toronto/East York
Too little information	7%	7%	7%	6%
Just the right amount of information	73%	74%	77%	73%
Too much information	20%	19%	17%	21%

	LEAP Qualification			
	LEAP Qualified	Income <$52k, not Leap Qualified	Income>$52k, not LEAP Qualified	Prefer not to say
Too little information	9%	7%	5%	9%
Just the right amount of information	73%	76%	75%	69%
Too much information	18%	18%	20%	22%

	Consumption Quartiles			
	First	Second	Third	Fourth
Too little information	7%	6%	6%	7%
Just the right amount of information	72%	73%	75%	75%
Too much information	21%	21%	19%	18%

Online Workbook

Content Missing from Engagement

Residential

Q Was there any content missing that you would have liked to have seen included in this survey?

Response	%
Operational efficiencies (salaries, spending) and accountability	3.8%
Environmental sustainability, info about EVs/charging	1.7%
More information on the costs, breakdown of either the plan or bill	1.4%
Confusing, navigational issues in the survey	1.0%
Delivery charges	0.7%
Satisfied with the information presented	0.5%
Information about power generation	0.5%
Comparison to other regions or utilities	0.4%
Ways to reduce usage, save money on bill	0.3%
More historic context, past rate increases and spending	0.3%
Reliability (e.g. Plans for underground cables)	0.3%
How this benefits customers	0.3%
Survey is biased	0.3%
Other	0.7%
No response	87.7%

Note: Responses were optional. Only responses > 0.1% are shown.

Online Workbook

Outstanding Questions

Q Is there anything that you would still like answered?

Response	%
More information on the costs, breakdown of either the plan or bill	2.0%
Operational efficiencies (salaries, spending) and accountability	1.6%
Environmental sustainability, info about EVs/charging	1.1%
Reliability (e.g. Plans for underground cables)	1.1%
Ways to reduce usage, save money on bill	0.9%
Confusing, navigational issues in the survey	0.3%
Delivery charges	0.3%
Satisfied with the information presented	0.2%
Comparison to other regions or utilities	0.2%
Information about power generation	0.1%
Other	0.5%
No response	91.8%

Note: Responses were optional. Only responses > 0.1% are shown.

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro. The conclusions drawn and opinions expressed are those of the authors.

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CONFIDENTIAL

APPENDIX 10

Small Business
Workbook Report

TORONTO HYDRO

November 2, 2023

2025 – 2029 Rate Application

Report Navigation

APPENDICIES

PHASE I

- APPENDIX.01 – Customer Engagement Focus Groups
- APPENDIX.02 – Customer Sample Validation
- APPENDIX.03 – Residential Needs and Preferences Survey
- APPENDIX.04 – Small Business Needs and Preferences Survey
- APPENDIX.05 – Commercial & Industrial Needs and Preferences Survey
- APPENDIX.06 – Key Accounts Needs and Preferences Survey
- APPENDIX.07 – Needs and Preferences Planning Placemat

PHASE II

- APPENDIX.08 – Customer Engagement Workbook Overview
- APPENDIX.09 – Residential Workbook Report
- APPENDIX.10 – Small Business Workbook Report
- APPENDIX.11 – Commercial & Industrial Workbook Report
- APPENDIX.12 – Key Accounts Workbook Report
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INNOVATIVE RESEARCH GROUP

Small Business Customers

Online Workbook Report

Section 10.1



Online Survey

Survey Design & Methodology

Small Business



Toronto Hydro Electric-System Ltd. (THESL) engaged Innovative Research Group (INNOVATIVE) to design, execute and document the results of THESL's customer engagement process as part of the development of its 2025–2029 business plan.

Field Dates

All Toronto Hydro GS<50 kW (small business) customers with an email address on Toronto Hydro's file received the **Small Business Online Workbook**. Customers had the opportunity to complete the survey between **March 23rd and May 1st, 2023**.

Incentives

Customers who completed the survey between March 23rd and May 1st were invited to enter a draw to win free electricity for a year, which was provided as a lump-sum credit valued at $1,500 to be applied to the winning customer's account. The incentive as it appeared to customers in the workbook is on pg.8 of this appendix.

Small Business Online Survey Completes

A total of **695** (unweighted) Toronto Hydro small business customers completed the online survey.

Customers could complete the survey either via a unique URL sent to their emails or an open access link promoted by THESL. Customers with email addresses on file received an email invitation. It included a unique survey URL that linked back to their annual consumption, region and rate class.

Customers without email addresses on file received a paper bill insert that invited them to participate via an open access link. The open access link asked customers to enter their Toronto Hydro account number and the first three characters of the corresponding postal code. Once their account information was verified, their answers were linked back to their annual consumption, region and rate class.

Each customer was only able to complete the survey once, be it through the unique URL or the open access link.

A total of 2 (unweighted) customers entered the survey through the open access link. All other remaining completes (693 (unweighted)) entered it via the unique URL.

Online Survey

Survey Design & Methodology

Sample Weighting

The small business online survey sample has been weighted proportionately by consumption quartiles and region in order to be representative of the broader Toronto Hydro service territory.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region.

Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
Etobicoke/York	29 (27)	34 (31)	38 (33)	22 (32)	123 (123)
North York	35 (37)	40 (41)	34 (40)	36 (40)	145 (159)
Scarborough	22 (33)	54 (41)	32 (37)	31 (37)	139 (147)
Toronto/East York	80 (76)	70 (61)	73 (64)	65 (65)	288 (266)
Total	166 (174)	198 (174)	177 (174)	154 (174)	695 (695)

Graphs and tables may not always total 100% due to rounding values rather than any error in data.
Sums are added before rounding numbers.

Online Survey
Firmographic breakdown

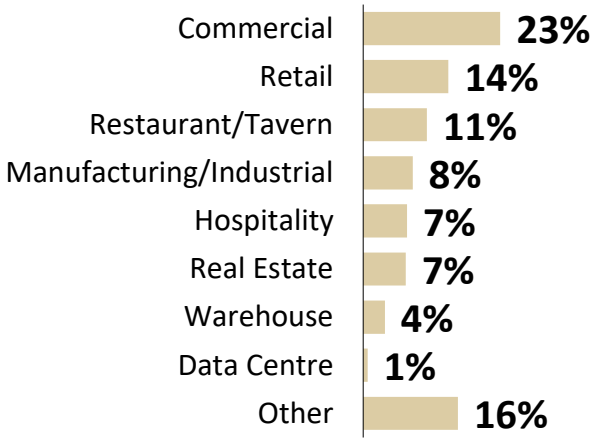
Small Business

Managing/Overseeing Organization's Electrical or Hydro Bill



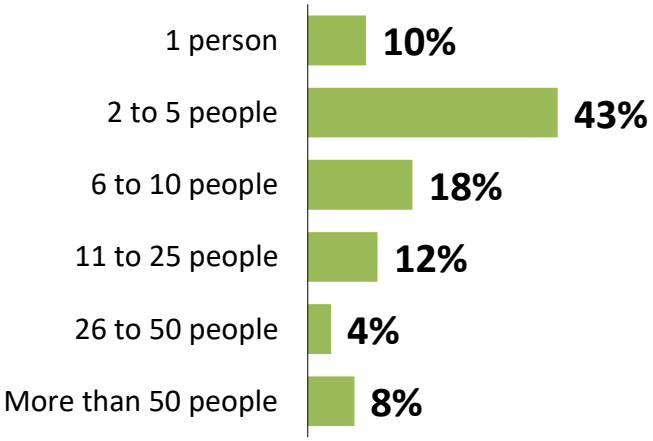
"Prefer not to say" (5%) and "Don't know" (4%) not shown.

Sector



"Prefer not to say" (6%) and "Don't know" (2%) not shown.

Number of Employees at the Organization



"Prefer not to say" (4%) and "Don't know" (1%) not shown.

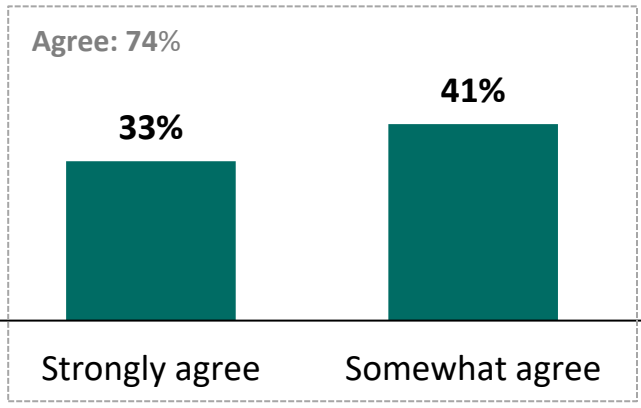
Online Survey
Environmental Controls

Small Business

To what extent do you agree or disagree with the following statements?

Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

TORONTO HYDRO

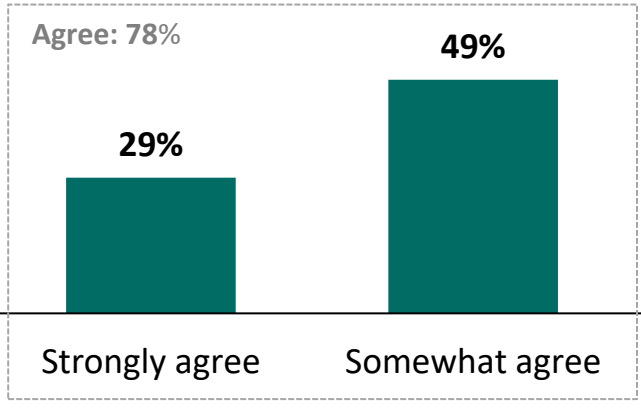


"Don't know/no opinion" (7%) not shown.

n=695

Q Customers are well-served by the electricity system in Ontario.

TORONTO HYDRO



"Don't know/no opinion" (7%) not shown.

n=695

INNOVATIVE RESEARCH GROUP

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Small Business

Welcome to Toronto Hydro's customer feedback survey!

Toronto Hydro needs your input to find the right balance between the services you receive and the price you pay.



Land Acknowledgement: Toronto Hydro's grid is located on the traditional territory of many nations including the Mississaugas of the Credit, the Anishnabeg, the Chippewa, the Haudenosaunee and the Wendat peoples and is now home to many diverse First Nations, Inuit and Métis peoples.

The purpose of this survey is to get your feedback on the draft 2025–2029 business plan. Your feedback will help Toronto Hydro align this plan with what you need and want.

1. Your electricity rates pay for this plan, so your views must be considered.
2. You don't need to be an electricity expert to participate. The survey is focused on basic choices and provides the background information you need to answer the questions.
3. Recognizing that people absorb information in different ways, Toronto Hydro and its research partner have designed this survey to include diagrams, charts, images and videos to help explain Toronto Hydro's draft plan and what it means for you. If you prefer to skip the videos, the content is also explained in the body of the survey.
4. Depending on how much feedback you wish to provide and the number of videos watched, this survey should take approximately **20-30 minutes** to complete. If you need to pause and return later to finish the survey, your completed answers will be saved.
5. Some of the survey content may not display correctly on a mobile browser. It is strongly recommended that you complete this workbook on a desktop or laptop computer.

Those who complete the survey will be invited to enter a draw to win one of 10 "*free electricity for a year*" prizes!

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Toronto Hydro to gather your feedback, while protecting your confidentiality. Your individual answers will not be shared with Toronto Hydro in any identifiable way.

INNOVATIVE RESEARCH GROUP

WORKBOOK PREVIEW

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Small Business

What is this customer engagement about?

The goal of this engagement is to share Toronto Hydro's draft five-year business plan for the future of the city's electrical grid and collect your feedback. This will help Toronto Hydro align its plans with your needs and preferences.

Click on the video below to learn about Toronto Hydro's customer engagement.



Every five years, Toronto Hydro is required to submit a plan for its proposed prices (rates) and spending to the Ontario Energy Board (OEB) for approval.

- **In 2021 and 2022, thousands of its customers told Toronto Hydro about what they need and want** to help Toronto Hydro prepare the draft 2025–2029 business plan.
- **Toronto Hydro is now looking for your input on this draft business plan** to align its investments and spending decisions with what matters to you as its customers.
- **Later this year, Toronto Hydro will present its updated business plan to the independent regulator,** the OEB. Toronto Hydro is accountable to the OEB for considering your feedback.

How will this customer engagement work?



1. The workbook explains what Toronto Hydro does and summarizes the key planning considerations that Toronto Hydro's draft plan needs to address.



2. The workbook explains how much of your electricity bill goes to Toronto Hydro, how that money is spent, and the impact of the draft plan on your 2025–2029 prices.
3. The workbook asks for your input on seven key choices that will affect the services you receive and the price you pay from 2025–2029.



Once you have finished giving feedback on the key choices, **you will have an opportunity to review and change your responses** until you feel you have found the right balance.

Want to know more about Toronto Hydro's customer engagement process? Click here.

WORKBOOK PREVIEW

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Small Business

How will your feedback impact Toronto Hydro's plan and prices?

Toronto Hydro has a five-step approach to customer feedback.

✓ **1. Identify Customer Needs, Preferences, and Priorities**

In 2022, Toronto Hydro asked many types of customers from across the city about their needs and priorities for electricity distribution service.

✓ **2. Use Customer Feedback to Guide Development of Draft Plan**

Toronto Hydro planners were given summaries of the key findings from the initial customer engagement to consider as they began building their plans.

We are here

3. Collect Customer Feedback on the Draft Plan

Toronto Hydro is returning to customers to get feedback on the draft plan and ask customers how the draft plan could better meet their needs and preferences.

4. Use Customer Feedback to Finalize the Plan

Toronto Hydro will re-examine and make appropriate changes to the plan based on the feedback provided by customers in this engagement.

5. Submit the Plan to the Ontario Energy Board (OEB)

Toronto Hydro will file the plan with the OEB along with a report summarizing the results of this engagement. The OEB, consumer advocates and other interested groups will examine the plan in an open and transparent public process known as a rate application.

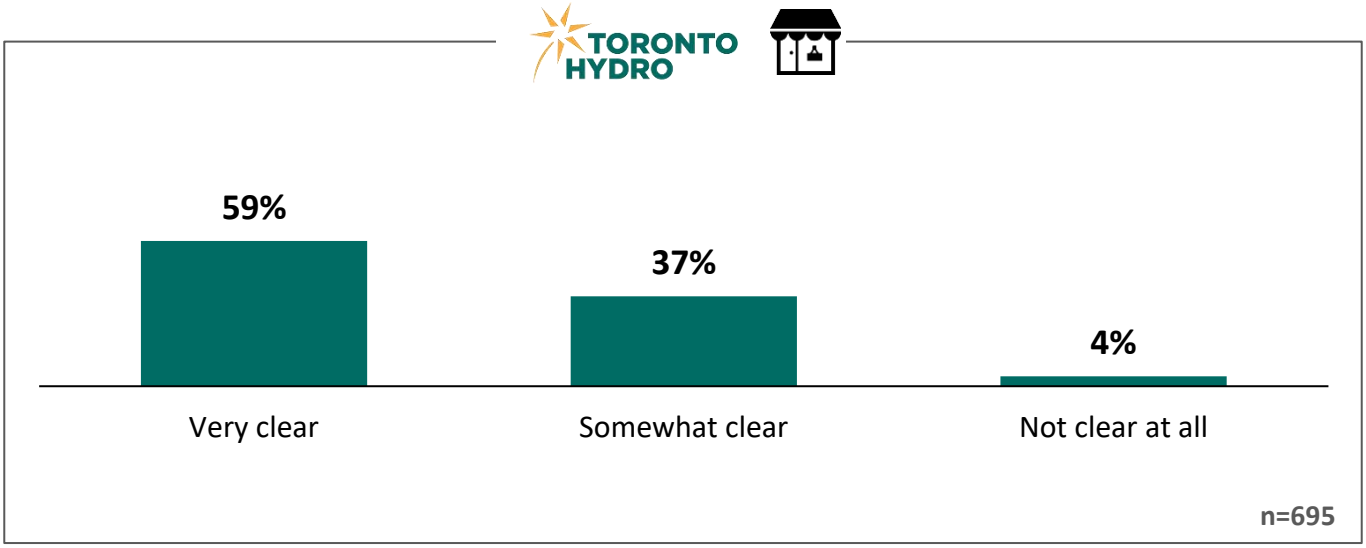
WORKBOOK PAGE

Online Workbook

Small Business

Understanding the Purpose of the Customer Engagement

Q Do you feel that the purpose of Toronto Hydro's customer engagement is clear?



	Region				Consumption Quartiles			
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Very clear	52%	56%	60%	65%	59%	61%	58%	60%
Somewhat clear	45%	41%	36%	31%	35%	36%	41%	34%
Not clear at all	3%	3%	4%	5%	6%	3%	2%	6%

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Small Business

Electricity 101

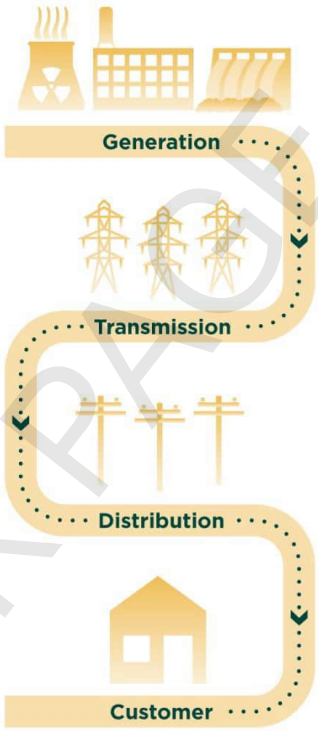
Toronto Hydro's role in Ontario's electricity system

Ontario's electricity system is made up of three parts: **generation**, **transmission** and **distribution**.

Generation

How electricity is made

About half of the electricity used in Ontario comes from nuclear power. The rest comes from a mix of hydroelectric, natural gas, wind and solar sources. Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from other generators contracted by the grid operator.



Transmission

How electricity travels across Ontario

Once electricity is made, it must be sent to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. Ontario has approximately 30,000 kilometers of transmission lines, mostly owned and operated by Hydro One.

Distribution

How electricity is delivered to you

Toronto Hydro is responsible for the last step of the journey: distributing electricity locally to end-use customers.

- Toronto Hydro does not generate or transmit electricity — it owns and operates the local electricity system made up of approximately 183,620 poles, 61,300 distribution transformers, 17,060 primary switches, 15,393 kilometers of overhead wires and 13,765 kilometers of underground cables.
- Toronto Hydro is wholly owned by the City of Toronto, but it does not receive taxpayer money — it is entirely funded by the distribution rates that you pay on your electricity bill.
- Toronto Hydro provides power to roughly 2.8 million people across the city of Toronto.

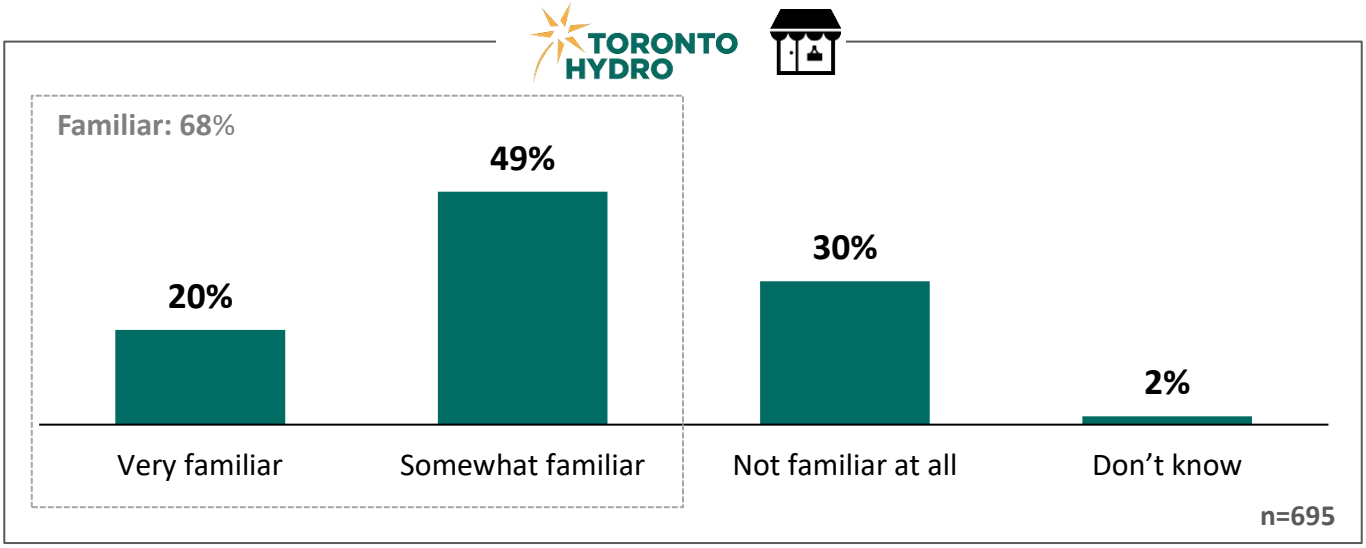
WORKBOOK PAGE

Online Workbook

Familiarity with Ontario's Electricity System

Small Business

Q Before this engagement, how familiar were you with the various parts of the electricity system, how they work together and for which services Toronto Hydro is responsible?



	Region				Consumption Quartiles			
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Very familiar	22%	23%	18%	17%	17%	21%	17%	23%
Somewhat familiar	46%	48%	50%	50%	50%	51%	47%	47%
Not familiar at all	29%	27%	31%	31%	32%	27%	33%	28%
Don't know	3%	1%	1%	2%	1%	1%	2%	2%
Familiar (Very + Somewhat)	**68%**	**72%**	**68%**	**67%**	**67%**	**72%**	**65%**	**70%**

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Small Business

Toronto Hydro's Draft Plan
Planning Considerations

In preparing its plan, Toronto Hydro must consider many existing and emerging challenges of delivering safe, reliable and clean electricity at a reasonable price.

To learn more about what Toronto Hydro must consider in preparing its draft plan, click on the topics below.

Key challenges that Toronto Hydro's 2025–2029 draft plan addresses:

Keeping prices reasonable

- Many customers are concerned about the rising cost of doing business
- Toronto Hydro must find the right balance between the investment needs of the local grid and the financial needs of its customers.

Responding to rising costs

- Like many companies, Toronto Hydro faces rising costs in purchasing equipment for the grid and doing construction work in the city.
- For example, from 2021 to 2022, the cost of buying electrical equipment increased by 9.9% while the cost of non-residential construction in the city of Toronto rose by 15.6%.

Powering a growing urban city

- Toronto is not just the largest city in Canada and an engine of the Canadian economy, it is also one of the fastest growing cities in North America.
- As the city continues to grow, the grid needs to be ready to power new condo towers, residential communities and businesses.

Fixing and replacing equipment in poor condition

- Much of Toronto Hydro's grid was installed in the 1950s and 1960s and needs to be replaced or upgraded.
- To keep the grid safe and reliable now and in the future, Toronto Hydro monitors the condition of its grid and uses this information to upgrade the equipment most at risk.

Reducing emissions from its own operations

- Toronto Hydro is committed to decarbonizing the company's footprint by 2040. To meet this goal, it must invest in reducing emissions from its vehicles and work centres.
- Toronto Hydro is expected to reduce its emissions by switching from oil and natural gas to clean electricity for powering its own operations.

Keeping up with the way customers use electricity

- Customers are using more electricity for their day-to-day energy needs such as electric vehicles for transportation and electric heat pumps for heating. They are also choosing new technologies such as solar panels and battery storage to manage their electricity use and sell electricity to the local grid.
- To ensure customers can connect new technologies to the grid safely and reliably, Toronto Hydro needs to upgrade its equipment and modernize its systems.

WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Rate Application

Small Business



Responding to extreme weather and cyber security attacks

- Extreme weather such as high heat, high winds, flooding and ice storms is increasingly straining and damaging to electricity grids.
- Cybercrime is on the rise across Canada. For example, Toronto Hydro is the target of around one million attempted cyber attacks each year, with attempts going over one million in 2022 (successfully deflected).
- Toronto Hydro needs to make the grid more resilient against extreme weather and cyber security attacks that could compromise reliability and put customers at risk.



Protecting public and employee safety

- Toronto Hydro and its customers have a strong safety record, but electricity is dangerous and safety cannot be taken for granted.
- As homes and businesses add new technologies that increase the amount of electricity flowing around us, Toronto Hydro must ensure that the grid remains safe for its employees and the public.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Small Business

How much of my electricity bill goes to Toronto Hydro?

Every item on your bill is required by provincial regulation.

- Toronto Hydro collects payment for the entire electricity system, but only keeps the distribution portion of the "**Delivery**" charge. This charge pays for both Toronto Hydro's **distribution** system and Hydro One's **transmission** system, as well as line losses (power that is lost when electricity travels across the wires).
- **About 31% of the electricity bill goes to Toronto Hydro** to pay for the local distribution grid. The **remaining 69%** of the bill goes to generation companies, transmission companies, the federal and provincial governments, and regulatory agencies.

Typical Small Business Bill

Sample Toronto Hydro Monthly Bill
(based on consumption of 2,000 kWh as of Jan. 1, 2023)

Account Number:
0000000000

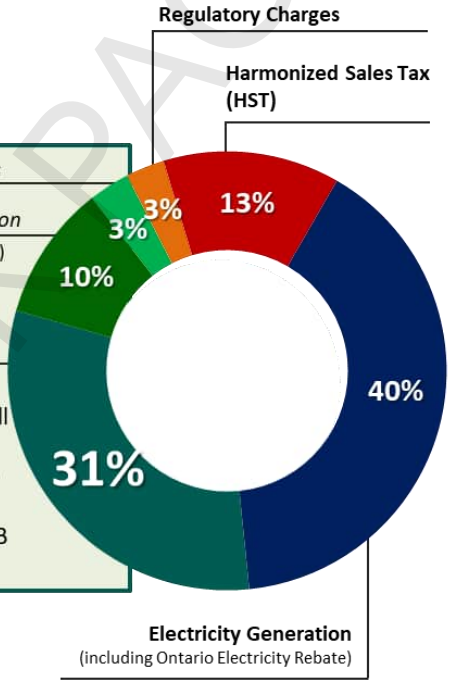
Meter Number:
00000000

Your Electricity Charges	
Electricity	
On-Peak (highest price) @ 15.1 c/kWh	54.36
Mid-Peak (mid price) @ 10.2 c/kWh	36.72
Off-Peak (lowest price) @ 7.4 c/kWh	94.72
Delivery	161.89
Regulatory Charges	10.96
Total Electricity Charges	**$358.65**
HST	46.62
Ontario Electricity Rebate	(-$41.96)
Total Amount	**$363.31**

Delivery: *Line Losses*
$12.17

Delivery: *Transmission*
(varies based on usage)
$36.71

Delivery: *Distribution*
Toronto Hydro's part of the total bill is **$113.01**. This charge is the same for all small businesses per OEB requirements.



Note: For time of use Off-/Mid-/On-peak split 64%/18%/18% according to the OEB rate model. The Sample Bill is based on the OEB rates effective January 1, 2023.

Who holds Toronto Hydro accountable?

The **Ontario Energy Board (OEB)** is the public interest regulator responsible for setting electricity distribution rates (prices) and for protecting customers in Ontario.

The OEB holds Toronto Hydro accountable for:

- How it spends your money in current and future plans.
- Reporting on key outcomes (reliability) through an annual scorecard.
- Finding savings and efficiencies to absorb rising costs.

Want to know more about what Toronto Hydro has done to become more efficient? Click here.

WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Rate Application

Small Business

What has Toronto Hydro done to become more efficient?

- Reduced the total number of facilities and gave back roughly $158 million to customers, resulting in a total credit of $232.80 on the average customer's bill in this rate class from 2016 to 2021.
- Delivered approximately $10 million in reduced or avoided costs in this current 2020–2024 period by replacing outdated information systems with consolidated programs, enabling automation and lowering maintenance costs.
- Implemented new technology to automate crew scheduling, enabling Toronto Hydro to maximize crew working hours and respond to power outages quicker.

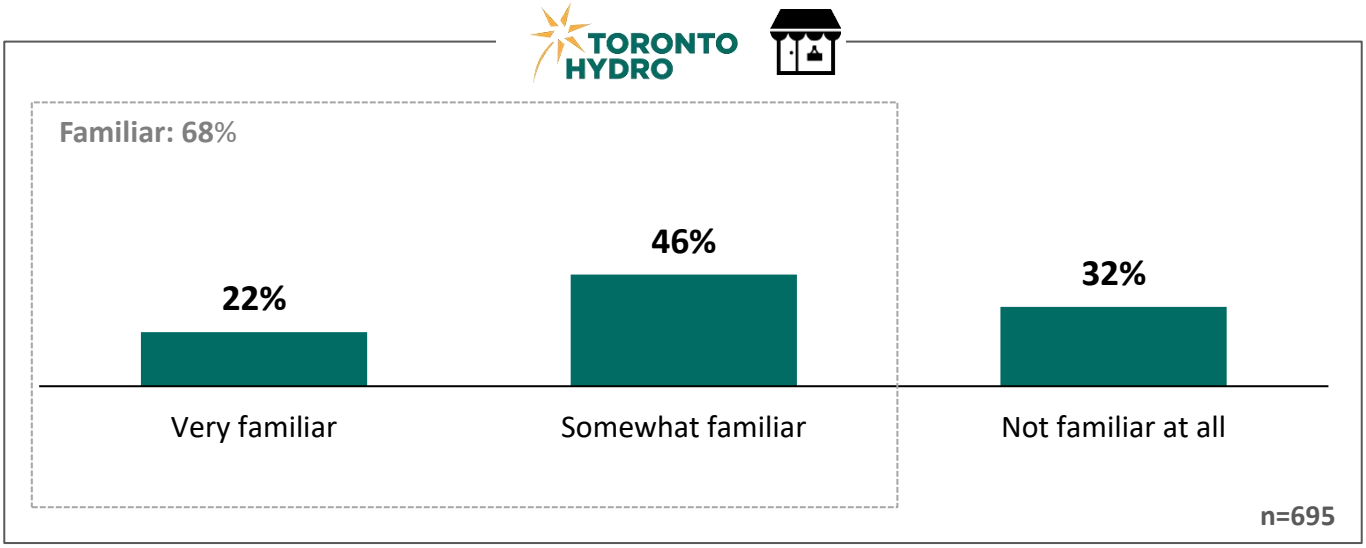
WORKBOOK PAGE

Online Workbook

Small Business

Familiarity with the Percentage of Bill Remitted to Toronto Hydro

Q Before this customer engagement, how familiar were you with the amount of your electricity bill that went to Toronto Hydro?



	Region				Consumption Quartiles			
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Very familiar	24%	27%	19%	20%	17%	27%	17%	28%
Somewhat familiar	46%	46%	44%	46%	49%	45%	50%	39%
Not familiar at all	29%	27%	38%	34%	34%	29%	34%	33%
Familiar (Very + Somewhat)	**71%**	**73%**	**62%**	**66%**	**66%**	**71%**	**66%**	**67%**

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Small Business

How does Toronto Hydro propose to spend the money?

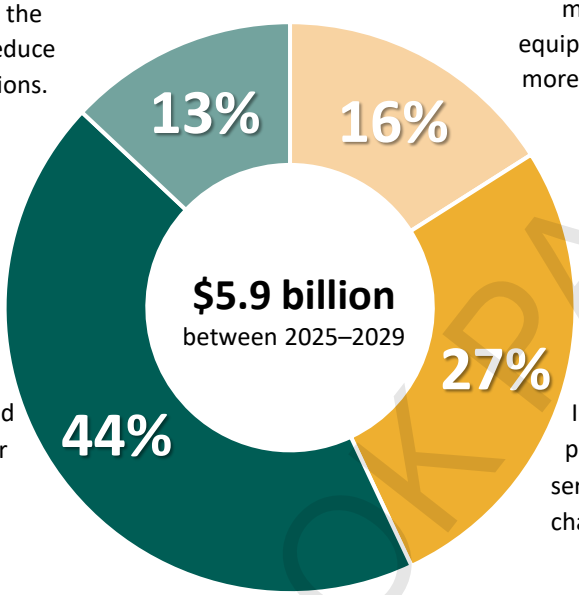
Toronto Hydro's five-year 2025–2029 draft plan is made up of four spending categories.

General Plant

Investments in vehicles, work centres and IT to keep the business running and reduce Toronto Hydro's emissions.

Modernization

Investments in technology to get more use out of existing equipment, and build a smarter, more efficient and reliable grid.



Sustainment

Investments to upkeep old equipment that is in poor condition and replace outdated equipment.

Growth

Investments in capacity to power the growing city and serve customers' growing and changing needs for electricity.

Want to know more about Toronto Hydro's current and future budgets? Click here.

How much will Toronto Hydro's draft plan cost me?

At the end of the five-year plan (2029), the typical customer in this rate class would see the distribution portion of their electricity bill increase by **$50.88**: from an estimated rate (price) of $117.57 in 2024 to a proposed rate (price) of **$168.45 by 2029.**

Rate Period	Year	Avg. Monthly Bill	Toronto Hydro Portion	Toronto Hydro's Portion: Annual Increase (%)	Toronto Hydro's Portion: Annual Increase ($)
	2023	$363.31	$113.01	n/a	n/a
	2024	$361.57	$117.57	4%	$4.56
	2025	$376.64	$132.47	13%	$14.90
	2026	$383.83	$139.56	5%	$7.09
	2027	$392.73	$148.33	6%	$8.77
	2028	$406.18	$161.61	9%	$13.28
	2029	$413.12	$168.45	4%	$6.84
	5-yr impact		**$50.88**	**43%**	**$50.88**

Note: These estimated rate increases are preliminary and are subject to change based on customer feedback and other factors. A typical customer in this rate class is assumed to use 2,000 kWh per month and enrolled under Time-of-use Regulated Price Plan. Bill projections assume that other aspects of the electricity bill that are outside of Toronto Hydro's control (commodity, transmission, government, regulatory fees) remain constant.

RKBOOKPAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Small Business

Toronto Hydro Background

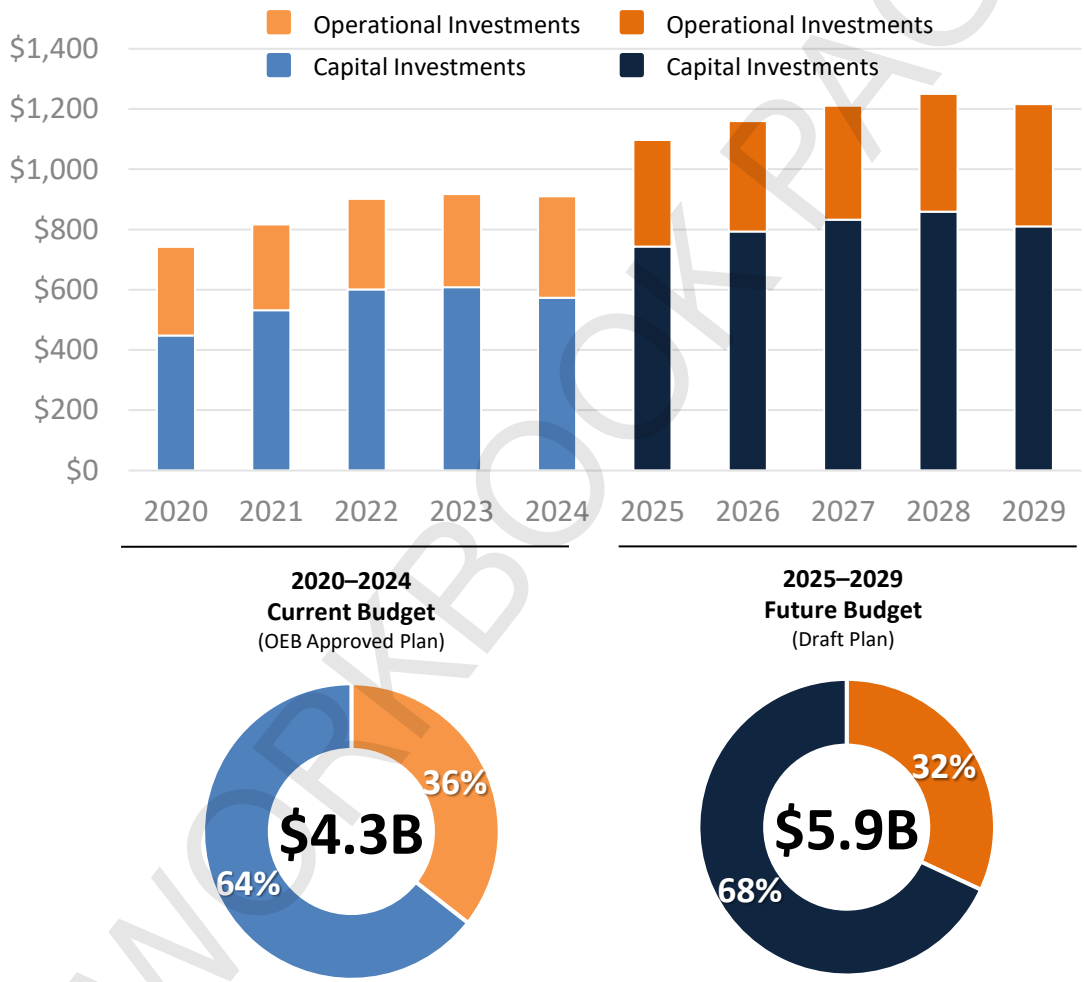
How much does it cost to run the local grid?

To run the local grid and serve customers, Toronto Hydro manages two budgets:

1. A **capital investment** budget which pays for the cost of buying and constructing physical infrastructure such as poles, wires, transformers, facilities, trucks and computers.

2. An **operational investment** budget which pays for maintenance and operation of the equipment, as well as the staff needed to manage the grid and serve customers daily.

Current and Future Budgets per year ($ millions)



WORKBOOK PAGE

The current five-year budget of **$4.3 billion** is based on the 2020–2024 plan approved by the OEB in a previous rate application. As mentioned earlier, this amount is funded by your 2020–2024 distribution rates.

The future five-year budget of **$5.9 billion** is based on the 2025–2029 draft plan presented in this customer feedback survey. The final budget for this next rate period will be adjusted to reflect customer feedback collected through this engagement and will be subject to extensive OEB review before rates are set for 2025–2029.

How does the survey work?

The next sections are about 7 key choices that Toronto Hydro needs to make to finalize its plan.

Each section provides some key background information. We encourage you to take the time to learn about your local electricity grid and where your money is going.

We also understand that life is busy. Many people find this information interesting — but if you would prefer to skip over the videos or the background information, you can jump right to the key choices.

How do I make choices?

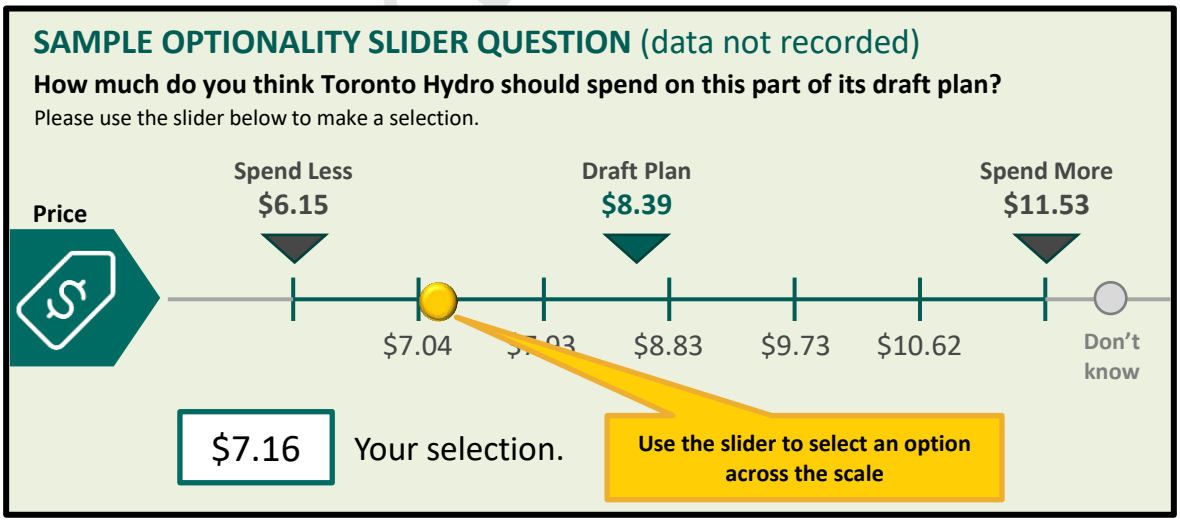
Each choice has a summary of three options that Toronto Hydro considered:

- **Spend Less:** A minimum spending option that keeps prices lower and meets the basic performance requirements but may entail some trade-offs on key outcomes, such as reliability.
- **Toronto Hydro's Draft Plan:** An option currently in the draft plan which makes additional progress toward key outcomes but delays some important work.
- **Spend More:** A faster paced spending option that makes additional progress towards better outcomes while recognizing practical limits due to resources and construction issues.

In each option, there is a sliding scale that enables you to dial the draft plan up or down. While Toronto Hydro's technical experts can tell us the maximum and minimum amounts we can practically spend, the balance of how much Toronto Hydro spends on the spectrum is up to customers like you.

At the end of the survey, you will get a summary of your choices and you will have the opportunity to change your answers to find the right balance for you.

BOOK PAGE

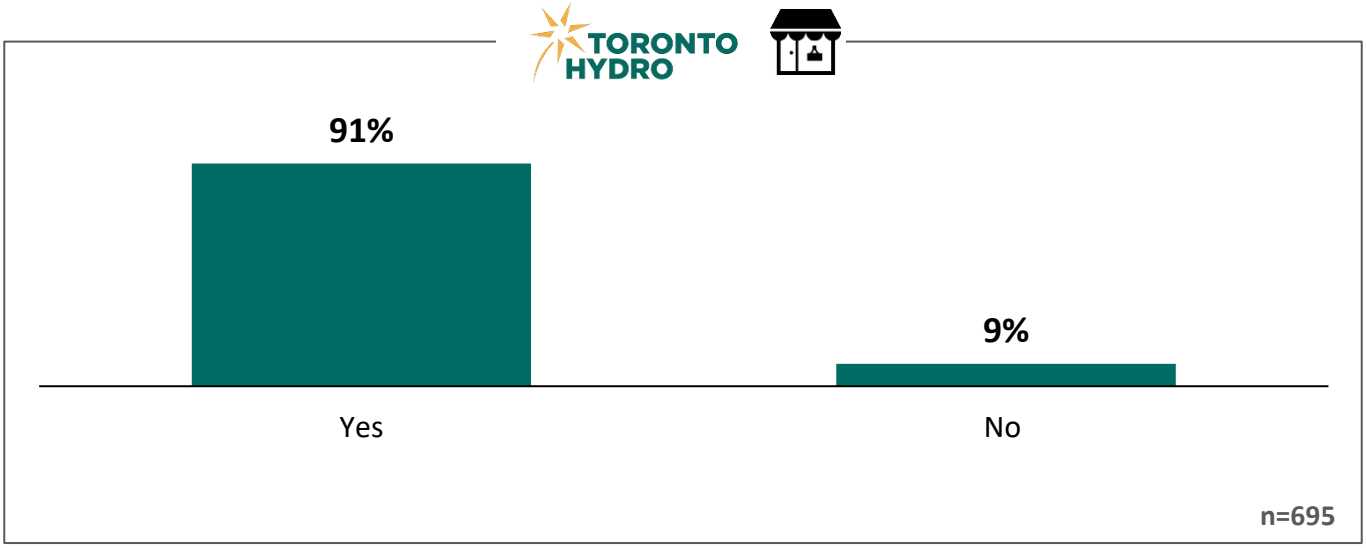


Online Workbook

Understanding the Slider

Small Business

Q Is it clear that you can move the slider to any amount you feel best reflects your personal view of the best balance between lower costs and faster improvements?



	Region				Consumption Quartiles			
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Yes	88%	89%	91%	93%	90%	91%	92%	90%
No	12%	11%	9%	7%	10%	9%	8%	10%

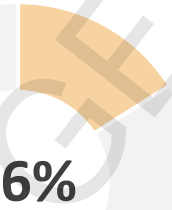
Draft Modernization Plan

Build a Smarter, More Efficient and Resilient Grid

What is this section about?

- This section explains how technology is changing the way customers use electricity and how Toronto Hydro operates and manages the grid to make it smarter, more efficient and resilient for customers.

  Want to learn more about how grid modernization benefits you? Click on the topics below.



- **Toronto Hydro's draft modernization plan enables:**
  - Faster and cheaper power restoration
  - More efficient use of existing equipment
  - Customer choice to adopt new technologies
  - Resilience against weather and cyber attacks

- This spending category makes up **16% of the draft plan** and would add **$8.39** on the average customer in this rate class's monthly bill by 2029.

*Click on the video below to learn about Toronto Hydro's **draft modernization plan**.*



WORKBOOK PAGE

Modernization Plan

Building a Smarter, more Efficient and Reliable Grid

Toronto Hydro's Modernization Plan has four main objectives:

Faster and cheaper power restoration



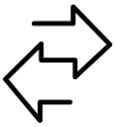
- Through automation, the smart grid can achieve self-healing capabilities. This means that the distribution grid on your street will be able to locate outages and restore power automatically.
- The smart grid enables Toronto Hydro to reduce the number and length of outages customers experience. It also reduces manual costs (trucks and crews) of responding to power outage events.

More efficient use of existing equipment



- As customers use more electricity, some equipment will reach its limits. Sensors and meters detect when and where these limits are approaching, enabling Toronto Hydro to make better decisions.
- The smart grid enables Toronto Hydro to get more use out of the existing equipment so that it can serve a greater customer need for electricity without having to build as much new infrastructure.

Customer choice to adopt new technologies



- Sensors, switches and software enable Toronto Hydro to monitor and control the flow of electricity so that customers can choose technologies to produce, store and sell power to the grid.
- The smart grid is designed to allow safe and reliable two-way power flow — from the grid to the customers and from customers to the grid. This system can reduce costs and makes the local grid more resilient to outages.

Resilience against weather and cyber attacks



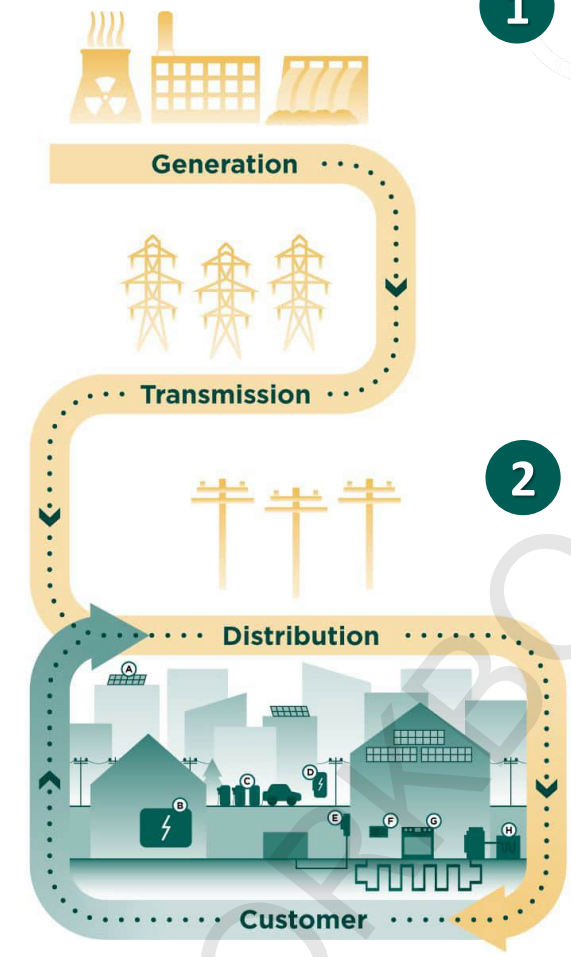
- Cyber attacks are increasing and getting more complex. Toronto Hydro must be prepared to respond to these threats to maintain reliable service and protect customer information.
- In addition to being able to restore power quicker, the smart grid can sense when environmental conditions like flooding pose a risk. This enables grid operators to strengthen the grid.

WORKBOOK PAGE

Modernization: Changing Technology, Changing Needs

For more than 100 years, things changed relatively slowly in terms of grid technology. Electricity was generated in large power stations and transmitted from around the province to Toronto Hydro's grid, and ultimately to homes and businesses. That is all changing, and because of technological advancement, the pace of change could be fast.

Toronto Hydro's 2025–2029 plan is shaped by two key changes in technology:



1. **Technologies that change how customers use electricity.** These include:
   - Electricity products like electric vehicles, heat pumps and electric stoves that enable customers to use less fossil fuels (oil and gas), which contribute to climate change.
   - Technologies like solar panels and battery energy storage that allow customers to produce and manage their electricity as well as sell it back onto the grid.

2. **Technologies that change how Toronto Hydro operates the grid**. These key changes are:
   - The grid must shift from a **one-way system** that only sends electricity to customers to a **two-way system** that allows customers to generate and sell electricity to the grid.
   - **Smart grid technology like sensors and automation** enables Toronto Hydro to monitor key equipment to prevent outages and get better use out of existing equipment. When outages do occur, this technology can re-route the grid to restore power much more quickly and at a lower cost than today.

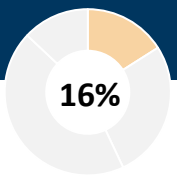
WORKBOOK PAGE

How much electricity does it take to charge an Electric Vehicle (EV)?

Did you know that when an EV is charging it can use as much electricity as two average homes? If everyone in a neighbourhood came home from work or school and started charging their EVs at the same time, the electricity demand could overload the grid.

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Modernization Plan

Small Business



Making Choices: **Modernization**

By 2029, Toronto Hydro's draft **modernization plan** would cost the typical customer in this rate class **$8.39** more per month on their monthly electricity bill. Toronto Hydro could spend more to increase the pace of modernizing the grid to get better reliability sooner, or it could spend less and slow down the progress.

	Spend Less	Draft Plan	Spend More
Reliability	Being ready to automate the grid by 2035 means that better reliability won't happen until the end of the next decade or beyond.	Being ready to automate the grid by 2030 means that better reliability will happen in the earlier part of the next decade.	Faster progress towards grid automation means better reliability earlier and improved reliability for critical loads located in the downtown area.
Customer Service	May reduce service levels (longer waits and higher costs) for some customers connecting new services. May reduce customer choice for new technologies.	Maintains service levels for customers connecting new services to the grid. Enables customer choice for new technologies such as solar panels.	Same as draft plan.
Efficiency	It will take longer for the grid to become more efficient. This may lead to higher costs in the next decade.	The grid will become more efficient in the next decade, which will help reduce costs.	Same as draft plan.

Choice 1 of 7:

Price

Spend Less $6.15 | Draft Plan $8.39 | Spend More $11.53

$7.04 | $7.93 | $8.83 | $9.73 | $10.62 | Don't know

$-.-- Your selection.

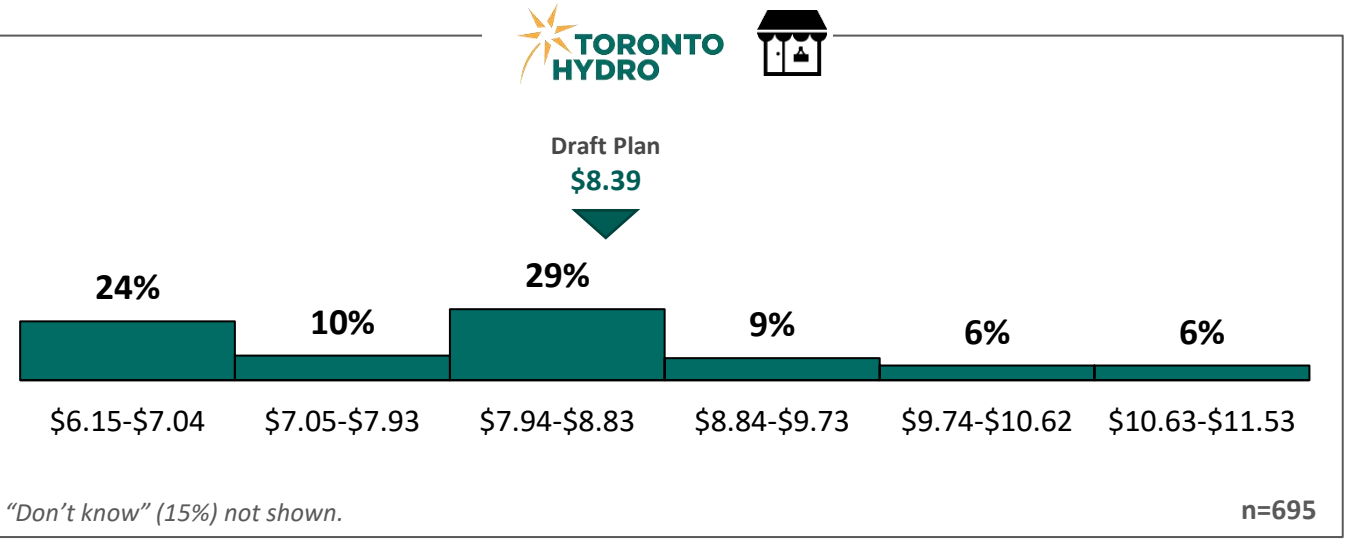
WORKBOOK PAGE

Online Workbook

Amount Spent on the Modernization Plan

Small Business

Q How much do you think Toronto Hydro should spend on its modernization plan?



"Don't know" (15%) not shown.

n=695

	Overall	Region				Consumption Quartiles			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Below Plan	38%	39%	39%	38%	38%	44%	41%	40%	29%
On Plan	22%	20%	23%	20%	24%	20%	14%	24%	30%
Above Plan	24%	27%	20%	22%	27%	22%	31%	22%	22%
Don't Know	15%	14%	18%	20%	11%	13%	15%	15%	18%
TOTAL On Plan + Above Plan	46%	47%	43%	42%	51%	43%	45%	46%	53%

Online Workbook

Additional Feedback on the Modernization Plan

Small Business

Q Do you have additional feedback on Toronto Hydro's draft modernization plan?

Response	%
Modernize, be proactive, invest for the long term	2.8%
Costs are too high already, cost of living, struggling to pay bills	1.6%
Prioritize renewables, solar/wind, and electric vehicles	1.4%
Oppose the increase, increase is too high (general)	1.1%
Need more information	0.8%
Should be funded by tax dollars/government	0.8%
Cost shouldn't be borne by all customers	0.7%
Support the increase (general)	0.6%
Find efficiencies, cut wasteful spending, lower salaries	0.6%
Prevent outages, stable power, system reliability	0.6%
Support developing new technology and innovation	0.4%
Good information	0.3%
Other	0.3%
No response	88.1%

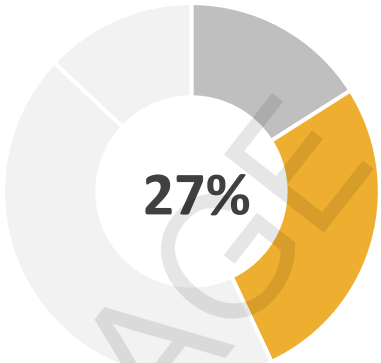
Note: Responses were optional. Only responses > 0.1% are shown.

Draft Growth Plan

Increase Capacity to Serve Customers

What is this section about?

- This section explains how fast the city of Toronto is growing and what it takes for the grid to serve customers' needs for more electricity.
- Toronto Hydro's draft growth plan is about increasing grid capacity to serve customers reliably now and in the future.



- This spending category makes up **27% of the draft plan** and would add **$13.67** on the average customer in this rate class's monthly bill by 2029.

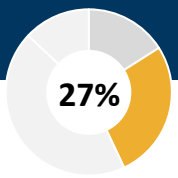
*Click on the video below to learn about Toronto Hydro's **draft growth plan**.*



WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Growth Plan

Small Business



Growing City, Growing Needs

1 Toronto is growing, fast.

Toronto is one of the fastest growing cities in North America. A growing city means that we need a bigger local grid so that homes and businesses can get the power they need, when they need it.



Population Growth

Toronto will add approximately 500,000 more people this decade. To put this into context, Toronto is growing five times faster than Los Angeles.



230 Cranes
Toronto has led the crane count in North America since 2015.



2,114 Projects
including residential and non-residential in development in the city of Toronto.



+$1B in Construction
work planned for city infrastructure in Toronto annually (transportation and water).

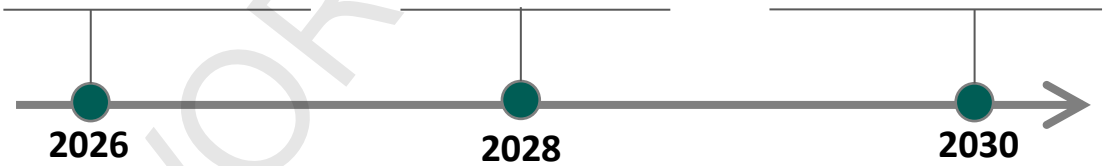
2 Individual customers will use more electricity than ever before.

The average customer will use more electricity in the next 10–15 years, as governments encourage businesses and communities to use less fossil fuels (oil and gas) to address climate change. Here are the key government policies that drive the need for more electricity in Toronto:

The Government of Canada may require 20% of all new car sales to be zero emission and is working towards a target of 60% by 2030.

The City of Toronto Green Building Standard requires all new mid- and high-rise buildings to be near zero GHG emissions.

The carbon tax may increase 161% by 2030 so customers use less oil and gas, and switch to clean electricity for cooking, heating and transportation.



23% **Forecasted increase in customers' need for electricity by the year 2030.**

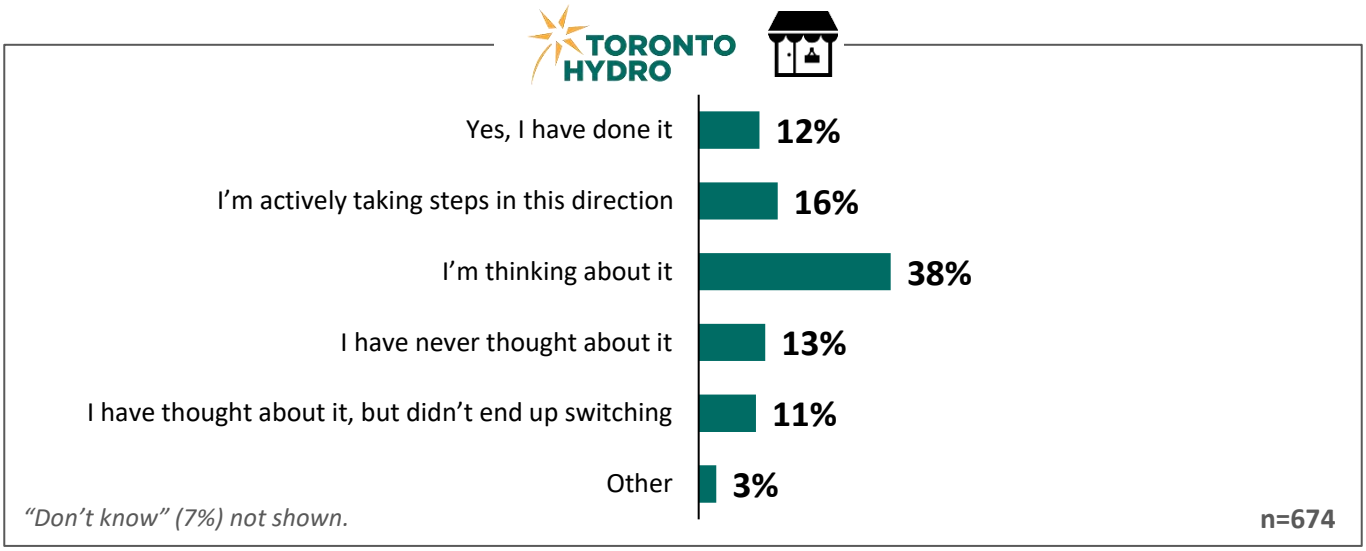
Conservation and energy efficiency has helped manage electricity use over the past 20 years and will continue to play an important role in the future. But conservation alone is not enough. We need a bigger grid to serve customers in the long term.

WORKBOOK PAGE

Online Workbook

Amount Spent on Growth Plan

Q When you think about all your energy bills, has your organization ever considered shifting from one energy source to another to save money or reduce your impact on the environment?
For example, changing from a natural gas-fuelled furnace to an electric heat pump, or from a gas-fuelled vehicle to an electric vehicle?

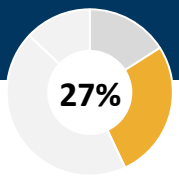


	Region				Consumption Quartiles			
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Yes, I have done it	11%	13%	14%	11%	16%	13%	11%	8%
Actively taking steps	14%	17%	14%	16%	17%	12%	15%	18%
I'm thinking about it	40%	39%	39%	35%	32%	45%	38%	36%
I have never thought about it	12%	11%	14%	14%	11%	12%	16%	13%
I didn't end up switching	13%	11%	12%	10%	12%	10%	12%	11%
Other	7%	7%	3%	9%	8%	4%	6%	10%

Note: Responses were optional.

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Growth Plan

Small Business



Building a bigger grid takes time

It's easy to say Toronto needs more electricity, but meeting this need requires Toronto Hydro to make major investments in the grid, including:



Expand Transformer Stations

Bring more power into the city from the provincial grid to serve growing communities along the new transit corridors (Eglinton LRT, Finch LRT, Ontario Line) and the redevelopment of areas like Downsview Park and the Portlands.



Upgrade and Reconfigure the Grid

Make more space on the grid to enable customers to plug in. Upgrade equipment like cables and transformers and reconfigure how the existing system serves customers to make more space on the grid to accommodate new services like electric vehicle charging stations and solar panels.



Major Infrastructure Developments

Connect major projects like the Finch Light Rail Transit system and the Ontario Line, and relocate Toronto Hydro's grid equipment to enable these and other major infrastructure developments to be constructed in the city.

This work cannot happen quickly. Toronto is densely populated and congested. **Building new power lines and stations takes years of planning and construction.** There are also equipment and resource constraints that limit how quickly Toronto Hydro can build a bigger grid.

Managing Uncertainty

Toronto Hydro develops its forecast from information such as building permits and projected electric vehicle sales. However, customer adoption of new technology is uncertain due to:

Supply chain issues such as equipment and resource shortages can affect the availability of customer technologies.

Technological advancements can lead to fast cost reductions. For example, the price of lithium ion batteries (EVs) decreased by 79% from 2013 to 2022.

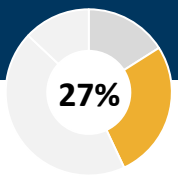
Government policies such as rebates for electric vehicles and solar panels drive customers and suppliers to make certain choices.

If Toronto Hydro invests too quickly to build a bigger grid, it means customers' rates will go up to pay for equipment that will not be used for some time. On the other hand, if it doesn't do enough to expand the grid for higher use of electricity, customers could experience less reliability (brownouts) and delays when they want to connect to the grid or plug in new technologies. Toronto Hydro needs your input on the pace for these investments.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Growth Plan

Small Business

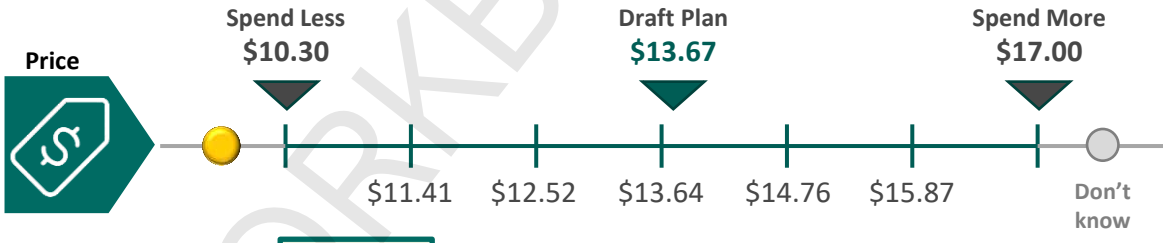


Making Choices: **Growth**

By 2029, Toronto Hydro's draft **growth plan** would cost the typical customer in this rate class **$13.67** more per month on their monthly electricity bill. Toronto Hydro could spend more to better prepare the grid to serve customers' changing needs, or could spend less and wait and see if customers adopt new technologies over the 2025–2029 plan.

	Spend Less	Draft Plan	Spend More
Reliability	May lead to less reliability for customers in high-growth neighbourhoods. Increases reliability risk for the next decade.	Maintains reliability for customers in high-growth neighbourhoods. Manages reliability risk for the next decade.	Maintains reliability for customers in high-growth neighbourhoods. Improves reliability risk for the next decade.
Customer Service	May reduce service levels (longer waits and higher costs) for some customers connecting new services. May reduce customer choice for new technologies.	Maintains service levels for customers connecting new services to the grid. Enables customer choice for new technologies such as solar panels.	May improve service levels (shorter waits and lower costs) for some customers connecting new services to the grid. Improves customer choice for new technologies.
Efficiency	May lead to less efficient work if Toronto Hydro has to build a bigger grid reactively to serve customers.	Supports the ability to serve customers efficiently in the five-year plan based on the projected demand.	Supports the ability to serve customers efficiently in the five-year plan and beyond in the next decade.

Choice 2 of 7:



$-.-- Your selection.

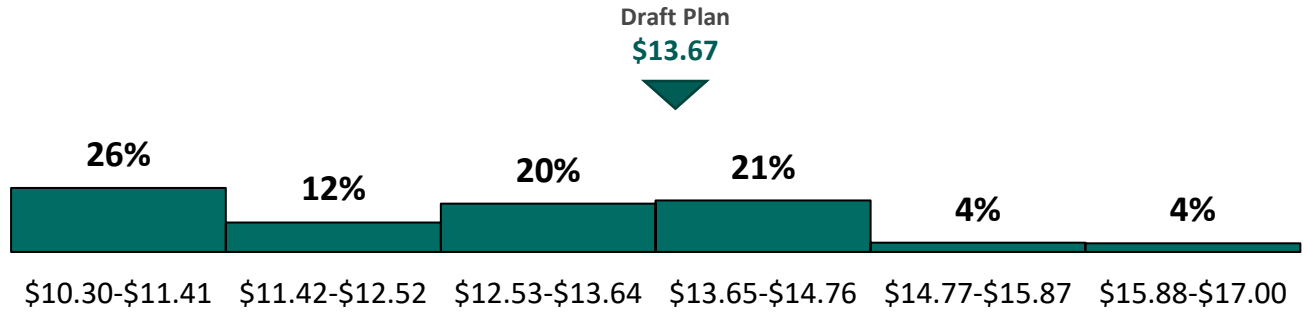
WORKBOOK PAGE

Online Workbook

Amount Spent on the Growth Plan

Small Business

Q How much do you think Toronto Hydro should spend on its growth plan?



"Don't know" (13%) not shown.

n=695

	Overall	Region				Consumption Quartiles			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Below Plan	51%	54%	47%	54%	50%	57%	52%	53%	41%
On Plan	25%	22%	27%	23%	26%	22%	21%	26%	30%
Above Plan	11%	12%	9%	7%	14%	9%	14%	9%	12%
Don't know	13%	13%	17%	16%	11%	12%	12%	13%	17%
TOTAL On Plan + Above Plan	36%	34%	36%	30%	40%	31%	36%	34%	42%

Online Workbook

Additional Feedback on the Growth Plan

Q Do you have additional feedback on Toronto Hydro's draft growth plan?

Response	%
Costs are too high already, cost of living, struggling to pay bills	1.4%
Prioritize renewables, solar/wind, and electric vehicles	1.4%
Find efficiencies, cut wasteful spending, lower salaries	1.2%
Should be funded by developers	1.0%
Oppose the increase, increase is too high (general)	0.6%
Should be funded by tax dollars/government	0.6%
Cost shouldn't be borne by all customers	0.5%
Modernize, be proactive, invest for the long term	0.4%
Prevent outages, stable power, system reliability	0.3%
Need more information	0.3%
Address equity, protect low-income customers	0.2%
Make use of existing infrastructure, past spending	0.1%
Other	0.4%
No response	91.8%

Note: Responses were optional. Only responses > 0.1% are shown.

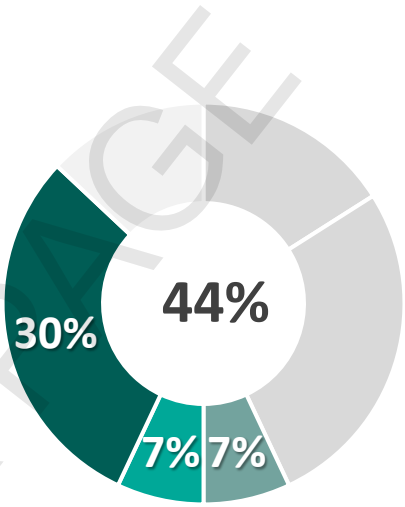
Draft Sustainment Plan

Replacing and Updating Equipment

What is this section about?

- This section is about upkeeping the grid to manage reliability and maintain safe and efficient operations.
- Toronto Hydro's draft sustainment plan section seeks your input in three areas:

1. Managing equipment in very poor condition with a high risk of failure.
2. Pacing the upkeep of equipment near the end of its expected life.
3. Standardizing outdated equipment.



- This spending category makes up **44% of the draft plan** and would add **$22.28** on the average customer in this rate class's monthly bill by 2029.

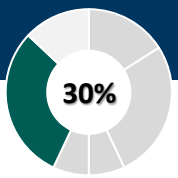
*Click on the video below to learn about Toronto Hydro's **draft sustainment plan**.*



WORK BOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Sustainment Plan

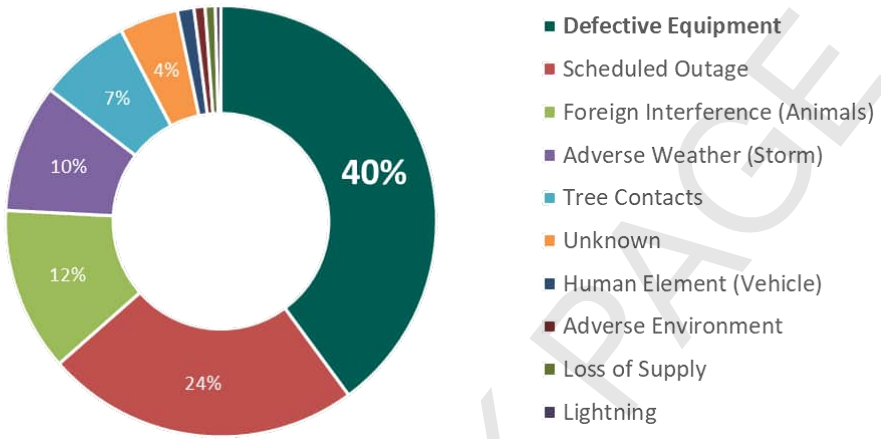
Small Business



1 Reliability: Managing Equipment Failure Risk

While many power outages are caused by external events such as weather and falling trees, roughly **40%** of customer outages are caused by equipment failure. This is the largest single cause of outages, and customers look to Toronto Hydro to manage this risk.

Customer Outage Duration (Hours) by Cause 2018-2022



Toronto Hydro manages failure risk by:

- Inspecting equipment condition regularly, so that maintenance or replacement can be done before the equipment fails.
- Replacing and repairing equipment that is in bad condition or performing poorly. This includes replacing lines with a high number of outages or replacing transformers with visible signs of wear and tear such as rust.

Since 2014, Toronto Hydro's work to upkeep the grid has delivered a 13% reduction in the average number of outages experienced by customers and a 25% reduction in the length of those outages. Toronto Hydro's draft plan is to maintain these reliability results for customers.

Want to learn more about grid reliability and what causes power outages? Click here.

What type of work is Toronto Hydro doing to manage equipment failure risk?

Below is an example of a key investment that Toronto Hydro needs to make to prevent increased outages due to equipment failure.



Replacing Direct-Buried Cable

In parts of the grid that were built a long time ago, cables are laid directly in underground trenches without any protective barrier. **Underground equipment failures contribute to 57% of defective equipment failures, the large majority of which (75%) are due to cables.** Toronto Hydro's draft plan intends to replace 182 kilometers of direct buried cables by 2029 to manage the risk of power outages caused by this equipment.

WORKBOOK PAGE

System reliability

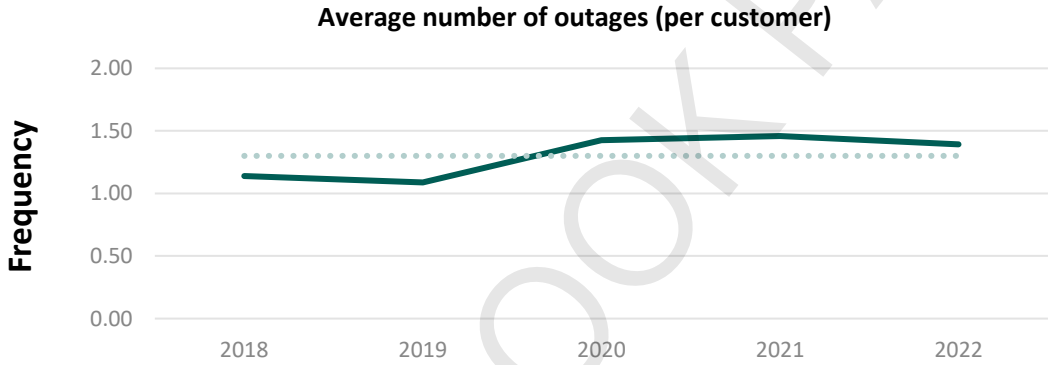
In order to provide feedback on Toronto Hydro's plans, it's important to understand how the distribution system has performed in the past, as well as what's expected in the future.

A core objective of Toronto Hydro's plan is to maintain current levels of reliability over the 2025–2029 plan period, while making foundational technology investments to reduce the length of power outages in the long-term.

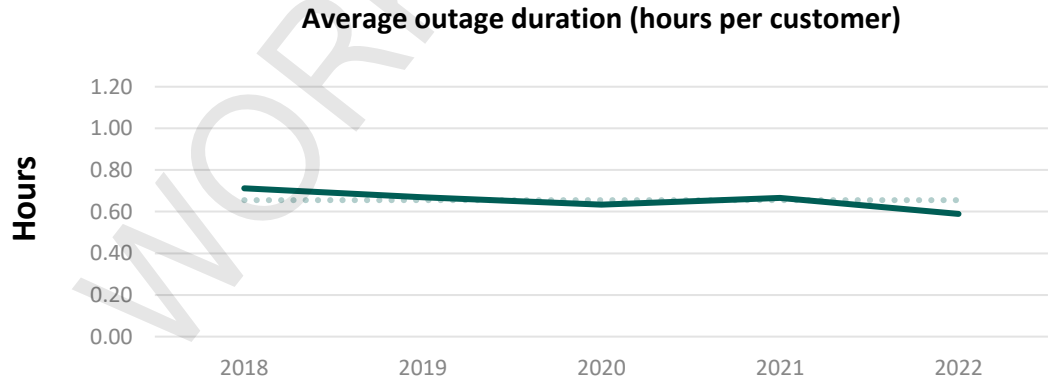
Toronto Hydro recognizes that power interruptions are inconvenient for residential customers and can be very costly for commercial and industrial customers.

Toronto Hydro tracks both the average number of power outages per customer and how long those interruptions last.

Between 2018 and 2022, the typical Toronto Hydro customer has experienced about two outages per year (*or 1.3 outages per customer to be exact*).



Over the same period, the average **duration** of an outage has been about 0.62 hours. Meaning, when the power does go out, Toronto Hydro is typically able to restore power in about 35 minutes.



It's important to keep in mind that these are system averages, and that your actual experience may be different. Some customers connected to newer lines may not experience any outages, while others are experiencing more than the average number of outages each year.

WORKBOOK PAGE

What is most likely to cause an outage?

Although both the number and length of outages have decreased compared to the previous five-year average, equipment failure remains the top cause of outages within Toronto Hydro's control.

That said, in 2022, severe weather presented a unique set of challenges for Toronto Hydro's distribution system.

Causes of Unscheduled Power Outages (five-year average: 2018 to 2022)



12%

Animal Contact: Outages caused by animals such as racoons, squirrels and birds coming in contact with overhead powerlines or transformers.



40%

Equipment Failure: Unscheduled power outages from equipment failure usually occur with distribution equipment that's beyond or approaching the end of their expected useful lives.



10%

Weather-Related Events: Adverse weather such as heavy rain, lightning strikes, ice, snow, wind, extreme temperatures, and freezing rain can disrupt the distribution system.



14%

Other: Includes tree contact (7%) and human interference (1%), such as construction workers accidentally cutting powerlines or motor vehicle accidents involving contact with distribution equipment. 4% of outages are unknown, but most are likely caused by animal contact.

Note: *statistics do not include loss of supply from Hydro One.*

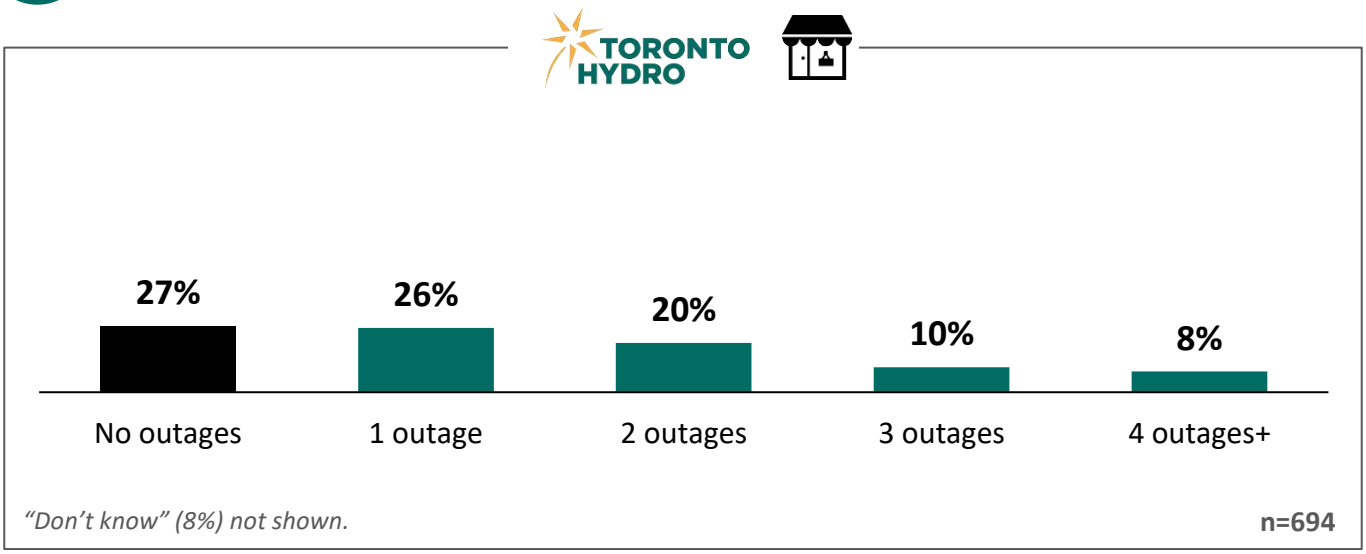
WORKBOOK PAGE

Online Workbook

Amount Spent on the Grid Reliability Plan

Small Business

Q Over the past 12 months, have you experienced any power outages at your organization which lasted longer than one minute?



"Don't know" (8%) not shown.

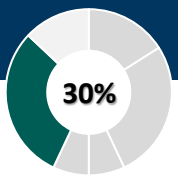
n=694

	Region				Consumption Quartiles			
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
No outages	20%	24%	21%	35%	32%	24%	28%	24%
1 outage	23%	26%	27%	28%	23%	28%	30%	24%
2 outages	24%	21%	24%	15%	17%	25%	16%	22%
3 outages	11%	14%	9%	8%	9%	7%	12%	13%
4 outages+	10%	9%	10%	6%	7%	8%	7%	12%

Note: Responses were optional.

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Sustainment Plan

Small Business



Making Choices: **Managing Equipment Failure Risk**

By 2029, Toronto Hydro's draft plan to manage equipment failure risk would cost the typical customer in this rate class **$15.41** more per month on their monthly electricity bill. Toronto Hydro could spend more to improve reliability, or it could spend less and take on more risk of outages.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of the grid by 2029.	Maintains the overall health (age and condition) of the grid by 2029.	Improves the overall health (age and condition) of the grid by 2029.
Reliability	Reduces reliability compared to current levels. This means more power outages due to equipment failure.	Maintains reliability at current levels. This means holding steady on power outages due to equipment failure.	Improves reliability compared to current levels. This means less power outages due to equipment failure.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work. Increases work volumes and costs for the next decade.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work. Reduces work volumes and costs for the next decade.

Choice 3 of 7:

Price

Spend Less **$10.71**

Draft Plan **$15.41**

Spend More **$19.03**

$12.09 $13.47 $14.86 $16.25 $17.63 Don't know

$-.-- Your selection.

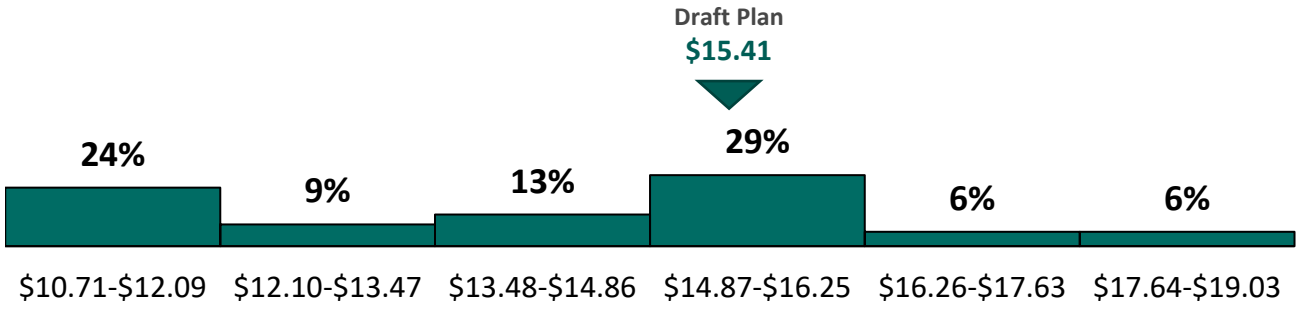
WORKBOOK PAGE

Online Workbook

Amount Spent on the Grid Reliability Plan

Small Business

Q How much do you think Toronto Hydro should spend on its grid reliability plan?



"Don't know" (14%) not shown.

n=695

	Overall	Region				Consumption Quartiles			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Below Plan	48%	50%	48%	52%	46%	54%	46%	55%	38%
On Plan	24%	23%	24%	19%	27%	22%	22%	24%	28%
Above Plan	14%	14%	12%	11%	17%	12%	16%	11%	17%
Don't Know	14%	13%	17%	18%	10%	12%	16%	10%	17%
TOTAL On Plan + Above Plan	38%	37%	36%	30%	44%	34%	38%	35%	45%

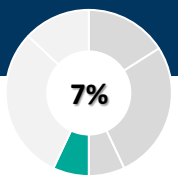
Online Workbook

Additional Feedback on the Grid Reliability Plan

Q Do you have additional feedback on Toronto Hydro's draft grid reliability plan?

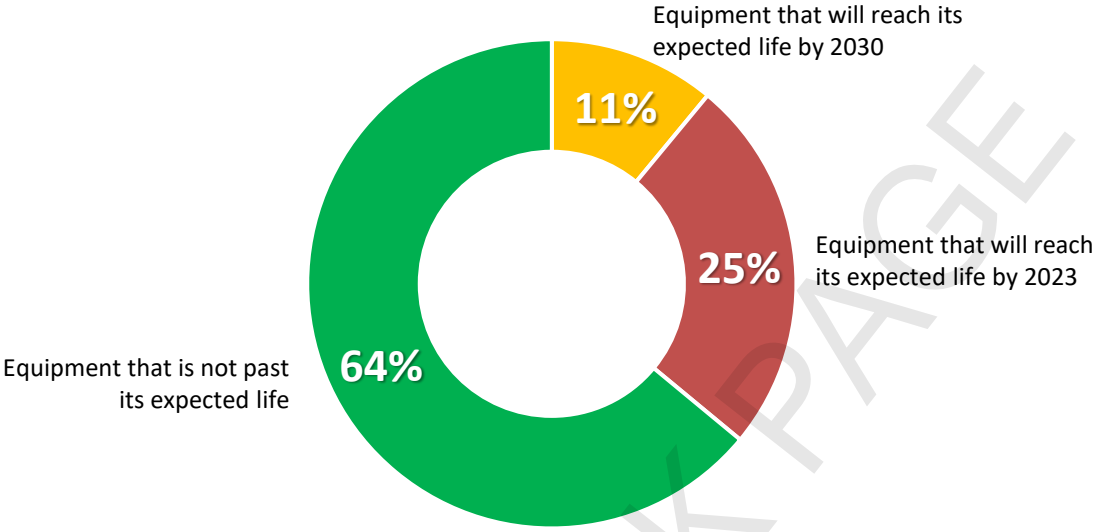
Response	%
Prevent outages, stable power, system reliability	2.0%
Find efficiencies, cut wasteful spending, lower salaries	1.0%
Modernize, be proactive, invest for the long term	0.9%
Need more information	0.5%
Should be funded by tax dollars/government	0.4%
Oppose the increase, increase is too high (general)	0.4%
Make use of existing infrastructure, past spending	0.3%
Costs are too high already, cost of living, struggling to pay bills	0.3%
Address equity, protect low-income customers	0.2%
Cost shouldn't be borne by all customers	0.1%
Prioritize renewables, solar/wind, and electric vehicles	0.1%
Support the increase (general)	0.1%
Support developing new technology and innovation	0.1%
Other	0.2%
No response	93.5%

Note: Responses were optional. Only responses > 0.1% are shown.



2 Paced Upkeep of the Grid

About 25% of Toronto Hydro's equipment is operating past its expected life and an additional 11% is estimated to reach that point by 2030.



In this part of the plan, the key question is whether Toronto Hydro should wait until there are clear signs of equipment failure risk (such as rust or oil leaks), or whether it should get ahead of the problem by replacing old equipment proactively.

If Toronto Hydro waits, it can keep prices lower in the short term. However, this could create a surge of work in future years that will spike prices in the 2030s. There is also a risk that Toronto Hydro will not be able to do the amount of work required to deal with this equipment in the future, which could lead to more outages and higher safety risks due to equipment failures.

Want to learn more about Toronto Hydro's distribution grid? Click here.

What type of work is Toronto Hydro doing to upkeep the grid?

Below is an example of key investments that Toronto Hydro needs to make in a paced way to upkeep the grid and prevent a surge of work to address equipment failure risk in the future.



Paced Replacement of Network Vaults

This equipment is located in underground vaults in the downtown area, which serves many critical customers, such as hospitals and financial institutions. A very large portion of this equipment is going to be in poor condition and past its expected life in the 2030-34 period. To manage this risk, Toronto Hydro's draft plan intends to replace network vaults in a paced manner.

WORKBOOK PAGE

Renewing and replacing infrastructure

Toronto Hydro's grid is a mix of overhead, underground, network and station infrastructure. It operates at three different voltages (27.6kV, 13.8kV, and 4.16kV) and includes approximately:

- 61,300 distribution transformers
- 17,060 primary switches
- 15,393 km of overhead wires
- 13,765 km of underground wires
- 37 transformer stations



Overhead Infrastructure

The overhead system is made up of poles, wires, transformers, switches and other equipment. They are easier to replace, repair and inspect.

However, they are also more prone to foreign interference such as vehicles, trees, animals and weather-related outages.

This system consists of three different types of configurations two of which are outdated configurations from the 1950s and 1960s, making them more challenging to replace and restore particularly after a weather-related outage.



Underground Infrastructure

Toronto Hydro's underground system consists of cables, transformers, switches and civil infrastructures (like manholes). They can be placed either at ground level (green box above ground in your neighbourhood), underground, or inside building vaults (typical for multi-storey buildings). This system is made up of two different types of configurations where the downtown Toronto area consists of lead-covered cable, an outdated equipment with little to no suppliers.

While underground equipment is more resilient during weather-related events, it is more susceptible to flooding and at risk of faster deterioration due to moisture build-up.



Network Infrastructure

Toronto Hydro's network system, predominantly found in the downtown Toronto area, was installed in the early-to-mid 1900s to improve reliability (service levels) for critical loads (like financial institutions) and serves medium-sized loads in high-density areas, and areas with small and narrow sidewalks. It consists of interconnected low-voltage cables, vaults and network units.

While this system is better at handling normal equipment failures, proactive replacement and maintenance of this equipment are critical to avoid vault fires from occurring.



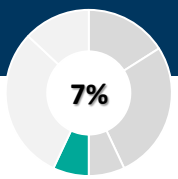
Station Infrastructure

Toronto Hydro's distribution stations receive the transmission supply from Hydro One at very high voltages. Station infrastructure consists of switchgear, power transformers, circuit breakers, remote terminal units (station computers) and battery systems. Toronto Hydro proactively replaces this equipment, as failure at the station level can cause widespread and lengthy power outages.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Sustainment Plan

Small Business



Making Choices: **Paced Upkeep of the Grid**

By 2029, Toronto Hydro's draft plan to ensure paced upkeep of the grid would cost the typical customer in this rate class **$3.40** more on their monthly electricity bill. Toronto Hydro could spend more to get ahead of future equipment failure risk, or it could spend less and defer some of this work at the risk of managing more power outages due to equipment failure in the next decade.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of the grid by 2029.	Maintains the overall health (age and condition) of the grid by 2029.	Improves the overall health (age and condition) of the grid by 2029.
Reliability	Higher risk of power outages due to equipment failure in the next decade.	Manages the risk of power outages due to equipment failure in the next decade.	Reduces the risk of power outages due to equipment failure in the next decade.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work. Increases work volumes and costs for the next decade.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work. Reduces work volumes and costs for the next decade.

Choice 4 of 7:

Price

Spend Less $2.29 | Draft Plan $3.40 | Spend More $5.38

$2.80 | $3.31 | $3.83 | $4.35 | $4.86 | Don't know

$-.-- Your selection.

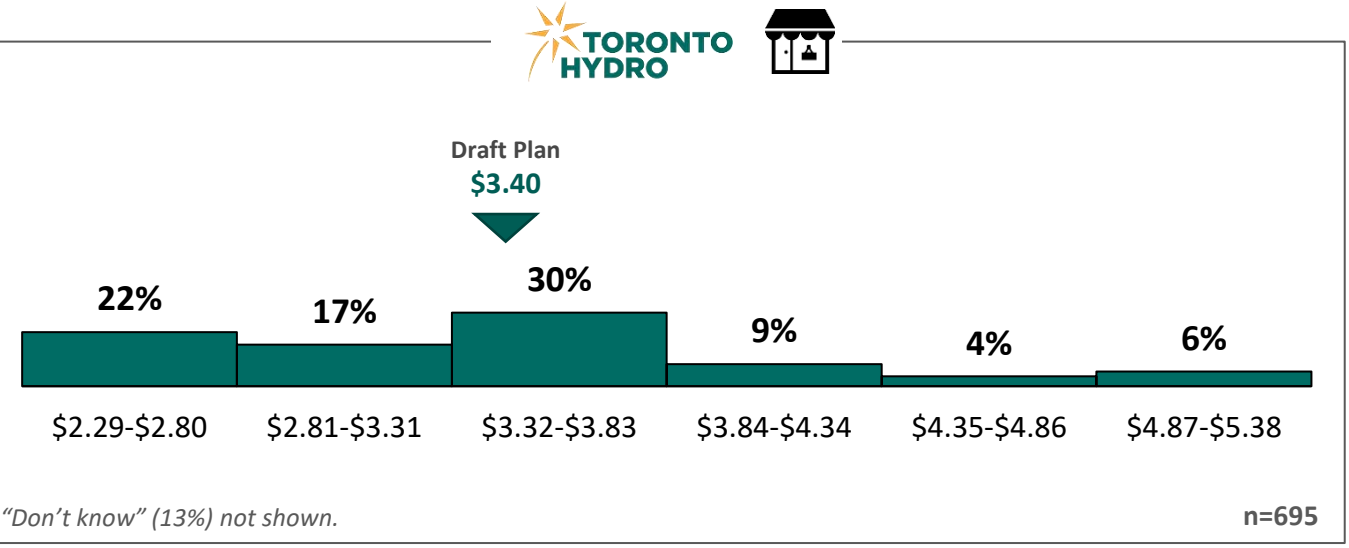
WORKBOOK PAGE

Online Workbook

Amount Spent on the Grid Stewardship Plan

Small Business

Q How much do you think Toronto Hydro should spend on its grid stewardship plan?



"Don't know" (13%) not shown.

n=695

	Overall	Region				Consumption Quartiles			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Below Plan	36%	38%	38%	34%	36%	44%	37%	38%	27%
On Plan	28%	24%	29%	28%	29%	23%	23%	32%	33%
Above Plan	23%	28%	17%	21%	25%	21%	27%	20%	24%
Don't Know	13%	10%	16%	18%	10%	12%	14%	10%	16%
TOTAL On Plan + Above Plan	51%	52%	46%	48%	54%	44%	49%	52%	57%

Online Workbook

Small Business

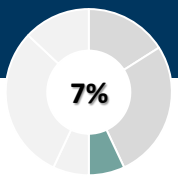
Additional Feedback on the Grid Stewardship Plan

Q Do you have additional feedback on Toronto Hydro's draft grid stewardship plan?

Response	%
Modernize, be proactive, invest for the long term	1.0%
Find efficiencies, cut wasteful spending, lower salaries	0.5%
Support the increase (general)	0.5%
Prevent outages, stable power, system reliability	0.5%
Should be funded by tax dollars/government	0.2%
Should be funded by developers	0.2%
Prioritize renewables, solar/wind, and electric vehicles	0.2%
Focus on demand side management/provide education about reducing usage	0.2%
Need more information	0.1%
Costs are too high already, cost of living, struggling to pay bills	0.1%
Cost shouldn't be borne by all customers	0.1%
Other	0.1%
No response	96.2%

Note: Responses were optional. Only responses > 0.1% are shown.

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Sustainment Plan

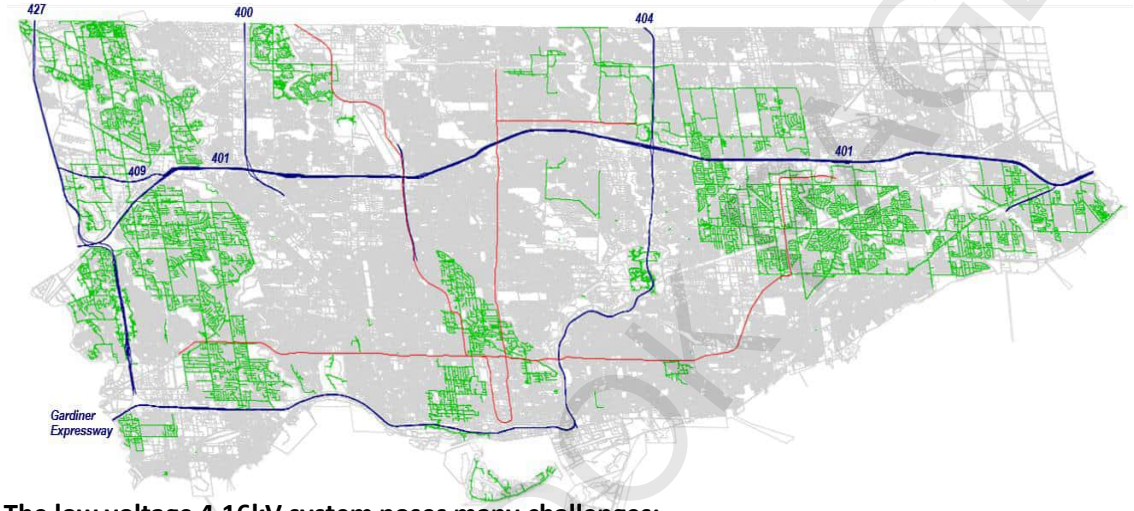


3 Standardize the Grid

Because of its history, Toronto Hydro has an old and diverse grid. Toronto Hydro is made up of 6 municipal utilities that were joined in 1998 when the City of Toronto was formed. Each utility owned and operated different types of equipment. As a result, Toronto Hydro's grid has three different voltage levels: 4.16kV, 13.8kV and 27.6kV.

The 27.6kV voltage level is the current standard for local grids. However, a large part of Toronto Hydro's grid is served at 4.16kV and 13.8kV.

Location of Outdated Voltage Lines



The low voltage 4.16kV system poses many challenges:

- Long outages for customers and higher cost to restore power – in 2022, the longest outage on the 4.16 kV system was 80 hours.
- Less efficient at carrying power over long distances, which means more electricity is lost as it travels from point A to point B (line losses).
- Less capacity to serve customers' growing electricity needs, which means longer waits and higher costs to connect new services such as electric vehicles and solar panels.
- Risk of supply chain and labour shortages as manufacturers stop making this equipment and technicians trained on this equipment retire.

What type of work is Toronto Hydro doing to standardize the grid?

Below is an example of a key investment to replace outdated equipment.



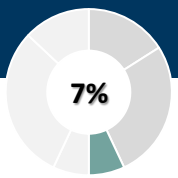
Voltage Conversion from 4.16kV/13.8kV to 27.6kV

Voltage conversion entails a full rebuild of outdated equipment such as rear lot construction (poles and wires in customers' backyards). This work improves reliability, safety and makes the grid more efficient. Toronto Hydro's draft plan intends to convert 1400 customers from rear lot service and works to eliminate rear lot construction from the grid by the late 2040s.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Sustainment Plan

Small Business



Making Choices: **Standardize the Grid**

By 2029, Toronto Hydro's draft **plan to standardize the grid** would cost the typical customer in this rate class **$3.47** more on their monthly electricity bill. Toronto Hydro could spend more to speed up the pace of replacing outdated equipment or it could spend less to slow down the pace and delay the benefits of this work. For example, under spend more Toronto Hydro would convert all rear lot customers by the early 2040s, and under spend less by the 2050s.

	Spend Less	Draft Plan	Spend More
Reliability	Slower progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.	Steady progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.	Faster progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.
Customer Service	Less progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels.	Steady progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels	Faster progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels.
Efficiency	Slower progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.	Steady progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.	Faster progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.

Choice 5 of 7:

Price

Spend Less $2.69 | Draft Plan $3.47 | Spend More $4.46

$2.98 | $3.27 | $3.57 | $3.86 | $4.16 | Don't know

$-.-- Your selection.

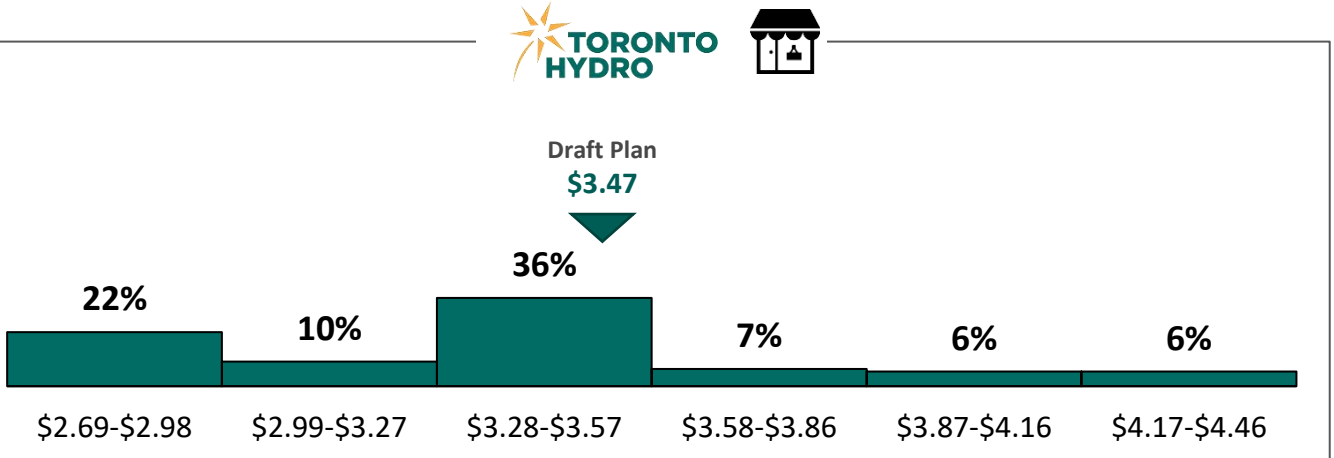
WORKBOOK PAGE

Online Workbook

Amount Spent on the Equipment Standardization Plan

Small Business

Q How much do you think Toronto Hydro should spend on its equipment standardization plan?



"Don't know" (13%) not shown.

n=695

	Overall	Region				Consumption Quartiles			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Below Plan	38%	42%	39%	37%	37%	45%	37%	42%	30%
On Plan	28%	23%	32%	25%	30%	28%	25%	29%	30%
Above Plan	20%	25%	13%	18%	24%	15%	23%	19%	23%
Don't Know	13%	10%	16%	20%	9%	12%	15%	10%	17%
TOTAL On Plan + Above Plan	48%	47%	46%	43%	54%	43%	48%	48%	54%

Online Workbook

Small Business

Additional Feedback on the Equipment Standardization Plan

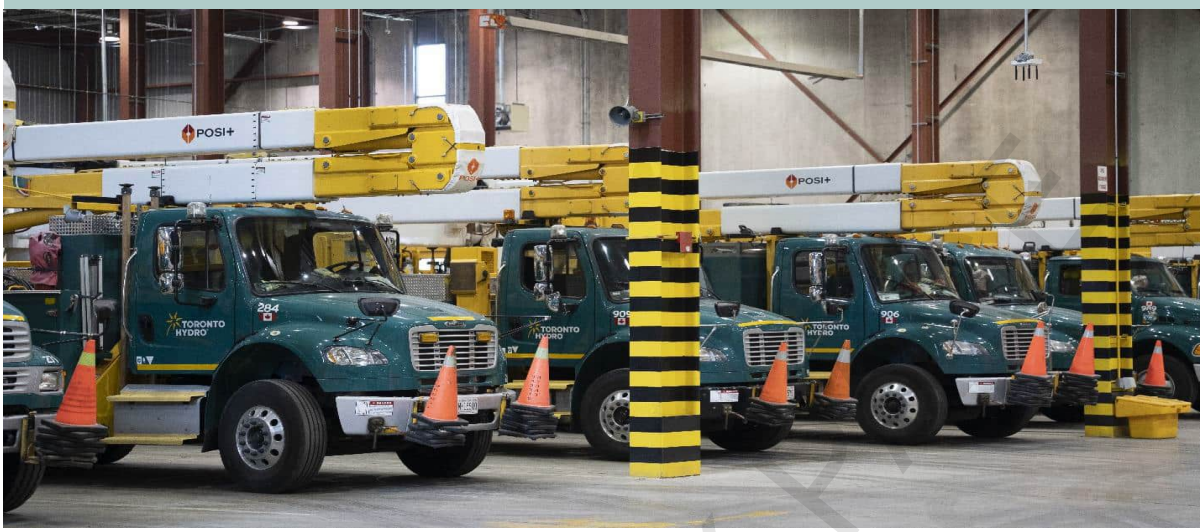
Q Do you have additional feedback on Toronto Hydro's draft equipment standardization plan?

Response	%
Modernize, be proactive, invest for the long term	1.3%
Find efficiencies, cut wasteful spending, lower salaries	0.7%
Need more information	0.6%
Should be funded by tax dollars/government	0.5%
Prioritize renewables, solar/wind, and electric vehicles	0.4%
Costs are too high already, cost of living, struggling to pay bills	0.3%
Cost shouldn't be borne by all customers	0.3%
Other	0.1%
No response	95.9%

Note: Responses were optional. Only responses > 0.1% are shown.

Draft General Plant Plan

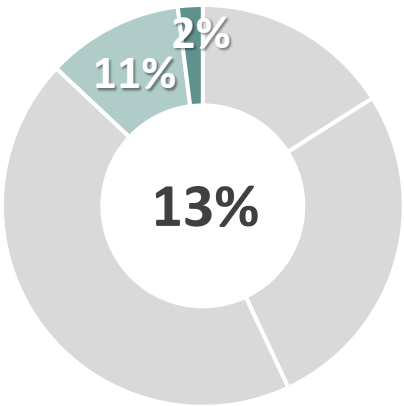
Keeping the Business Running



What is this section about?

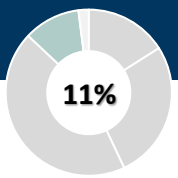
- This section is about the vehicles, work centres and IT systems that keep Toronto Hydro's business running efficiently.
- Toronto Hydro seeks your input on two choices within this part of the plan:

1. The pace of replacing the equipment needed to keep the business running.
2. The pace of reducing Toronto Hydro's emissions from its own operations.



- This spending category makes up **13% of the draft plan** and would add **$6.53** on the average customer in this rate class's monthly bill by 2029.

WORKBOOK



1 Keep the Business Running

Work centres, vehicles and information technology systems are the backbone of Toronto Hydro's day-to-day operations. This equipment must be maintained in good working condition for efficient and reliable operations so that crews can restore power and customers can access key services like their online account and the outage restoration map.

- As with grid equipment, Toronto Hydro uses information such as age and condition data from inspections to decide which equipment should be replaced versus repaired.
- Toronto Hydro repairs equipment in poor condition such as leaking roofs, failed furnaces and worn-out vehicle braking systems. It also replaces equipment like software programs and hardware servers that are past expected useful life.

What type of work is Toronto Hydro doing to manage failure risk?

Below is an example of a key investment that Toronto Hydro needs to make to keep the business running and manage the risk of equipment failure.



Station Buildings

Toronto Hydro has approximately 250 properties that either house distribution stations equipment such as cables and transformers or support the distribution system.

Over 80% of station buildings are older than 40 years and require repairs and investments to address the following types of problems:

- Structural damage to the building (cracked foundations, leaking roofs)
- Mechanical, electrical and plumbing equipment in poor condition
- Compliance with building and fire code requirements

This work ensures safe and efficient operations and minimizes the risk of outages that can affect many customers. For example, structural damage to a station building poses a direct risk to distribution equipment such as power transformers.

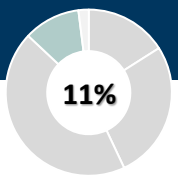
So, how much and how quickly Toronto Hydro decides to invest in keeping their business running has a direct impact on customers. While this equipment may remain in service for a long time, when they unexpectedly fail, the costs incurred usually far exceed proactive investments (repairs and replacements) and can have a significant impact on system reliability and customer service.

WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Draft General Plant Plan

Small Business



Making Choices: **Keep the Business Running**

By 2029, Toronto Hydro's draft plan to keep the business running would cost the typical customer in this rate class **$5.73** more on their monthly electricity bill. Toronto Hydro could spend more to improve equipment health (age and condition) and functionality (better safety features) or spend less and take on more risk of equipment downtime.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of general plant equipment by 2029.	Maintains the overall health (age and condition) of general plant equipment by 2029.	Improves the overall health (age and condition) of general plant equipment by 2029.
Reliability & Service	Reduces equipment availability, which could mean longer outages or lower levels of customer service.	Maintains equipment availability consistent with current levels.	Improves equipment availability and functionality, which could mean better reliability and customer service levels.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work, which is more costly and increases equipment downtime.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work, and better equipment functionality.

Choice 6 of 7:

Price

Spend Less **$3.96** | Draft Plan **$5.73** | Spend More **$6.78**

$4.42 | $4.89 | $5.36 | $5.83 | $6.30 | Don't know

$-.-- Your selection.

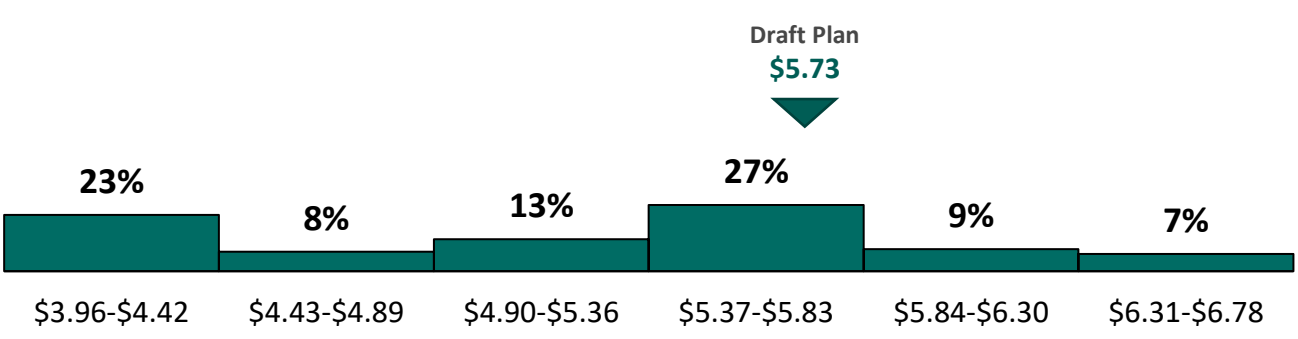
WORKBOOK PAGE

Online Workbook

Amount Spent on Keeping the Business Running

Small Business

Q How much do you think Toronto Hydro should spend to keep the business running?



"Don't know" (13%) not shown.

n=695

	Overall	Region				Consumption Quartiles			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Below Plan	51%	51%	50%	50%	51%	57%	48%	54%	44%
On Plan	22%	24%	23%	21%	21%	18%	21%	24%	25%
Above Plan	14%	15%	12%	11%	17%	13%	17%	11%	15%
Don't Know	13%	11%	15%	18%	11%	11%	15%	10%	16%
TOTAL On Plan + Above Plan	36%	38%	36%	32%	38%	32%	37%	36%	40%

Online Workbook

Additional Feedback on Keeping the Business Running

Q Do you have additional feedback on Toronto Hydro's draft plan for keeping the business running?

Response	%
Find efficiencies, cut wasteful spending, lower salaries	1.5%
Modernize, be proactive, invest for the long term	0.6%
Costs are too high already, cost of living, struggling to pay bills	0.3%
Should be funded by tax dollars/government	0.2%
Make use of existing infrastructure, past spending	0.1%
Cost shouldn't be borne by all customers	0.1%
Prioritize renewables, solar/wind, and electric vehicles	0.1%
Need more information	0.1%
Other	0.2%
No response	96.8%

Note: Responses were optional. Only responses > 0.1% are shown.

2 Reducing Toronto Hydro's Emissions

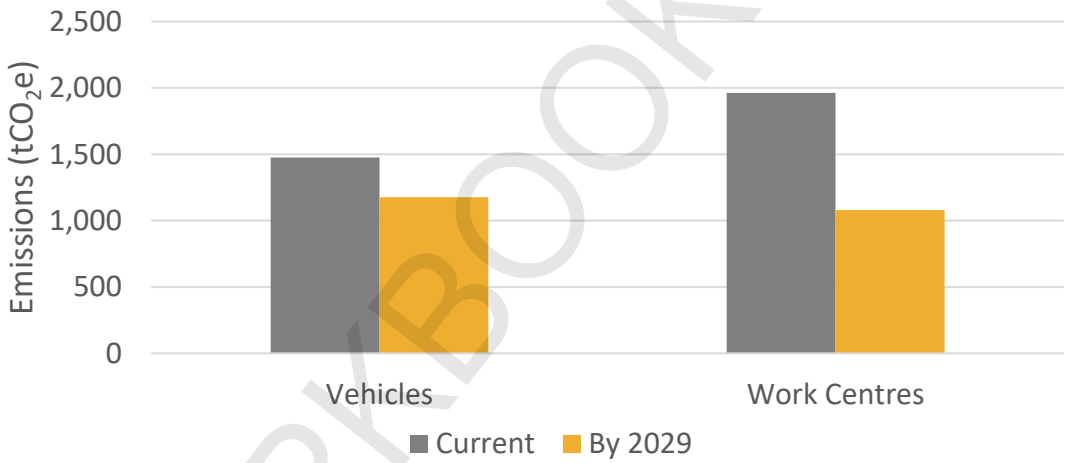
To address climate change, companies around the world are setting targets to reduce greenhouse gas (GHG) emissions from fossil fuels — a pledge commonly known as Net Zero.

Moving toward Net Zero has increasingly become the expectation of governments, financial markets, stakeholders and customers. For example, in October 2019, Toronto City Council unanimously voted to accelerate efforts to reduce emissions across the city.

To do its part in addressing climate change, Toronto Hydro is committed to reducing emissions from its vehicles and work centres by:

- Replacing gasoline and diesel power vehicles with hybrid and electric vehicles
- Converting natural gas boilers and heaters in its work centres to electric ones.

Toronto Hydro's Draft Plan to Reduce Emissions



Carbon Tax Savings

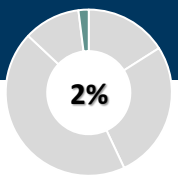
Reducing carbon emissions from vehicles and work centres could help Toronto Hydro manage rising costs due to the carbon tax (recall that the carbon tax may increase by 161% from 2023 to 2030). **Over the 2025–2029 period, Toronto Hydro's draft plan could reduce carbon tax payments by roughly half a million dollars.**

With your feedback, Toronto Hydro needs to decide how quickly to transition to cleaner sources of energy for its operations. In the next section, you will be presented these options.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft General Plant Plan

Small Business



Making Choices: **Reducing Toronto Hydro's Emissions**

By 2029, Toronto Hydro's draft plan to reduce emissions would cost the typical customer in this rate class **$0.81** more on their monthly electricity bill. Toronto Hydro could spend more for faster progress towards reducing its emissions, or spend less to slow down the progress.

	Spend Less	Draft Plan	Spend More
Environment	Less progress to reduce emissions — about 27% reduction by the end of the decade.	Steady progress to reduce emissions — about 35% reduction by the end of the decade.	Faster progress to reduce emissions — about 36% reduction by the end of the decade.
Efficiency	Higher exposure to rising energy costs (oil and gas) due to the carbon taxes and other pressures.	Managed exposure to rising energy costs (oil and gas) due to the carbon tax and other pressures.	Less exposure to rising energy costs (oil and gas) due to carbon taxes and other pressures.

WORKBOOK PAGE

Choice 7 of 7:

Price

Spend Less $0.58 | Draft Plan $0.81 | Spend More $0.90

$0.62 | $0.68 | $0.73 | $0.78 | $0.84 | Don't know

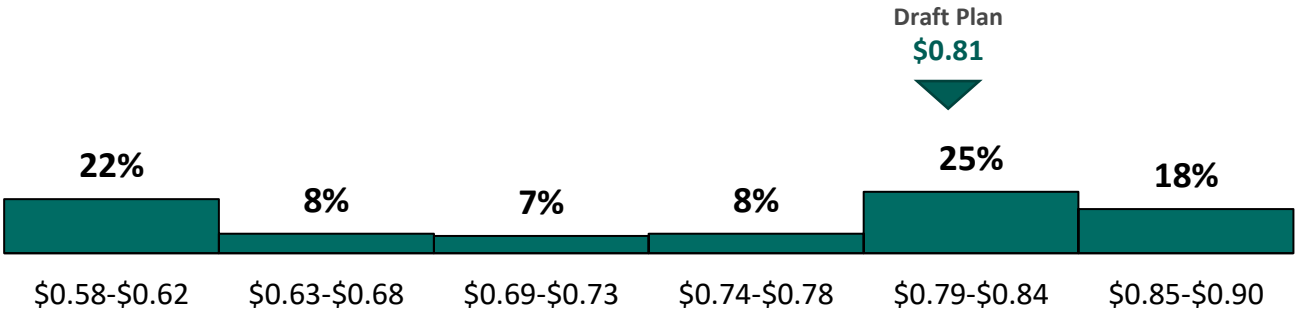
$-.-- Your selection.

Online Workbook

Amount Spent on Decarbonization

Small Business

Q How much do you think Toronto Hydro should spend to reduce its own emissions?



"Don't know" (13%) not shown.

n=695

	Overall	Region				Consumption Quartiles			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Below Plan	45%	54%	43%	45%	41%	50%	43%	46%	41%
On Plan	23%	15%	25%	21%	25%	18%	24%	23%	26%
Above Plan	20%	19%	16%	17%	25%	23%	20%	22%	16%
Don't Know	13%	12%	16%	16%	9%	10%	14%	10%	17%
TOTAL On Plan + Above Plan	43%	34%	41%	38%	50%	40%	43%	45%	42%

Online Workbook

Additional Feedback on Decarbonization

Q Do you have additional feedback on Toronto Hydro's draft decarbonization plan?

Response	%
Prioritize renewables, solar/wind, and electric vehicles	1.6%
Support the increase (general)	0.4%
Find efficiencies, cut wasteful spending, lower salaries	0.4%
Modernize, be proactive, invest for the long term	0.3%
Cost shouldn't be borne by all customers	0.3%
Should be funded by tax dollars/government	0.3%
Oppose the increase, increase is too high (general)	0.3%
Need more information	0.2%
Other	0.1%
No response	96.2%

Note: Responses were optional. Only responses > 0.1% are shown.

Online Workbook

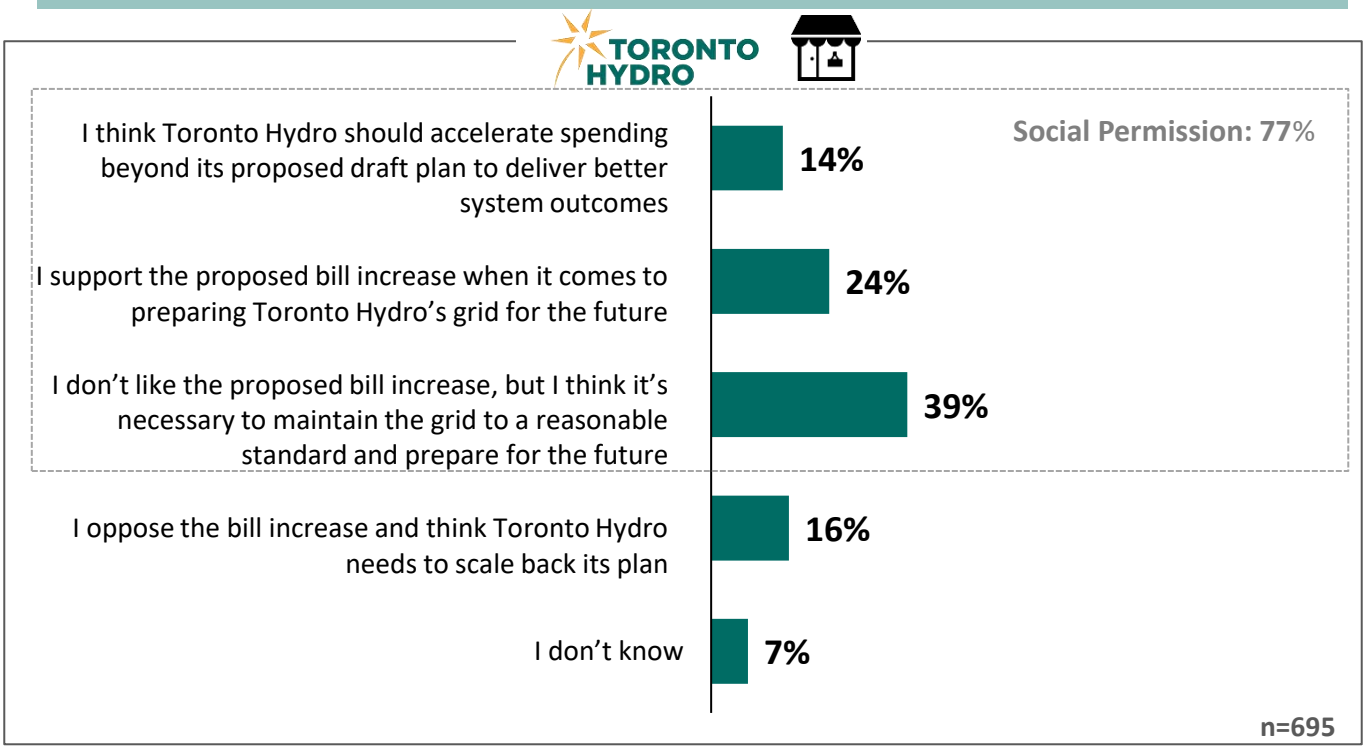
Social Permission

Small Business

Q

Toronto Hydro has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Toronto Hydro would like to know how you feel about the total rate impact of its current draft plan.

Considering what you have learned about Toronto Hydro's 2025–2029 draft plan and that this may result in a **$50.88 increase** in the distribution portion of your monthly electricity bill by 2029, which of the following best represents your point of view?



Online Workbook

Social Permission

Small Business

Q

Toronto Hydro has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Toronto Hydro would like to know how you feel about the total rate impact of its current draft plan.

Considering what you have learned about Toronto Hydro's 2025–2029 draft plan and that this may result in a **$50.88 increase** in the distribution portion of your monthly electricity bill by 2029, which of the following best represents your point of view?

	Region			
	Etobicoke/York	North York	Scarborough	Toronto/East York
Accelerate spending	16%	14%	18%	12%
Support proposed bill	23%	22%	19%	27%
Necessary to maintain grid	35%	41%	45%	37%
Oppose the bill increase	17%	16%	12%	17%
I don't know	9%	8%	5%	7%
Social Permission	**74%**	**77%**	**82%**	**76%**

	Consumption Quartiles			
	First	Second	Third	Fourth
Accelerate spending	14%	17%	9%	18%
Support proposed bill	21%	21%	27%	25%
Necessary to maintain grid	40%	39%	47%	31%
Oppose the bill increase	19%	17%	12%	13%
I don't know	6%	6%	5%	13%
Social Permission	**74%**	**77%**	**83%**	**74%**

Online Workbook

Small Business

Final Comments for the Draft Plan & Proposed Rate Increase

Q Do you have any final comments regarding Toronto Hydro's draft plan for 2025–2029 and the proposed rate increase?

Response	%
Find efficiencies, cut wasteful spending, lower salaries	1.5%
Modernize, be proactive, invest for the long term	1.5%
Costs are too high already, cost of living, struggling to pay bills	1.2%
Should be funded by tax dollars/government	1.0%
Need more information	0.8%
Support the increase (general)	0.7%
Prioritize renewables, solar/wind, and electric vehicles	0.7%
Oppose the increase, increase is too high (general)	0.7%
Address equity, protect low-income customers	0.5%
Should be funded by developers	0.3%
Prevent outages, stable power, system reliability	0.3%
Cost shouldn't be borne by all customers	0.1%
Other	0.1%
No response	90.5%

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Small Business Customers

Online Workbook Diagnostics

Section 10.2

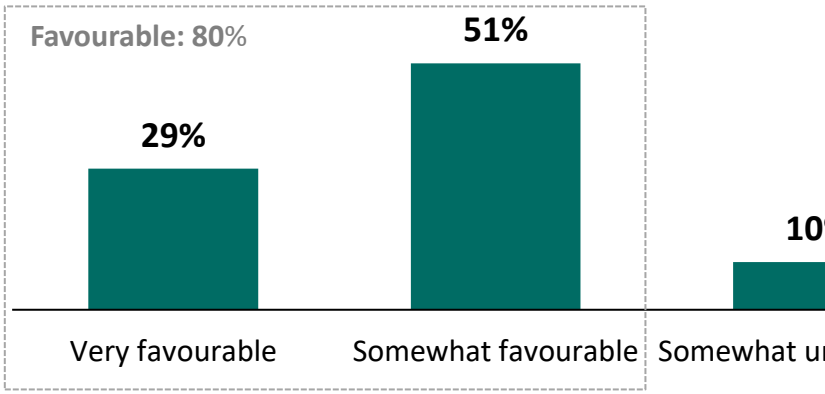


Online Workbook

Workbook Impression

Small Business

Q Overall, what is your impression of the survey you just completed?



"Don't know" (7%) not shown.

n=695

Online Workbook

Workbook Impression

Small Business

Q Overall, what is your impression of the survey you just completed?

	Region			
	Etobicoke/York	North York	Scarborough	Toronto/East York
Very favourable	24%	25%	34%	31%
Somewhat favourable	50%	57%	50%	49%
Somewhat unfavourable	15%	10%	5%	10%
Very unfavourable	4%	1%	1%	4%
Don't know	6%	7%	9%	6%
Favourable (Very + Somewhat)	**74%**	**82%**	**84%**	**80%**
Unfavourable (Very + Somewhat)	**19%**	**11%**	**6%**	**14%**

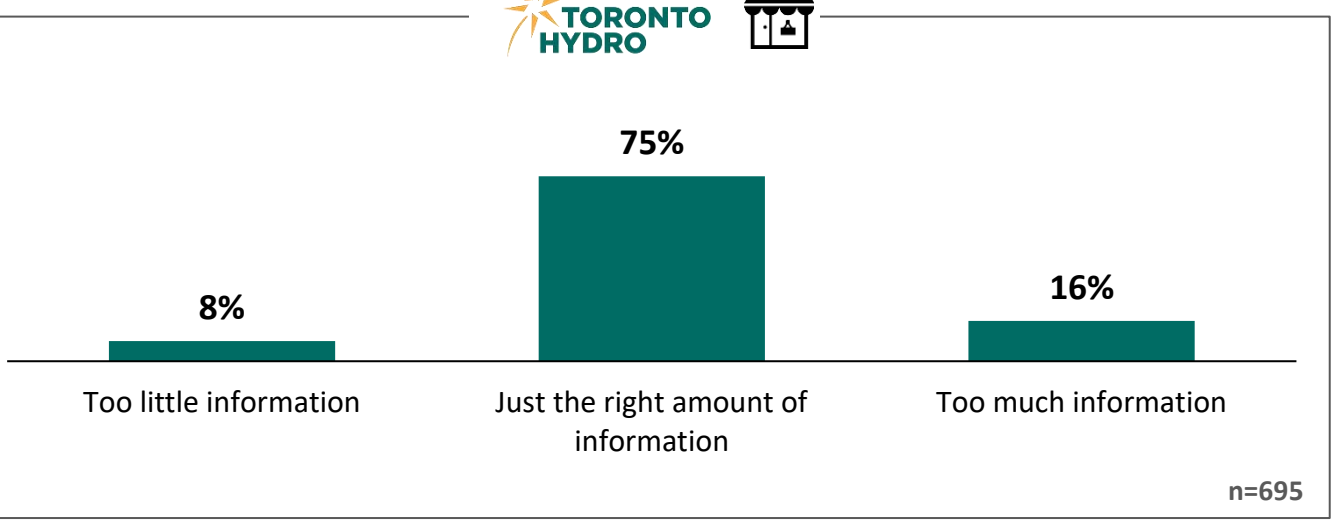
	Consumption Quartiles			
	First	Second	Third	Fourth
Very favourable	26%	31%	28%	32%
Somewhat favourable	51%	50%	56%	47%
Somewhat unfavourable	13%	12%	6%	9%
Very unfavourable	4%	4%	2%	2%
Don't know	6%	4%	8%	11%
Favourable (Very + Somewhat)	**77%**	**81%**	**84%**	**79%**
Unfavourable (Very + Somewhat)	**17%**	**15%**	**8%**	**11%**

Online Workbook

Amount of Information

Small Business

Q In this survey, do you feel that Toronto Hydro provided too much information, not enough, or just the right amount?



	Region				Consumption Quartiles			
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Too little information	10%	7%	8%	8%	11%	6%	8%	7%
Just the right amount of information	75%	77%	79%	73%	74%	80%	74%	73%
Too much information	15%	17%	13%	19%	16%	13%	17%	19%

Online Workbook

Content Missing from Engagement

Q Was there any content missing that you would have liked to have seen included in this survey?

Response	%
Operational efficiencies (salaries, spending) and accountability	3.9%
Environmental sustainability, info about EVs/charging	1.4%
More information on the costs, breakdown of either the plan or bill	0.6%
Confusing, navigational issues in the survey	0.6%
How this benefits customers	0.6%
Ways to reduce usage, save money on bill	0.5%
Satisfied with the information presented	0.4%
Comparison to other regions or utilities	0.4%
Information about power generation	0.2%
Reliability (e.g. Plans for underground cables)	0.1%
Delivery charges	0.1%
Other	0.6%
No response	90.6%

Online Workbook

Outstanding Questions

Q Is there anything that you would still like answered?

Response	%
More information on the costs, breakdown of either the plan or bill	2.4%
Environmental sustainability, info about EVs/charging	1.1%
Operational efficiencies (salaries, spending) and accountability	1.0%
Reliability (e.g. Plans for underground cables)	0.5%
Ways to reduce usage, save money on bill	0.3%
Delivery charges	0.2%
Satisfied with the information presented	0.2%
More historic context, past rate increases and spending	0.2%
Confusing, navigational issues in the survey	0.1%
Comparison to other regions or utilities	0.1%
Other	0.3%
No response	93.6%

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro. The conclusions drawn and opinions expressed are those of the authors.

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INNOVATIVE RESEARCH GROUP

CONFIDENTIAL

APPENDIX 11

Commercial & Industrial
Workbook Report

TORONTO HYDRO

November 2, 2023

STRICTLY CONFIDENTIAL

2025 – 2029 Rate Application

Report Navigation

APPENDICIES

PHASE I

- APPENDIX.01 – Customer Engagement Focus Groups
- APPENDIX.02 – Customer Sample Validation
- APPENDIX.03 – Residential Needs and Preferences Survey
- APPENDIX.04 – Small Business Needs and Preferences Survey
- APPENDIX.05 – Commercial & Industrial Needs and Preferences Survey
- APPENDIX.06 – Key Accounts Needs and Preferences Survey
- APPENDIX.07 – Needs and Preferences Planning Placemat

PHASE II

- APPENDIX.08 – Customer Engagement Workbook Overview
- APPENDIX.09 – Residential Workbook Report
- APPENDIX.10 – Small Business Workbook Report
- APPENDIX.11 – Commercial & Industrial Workbook Report
- APPENDIX.12 – Key Accounts Workbook Report
- APPENDIX.13 – Customer Engagement Workbook (Residential Version)

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Commercial & Industrial Customers

Online Workbook Report

Section 11.1



Online Survey

Survey Design & Methodology

C&I

Toronto Hydro Electric-System Ltd. (THESL) engaged Innovative Research Group (INNOVATIVE) to design, execute and document the results of THESL's customer engagement process as part of the development of its 2025–2029 business plan.

Field Dates

All Toronto Hydro GS 50-999kW (commercial & industrial) customers with an email address on Toronto Hydro's file received the **Commercial & Industrial Online Workbook**. Customers had the opportunity to complete the survey between **April 3rd and May 22nd, 2023**.

Incentives

Customers who completed the survey from April 3rd to May 10th were invited to enter a draw to win a $5,000 donation to a charity of the organization's choosing (as shown on pg.7). To increase the response rate, INNOVATIVE structured a more direct incentive for customers who filled out the survey from May 11th to May 22nd. Those who completed the survey then received a $50 Uber Eats gift card.

Commercial & Industrial Online Survey Completes

Customers with email addresses on file received an email invitation. It included a unique survey URL that linked back to their annual consumption, region and rate class.

A total of **264** (unweighted) Toronto Hydro commercial & industrial customers completed the online survey.

Sample Weighting

The commercial & industrial online survey sample has been weighted proportionately by consumption quartiles and region in order to be representative of the broader Toronto Hydro service territory.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region.

Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
Etobicoke/York	15 (11)	14 (14)	7 (13)	14 (15)	50 (53)
North York	25 (15)	22 (19)	15 (19)	21 (19)	83 (73)
Scarborough	17 (15)	15 (12)	8 (13)	13 (12)	53 (52)
Toronto/East York	28 (24)	20 (21)	10 (21)	20 (20)	78 (86)
Total	85 (66)	71 (66)	40 (66)	68 (66)	264 (264)

Graphs and tables may not always total 100% due to rounding values rather than any error in data.
Sums are added before rounding numbers.

Online Survey
Firmographics breakdown

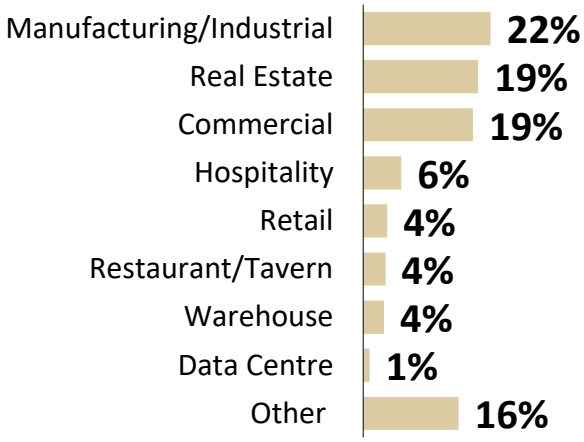
C&I

Managing/Overseeing Organization's Electrical or Hydro Bill



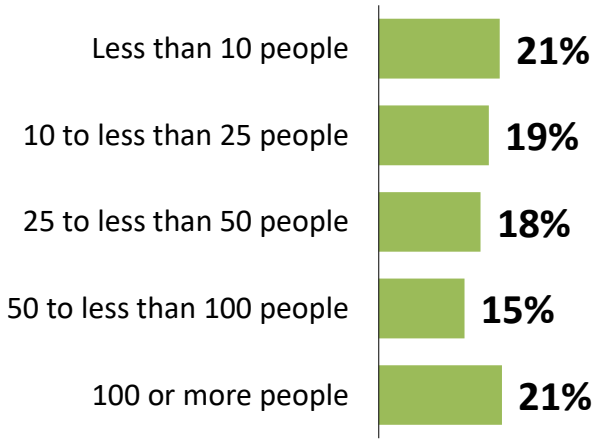
"Prefer not to say" (9%) and "Don't know" (2%) not shown.

Sector



"Prefer not to say" (5%) and "Don't know" (1%) not shown.

Number of Employees at the Organization



"Prefer not to say" (5%) and "Don't know" (2%) not shown.

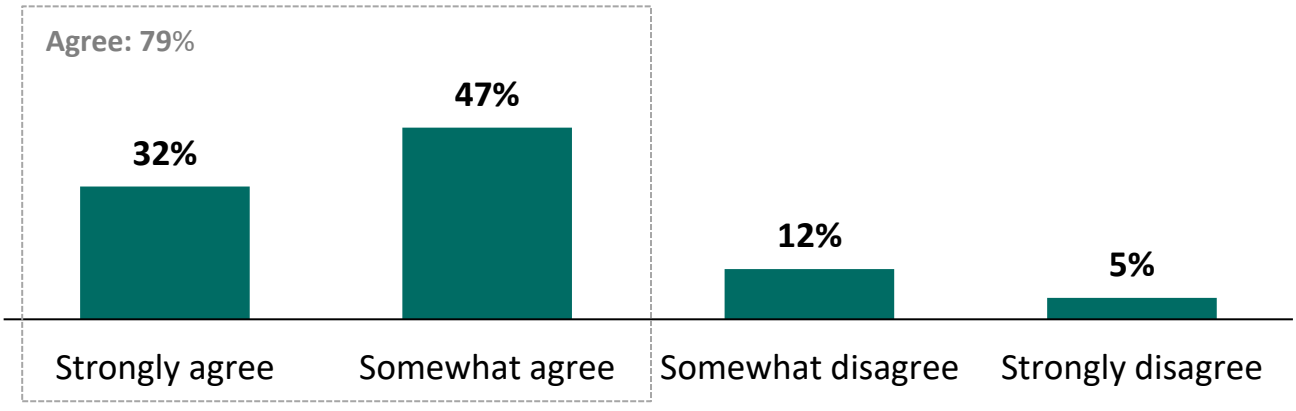
Online Survey
Environmental Controls

C&I

To what extent do you agree or disagree with the following statements?

Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

TORONTO HYDRO

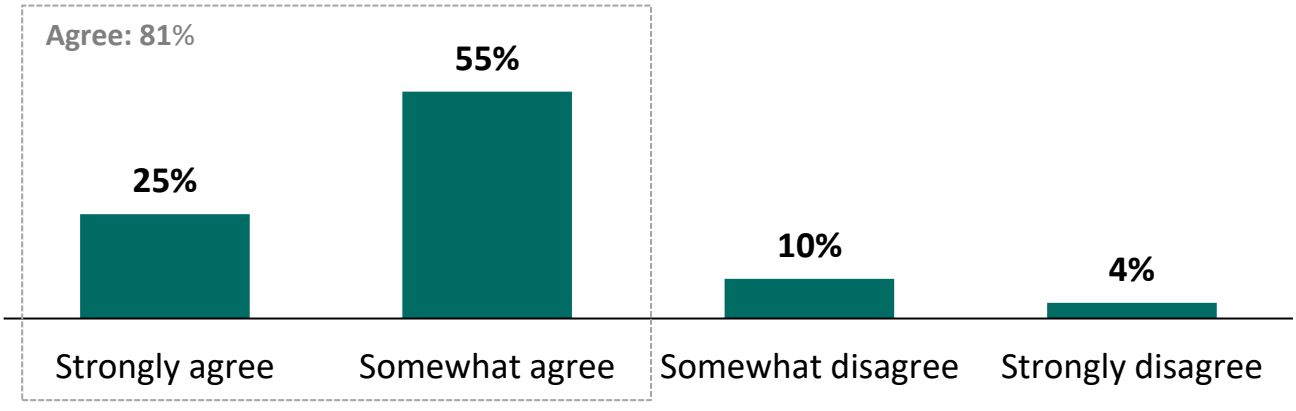


"Don't know/no opinion" (4%) not shown.

n=264

Q Customers are well-served by the electricity system in Ontario.

TORONTO HYDRO



"Don't know/no opinion" (6%) not shown.

n=264

INNOVATIVE RESEARCH GROUP

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

C&I

Welcome to Toronto Hydro's customer feedback survey!

Toronto Hydro needs your input to find the right balance between the services you receive and the price you pay.



Land Acknowledgement: Toronto Hydro's grid is located on the traditional territory of many nations including the Mississaugas of the Credit, the Anishnabeg, the Chippewa, the Haudenosaunee and the Wendat peoples and is now home to many diverse First Nations, Inuit and Métis peoples.

The purpose of this survey is to get your feedback on the draft 2025–2029 business plan. Your feedback will help Toronto Hydro align this plan with what you need and want.

1. Your electricity rates pay for this plan, so your views must be considered.
2. You don't need to be an electricity expert to participate. The survey is focused on basic choices and provides the background information you need to answer the questions.
3. Recognizing that people absorb information in different ways, Toronto Hydro and its research partner have designed this survey to include diagrams, charts, images and videos to help explain Toronto Hydro's draft plan and what it means for you. If you prefer to skip the videos, the content is also explained in the body of the survey.
4. Depending on how much feedback you wish to provide and the number of videos watched, this survey should take approximately **20-30 minutes** to complete. If you need to pause and return later to finish the survey, your completed answers will be saved.
5. Some of the survey content may not display correctly on a mobile browser. It is strongly recommended that you complete this workbook on a desktop or laptop computer.

Those who complete the survey will be invited to enter a draw to win a $5,000 donation to a charity of your organization's choosing!

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Toronto Hydro to gather your feedback, while protecting your confidentiality. Your individual answers will not be shared with Toronto Hydro in any identifiable way.

INNOVATIVE RESEARCH GROUP

WORKBOOK PREVIEW

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

C&I

What is this customer engagement about?

The goal of this engagement is to share Toronto Hydro's draft five-year business plan for the future of the city's electrical grid and collect your feedback. This will help Toronto Hydro align its plans with your needs and preferences.

Click on the video below to learn about Toronto Hydro's customer engagement.



Every five years, Toronto Hydro is required to submit a plan for its proposed prices (rates) and spending to the Ontario Energy Board (OEB) for approval.

- **In 2021 and 2022, thousands of its customers told Toronto Hydro about what they need and want** to help Toronto Hydro prepare the draft 2025–2029 business plan.
- **Toronto Hydro is now looking for your input on this draft business plan** to align its investments and spending decisions with what matters to you as its customers.
- **Later this year, Toronto Hydro will present its updated business plan to the independent regulator,** the OEB. Toronto Hydro is accountable to the OEB for considering your feedback.

How will this customer engagement work?



1. The workbook explains what Toronto Hydro does and summarizes the key planning considerations that Toronto Hydro's draft plan needs to address.



2. The workbook explains how much of your electricity bill goes to Toronto Hydro, how that money is spent, and the impact of the draft plan on your 2025–2029 prices.
3. The workbook asks for your input on seven key choices that will affect the services you receive and the price you pay from 2025–2029.



Once you have finished giving feedback on the key choices, **you will have an opportunity to review and change your responses** until you feel you have found the right balance.



Want to know more about Toronto Hydro's customer engagement process? Click here.

WORKBOOK PREVIEW

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

C&I

How will your feedback impact Toronto Hydro's plan and prices?

Toronto Hydro has a five-step approach to customer feedback.

We are here

✓ **1. Identify Customer Needs, Preferences, and Priorities**

In 2022, Toronto Hydro asked many types of customers from across the city about their needs and priorities for electricity distribution service.

✓ **2. Use Customer Feedback to Guide Development of Draft Plan**

Toronto Hydro planners were given summaries of the key findings from the initial customer engagement to consider as they began building their plans.

3. Collect Customer Feedback on the Draft Plan

Toronto Hydro is returning to customers to get feedback on the draft plan and ask customers how the draft plan could better meet their needs and preferences.

4. Use Customer Feedback to Finalize the Plan

Toronto Hydro will re-examine and make appropriate changes to the plan based on the feedback provided by customers in this engagement.

5. Submit the Plan to the Ontario Energy Board (OEB)

Toronto Hydro will file the plan with the OEB along with a report summarizing the results of this engagement. The OEB, consumer advocates and other interested groups will examine the plan in an open and transparent public process known as a rate application.

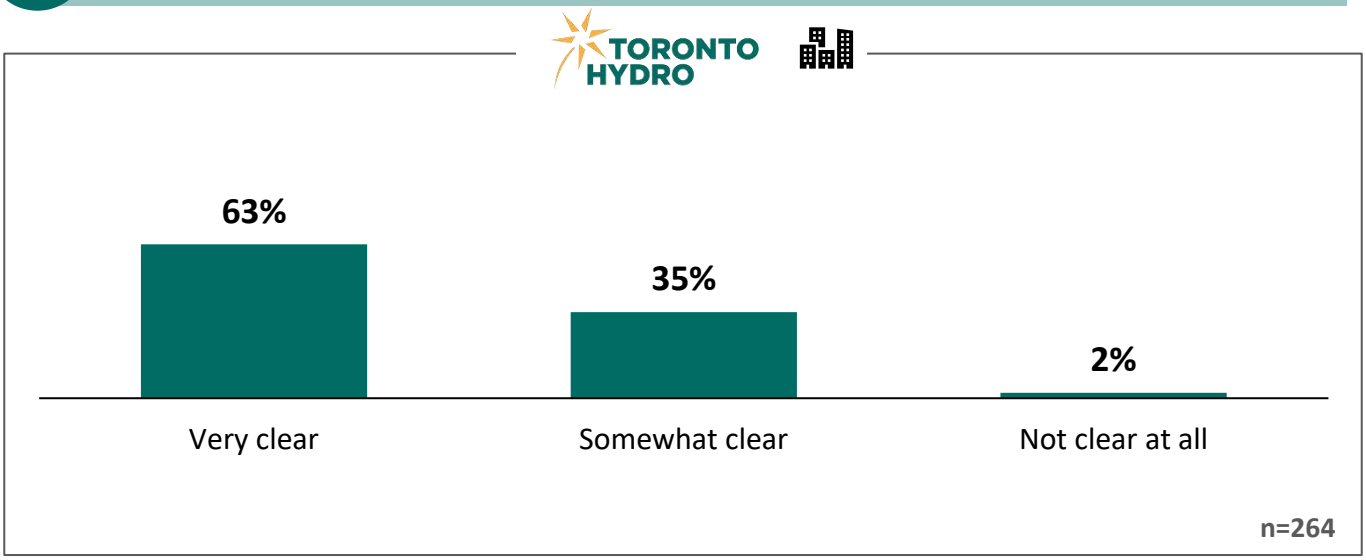
WORKBOOK PAGE

Online Workbook

Understanding the Purpose of the Customer Engagement

C&I

Q Do you feel that the purpose of Toronto Hydro's customer engagement is clear?



	Region				Consumption Quartiles			
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Very clear	70%	49%	72%	64%	70%	68%	58%	55%
Somewhat clear	28%	48%	23%	36%	30%	30%	37%	42%
Not clear at all	2%	3%	5%	0%	0%	1%	4%	3%

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

C&I

Electricity 101

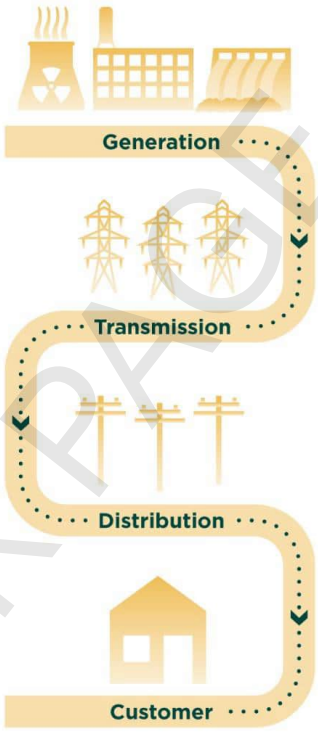
Toronto Hydro's role in Ontario's electricity system

Ontario's electricity system is made up of three parts: **generation**, **transmission** and **distribution**.

Generation

How electricity is made

About half of the electricity used in Ontario comes from nuclear power. The rest comes from a mix of hydroelectric, natural gas, wind and solar sources. Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from other generators contracted by the grid operator.



Transmission

How electricity travels across Ontario

Once electricity is made, it must be sent to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. Ontario has approximately 30,000 kilometers of transmission lines, mostly owned and operated by Hydro One.

Distribution

How electricity is delivered to you

Toronto Hydro is responsible for the last step of the journey: distributing electricity locally to end-use customers.

- Toronto Hydro does not generate or transmit electricity — it owns and operates the local electricity system made up of approximately 183,620 poles, 61,300 distribution transformers, 17,060 primary switches, 15,393 kilometers of overhead wires and 13,765 kilometers of underground cables.
- Toronto Hydro is wholly owned by the City of Toronto, but it does not receive taxpayer money — it is entirely funded by the distribution rates that you pay on your electricity bill.
- Toronto Hydro provides power to roughly 2.8 million people across the city of Toronto.

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Familiarity with Ontario's Electricity System

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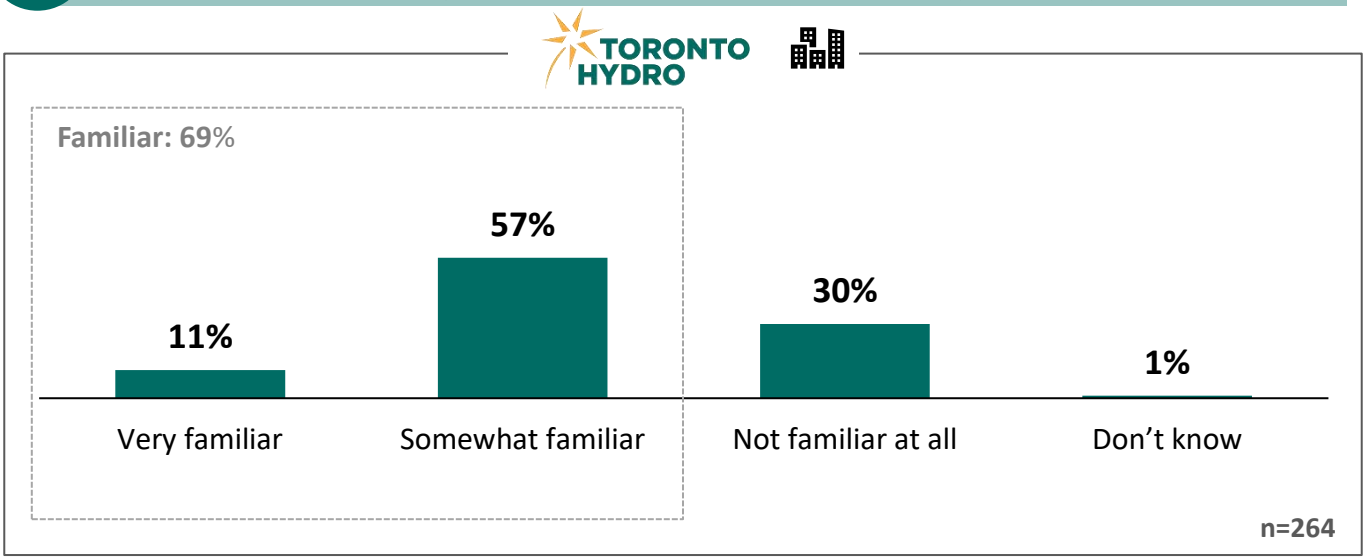
Q Before this engagement, how familiar were you with the various parts of the electricity system, how they work together and for which services Toronto Hydro is responsible?



	Region				Consumption Quartiles			
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Very familiar	13%	9%	10%	13%	15%	8%	15%	9%
Somewhat familiar	57%	67%	53%	53%	53%	49%	61%	66%
Not familiar at all	28%	23%	37%	34%	33%	40%	24%	23%
Don't know	2%	1%	0%	1%	0%	3%	0%	2%
Familiar (Very + Somewhat)	70%	76%	63%	65%	67%	57%	76%	75%

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Rate Application

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Toronto Hydro's Draft Plan

Planning Considerations

In preparing its plan, Toronto Hydro must consider many existing and emerging challenges of delivering safe, reliable and clean electricity at a reasonable price.

To learn more about what Toronto Hydro must consider in preparing its draft plan, click on the topics below.

Key challenges that Toronto Hydro's 2025–2029 draft plan addresses:



Keeping prices reasonable

- Many customers are concerned about the rising cost of doing business.
- Toronto Hydro must find the right balance between the investment needs of the local grid and the financial needs of its customers.



Responding to rising costs

- Like many companies, Toronto Hydro faces rising costs in purchasing equipment for the grid and doing construction work in the city.
- For example, from 2021 to 2022, the cost of buying electrical equipment increased by 9.9% while the cost of non-residential construction in the city of Toronto rose by 15.6%.



Powering a growing urban city

- Toronto is not just the largest city in Canada and an engine of the Canadian economy, it is also one of the fastest growing cities in North America.
- As the city continues to grow, the grid needs to be ready to power new condo towers, residential communities and businesses.



Fixing and replacing equipment in poor condition

- Much of Toronto Hydro's grid was installed in the 1950s and 1960s and needs to be replaced or upgraded.
- To keep the grid safe and reliable now and in the future, Toronto Hydro monitors the condition of its grid and uses this information to upgrade the equipment most at risk.



Reducing emissions from its own operations

- Toronto Hydro is committed to decarbonizing the company's footprint by 2040. To meet this goal, it must invest in reducing emissions from its vehicles and work centres.
- Toronto Hydro is expected to reduce its emissions by switching from oil and natural gas to clean electricity for powering its own operations.



Keeping up with the way customers use electricity

- Customers are using more electricity for their day-to-day energy needs, such as for transportation and electric heat pumps for heating. They are also choosing new technologies such as solar panels and battery storage to manage their electricity usage and sell electricity to the local grid.
- To ensure customers can connect new technologies to the grid safely and reliably, Toronto Hydro needs to upgrade its equipment and modernize its systems.

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Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Rate Application

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Responding to extreme weather and cyber security attacks

- Extreme weather such as high heat, high winds, flooding and ice storms is increasingly straining and damaging to electricity grids.
- Cybercrime is on the rise across Canada. For example, Toronto Hydro is the target of around one million attempted cyber attacks each year, with attempts going over one million in 2022 (successfully deflected).
- Toronto Hydro needs to make the grid more resilient against extreme weather and cyber security attacks that could compromise reliability and put customers at risk.



Protecting public and employee safety

- Toronto Hydro and its customers have a strong safety record, but electricity is dangerous and safety cannot be taken for granted.
- As homes and businesses add new technologies that increase the amount of electricity flowing around us, Toronto Hydro must ensure that the grid remains safe for its employees and the public.

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Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

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How much of my electricity bill goes to Toronto Hydro?

Every item on your bill is required by provincial regulation.

- Toronto Hydro collects payment for the entire electricity system, but only keeps the distribution portion of the "**Delivery**" charge. This charge pays for both Toronto Hydro's **distribution** system and Hydro One's **transmission** system, as well as line losses (power that is lost when electricity travels across the wires).
- **About 14% of the electricity bill goes to Toronto Hydro** to pay for the local distribution grid. The **remaining 86%** of the bill goes to generation companies, transmission companies, the federal and provincial governments, and regulatory agencies.

Typical Bill

Sample Toronto Hydro Monthly Bill

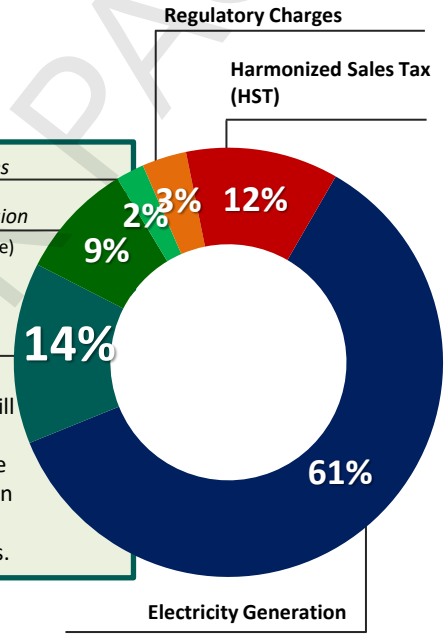
Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges

Electricity	7,639.30
Delivery	3,105.41
Regulatory Charges	423.17
Total Electricity Charges	**$11,167.88**
HST	1,451.82
Total Amount	**$12,619.71**

Delivery: *Line Losses*
$269.01
Delivery: *Transmission*
(varies based on usage)
$1,112.63
Delivery: *Distribution*
Toronto Hydro's part of the total bill is **$1,723.77**. This charge is the same for all customers in this rate class per OEB requirements.



Who holds Toronto Hydro accountable?

ONTARIO ENERGY BOARD

The **Ontario Energy Board (OEB)** is the public interest regulator responsible for setting electricity distribution rates (prices) and for protecting customers in Ontario.

The OEB holds Toronto Hydro accountable for:

- How it spends your money in current and future plans.
- Reporting on key outcomes (reliability) through an annual scorecard.
- Finding savings and efficiencies to absorb rising costs.

Want to know more about what Toronto Hydro has done to become more efficient?
Click here.

WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Rate Application

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What has Toronto Hydro done to become more efficient?

- Reduced the total number of facilities and gave back roughly $158 million to customers, resulting in a total credit of $3,905.52 on the average customer's bill in this rate class from 2016 to 2021.
- Delivered approximately $10 million in reduced or avoided costs in this current 2020–2024 period by replacing outdated information systems with consolidated programs, enabling automation and lowering maintenance costs.
- Implemented new technology to automate crew scheduling, enabling Toronto Hydro to maximize crew working hours and respond to power outages quicker.

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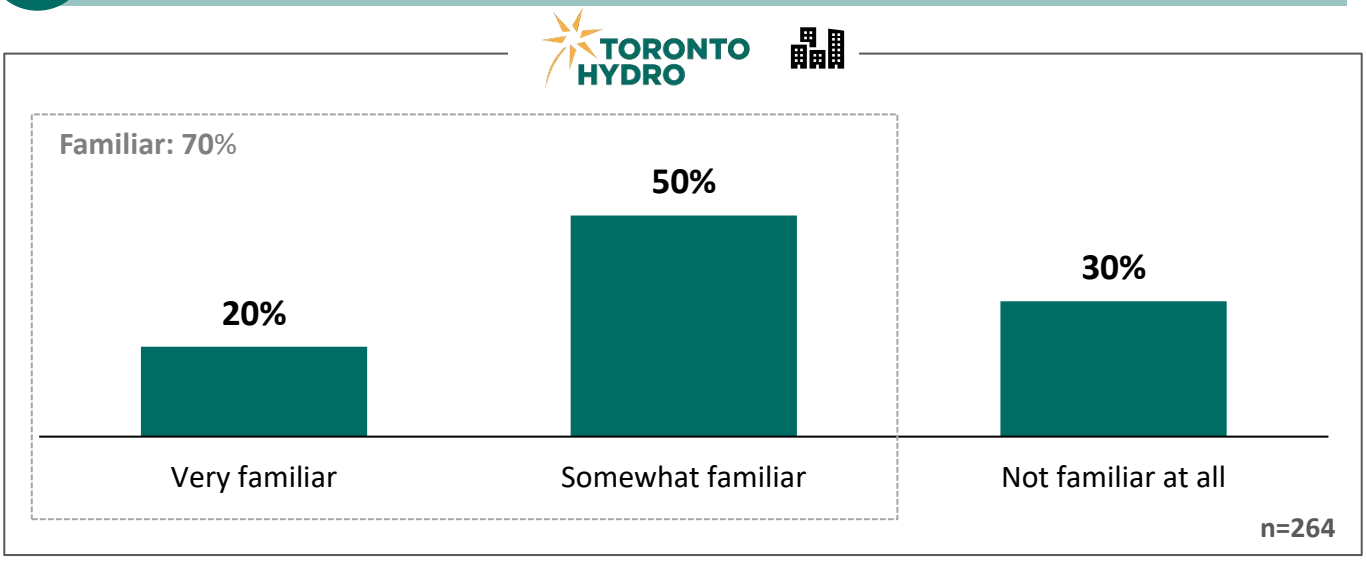
Familiarity with the Percentage of Bill Remitted to Toronto Hydro

Q Before this customer engagement, how familiar were you with the amount of your electricity bill that went to Toronto Hydro?



	Region				Consumption Quartiles			
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Very familiar	23%	20%	25%	15%	16%	16%	25%	23%
Somewhat familiar	48%	44%	46%	58%	48%	50%	51%	50%
Not familiar at all	29%	37%	29%	27%	36%	35%	24%	27%
Familiar (Very + Somewhat)	71%	63%	71%	73%	64%	65%	76%	73%

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

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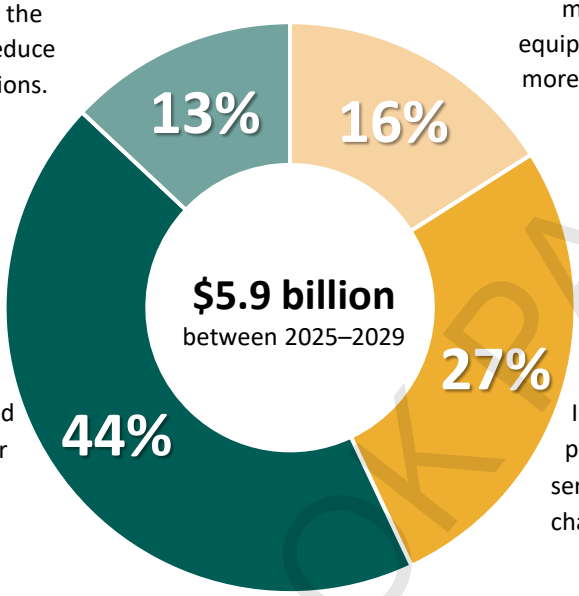
How does Toronto Hydro propose to spend the money?

Toronto Hydro's five-year 2025–2029 draft plan is made up of four spending categories.

General Plant
Investments in vehicles, work centres and IT to keep the business running and reduce Toronto Hydro's emissions.

Modernization
Investments in technology to get more use out of existing equipment, and build a smarter, more efficient and reliable grid.



Sustainment
Investments to upkeep old equipment that is in poor condition and replace outdated equipment.

Growth
Investments in capacity to power the growing city and serve customers' growing and changing needs for electricity.

Want to know more about Toronto Hydro's current and future budgets? Click here.

How much will Toronto Hydro's draft plan cost me?

At the end of the five-year plan (2029), the typical customer in this rate class would see the distribution portion of their electricity bill increase by **$870.85**: from an estimated rate (price) of $1,794.37 in 2024 to a proposed rate (price) of **$2,665.22 by 2029.**

				Toronto Hydro's Portion	
	Year	Avg. Monthly Bill	Toronto Hydro Portion	Annual Increase (%)	Annual Increase ($)
	2023	$12,619.71	$1,723.77	n/a	n/a
	2024	$12,650.16	$1,794.37	4%	$70.60
Rate Period	**2025**	$12,988.01	$2,093.35	17%	$298.98
	2026	$13,115.22	$2,205.93	5%	$112.58
	2027	$13,272.78	$2,345.36	6%	$139.43
	2028	$13,511.20	$2,556.35	9%	$210.99
	2029	$13,634.22	$2,665.22	4%	$108.87
	5-yr impact		**$870.85**	**49%**	**$870.85**

Note: These estimated rate increases are preliminary and are subject to change based on customer feedback and other factors. A typical customer in this rate class is assumed to use 2,000 kWh per month and enrolled under Time-of-use Regulated Price Plan. Bill projections assume that other aspects of the electricity bill that are outside of Toronto Hydro's control (commodity, transmission, government, regulatory fees) remain constant.

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Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

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Toronto Hydro Background

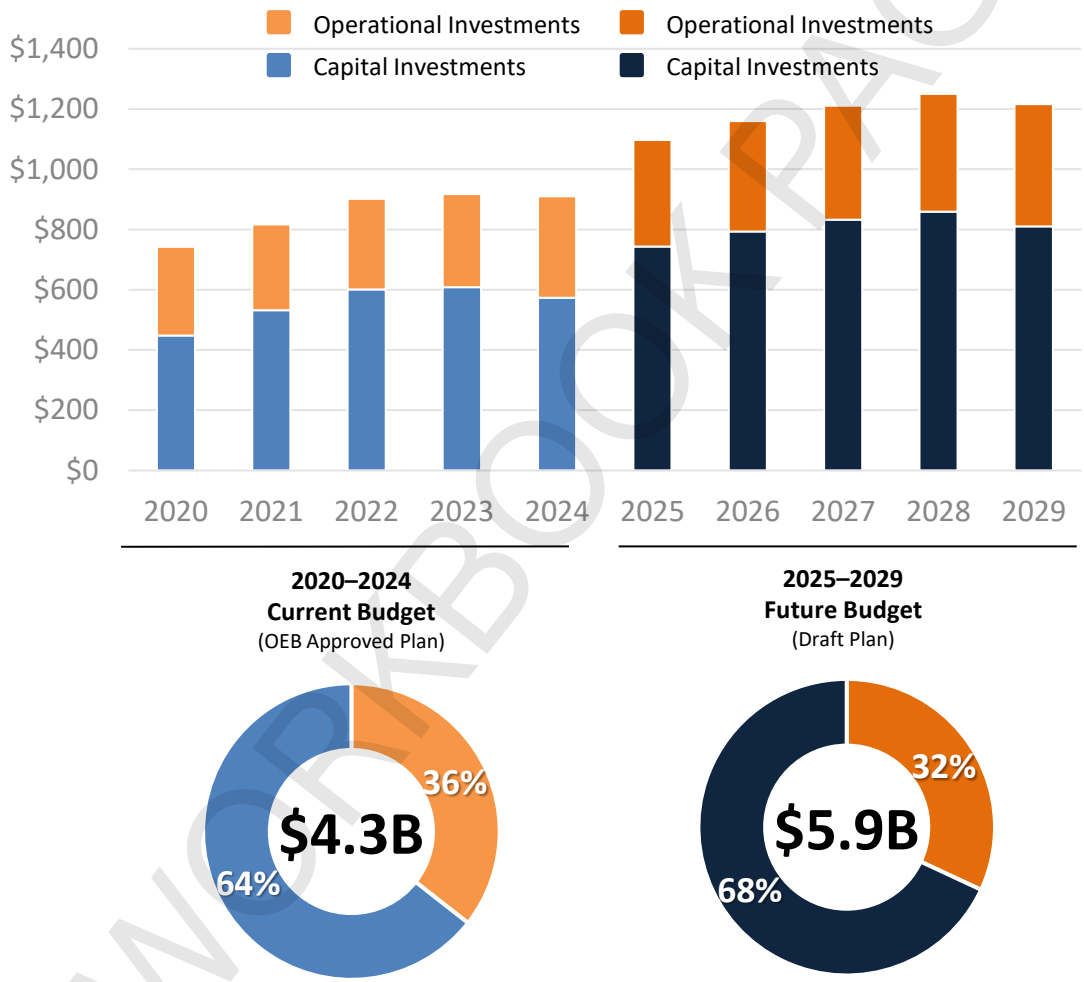
How much does it cost to run the local grid?

To run the local grid and serve customers, Toronto Hydro manages two budgets:

1. A **capital investment** budget which pays for the cost of buying and constructing physical infrastructure such as poles, wires, transformers, facilities, trucks and computers.

2. An **operational investment** budget which pays for maintenance and operation of the equipment, as well as the staff needed to manage the grid and serve customers daily.

Current and Future Budgets per year ($ millions)



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The current five-year budget of **$4.3 billion** is based on the 2020–2024 plan approved by the OEB in a previous rate application. As mentioned earlier, this amount is funded by your 2020–2024 distribution rates.

The future five-year budget of **$5.9 billion** is based on the 2025–2029 draft plan presented in this customer feedback survey. The final budget for this next rate period will be adjusted to reflect customer feedback collected through this engagement and will be subject to extensive OEB review before rates are set for 2025–2029.

How does the survey work?

The next sections are about 7 key choices that Toronto Hydro needs to make to finalize its plan.

Each section provides some key background information. We encourage you to take the time to learn about your local electricity grid and where your money is going.

We also understand that life is busy. Many people find this information interesting — but if you would prefer to skip over the videos or the background information, you can jump right to the key choices.

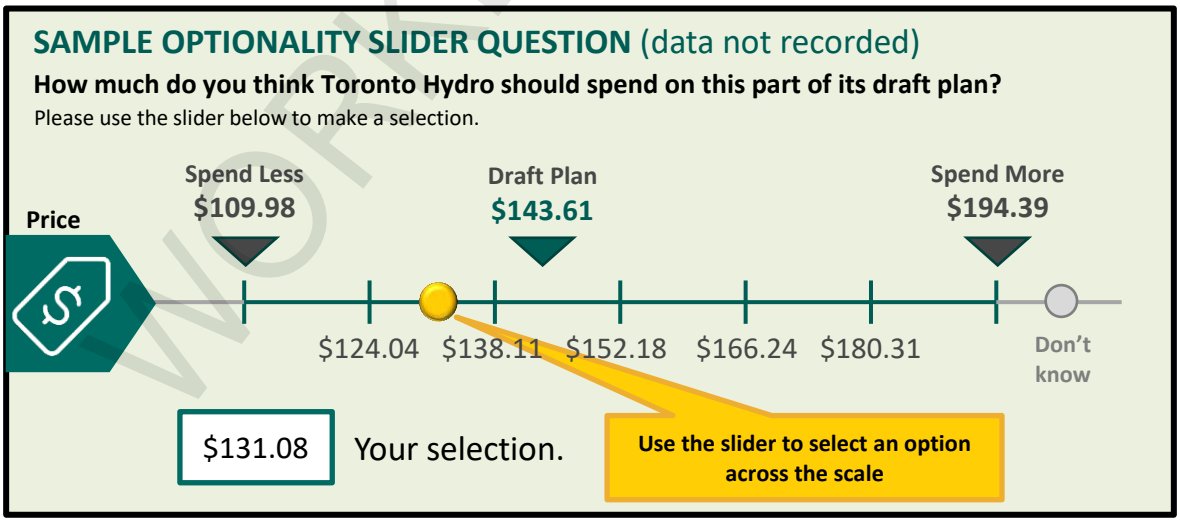
How do I make choices?

Each choice has a summary of three options that Toronto Hydro considered:

- **Spend Less:** A minimum spending option that keeps prices lower and meets the basic performance requirements but may entail some trade-offs on key outcomes, such as reliability.
- **Toronto Hydro's Draft Plan:** An option currently in the draft plan which makes additional progress toward key outcomes but delays some important work.
- **Spend More:** A faster paced spending option that makes additional progress towards better outcomes while recognizing practical limits due to resources and construction issues.

In each option, there is a sliding scale that enables you to dial the draft plan up or down. While Toronto Hydro's technical experts can tell us the maximum and minimum amounts we can practically spend, the balance of how much Toronto Hydro spends on the spectrum is up to customers like you.

At the end of the survey, you will get a summary of your choices and you will have the opportunity to change your answers to find the right balance for you.



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Understanding the Slider

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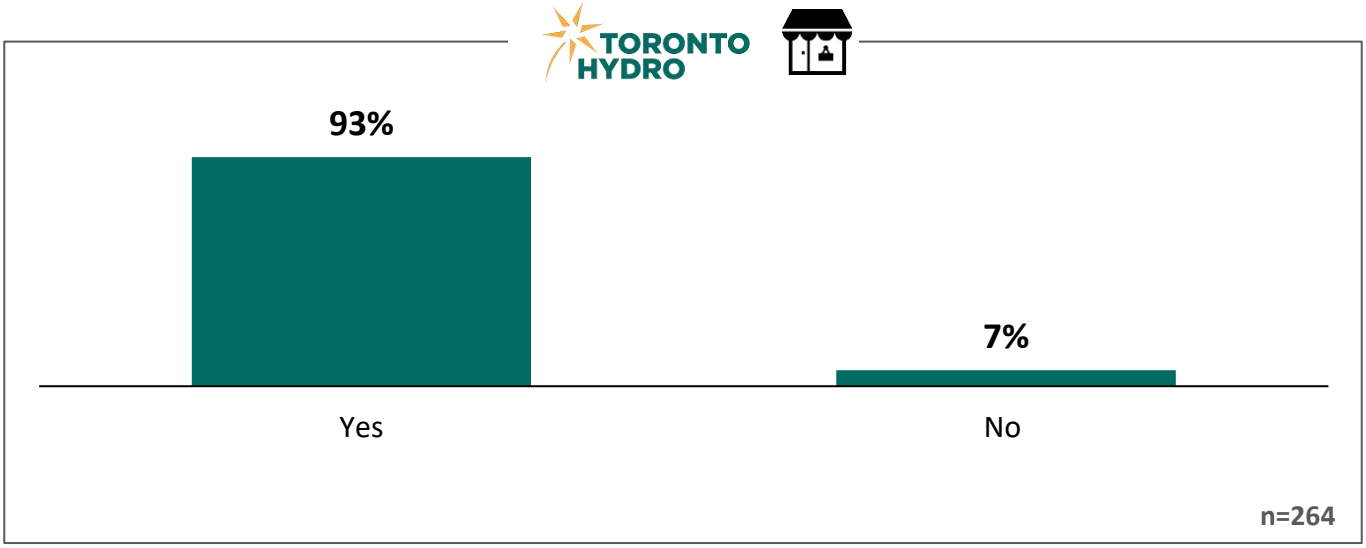
Q Is it clear that you can move the slider to any amount you feel best reflects your personal view of the best balance between lower costs and faster improvements?



	Region				Consumption Quartiles			
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Yes	94%	92%	97%	92%	90%	95%	92%	96%
No	6%	8%	3%	8%	10%	5%	8%	4%

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Draft Modernization Plan

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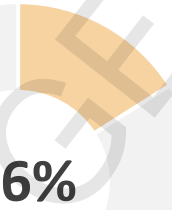
Draft Modernization Plan

Build a Smarter, More Efficient and Resilient Grid

What is this section about?

- This section explains how technology is changing the way customers use electricity and how Toronto Hydro operates and manages the grid to make it smarter, more efficient and resilient for customers.

  Want to learn more about how grid modernization benefits you? Click on the topics below.



- **Toronto Hydro's draft modernization plan enables:**
  - Faster and cheaper power restoration
  - More efficient use of existing equipment
  - Customer choice to adopt new technologies
  - Resilience against weather and cyber attacks

- This spending category makes up **16% of the draft plan** and would add **$143.61** on the average customer in this rate class's monthly bill by 2029.

*Click on the video below to learn about Toronto Hydro's **draft modernization plan**.*



WORKBOOK PAGE

Modernization Plan

Building a Smarter, more Efficient and Reliable Grid

Toronto Hydro's Modernization Plan has four main objectives:

Faster and cheaper power restoration



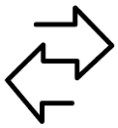
- Through automation, the smart grid can achieve self-healing capabilities. This means that the distribution grid on your street will be able to locate outages and restore power automatically.
- The smart grid enables Toronto Hydro to reduce the number and length of outages customers experience. It also reduces manual costs (trucks and crews) of responding to power outage events.

More efficient use of existing equipment



- As customers use more electricity, some equipment will reach its limits. Sensors and meters detect when and where these limits are approaching, enabling Toronto Hydro to make better decisions.
- The smart grid enables Toronto Hydro to get more use out of the existing equipment so that it can serve a greater customer need for electricity without having to build as much new infrastructure.

Customer choice to adopt new technologies



- Sensors, switches and software enable Toronto Hydro to monitor and control the flow of electricity so that customers can choose technologies to produce, store and sell power to the grid.
- The smart grid is designed to allow safe and reliable two-way power flow — from the grid to the customers and from customers to the grid. This system can reduce costs and makes the local grid more resilient to outages.

Resilience against weather and cyber attacks



- Cyber attacks are increasing and getting more complex. Toronto Hydro must be prepared to respond to these threats to maintain reliable service and protect customer information.
- In addition to being able to restore power quicker, the smart grid can sense when environmental conditions like flooding pose a risk. This enables grid operators to strengthen the grid.

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Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Draft Modernization Plan

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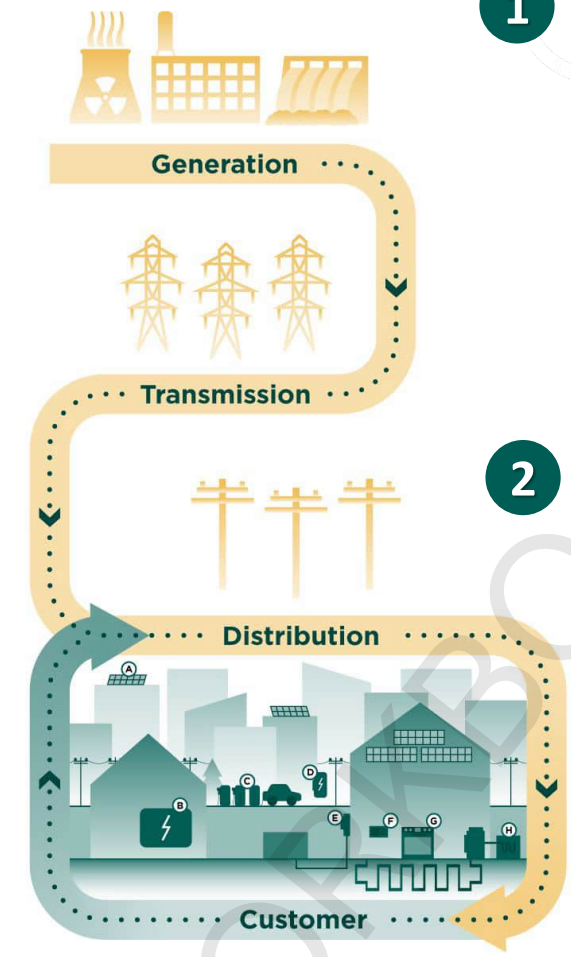
16%

Modernization: Changing Technology, Changing Needs

For more than 100 years, things changed relatively slowly in terms of grid technology. Electricity was generated in large power stations and transmitted from around the province to Toronto Hydro's grid, and ultimately to homes and businesses. That is all changing, and because of technological advancement, the pace of change could be fast.

Toronto Hydro's 2025–2029 plan is shaped by two key changes in technology:



A. Solar panel
B. Battery storage
C. Public electric vehicle charging station
D. On-site backup generation
E. Smart meter
F. Home energy manager
G. Energy-efficient appliances
H. Heat pump

1 **Technologies that change how customers use electricity.** These include:

- Electricity products like electric heating, battery storage, and vehicles that enable customers to use less fossil fuels (oil and gas), which contribute to climate change.
- Technologies like solar panels and battery energy storage that allow customers to produce and manage their electricity as well as sell it back onto the grid.

2 **Technologies that change how Toronto Hydro operates the grid**. These key changes are:

- The grid must shift from a **one-way system** that only sends electricity to customers to a **two-way system** that allows customers to generate and sell electricity to the grid.
- **Smart grid technology like sensors and automation** enables Toronto Hydro to monitor key equipment to prevent outages and get better use out of existing equipment. When outages do occur, this technology can re-route the grid to restore power much more quickly and at a lower cost than today.

WORKBOOK PAGE

How much electricity does it take to charge an Electric Vehicle (EV)?



Did you know that when an EV is charging it can use as much electricity as two average homes? If everyone in a neighbourhood came home from work or school and started charging their EVs at the same time, the electricity demand could overload the grid.

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Modernization Plan

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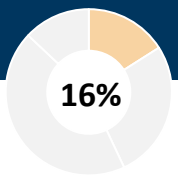
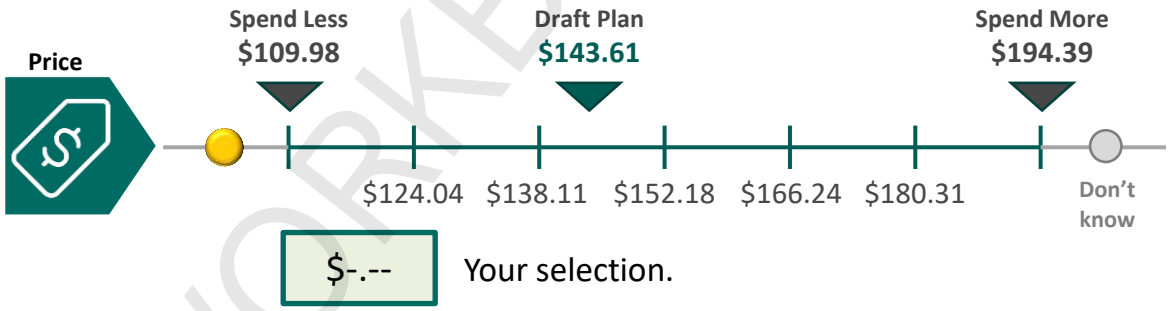


Making Choices: **Modernization**

By 2029, Toronto Hydro's draft **modernization plan** would cost the typical customer in this rate class **$143.61** more per month on their monthly electricity bill. Toronto Hydro could spend more to increase the pace of modernizing the grid to get better reliability sooner, or it could spend less and slow down the progress.

	Spend Less	Draft Plan	Spend More
Reliability	Being ready to automate the grid by 2035 means that better reliability won't happen until the end of the next decade or beyond.	Being ready to automate the grid by 2030 means that better reliability will happen in the earlier part of the next decade.	Faster progress towards grid automation means better reliability earlier and improved reliability for critical loads located in the downtown area.
Customer Service	May reduce service levels (longer waits and higher costs) for some customers connecting new services. May reduce customer choice for new technologies.	Maintains service levels for customers connecting new services to the grid. Enables customer choice for new technologies such as solar panels.	Same as draft plan.
Efficiency	It will take longer for the grid to become more efficient. This may lead to higher costs in the next decade.	The grid will become more efficient in the next decade, which will help reduce costs.	Same as draft plan.

Choice 1 of 7:



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Amount Spent on the Modernization Plan

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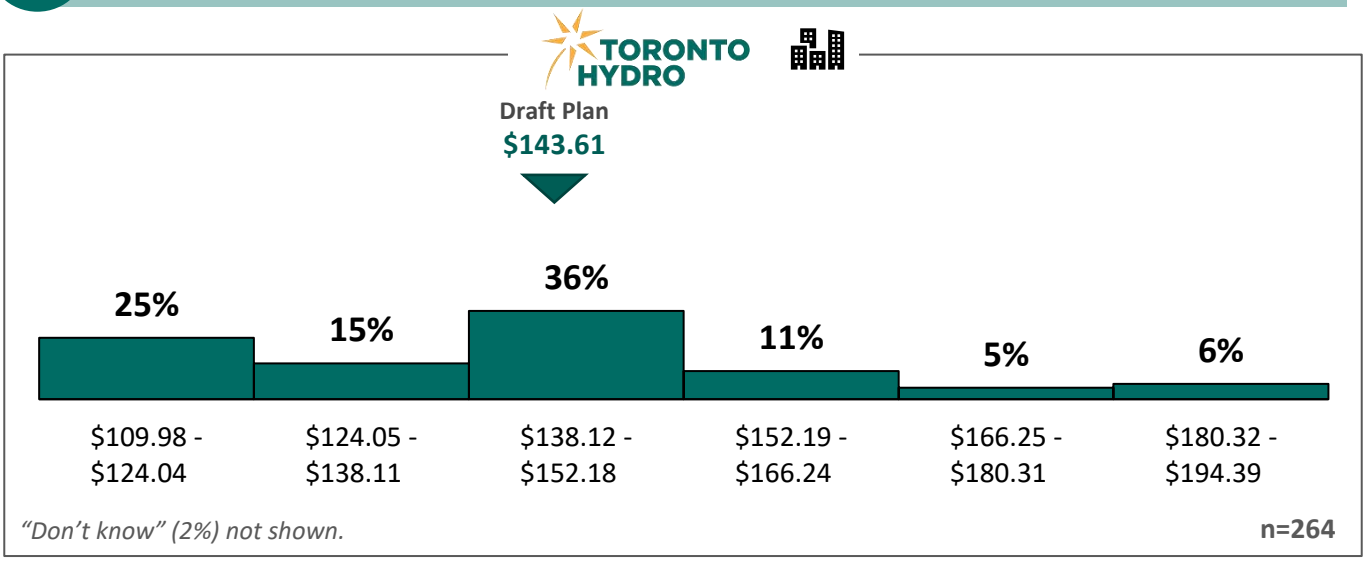
Q How much do you think Toronto Hydro should spend on its modernization plan?



"Don't know" (2%) not shown.

n=264

	Overall	Region				Consumption Quartiles			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Below Plan	41%	45%	40%	40%	40%	36%	40%	41%	47%
On Plan	29%	30%	28%	29%	31%	33%	29%	37%	19%
Above Plan	28%	21%	31%	28%	28%	28%	27%	22%	34%
Don't Know	2%	4%	1%	3%	1%	4%	4%	0%	0%
TOTAL On Plan + Above Plan	57%	51%	59%	57%	59%	61%	55%	59%	53%

Online Workbook

Additional Feedback on the Modernization Plan

C&I

Q Do you have additional feedback on Toronto Hydro's draft modernization plan?

Response	%
Costs are too high already, cost of living, struggling to pay bills	1.9%
Good information	1.1%
Support the increase (general)	1.1%
Modernize, be proactive, invest for the long term	1.0%
Support developing new technology and innovation	0.7%
Prioritize renewables, solar/wind, and electric vehicles	0.5%
Make use of existing infrastructure, past spending	0.5%
Prevent outages, stable power, system reliability	0.4%
Need more information	0.3%
Find efficiencies, cut wasteful spending, lower salaries	0.2%
Other	0.4%
No response	91.8%

Note: Responses were optional. Only responses > 0.1% are shown.

Toronto Hydro Customer Engagement

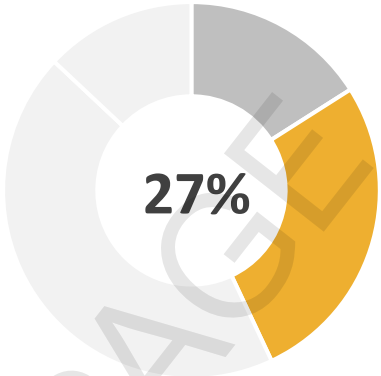
Planning Process: 2025–2029 Draft Growth Plan

C&I

Draft Growth Plan

Increase Capacity to Serve Customers

What is this section about?



- This section explains how fast the city of Toronto is growing and what it takes for the grid to serve customers' needs for more electricity.
- Toronto Hydro's draft growth plan is about increasing grid capacity to serve customers reliably now and in the future.

- This spending category makes up **27% of the draft plan** and would add **$233.98** on the average customer in this rate class's monthly bill by 2029.

*Click on the video below to learn about Toronto Hydro's **draft growth plan**.*



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Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Growth Plan

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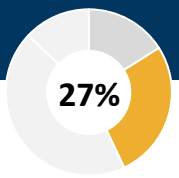


Growing City, Growing Needs

1 Toronto is growing, fast.

Toronto is one of the fastest growing cities in North America. A growing city means that we need a bigger local grid so that homes and businesses can get the power they need, when they need it.



Population Growth

Toronto will add approximately 500,000 more people this decade. To put this into context, Toronto is growing five times faster than Los Angeles.



230 Cranes
Toronto has led the crane count in North America since 2015.



2,114 Projects
including residential and non-residential in development in the city of Toronto.



+$1B in Construction
work planned for city infrastructure in Toronto annually (transportation and water).

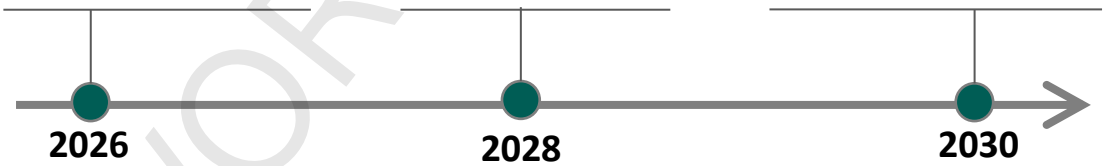
2 Individual customers will use more electricity than ever before.

The average customer will use more electricity in the next 10–15 years, as governments encourage businesses and communities to use less fossil fuels (oil and gas) to address climate change. Here are the key government policies that drive the need for more electricity in Toronto:

The Government of Canada may require 20% of all new car sales to be zero emission and is working towards a target of 60% by 2030.

The City of Toronto Green Building Standard requires all new mid- and high-rise buildings to be near zero GHG emissions.

The carbon tax may increase 161% by 2030 so customers use less oil and gas, and switch to clean electricity for cooking, heating and transportation.



23% **Forecasted increase in customers' need for electricity by the year 2030.**

Conservation and energy efficiency has helped manage electricity use over the past 20 years and will continue to play an important role in the future. But conservation alone is not enough. We need a bigger grid to serve customers in the long term.

WORKBOOK PAGE

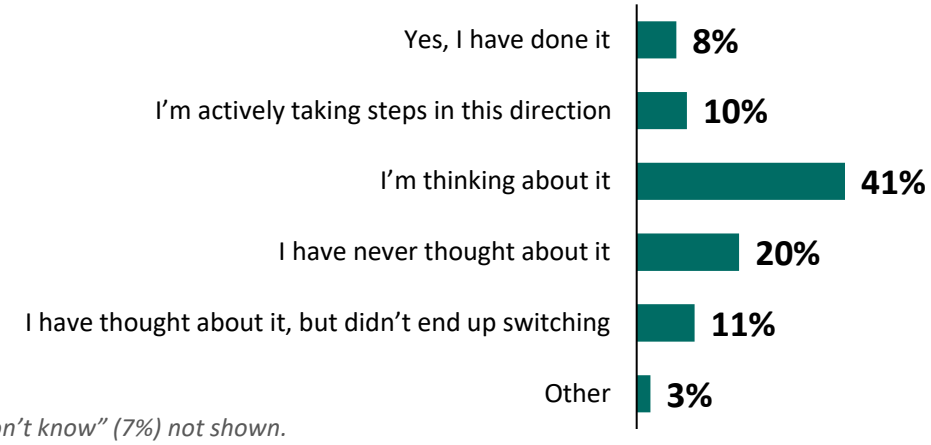
Online Workbook

Amount Spent on Modernization Plan

C&I

Q When you think about all your energy bills, has your organization ever considered shifting from one energy source to another to save money or reduce your impact on the environment?
For example, changing from a natural gas-fuelled furnace to an electric heat pump, or from a gas-fuelled vehicle to an electric vehicle?

TORONTO HYDRO



"Don't know" (7%) not shown.

n=251

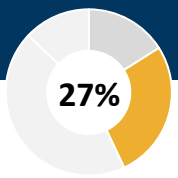
	Region				Consumption Quartiles			
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Yes, I have done it	7%	6%	10%	8%	8%	4%	10%	10%
Actively taking steps	9%	12%	7%	10%	6%	9%	10%	15%
I'm thinking about it	41%	37%	31%	49%	44%	32%	43%	44%
I have never thought about it	20%	24%	31%	11%	19%	27%	17%	17%
I didn't end up switching	8%	12%	12%	13%	8%	12%	16%	9%
Other	0%	3%	2%	5%	4%	3%	2%	2%

Note: Responses were optional.

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Draft Growth Plan

C&I



Building a bigger grid takes time

It's easy to say Toronto needs more electricity, but meeting this need requires Toronto Hydro to make major investments in the grid, including:



Expand Transformer Stations

Bring more power into the city from the provincial grid to serve growing communities along the new transit corridors (Eglinton LRT, Finch LRT, Ontario Line) and the redevelopment of areas like Downsview Park and the Portlands.



Upgrade and Reconfigure the Grid

Make more space on the grid to enable customers to plug in. Upgrade equipment like cables and transformers and reconfigure how the existing system serves customers to make more space on the grid to accommodate new services like electric vehicle charging stations and solar panels.



Major Infrastructure Developments

Connect major projects like the Finch Light Rail Transit system and the Ontario Line, and relocate Toronto Hydro's grid equipment to enable these and other major infrastructure developments to be constructed in the city.

This work cannot happen quickly. Toronto is densely populated and congested. **Building new power lines and stations takes years of planning and construction.** There are also equipment and resource constraints that limit how quickly Toronto Hydro can build a bigger grid.

Managing Uncertainty

Toronto Hydro develops its forecast from information such as building permits and projected electric vehicle sales. However, customer adoption of new technology is uncertain due to:

Supply chain issues such as equipment and resource shortages can affect the availability of customer technologies.

Technological advancements can lead to fast cost reductions. For example, the price of lithium ion batteries (EVs) decreased by 79% from 2013 to 2022.

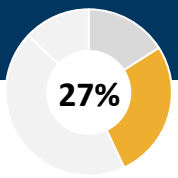
Government policies such as rebates for electric vehicles and solar panels drive customers and suppliers to make certain choices.

If Toronto Hydro invests too quickly to build a bigger grid, it means customers' rates will go up to pay for equipment that will not be used for some time. On the other hand, if it doesn't do enough to expand the grid for higher use of electricity, customers could experience less reliability (brownouts) and delays when they want to connect to the grid or plug in new technologies. Toronto Hydro needs your input on the pace for these investments.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Growth Plan

C&I

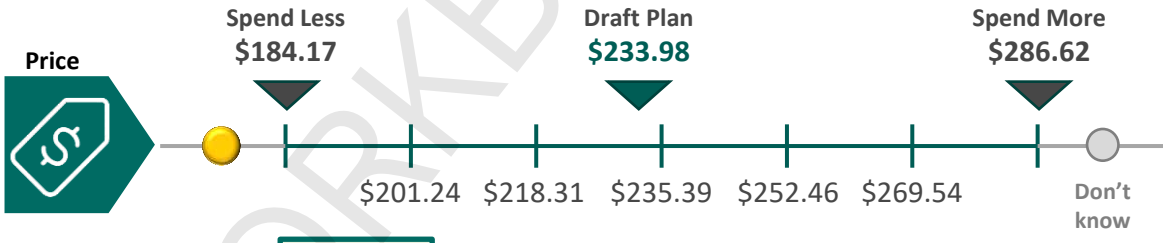


Making Choices: **Growth**

By 2029, Toronto Hydro's draft **growth plan** would cost the typical customer in this rate class **$233.98** more per month on their monthly electricity bill. Toronto Hydro could spend more to better prepare the grid to serve customers' changing needs, or could spend less and wait and see if customers adopt new technologies over the 2025-2029 plan.

	Spend Less	Draft Plan	Spend More
Reliability	May lead to less reliability for customers in high-growth neighbourhoods. Increases reliability risk for the next decade.	Maintains reliability for customers in high-growth neighbourhoods. Manages reliability risk for the next decade.	Maintains reliability for customers in high-growth neighbourhoods. Improves reliability risk for the next decade.
Customer Service	May reduce service levels (longer waits and higher costs) for some customers connecting new services. May reduce customer choice for new technologies.	Maintains service levels for customers connecting new services to the grid. Enables customer choice for new technologies such as solar panels.	May improve service levels (shorter waits and lower costs) for some customers connecting new services to the grid. Improves customer choice for new technologies.
Efficiency	May lead to less efficient work if Toronto Hydro has to build a bigger grid reactively to serve customers.	Supports the ability to serve customers efficiently in the five-year plan based on the projected demand.	Supports the ability to serve customers efficiently in the five-year plan and beyond in the next decade.

Choice 2 of 7:



$-.-- Your selection.

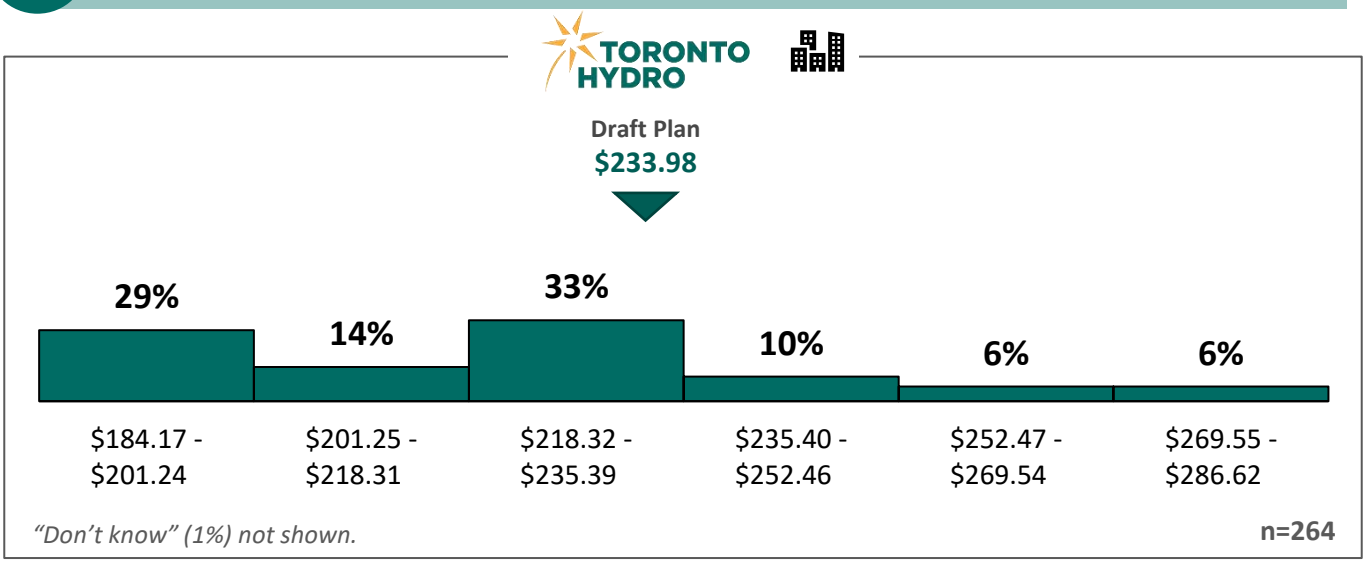
WORKBOOK PAGE

Online Workbook

Amount Spent on the Growth Plan

C&I

Q How much do you think Toronto Hydro should spend on its growth plan?



"Don't know" (1%) not shown.

n=264

	Overall	Region				Consumption Quartiles			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Below Plan	54%	57%	51%	63%	47%	50%	53%	58%	53%
On Plan	28%	22%	29%	22%	35%	33%	28%	30%	22%
Above Plan	17%	19%	18%	13%	16%	15%	16%	11%	25%
Don't Know	1%	2%	1%	2%	1%	2%	3%	0%	0%
TOTAL On Plan + Above Plan	45%	41%	48%	35%	52%	48%	44%	42%	47%

Online Workbook

Additional Feedback on the Growth Plan

C&I

Q Do you have additional feedback on Toronto Hydro's draft growth plan?

Response	%
Should be funded by developers	1.1%
Find efficiencies, cut wasteful spending, lower salaries	0.7%
Costs are too high already, cost of living, struggling to pay bills	0.7%
Support developing new technology and innovation	0.4%
Modernize, be proactive, invest for the long term	0.3%
Should be funded by tax dollars/government	0.3%
Prioritize renewables, solar/wind, and electric vehicles	0.3%
Need more information	0.2%
No response	95.9%

Note: Responses were optional. Only responses > 0.1% are shown.

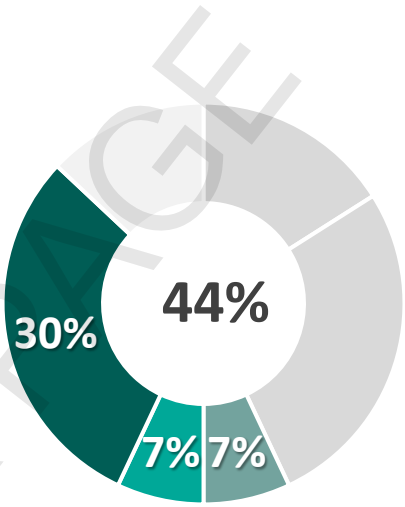
Draft Sustainment Plan

Replacing and Updating Equipment

What is this section about?

- This section is about upkeeping the grid to manage reliability and maintain safe and efficient operations.
- Toronto Hydro's draft sustainment plan section seeks your input in three areas:

1. Managing equipment in very poor condition with a high risk of failure.
2. Pacing the upkeep of equipment near the end of its expected life.
3. Standardizing outdated equipment.



- This spending category makes up **44% of the draft plan** and would add **$381.41** on the average customer in this rate class's monthly bill by 2029.

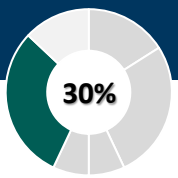
*Click on the video below to learn about Toronto Hydro's **draft sustainment plan**.*



WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Sustainment Plan

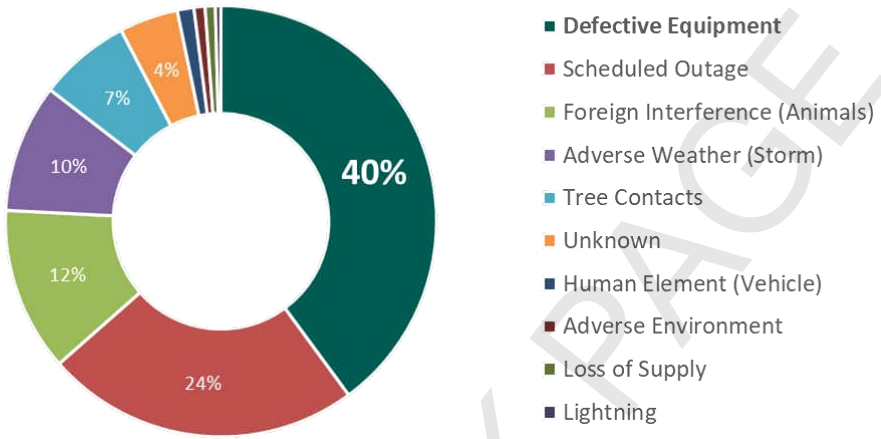
C&I



1 Reliability: Managing Equipment Failure Risk

While many power outages are caused by external events such as weather and falling trees, roughly **40%** of customer outages are caused by equipment failure. This is the largest single cause of outages, and customers look to Toronto Hydro to manage this risk.

Customer Outage Duration (Hours) by Cause 2018-2022



Toronto Hydro manages failure risk by:

- Inspecting equipment condition regularly, so that maintenance or replacement can be done before the equipment fails.
- Replacing and repairing equipment that is in bad condition or performing poorly. This includes replacing lines with a high number of outages or replacing transformers with visible signs of wear and tear such as rust.

Since 2014, Toronto Hydro's work to upkeep the grid has delivered a 13% reduction in the average number of outages experienced by customers and a 25% reduction in the length of those outages. Toronto Hydro's draft plan is to maintain these reliability results for customers.

Want to learn more about grid reliability and what causes power outages? Click here.

What type of work is Toronto Hydro doing to manage equipment failure risk?

Below is an example of a key investment that Toronto Hydro needs to make to prevent increased outages due to equipment failure.



Replacing Direct-Buried Cable

In parts of the grid that were built a long time ago, cables are laid directly in underground trenches without any protective barrier. **Underground equipment failures contribute to 57% of defective equipment failures, the large majority of which (75%) are due to cables**. Toronto Hydro's draft plan intends to replace 182 kilometers of direct buried cables by 2029 to manage the risk of power outages caused by this equipment.

WORKBOOK PAGE

System reliability

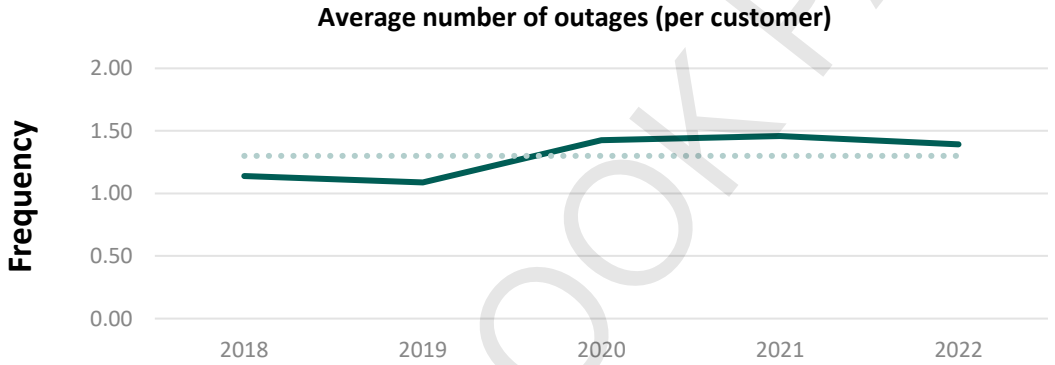
In order to provide feedback on Toronto Hydro's plans, it's important to understand how the distribution system has performed in the past, as well as what's expected in the future.

A core objective of Toronto Hydro's plan is to maintain current levels of reliability over the 2025–2029 plan period, while making foundational technology investments to reduce the length of power outages in the long-term.

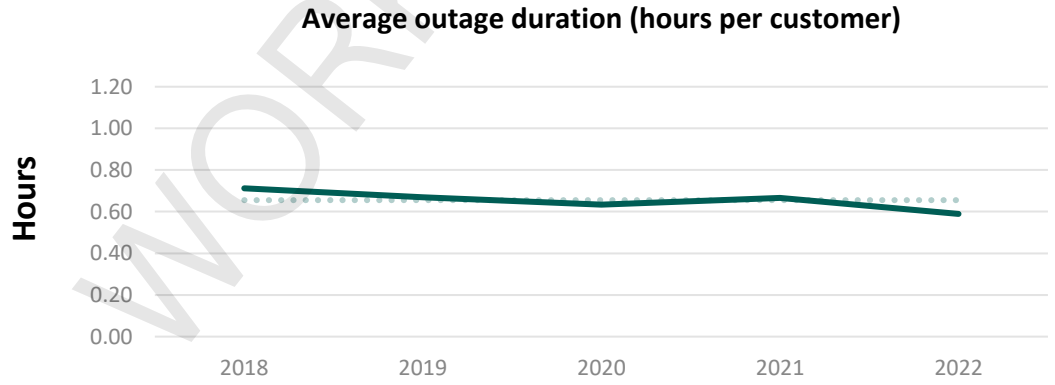
Toronto Hydro recognizes that power interruptions are inconvenient for residential customers and can be very costly for commercial and industrial customers.

Toronto Hydro tracks both the average number of power outages per customer and how long those interruptions last.

Between 2018 and 2022, the typical Toronto Hydro customer has experienced about two outages per year (*or 1.3 outages per customer to be exact*).



Over the same period, the average **duration** of an outage has been about 0.62 hours. Meaning, when the power does go out, Toronto Hydro is typically able to restore power in about 35 minutes.



It's important to keep in mind that these are system averages, and that your actual experience may be different. Some customers connected to newer lines may not experience any outages, while others are experiencing more than the average number of outages each year.

WORKBOOK PAGE

What is most likely to cause an outage?

Although both the number and length of outages have decreased compared to the previous five-year average, equipment failure remains the top cause of outages within Toronto Hydro's control.

That said, in 2022, severe weather presented a unique set of challenges for Toronto Hydro's distribution system.

Causes of Unscheduled Power Outages (five-year average: 2018 to 2022)



12%

Animal Contact: Outages caused by animals such as racoons, squirrels and birds coming in contact with overhead powerlines or transformers.



40%

Equipment Failure: Unscheduled power outages from equipment failure usually occur with distribution equipment that's beyond or approaching the end of their expected useful lives.



10%

Weather-Related Events: Adverse weather such as heavy rain, lightning strikes, ice, snow, wind, extreme temperatures, and freezing rain can disrupt the distribution system.



14%

Other: Includes tree contact (7%) and human interference (1%), such as construction workers accidentally cutting powerlines or motor vehicle accidents involving contact with distribution equipment. 4% of outages are unknown, but most are likely caused by animal contact.

Note: *statistics do not include loss of supply from Hydro One.*

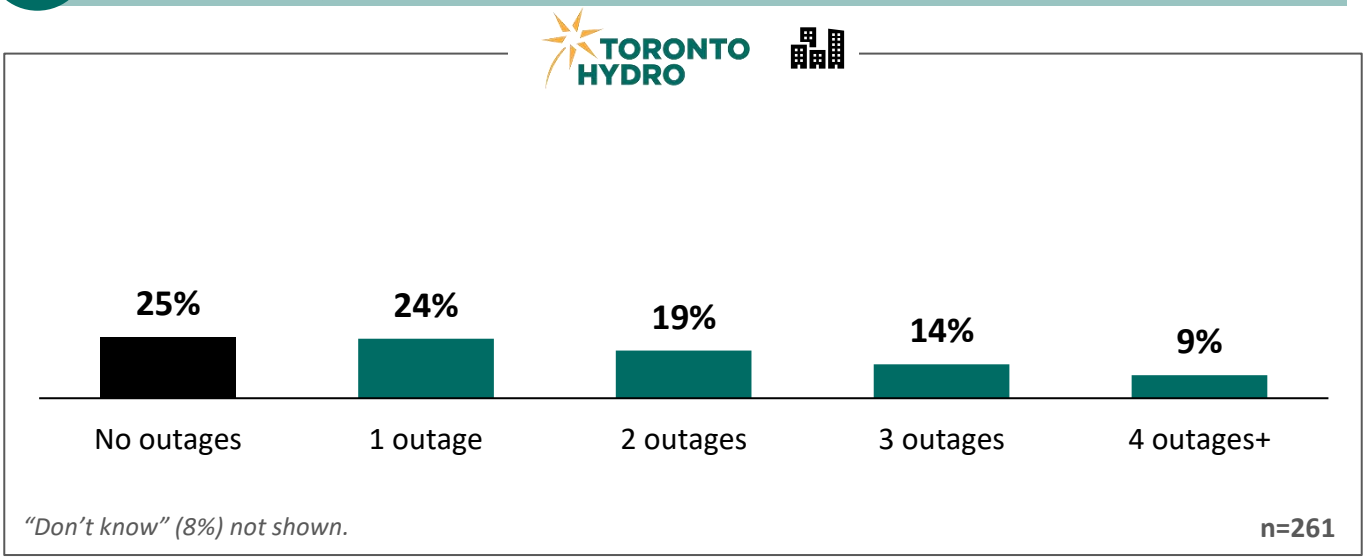
WORKBOOK PAGE

Online Workbook

Amount Spent on the Grid Reliability Plan

C&I

Q Over the past 12 months, have you experienced any power outages at your organization which lasted longer than one minute?



"Don't know" (8%) not shown.

n=261

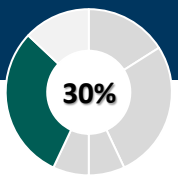
	Region				Consumption Quartiles			
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
No outages	17%	25%	20%	33%	29%	35%	15%	21%
1 outage	21%	36%	10%	25%	13%	20%	42%	23%
2 outages	27%	16%	26%	13%	24%	20%	8%	26%
3 outages	5%	13%	21%	15%	11%	16%	18%	9%
4 outages+	10%	8%	18%	5%	9%	4%	8%	16%

Note: Responses were optional.

INNOVATIVE RESEARCH GROUP

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Sustainment Plan

C&I

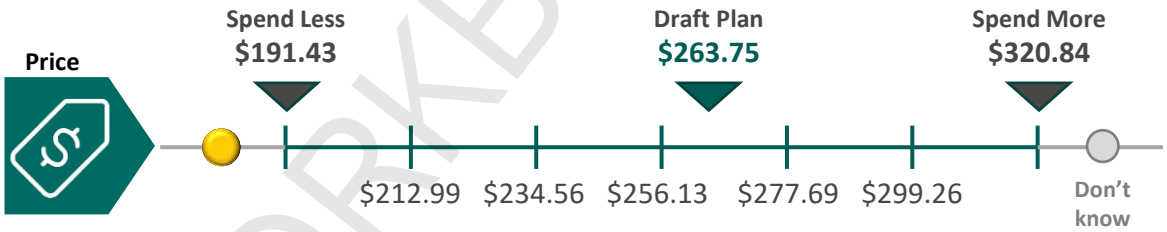


Making Choices: **Managing Equipment Failure Risk**

By 2029, Toronto Hydro's draft plan to manage equipment failure risk would cost the typical customer in this rate class **$263.75** more per month on their monthly electricity bill. Toronto Hydro could spend more to improve reliability, or it could spend less and take on more risk of outages.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of the grid by 2029.	Maintains the overall health (age and condition) of the grid by 2029.	Improves the overall health (age and condition) of the grid by 2029.
Reliability	Reduces reliability compared to current levels. This means more power outages due to equipment failure.	Maintains reliability at current levels. This means holding steady on power outages due to equipment failure.	Improves reliability compared to current levels. This means less power outages due to equipment failure.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work. Increases work volumes and costs for the next decade.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work. Reduces work volumes and costs for the next decade.

Choice 3 of 7:



$-.-- Your selection.

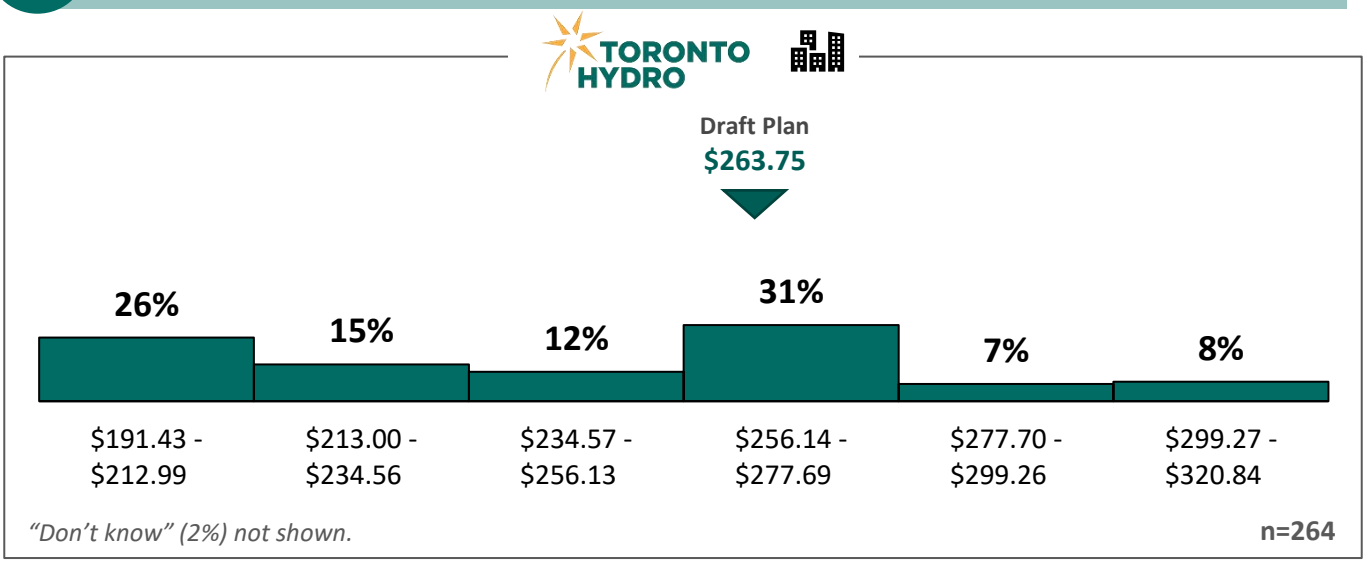
WORKBOOK PAGE

Online Workbook

Amount Spent on the Grid Reliability Plan

C&I

Q How much do you think Toronto Hydro should spend on its grid reliability plan?



"Don't know" (2%) not shown.

n=264

	Overall	Region				Consumption Quartiles			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Below Plan	55%	59%	53%	64%	49%	57%	57%	56%	51%
On Plan	25%	24%	27%	20%	27%	26%	26%	25%	23%
Above Plan	18%	16%	18%	16%	20%	15%	14%	19%	24%
Don't Know	2%	2%	2%	0%	3%	2%	3%	0%	3%
TOTAL On Plan + Above Plan	43%	39%	45%	36%	47%	41%	40%	44%	46%

Online Workbook

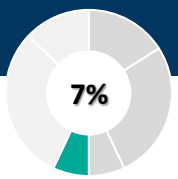
Additional Feedback on the Grid Reliability Plan

C&I

Q Do you have additional feedback on Toronto Hydro's draft grid reliability plan?

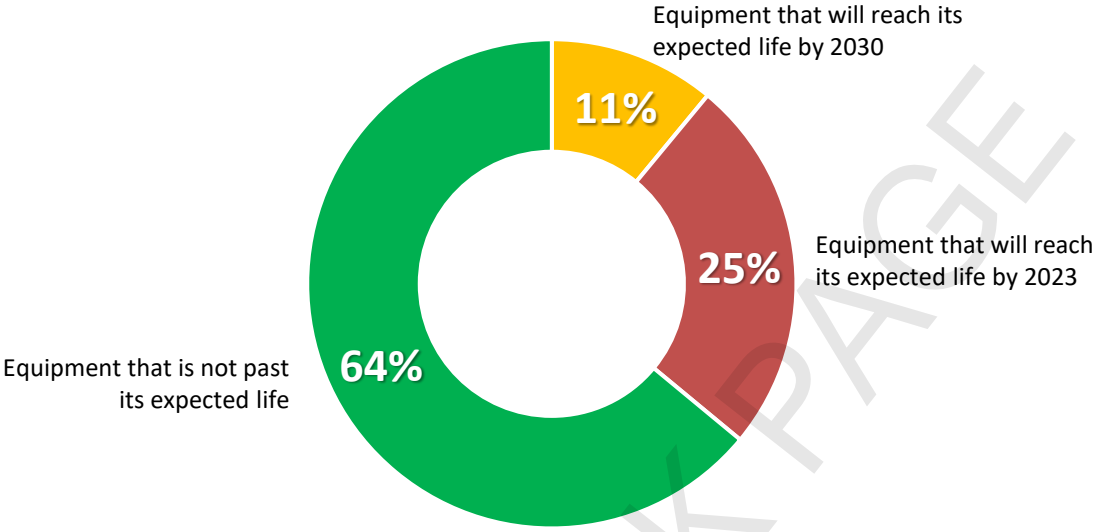
Response	%
Modernize, be proactive, invest for the long term	1.2%
Prevent outages, stable power, system reliability	0.8%
Make use of existing infrastructure, past spending	0.3%
Costs are too high already, cost of living, struggling to pay bills	0.3%
Support the increase (general)	0.3%
Find efficiencies, cut wasteful spending, lower salaries	0.2%
No response	96.8%

Note: Responses were optional. Only responses > 0.1% are shown.



2 Paced Upkeep of the Grid

About 25% of Toronto Hydro's equipment is operating past its expected life and an additional 11% is estimated to reach that point by 2030.



In this part of the plan, the key question is whether Toronto Hydro should wait until there are clear signs of equipment failure risk (such as rust or oil leaks), or whether it should get ahead of the problem by replacing old equipment proactively.

If Toronto Hydro waits, it can keep prices lower in the short term. However, this could create a surge of work in future years that will spike prices in the 2030s. There is also a risk that Toronto Hydro will not be able to do the amount of work required to deal with this equipment in the future, which could lead to more outages and higher safety risks due to equipment failures.

Want to learn more about Toronto Hydro's distribution grid? Click here.

What type of work is Toronto Hydro doing to upkeep the grid?

Below is an example of key investments that Toronto Hydro needs to make in a paced way to upkeep the grid and prevent a surge of work to address equipment failure risk in the future.



Paced Replacement of Network Vaults

This equipment is located in underground vaults in the downtown area, which serves many critical customers, such as hospitals and financial institutions. A very large portion of this equipment is going to be in poor condition and past its expected life in the 2030-34 period. To manage this risk, Toronto Hydro's draft plan intends to replace network vaults in a paced manner.

WORKBOOK PAGE

Renewing and replacing infrastructure

Toronto Hydro's grid is a mix of overhead, underground, network and station infrastructure. It operates at three different voltages (27.6kV, 13.8kV, and 4.16kV) and includes approximately:

- 61,300 distribution transformers
- 17,060 primary switches
- 15,393 km of overhead wires
- 13,765 km of underground wires
- 37 transformer stations



Overhead Infrastructure

The overhead system is made up of poles, wires, transformers, switches and other equipment. They are easier to replace, repair and inspect.

However, they are also more prone to foreign interference such as vehicles, trees, animals and weather-related outages.

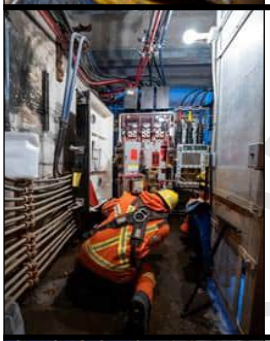
This system consists of three different types of configurations two of which are outdated configurations from the 1950s and 1960s, making them more challenging to replace and restore particularly after a weather-related outage.



Underground Infrastructure

Toronto Hydro's underground system consists of cables, transformers, switches and civil infrastructures (like manholes). They can be placed either at ground level (green box above ground in your neighbourhood), underground, or inside building vaults (typical for multi-storey buildings). This system is made up of two different types of configurations where the downtown Toronto area consists of lead-covered cable, an outdated equipment with little to no suppliers.

While underground equipment is more resilient during weather-related events, it is more susceptible to flooding and at risk of faster deterioration due to moisture build-up.



Network Infrastructure

Toronto Hydro's network system, predominantly found in the downtown Toronto area, was installed in the early-to-mid 1900s to improve reliability (service levels) for critical loads (like financial institutions) and serves medium-sized loads in high-density areas, and areas with small and narrow sidewalks. It consists of interconnected low-voltage cables, vaults and network units.

While this system is better at handling normal equipment failures, proactive replacement and maintenance of this equipment are critical to avoid vault fires from occurring.



Station Infrastructure

Toronto Hydro's distribution stations receive the transmission supply from Hydro One at very high voltages. Station infrastructure consists of switchgear, power transformers, circuit breakers, remote terminal units (station computers) and battery systems. Toronto Hydro proactively replaces this equipment, as failure at the station level can cause widespread and lengthy power outages.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Sustainment Plan

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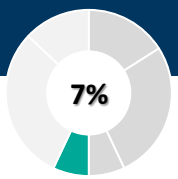
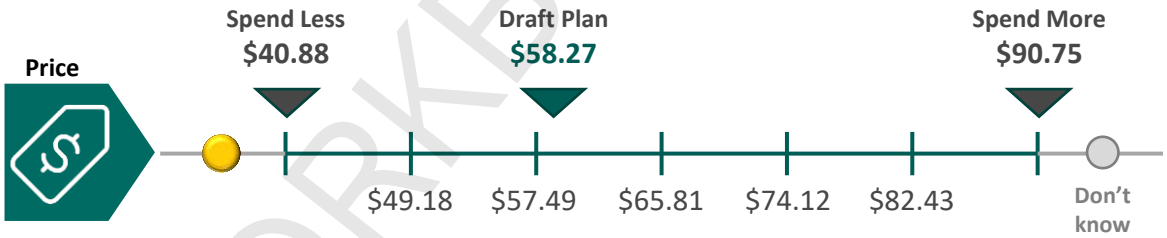


Making Choices: **Paced Upkeep of the Grid**

By 2029, Toronto Hydro's draft plan to ensure paced upkeep of the grid would cost the typical customer in this rate class **$58.27** more on their monthly electricity bill. Toronto Hydro could spend more to get ahead of future equipment failure risk, or it could spend less and defer some of this work at the risk of managing more power outages due to equipment failure in the next decade.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of the grid by 2029.	Maintains the overall health (age and condition) of the grid by 2029.	Improves the overall health (age and condition) of the grid by 2029.
Reliability	Higher risk of power outages due to equipment failure in the next decade.	Manages the risk of power outages due to equipment failure in the next decade.	Reduces the risk of power outages due to equipment failure in the next decade.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work. Increases work volumes and costs for the next decade.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work. Reduces work volumes and costs for the next decade.

Choice 4 of 7:



$-.-- Your selection.

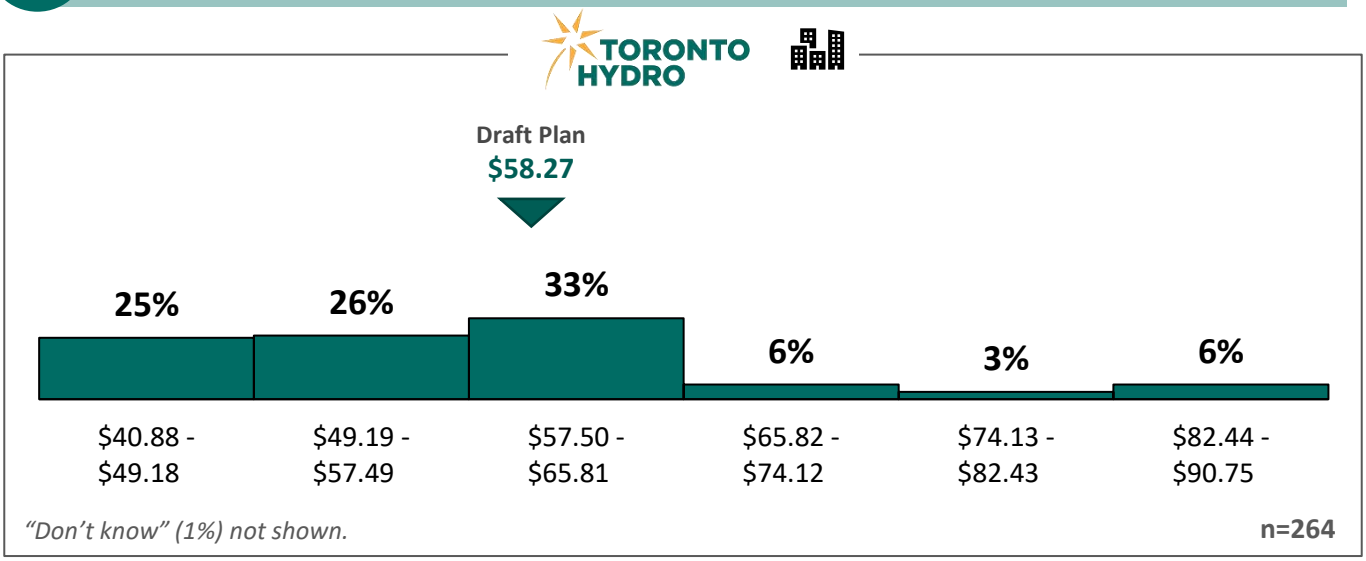
WORKBOOK PAGE

Online Workbook

Amount Spent on the Grid Stewardship Plan

C&I

Q How much do you think Toronto Hydro should spend on its grid stewardship plan?



"Don't know" (1%) not shown.

n=264

	Overall	Region				Consumption Quartiles			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Below Plan	42%	47%	46%	44%	33%	41%	48%	35%	42%
On Plan	34%	33%	29%	31%	40%	34%	32%	44%	25%
Above Plan	23%	19%	22%	24%	25%	22%	18%	21%	31%
Don't Know	1%	2%	3%	0%	1%	3%	1%	0%	1%
TOTAL On Plan + Above Plan	57%	52%	51%	56%	66%	56%	50%	65%	57%

Online Workbook

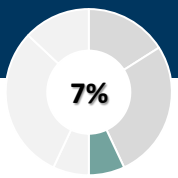
Additional Feedback on the Grid Stewardship Plan

C&I

Q Do you have additional feedback on Toronto Hydro's draft grid stewardship plan?

Response	%
Support the increase (general)	0.5%
Make use of existing infrastructure, past spending	0.5%
Should be funded by tax dollars/government	0.4%
Modernize, be proactive, invest for the long term	0.3%
Costs are too high already, cost of living, struggling to pay bills	0.3%
Find efficiencies, cut wasteful spending, lower salaries	0.2%
Prevent outages, stable power, system reliability	0.2%
No response	97.5%

Note: Responses were optional. Only responses > 0.1% are shown.

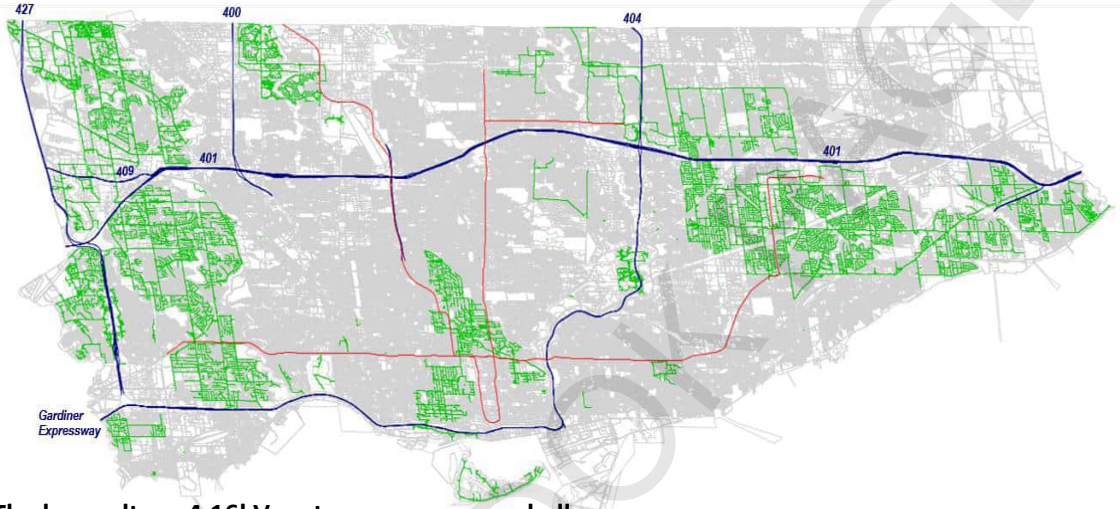


3 Standardize the Grid

Because of its history, Toronto Hydro has an old and diverse grid. Toronto Hydro is made up of 6 municipal utilities that were joined in 1998 when the City of Toronto was formed. Each utility owned and operated different types of equipment. As a result, Toronto Hydro's grid has three different voltage levels: 4.16kV, 13.8kV and 27.6kV.

The 27.6kV voltage level is the current standard for local grids. However, a large part of Toronto Hydro's grid is served at 4.16kV and 13.8kV.

Location of Outdated Voltage Lines



The low voltage 4.16kV system poses many challenges:

- Long outages for customers and higher cost to restore power – in 2022, the longest outage on the 4.16 kV system was 80 hours.
- Less efficient at carrying power over long distances, which means more electricity is lost as it travels from point A to point B (line losses).
- Less capacity to serve customers' growing electricity needs, which means longer waits and higher costs to connect new services such as electric vehicles and solar panels.
- Risk of supply chain and labour shortages as manufacturers stop making this equipment and technicians trained on this equipment retire.

What type of work is Toronto Hydro doing to standardize the grid?

Below is an example of a key investment to replace outdated equipment.



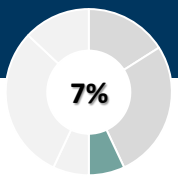
Voltage Conversion from 4.16kV/13.8kV to 27.6kV

Voltage conversion entails a full rebuild of outdated equipment such as rear lot construction (poles and wires in customers' backyards). This work improves reliability, safety and makes the grid more efficient. Toronto Hydro's draft plan intends to convert 1400 customers from rear lot service and works to eliminate rear lot construction from the grid by the late 2040s.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Sustainment Plan

C&I



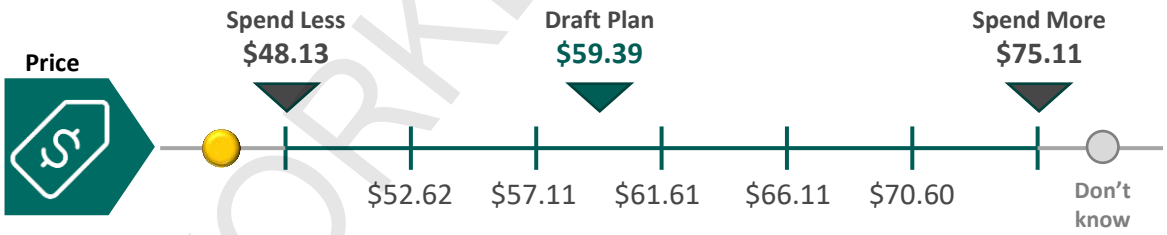
Making Choices: **Standardize the Grid**

By 2029, Toronto Hydro's draft **plan to standardize the grid** would cost the typical customer in this rate class **$59.39** more on their monthly electricity bill. Toronto Hydro could spend more to speed up the pace of replacing outdated equipment or it could spend less to slow down the pace and delay the benefits of this work. For example, under spend more Toronto Hydro would convert all rear lot customers by the early 2040s, and under spend less by the 2050s.

	Spend Less	Draft Plan	Spend More
Reliability	Slower progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.	Steady progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.	Faster progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.
Customer Service	Less progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels.	Steady progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels.	Faster progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels.
Efficiency	Slower progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.	Steady progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.	Faster progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.

WORKBOOK PAGE

Choice 5 of 7:



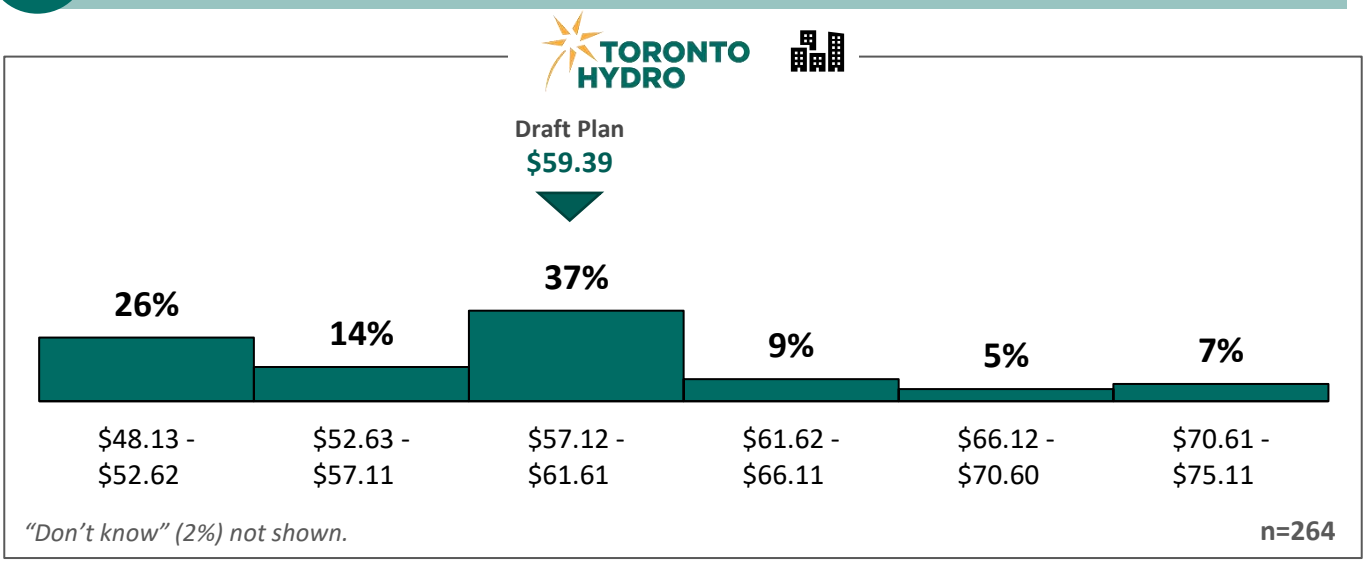
$-.-- Your selection.

Online Workbook

Amount Spent on the Equipment Standardization Plan

C&I

Q How much do you think Toronto Hydro should spend on its equipment standardization plan?



"Don't know" (2%) not shown.

n=264

	Overall	Region				Consumption Quartiles			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Below Plan	44%	47%	52%	41%	38%	49%	43%	37%	47%
On Plan	31%	24%	25%	31%	39%	31%	36%	32%	24%
Above Plan	24%	28%	20%	26%	22%	17%	19%	29%	29%
Don't Know	2%	2%	3%	2%	1%	2%	3%	2%	0%
TOTAL On Plan + Above Plan	54%	51%	46%	57%	61%	48%	54%	61%	53%

Online Workbook

Additional Feedback on the Equipment Standardization Plan

C&I

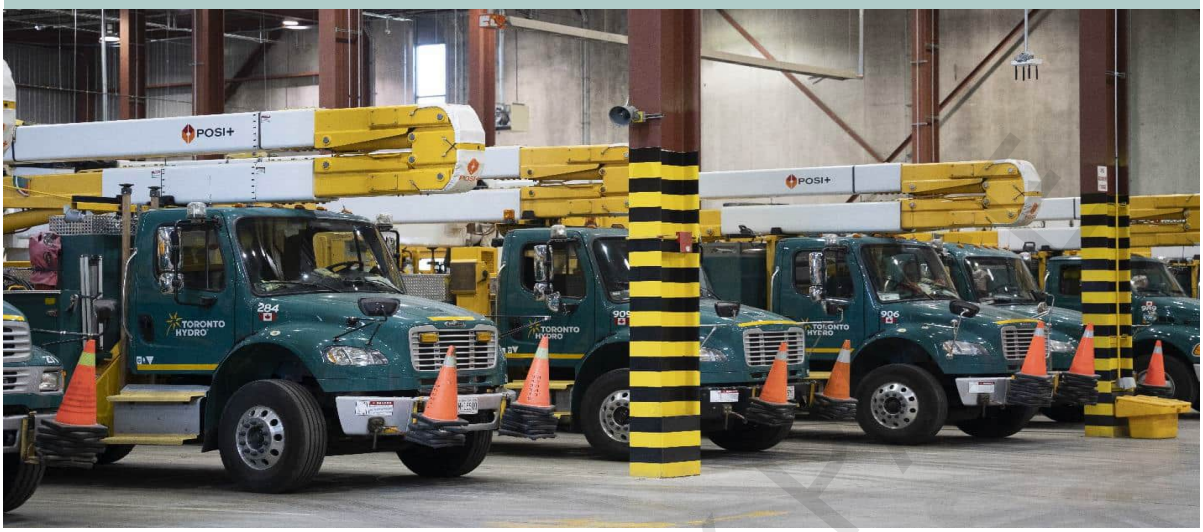
Q Do you have additional feedback on Toronto Hydro's draft equipment standardization plan?

Response	%
Modernize, be proactive, invest for the long term	0.7%
Support the increase (general)	0.7%
Costs are too high already, cost of living, struggling to pay bills	0.5%
Oppose the increase, increase is too high (general)	0.3%
Find efficiencies, cut wasteful spending, lower salaries	0.2%
No response	97.6%

Note: Responses were optional. Only responses > 0.1% are shown.

Draft General Plant Plan

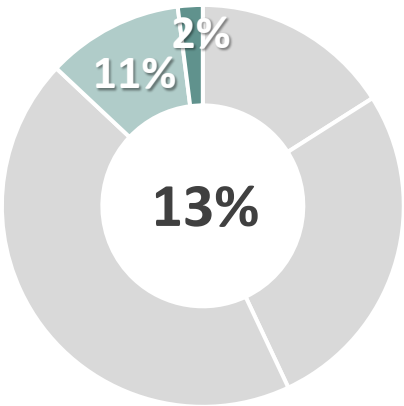
Keeping the Business Running



What is this section about?

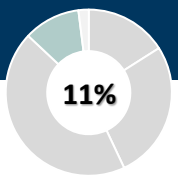
- This section is about the vehicles, work centres and IT systems that keep Toronto Hydro's business running efficiently.
- Toronto Hydro seeks your input on two choices within this part of the plan:

1. The pace of replacing the equipment needed to keep the business running.
2. The pace of reducing Toronto Hydro's emissions from its own operations.



- This spending category makes up **13% of the draft plan** and would add **$111.85** on the average customer in this rate class's monthly bill by 2029.

WORKBOOK



1 Keep the Business Running

Work centres, vehicles and information technology systems are the backbone of Toronto Hydro's day-to-day operations. This equipment must be maintained in good working condition for efficient and reliable operations so that crews can restore power and customers can access key services like their online account and the outage restoration map.

- As with grid equipment, Toronto Hydro uses information such as age and condition data from inspections to decide which equipment should be replaced versus repaired.
- Toronto Hydro repairs equipment in poor condition such as leaking roofs, failed furnaces and worn-out vehicle braking systems. It also replaces equipment like software programs and hardware servers that are past expected useful life.

What type of work is Toronto Hydro doing to manage failure risk?

Below is an example of a key investment that Toronto Hydro needs to make to keep the business running and manage the risk of equipment failure.



Station Buildings

Toronto Hydro has approximately 250 properties that either house distribution stations equipment such as cables and transformers or support the distribution system.

Over 80% of station buildings are older than 40 years and require repairs and investments to address the following types of problems:

- Structural damage to the building (cracked foundations, leaking roofs)
- Mechanical, electrical and plumbing equipment in poor condition
- Compliance with building and fire code requirements

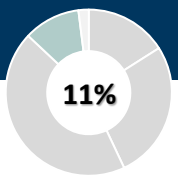
This work ensures safe and efficient operations and minimizes the risk of outages that can affect many customers. For example, structural damage to a station building poses a direct risk to distribution equipment such as power transformers.

So, how much and how quickly Toronto Hydro decides to invest in keeping their business running has a direct impact on customers. While this equipment may remain in service for a long time, when they unexpectedly fail, the costs incurred usually far exceed proactive investments (repairs and replacements) and can have a significant impact on system reliability and customer service.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft General Plant Plan

C&I



Making Choices: **Keep the Business Running**

By 2029, Toronto Hydro's draft plan to keep the business running would cost the typical customer in this rate class **$98.05** more on their monthly electricity bill. Toronto Hydro could spend more to improve equipment health (age and condition) and functionality (better safety features) or spend less and take on more risk of equipment downtime.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of general plant equipment by 2029.	Maintains the overall health (age and condition) of general plant equipment by 2029.	Improves the overall health (age and condition) of general plant equipment by 2029.
Reliability & Service	Reduces equipment availability, which could mean longer outages or lower levels of customer service.	Maintains equipment availability consistent with current levels.	Improves equipment availability and functionality, which could mean better reliability and customer service levels.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work, which is more costly and increases equipment downtime.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work, and better equipment functionality.

Choice 6 of 7:

Price

Spend Less **$70.76** | Draft Plan **$98.05** | Spend More **$114.27**

$78.00 | $85.25 | $92.51 | $99.76 | $107.01 | Don't know

$-.-- Your selection.

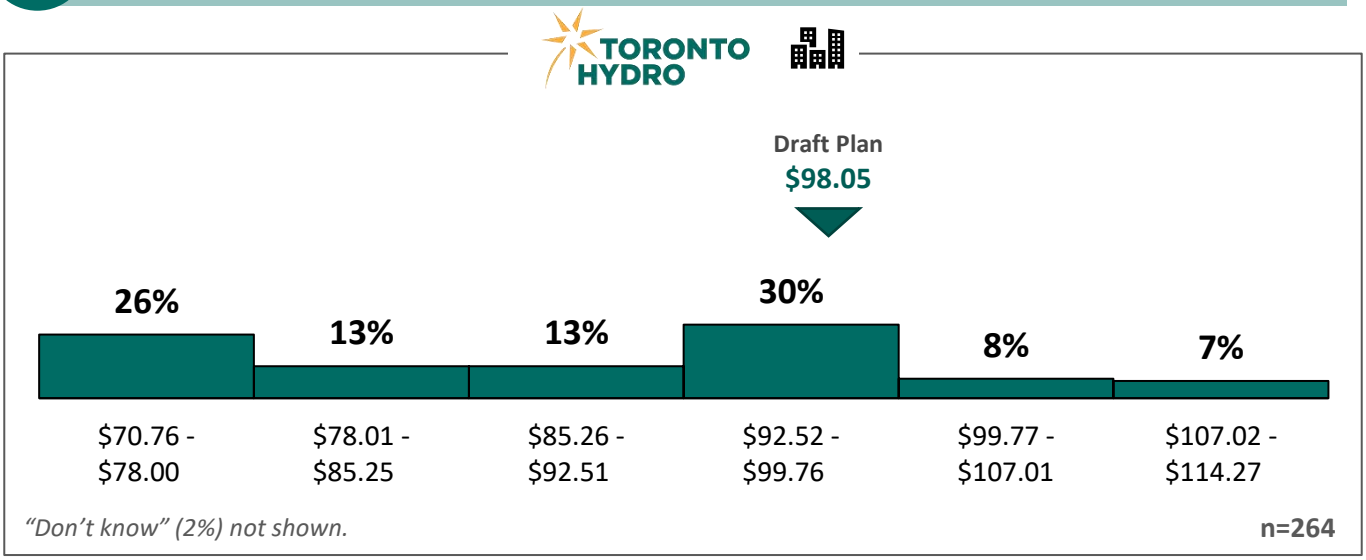
WORKBOOK PAGE

Online Workbook

Amount Spent on Keeping the Business Running

C&I

Q How much do you think Toronto Hydro should spend to keep the business running?



"Don't know" (2%) not shown.

n=264

	Overall	Region				Consumption Quartiles			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Below Plan	59%	57%	57%	62%	61%	62%	59%	61%	56%
On Plan	25%	27%	22%	22%	27%	23%	29%	22%	24%
Above Plan	14%	15%	19%	15%	8%	12%	10%	14%	21%
Don't Know	2%	2%	2%	2%	3%	3%	3%	3%	0%
TOTAL On Plan + Above Plan	39%	42%	41%	36%	36%	35%	39%	36%	44%

Online Workbook

Additional Feedback on Keeping the Business Running

C&I

Q Do you have additional feedback on Toronto Hydro's draft plan for keeping the business running?

Response	%
Find efficiencies, cut wasteful spending, lower salaries	1.0%
Support the increase (general)	0.7%
Prevent outages, stable power, system reliability	0.5%
Make use of existing infrastructure, past spending	0.4%
Oppose the increase, increase is too high (general)	0.3%
Modernize, be proactive, invest for the long term	0.2%
No response	96.9%

Note: Responses were optional. Only responses > 0.1% are shown.

2 Reducing Toronto Hydro's Emissions

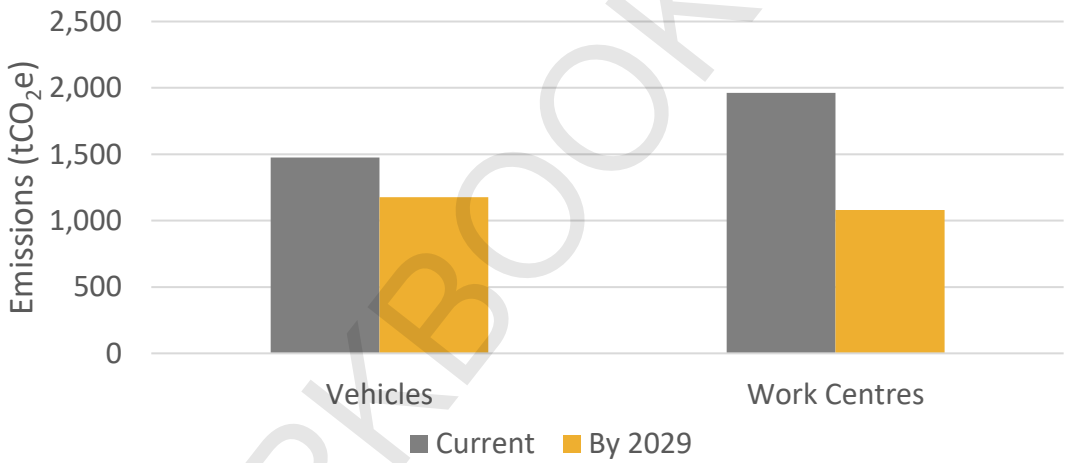
To address climate change, companies around the world are setting targets to reduce greenhouse gas (GHG) emissions from fossil fuels — a pledge commonly known as Net Zero.

Moving toward Net Zero has increasingly become the expectation of governments, financial markets, stakeholders and customers. For example, in October 2019, Toronto City Council unanimously voted to accelerate efforts to reduce emissions across the city.

To do its part in addressing climate change, Toronto Hydro is committed to reducing emissions from its vehicles and work centres by:

- Replacing gasoline and diesel power vehicles with hybrid and electric vehicles.
- Converting natural gas boilers and heaters in its work centres to electric ones.

Toronto Hydro's Draft Plan to Reduce Emissions



Carbon Tax Savings

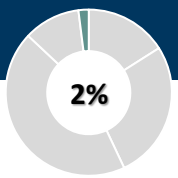
Reducing carbon emissions from vehicles and work centres could help Toronto Hydro manage rising costs due to the carbon tax (recall that the carbon tax may increase by 161% from 2023 to 2030). **Over the 2025-2029 period, Toronto Hydro's draft plan could reduce carbon tax payments by roughly half a million dollars.**

With your feedback, Toronto Hydro needs to decide how quickly to transition to cleaner sources of energy for its operations. In the next section, you will be presented these options.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft General Plant Plan

C&I

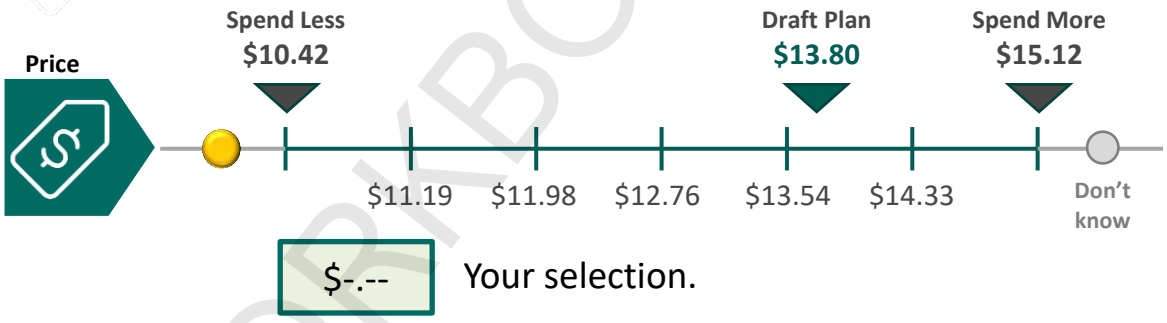


Making Choices: **Reducing Toronto Hydro's Emissions**

By 2029, Toronto Hydro's draft plan to reduce emissions would cost the typical customer in this rate class **$13.80** more on their monthly electricity bill. Toronto Hydro could spend more for faster progress towards reducing its emissions, or spend less to slow down the progress.

	Spend Less	Draft Plan	Spend More
Environment	Less progress to reduce emissions — about 27% reduction by the end of the decade.	Steady progress to reduce emissions — about 35% reduction by the end of the decade.	Faster progress to reduce emissions — about 36% reduction by the end of the decade.
Efficiency	Higher exposure to rising energy costs (oil and gas) due to the carbon taxes and other pressures.	Managed exposure to rising energy costs (oil and gas) due to the carbon tax and other pressures.	Less exposure to rising energy costs (oil and gas) due to carbon taxes and other pressures.

Choice 7 of 7:



$-.-- Your selection.

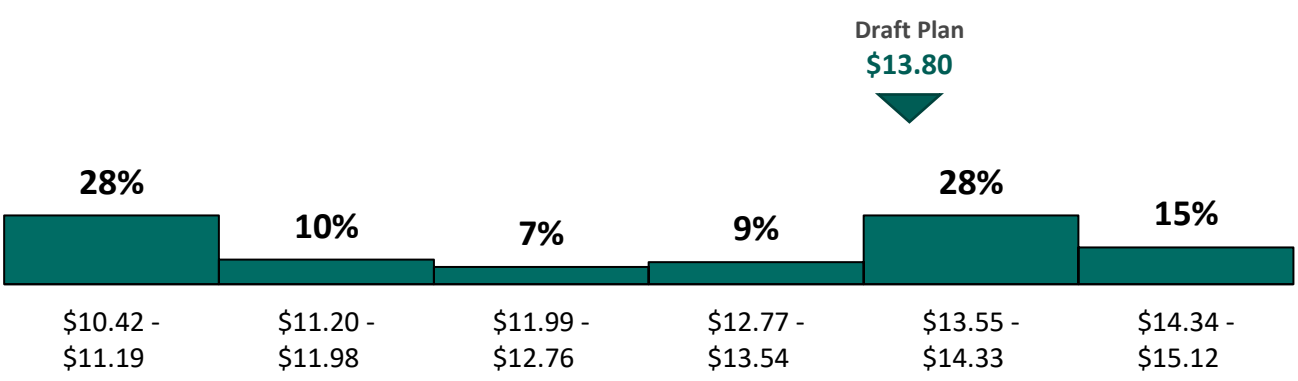
WORKBOOK PAGE

Online Workbook

Amount Spent on Decarbonization

C&I

Q How much do you think Toronto Hydro should spend to reduce its own emissions?



"Don't know" (3%) not shown.

n=264

	Overall	Region				Consumption Quartiles			
		Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Below Plan	56%	57%	58%	54%	55%	56%	57%	57%	55%
On Plan	22%	24%	21%	20%	22%	25%	22%	21%	18%
Above Plan	20%	18%	19%	23%	19%	16%	17%	19%	26%
Don't Know	3%	2%	2%	3%	3%	3%	4%	3%	0%
TOTAL On Plan + Above Plan	41%	41%	40%	43%	41%	41%	39%	40%	45%

Online Workbook

Additional Feedback on Decarbonization

C&I

Q Do you have additional feedback on Toronto Hydro's draft decarbonization plan?

Response	%
Oppose the increase, increase is too high (general)	0.7%
Cost shouldn't be borne by all customers	0.5%
Costs are too high already, cost of living, struggling to pay bills	0.4%
Should be funded by tax dollars/government	0.3%
Other	0.2%
No response	97.9%

Note: Responses were optional. Only responses > 0.1% are shown.

Online Workbook

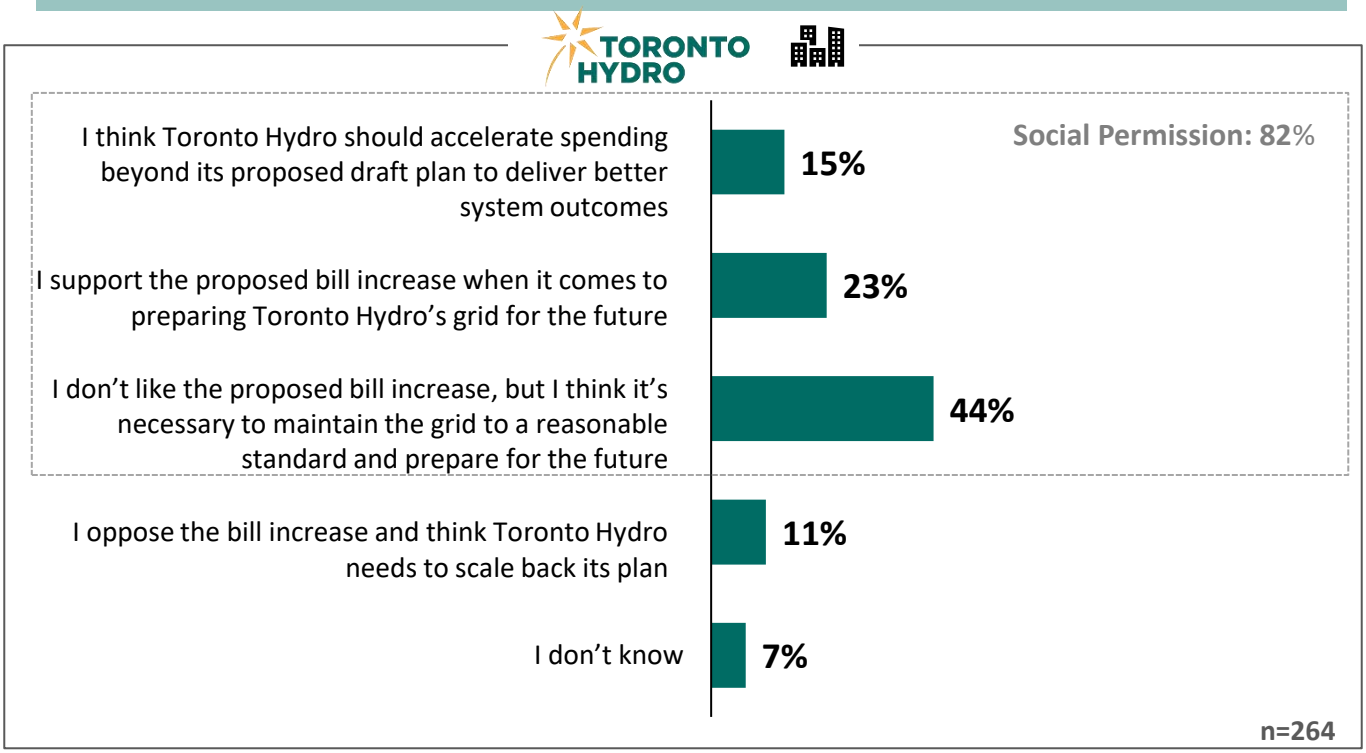
Social Permission

C&I

Q

Toronto Hydro has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Toronto Hydro would like to know how you feel about the total rate impact of its current draft plan.

Considering what you have learned about Toronto Hydro's 2025–2029 draft plan and that this may result in a **$870.85 increase** in the distribution portion of your monthly electricity bill by 2029, which of the following best represents your point of view?



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Online Workbook

Social Permission

C&I

Q

Toronto Hydro has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Toronto Hydro would like to know how you feel about the total rate impact of its current draft plan.

Considering what you have learned about Toronto Hydro's 2025–2029 draft plan and that this may result in a **$870.85 increase** in the distribution portion of your monthly electricity bill by 2029, which of the following best represents your point of view?

	Region			
	Etobicoke/York	North York	Scarborough	Toronto/East York
Accelerate spending	14%	22%	12%	11%
Support proposed bill	19%	19%	33%	23%
Necessary to maintain grid	48%	40%	39%	50%
Oppose the bill increase	12%	13%	9%	10%
I don't know	7%	7%	8%	6%
Social Permission	82%	80%	83%	83%

	Consumption Quartiles			
	First	Second	Third	Fourth
Accelerate spending	14%	11%	11%	23%
Support proposed bill	25%	21%	28%	18%
Necessary to maintain grid	42%	48%	53%	35%
Oppose the bill increase	10%	16%	2%	16%
I don't know	8%	4%	6%	9%
Social Permission	81%	80%	92%	76%

Online Workbook

Final Comments for the Draft Plan & Proposed Rate Increase

C&I

Q Do you have any final comments regarding Toronto Hydro's draft plan for 2025–2029 and the proposed rate increase?

Response	%
Modernize, be proactive, invest for the long term	3.3%
Find efficiencies, cut wasteful spending, lower salaries	1.4%
Oppose the increase, increase is too high (general)	1.1%
Costs are too high already, cost of living, struggling to pay bills	0.7%
Need more information	0.3%
Support the increase (general)	0.3%
Address equity, protect low-income customers	0.3%
No response	92.6%

INNOVATIVE RESEARCH GROUP

Commercial & Industrial Customers

Online Workbook Diagnostics

Section 11.2



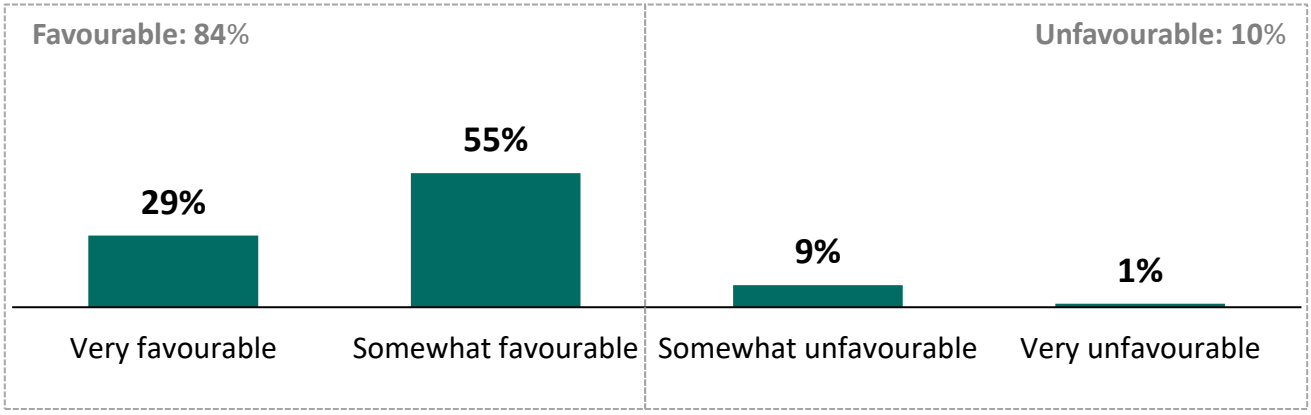
Online Workbook

Workbook Impression

C&I

Q Overall, what is your impression of the survey you just completed?

TORONTO HYDRO



"Don't know" (6%) not shown.

n=264

INNOVATIVE RESEARCH GROUP

Online Workbook

Workbook Impression

C&I

Q Overall, what is your impression of the survey you just completed?

	Region			
	Etobicoke/York	North York	Scarborough	Toronto/East York
Very favourable	23%	21%	40%	34%
Somewhat favourable	63%	61%	44%	51%
Somewhat unfavourable	8%	10%	8%	9%
Very unfavourable	0%	2%	2%	2%
Don't know	6%	6%	7%	4%
Favourable (Very + Somewhat)	86%	82%	83%	85%
Unfavourable (Very + Somewhat)	8%	12%	10%	11%

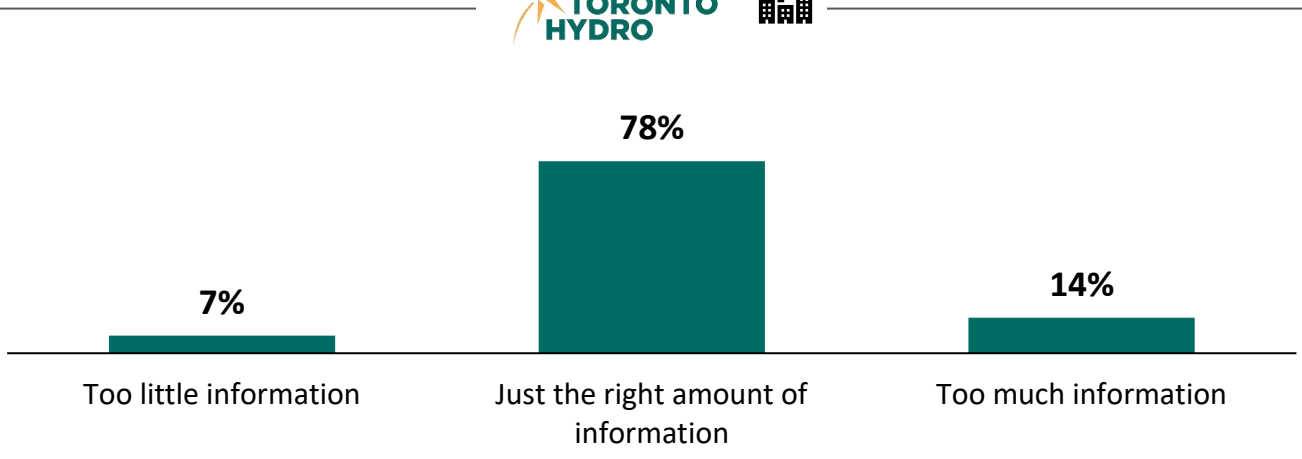
	Consumption Quartiles			
	First	Second	Third	Fourth
Very favourable	24%	26%	43%	24%
Somewhat favourable	56%	56%	51%	56%
Somewhat unfavourable	10%	10%	4%	11%
Very unfavourable	3%	0%	2%	1%
Don't know	7%	8%	0%	7%
Favourable (Very + Somewhat)	80%	82%	94%	80%
Unfavourable (Very + Somewhat)	13%	10%	6%	13%

Online Workbook

Amount of Information

C&I

Q In this survey, do you feel that Toronto Hydro provided too much information, not enough, or just the right amount?



	Region				Consumption Quartiles			
	Etobicoke/ York	North York	Scarborough	Toronto/ East York	First	Second	Third	Fourth
Too little information	10%	5%	5%	8%	5%	8%	5%	10%
Just the right amount of information	78%	78%	79%	79%	79%	77%	83%	74%
Too much information	12%	16%	16%	13%	16%	14%	12%	16%

Online Workbook

Content Missing from Engagement

C&I

Q Was there any content missing that you would have liked to have seen included in this survey?

Response	%
Operational efficiencies (salaries, spending) and accountability	3.0%
Reliability (e.g. Plans for underground cables)	1.1%
Delivery charges	0.8%
More information on the costs, breakdown of either the plan or bill	0.7%
Confusing, navigational issues in the survey	0.5%
More historic context, past rate increases and spending	0.3%
Comparison to other regions or utilities	0.3%
Satisfied with the information presented	0.3%
How this benefits customers	0.2%
Other	0.6%
No response	92.1%

Online Workbook

Outstanding Questions

C&I

Q Is there anything that you would still like answered?

Response	%
More information on the costs, breakdown of either the plan or bill	0.8%
Operational efficiencies (salaries, spending) and accountability	0.6%
Environmental sustainability, info about EVs/charging	0.3%
Ways to reduce usage, save money on bill	0.3%
Reliability (e.g. Plans for underground cables)	0.3%
Other	0.4%
No response	97.2%

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro. The conclusions drawn and opinions expressed are those of the authors.

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INNOVATIVE RESEARCH GROUP

CONFIDENTIAL

APPENDIX 12

Key Accounts
Workbook Report

TORONTO HYDRO

November 2, 2023

STRICTLY CONFIDENTIAL

2025 – 2029 Rate Application

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Key Account Customers

Online Workbook Report

Section 12.1



Online Survey
Survey Design & Methodology

Toronto Hydro Electric-System Ltd. (THESL) engaged Innovative Research Group (INNOVATIVE) to design, execute and document the results of THESL's customer engagement process as part of the development of its 2025–2029 business plan.

Field Dates

There were two versions of the workbook; one for GS 1,000-4,999kW and the other one for large use, as indicated on the top right corner of the workbook pages. Since the number of key accounts and large use customers within Toronto Hydro's customer base was limited, this report aggregates the responses from these two rate classes for reporting purposes.

All Toronto Hydro GS 1,000-4,999kW (key accounts) customers with an email address on Toronto Hydro's file received the **Key Accounts Online Workbook**. All Toronto Hydro large use customers with an email address on Toronto Hydro's file received the **Large Use Online Workbook**. Customers had the opportunity to complete the survey between **April 3rd and June 2nd, 2023**.

Incentives

Customers who completed the survey were invited to enter a draw to win a $5,000 donation to a charity of the organization's choosing (as shown on pg.7).

Key Accounts Online Survey Completes

All customers with email addresses on file received an email invitation, which included a unique survey URL that linked back to their annual consumption, region and rate class. A total of **52** (unweighted) Toronto Hydro key account customers completed the online survey.

Sample Weighting

The key account online survey sample has been weighted proportionately by sector in order to be representative of the broader Toronto Hydro service territory. *The table below summarizes the unweighted and weighted (in brackets) sample breakdown by sector.*

Sector	Total
MASH (Municipalities, Academic Institutions, Schools and Hospitals)	15 (8)
Commercial/MURB (Multi-Unit Residential Buildings)	21 (28)
Industrial	16 (16)
Total	52 (52)

Note: *Due to the small sample size, the findings should be interpreted as directional only. In most cases, the section uses frequencies instead of percentages to present the data.*

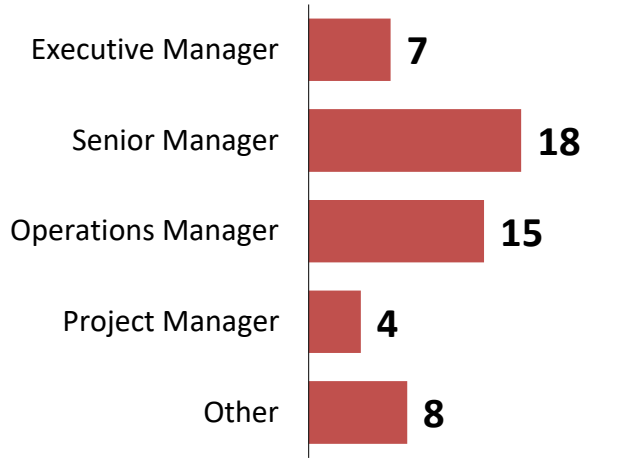
Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers.

Online Survey

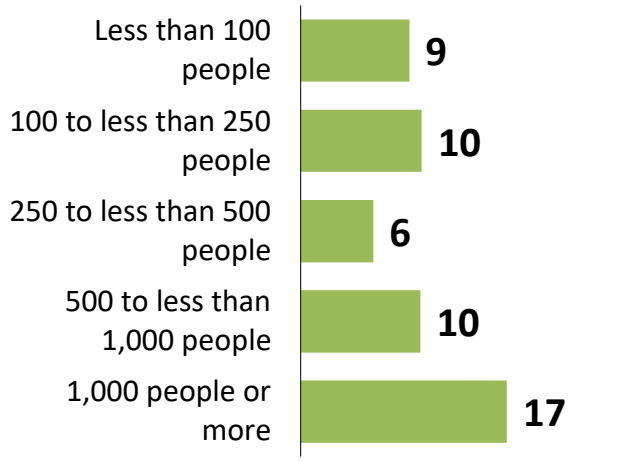
Firmographics breakdown

Key Accounts

Role at Organization

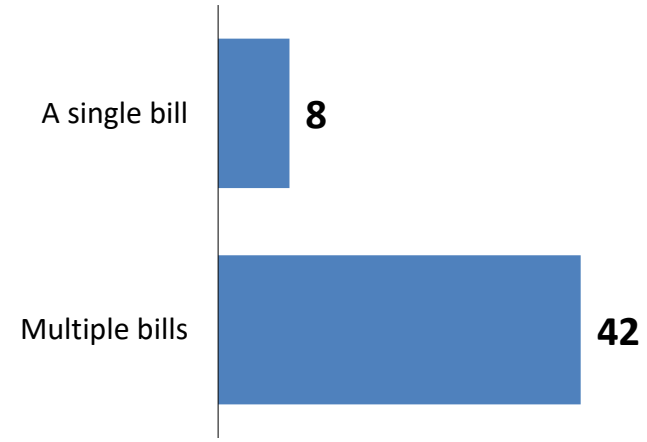


Number of Employees at the Organization



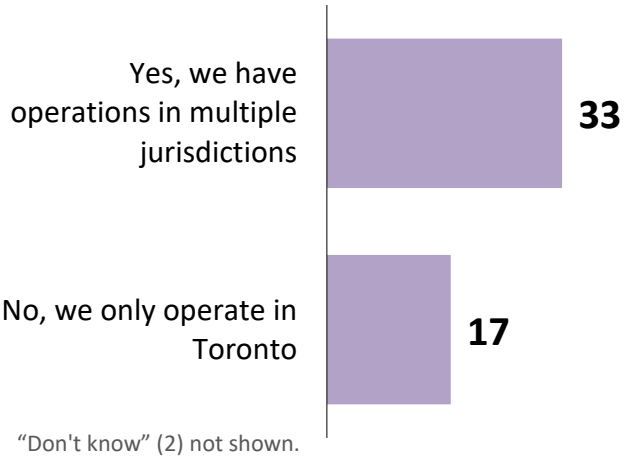
"Don't know" (1) not shown.

Number of Bills



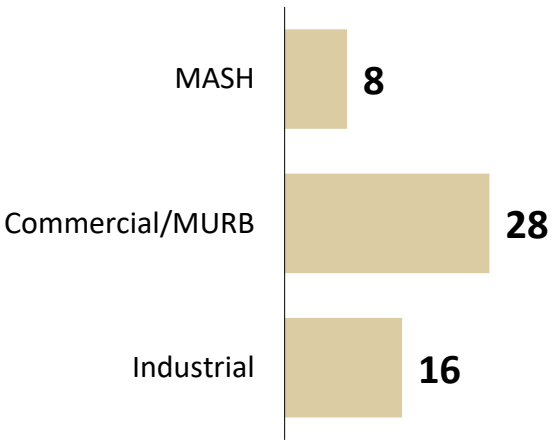
"Don't know" (2) not shown.

Bills from other Utilities



"Don't know" (2) not shown.

Sector



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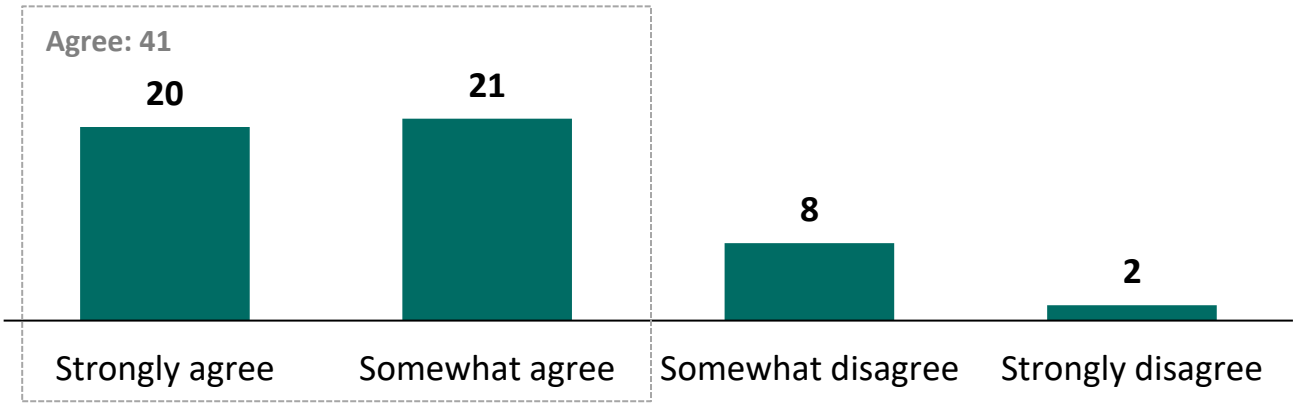
Online Survey
Environmental Controls

Key Accounts

To what extent do you agree or disagree with the following statements?

Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.

TORONTO HYDRO

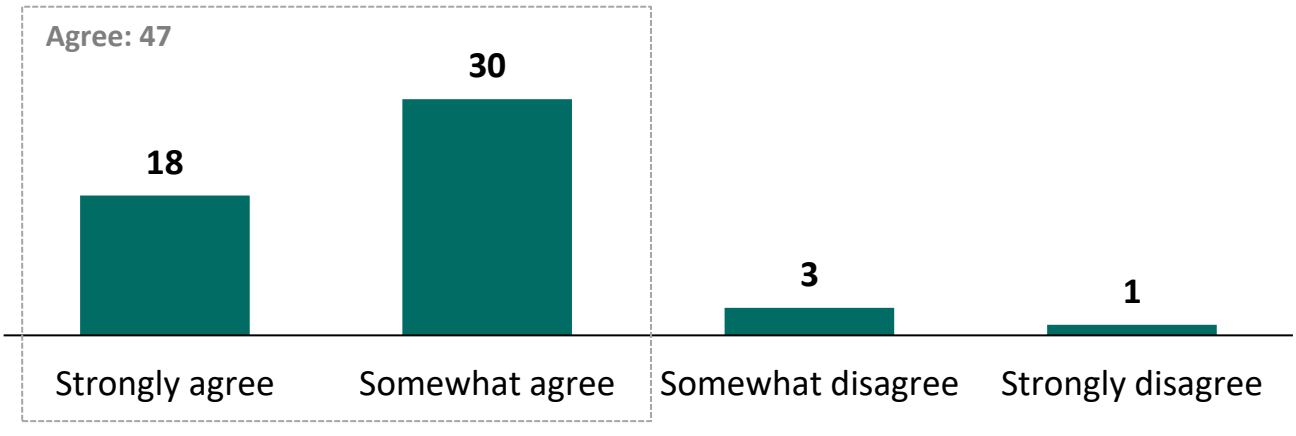


"Don't know/no opinion" (2) not shown.

n=52

Q Customers are well-served by the electricity system in Ontario.

TORONTO HYDRO



n=52

INNOVATIVE RESEARCH GROUP

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Key Accounts

Welcome to Toronto Hydro's customer feedback survey!

Toronto Hydro needs your input to find the right balance between the services you receive and the price you pay.



Land Acknowledgement: Toronto Hydro's grid is located on the traditional territory of many nations including the Mississaugas of the Credit, the Anishnabeg, the Chippewa, the Haudenosaunee and the Wendat peoples and is now home to many diverse First Nations, Inuit and Métis peoples.

The purpose of this survey is to get your feedback on the draft 2025–2029 business plan. Your feedback will help Toronto Hydro align this plan with what you need and want.

1. Your electricity rates pay for this plan, so your views must be considered.
2. You don't need to be an electricity expert to participate. The survey is focused on basic choices and provides the background information you need to answer the questions.
3. Recognizing that people absorb information in different ways, Toronto Hydro and its research partner have designed this survey to include diagrams, charts, images and videos to help explain Toronto Hydro's draft plan and what it means for you. If you prefer to skip the videos, the content is also explained in the body of the survey.
4. Depending on how much feedback you wish to provide and the number of videos watched, this survey should take approximately **20-30 minutes** to complete. If you need to pause and return later to finish the survey, your completed answers will be saved.
5. Some of the survey content may not display correctly on a mobile browser. It is strongly recommended that you complete this workbook on a desktop or laptop computer.

Those who complete the survey will be invited to enter a draw to win a $5,000 donation to a charity of your organization's choosing!

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Toronto Hydro to gather your feedback, while protecting your confidentiality. Your individual answers will not be shared with Toronto Hydro in any identifiable way.

INNOVATIVE RESEARCH GROUP

WORKBOOK PREVIEW

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Key Accounts

What is this customer engagement about?

The goal of this engagement is to share Toronto Hydro's draft five-year business plan for the future of the city's electrical grid and collect your feedback. This will help Toronto Hydro align its plans with your needs and preferences.

Click on the video below to learn about Toronto Hydro's customer engagement.



Every five years, Toronto Hydro is required to submit a plan for its proposed prices (rates) and spending to the Ontario Energy Board (OEB) for approval.

- **In 2021 and 2022, thousands of its customers told Toronto Hydro about what they need and want** to help Toronto Hydro prepare the draft 2025–2029 business plan.
- **Toronto Hydro is now looking for your input on this draft business plan** to align its investments and spending decisions with what matters to you as its customers.
- **Later this year, Toronto Hydro will present its updated business plan to the independent regulator,** the OEB. Toronto Hydro is accountable to the OEB for considering your feedback.

How will this customer engagement work?



1. The workbook explains what Toronto Hydro does and summarizes the key planning considerations that Toronto Hydro's draft plan needs to address.



2. The workbook explains how much of your electricity bill goes to Toronto Hydro, how that money is spent, and the impact of the draft plan on your 2025–2029 prices.
3. The workbook asks for your input on seven key choices that will affect the services you receive and the price you pay from 2025–2029.



Once you have finished giving feedback on the key choices, **you will have an opportunity to review and change your responses** until you feel you have found the right balance.



Want to know more about Toronto Hydro's customer engagement process? Click here.

WORKBOOK PREVIEW

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Key Accounts

How will your feedback impact Toronto Hydro's plan and prices?

Toronto Hydro has a five-step approach to customer feedback.

We are here

✓ **1. Identify Customer Needs, Preferences, and Priorities**

In 2022, Toronto Hydro asked many types of customers from across the city about their needs and priorities for electricity distribution service.

✓ **2. Use Customer Feedback to Guide Development of Draft Plan**

Toronto Hydro planners were given summaries of the key findings from the initial customer engagement to consider as they began building their plans.

3. Collect Customer Feedback on the Draft Plan

Toronto Hydro is returning to customers to get feedback on the draft plan and ask customers how the draft plan could better meet their needs and preferences.

4. Use Customer Feedback to Finalize the Plan

Toronto Hydro will re-examine and make appropriate changes to the plan based on the feedback provided by customers in this engagement.

5. Submit the Plan to the Ontario Energy Board (OEB)

Toronto Hydro will file the plan with the OEB along with a report summarizing the results of this engagement. The OEB, consumer advocates and other interested groups will examine the plan in an open and transparent public process known as a rate application.

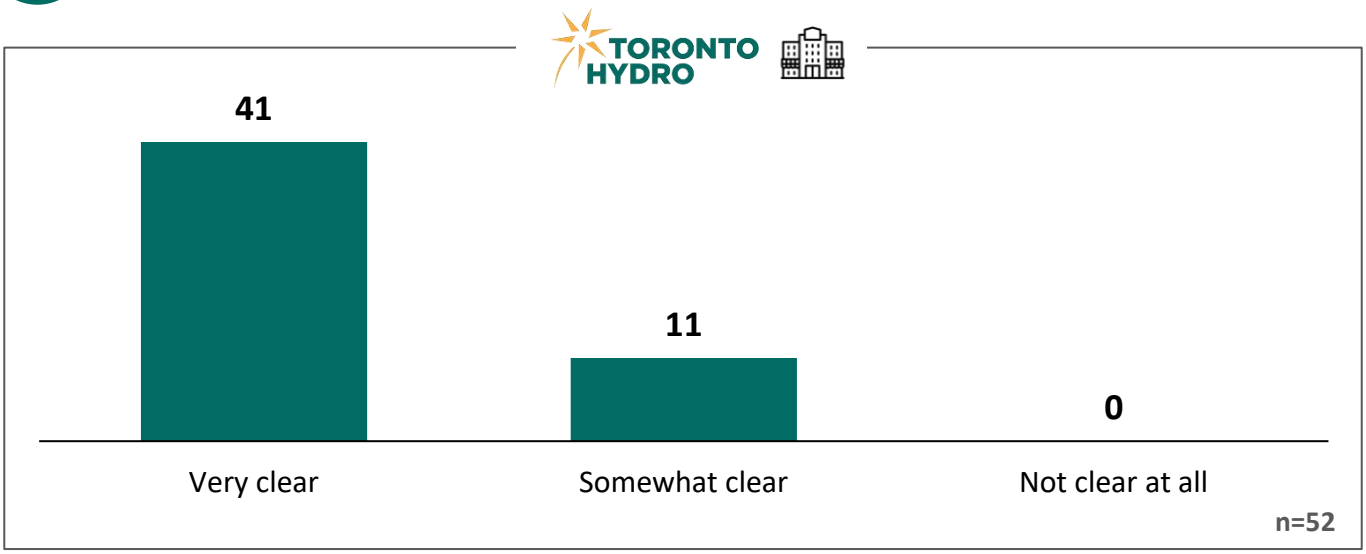
WORKBOOK PAGE

Online Workbook

Understanding the Purpose of the Customer Engagement

Key Accounts

Q Do you feel that the purpose of Toronto Hydro's customer engagement is clear?



	Sector		
	MASH	Commercial/MURB	Industrial
Very clear	5	24	12
Somewhat clear	3	4	4
Not clear at all	-	-	-

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Key Accounts

Electricity 101

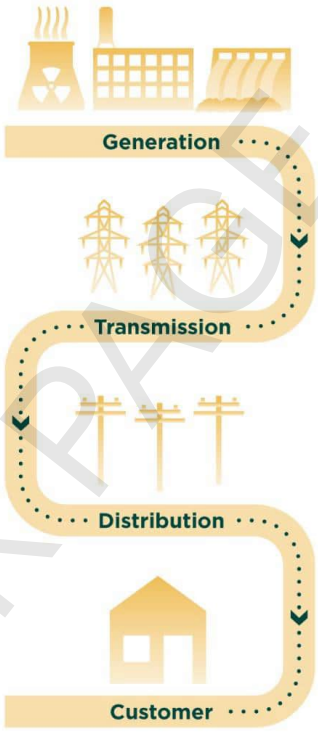
Toronto Hydro's role in Ontario's electricity system

Ontario's electricity system is made up of three parts: **generation**, **transmission** and **distribution**.

Generation

How electricity is made

About half of the electricity used in Ontario comes from nuclear power. The rest comes from a mix of hydroelectric, natural gas, wind and solar sources. Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from other generators contracted by the grid operator.



Transmission

How electricity travels across Ontario

Once electricity is made, it must be sent to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. Ontario has approximately 30,000 kilometers of transmission lines, mostly owned and operated by Hydro One.

Distribution

How electricity is delivered to you

Toronto Hydro is responsible for the last step of the journey: distributing electricity locally to end-use customers.

- Toronto Hydro does not generate or transmit electricity — it owns and operates the local electricity system made up of approximately 183,620 poles, 61,300 distribution transformers, 17,060 primary switches, 15,393 kilometers of overhead wires and 13,765 kilometers of underground cables.
- Toronto Hydro is wholly owned by the City of Toronto, but it does not receive taxpayer money — it is entirely funded by the distribution rates that you pay on your electricity bill.
- Toronto Hydro provides power to roughly 2.8 million people across the city of Toronto.

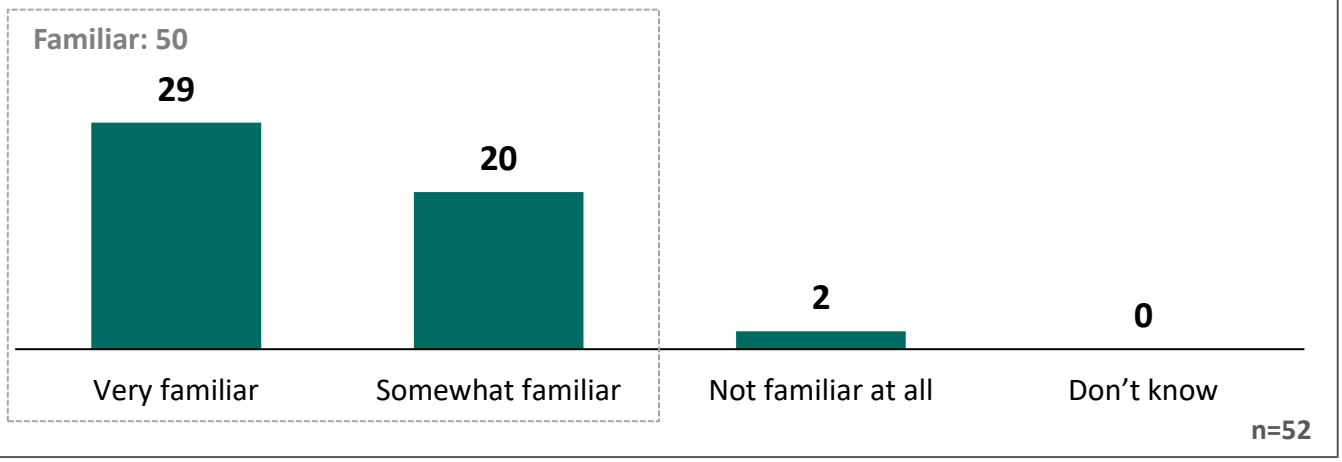
WORKBOOK PAGE

Online Workbook

Familiarity with Ontario's Electricity System

Key Accounts

Q Before this engagement, how familiar were you with the various parts of the electricity system, how they work together and for which services Toronto Hydro is responsible?



	Sector		
	MASH	Commercial/MURB	Industrial
Very familiar	4	18	7
Somewhat familiar	5	8	8
Not familiar at all	-	1	1
Familiar (Very + Somewhat)	**8**	**26**	**15**

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Rate Application

Key Accounts

Toronto Hydro's Draft Plan

Planning Considerations

In preparing its plan, Toronto Hydro must consider many existing and emerging challenges of delivering safe, reliable and clean electricity at a reasonable price.

To learn more about what Toronto Hydro must consider in preparing its draft plan, click on the topics below.

Key challenges that Toronto Hydro's 2025–2029 draft plan addresses:



Keeping prices reasonable

- Many customers are concerned about the rising cost of doing business.
- Toronto Hydro must find the right balance between the investment needs of the local grid and the financial needs of its customers.



Responding to rising costs

- Like many companies, Toronto Hydro faces rising costs in purchasing equipment for the grid and doing construction work in the city.
- For example, from 2021 to 2022, the cost of buying electrical equipment increased by 9.9% while the cost of non-residential construction in the city of Toronto rose by 15.6%.



Powering a growing urban city

- Toronto is not just the largest city in Canada and an engine of the Canadian economy, it is also one of the fastest growing cities in North America.
- As the city continues to grow, the grid needs to be ready to power new condo towers, residential communities and businesses.



Fixing and replacing equipment in poor condition

- Much of Toronto Hydro's grid was installed in the 1950s and 1960s and needs to be replaced or upgraded.
- To keep the grid safe and reliable now and in the future, Toronto Hydro monitors the condition of its grid and uses this information to upgrade the equipment most at risk.



Reducing emissions from its own operations

- Toronto Hydro is committed to decarbonizing the company's footprint by 2040. To meet this goal, it must invest in reducing emissions from its vehicles and work centres.
- Toronto Hydro is expected to reduce its emissions by switching from oil and natural gas to clean electricity for powering its own operations.



Keeping up with the way customers use electricity

- Customers are using more electricity for their day-to-day energy needs such as electric vehicles for transportation and electric heat pumps for heating. They are also choosing new technologies such as solar panels and battery storage to manage their electricity use and sell electricity to the local grid.
- To ensure customers can connect new technologies to the grid safely and reliably, Toronto Hydro needs to upgrade its equipment and modernize its systems.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Key Accounts



Responding to extreme weather and cyber security attacks

- Extreme weather such as high heat, high winds, flooding and ice storms is increasingly straining and damaging to electricity grids.
- Cybercrime is on the rise across Canada. For example, Toronto Hydro is the target of around one million attempted cyber attacks each year, with attempts going over one million in 2022 (successfully deflected).
- Toronto Hydro needs to make the grid more resilient against extreme weather and cyber security attacks that could compromise reliability and put customers at risk.



Protecting public and employee safety

- Toronto Hydro and its customers have a strong safety record, but electricity is dangerous and safety cannot be taken for granted.
- As homes and businesses add new technologies that increase the amount of electricity flowing around us, Toronto Hydro must ensure that the grid remains safe for its employees and the public.

WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Rate Application

Key Accounts
GS 1,000-4,999kW

How much of my electricity bill goes to Toronto Hydro?

Every item on your bill is required by provincial regulation.

- Toronto Hydro collects payment for the entire electricity system, but only keeps the distribution portion of the "**Delivery**" charge. This charge pays for both Toronto Hydro's **distribution** system and Hydro One's **transmission** system, as well as line losses (power that is lost when electricity travels across the wires).
- **About 11% of the electricity bill goes to Toronto Hydro** to pay for the local distribution grid. The **remaining 89%** of the bill goes to generation companies, transmission companies, the federal and provincial governments, and regulatory agencies.

Typical Bill

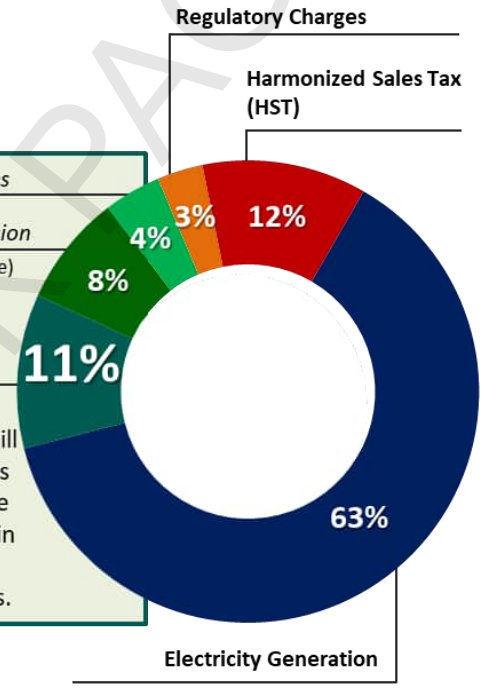
Sample Toronto Hydro Monthly Bill
(based on demand of 2,000 kVA as of Jan. 1, 2023)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	87,030.00
Delivery	31,345.40
Regulatory Charges	4,447.69
Total Electricity Charges	**$122,823.09**
HST	15,967.00
Total Amount	**$138,790.09**

Delivery: *Line Losses*
$5,534.79
Delivery: *Transmission*
(varies based on usage)
$10,890.18
Delivery:
Distribution
Toronto Hydro's part of the total bill is **$14,920.43**. This charge is the same for all customers in this rate class per OEB requirements.



Who holds Toronto Hydro accountable?

ONTARIO ENERGY BOARD

The **Ontario Energy Board (OEB)** is the public interest regulator responsible for setting electricity distribution rates (prices) and for protecting customers in Ontario.

The OEB holds Toronto Hydro accountable for:

- How it spends your money in current and future plans.
- Reporting on key outcomes (reliability) through an annual scorecard.
- Finding savings and efficiencies to absorb rising costs.

Want to know more about what Toronto Hydro has done to become more efficient? Click here.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Key Accounts
Large Use

How much of my electricity bill goes to Toronto Hydro?

Every item on your bill is required by provincial regulation.

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- **About 12% of the electricity bill goes to Toronto Hydro** to pay for the local distribution grid. The **remaining 88%** of the bill goes to generation companies, transmission companies, the federal and provincial governments, and regulatory agencies.

Typical Bill

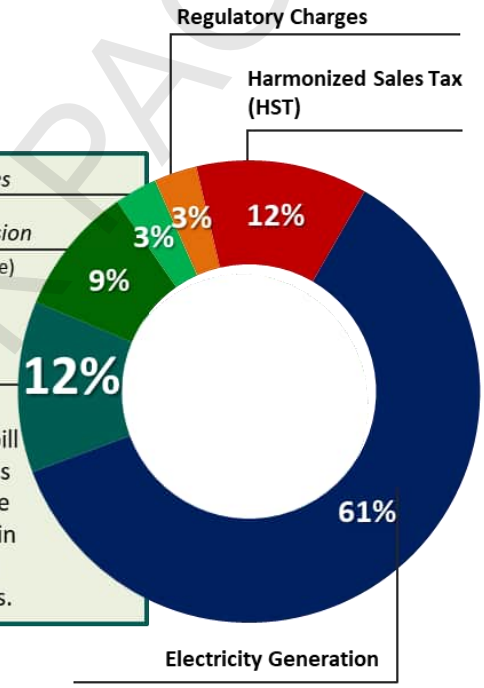
Sample Toronto Hydro Monthly Bill
(based on demand of 9,700 kVA as of Jan. 1, 2023)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	396,470.00
Delivery	158,804.92
Regulatory Charges	20,018.75
Total Electricity Charges	**$575,293.67**
HST	74,788.18
Total Amount	**$582,772.49**

Delivery: *Line Losses*
$20,893.98
Delivery: *Transmission*
(varies based on usage)
$60,770.98
Delivery:
Distribution
Toronto Hydro's part of the total bill is **$77,139.96**. This charge is the same for all customers in this rate class per OEB requirements.



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WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Rate Application

Key Accounts

What has Toronto Hydro done to become more efficient?

- Reduced the total number of facilities and gave back roughly $158 million to customers, resulting in a total credit of [GS 1,000-4,999kW: $30,277.20 / Large Use: $163,479.92] on the average customer's bill in this rate class from 2016 to 2021.
- Delivered approximately $10 million in reduced or avoided costs in this current 2020–2024 period by replacing outdated information systems with consolidated programs, enabling automation and lowering maintenance costs.
- Implemented new technology to automate crew scheduling, enabling Toronto Hydro to maximize crew working hours and respond to power outages quicker.

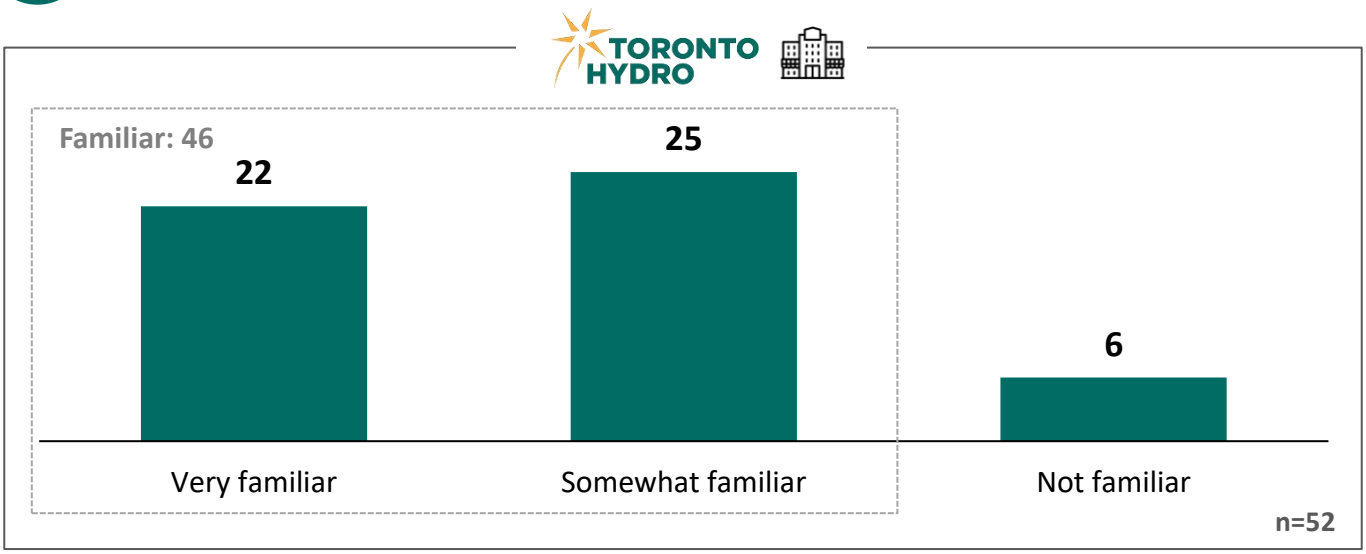
WORKBOOK PAGE

Online Workbook

Key Accounts

Familiarity with the Percentage of Bill Remitted to Toronto Hydro

Q Before this customer engagement, how familiar were you with the amount of your electricity bill that went to Toronto Hydro?



	Sector		
	MASH	Commercial/MURB	Industrial
Very familiar	3	13	5
Somewhat familiar	5	9	11
Not familiar at all	1	5	-
Familiar (Very + Somewhat)	**8**	**22**	**16**

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

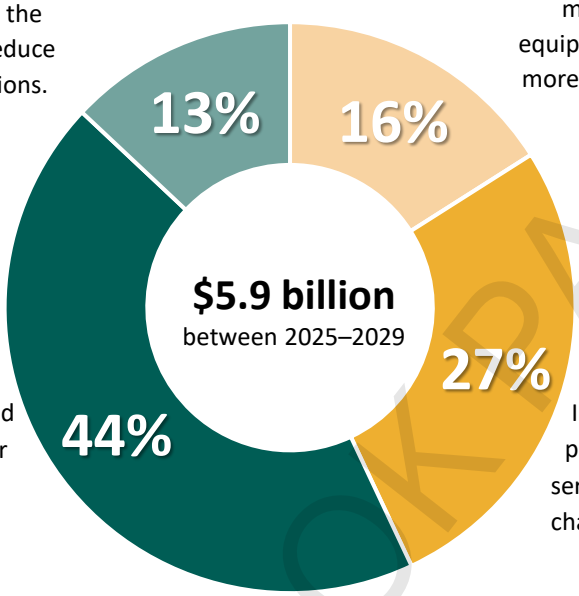
Key Accounts
GS 1,000-4,999kW

How does Toronto Hydro propose to spend the money?

Toronto Hydro's five-year 2025–2029 draft plan is made up of four spending categories.

General Plant
Investments in vehicles, work centres and IT to keep the business running and reduce Toronto Hydro's emissions.

Modernization
Investments in technology to get more use out of existing equipment, and build a smarter, more efficient and reliable grid.



Sustainment
Investments to upkeep old equipment that is in poor condition and replace outdated equipment.

Growth
Investments in capacity to power the growing city and serve customers' growing and changing needs for electricity.

Want to know more about Toronto Hydro's current and future budgets? Click here.

How much will Toronto Hydro's draft plan cost me?

At the end of the five-year plan (2029), the typical customer in this rate class would see the distribution portion of their electricity bill increase by **$7,480.60**: from an estimated rate (price) of $15,526.40 in 2024 to a proposed rate (price) of **$23,007.00 by 2029.**

				Toronto Hydro's Portion	
	Year	Avg. Monthly Bill	Toronto Hydro Portion	Annual Increase (%)	Annual Increase ($)
	2023	$138,790.09	$14,920.43	n/a	n/a
	2024	$136,540.47	$15,526.40	4%	$605.97
Rate Period	**2025**	$139,426.14	$18,080.09	16%	$2,553.69
	2026	$140,521.98	$19,049.86	5%	$969.77
	2027	$141,879.48	$20,251.19	6%	$1,201.33
	2028	$143,933.51	$22,068.91	9%	$1,817.72
	2029	$144,993.55	$23,007.00	4%	$938.09
	5-yr impact		**$7,480.60**	**49%**	**$7,480.60**

Note: These estimated rate increases are preliminary and are subject to change based on customer feedback and other factors. A typical customer in this rate class is assumed to use 2,000 kWh per month and enrolled under Time-of-use Regulated Price Plan. Bill projections assume that other aspects of the electricity bill that are outside of Toronto Hydro's control (commodity, transmission, government, regulatory fees) remain constant.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Rate Application

Key Accounts
Large Use

How does Toronto Hydro propose to spend the money?

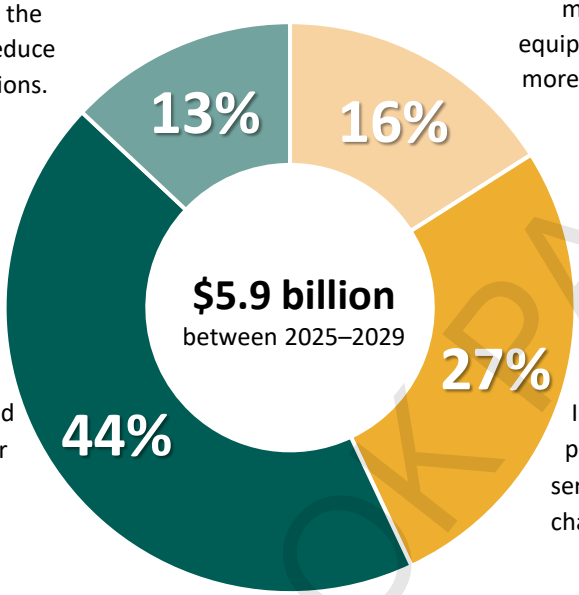
Toronto Hydro's five-year 2025–2029 draft plan is made up of four spending categories.

General Plant

Investments in vehicles, work centres and IT to keep the business running and reduce Toronto Hydro's emissions.

Modernization

Investments in technology to get more use out of existing equipment, and build a smarter, more efficient and reliable grid.



Sustainment

Investments to upkeep old equipment that is in poor condition and replace outdated equipment.

Growth

Investments in capacity to power the growing city and serve customers' growing and changing needs for electricity.

Want to know more about Toronto Hydro's current and future budgets? Click here.

How much will Toronto Hydro's draft plan cost me?

At the end of the five-year plan (2029), the typical customer in this rate class would see the distribution portion of their electricity bill increase by **$39,221.50**: from an estimated rate (price) of $80,290.82 in 2024 to a proposed rate (price) of **$119,512.32 by 2029.**

			Toronto Hydro's Portion	
Rate Period	Year	Avg. Monthly Bill	Toronto Hydro Portion	Annual Increase (%)	Annual Increase ($)
	2023	$650,081.85	$77,139.96	n/a	n/a
	2024	$637,737.91	$80,290.82	4%	$3,150.86
	2025	$653,074.77	$93,862.29	17%	$13,571.47
	2026	$658,780.67	$98,911.76	5%	$5,049.47
	2027	$665,846.91	$105,166.04	6%	$6,254.28
	2028	$676,540.22	$114,629.15	9%	$9,463.11
	2029	$682,058.20	$119,512.32	4%	$4,883.17
	5-yr impact		**$39,221.50**	**49%**	**$39,221.50**

Note: These estimated rate increases are preliminary and are subject to change based on customer feedback and other factors. A typical customer in this rate class is assumed to use 2,000 kWh per month and enrolled under Time-of-use Regulated Price Plan. Bill projections assume that other aspects of the electricity bill that are outside of Toronto Hydro's control (commodity, transmission, government, regulatory fees) remain constant.

WORKBOOK PAGE

Toronto Hydro Background

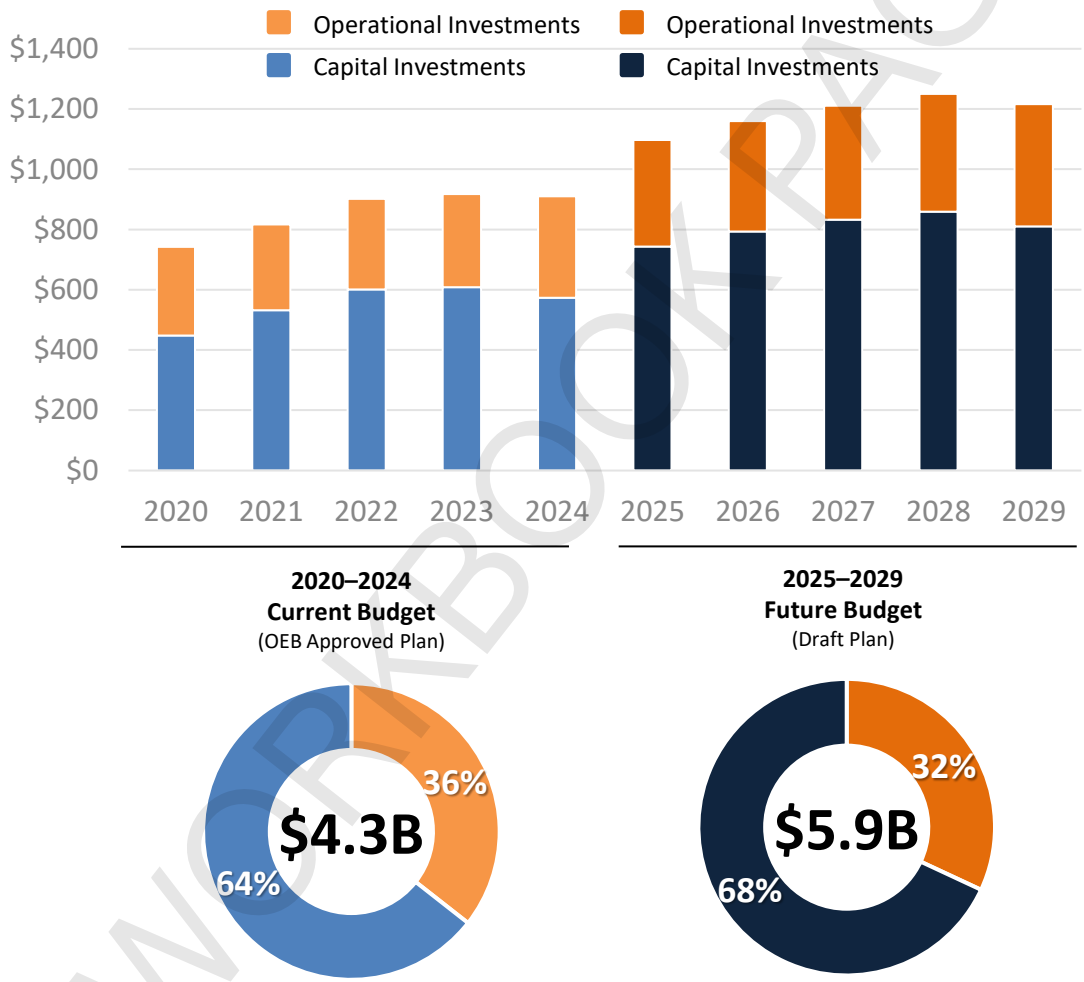
How much does it cost to run the local grid?

To run the local grid and serve customers, Toronto Hydro manages two budgets:

1. A **capital investment** budget which pays for the cost of buying and constructing physical infrastructure such as poles, wires, transformers, facilities, trucks and computers.

2. An **operational investment** budget which pays for maintenance and operation of the equipment, as well as the staff needed to manage the grid and serve customers daily.

Current and Future Budgets per year ($ millions)



WORKBOOK PAGE

The current five-year budget of **$4.3 billion** is based on the 2020–2024 plan approved by the OEB in a previous rate application. As mentioned earlier, this amount is funded by your 2020–2024 distribution rates.

The future five-year budget of **$5.9 billion** is based on the 2025–2029 draft plan presented in this customer feedback survey. The final budget for this next rate period will be adjusted to reflect customer feedback collected through this engagement and will be subject to extensive OEB review before rates are set for 2025–2029.

How does the survey work?

The next sections are about 7 key choices that Toronto Hydro needs to make to finalize its plan.

Each section provides some key background information. We encourage you to take the time to learn about your local electricity grid and where your money is going.

We also understand that life is busy. Many people find this information interesting — but if you would prefer to skip over the videos or the background information, you can jump right to the key choices.

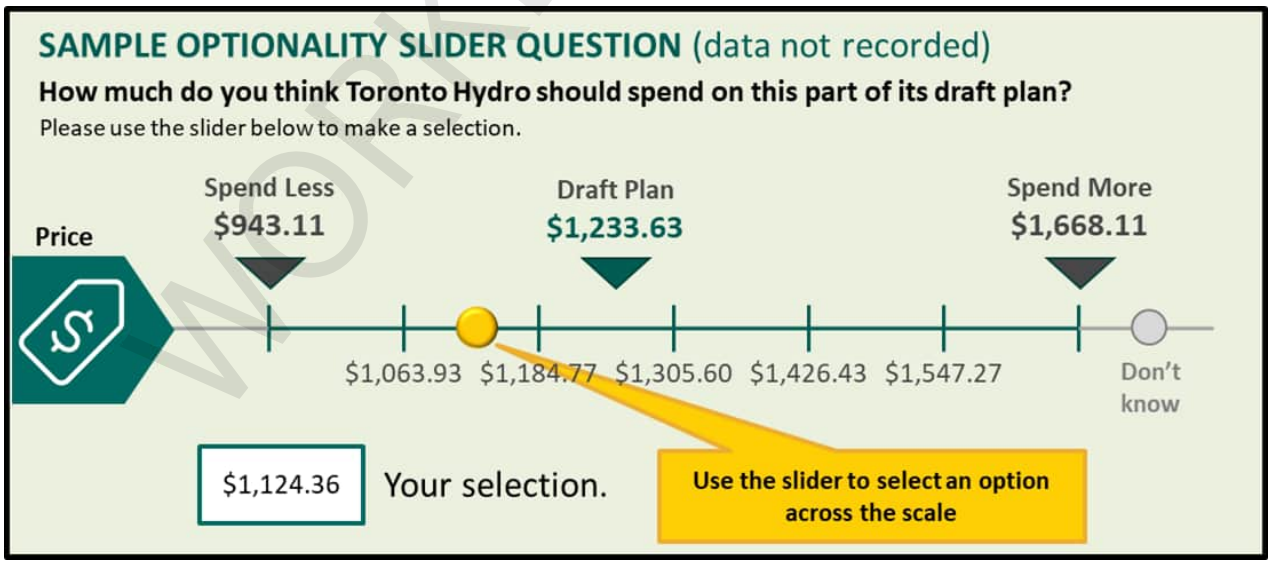
How do I make choices?

Each choice has a summary of three options that Toronto Hydro considered:

- **Spend Less:** A minimum spending option that keeps prices lower and meets the basic performance requirements but may entail some trade-offs on key outcomes, such as reliability.
- **Toronto Hydro's Draft Plan:** An option currently in the draft plan which makes additional progress toward key outcomes but delays some important work.
- **Spend More:** A faster paced spending option that makes additional progress towards better outcomes while recognizing practical limits due to resources and construction issues.

In each option, there is a sliding scale that enables you to dial the draft plan up or down. While Toronto Hydro's technical experts can tell us the maximum and minimum amounts we can practically spend, the balance of how much Toronto Hydro spends on the spectrum is up to customers like you.

At the end of the survey, you will get a summary of your choices and you will have the opportunity to change your answers to find the right balance for you.



WORKBOOK PAGE

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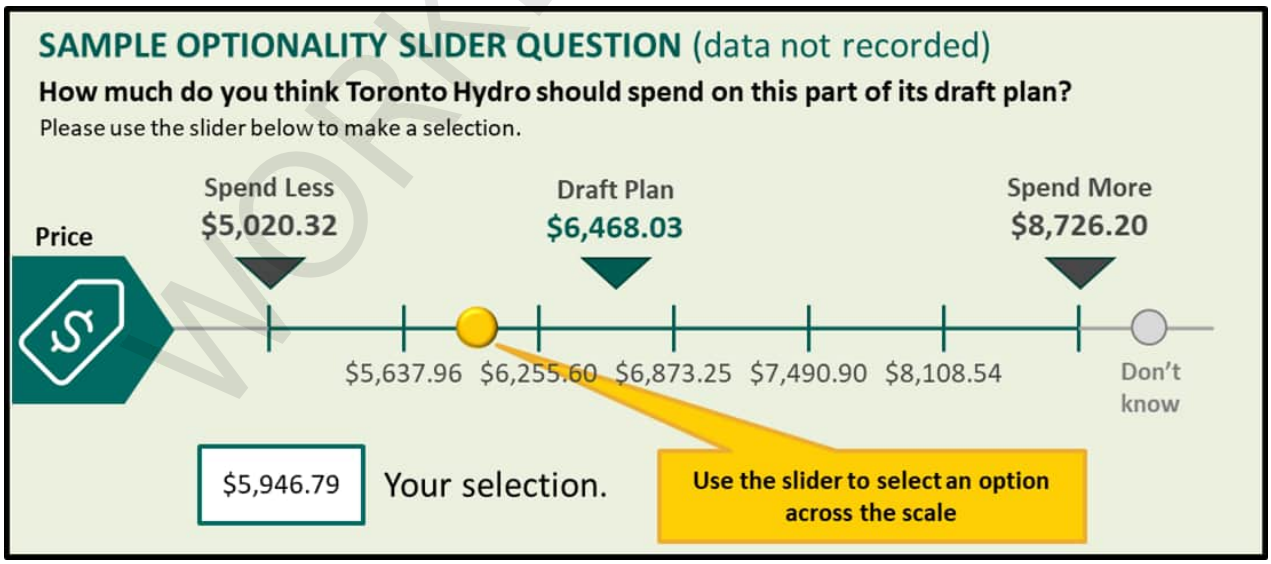


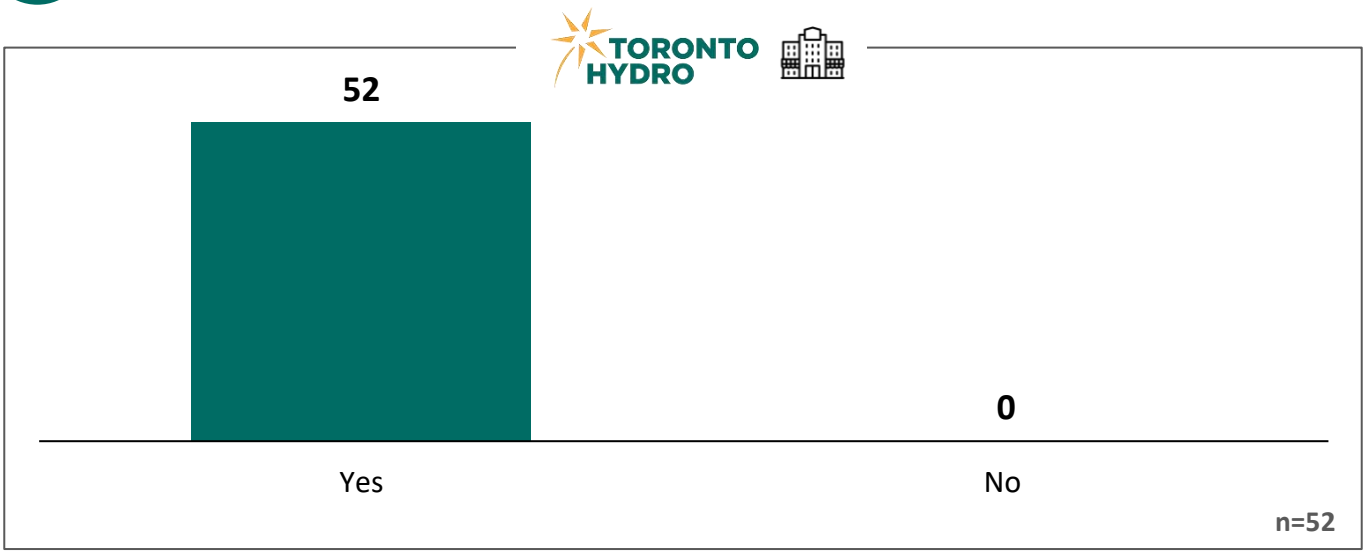
WORKBOOK PAGE

Online Workbook

Understanding the Slider

Key Accounts

Q Is it clear that you can move the slider to any amount you feel best reflects your personal view of the best balance between lower costs and faster improvements?



	Sector		
	MASH	Commercial/MURB	Industrial
Yes	8	28	16
No	-	-	-

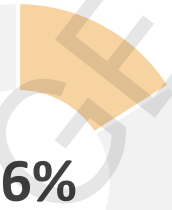
Draft Modernization Plan

Build a Smarter, More Efficient and Resilient Grid

What is this section about?

- This section explains how technology is changing the way customers use electricity and how Toronto Hydro operates and manages the grid to make it smarter, more efficient and resilient for customers.

  Want to learn more about how grid modernization benefits you? Click on the topics below.



- **Toronto Hydro's draft modernization plan enables:**
  - Faster and cheaper power restoration
  - More efficient use of existing equipment
  - Customer choice to adopt new technologies
  - Resilience against weather and cyber attacks

- This spending category makes up **16% of the draft plan** and would add **[**GS 1,000-4,999kW: $1,233.63 **/** Large Use: $6,468.03**]** on the average customer's in this rate class's monthly bill by 2029.

*Click on the video below to learn about Toronto Hydro's **draft modernization plan**.*



WORKBOOK PAGE

Modernization Plan

Building a Smarter, more Efficient and Reliable Grid

Toronto Hydro's Modernization Plan has four main objectives:

Faster and cheaper power restoration



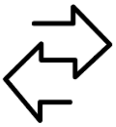
- Through automation, the smart grid can achieve self-healing capabilities. This means that the distribution grid on your street will be able to locate outages and restore power automatically.
- The smart grid enables Toronto Hydro to reduce the number and length of outages customers experience. It also reduces manual costs (trucks and crews) of responding to power outage events.

More efficient use of existing equipment



- As customers use more electricity, some equipment will reach its limits. Sensors and meters detect when and where these limits are approaching, enabling Toronto Hydro to make better decisions.
- The smart grid enables Toronto Hydro to get more use out of the existing equipment so that it can serve a greater customer need for electricity without having to build as much new infrastructure.

Customer choice to adopt new technologies



- Sensors, switches and software enable Toronto Hydro to monitor and control the flow of electricity so that customers can choose technologies to produce, store and sell power to the grid.
- The smart grid is designed to allow safe and reliable two-way power flow — from the grid to the customers and from customers to the grid. This system can reduce costs and makes the local grid more resilient to outages.

Resilience against weather and cyber attacks



- Cyber attacks are increasing and getting more complex. Toronto Hydro must be prepared to respond to these threats to maintain reliable service and protect customer information.
- In addition to being able to restore power quicker, the smart grid can sense when environmental conditions like flooding pose a risk. This enables grid operators to strengthen the grid.

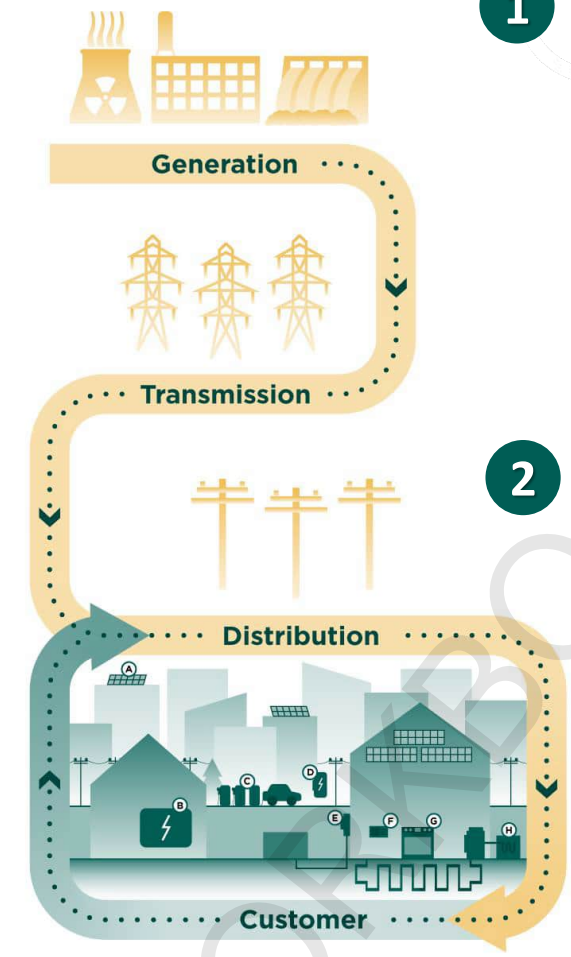
WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Modernization Plan

Modernization: Changing Technology, Changing Needs

For more than 100 years, things changed relatively slowly in terms of grid technology. Electricity was generated in large power stations and transmitted from around the province to Toronto Hydro's grid, and ultimately to homes and businesses. That is all changing, and because of technological advancement, the pace of change could be fast.

Toronto Hydro's 2025–2029 plan is shaped by two key changes in technology:



1. **Technologies that change how customers use electricity.** These include:
   - Electricity products like electric heating, battery storage, and vehicles that enable customers to use less fossil fuels (oil and gas) which contribute to climate change
   - Technologies like solar panels and battery energy storage that allow customers to produce and manage their electricity as well as sell it back onto the grid.

2. **Technologies that change how Toronto Hydro operates the grid**. These key changes are:
   - The grid must shift from a **one-way system** that only sends electricity to customers to a **two-way system** that allows customers to generate and sell electricity to the grid.
   - **Smart grid technology like sensors and automation** enables Toronto Hydro to monitor key equipment to prevent outages and get better use out of existing equipment. When outages do occur, this technology can re-route the grid to restore power much more quickly and at a lower cost than today.

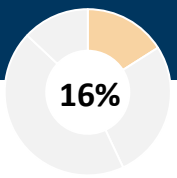
WORKBOOK PAGE

How much electricity does it take to charge an Electric Vehicle (EV)?

Did you know that when an EV is charging it can use as much electricity as two average homes? If everyone in a neighbourhood came home from work or school and started charging their EVs at the same time, the electricity demand could overload the grid.

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Modernization Plan

Key Accounts



Making Choices: **Modernization**

By 2029, Toronto Hydro's draft **modernization plan** would cost the typical small business customer **[GS 1,000-4,999kW: $1,233.63 / Large Use: $6,468.03]** more per month on their monthly electricity bill. Toronto Hydro could spend more to increase the pace of modernizing the grid to get better reliability sooner, or it could spend less and slow down the progress.

	Spend Less	Draft Plan	Spend More
Reliability	Being ready to automate the grid by 2035 means that better reliability won't happen until the end of the next decade or beyond.	Being ready to automate the grid by 2030 means that better reliability will happen in the earlier part of the next decade.	Faster progress towards grid automation means better reliability earlier and improved reliability for critical loads located in the downtown area.
Customer Service	May reduce service levels (longer waits and higher costs) for some customers connecting new services. May reduce customer choice for new technologies.	Maintains service levels for customers connecting new services to the grid. Enables customer choice for new technologies such as solar panels.	Same as draft plan.
Efficiency	It will take longer for the grid to become more efficient. This may lead to higher costs in the next decade.	The grid will become more efficient in the next decade, which will help reduce costs.	Same as draft plan.

Choice 1 of 7:

	Spend Less	Draft Plan	Spend More
GS 1,000-4,999kW	$943.11	$1,233.63	$1,668.11
Large Use	$5,020.32	$6,468.03	$8,726.20

Price

GS 1,000-4,999kW	$1,063.93	$1,184.77	$1,305.60	$1,426.43	$1,547.27	Don't know
Large Use	$5,637.96	$6,255.60	$6,873.25	$7,490.90	$8,108.54	

$-.-- Your selection.

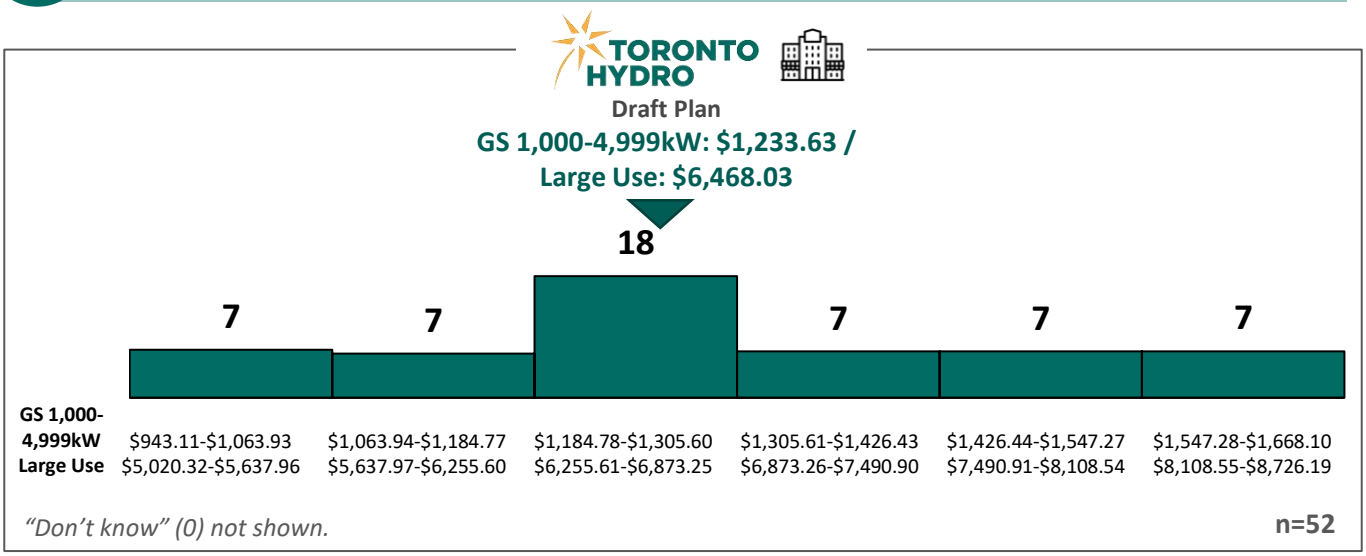
WORKBOOK

Online Workbook

Amount Spent on the Modernization Plan

Key Accounts

Q How much do you think Toronto Hydro should spend on its modernization plan?



"Don't know" (0) not shown.

n=52

	Overall	Sector		
		MASH	Commercial/MURB	Industrial
Below Plan	14	2	8	4
On Plan	18	3	7	8
Above Plan	21	3	13	4

Online Workbook

Additional Feedback on the Modernization Plan

Q Do you have additional feedback on Toronto Hydro's draft modernization plan?

Response	Count
Modernize, be proactive, invest for the long term	5
Prevent outages, stable power, system reliability	3
Oppose the increase, increase is too high (general)	1
Support the increase (general)	1
Prioritize renewables, solar/wind, and electric vehicles	1
Focus on demand side management/provide education about reducing usage	1
No response	41

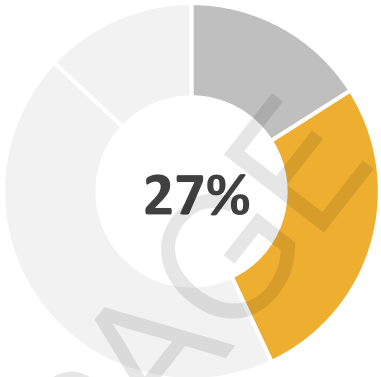
Note: Responses were optional.

Draft Growth Plan

Increase Capacity to Serve Customers

What is this section about?

- This section explains how fast the city of Toronto is growing and what it takes for the grid to serve customers' needs for more electricity.
- Toronto Hydro's draft growth plan is about increasing grid capacity to serve customers reliably now and in the future.



- This spending category makes up **27% of the draft plan** and would add **[GS 1,000-4,999kW: $2,009.85 / Large Use: $10,537.81]** on the average customer's in this rate class's monthly bill by 2029.

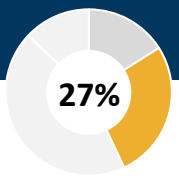
*Click on the video below to learn about Toronto Hydro's **draft growth plan**.*



WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Growth Plan

Key Accounts



Growing City, Growing Needs

1 Toronto is growing, fast.

Toronto is one of the fastest growing cities in North America. A growing city means that we need a bigger local grid so that homes and businesses can get the power they need, when they need it.



Population Growth

Toronto will add approximately 500,000 more people this decade. To put this into context, Toronto is growing five times faster than Los Angeles.



230 Cranes
Toronto has led the crane count in North America since 2015.



2,114 Projects
including residential and non-residential in development in the city of Toronto.



+$1B in Construction
work planned for city infrastructure in Toronto annually (transportation and water).

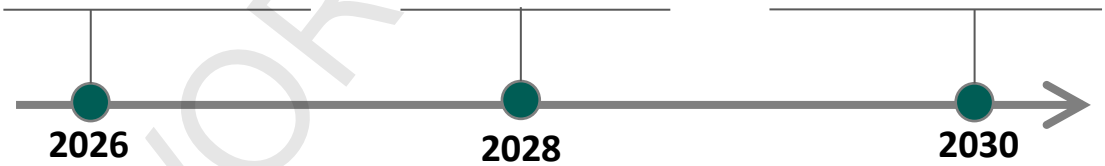
2 Individual customers will use more electricity than ever before.

The average customer will use more electricity in the next 10–15 years, as governments encourage businesses and communities to use less fossil fuels (oil and gas) to address climate change. Here are the key government policies that drive the need for more electricity in Toronto:

The Government of Canada may require 20% of all new car sales to be zero emission and is working towards a target of 60% by 2030.

The City of Toronto Green Building Standard requires all new mid- and high-rise buildings to be near zero GHG emissions.

The carbon tax may increase 161% by 2030 so customers use less oil and gas, and switch to clean electricity for cooking, heating and transportation.



23% **Forecasted increase in customers' need for electricity by the year 2030.**

Conservation and energy efficiency has helped manage electricity use over the past 20 years and will continue to play an important role in the future. But conservation alone is not enough. We need a bigger grid to serve customers in the long term.

WORKBOOK PAGE

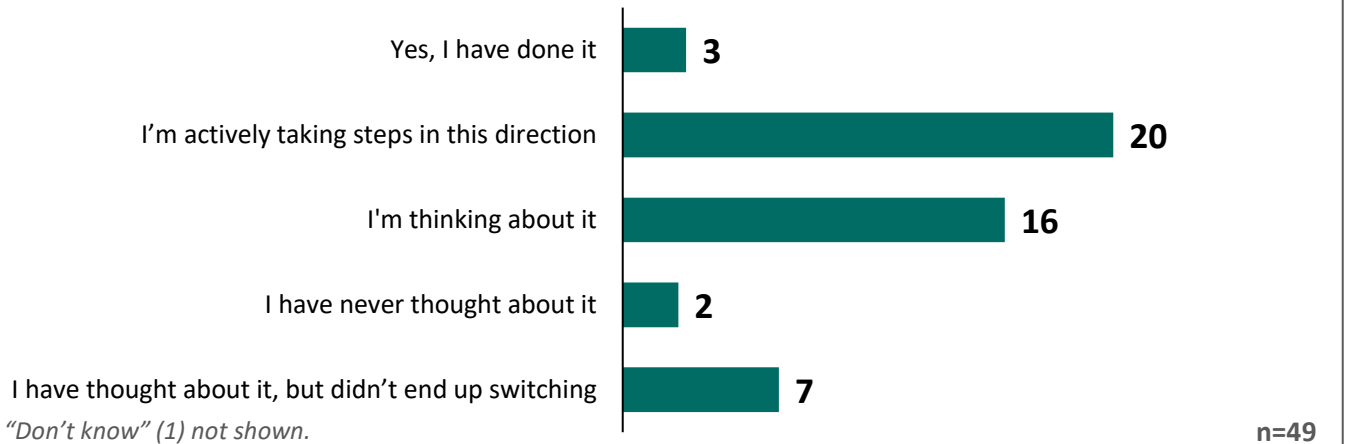
Online Workbook

Amount Spent on Modernization Plan

Key Accounts

Q When you think about all your energy bills, has your organization ever considered shifting from one energy source to another to save money or reduce your impact on the environment?
For example, changing from a natural gas-fuelled furnace to an electric heat pump, or from a gas-fuelled vehicle to an electric vehicle?

TORONTO HYDRO



"Don't know" (1) not shown.

n=49

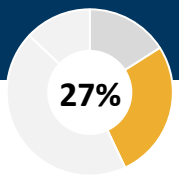
	Sector		
	MASH	Commercial/MURB	Industrial
Yes, I have done it	-	3	-
Actively taking steps	4	11	6
I'm thinking about it	3	7	6
I have never thought about it	-	1	1
I didn't end up switching	1	4	2

Note: Responses were optional.

INNOVATIVE RESEARCH GROUP

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Growth Plan

Key Accounts



Building a bigger grid takes time

It's easy to say Toronto needs more electricity, but meeting this need requires Toronto Hydro to make major investments in the grid, including:



Expand Transformer Stations

Bring more power into the city from the provincial grid to serve growing communities along the new transit corridors (Eglinton LRT, Finch LRT, Ontario Line) and the redevelopment of areas like Downsview Park and the Portlands.



Upgrade and Reconfigure the Grid

Make more space on the grid to enable customers to plug in. Upgrade equipment like cables and transformers and reconfigure how the existing system serves customers to make more space on the grid to accommodate new services like electric vehicle charging stations and solar panels.



Major Infrastructure Developments

Connect major projects like the Finch Light Rail Transit system and the Ontario Line, and relocate Toronto Hydro's grid equipment to enable these and other major infrastructure developments to be constructed in the city.

This work cannot happen quickly. Toronto is densely populated and congested. **Building new power lines and stations takes years of planning and construction.** There are also equipment and resource constraints that limit how quickly Toronto Hydro can build a bigger grid.

Managing Uncertainty

Toronto Hydro develops its forecast from information such as building permits and projected electric vehicle sales. However, customer adoption of new technology is uncertain due to:

Supply chain issues such as equipment and resource shortages can affect the availability of customer technologies.

Technological advancements can lead to fast cost reductions. For example, the price of lithium ion batteries (EVs) decreased by 79% from 2013 to 2022.

Government policies such as rebates for electric vehicles and solar panels drive customers and suppliers to make certain choices.

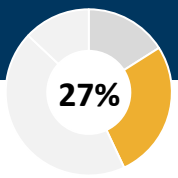
If Toronto Hydro invests too quickly to build a bigger grid, it means customers' rates will go up to pay for equipment that will not be used for some time. On the other hand, if it doesn't do enough to expand the grid for higher use of electricity, customers could experience less reliability (brownouts) and delays when they want to connect to the grid or plug in new technologies. Toronto Hydro needs your input on the pace for these investments.

WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Draft Growth Plan

Key Accounts



Making Choices: **Growth**

By 2029, Toronto Hydro's draft **growth plan** would cost the typical small business customer **[GS 1,000-4,999kW: $2,009.85 / Large Use: $10,537.81]** more per month on their monthly electricity bill. Toronto Hydro could spend more to better prepare the grid to serve customers' changing needs, or could spend less and wait and see if customers adopt new technologies over the 2025–2029 plan.

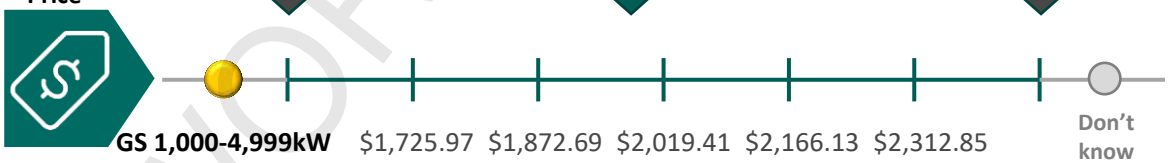
	Spend Less	Draft Plan	Spend More
Reliability	May lead to less reliability for customers in high-growth neighbourhoods. Increases reliability risk for the next decade.	Maintains reliability for customers in high-growth neighbourhoods. Manages reliability risk for the next decade.	Maintains reliability for customers in high-growth neighbourhoods. Improves reliability risk for the next decade.
Customer Service	May reduce service levels (longer waits and higher costs) for some customers connecting new services. May reduce customer choice for new technologies.	Maintains service levels for customers connecting new services to the grid. Enables customer choice for new technologies such as solar panels.	May improve service levels (shorter waits and lower costs) for some customers connecting new services to the grid. Improves customer choice for new technologies.
Efficiency	May lead to less efficient work if Toronto Hydro has to build a bigger grid reactively to serve customers.	Supports the ability to serve customers efficiently in the five-year plan based on the projected demand.	Supports the ability to serve customers efficiently in the five-year plan and beyond in the next decade.

WORKBOOK PAGE

Choice 2 of 7:

	Spend Less	Draft Plan	Spend More
GS 1,000-4,999kW	$1,579.26	$2,009.85	$2,459.58
Large Use	$8,406.67	$10,537.81	$12,866.56

Price



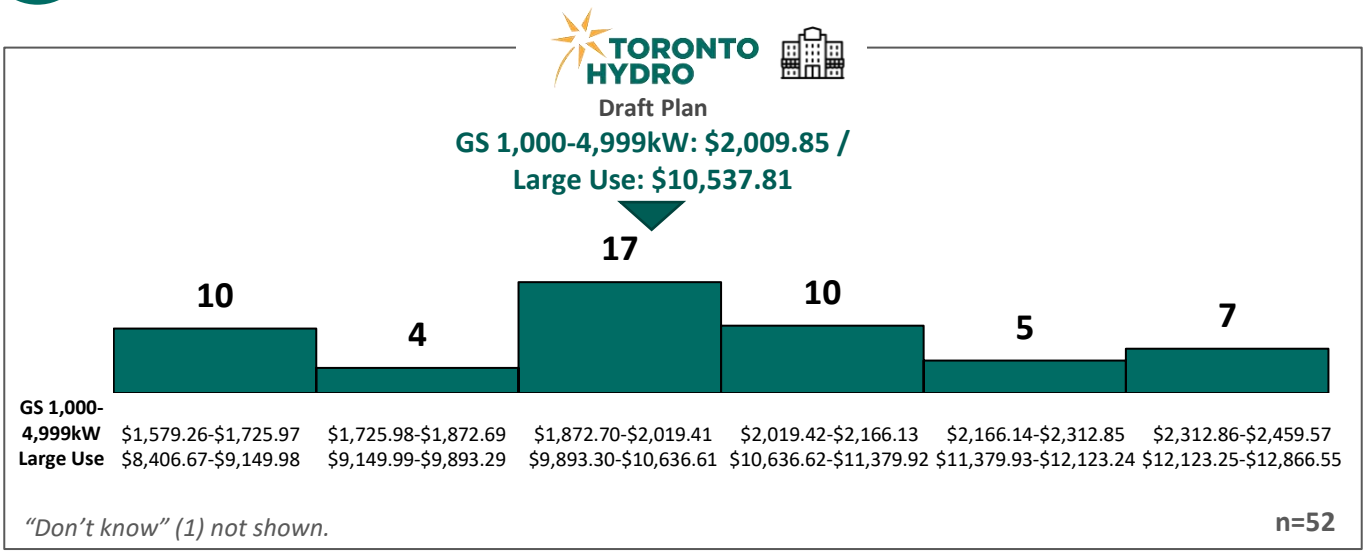
GS 1,000-4,999kW	$1,725.97	$1,872.69	$2,019.41	$2,166.13	$2,312.85	
Large Use	$9,149.98	$9,893.29	10,636.61	11,379.92	12,123.24	

$-.-- Your selection.

Online Workbook

Amount Spent on the Growth Plan

Q How much do you think Toronto Hydro should spend on its growth plan?



"Don't know" (1) not shown.

n=52

	Overall	Sector		
		MASH	Commercial/MURB	Industrial
Below Plan	13	3	7	4
On Plan	22	2	15	5
Above Plan	16	3	7	7

Online Workbook

Additional Feedback on the Growth Plan

Q Do you have additional feedback on Toronto Hydro's draft growth plan?

Response	Count
Modernize, be proactive, invest for the long term	3
Prioritize renewables, solar/wind, and electric vehicles	2
Should be funded by developers	2
Focus on demand side management/provide education about reducing usage	1
Prevent outages, stable power, system reliability	1
No response	43

Note: Responses were optional.

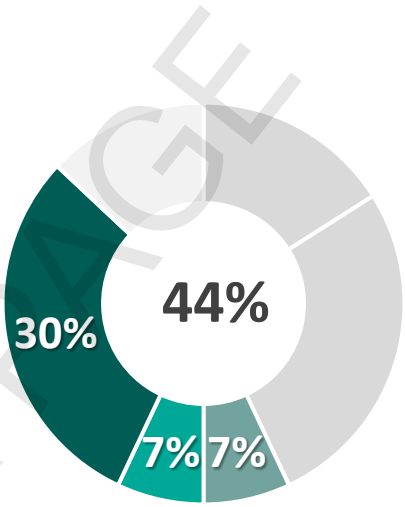
Draft Sustainment Plan

Replacing and Updating Equipment

What is this section about?

- This section is about upkeeping the grid to manage reliability and maintain safe and efficient operations.
- Toronto Hydro's draft sustainment plan section seeks your input in three areas:

1. Managing equipment in very poor condition with a high risk of failure.
2. Pacing the upkeep of equipment near the end of its expected life.
3. Standardizing outdated equipment.



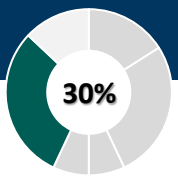
- This spending category makes up **44% of the draft plan** and would add **[GS 1,000-4,999kW: $3,276.35 / Large Use: $17,178.24]** on the average customer's in this rate class's monthly bill by 2029.

*Click on the video below to learn about Toronto Hydro's **draft sustainment plan**.*



WORK BOOK PAGE

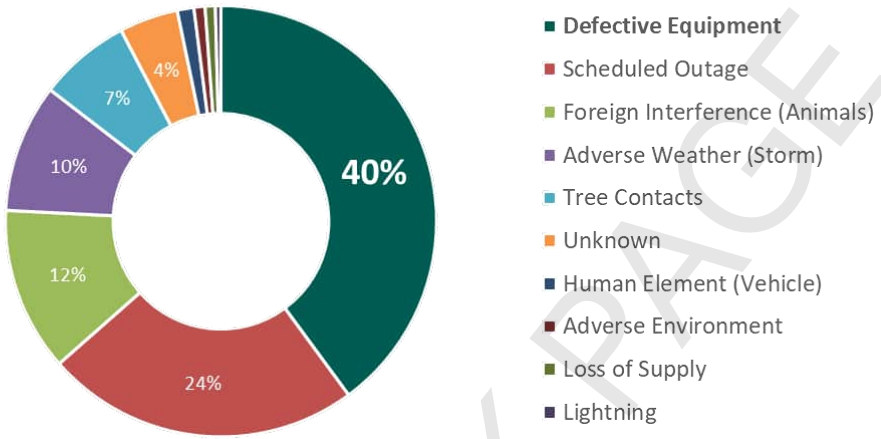
Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft Sustainment Plan



1 Reliability: Managing Equipment Failure Risk

While many power outages are caused by external events such as weather and falling trees, roughly **40%** of customer outages are caused by equipment failure. This is the largest single cause of outages, and customers look to Toronto Hydro to manage this risk.

Customer Outage Duration (Hours) by Cause 2018-2022



Toronto Hydro manages failure risk by:

- Inspecting equipment condition regularly, so that maintenance or replacement can be done before the equipment fails.
- Replacing and repairing equipment that is in bad condition or performing poorly. This includes replacing lines with a high number of outages or replacing transformers with visible signs of wear and tear such as rust.

Since 2014, Toronto Hydro's work to upkeep the grid has delivered a 13% reduction in the average number of outages experienced by customers and a 25% reduction in the length of those outages. Toronto Hydro's draft plan is to maintain these reliability results for customers.

Want to learn more about grid reliability and what causes power outages? Click here.

What type of work is Toronto Hydro doing to manage equipment failure risk?

Below is an example of a key investment that Toronto Hydro needs to make to prevent increased outages due to equipment failure.



Replacing Direct-Buried Cable

In parts of the grid that were built a long time ago, cables are laid directly in underground trenches without any protective barrier. **Underground equipment failures contribute to 57% of defective equipment failures, the large majority of which (75%) are due to cables.** Toronto Hydro's draft plan intends to replace 182 kilometers of direct buried cables by 2029 to manage the risk of power outages caused by this equipment.

WORKBOOK PAGE

System reliability

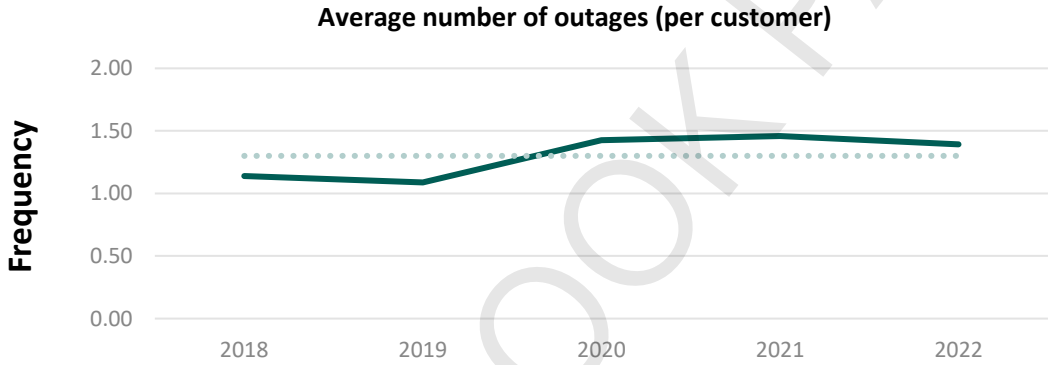
In order to provide feedback on Toronto Hydro's plans, it's important to understand how the distribution system has performed in the past, as well as what's expected in the future.

A core objective of Toronto Hydro's plan is to maintain current levels of reliability over the 2025–2029 plan period, while making foundational technology investments to reduce the length of power outages in the long-term.

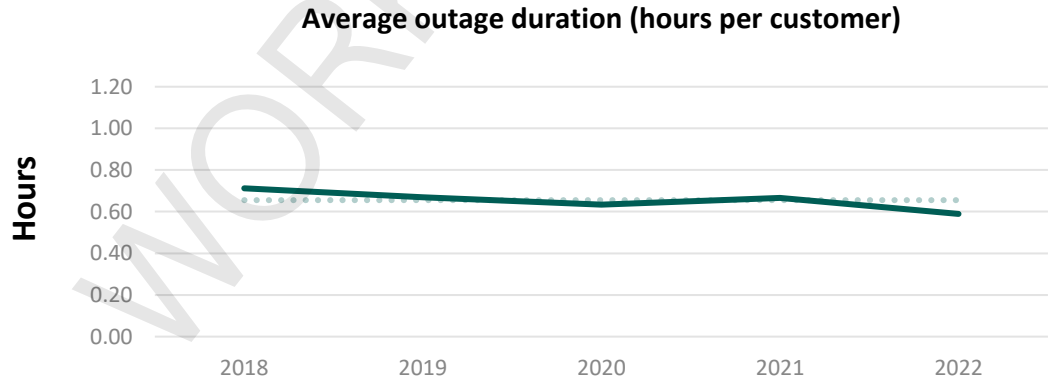
Toronto Hydro recognizes that power interruptions are inconvenient for residential customers and can be very costly for commercial and industrial customers.

Toronto Hydro tracks both the average number of power outages per customer and how long those interruptions last.

Between 2018 and 2022, the typical Toronto Hydro customer has experienced about two outages per year (*or 1.3 outages per customer to be exact*).



Over the same period, the average **duration** of an outage has been about 0.62 hours. Meaning, when the power does go out, Toronto Hydro is typically able to restore power in about 35 minutes.



It's important to keep in mind that these are system averages, and that your actual experience may be different. Some customers connected to newer lines may not experience any outages, while others are experiencing more than the average number of outages each year.

WORKBOOK PAGE

What is most likely to cause an outage?

Although both the number and length of outages have decreased compared to the previous five-year average, equipment failure remains the top cause of outages within Toronto Hydro's control.

That said, in 2022, severe weather presented a unique set of challenges for Toronto Hydro's distribution system.

Causes of Unscheduled Power Outages (five-year average: 2018 to 2022)



12%

Animal Contact: Outages caused by animals such as racoons, squirrels and birds coming in contact with overhead powerlines or transformers.



40%

Equipment Failure: Unscheduled power outages from equipment failure usually occur with distribution equipment that's beyond or approaching the end of their expected useful lives.



10%

Weather-Related Events: Adverse weather such as heavy rain, lightning strikes, ice, snow, wind, extreme temperatures, and freezing rain can disrupt the distribution system.



14%

Other: Includes tree contact (7%) and human interference (1%), such as construction workers accidentally cutting powerlines or motor vehicle accidents involving contact with distribution equipment. 4% of outages are unknown, but most are likely caused by animal contact.

Note: *statistics do not include loss of supply from Hydro One.*

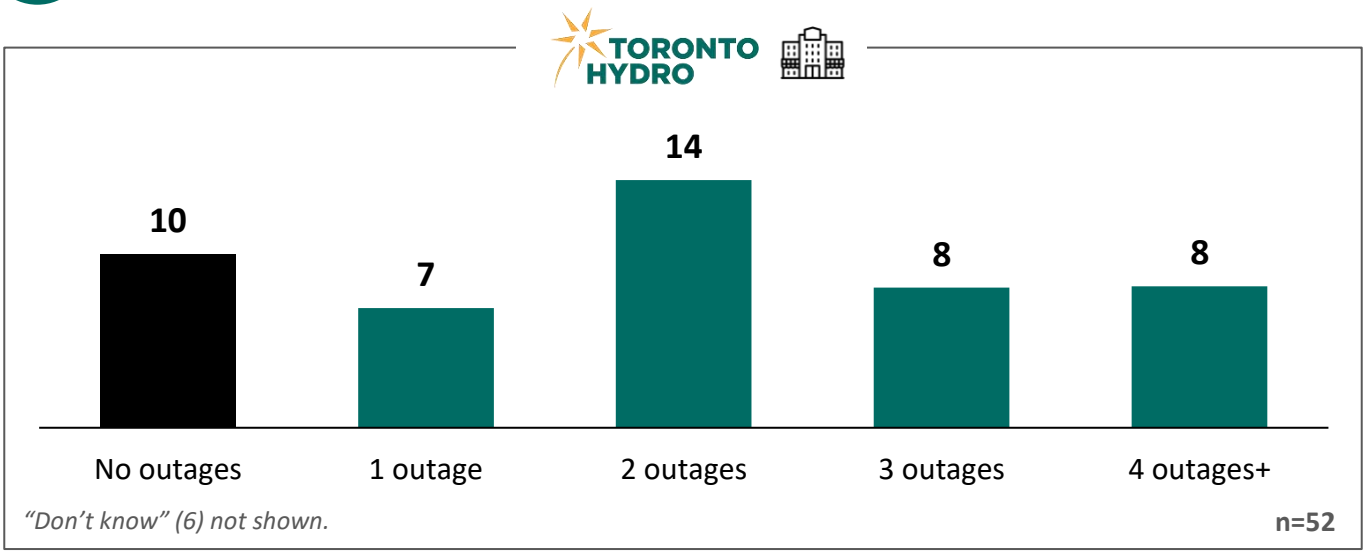
WORKBOOK PAGE

Online Workbook

Amount Spent on the Grid Reliability Plan

Key Accounts

Q Over the past 12 months, have you experienced any power outages at your organization which lasted longer than one minute?



"Don't know" (6) not shown.

n=52

	Sector		
	MASH	Commercial/MURB	Industrial
No outages	1	5	4
1 outage	3	4	-
2 outages	1	8	5
3 outages	-	4	4
4 outages+	3	3	2

Note: Responses were optional.

Toronto Hydro Customer Engagement
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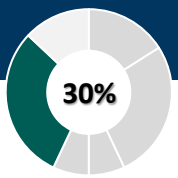
Key Accounts



Making Choices: **Managing Equipment Failure Risk**

By 2029, Toronto Hydro's draft plan to manage equipment failure risk would cost the typical small business customer **[GS 1,000-4,999kW: $2,265.64 / Large Use: $11,878.96]** more per month on their monthly electricity bill. Toronto Hydro could spend more to improve reliability, or it could spend less and take on more risk of outages.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of the grid by 2029.	Maintains the overall health (age and condition) of the grid by 2029.	Improves the overall health (age and condition) of the grid by 2029.
Reliability	Reduces reliability compared to current levels. This means more power outages due to equipment failure.	Maintains reliability at current levels. This means holding steady on power outages due to equipment failure.	Improves reliability compared to current levels. This means less power outages due to equipment failure.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work. Increases work volumes and costs for the next decade.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work. Reduces work volumes and costs for the next decade.

WORKBOOK PAGE

Choice 3 of 7:

	Spend Less	Draft Plan	Spend More
GS 1,000-4,999kW Price	$1,641.50	$2,265.64	$2,753.26
Large Use Price	$8,737.96	$11,878.96	$14,402.85

GS 1,000-4,999kW	$1,826.78	$2,012.08	$2,197.37	$2,382.66	$2,567.96	Don't know
Large Use	$9,682.10	$10,626.25	$11,570.40	$12,514.54	$13,458.69	

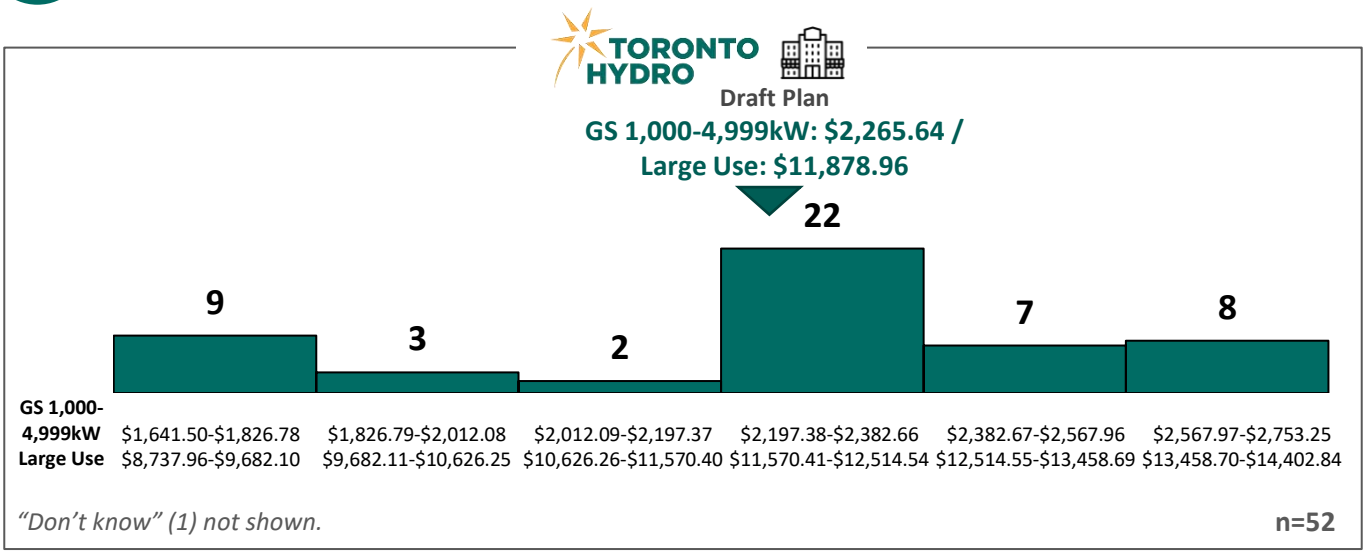
$-.-- Your selection.

Online Workbook

Amount Spent on the Grid Reliability Plan

Key Accounts

Q How much do you think Toronto Hydro should spend on its grid reliability plan?



"Don't know" (1) not shown.

n=52

	Overall	Sector		
		MASH	Commercial/MURB	Industrial
Below Plan	14	2	9	3
On Plan	19	3	11	5
Above Plan	19	3	8	8

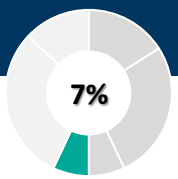
Online Workbook

Additional Feedback on the Grid Reliability Plan

Q Do you have additional feedback on Toronto Hydro's draft grid reliability plan?

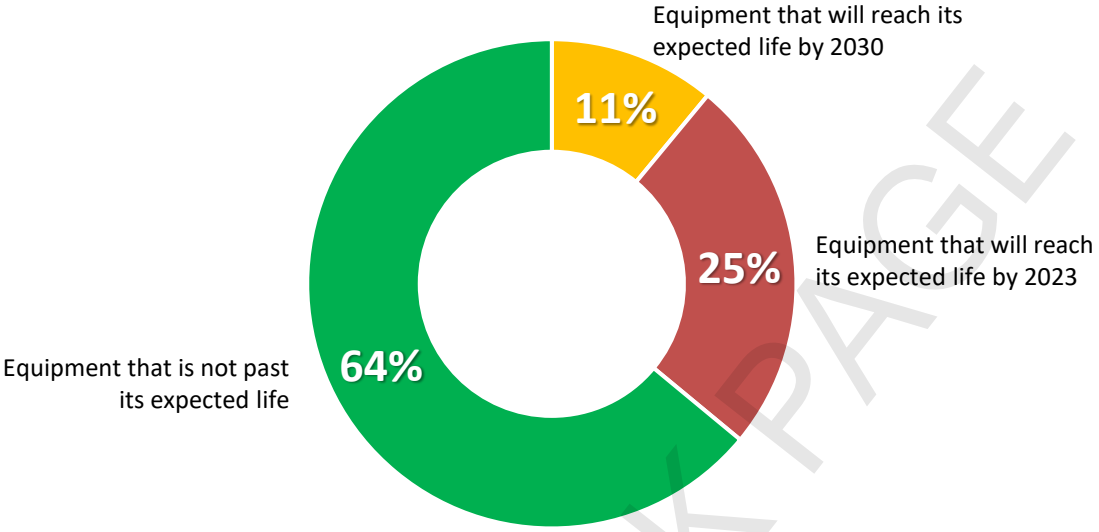
Response	Count
Prevent outages, stable power, system reliability	6
Modernize, be proactive, invest for the long term	2
Find efficiencies, cut wasteful spending, lower salaries	1
Support the increase (general)	1
No response	44

Note: Responses were optional.



2 Paced Upkeep of the Grid

About 25% of Toronto Hydro's equipment is operating past its expected life and an additional 11% is estimated to reach that point by 2030.



In this part of the plan, the key question is whether Toronto Hydro should wait until there are clear signs of equipment failure risk (such as rust or oil leaks), or whether it should get ahead of the problem by replacing old equipment proactively.

If Toronto Hydro waits, it can keep prices lower in the short term. However, this could create a surge of work in future years that will spike prices in the 2030s. There is also a risk that Toronto Hydro will not be able to do the amount of work required to deal with this equipment in the future, which could lead to more outages and higher safety risks due to equipment failures.

Want to learn more about Toronto Hydro's distribution grid? Click here.

What type of work is Toronto Hydro doing to upkeep the grid?

Below is an example of key investments that Toronto Hydro needs to make in a paced way to upkeep the grid and prevent a surge of work to address equipment failure risk in the future.



Paced Replacement of Network Vaults

This equipment is located in underground vaults in the downtown area, which serves many critical customers, such as hospitals and financial institutions. A very large portion of this equipment is going to be in poor condition and past its expected life in the 2030-34 period. To manage this risk, Toronto Hydro's draft plan intends to replace network vaults in a paced manner.

WORKBOOK PAGE

Renewing and replacing infrastructure

Toronto Hydro's grid is a mix of overhead, underground, network and station infrastructure. It operates at three different voltages (27.6kV, 13.8kV, and 4.16kV) and includes approximately:

- 61,300 distribution transformers
- 17,060 primary switches
- 15,393 km of overhead wires
- 13,765 km of underground wires
- 37 transformer stations



Overhead Infrastructure

The overhead system is made up of poles, wires, transformers, switches and other equipment. They are easier to replace, repair and inspect.

However, they are also more prone to foreign interference such as vehicles, trees, animals and weather-related outages.

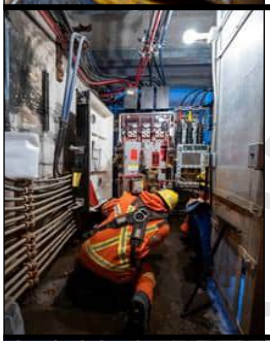
This system consists of three different types of configurations two of which are outdated configurations from the 1950s and 1960s, making them more challenging to replace and restore particularly after a weather-related outage.



Underground Infrastructure

Toronto Hydro's underground system consists of cables, transformers, switches and civil infrastructures (like manholes). They can be placed either at ground level (green box above ground in your neighbourhood), underground, or inside building vaults (typical for multi-storey buildings). This system is made up of two different types of configurations where the downtown Toronto area consists of lead-covered cable, an outdated equipment with little to no suppliers.

While underground equipment is more resilient during weather-related events, it is more susceptible to flooding and at risk of faster deterioration due to moisture build-up.



Network Infrastructure

Toronto Hydro's network system, predominantly found in the downtown Toronto area, was installed in the early-to-mid 1900s to improve reliability (service levels) for critical loads (like financial institutions) and serves medium-sized loads in high-density areas, and areas with small and narrow sidewalks. It consists of interconnected low-voltage cables, vaults and network units.

While this system is better at handling normal equipment failures, proactive replacement and maintenance of this equipment are critical to avoid vault fires from occurring.



Station Infrastructure

Toronto Hydro's distribution stations receive the transmission supply from Hydro One at very high voltages. Station infrastructure consists of switchgear, power transformers, circuit breakers, remote terminal units (station computers) and battery systems. Toronto Hydro proactively replaces this equipment, as failure at the station level can cause widespread and lengthy power outages.

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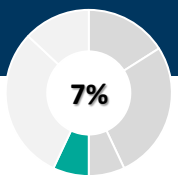
Key Accounts



Making Choices: **Paced Upkeep of the Grid**

By 2029, Toronto Hydro's draft plan to ensure paced upkeep of the grid would cost the typical small business customer **[GS 1,000-4,999kW: $500.55 / Large Use: $2,624.45]** more on their monthly electricity bill. Toronto Hydro could spend more to get ahead of future equipment failure risk, or it could spend less and defer some of this work at the risk of managing more power outages due to equipment failure in the next decade.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of the grid by 2029.	Maintains the overall health (age and condition) of the grid by 2029.	Improves the overall health (age and condition) of the grid by 2029.
Reliability	Higher risk of power outages due to equipment failure in the next decade.	Manages the risk of power outages due to equipment failure in the next decade.	Reduces the risk of power outages due to equipment failure in the next decade.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work. Increases work volumes and costs for the next decade.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work. Reduces work volumes and costs for the next decade.

WORKBOOK PAGE

Choice 4 of 7:

	Spend Less	Draft Plan	Spend More
GS 1,000-4,999kW	$350.51	$500.55	$778.73
Large Use	$1,865.83	$2,624.46	$4,073.70

Price

GS 1,000-4,999kW	$421.87	$493.24	$564.61	$635.98	$707.35		Don't know
Large Use	$2,233.80	$2,601.78	$2,969.76	$3,337.73	$3,705.71		

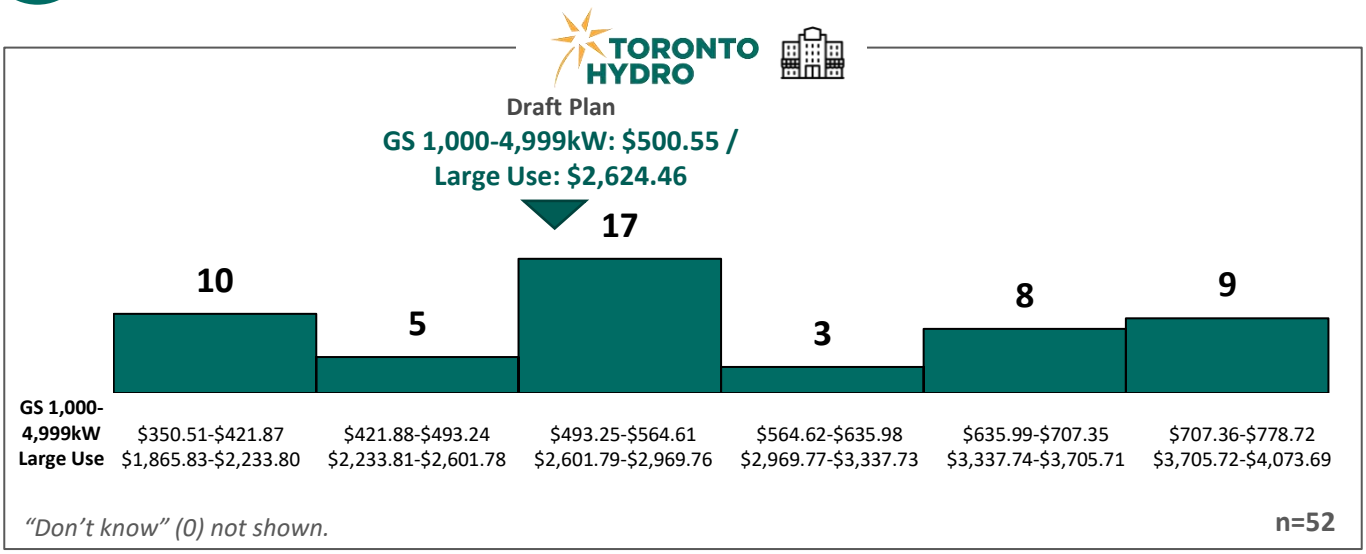
$-.-- Your selection.

Online Workbook

Amount Spent on the Grid Stewardship Plan

Key Accounts

Q How much do you think Toronto Hydro should spend on its grid stewardship plan?



"Don't know" (0) not shown.

n=52

	Overall	Sector		
		MASH	Commercial/MURB	Industrial
Below Plan	12	2	7	3
On Plan	17	3	9	4
Above Plan	24	3	12	9

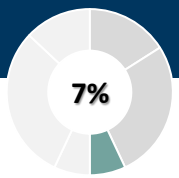
Online Workbook

Additional Feedback on the Grid Stewardship Plan

Q Do you have additional feedback on Toronto Hydro's draft grid stewardship plan?

Response	Count
Prevent outages, stable power, system reliability	2
Modernize, be proactive, invest for the long term	2
Find efficiencies, cut wasteful spending, lower salaries	2
Support developing new technology and innovation	1
Make use of existing infrastructure, past spending	1
No response	45

Note: Responses were optional.

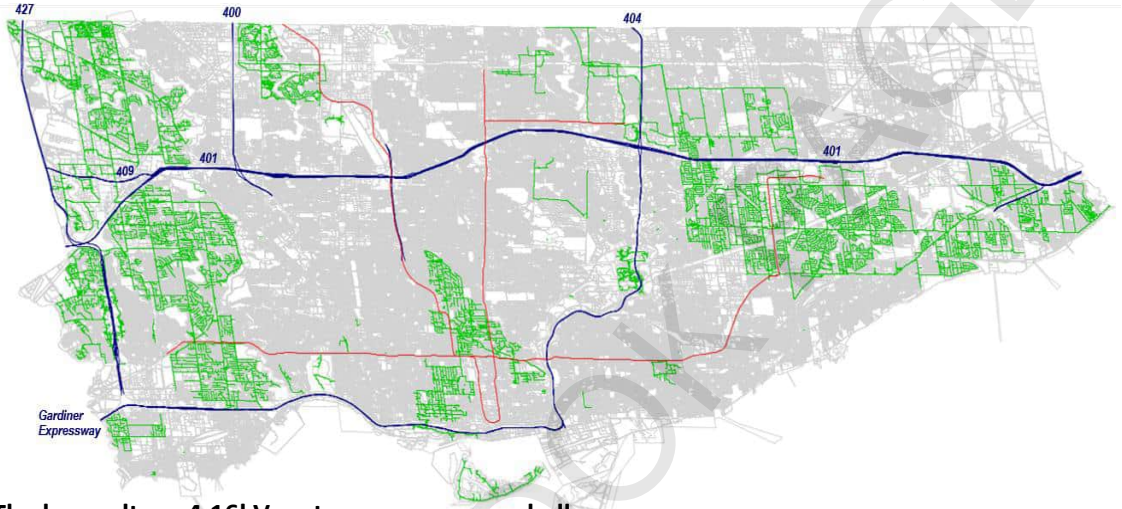


3 Standardize the Grid

Because of its history, Toronto Hydro has an old and diverse grid. Toronto Hydro is made up of 6 municipal utilities that were joined in 1998 when the City of Toronto was formed. Each utility owned and operated different types of equipment. As a result, Toronto Hydro's grid has three different voltage levels: 4.16kV, 13.8kV and 27.6kV.

The 27.6kV voltage level is the current standard for local grids. However, a large part of Toronto Hydro's grid is served at 4.16kV and 13.8kV.

Location of Outdated Voltage Lines



The low voltage 4.16kV system poses many challenges:

- Long outages for customers and higher cost to restore power – in 2022, the longest outage on the 4.16 kV system was 80 hours.
- Less efficient at carrying power over long distances, which means more electricity is lost as it travels from point A to point B (line losses).
- Less capacity to serve customers' growing electricity needs, which means longer waits and higher costs to connect new services such as electric vehicles and solar panels.
- Risk of supply chain and labour shortages as manufacturers stop making this equipment and technicians trained on this equipment retire.

What type of work is Toronto Hydro doing to standardize the grid?

Below is an example of a key investment to replace outdated equipment.



Voltage Conversion from 4.16kV/13.8kV to 27.6kV

Voltage conversion entails a full rebuild of outdated equipment such as rear lot construction (poles and wires in customers' backyards). This work improves reliability, safety and makes the grid more efficient. Toronto Hydro's draft plan intends to convert 1400 customers from rear lot service and works to eliminate rear lot construction from the grid by the late 2040s.

WORKBOOK ONLY

Toronto Hydro Customer Engagement
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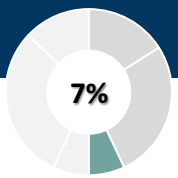
Key Accounts



Making Choices: **Standardize the Grid**

By 2029, Toronto Hydro's draft **plan to standardize the grid** would cost the typical small business customer **[GS 1,000-4,999kW: $510.16 / Large Use: $2,674.82]** more on their monthly electricity bill. Toronto Hydro could spend more to speed up the pace of replacing outdated equipment or it could spend less to slow down the pace and delay the benefits of this work. For example, under spend more Toronto Hydro would convert all rear lot customers by the early 2040s, and under spend less by the 2050s.

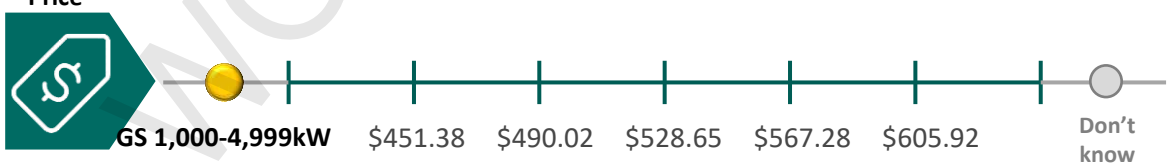
	Spend Less	Draft Plan	Spend More
Reliability	Slower progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.	Steady progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.	Faster progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.
Customer Service	Less progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels.	Steady progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels	Faster progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels.
Efficiency	Slower progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.	Steady progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.	Faster progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.

WORKBOOK PAGE

Choice 5 of 7:

	Spend Less	Draft Plan	Spend More
GS 1,000-4,999kW	$412.76	$510.16	$644.56
Large Use	$ 2,197.16	$2,674.82	$3,371.82

Price



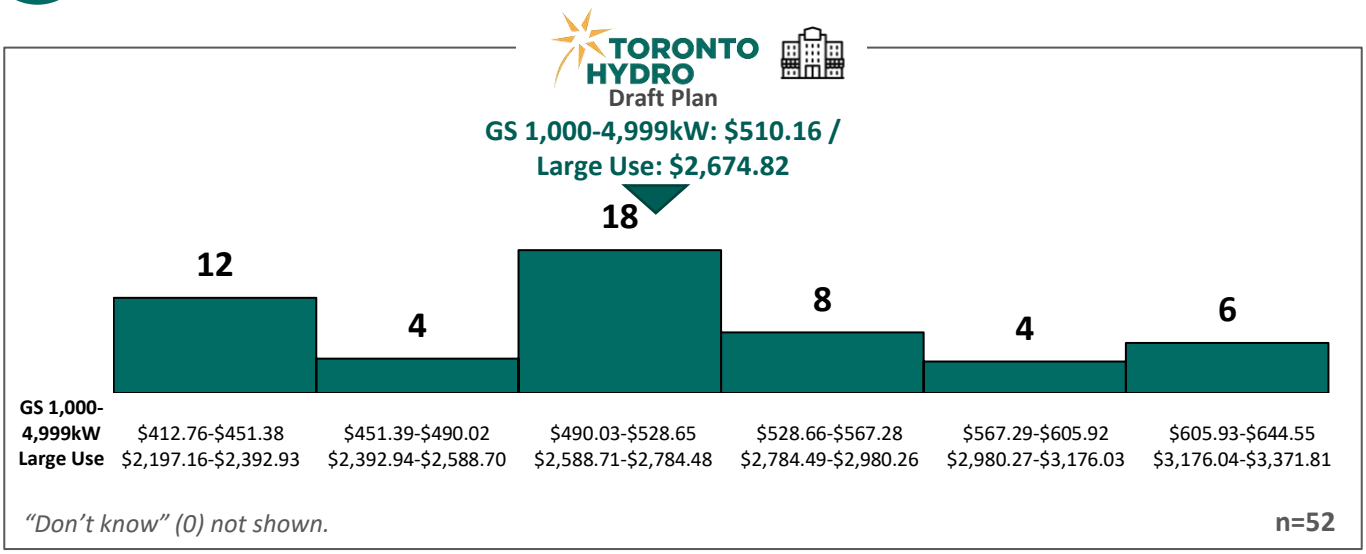
$-.-- Your selection.

Online Workbook

Amount Spent on the Equipment Standardization Plan

Key Accounts

Q How much do you think Toronto Hydro should spend on its equipment standardization plan?



"Don't know" (0) not shown.

n=52

	Overall	Sector		
		MASH	Commercial/MURB	Industrial
Below Plan	16	3	8	5
On Plan	17	3	9	4
Above Plan	19	2	11	7

Online Workbook

Key Accounts

Additional Feedback on the Equipment Standardization Plan

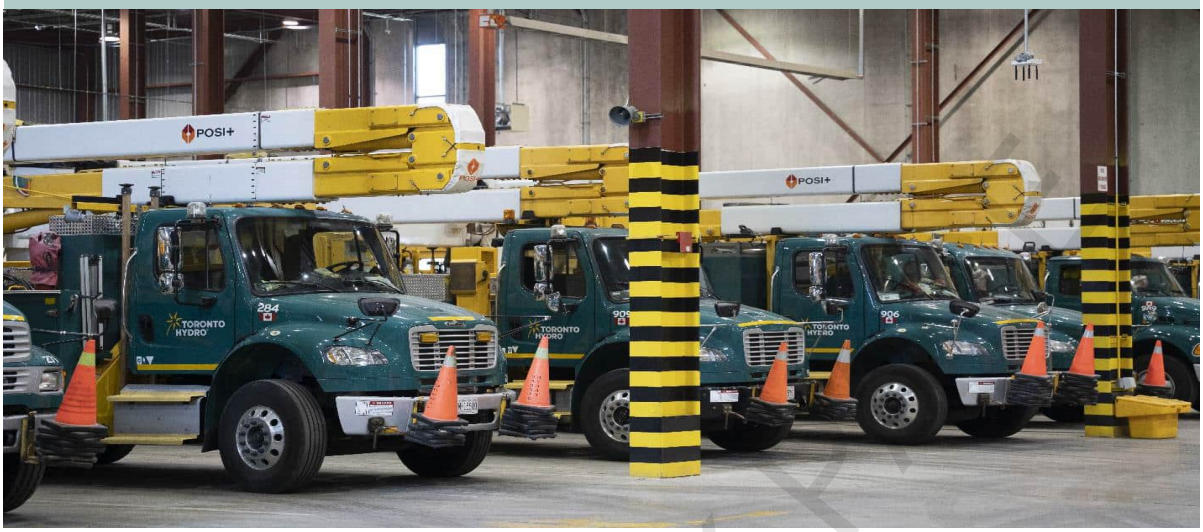
Q Do you have additional feedback on Toronto Hydro's draft equipment standardization plan?

Response	Count
Modernize, be proactive, invest for the long term	4
Find efficiencies, cut wasteful spending, lower salaries	1
Prevent outages, stable power, system reliability	1
Other	1
No response	46

Note: Responses were optional.

Draft General Plant Plan

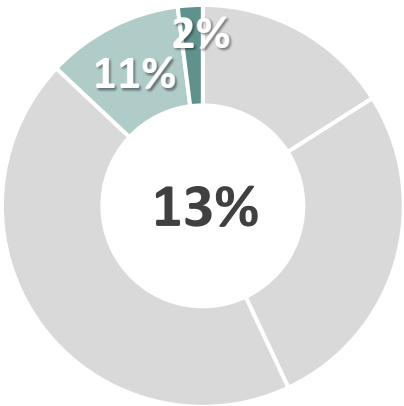
Keeping the Business Running



What is this section about?

- This section is about the vehicles, work centres and IT systems that keep Toronto Hydro's business running efficiently.
- Toronto Hydro seeks your input on two choices within this part of the plan:

1. The pace of replacing the equipment needed to keep the business running.
2. The pace of reducing Toronto Hydro's emissions from its own operations.



- This spending category makes up **13% of the draft plan** and would add **[GS 1,000-4,999kW: $960.77 / Large Use: $5,037.42]** on the average customer's in this rate class's monthly bill by 2029.

WORKBOOK

1 Keep the Business Running

Work centres, vehicles and information technology systems are the backbone of Toronto Hydro's day-to-day operations. This equipment must be maintained in good working condition for efficient and reliable operations so that crews can restore power and customers can access key services like their online account and the outage restoration map.

- As with grid equipment, Toronto Hydro uses information such as age and condition data from inspections to decide which equipment should be replaced versus repaired.
- Toronto Hydro repairs equipment in poor condition such as leaking roofs, failed furnaces and worn-out vehicle braking systems. It also replaces equipment like software programs and hardware servers that are past expected useful life.

What type of work is Toronto Hydro doing to manage failure risk?

Below is an example of a key investment that Toronto Hydro needs to make to keep the business running and manage the risk of equipment failure.



Station Buildings

Toronto Hydro has approximately 250 properties that either house distribution stations equipment such as cables and transformers or support the distribution system.

Over 80% of station buildings are older than 40 years and require repairs and investments to address the following types of problems:

- Structural damage to the building (cracked foundations, leaking roofs)
- Mechanical, electrical and plumbing equipment in poor condition
- Compliance with building and fire code requirements

This work ensures safe and efficient operations and minimizes the risk of outages that can affect many customers. For example, structural damage to a station building poses a direct risk to distribution equipment such as power transformers.

So, how much and how quickly Toronto Hydro decides to invest in keeping their business running has a direct impact on customers. While this equipment may remain in service for a long time, when they unexpectedly fail, the costs incurred usually far exceed proactive investments (repairs and replacements) and can have a significant impact on system reliability and customer service.

WORKBOOK PAGE

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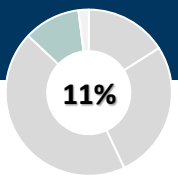
Key Accounts



Making Choices: **Keep the Business Running**

By 2029, Toronto Hydro's draft plan to keep the business running would cost the typical small business customer **[GS 1,000-4,999kW: $842.21 / Large Use: $4,415.78]** more on their monthly electricity bill. Toronto Hydro could spend more to improve equipment health (age and condition) and functionality (better safety features) or spend less and take on more risk of equipment downtime.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of general plant equipment by 2029.	Maintains the overall health (age and condition) of general plant equipment by 2029.	Improves the overall health (age and condition) of general plant equipment by 2029.
Reliability & Service	Reduces equipment availability, which could mean longer outages or lower levels of customer service.	Maintains equipment availability consistent with current levels.	Improves equipment availability and functionality, which could mean better reliability and customer service levels.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work, which is more costly and increases equipment downtime.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work, and better equipment functionality.

WORKBOOK PAGE

Choice 6 of 7:

	Spend Less	Draft Plan	Spend More
GS 1,000-4,999kW	$606.80	$842.21	$980.59
Large Use	$3,230.08	$4,415.78	$ 5,129.64

Price

GS 1,000-4,999kW	$669.09	$731.39	$793.69	$855.98	$918.28		Don't know
Large Use	$3,546.66	$3,863.26	$4,179.85	$4,496.44	$4,813.04		

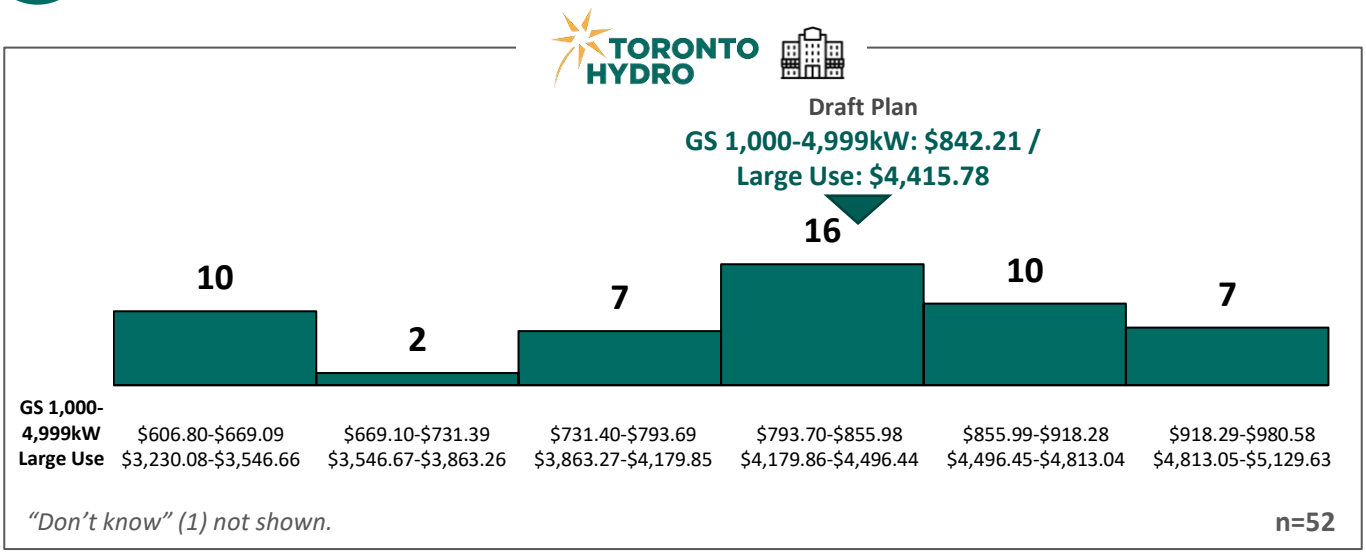
$-.-- Your selection.

Online Workbook

Amount Spent on Keeping the Business Running

Key Accounts

Q How much do you think Toronto Hydro should spend to keep the business running?



"Don't know" (1) not shown.

n=52

	Overall	Sector		
		MASH	Commercial/MURB	Industrial
Below Plan	23	5	15	4
On Plan	17	2	7	8
Above Plan	12	1	7	4

Online Workbook

Key Accounts

Additional Feedback on Keeping the Business Running

Q Do you have additional feedback on Toronto Hydro's draft plan for keeping the business running?

Response	Count
Find efficiencies, cut wasteful spending, lower salaries	3
Make use of existing infrastructure, past spending	2
Modernize, be proactive, invest for the long term	1
Oppose the increase, increase is too high (general)	1
Support the increase (general)	1
No response	45

Note: Responses were optional.

2 Reducing Toronto Hydro's Emissions

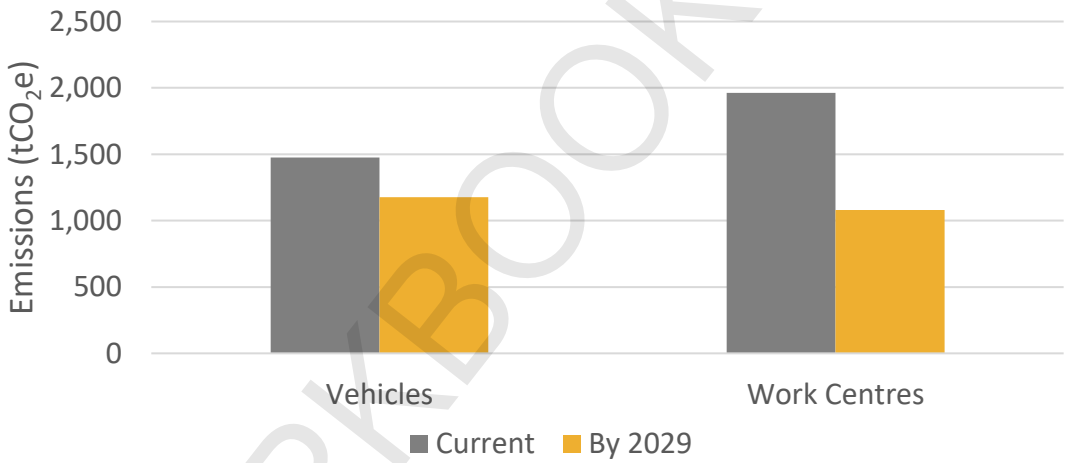
To address climate change, companies around the world are setting targets to reduce greenhouse gas (GHG) emissions from fossil fuels — a pledge commonly known as Net Zero.

Moving toward Net Zero has increasingly become the expectation of governments, financial markets, stakeholders and customers. For example, in October 2019, Toronto City Council unanimously voted to accelerate efforts to reduce emissions across the city.

To do its part in addressing climate change, Toronto Hydro is committed to reducing emissions from its vehicles and work centres by:

- Replacing gasoline and diesel power vehicles with hybrid and electric vehicles
- Converting natural gas boilers and heaters in its work centres to electric ones.

Toronto Hydro's Draft Plan to Reduce Emissions



Carbon Tax Savings

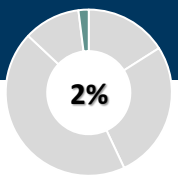
Reducing carbon emissions from vehicles and work centres could help Toronto Hydro manage rising costs due to the carbon tax (recall that the carbon tax may increase by 161% from 2023 to 2030). **Over the 2025–2029 period, Toronto Hydro's draft plan could reduce carbon tax payments by roughly half a million dollars.**

With your feedback, Toronto Hydro needs to decide how quickly to transition to cleaner sources of energy for its operations. In the next section, you will be presented these options.

WORKBOOK PAGE

Toronto Hydro Customer Engagement
Planning Process: 2025–2029 Draft General Plant Plan

Key Accounts



Making Choices: **Reducing Toronto Hydro's Emissions**

By 2029, Toronto Hydro's draft plan to reduce emissions would cost the typical small business customer **[GS 1,000-4,999kW: $118.56 / Large Use: $621.64]** more on their monthly electricity bill. Toronto Hydro could spend more for faster progress towards reducing its emissions, or spend less to slow down the progress.

	Spend Less	Draft Plan	Spend More
Environment	Less progress to reduce emissions — about 27% reduction by the end of the decade.	Steady progress to reduce emissions — about 35% reduction by the end of the decade.	Faster progress to reduce emissions — about 36% reduction by the end of the decade.
Efficiency	Higher exposure to rising energy costs (oil and gas) due to the carbon taxes and other pressures.	Managed exposure to rising energy costs (oil and gas) due to the carbon tax and other pressures.	Less exposure to rising energy costs (oil and gas) due to carbon taxes and other pressures.

WORKBOOK PAGE

Choice 7 of 7:

	Spend Less		Draft Plan		Spend More	
GS 1,000-4,999kW	$89.39		**$118.56**		$129.73	
Large Use	$475.86		**$621.64**		$678.65	
Price						
GS 1,000-4,999kW	$96.10	$102.83	$109.55	$116.27	$123.00	Don't know
Large Use	$509.65	$543.45	$577.25	$611.04	$644.84	

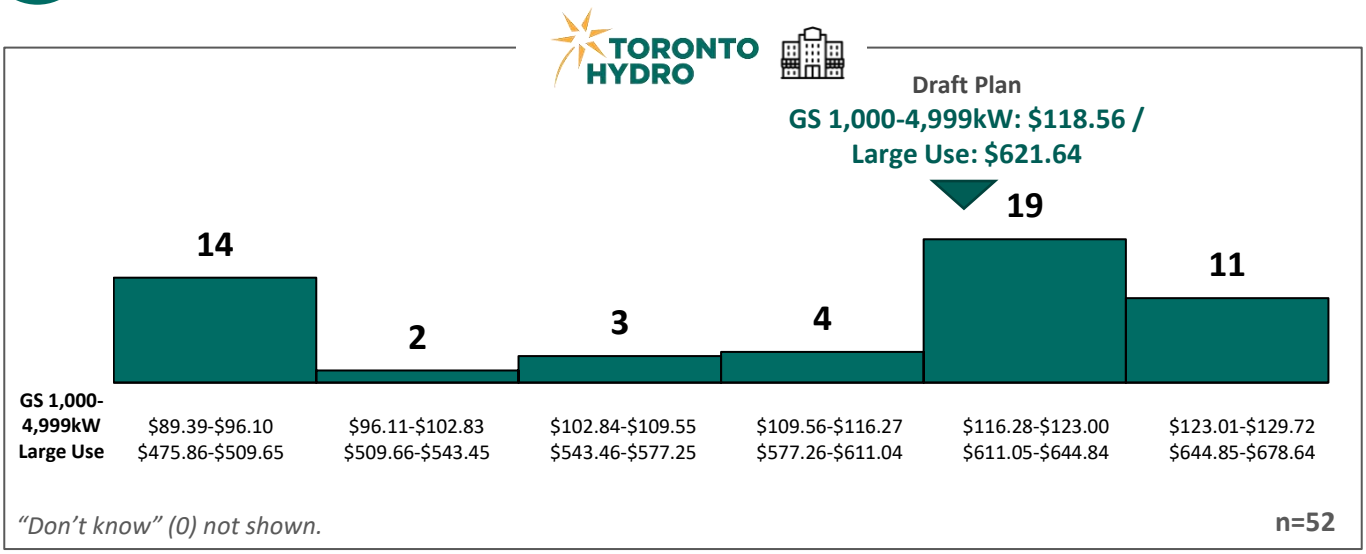
$-.-- Your selection.

Online Workbook

Amount Spent on Reducing Emissions & Feedback

Key Accounts

Q How much do you think Toronto Hydro should spend to reduce its own emissions?



"Don't know" (0) not shown.

n=52

	Overall	Sector		
		MASH	Commercial/MURB	Industrial
Below Plan	23	3	13	6
On Plan	19	3	9	6
Above Plan	11	2	5	4

Online Workbook

Amount Spent on Reducing Emissions & Feedback

Q Do you have additional feedback on Toronto Hydro's draft decarbonization plan?

Response	Count
Modernize, be proactive, invest for the long term	2
Support the increase (general)	2
Find efficiencies, cut wasteful spending, lower salaries	2
Prioritize renewables, solar/wind, and electric vehicles	1
Costs are too high already, cost of living, struggling to pay bills	1
Prevent outages, stable power, system reliability	1
No response	44

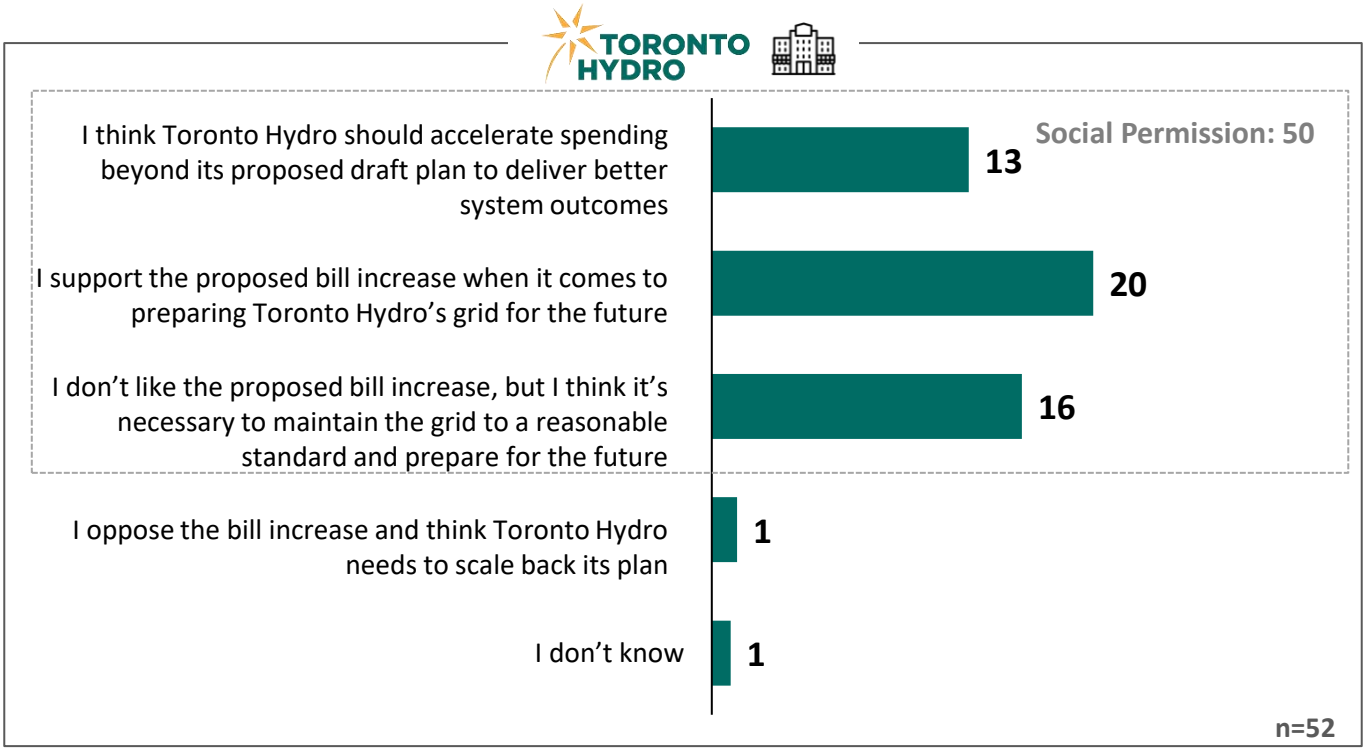
Online Workbook

Social Permission

Q

Toronto Hydro has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Toronto Hydro would like to know how you feel about the total rate impact of its current draft plan.

Considering what you have learned about Toronto Hydro's 2025–2029 draft plan and that this may result in a **[GS 1,000-4,999kW: $7,480.60 / Large Use $39,221.50] increase** in the distribution portion of your monthly electricity bill by 2029, which of the following best represents your point of view?



	Sector		
	MASH	Commercial/MURB	Industrial
Accelerate spending	2	9	2
Support proposed bill	3	9	8
Necessary to maintain grid	3	8	5
Oppose the bill increase	-	1	-
I don't know	-	-	1
Social Permission	**8**	**26**	**15**

Online Workbook

Key Accounts

Final Comments for the Draft Plan & Proposed Rate Increase

Q Do you have any final comments regarding Toronto Hydro's draft plan for 2025–2029 and the proposed rate increase?

Response	Count
Prevent outages, stable power, system reliability	3
Find efficiencies, cut wasteful spending, lower salaries	1
Should be funded by tax dollars/government	1
Prioritize renewables, solar/wind, and electric vehicles	1
Modernize, be proactive, invest for the long term	1
Support the increase (general)	1
Other	2
No response	42

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Key Account Customers

Online Workbook Diagnostics

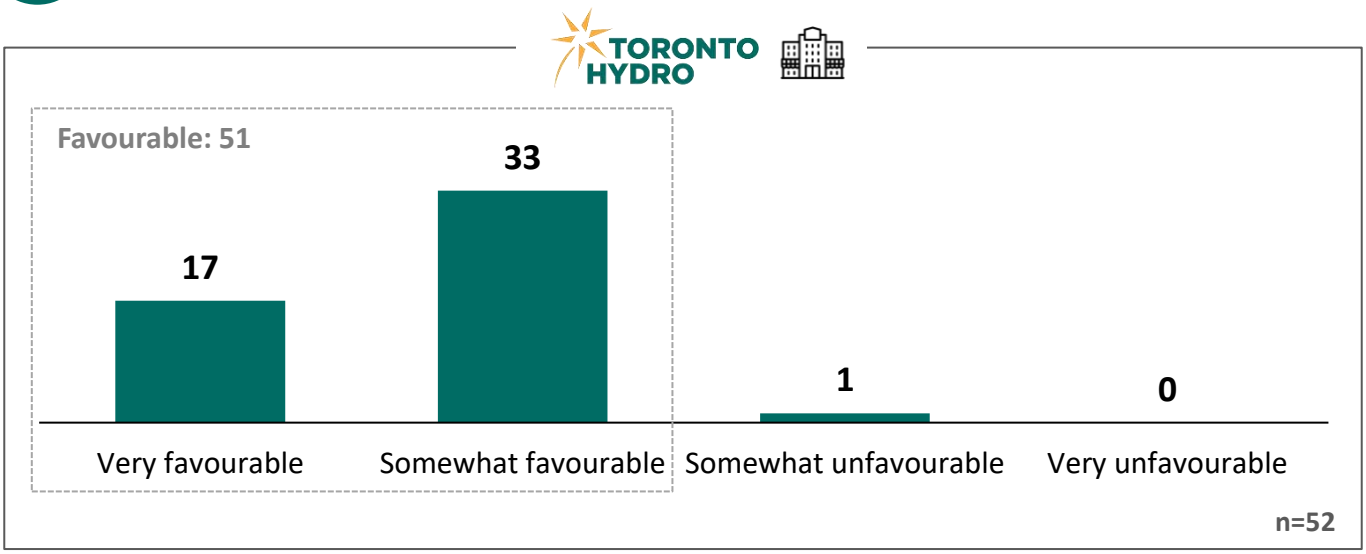
Section 12.2



Online Workbook

Workbook Impression

Q Overall, what is your impression of the survey you just completed?

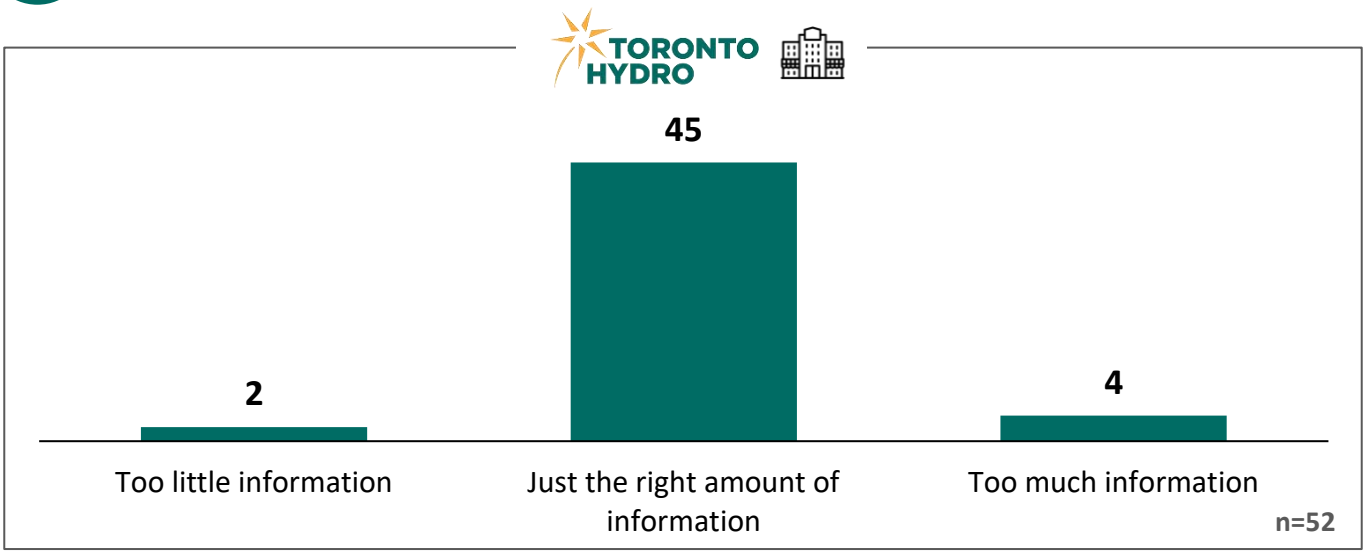


	Sector		
	MASH	Commercial/MURB	Industrial
Very favourable	4	11	3
Somewhat favourable	5	16	13
Somewhat unfavourable	-	1	-
Very unfavourable	-	-	-
Favourable (Very + Somewhat)	**8**	**26**	**16**
Unfavourable (Very + Somewhat)	**-**	**1**	**-**

Online Workbook

Amount of Information

Q In this survey, do you feel that Toronto Hydro provided too much information, not enough, or just the right amount?



	Sector		
	MASH	Commercial/MURB	Industrial
Too little information	-	1	1
Just the right amount of information	8	24	14
Too much information	1	3	1

Online Workbook

Content Missing from Engagement

Q Was there any content missing that you would have liked to have seen included in this survey?

Response	Count
Operational efficiencies (salaries, spending) and accountability	6
How this benefits customers	1
Other	1
No response	44

Q Is there anything that you would still like answered?

Response	Count
Operational efficiencies (salaries, spending) and accountability	1
Reliability (e.g. Plans for underground cables)	1
More information on the costs, breakdown of either the plan or bill	1
No response	48

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro. The conclusions drawn and opinions expressed are those of the authors.

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INNOVATIVE RESEARCH GROUP

CONFIDENTIAL

APPENDIX 13

Customer Engagement Workbook
Residential Version

TORONTO HYDRO

November 2, 2023

STRICTLY CONFIDENTIAL

2025 – 2029 Rate Application

Report Navigation

APPENDICIES

PHASE I

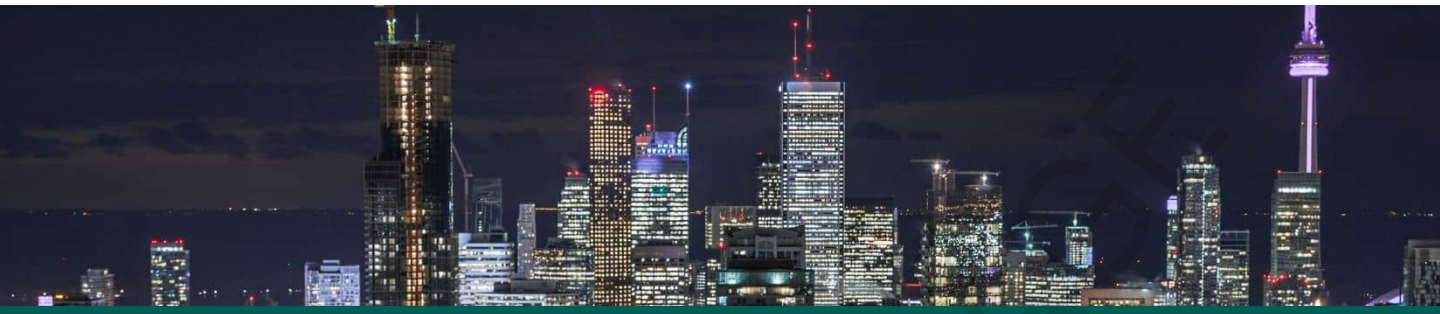
- APPENDIX.01 – Customer Engagement Focus Groups
- APPENDIX.02 – Customer Sample Validation
- APPENDIX.03 – Residential Needs and Preferences Survey
- APPENDIX.04 – Small Business Needs and Preferences Survey
- APPENDIX.05 – Commercial & Industrial Needs and Preferences Survey
- APPENDIX.06 – Key Accounts Needs and Preferences Survey
- APPENDIX.07 – Needs and Preferences Planning Placemat

PHASE II

- APPENDIX.08 – Customer Engagement Workbook Overview
- APPENDIX.09 – Residential Workbook Report
- APPENDIX.10 – Small Business Workbook Report
- APPENDIX.11 – Commercial & Industrial Workbook Report
- APPENDIX.12 – Key Accounts Workbook Report
- APPENDIX.13 – Customer Engagement Workbook (Residential Version)

Welcome to Toronto Hydro's customer feedback survey!

Toronto Hydro needs your input to find the right balance between the services you receive and the price you pay.



Land Acknowledgement: Toronto Hydro's grid is located on the traditional territory of many nations including the Mississaugas of the Credit, the Anishnabeg, the Chippewa, the Haudenosaunee and the Wendat peoples and is now home to many diverse First Nations, Inuit and Métis peoples.

The purpose of this survey is to get your feedback on the draft 2025–2029 business plan. Your feedback will help Toronto Hydro align this plan with what you need and want.

1. Your electricity rates pay for this plan, so your views must be considered.
2. You don't need to be an electricity expert to participate. The survey is focused on basic choices and provides the background information you need to answer the questions.
3. Recognizing that people absorb information in different ways, Toronto Hydro and its research partner have designed this survey to include diagrams, charts, images and videos to help explain Toronto Hydro's draft plan and what it means for you. If you prefer to skip the videos, the content is also explained in the body of the survey.
4. Depending on how much feedback you wish to provide and the number of videos watched, this survey should take approximately **20-30 minutes** to complete. If you need to pause and return later to finish the survey, your completed answers will be saved.
5. Some of the survey content may not display correctly on a mobile browser. It is strongly recommended that you complete this workbook on a desktop or laptop computer.

Those who complete the survey will be invited to enter a draw to win one of 10 "*free electricity for a year*" prizes!

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Toronto Hydro to gather your feedback, while protecting your confidentiality. Your individual answers will not be shared with Toronto Hydro in any identifiable way.

INNOVATIVE RESEARCH GROUP

WORKBOOK PREVIEW

What is this customer engagement about?

The goal of this engagement is to share Toronto Hydro's draft five-year business plan for the future of the city's electrical grid and collect your feedback. This will help Toronto Hydro align its plans with your needs and preferences.

Every five years, Toronto Hydro is required to submit a plan for its proposed prices (rates) and spending to the Ontario Energy Board (OEB) for approval.

- **In 2021 and 2022, thousands of its customers told Toronto Hydro about what they need and want** to help Toronto Hydro prepare the draft 2025–2029 business plan.
- **Toronto Hydro is now looking for your input on this draft business plan** to align its investments and spending decisions with what matters to you as its customers.
- **Later this year, Toronto Hydro will present its updated business plan to the independent regulator**, the OEB. Toronto Hydro is accountable to the OEB for considering your feedback.

How will this customer engagement work?



1. The workbook explains what Toronto Hydro does and summarizes the key planning considerations that Toronto Hydro's draft plan needs to address.



2. The workbook explains how much of your electricity bill goes to Toronto Hydro, how that money is spent, and the impact of the draft plan on your 2025–2029 prices.
3. The workbook asks for your input on seven key choices that will affect the services you receive and the price you pay from 2025–2029.



Once you have finished giving feedback on the key choices, **you will have an opportunity to review and change your responses** until you feel you have found the right balance.



Want to know more about Toronto Hydro's customer engagement process? See the next page for more.

Do you feel that the purpose of Toronto Hydro's customer engagement is clear?

- □ Very clear
- □ Somewhat clear
- □ Not clear at all

WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Rate Application

How will your feedback impact Toronto Hydro's plan and prices?

Toronto Hydro has a five-step approach to customer feedback.

We are here

✓ 1. Identify Customer Needs, Preferences and Priorities

In 2022, Toronto Hydro asked many types of customers from across the city about their needs and priorities for electricity distribution service.

✓ 2. Use Customer Feedback to Guide Development of Draft Plan

Toronto Hydro planners were given summaries of the key findings from the initial customer engagement to consider as they began building their plans.

3. Collect Customer Feedback on Draft Plan

Toronto Hydro is returning to customers to get feedback on the draft plan and ask customers how the draft plan could better meet their needs and preferences.

4. Use Customer Feedback to Finalize the Plan

Toronto Hydro will re-examine and make appropriate changes to the plan based on the feedback provided by customers in this engagement.

5. Submit the Plan to the Ontario Energy Board (OEB)

Toronto Hydro will file the plan with the OEB along with a report summarizing the results of this engagement. The OEB, consumer advocates and other interested groups will examine the plan in an open and transparent public process known as a rate application.

WORKBOOK PAGE

Electricity 101

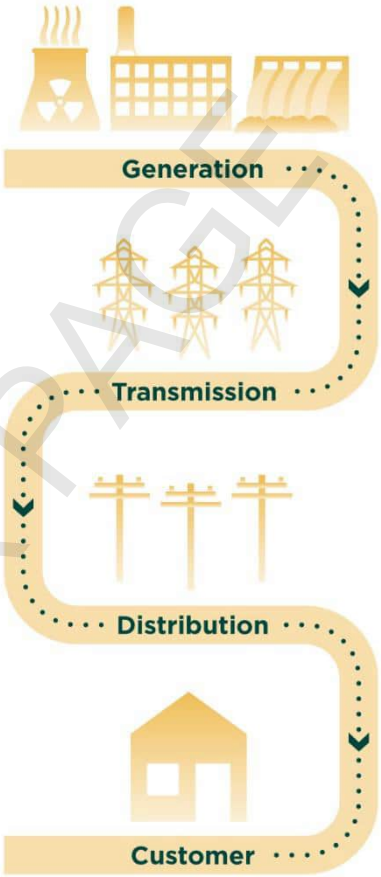
Toronto Hydro's role in Ontario's electricity system

Ontario's electricity system is made up of three parts: **generation**, **transmission** and **distribution**.

Generation

How electricity is made

About half of the electricity used in Ontario comes from nuclear power. The rest comes from a mix of hydroelectric, natural gas, wind and solar sources. Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from other generators contracted by the grid operator.



Transmission

How electricity travels across Ontario

Once electricity is made, it must be sent to urban and rural areas across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. Ontario has approximately 30,000 kilometers of transmission lines, mostly owned and operated by Hydro One.

Distribution

How electricity is delivered to you

Toronto Hydro is responsible for the last step of the journey: distributing electricity locally to end-use customers.

- Toronto Hydro does not generate or transmit electricity — it owns and operates the local electricity system made up of approximately 183,620 poles, 61,300 distribution transformers, 17,060 primary switches, 15,393 kilometers of overhead wires and 13,765 kilometers of underground cables.
- Toronto Hydro is wholly owned by the City of Toronto, but it does not receive taxpayer money — it is entirely funded by the distribution rates that you pay on your electricity bill.
- Toronto Hydro provides power to roughly 2.8 million people across the city of Toronto.

Before this engagement, how familiar were you with the various parts of the electricity system, how they work together and for which services Toronto Hydro is responsible?

- □ Very familiar
- □ Somewhat familiar
- □ Not familiar at all
- □ Don't know

WORKBOOK PAGE

Toronto Hydro's Draft Plan

Planning Considerations

In preparing its plan, Toronto Hydro must consider many existing and emerging challenges of delivering safe, reliable and clean electricity at a reasonable price.

To learn more about what Toronto Hydro must consider in preparing its draft plan, see the next two pages for more.

Key challenges that Toronto Hydro's 2025–2029 draft plan addresses:



Keeping prices reasonable



Responding to rising costs



Powering a growing urban city



Fixing and replacing equipment in poor condition



Reducing emissions from its own operations



Keeping up with the way customers use electricity



Responding to extreme weather and cyber security attacks



Protecting public and employee safety

WORKBOOK PAGE

Toronto Hydro's Draft Plan

Planning Considerations

In preparing its plan, Toronto Hydro must consider many existing and emerging challenges of delivering safe, reliable and clean electricity at a fair price.

Key challenges that Toronto Hydro's 2025–2029 draft plan addresses:



Keeping prices reasonable

- Many customers are concerned about the rising cost of living.
- Toronto Hydro must find the right balance between the investment needs of the local grid and the financial needs of its customers.



Responding to rising costs

- Like many companies, Toronto Hydro faces rising costs in purchasing equipment for the grid and doing construction work in the city.
- For example, from 2021 to 2022, the cost of buying electrical equipment increased by 9.9% while the cost of non-residential construction in the city of Toronto rose by 15.6%.



Powering a growing urban city

- Toronto is not just the largest city in Canada and an engine of the Canadian economy, it is also one of the fastest growing cities in North America.
- As the city continues to grow, the grid needs to be ready to power new condo towers, residential communities and businesses.



Fixing and replacing equipment in poor condition

- Much of Toronto Hydro's grid was installed in the 1950s and 1960s and needs to be replaced or upgraded.
- To keep the grid safe and reliable now and in the future, Toronto Hydro monitors the condition of its grid and uses this information to upgrade the equipment most at risk.



Reducing emissions from its own operations

- Toronto Hydro is committed to decarbonizing the company's footprint by 2040. To meet this goal, it must invest in reducing emissions from its vehicles and work centres.
- Toronto Hydro is expected to reduce its emissions by switching from oil and natural gas to clean electricity for powering its own operations.



Keeping up with the way customers use electricity

- Customers are using more electricity for their day-to-day energy needs, such as for transportation and electric heat pumps for home heating. They are also choosing new technologies such as solar panels and battery storage to manage their electricity usage and sell electricity to the local grid.
- To ensure customers can connect new technologies to the grid safely and reliably, Toronto Hydro needs to upgrade its equipment and modernize its systems.

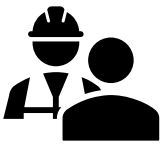
WORKBOOK PAGE

Planning Considerations (continued)



Responding to extreme weather and cyber security attacks

- Extreme weather such as high heat, high winds, flooding and ice storms is increasingly straining and damaging to electricity grids.
- Cybercrime is on the rise across Canada. For example, Toronto Hydro is the target of around one million attempted cyber attacks each year, with attempts going over one million in 2022 (successfully deflected).
- Toronto Hydro needs to make the grid more resilient against extreme weather and cyber security attacks that could compromise reliability and put customers at risk.



Protecting public and employee safety

- Toronto Hydro and its customers have a strong safety record, but electricity is dangerous and safety cannot be taken for granted.
- As homes and businesses add new technologies that increase the amount of electricity flowing around us, Toronto Hydro must ensure that the grid remains safe for its employees and the public.

WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Rate Application

How much of my electricity bill goes to Toronto Hydro?

Every item on your bill is required by provincial regulation.

- Toronto Hydro collects payment for the entire electricity system, but only keeps the distribution portion of the "**Delivery**" charge. This charge pays for both Toronto Hydro's **distribution** system and Hydro One's **transmission** system, as well as line losses (power that is lost when electricity travels across the wires).
- **About 30% of the electricity bill goes to Toronto Hydro** to pay for the local distribution grid. The **remaining 70%** of the bill goes to generation companies, transmission companies, the federal and provincial governments, and regulatory agencies.

Typical Residential Bill

Sample Toronto Hydro Monthly Bill
(based on consumption of 750 kWh as of Jan. 1, 2023)

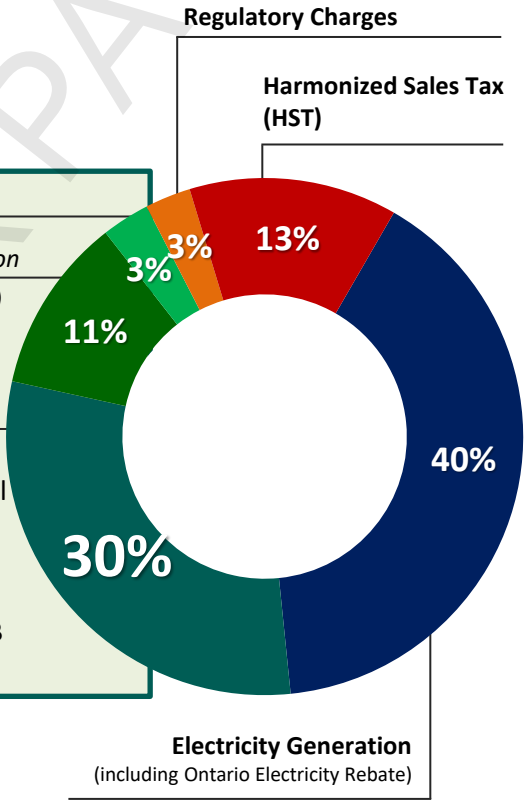
Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
On-Peak (highest price) @ 15.1 c/kWh	20.39
Mid-Peak (mid price) @ 10.2 c/kWh	13.77
Off-Peak (lowest price) @ 7.4 c/kWh	35.52
Delivery	60.05
Regulatory Charges	4.27
Total Electricity Charges	**$134.00**
HST	17.42
Ontario Electricity Rebate	**(-$15.68)**
Total Amount	**$135.74**

Delivery: *Line Losses*
$4.75
Delivery: *Transmission*
(varies based on usage)
$14.60

Delivery:
Distribution
Toronto Hydro's part of the total bill is **$40.70**. This charge is the same for all residential customers per OEB requirements.



Note: For time of use Off-/Mid-/On-peak split 64%/18%/18% according to the OEB rate model. The Sample Bill is based on the OEB rates effective January 1, 2023.

Who holds Toronto Hydro accountable?

The **Ontario Energy Board (OEB)** is the public interest regulator responsible for setting electricity distribution rates (prices) and for protecting customers in Ontario.

The OEB holds Toronto Hydro accountable for:

- How it spends your money in current and future plans.
- Reporting on key outcomes (reliability) through an annual scorecard.
- Finding savings and efficiencies to absorb rising costs.

Want to know more about what Toronto Hydro has done to become more efficient? See the next page for more.

Before this customer engagement, how familiar were you with the amount of your electricity bill that went to Toronto Hydro?

- ☐ Very familiar
- ☐ Somewhat familiar
- ☐ Not familiar

WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Rate Application

What has Toronto Hydro done to become more efficient?

- Reduced the total number of facilities and gave back roughly $158 million to customers, resulting in a total credit of $104.66 on the average residential customer's bill from 2016 to 2021.
- Delivered approximately $10 million in reduced or avoided costs in this current 2020–2024 period by replacing outdated information systems with consolidated programs, enabling automation and lowering maintenance costs.
- Implemented new technology to automate crew scheduling, enabling Toronto Hydro to maximize crew working hours and respond to power outages quicker.

WORKBOOK PAGE

How does Toronto Hydro propose to spend the money?

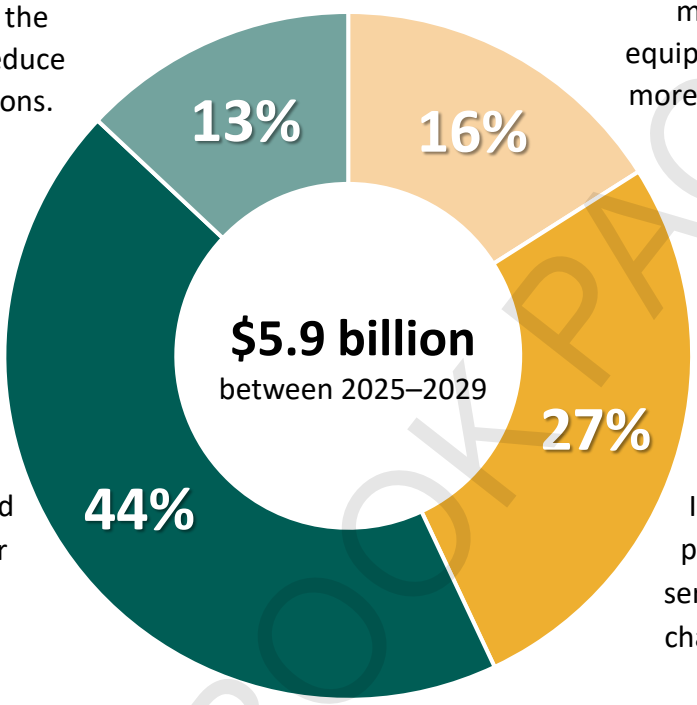
Toronto Hydro's five-year 2025–2029 draft plan is made up of four spending categories.

General Plant

Investments in vehicles, work centres and IT to keep the business running and reduce Toronto Hydro's emissions.

Modernization

Investments in technology to get more use out of existing equipment, and build a smarter, more efficient and reliable grid.



Sustainment

Investments to upkeep old equipment that is in poor condition and replace outdated equipment.

Growth

Investments in capacity to power the growing city and serve customers' growing and changing needs for electricity.

Want to know more about Toronto Hydro's current and future budgets? See the next page for more.

How much will Toronto Hydro's draft plan cost me?

At the end of the five-year plan (2029), the typical residential customer would see the distribution portion of their electricity bill increase by **$17.18**: from an estimated rate (price) of $42.36 in 2024 to a proposed rate (price) of **$59.54 by 2029.**

Rate Period	Year	Avg. Monthly Bill	Toronto Hydro Portion	Toronto Hydro's Portion: Annual Increase (%)	Toronto Hydro's Portion: Annual Increase ($)
	2023	$135.74	$40.70	n/a	n/a
	2024	$135.11	$42.36	4%	$1.66
	2025	$139.55	$46.76	10%	$4.40
	2026	$142.10	$49.28	5%	$2.52
	2027	$145.26	$52.39	6%	$3.11
	2028	$150.04	$57.11	9%	$4.72
	2029	$152.51	$59.54	4%	$2.43
	5-yr impact		**$17.18**	**41%**	**$17.18**

Note: These estimated rate increases are preliminary and are subject to change based on customer feedback and other factors. A typical residential customer is assumed to use 750 kWh per month and enrolled under Time-of-use Regulated Price Plan. Bill projections assume that other aspects of the electricity bill that are outside of Toronto Hydro's control (commodity, transmission, government, regulatory fees) remain constant.

WORKBOOK PAGE

Toronto Hydro Background

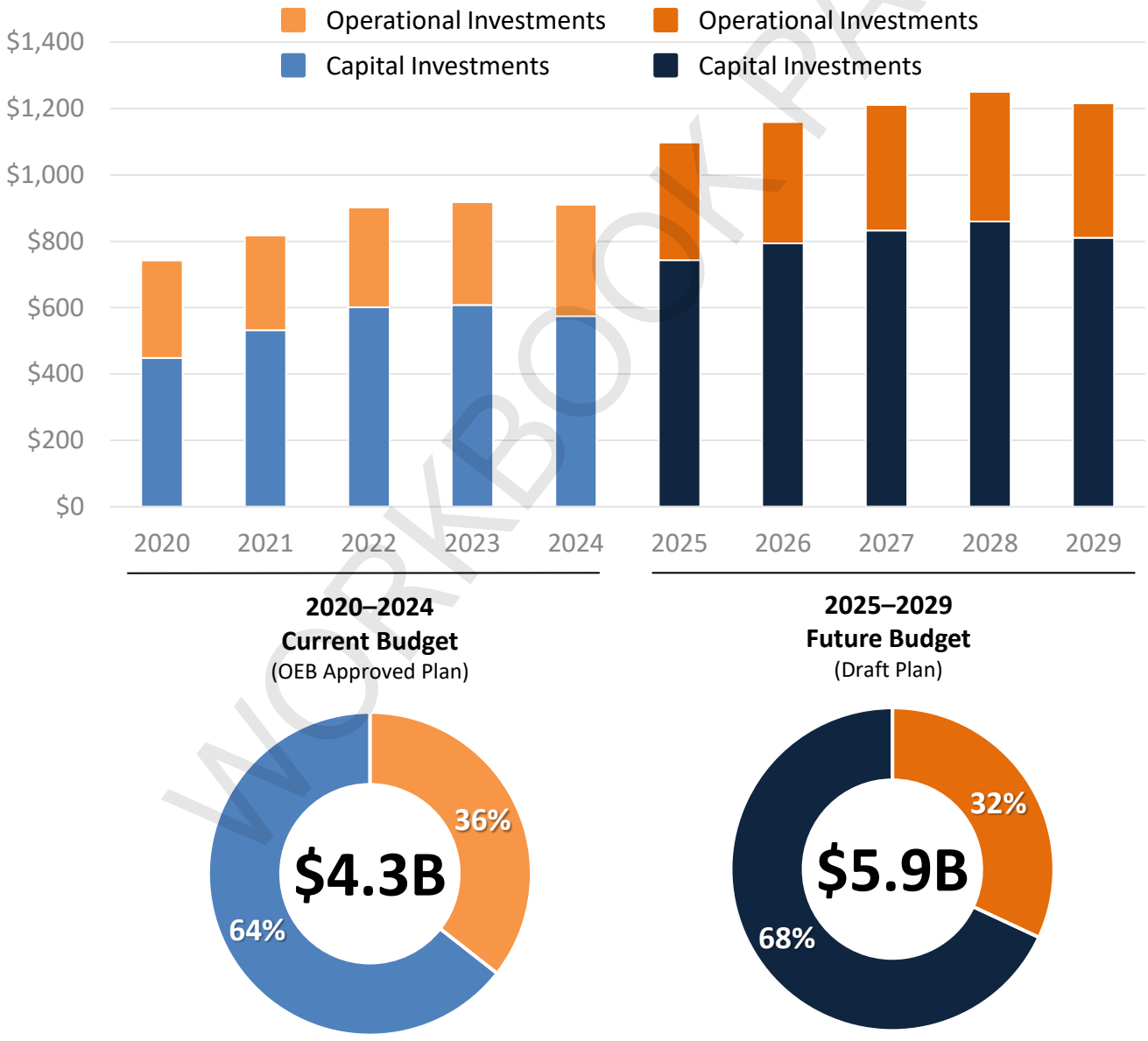
How much does it cost to run the local grid?

To run the local grid and serve customers, Toronto Hydro manages two budgets:

1. A **capital investment** budget which pays for the cost of buying and constructing physical infrastructure such as poles, wires, transformers, facilities, trucks and computers.

2. An **operational investment** budget which pays for maintenance and operation of the equipment, as well as the staff needed to manage the grid and serve customers daily.

Current and Future Budgets per year ($ millions)



The current five-year budget of **$4.3 billion** is based on the 2020–2024 plan approved by the OEB in a previous rate application. As mentioned earlier, this amount is funded by your 2020–2024 distribution rates.

The future five-year budget of **$5.9 billion** is based on the 2025–2029 draft plan presented in this customer feedback survey. The final budget for this next rate period will be adjusted to reflect customer feedback collected through this engagement and will be subject to extensive OEB review before rates are set for 2025–2029.

WORKBOOK PAGE

How does the survey work?

The next sections are about 7 key choices that Toronto Hydro needs to make to finalize its plan.

Each section provides some key background information. We encourage you to take the time to learn about your local electricity grid and where your money is going.

We also understand that life is busy. Many people find this information interesting — but if you would prefer to skip over the background information, you can jump right to the key choices.

How do I make choices?

Each choice has a summary of three options that Toronto Hydro considered:

- **Spend Less:** A minimum spending option that keeps prices lower and meets the basic performance requirements but may entail some trade-offs on key outcomes, such as reliability.
- **Toronto Hydro's Draft Plan:** An option currently in the draft plan which makes additional progress toward key outcomes but delays some important work.
- **Spend More:** A faster paced spending option that makes additional progress towards better outcomes while recognizing practical limits due to resources and construction issues.

In each option, there is a sliding scale that enables you to dial the draft plan up or down. While Toronto Hydro's technical experts can tell us the maximum and minimum amounts we can practically spend, the balance of how much Toronto Hydro spends on the spectrum is up to customers like you.

WORKBOOK PAGE

SAMPLE OPTIONALITY SLIDER QUESTION (data not recorded)

How much do you think Toronto Hydro should spend on this part of its draft plan?

Please write down the $ amount within the ranges on the slider in the blank fill.



$__.__ Your selection.

Is it clear that you can enter the $ amount within the ranges on the slider to any amount you feel best reflects your personal view of the best balance between lower costs and faster improvements?

- ☐ Yes
- ☐ No

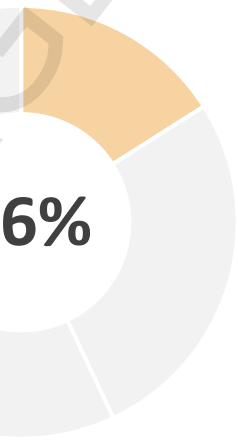
Draft Modernization Plan

Build a Smarter, More Efficient and Resilient Grid

What is this section about?

- This section explains how technology is changing the way customers use electricity and how Toronto Hydro operates and manages the grid to make it smarter, more efficient and resilient for customers.

  Want to learn more about how grid modernization benefits you? See the next page for more.



- **Toronto Hydro's draft modernization plan enables:**
  - Faster and cheaper power restoration
  - More efficient use of existing equipment
  - Customer choice to adopt new technologies
  - Resilience against weather and cyber attacks

- This spending category makes up **16% of the draft plan** and would add **$2.83** on the average residential customer's monthly bill by 2029.

WORKBOOK PAGE

Modernization Plan

Building a Smarter, more Efficient and Reliable Grid

Toronto Hydro's Modernization Plan has four main objectives:

WORKBOOK PAGE

Faster and cheaper power restoration



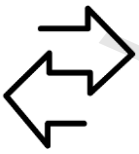
- Through automation, the smart grid can achieve self-healing capabilities. This means that the distribution grid on your street will be able to locate outages and restore power automatically.
- The smart grid enables Toronto Hydro to reduce the number and length of outages customers experience. It also reduces manual costs (trucks and crews) of responding to power outage events.

More efficient use of existing equipment



- As customers use more electricity, some equipment will reach its limits. Sensors and meters detect when and where these limits are approaching, enabling Toronto Hydro to make better decisions.
- The smart grid enables Toronto Hydro to get more use out of the existing equipment so that it can serve a greater customer need for electricity without having to build as much new infrastructure.

Customer choice to adopt new technologies

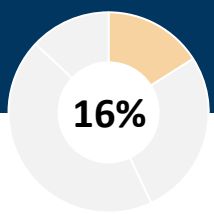


- Sensors, switches and software enable Toronto Hydro to monitor and control the flow of electricity so that customers can choose technologies to produce, store and sell power to the grid.
- The smart grid is designed to allow safe and reliable two-way power flow — from the grid to the customers and from customers to the grid. This system can reduce costs and makes the local grid more resilient to outages.

Resilience against weather and cyber attacks



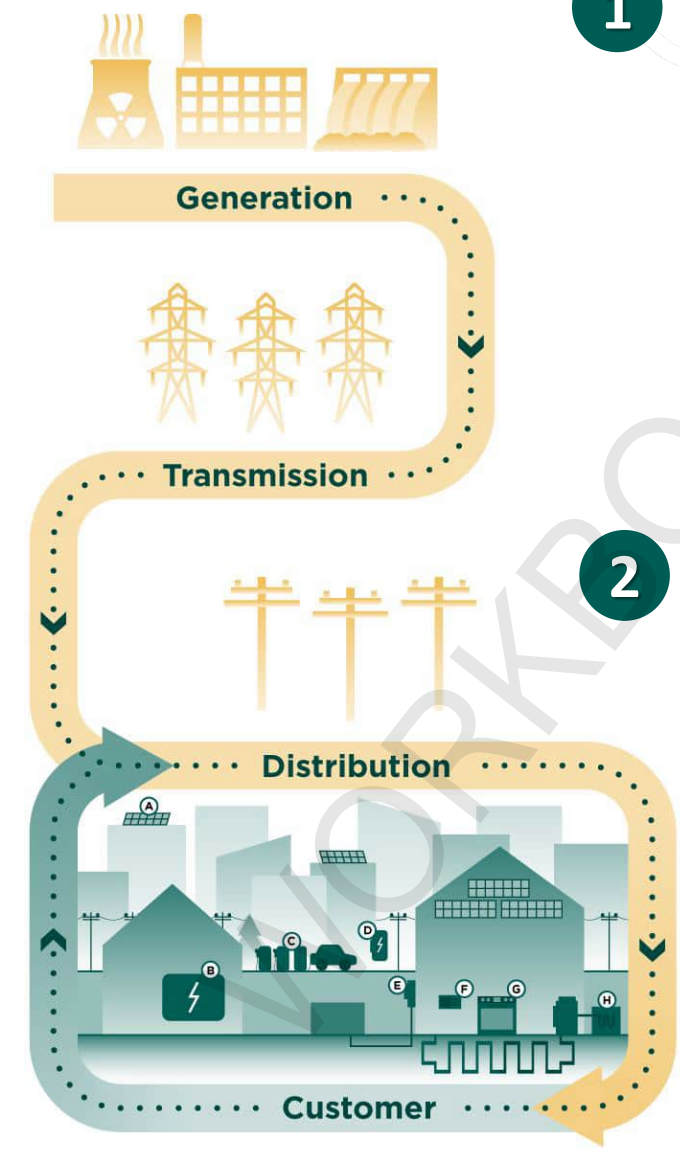
- Cyber attacks are increasing and getting more complex. Toronto Hydro must be prepared to respond to these threats to maintain reliable service and protect customer information.
- In addition to being able to restore power quicker, the smart grid can sense when environmental conditions like flooding pose a risk. This enables grid operators to strengthen the grid.



Modernization: Changing Technology, Changing Needs

For more than 100 years, things changed relatively slowly in terms of grid technology. Electricity was generated in large power stations and transmitted from around the province to Toronto Hydro's grid, and ultimately to homes and businesses. That is all changing, and because of technological advancement, the pace of change could be fast.

Toronto Hydro's 2025–2029 plan is shaped by two key changes in technology:



A. Solar panel
B. Battery storage
C. Public electric vehicle charging station
D. On-site backup generation
E. Smart meter
F. Home energy manager
G. Energy-efficient appliances
H. Heat pump

1 **Technologies that change how customers use electricity.** These include:

- Electricity products like electric vehicles, heat pumps and electric stoves that enable customers to use less fossil fuels (oil and gas), which contribute to climate change.
- Technologies like solar panels and battery energy storage that allow customers to produce and manage their electricity as well as sell it back onto the grid.

2 **Technologies that change how Toronto Hydro operates the grid**. These key changes are:

- The grid must shift from a **one-way system** that only sends electricity to customers to a **two-way system** that allows customers to generate and sell electricity to the grid.
- **Smart grid technology like sensors and automation** enables Toronto Hydro to monitor key equipment to prevent outages and get better use out of existing equipment. When outages do occur, this technology can re-route the grid to restore power much more quickly and at a lower cost than today.

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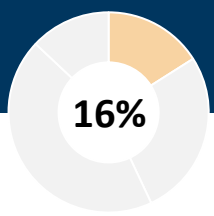
How much electricity does it take to charge an Electric Vehicle (EV)?



Did you know that when an EV is charging it can use as much electricity as two average homes? If everyone in a neighbourhood came home from work or school and started charging their EVs at the same time, the electricity demand could overload the grid.

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Draft Modernization Plan



Making Choices: **Modernization**

By 2029, Toronto Hydro's draft **modernization plan** would cost the typical residential customer **$2.83** more per month on their monthly electricity bill. Toronto Hydro could spend more to increase the pace of modernizing the grid to get better reliability sooner, or it could spend less and slow down the progress.

	Spend Less	Draft Plan	Spend More
Reliability	Being ready to automate the grid by 2035 means that better reliability won't happen until the end of the next decade or beyond.	Being ready to automate the grid by 2030 means that better reliability will happen in the earlier part of the next decade.	Faster progress towards grid automation means better reliability earlier and improved reliability for critical loads located in the downtown area.
Customer Service	May reduce service levels (longer waits and higher costs) for some customers connecting new services. May reduce customer choice for new technologies.	Maintains service levels for customers connecting new services to the grid. Enables customer choice for new technologies such as solar panels.	Same as draft plan.
Efficiency	It will take longer for the grid to become more efficient. This may lead to higher costs in the next decade.	The grid will become more efficient in the next decade, which will help reduce costs.	Same as draft plan.

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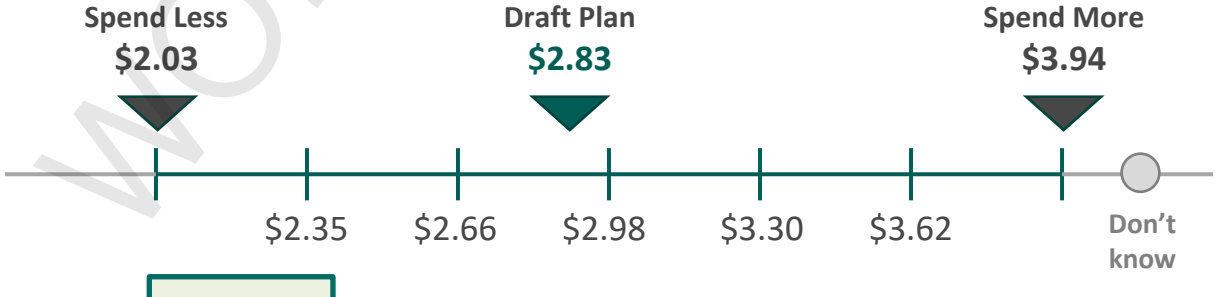
Choice 1 of 7:

Price



$__.__ Your selection.

How much do you think Toronto Hydro should spend on its modernization plan?

Please write down the $ amount within the ranges on the slider in the blank fill.

Do you have additional feedback on Toronto Hydro's draft modernization plan?
(Response optional)

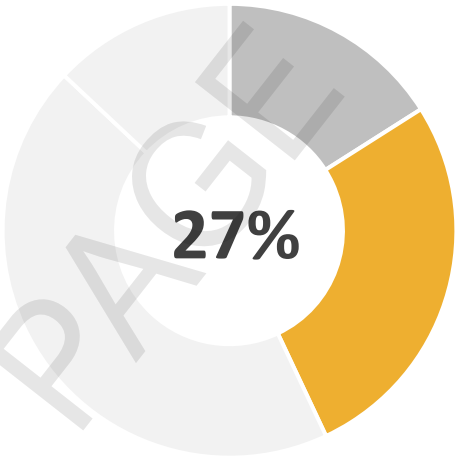
Confirm selection above to continue.

Draft Growth Plan

Increase Capacity to Serve Customers

What is this section about?

- This section explains how fast the city of Toronto is growing and what it takes for the grid to serve customers' needs for more electricity.
- Toronto Hydro's draft growth plan is about increasing grid capacity to serve customers reliably now and in the future.



- This spending category makes up **27% of the draft plan** and would add **$4.62** on the average residential customer's monthly bill by 2029.

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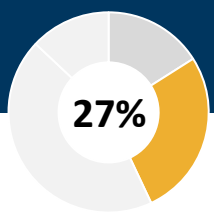


Growing City, Growing Needs

1 Toronto is growing, fast.

Toronto is one of the fastest growing cities in North America. A growing city means that we need a bigger local grid so that homes and businesses can get the power they need, when they need it.



Population Growth

Toronto will add approximately 500,000 more people this decade. To put this into context, Toronto is growing five times faster than Los Angeles.



230 Cranes
Toronto has led the crane count in North America since 2015.



2,114 Projects
including residential and non-residential in development in the city of Toronto.



+$1B in Construction
work planned for city infrastructure in Toronto annually (transportation and water).

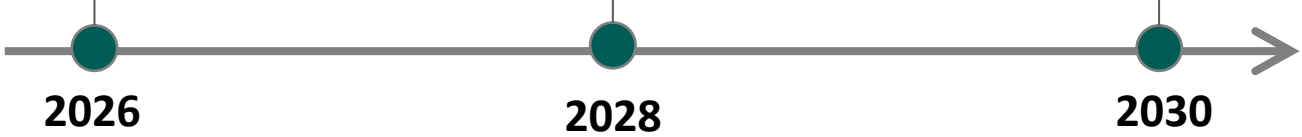
2 Individual customers will use more electricity than ever before.

The average customer will use more electricity in the next 10–15 years, as governments encourage businesses and communities to use less fossil fuels (oil and gas) to address climate change. Here are the key government policies that drive the need for more electricity in Toronto:

The Government of Canada may require 20% of all new car sales to be zero emission and is working towards a target of 60% by 2030.

The City of Toronto Green Building Standard requires all new mid- and high-rise buildings to be near zero GHG emissions.

The carbon tax may increase 161% by 2030 so customers use less oil and gas, and switch to clean electricity for cooking, heating and transportation.



23% **Forecasted increase in customers' need for electricity by the year 2030.**

Conservation and energy efficiency has helped manage electricity use over the past 20 years and will continue to play an important role in the future. But conservation alone is not enough. We need a bigger grid to serve customers in the long term.

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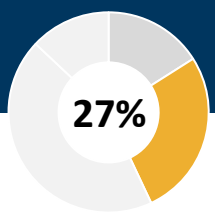

Growing City, Growing Need (continued)

When you think about all your energy bills, has your household ever considered shifting from one energy source to another to save money or reduce your impact on the environment?

For example, changing from a natural gas-fuelled furnace to an electric heat pump, or from a gas-fuelled vehicle to an electric vehicle?

- □ Yes, I have done it
- □ I'm actively taking steps in this direction
- □ I'm thinking about it
- □ I have never thought about it
- □ I have thought about it, but didn't end up switching
- □ Other [please specify:_____]
- □ Don't know

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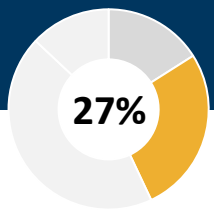

Building a bigger grid takes time

It's easy to say Toronto needs more electricity, but meeting this need requires Toronto Hydro to make major investments in the grid, including:



Expand Transformer Stations

Bring more power into the city from the provincial grid to serve growing communities along the new transit corridors (Eglinton LRT, Finch LRT, Ontario Line) and the redevelopment of areas like Downsview Park and the Portlands.



Upgrade and Reconfigure the Grid

Make more space on the grid to enable customers to plug in. Upgrade equipment like cables and transformers and reconfigure how the existing system serves customers to make more space on the grid to accommodate new services like electric vehicle charging stations and solar panels.



Major Infrastructure Developments

Connect major projects like the Finch Light Rail Transit system and the Ontario Line, and relocate Toronto Hydro's grid equipment to enable these and other major infrastructure developments to be constructed in the city.

This work cannot happen quickly. Toronto is densely populated and congested. **Building new power lines and stations takes years of planning and construction**. There are also equipment and resource constraints that limit how quickly Toronto Hydro can build a bigger grid.

Managing Uncertainty

Toronto Hydro develops its forecast from information such as building permits and projected electric vehicle sales. However, customer adoption of new technology is uncertain due to:

Supply chain issues such as equipment and resource shortages can affect the availability of customer technologies.

Technological advancements can lead to fast cost reductions. For example, the price of lithium ion batteries (EVs) decreased by 79% from 2013 to 2022.

Government policies such as rebates for electric vehicles and solar panels drive customers and suppliers to make certain choices.

If Toronto Hydro invests too quickly to build a bigger grid, it means customers' rates will go up to pay for equipment that will not be used for some time. On the other hand, if it doesn't do enough to expand the grid for higher use of electricity, customers could experience less reliability (brownouts) and delays when they want to connect to the grid or plug in new technologies. Toronto Hydro needs your input on the pace for these investments.

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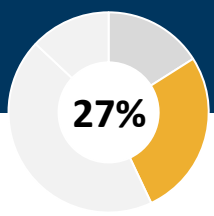
Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Draft Growth Plan



Making Choices: **Growth**

By 2029, Toronto Hydro's draft **growth plan** would cost the typical residential customer **$4.62** more per month on their monthly electricity bill. Toronto Hydro could spend more to better prepare the grid to serve customers' changing needs, or could spend less and wait and see if customers adopt new technologies over the 2025–2029 plan.

	Spend Less	Draft Plan	Spend More
Reliability	May lead to less reliability for customers in high-growth neighbourhoods. Increases reliability risk for the next decade.	Maintains reliability for customers in high-growth neighbourhoods. Manages reliability risk for the next decade.	Maintains reliability for customers in high-growth neighbourhoods. Improves reliability risk for the next decade.
Customer Service	May reduce service levels (longer waits and higher costs) for some customers connecting new services. May reduce customer choice for new technologies.	Maintains service levels for customers connecting new services to the grid. Enables customer choice for new technologies such as solar panels.	May improve service levels (shorter waits and lower costs) for some customers connecting new services to the grid. Improves customer choice for new technologies.
Efficiency	May lead to less efficient work if Toronto Hydro has to build a bigger grid reactively to serve customers.	Supports the ability to serve customers efficiently in the five-year plan based on the projected demand.	Supports the ability to serve customers efficiently in the five-year plan and beyond in the next decade.

WORKBOOK PAGE

Choice 2 of 7:

Price



$__.__ Your selection.

How much do you think Toronto Hydro should spend on its growth plan?

Please write down the $ amount within the ranges on the slider in the blank fill.

Do you have additional feedback on Toronto Hydro's draft growth plan?

(Response optional)

Confirm selection above to continue.

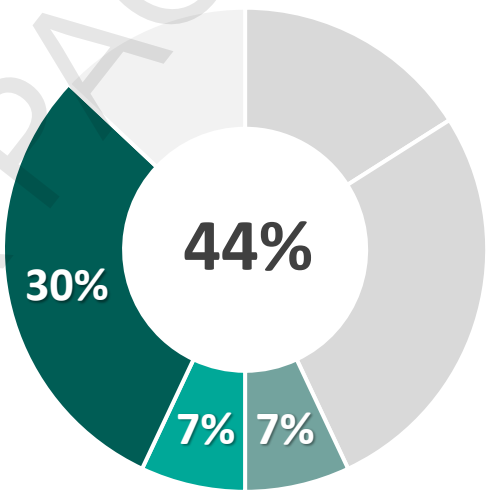
Draft Sustainment Plan

Replacing and Updating Equipment

What is this section about?

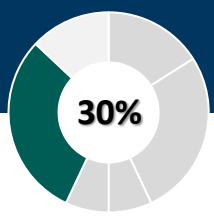
- This section is about upkeeping the grid to manage reliability and maintain safe and efficient operations.
- Toronto Hydro's draft sustainment plan section seeks your input in three areas:

1. Managing equipment in very poor condition with a high risk of failure.
2. Pacing the upkeep of equipment near the end of its expected life.
3. Standardizing outdated equipment.



- This spending category makes up **44% of the draft plan** and would add **$7.52** on the average residential customer's monthly bill by 2029.

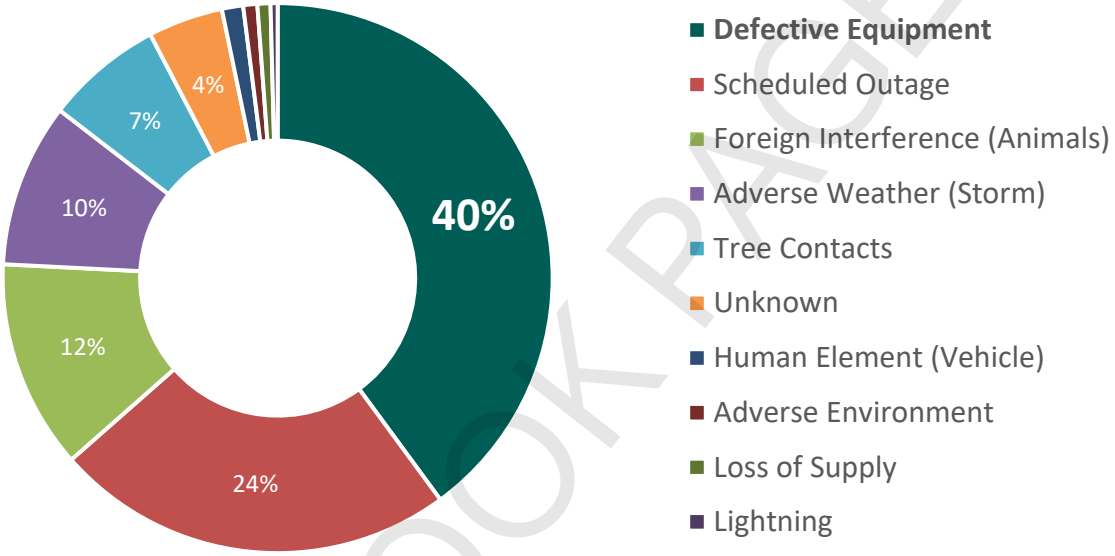
WORKBOOK PAGE



1 Reliability: Managing Equipment Failure Risk

While many power outages are caused by external events such as weather and falling trees, roughly **40%** of customer outages are caused by equipment failure. This is the largest single cause of outages, and customers look to Toronto Hydro to manage this risk.

Customer Outage Duration (Hours) by Cause 2018-2022



Toronto Hydro manages failure risk by:

- Inspecting equipment condition regularly, so that maintenance or replacement can be done before the equipment fails.
- Replacing and repairing equipment that is in bad condition or performing poorly. This includes replacing lines with a high number of outages or replacing transformers with visible signs of wear and tear such as rust.

Since 2014, Toronto Hydro's work to upkeep the grid has delivered a 13% reduction in the average number of outages experienced by customers and a 25% reduction in the length of those outages. Toronto Hydro's draft plan is to maintain these reliability results for customers.

Want to learn more about grid reliability and what causes power outages?
See the next page for more.

What type of work is Toronto Hydro doing to manage equipment failure risk?

Below is an example of a key investment that Toronto Hydro needs to make to prevent increased outages due to equipment failure.



Replacing Direct-Buried Cable

In parts of the grid that were built a long time ago, cables are laid directly in underground trenches without any protective barrier. **Underground equipment failures contribute to 57% of defective equipment failures, the large majority of which (75%) are due to cables.** Toronto Hydro's draft plan intends to replace 182 kilometers of direct buried cables by 2029 to manage the risk of power outages caused by this equipment.

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System reliability

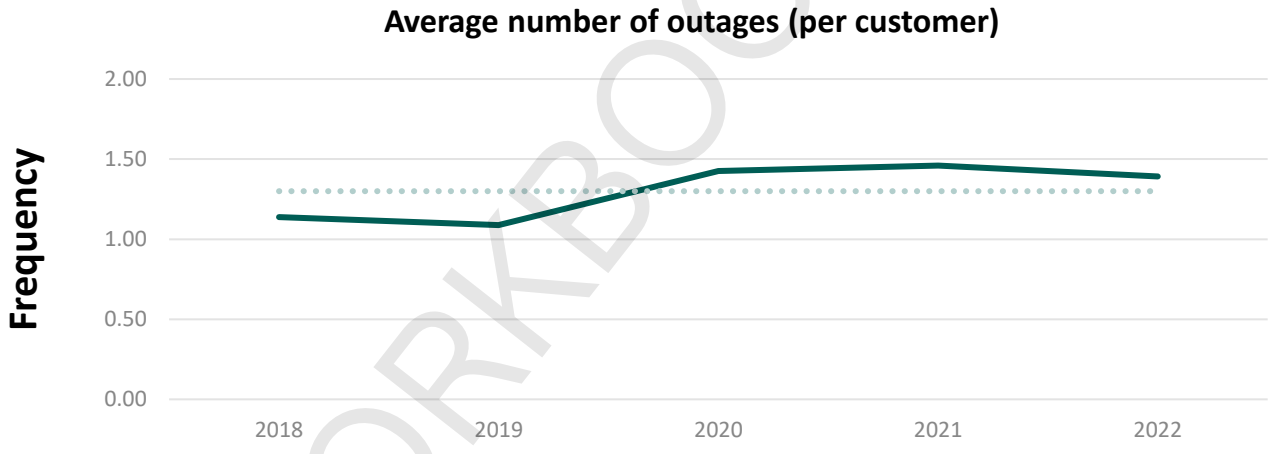
In order to provide feedback on Toronto Hydro's plans, it's important to understand how the distribution system has performed in the past, as well as what's expected in the future.

A core objective of Toronto Hydro's plan is to maintain current levels of reliability over the 2025-2029 plan period, while making foundational technology investments to reduce the length of power outages in the long-term.

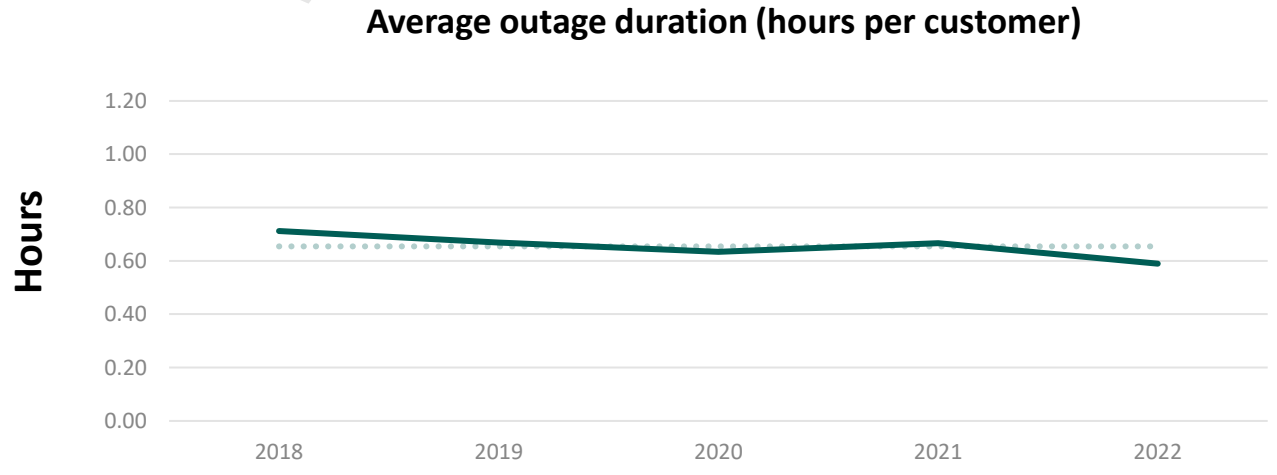
Toronto Hydro recognizes that power interruptions are inconvenient for residential customers and can be very costly for commercial and industrial customers.

Toronto Hydro tracks both the average number of power outages per customer and how long those interruptions last.

Between 2018 and 2022, the typical Toronto Hydro customer has experienced about two outages per year (*or 1.3 outages per customer to be exact*).



Over the same period, the average **duration** of an outage has been about 0.62 hours. Meaning, when the power does go out, Toronto Hydro is typically able to restore power in about 35 minutes.



It's important to keep in mind that these are system averages, and that your actual experience may be different. Some customers connected to newer lines may not experience any outages, while others are experiencing more than the average number of outages each year.

WORKBOOK PAGE

What is most likely to cause an outage?

Although both the number and length of outages have decreased compared to the previous five-year average, equipment failure remains the top cause of outages within Toronto Hydro's control.

That said, in 2022, severe weather presented a unique set of challenges for Toronto Hydro's distribution system.

Causes of Unscheduled Power Outages (five-year average: 2018 to 2022)



12%

Animal Contact: Outages caused by animals such as racoons, squirrels and birds coming in contact with overhead powerlines or transformers.



40%

Equipment Failure: Unscheduled power outages from equipment failure usually occur with distribution equipment that's beyond or approaching the end of their expected useful lives.



10%

Weather-Related Events: Adverse weather such as heavy rain, lightning strikes, ice, snow, wind, extreme temperatures, and freezing rain can disrupt the distribution system.



14%

Other: Includes tree contact (7%) and human interference (1%), such as construction workers accidentally cutting powerlines or motor vehicle accidents involving contact with distribution equipment. 4% of outages are unknown, but most are likely caused by animal contact.

Note: *statistics do not include loss of supply from Hydro One.*

WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Draft Sustainment Plan

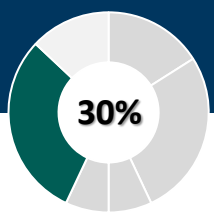
Over the past 12 months, have you experienced any power outages at your home which lasted longer than one minute?

- ☐ No outages
- ☐ 1 outage
- ☐ 2 outages
- ☐ 3 outages
- ☐ 4 outages or more
- ☐ Don't know

WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Draft Sustainment Plan



Making Choices: **Managing Equipment Failure Risk**

By 2029, Toronto Hydro's draft plan to manage equipment failure risk would cost the typical residential customer **$5.20** more per month on their monthly electricity bill. Toronto Hydro could spend more to improve reliability, or it could spend less and take on more risk of outages.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of the grid by 2029.	Maintains the overall health (age and condition) of the grid by 2029.	Improves the overall health (age and condition) of the grid by 2029.
Reliability	Reduces reliability compared to current levels. This means more power outages due to equipment failure.	Maintains reliability at current levels. This means holding steady on power outages due to equipment failure.	Improves reliability compared to current levels. This means less power outages due to equipment failure.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work. Increases work volumes and costs for the next decade.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work. Reduces work volumes and costs for the next decade.

WORKBOOK PAGE

Choice 3 of 7:

Price

Spend Less $3.53 | Draft Plan $5.20 | Spend More $6.50

$4.02 | $4.52 | $5.02 | $5.51 | $6.01 | Don't know

$__.__ Your selection.

How much do you think Toronto Hydro should spend on its grid reliability plan?

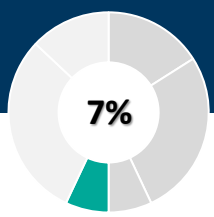
Please write down the $ amount within the ranges on the slider in the blank fill.

Do you have additional feedback on Toronto Hydro's draft grid reliability plan?

(Response optional)

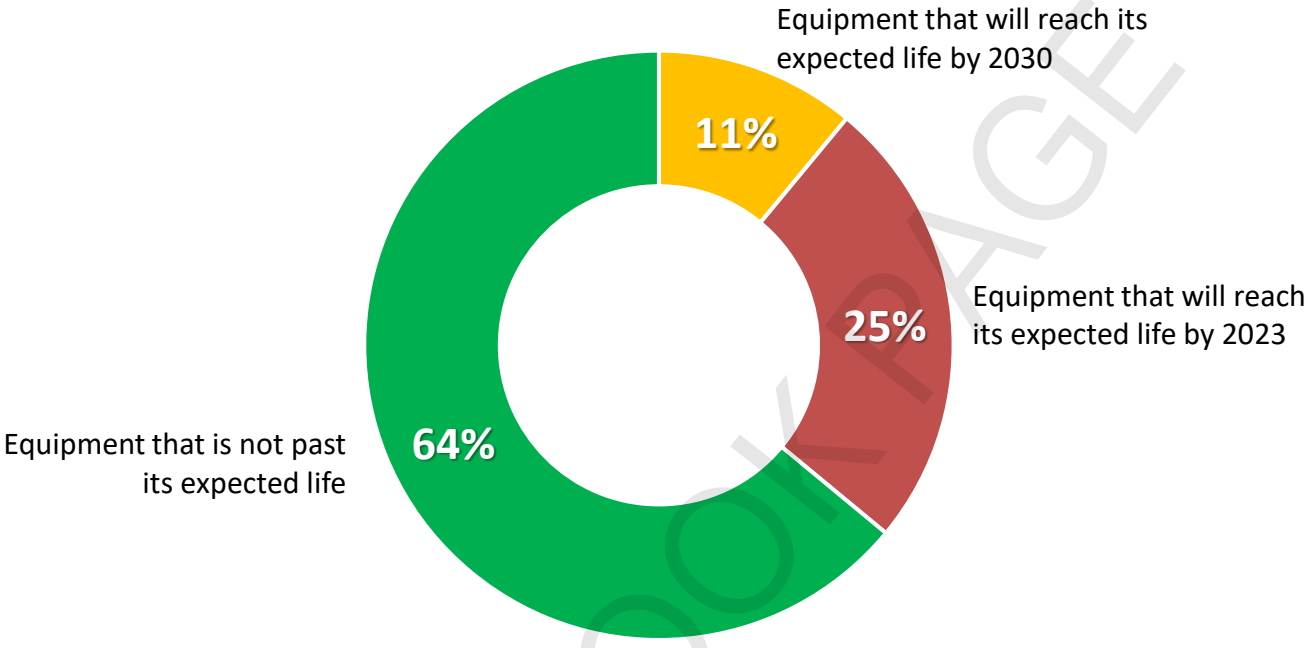
Confirm selection above to continue.

Confirm



2 Paced Upkeep of the Grid

About 25% of Toronto Hydro's equipment is operating past its expected life and an additional 11% is estimated to reach that point by 2030.



In this part of the plan, the key question is whether Toronto Hydro should wait until there are clear signs of equipment failure risk (such as rust or oil leaks), or whether it should get ahead of the problem by replacing old equipment proactively.

If Toronto Hydro waits, it can keep prices lower in the short term. However, this could create a surge of work in future years that will spike prices in the 2030s. There is also a risk that Toronto Hydro will not be able to do the amount of work required to deal with this equipment in the future, which could lead to more outages and higher safety risks due to equipment failures.

Want to learn more about Toronto Hydro's distribution grid?
See the next page fore more.

What type of work is Toronto Hydro doing to upkeep the grid?

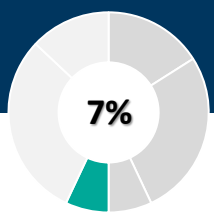
Below is an example of key investments that Toronto Hydro needs to make in a paced way to upkeep the grid and prevent a surge of work to address equipment failure risk in the future.



Paced Replacement of Network Vaults

This equipment is located in underground vaults in the downtown area, which serves many critical customers, such as hospitals and financial institutions. A very large portion of this equipment is going to be in poor condition and past its expected life in the 2030-34 period. To manage this risk, Toronto Hydro's draft plan intends to replace network vaults in a paced manner.

WORKBOOK PAGE



Renewing and replacing infrastructure

Toronto Hydro's grid is a mix of overhead, underground, network and station infrastructure. It operates at three different voltages (27.6kV, 13.8kV, and 4.16kV) and includes approximately:

- 61,300 distribution transformers
- 17,060 primary switches
- 15,393 km of overhead wires
- 13,765 km of underground wires
- 37 transformer stations

WORKBOOK PAGE



Overhead Infrastructure

The overhead system is made up of poles, wires, transformers, switches and other equipment. They are easier to replace, repair and inspect.

However, they are also more prone to foreign interference such as vehicles, trees, animals and weather-related outages.

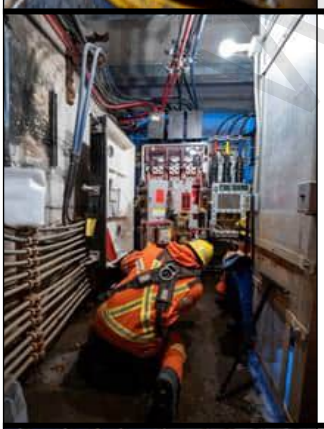
This system consists of three different types of configurations two of which are outdated configurations from the 1950s and 1960s, making them more challenging to replace and restore particularly after a weather-related outage.



Underground Infrastructure

Toronto Hydro's underground system consists of cables, transformers, switches and civil infrastructures (like manholes). They can be placed either at ground level (green box above ground in your neighbourhood), underground, or inside building vaults (typical for multi-storey buildings). This system is made up of two different types of configurations where the downtown Toronto area consists of lead-covered cable, an outdated equipment with little to no suppliers.

While underground equipment is more resilient during weather-related events, it is more susceptible to flooding and at risk of faster deterioration due to moisture build-up.



Network Infrastructure

Toronto Hydro's network system, predominantly found in the downtown Toronto area, was installed in the early-to-mid 1900s to improve reliability (service levels) for critical loads (like financial institutions) and serves medium-sized loads in high-density areas, and areas with small and narrow sidewalks. It consists of interconnected low-voltage cables, vaults and network units.

While this system is better at handling normal equipment failures, proactive replacement and maintenance of this equipment are critical to avoid vault fires from occurring.

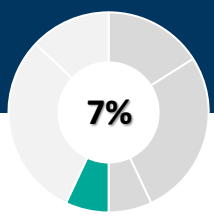


Station Infrastructure

Toronto Hydro's distribution stations receive the transmission supply from Hydro One at very high voltages. Station infrastructure consists of switchgear, power transformers, circuit breakers, remote terminal units (station computers) and battery systems. Toronto Hydro proactively replaces this equipment, as failure at the station level can cause widespread and lengthy power outages.

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Draft Sustainment Plan



Making Choices: **Paced Upkeep of the Grid**

By 2029, Toronto Hydro's draft plan to ensure paced upkeep of the grid would cost the typical residential customer **$1.15** more on their monthly electricity bill. Toronto Hydro could spend more to get ahead of future equipment failure risk, or it could spend less and defer some of this work at the risk of managing more power outages due to equipment failure in the next decade.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of the grid by 2029.	Maintains the overall health (age and condition) of the grid by 2029.	Improves the overall health (age and condition) of the grid by 2029.
Reliability	Higher risk of power outages due to equipment failure in the next decade.	Manages the risk of power outages due to equipment failure in the next decade.	Reduces the risk of power outages due to equipment failure in the next decade.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work. Increases work volumes and costs for the next decade.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work. Reduces work volumes and costs for the next decade.

WORKBOOK PAGE

Choice 4 of 7:

Price

Spend Less $0.75 | Toronto Hydro's Plan $1.15 | Spend More $1.84

$0.93 | $1.12 | $1.30 | $1.48 | $1.66 | Don't know

$_.__ Your selection.

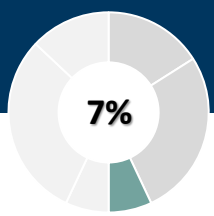
How much do you think Toronto Hydro should spend on its grid stewardship plan?

Please write down the $ amount within the ranges on the slider in the blank fill.

Do you have additional feedback on Toronto Hydro's draft grid stewardship plan?

(Response optional)

Confirm selection above to continue.

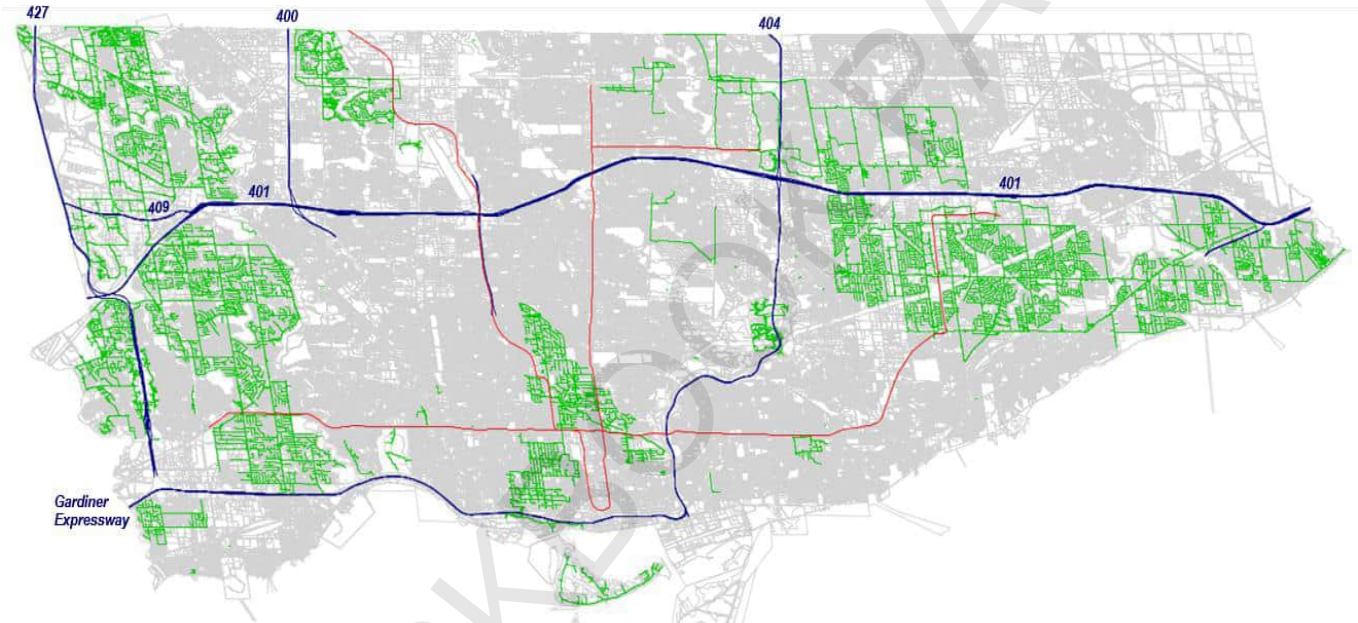


3 Standardize the Grid

Because of its history, Toronto Hydro has an old and diverse grid. Toronto Hydro is made up of 6 municipal utilities that were joined in 1998 when the City of Toronto was formed. Each utility owned and operated different types of equipment. As a result, Toronto Hydro's grid has three different voltage levels: 4.16kV, 13.8kV and 27.6kV.

The 27.6kV voltage level is the current standard for local grids. However, a large part of Toronto Hydro's grid is served at 4.16kV and 13.8kV.

Location of Outdated Voltage Lines



The low voltage 4.16kV system poses many challenges:

- Long outages for customers and higher cost to restore power – in 2022, the longest outage on the 4.16 kV system was 80 hours.
- Less efficient at carrying power over long distances, which means more electricity is lost as it travels from point A to point B (line losses).
- Less capacity to serve customers' growing electricity needs, which means longer waits and higher costs to connect new services such as electric vehicles and solar panels.
- Risk of supply chain and labour shortages as manufacturers stop making this equipment and technicians trained on this equipment retire.

What type of work is Toronto Hydro doing to standardize the grid?

Below is an example of a key investment to replace outdated equipment.



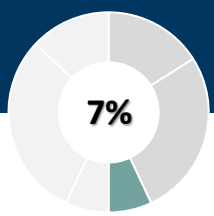
Voltage Conversion from 4.16kV/13.8kV to 27.6kV

Voltage conversion entails a full rebuild of outdated equipment such as rear lot construction (poles and wires in customers' backyards). This work improves reliability, safety and makes the grid more efficient. Toronto Hydro's draft plan intends to convert 1400 customers from rear lot service and works to eliminate rear lot construction from the grid by the late 2040s.

WORKING DRAFT PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Draft Sustainment Plan



Making Choices: **Standardize the Grid**

By 2029, Toronto Hydro's draft **plan to standardize the grid** would cost the typical residential customer **$1.17** more on their monthly electricity bill. Toronto Hydro could spend more to speed up the pace of replacing outdated equipment or it could spend less to slow down the pace and delay the benefits of this work. For example, under spend more Toronto Hydro would convert all rear lot customers by the early 2040s, and under spend less by the 2050s.

	Spend Less	Draft Plan	Spend More
Reliability	Slower progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.	Steady progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.	Faster progress to improve reliability (shorter and fewer outages) for customers who are currently connected to outdated equipment.
Customer Service	Less progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels.	Steady progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels	Faster progress to improve service levels for customers connecting new services or choosing new technologies such as solar panels.
Efficiency	Slower progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.	Steady progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.	Faster progress in making the grid more efficient, such as reducing line losses and long outages, which are more costly to restore.

WORKBOOK PAGE

Choice 5 of 7:

Price



$__.__ Your selection.

How much do you think Toronto Hydro should spend on its equipment standardization plan?

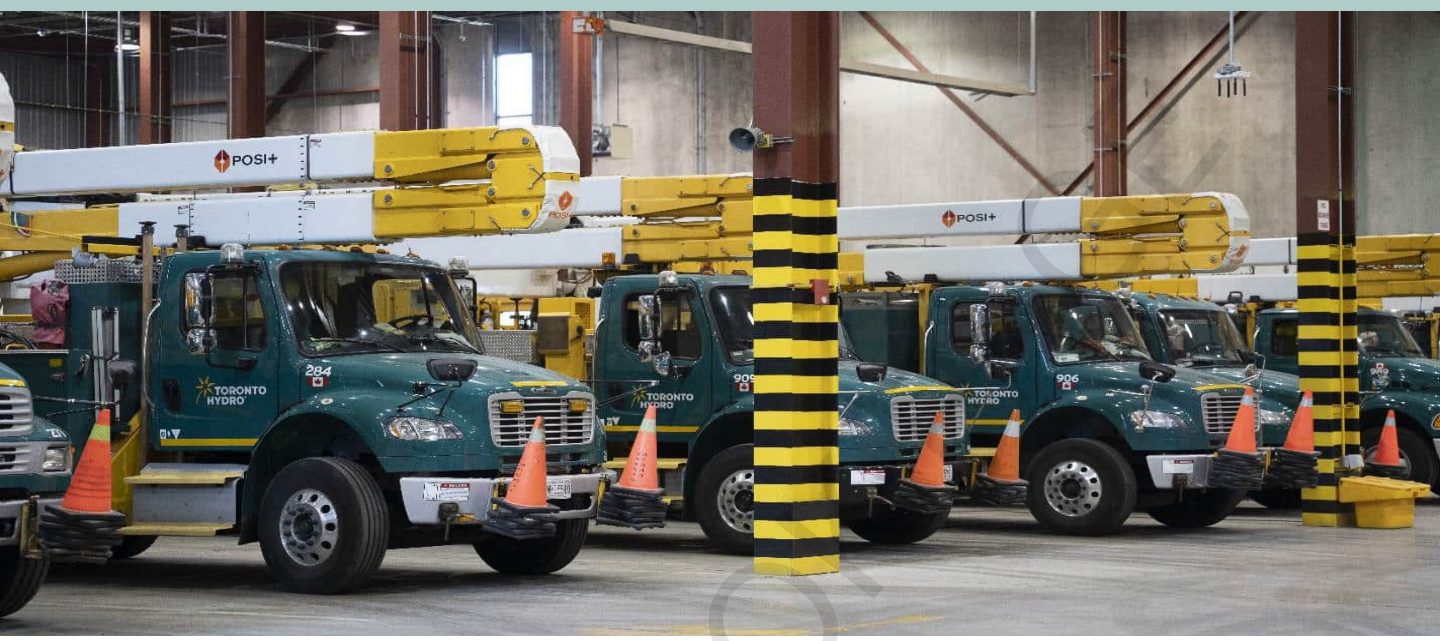
Please write down the $ amount within the ranges on the slider in the blank fill.

Do you have additional feedback on Toronto Hydro's draft equipment standardization plan?
(Response optional)

Confirm selection above to continue.

Draft General Plant Plan

Keeping the Business Running

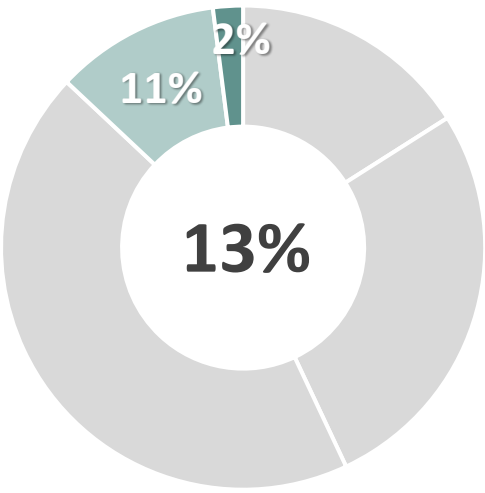


WORKBOOK

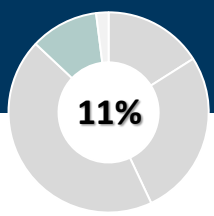
What is this section about?

- This section is about the vehicles, work centres and IT systems that keep Toronto Hydro's business running efficiently.
- Toronto Hydro seeks your input on two choices within this part of the plan:

1. The pace of replacing the equipment needed to keep the business running.
2. The pace of reducing Toronto Hydro's emissions from its own operations.



- This spending category makes up **13% of the draft plan** and would add **$2.21** on the average residential customer's monthly bill by 2029.



1 Keep the Business Running

Work centres, vehicles and information technology systems are the backbone of Toronto Hydro's day-to-day operations. This equipment must be maintained in good working condition for efficient and reliable operations so that crews can restore power and customers can access key services like their online account and the outage restoration map.

- As with grid equipment, Toronto Hydro uses information such as age and condition data from inspections to decide which equipment should be replaced versus repaired.
- Toronto Hydro repairs equipment in poor condition such as leaking roofs, failed furnaces and worn-out vehicle braking systems. It also replaces equipment like software programs and hardware servers that are past expected useful life.

WORKBOOK PAGE

What type of work is Toronto Hydro doing to manage failure risk?

Below is an example of a key investment that Toronto Hydro needs to make to keep the business running and manage the risk of equipment failure.



Station Buildings

Toronto Hydro has approximately 250 properties that either house distribution stations equipment such as cables and transformers or support the distribution system.

Over 80% of station buildings are older than 40 years and require repairs and investments to address the following types of problems:

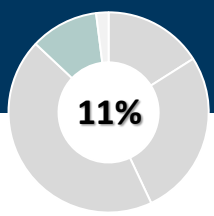
- Structural damage to the building (cracked foundations, leaking roofs)
- Mechanical, electrical and plumbing equipment in poor condition
- Compliance with building and fire code requirements

This work ensures safe and efficient operations and minimizes the risk of outages that can affect many customers. For example, structural damage to a station building poses a direct risk to distribution equipment such as power transformers.

So, how much and how quickly Toronto Hydro decides to invest in keeping their business running has a direct impact on customers. While this equipment may remain in service for a long time, when they unexpectedly fail, the costs incurred usually far exceed proactive investments (repairs and replacements) and can have a significant impact on system reliability and customer service.

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Draft General Plant Plan



Making Choices: **Keep the Business Running**

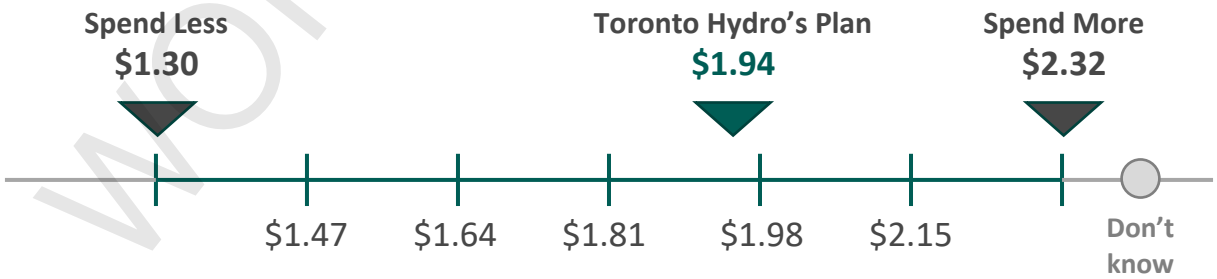
By 2029, Toronto Hydro's draft plan to keep the business running would cost the typical residential customer **$1.94** more on their monthly electricity bill. Toronto Hydro could spend more to improve equipment health (age and condition) and functionality (better safety features) or spend less and take on more risk of equipment downtime.

	Spend Less	Draft Plan	Spend More
Health	Reduces the overall health (age and condition) of general plant equipment by 2029.	Maintains the overall health (age and condition) of general plant equipment by 2029.	Improves the overall health (age and condition) of general plant equipment by 2029.
Reliability & Service	Reduces equipment availability, which could mean longer outages or lower levels of customer service.	Maintains equipment availability consistent with current levels.	Improves equipment availability and functionality, which could mean better reliability and customer service levels.
Efficiency	Reduces efficiency with higher amounts of reactive and emergency work, which is more costly and increases equipment downtime.	Maintains efficiency with stable amounts of reactive and emergency work. Manages work volumes and costs for the next decade.	Improves efficiency with lower amounts of reactive and emergency work, and better equipment functionality.

WORKBOOK PAGE

Choice 6 of 7:

Price



$__.__ Your selection.

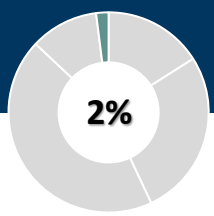
How much do you think Toronto Hydro should spend to keep the business running?

Please write down the $ amount within the ranges on the slider in the blank fill.

Do you have additional feedback on Toronto Hydro's draft plan for keeping the business running?

(Response optional)

Confirm selection above to continue.



2 Reducing Toronto Hydro's Emissions

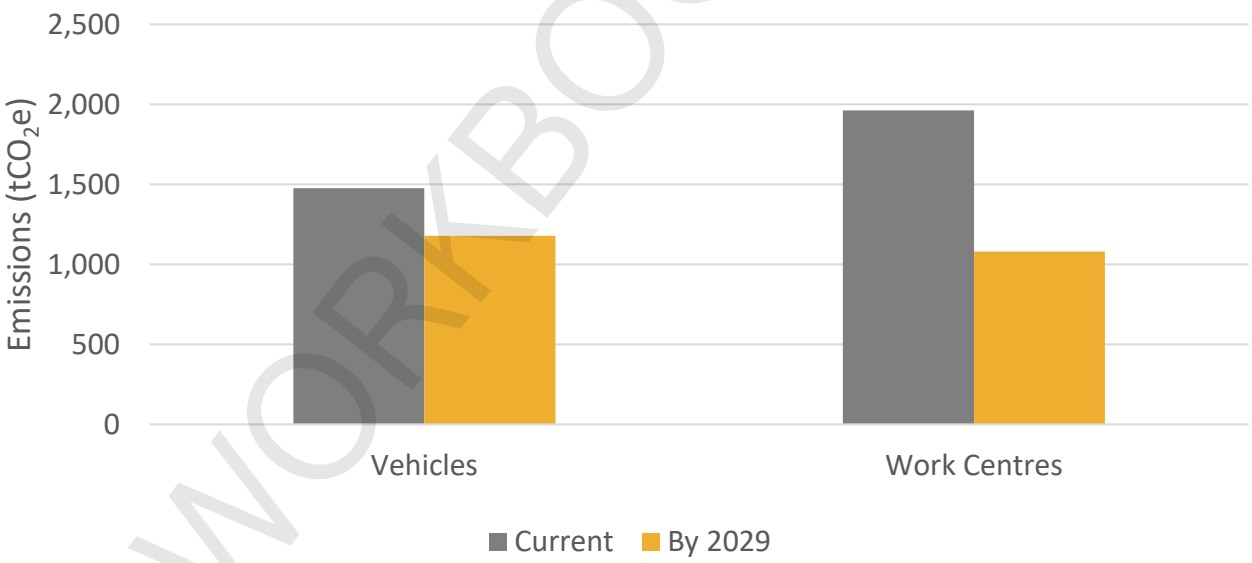
To address climate change, companies around the world are setting targets to reduce greenhouse gas (GHG) emissions from fossil fuels — a pledge commonly known as Net Zero.

Moving toward Net Zero has increasingly become the expectation of governments, financial markets, stakeholders and customers. For example, in October 2019, Toronto City Council unanimously voted to accelerate efforts to reduce emissions across the city.

To do its part in addressing climate change, Toronto Hydro is committed to reducing emissions from its vehicles and work centres by:

- Replacing gasoline and diesel power vehicles with hybrid and electric vehicles
- Converting natural gas boilers and heaters in its work centres to electric ones.

Toronto Hydro's Draft Plan to Reduce Emissions



Carbon Tax Savings

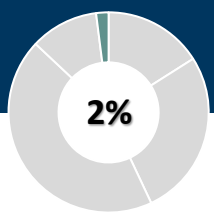
Reducing carbon emissions from vehicles and work centres could help Toronto Hydro manage rising costs due to the carbon tax (recall that the carbon tax may increase by 161% from 2023 to 2030). **Over the 2025-2029 period, Toronto Hydro's draft plan could reduce carbon tax payments by roughly half a million dollars.**

With your feedback, Toronto Hydro needs to decide how quickly to transition to cleaner sources of energy for its operations. In the next section, you will be presented these options.

WORKBOOK PAGE

Toronto Hydro Customer Engagement

Planning Process: 2025–2029 Draft General Plant Plan



Making Choices: **Reducing Toronto Hydro's Emissions**

By 2029, Toronto Hydro's draft plan to reduce emissions would cost the typical residential customer **$0.27** more on their monthly electricity bill. Toronto Hydro could spend more for faster progress towards reducing its emissions, or spend less to slow down the progress.

	Spend Less	Draft Plan	Spend More
Environment	Less progress to reduce emissions — about 27% reduction by the end of the decade.	Steady progress to reduce emissions — about 35% reduction by the end of the decade.	Faster progress to reduce emissions — about 36% reduction by the end of the decade.
Efficiency	Higher exposure to rising energy costs (oil and gas) due to the carbon taxes and other pressures.	Managed exposure to rising energy costs (oil and gas) due to the carbon tax and other pressures.	Less exposure to rising energy costs (oil and gas) due to carbon taxes and other pressures.

WORKBOOK PAGE

Choice 7 of 7:

Price

Spend Less $0.19 | Draft Plan $0.27 | Spend More $0.31

$0.21 $0.23 $0.25 $0.27 $0.29 Don't know

$__.__ Your selection.

How much do you think Toronto Hydro should spend to reduce its own emissions?

Please write down the $ amount within the ranges on the slider in the blank fill.

Do you have additional feedback on Toronto Hydro's draft decarbonization plan?
(Response optional)

Confirm selection above to continue.

Toronto Hydro has calculated an overall cost for its draft plan. While the plan may change based on feedback from the earlier questions in this survey, Toronto Hydro would like to know how you feel about the total rate impact of its current draft plan.

Considering what you have learned about Toronto Hydro's 2025–2029 draft plan and that this may result in a $17.18 increase in the distribution portion of your monthly electricity bill by 2029, which of the following best represents your point of view?

- □ I think Toronto Hydro should accelerate spending beyond its proposed draft plan to deliver better system outcomes
- □ I support the proposed bill increase when it comes to preparing Toronto Hydro's grid for the future
- □ I don't like the proposed bill increase, but I think it's necessary to maintain the grid to a reasonable standard and prepare for the future
- □ I oppose the bill increase and think Toronto Hydro needs to scale back its plan
- □ I don't know

Do you have any final comments regarding Toronto Hydro's draft plan for 2025–2029 and the proposed rate increase?

WORKBOOK PAGE

Survey Feedback

The following questions are for statistical purposes only. This information is used to segment and group similar people together when the survey results are analyzed.

To the best of your knowledge, does your home receive electrical service via overhead wires or underground cables?

- ☐ Overhead wires
- ☐ Underground cables
- ☐ Don't know

Do you identify as …

- ☐ Man
- ☐ Woman
- ☐ Prefer to self describe [_____]
- ☐ Prefer not to say

What age category do you fall into?

- ☐ Under 18
- ☐ 18-24
- ☐ 25-34
- ☐ 35-44
- ☐ 45-54
- ☐ 55-64
- ☐ 65-74
- ☐ 75 or older
- ☐ Prefer not to say

Including yourself, how many people live in your household?

- ☐ Single person household
- ☐ 2 people
- ☐ 3 people
- ☐ 4 people
- ☐ 5 people
- ☐ 6 people
- ☐ 7 or more people
- ☐ Prefer not to say

Which of the following categories best describes the total annual income, after taxes, of all the members of your household?

- ☐ Less than $28,000
- ☐ $28,000 to less than $39,000
- ☐ $39,000 to less than $48,000
- ☐ $48,000 to less than $52,000
- ☐ $52,000 or more
- ☐ Prefer not to say

WORKBOOK PAGE

Thinking generally about the electricity system in Ontario, including *generation*, *transmission* and *local distribution*, do you agree or disagree with the following statements?

	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree	Don't Know/No opinion
The cost of my electricity bill has a major impact on my household finances and requires that I do without some other important priorities.					
Customers are well-served by the electricity system in Ontario.					

WORKBOOK PAGE

Final Thoughts

Feedback on Toronto Hydro's survey

Toronto Hydro values your feedback. This is the first time the utility has conducted a review about its upcoming plans in this type of format.

Overall, what is your impression of the survey you just completed?
□ Very favourable □ Somewhat favourable □ Somewhat unfavourable □ Very unfavourable □ Don't know
In this survey, do you feel that Toronto Hydro provided too much information, not enough, or just the right amount?
□ Too little information □ Just the right amount of information □ Too much information
Was there any content missing that you would have liked to have seen included in this survey?
□ None
Is there anything that you would still like answered?
□ None

WORKBOOK PAGE

Thanks for Participating!

You have now completed Toronto Hydro's survey.

As indicated at the start, your individual responses are confidential and will only be shared with Toronto Hydro in aggregate, combined with the answers from all other respondents to this survey.

Keeping You Informed: If you would like Toronto Hydro to share the findings of this engagement and let you know how it will be responding to your input, please check the box below and confirm what email address is best used to contact you.

□ *I would like to learn about the findings of this engagement.*

Contest Draw: If you wish to be entered into the draw for your chance to win 1 of 10 prizes of "free electricity for a year," please check the box below and confirm what email address is best used to contact you.

□ *I would like to be entered into the draw.*

Email Address: _____

Confirm Email: _____

If you have any additional questions or comments about this survey, please email:
survey@innovativeresearch.ca

WORKBOOK PAGE

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Toronto Hydro. The conclusions drawn and opinions expressed are those of the authors.

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STAKEHOLDER ENGAGEMENT

This brief schedule presents an overview of the engagement sessions held by Toronto Hydro in connection with the Application. These sessions were distinct from the Customer Engagement activities described in Exhibit 1B, Tab 5, Schedule 1.

Toronto Hydro respects and values the regulatory process, and is committed to fostering and maintaining constructive relationships with the stakeholders that participate in this process. The utility invited parties that frequently intervene in the utility's rate applications, and other major rate applications before the Ontario Energy Board ("OEB"), to attend and participate in two facilitated stakeholder engagement sessions: the first on April 25, 2023 and the second on October 4, 2023. The second session was broken out into two parts with the first portion, led by Toronto Hydro, related to application substance and the second, led by the OEB Registrar, to discuss procedural timelines.

Prior to each session, Toronto Hydro's facilitator conducted preliminary meetings with one or more representatives from each party to understand the stakeholder expectations for the session, and get feedback with respect to areas or topic of particular interest. This feedback informed the development of content and materials for the sessions. Appendices to this schedule contain the facilitator's report for each session, including a list of participants, agenda, and a brief summary of the content presented and the discussions exchanged.

With the intention of facilitating a more effective and efficient adjudicative process, Toronto Hydro employed an open dialogue approach in conducting the stakeholder engagements that took place in the lead up to this Application. The utility approached the sessions as forum to inform parties about the status and evolution of its Application, share insights

about the plan, discuss rate-setting approaches, methodological and procedural aspects of the application, and identify novel issues or matters to be addressed in the application. To that end, the utility shared relevant information and provided interested parties an opportunity to engage with business and regulatory subject matter experts via questions, clarifications and other dialogue. This approach:

- provided parties a pre-emptive understanding of form and substance of this application, including the utility's investment plans and rate-setting proposals;
- solicited perspectives to help inform Toronto Hydro's proposals and evidence;
- explored procedural considerations, and the potential for consensus with respect to timelines for the adjudicative process; and
- established and reinforced lines of communication to facilitate ongoing constructive dialogue during the hearing process, hopefully minimizing the need for incremental procedural steps.

The discussions were courteous, constructive and overall helpful in providing the utility feedback and perspectives on range of topics that are relevant to the Application. Toronto Hydro thanks the participants for their attendance and contributions, and invites continued engagement and open dialogue throughout the proceeding.

Toronto Hydro Stakeholder Engagement Session
25 April 2023

Report of the Facilitator

Prepared by Cynthia Chaplin ICD.D

Toronto Hydro held a facilitated Stakeholder Engagement Session on 25 April 2023. This report presents background information, describes the process, and provides a summary of the session.

Background and Process

The following intervenors were invited to attend the Toronto Hydro Engagement Session:

- Association of Major Power Consumers of Ontario (AMPCO)
- Building Owners and Management Association (BOMA)
- Consumers' Council of Canada (CCC)
- Direct Resources Coalition (DRC)
- Energy Probe
- Environmental Defence
- Power Workers' Union (PWU)
- School Energy Coalition (SEC)
- Vulnerable Energy Consumers Council (VECC)

The Ontario Energy Board was also invited to attend.

I was retained by Toronto Hydro on 9 March 2023 to act as a facilitator.[1] Between April 4 and April 11, 2023, I conducted brief pre-meetings with one or more representatives from each intervenor. The purpose of these meetings was to:

- receive input on the issues that should be addressed
- receive input on how the session should be run

I prepared a brief report summarizing the input I received, and identified three key themes:

1. Toronto Hydro's objectives for the session should be clear and transparent.
2. The key issue is the energy transition/electrification/net-zero, with varying perspectives amongst intervenors.

[1] As a neutral facilitator, I did not provide any strategic advice to Toronto Hydro regarding the session, nor did I provide a substantive review of the materials prepared by Toronto Hydro.

3. Materials should be aligned with the session objectives and circulated in advance if possible.

Prior to the session, Toronto Hydro circulated an agenda which set out a description of each module and a statement of the type of input/feedback that it would find most useful as it works to finalize its proposals and complete its application.

The following intervenor representatives attended the engagement session:

- Shelley Grice – AMPCO
- Gillian Henderson – BOMA
- Julie Girvan – CCC
- Nicholas Daube – DRC
- Thomas Ladanyi – Energy Probe
- Daniel Rosenbluth – PWU
- Mark Rubenstein – SEC
- Mark Garner – VECC
- Bill Harper – VECC

The following OEB representatives attended:

- Ted Antonopoulos
- Michael Millar
- Alex Share
- Mima Micic
- Musab Qureshi

The following Toronto Hydro representatives attended:

- Amanda Klein
- Daliana Coban
- Matthew Higgins
- Hani Taki
- Kaleb Ruch
- Zoë Thoms
- Alana Spira
- Kiran Waterhouse
- Oluwanifemi Atanda
- Charles Keizer, external counsel
- MaryAnne Aldred, strategic advisor

Summary of the Session

Amanda Klein of Toronto Hydro provided introductory remarks to kick off the session. I then explained the process for the day, setting out the timing and approach. The session consisted of four modules, each with a presentation from Toronto Hydro, followed by time dedicated for questions and discussion.

Module 1 – 2025-2029 Application Process and Business Plan Overview

Daliana Coban and Matthew Higgins of Toronto Hydro provided an overview of the rate application process, and presented the investment categories, priorities and outcomes that comprise the 2025-2029 draft business plan, with particular emphasis on investment priorities that are driven by the need to prepare the grid for the energy transition. For this module, attendees were asked to:

- Ask questions about the rate application process or the investment priorities and outcomes.
- Identify specific information or analysis that would be helpful to have on the record.

Intervenors suggested several areas where specific data should be filed with the application, notably in relation to DERs, EVs, electrification, and load (including information on the data sources for related forecasts), as well as labour costs. It was also recommended that Toronto Hydro review the interrogatories in the prior hearing and consider filing the requested studies and reports as part of the application, rather than waiting until the interrogatory phase.

Module 2 – Future Energy Scenarios

Hani Taki of Toronto Hydro provided an overview of a new study that will be featured in the rate application: the *Future Energy Scenarios* study. Toronto Hydro explained the methodology used in this study, provided an overview of the results and explained how this study has been integrated into the capacity planning process. For this module, attendees were asked to:

- Ask questions about the Future Energy Scenarios study.
- Identify specific information or analysis that would be helpful to have on the record.

Discussion focused on how Toronto Hydro intends to use the results of the study in its planning and at the hearing. There were questions about the underlying methodology, the assumptions used, and how the study compares with other similar types of work (e.g., Enbridge's work in the area). Intervenors indicated they would want to see the model.

Module 3 – Distributed Energy Resources (DERs) Incentives

Kaleb Ruch of Toronto Hydro provided an overview of how the utility is leveraging behind the meter DERs to provide services to the grid as non-wires solutions, to set the context for a discussion about DER Incentives. This module then explored the OEB's newly released *Filing Guidelines for Incentives for LDCs to use Third-Party DERs as Non-Wires Solutions* and sought input on the incentive options and guidelines. This feedback was intended to help shape Toronto Hydro's proposals.

Questions and discussion focused on the various measures of costs and benefits associated with DERs. There was some discussion of incentives, and it was noted that Toronto Hydro would likely be one of the first LDCs to file under the new guidelines.

Module 4 – Regulatory Evolutions – Funding, Flexibility and Incentives

Daliana Coban of Toronto Hydro built on the context set in the previous modules and distilled the challenges that Toronto Hydro faces in the 2025-2029 period and identified the regulatory evolutions that it is considering to addresses these challenges, including:

- Funding adders to address multi-year investment needs
- Better incentives to recalibrate the risk/reward paradigm
- Flexibility mechanisms to manage uncertainty and protect customers.

In this module attendees were asked to provide feedback and ask questions about the challenges that the utility faces. Toronto Hydro sought input on the solutions/evolutions that it is contemplating to address these challenges. This input was intended to help shape Toronto Hydro's proposals.

There was discussion about incentives, what behaviours they are intended to drive and what behaviours they actually drive, the various attributes of "carrots" and "sticks", the specifications of outcomes, and the need for accountability if a utility is to get funding in advance of investment. Regarding the regulatory framework, the discussion focused on whether the appropriate evolution was toward a multi-year cost-of-service approach or an enhanced customer incentive regulation approach. The impact of the energy transition was noted as a key factor driving many of the challenges related to the level of investment required, the costs, and uncertainty about policy and customer decisions.

Observations

It was a productive engagement session. Useful information was conveyed from Toronto Hydro to the intervenor representatives, and the intervenor representatives were frank and respectful

in their questions and comments to Toronto Hydro. Productive exploratory discussions took place around several foundational issues, particularly related to the energy transition and what it means for Toronto Hydro and its customers.

My recommendation is that Toronto Hydro consider hosting a further engagement session or sessions in the period leading up to the filing of the application in October 2023. This would allow intervenors to get substantive information about how Toronto Hydro's thinking and the application are developing and could foster ongoing productive discussions around the foundational issues.

Report of the Facilitator

Toronto Hydro Stakeholder Engagement Session

4 October 2023

Prepared by Cynthia Chaplin ICD.D

Toronto Hydro held a facilitated Stakeholder Engagement Session on 4 October 2023. At the session Toronto Hydro presented key information about its 2025-2029 rate application and took questions from intervenors. The objective was to provide early information to intervenors to enhance the efficiency of the overall rate application process.

This report presents background information, describes the process, and provides a summary of the session.

Background and Process

The following intervenors were invited to attend the Engagement Session:

- Association of Major Power Consumers of Ontario (AMPCO)
- Building Owners and Managers Association (BOMA)
- Consumers' Council of Canada (CCC)
- Direct Resources Coalition (DRC)
- Energy Probe
- Environmental Defence
- Power Workers' Union (PWU)
- School Energy Coalition (SEC)
- Vulnerable Energy Consumers Council (VECC)

The Ontario Energy Board was also invited to attend.

I was retained by Toronto Hydro in August 2023 to act as a facilitator for the session. As a neutral facilitator, I did not provide any strategic advice to Toronto Hydro, nor did I provide a substantive review of the materials prepared by Toronto Hydro.

Between 1 September 2023 and 11 September 2023, I conducted pre-meetings with representatives from most intervenors to brief them on Toronto Hydro's objectives and

approach for the 4 October session. I also sought input on the issues/topics that should be addressed and input on the format for the session. I prepared a report summarizing the input received which identified the following key messages:

- The energy transition remains the key issue, with a variety of views.
- It is helpful if materials are circulated in advance, and specific numbers should be provided during the session.
- Toronto Hydro should identify any unusual aspects of the application, including any items needing specific OEB approval.
- Participants want to know the timing for the application and the planned OEB schedule, and how Toronto Hydro would handle evidence updates.
- Participants were pleased with the April session, and there were no recommendations for changes to the format for 4 October.

Prior to the session, Toronto Hydro circulated an agenda and materials.

The following intervenor representatives attended the engagement session:

- Shelley Grice – AMPCO
- Gillian Henderson – BOMA
- Daniel Vollmer – DRC
- Tom Ladanyi – Energy Probe
- Daniel Rosenbluth – PWU
- Mark Rubenstein – SEC
- Mark Garner – VECC
- Bill Harper – VECC

The following OEB representatives attended:

- Ted Antonopoulos
- Ravi Baichan
- Ceiran Bishop
- Thomas Eminowicz
- Donald Lau
- Nancy Marconi
- Mima Micic

- Lawren Murray
- Fiona O'Connell
- Ashley Sanasie

The following Toronto Hydro representatives attended:

- Amanda Klein
- Daliana Coban
- Matthew Higgins
- Elissar El-Hage
- Nathan Lev
- Courtney Fleury
- Deniz Oktem
- Zoë Thoms
- Charles Keizer, external counsel
- MaryAnne Aldred, strategic advisor

Summary of the Session

Amanda Klein of Toronto Hydro provided introductory remarks. I then explained the process for the day, setting out the timing and approach.

The session consisted of three modules. The first two included presentations from Toronto Hydro, followed by questions and discussion. The third module included a presentation by Toronto Hydro and a presentation by the Ontario Energy Board, followed by questions and discussion.

Module 1 – 2025-2029 Investment Plan

Daliana Coban and Matthew Higgins of Toronto Hydro provided an overview of the 2025-2029 investment plan and the associated residential rate impacts. They also described the Customer Engagement process and Phase 2 results, as well as a recap of the investment plan priorities. Toronto Hydro explained that the data presented has not yet been released publicly and

requested that attendees keep the data in confidence and only use it for purposes of preparing for the application process. No concerns were raised about this request.

There was a wide range of questions. Topics included rate impacts for other customer classes, forecasting methodologies, the impacts of electric vehicles and data centres, the ADMS project, and the reporting of board approved and actual results.

Module 2 – Rate Framework Evolution

Daliana Coban presented the proposed custom incentive rate-setting (CIR) framework and explained how the elements of the framework work together to address the challenges of managing funding, performance and uncertainty.

Most questions related to Toronto Hydro's Performance Incentive Proposal, including timing, measurement, interdependencies, and risk allocation. There were also questions about the inflation factor, earnings sharing mechanism, feeder performance, and the variance account proposed for demand-related uncertainty.

Module 3 – Application Administration

Daliana Coban provided an overview of the structure of the application, a list of novel issues that will be addressed, and a register of third-party expert evidence that will be filed. Nancy Marconi, Registrar at the Ontario Energy Board, presented information on potential schedules for the proceeding, under various assumptions regarding a settlement. All are designed to meet the OEB's performance metric of 355 days. Based on an intended application filing date of 17 November 2023, the targeted decision date would be 19 December 2024.[1]

There was substantial discussion about where parties need more time, particularly between interrogatory answers and the technical conference, and for the settlement conference (the conference itself and for preparation of the document). There was also substantial discussion about where time could be reduced, including the timing for interventions, the filing of interrogatories, the overall issues process, and the Argument-in-Chief. Parties also discussed the plan for any evidence updates after 2023 actuals are known and the process of accessing confidential data.

[1] This is longer than 355 days because the OEB holds the schedule in abeyance for 23 days over the holiday period. In addition, decisions are only released on Tuesdays and Thursdays.

The attendees requested that the OEB consider a summer abeyance or a hearing schedule that facilitates some ability to make summer plans outside the hearing. Attendees also noted the importance of having the Panel's commitment to the established schedule to facilitate overall planning and scheduling by all the parties.

Observations

It was a productive session. Important information was conveyed from Toronto Hydro to the intervenor representatives regarding the upcoming application, and the intervenor representatives were frank and respectful in their questions and comments to Toronto Hydro.

It was helpful to have the OEB's Registrar attend so that the day could include a discussion of the potential application schedule. There was substantive input offered on how the schedule could be improved for parties while still meeting the OEB's performance metric.

LETTERS OF COMMENT RESPONSES

Further to section 2.1.5 of the OEB's Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications (December 22, 2022), this schedule is filed as a placeholder for Toronto Hydro's future responses to matters raised in letters of comment filed with the OEB during the course of the application (when available).

Re: Toronto Hydro 2025–2029 Rate Application Letters of Comment

Dear Valued Customer,

Thank you for your letter of comment regarding Toronto Hydro's 2025–2029 rate application and investment plan. Customer letters are an important part of the rate application process and we appreciate you taking the time to provide your feedback.

The Ontario Energy Board (OEB) received 22 letters of comment in total. Many of the letters focused on similar themes, including that:

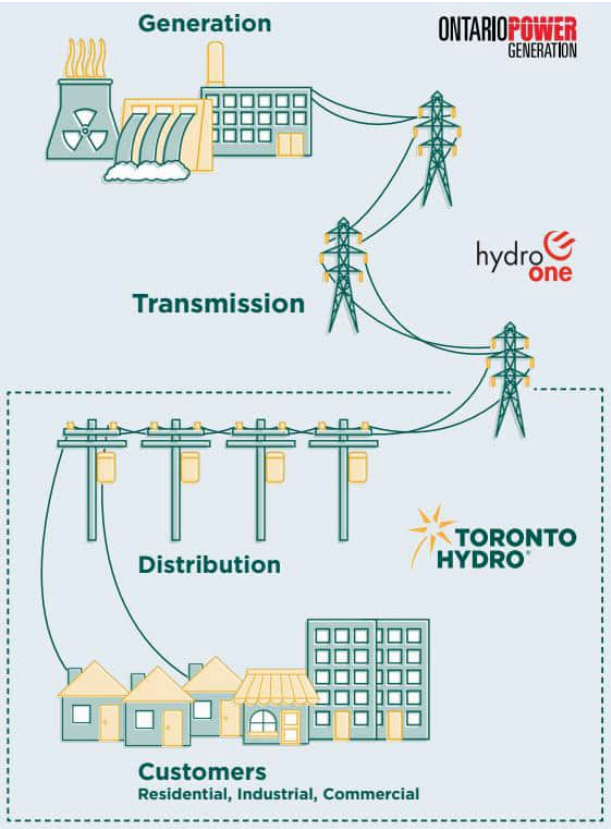
- Customers need clarity about what portion of their electricity bill goes to Toronto Hydro
- Customers believe the required electricity infrastructure already exists, so additional investment isn't required
- Customers are struggling with the cost of living and can't afford additional rate increases
- Customers want Toronto Hydro to explore other solutions rather than increasing costs

This letter represents Toronto Hydro's response to the comments raised and is divided into the following sections:

1. Electricity 101: – Toronto Hydro's Role in the Electricity System
2. Toronto Hydro Bill Breakdown
3. Toronto Hydro's Investment Needs
4. Toronto Hydro's Operating Environment
5. Customer Engagement and Business Planning
6. Timing and Pace of Investment
7. Supporting Electrification
8. Affordability and Cost-of-Living Challenges
9. Our Productivity and Performance
10. Additional Resources

1. Electricity 101: – Toronto Hydro's Role in the Electricity System

Ontario's electricity system is made up of three parts: **generation**, **transmission** and **distribution**:



Generation: Generation is the process of creating electricity from sources such as nuclear power, hydroelectric, natural gas wind and solar. Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from other generators contracted by the grid operator.

Transmission: Once electricity is generated, it must be sent to urban and rural areas across the province. This happens by way of high-voltage transmission lines that serve as highways for electricity. Ontario has approximately 30,000 kilometers of transmission lines, mostly owned and operated by Hydro One.

Distribution: Toronto Hydro is responsible for the last step of the journey: distributing electricity locally to customers. Toronto Hydro does not generate or transmit electricity — we own and operate the local electricity system made up of approximately 183,620 poles, 61,300 distribution transformers, 17,060 primary switches, 15,393 kilometers of overhead wires and 13,765 kilometers of underground cables.

2. Toronto Hydro Bill Breakdown

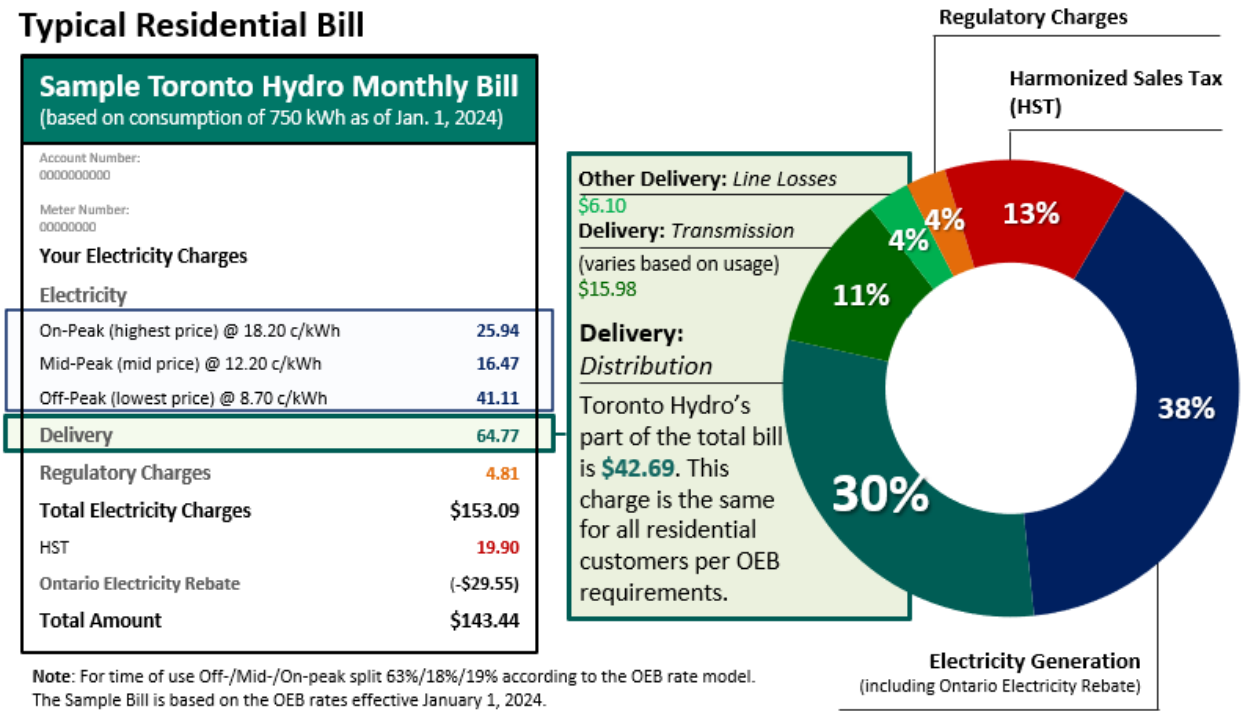
Toronto Hydro recognizes that there is some confusion among customers about how their electricity bill is distributed among the different parties involved in the electricity system, including what portion goes to Toronto Hydro and how Toronto Hydro spends the money we receive.

While the electricity bill you receive comes from Toronto Hydro, we actually collect payment for the entire electricity system. **Only about 30% of your electricity bill goes to Toronto Hydro** to pay for the local distribution grid. For example, if the typical monthly residential bill is $143.44**,** the **Delivery Charge** would be **$64.77** and would include:

- Toronto Hydro's Distribution: $42.69
- Hydro One's Transmission: $15.98
- Other Delivery including Line Losses (which is electricity lost during transmission): $6.10

The **remaining 70% of the bill** goes to generation companies, transmission companies, the federal and provincial governments, and regulatory agencies. Included in this amount is the 40% of your total bill that covers electricity generation costs. This is the part of your bill that changes based on your consumption. In other words, if you take steps to conserve energy, these actions will only impact 38% of your bill. For the typical residential customer, this amount is approximately $53.97.

The diagram below provides a breakdown of a typical residential bill:



3. Toronto Hydro's Investment Needs

The Delivery Charges found on your bill help fund Toronto Hydro's distribution system. For 2025 to 2029, we developed an investment plan to get the grid ready to serve the city's evolving electricity needs, including increased development from population and economic growth, as well as increased electrification and digitization. Our plan will help ensure that our grid and operations will remain safe, reliable and environmentally responsible.

Specifically, Toronto Hydro's 2025–2029 investment priorities include:

- **Sustainment and Stewardship:** These are investments to renew aging, deteriorating and obsolete distribution equipment to maintain the foundations of a safe and reliable grid.
- **Modernization**: These are investments to develop advanced technological and operational capabilities that will make the system better and more efficient over time
- **Growth and City Electrification**: These are necessary investments to connect customers (including distributed energy resources) and build the capacity to serve a growing and electrified local economy
- **General Plant**: These are investments in our vehicles, work centres and information technology infrastructure to keep the business running and reduce our greenhouse gas emissions

4. Toronto Hydro's Operating Environment

In developing the investment priorities that formed the basis of our 2025–2029 plan, we aimed to address certain needs and challenges of delivering safe, reliable and clean electricity, including:

- **Powering a mature and growing urban city**: We serve Canada's largest and North America's second fastest growing city (by population). We also operate in a dense urban environment, which makes it more complicated and more expensive for us to plan and build infrastructure. As Toronto continues to grow, we need to prepare the grid to power new condo towers, residential communities and businesses.
- **Fixing and replacing equipment in poor condition:** A large percentage of our grid was installed in the 1950s and 60s, and approximately a quarter of the utility's grid equipment continues to operate past useful life. We need to continue monitoring the condition of our grid and replace equipment most at risk to keep it safe and reliable for customers.
- **Keeping up with how customers use electricity:** Customers are increasingly adopting electrified technologies like electric vehicles and heat pumps for their day-to-day energy needs, and using new technologies like solar panels and battery storage to manage their energy usage. We need to upgrade our equipment and modernize our grid to keep up with these changes.
- **Responding to extreme weather and cybersecurity threats:** Extreme weather events such as extreme heat, high winds, flooding and ice storms are becoming more common due to climate change. In addition, cybercrime is on the rise across Canada. We need to invest in making our grid and operations more resilient against these emerging threats.

5. Customer Engagement and Business Planning

In preparing our plan, we recognized that we needed to balance addressing the operating challenges with price and other outcomes that customers value. Toronto Hydro has a robust planning process, which ensures that customer feedback informs our multi-year investment priorities.

During our planning process, we heard from over 37,000 customers across two phases of customer engagement:

- **Phase 1:** In 2022, we started preparing our plan by asking customers about their needs and preferences for electricity distribution services. Based on the Phase 1 Engagement and system conditions, we developed an initial plan that targeted certain short and long term goals.
- **Phase 2:** In March 2023, we went back to our customers with this draft plan — via a comprehensive online survey — to get feedback and to ask customers how the plan could better meet their needs and preferences.

With unprecedented levels of participation (more than 33,000 customers completed the survey), **84% of respondents supported our proposed plan** or one that does even more to improve services.

6. Timing and Pace of Investment

We understand that there are concerns about affordability, and questions regarding whether our proposed investments can be delayed until economic conditions improve.

Toronto Hydro's investment planning and rate application process operates on a five-year cycle. This means we only go to the OEB approximately every five years with an investment plan to ask for updated rates.

As described in this letter, there are certain investments which are necessary to renew aging equipment and prepare for increased growth in the city. These investments cannot happen quickly — particularly in a densely populated and congested city like Toronto. Building new powerlines and stations takes years of planning and construction. There are also equipment and resource constraints that limit how quickly we can build a bigger grid. That's why we need to start investing now to get the grid ready for future growth.

If we were to put off these investments, this could lead to lower reliability, lower service levels for customers looking to connect to the grid, and reduced efficiency. In addition, if we wait to make these proactive investments, we will likely have to spend even more to catch up on work that needs to be done, instead of spending more gradually. That's why we need to start investing in least-regrets investments now so as not to risk the safety, security, reliability and resiliency of the grid.

In the long term, increasing the utilization of the electricity system (through increasing the number of total users as well as the amount of electricity used by individual users) could help to bring down costs for individual customers.

7. Supporting Electrification

We understand that there are concerns that increased electricity rates will disincentivize customers from switching to electric vehicles (EVs) and heating. The rates we're proposing are necessary for making the investments needed to ensure the grid is ready when increased electricity demand materializes.

In addition, as customers increasingly turn to electricity for more of their day-to-day energy needs, it's expected that they will spend less of their income on energy over the long term as increased electricity costs are more than offset by savings from reducing or eliminating their use of fossil fuels, such as gasoline and natural gas.

Finally, there are a number of financial incentives available for EVs and electric heating, such as the Government of Canada's Incentives for Zero-Emission Vehicles Program[1] and the City of Toronto's Home Energy Loan Program.[2]

8. Affordability and Cost-of-Living Challenges

While our proposed rate increases are necessary for ensuring system safety and reliability and addressing the investment needs and challenges described in this letter, we recognize that there are some customers for whom rate increases will be particularly challenging.

[1] https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/incentives-zero-emission-vehicles/program-overview

[2] https://www.toronto.ca/services-payments/water-environment/environmental-grants-incentives/home-energy-loan-program-help/help-terms-and-conditions/

A number of financial assistance programs are available to eligible customers, with support ranging from helping customers reduce their electricity usage to on-bill credits that help offset monthly charges. The following programs are available to eligible customers:

- The City of Toronto's **Emergency Energy Fund (EEF)** assists customers with energy-related emergencies to reconnect, prevent disconnection or assist in payment of energy arrears
- The OEB's **Ontario Electricity Support Program (OESP)** provides an on-bill credit each month to qualifying households
- The Independent Electricity System Operator's **Energy Affordability Program** offers support to income-eligible electricity consumers by helping them to better manage their monthly electricity costs and to increase their home comfort
- The OEB's **Low-income Energy Assistance Program (LEAP)** provides a one-time emergency grant to help customers pay their electricity bill

To learn more about these assistance programs, visit **torontohydro.com/help**.

Additionally, as part of our commitment to improving how these programs work, Toronto Hydro is requesting enhancements to the LEAP program for the 2025-2029 rate period. Through these various enhancements, we're aiming to increase the average annual number of customers assisted to approximately 1,900 per year (or more than 9,000 over the entire five-year period).

We're also committed to working with the OEB, governments and other stakeholders to find additional targeted solutions that will help customers who need it most.

9. Our Productivity and Performance

Toronto Hydro always strives to provide value to our customers. Like many companies, Toronto Hydro faces rising costs in purchasing equipment for the grid and completing construction work in the city. Despite this, we're always looking for ways to minimize costs and rate increases by finding productivity and efficiencies in our plans and work. For example, as part of reducing our facilities footprint in the city, we consolidated from seven operating centres down to four. As part of this consolidation, the utility sold properties, and are returning proceeds of close to $200 million to customers by the end of the decade resulting in an annual credit of approximately $132 on the average residential customer's bill from 2016 to 2029.

During our business planning process, we asked external experts to assess our performance, including benchmarking with respect to our productivity, reliability, and cost efficiency. The results of those studies, which were publicly filed as part of our application, demonstrate that our performance on these measures is similar or better than our peer utilities.[3]

This also applies to employee compensation. Toronto Hydro balances cost-effectiveness with the need to attract and retain the talent required to provide service in an increasingly complex and dynamic operating environment. Toronto Hydro has external consultants who benchmark our total compensation, and we've been found to be within a market-competitive range in the energy market.

[3] For more information on Productivity initiatives, please see Exhibit 1B, Tab 3, Schedule 3.

In addition, our 2025–2029 plan is focused on delivering results that matter to customers like you. To help ensure that we achieve these outcomes, we'll be holding ourselves financially accountable through a framework that tracks and reports our performance on 12 distinct measures. This performance framework provides customers with an upfront rate reduction benefit of $65 million that we will only earn back if we achieve certain objectives.

10. Additional Resources

To learn more about Toronto Hydro's 2025–2029 rate application and investment plan, please refer to the following:

- Our 2025–2029 Rate Application
- 2025–2029 Rate Application Executive Summary (PDF, 894 KB)
- 2025–2029 Rate Application Customer Summary (PDF, 1.5 MB)
- Our 2025–2029 Investment Plan

OPERATING ENVIRONMENT

Toronto Hydro-Electric System Limited ("Toronto Hydro") is the electricity distributor licensed (ED-2002-0497) by the Ontario Energy Board ("OEB") to serve the City of Toronto. Toronto Hydro is the successor to the six former hydro-electric commissions of the municipalities which amalgamated on January 1, 1998 to form the City of Toronto. For information about Toronto Hydro's Corporate Structure and Governance, please refer to Exhibit 1C, Tab 2, Schedule 1.

Toronto Hydro is one of the largest municipal electrical distribution utilities in North America and serves the largest city in Canada. In 2022, Toronto Hydro distributed 24.0 terawatt-hours of electricity representing approximately 18 percent of the electricity consumed in the province of Ontario and served a peak demand of 4,276 megawatts.

Toronto Hydro serves two distinct customer demographic areas: (i) an urban centre in downtown Toronto; and (ii) a suburban area surrounding downtown Toronto, which is often referred to as the Horseshoe. Toronto Hydro has approximately 790,000 customers of various classes, ranging from residential to general service and large use.[1]

The utility's service area includes some of Canada's largest banks, the Toronto Stock Exchange, major manufacturers, and other large customers that are sensitive to service interruptions. In addition, Toronto Hydro supplies electricity to numerous healthcare and long-term care facilities, data centres, schools (including colleges and universities), Ontario's Provincial Legislature and Ministries, as well as Toronto's municipal government.

[1] Toronto has over 2,900 high-rise multi-residential condominium and apartment building accounts, many of which are "bulk-metered". Taking these bulk-metered multi-residential buildings into account, Toronto Hydro's effective customer count exceeds 1 million customers.

Toronto Hydro's distribution system consists of a mix of overhead, underground, secondary network, and stations infrastructure. These systems operate at voltages of 27.6 kV, 13.8 kV, or 4.16 kV, and distribute power through a complex network of 37 terminal stations, approximately 183,620 poles, 61,300 distribution transformers, 17,060 primary switches, 15,393 circuit kilometres of overhead primary conductors, and 13,765 circuit kilometres of underground primary cables. This network is composed of assets of varying vintages and types, reflective of the historical standards employed by the six pre-amalgamated utilities.

1. SERVICE TERRITORY

The City of Toronto is bounded by Lake Ontario to the South, Steeles Ave to the North, Mississauga (mainly Highway 427) to the West, and Scarborough/Pickering Townline to the East. A service territory map is filed at Exhibit 1C, Tab 1, Schedule 2.

2. NEIGHBOURING UTILITIES

Toronto Hydro's neighbouring electric distribution utilities are:

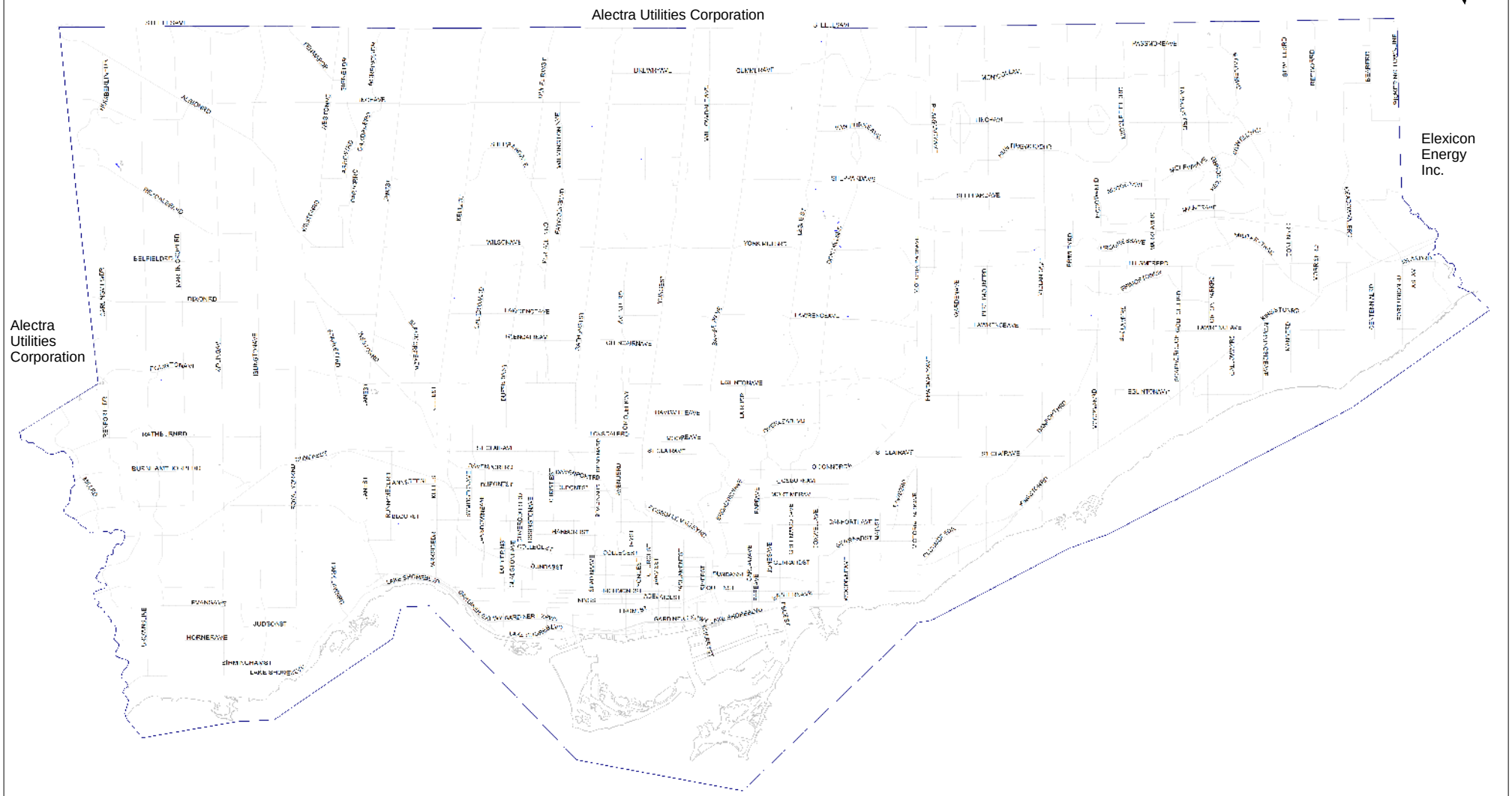
- To the north and west by Alectra Utilities Corporation; and
- To the east, Elexicon Energy Inc.

Toronto Hydro is not a host utility and there are no embedded utilities in Toronto Hydro's distribution service area.

3. TRANSMISSION ASSETS DEEMED DISTRIBUTION ASSETS

Toronto Hydro owns two transmission system terminal stations (two operational, one of which remains under construction) that have been deemed distribution assets, namely Cavanagh TS and Copeland TS, respectively. Toronto Hydro is not proposing any additional assets to be deemed as distribution assets as part of this application.

Toronto Hydro Service Territory



CORPORATE STRUCTURE AND GOVERNANCE

In accordance with section 2.1.3 of the OEB's Filing Requirements, this schedule provides information about Toronto Hydro's organizational structure and corporate governance framework.[1]

1. CORPORATE STRUCTURE

1.1 Corporate Structure and Governance

Toronto Hydro Corporation ("THC") is a holding company, the sole shareholder of which is the City of Toronto (the "Shareholder" or the "City"), which wholly owns two subsidiaries (see Figure 1, below): Toronto Hydro-Electric System Limited, a local distribution company ("LDC") which distributes electricity; and Toronto Hydro Energy Services Inc. ("TH Energy"), a company which provides street lighting and expressway lighting services in the city of Toronto (together, THC and its subsidiaries are hereby referred to as the "Company").

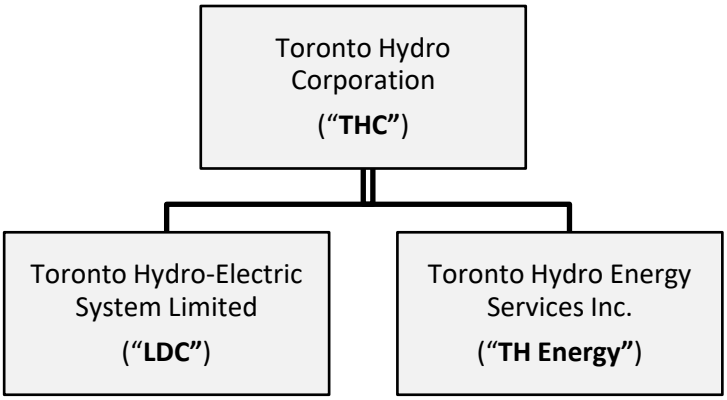


Figure 1: Toronto Hydro Corporate Organization Chart

[1] Ontario Energy Board Filing Requirements for Electricity Distribution Rate Applications, Chapter 2 (December 15, 2022).

Each of THC and its subsidiary entities have a Board of Directors, which is responsible for providing strategic guidance to management and supervising the business and affairs of their respective organizational segments. However, elements of the governance of the Company as a whole are undertaken at the THC level with its Board and its standing committees. The THC Board has specific responsibility for approving the overall business strategy and related business plan of the Company, which takes into account, among other things, the opportunities and risks of the businesses of the subsidiary entities and approves the financing strategy.

As THC has no substantive business beyond the regulated activities of LDC, having elements of the corporate governance of LDC provided at the parent company level accomplishes the same objective as having corporate governance solely at the LDC level. Additionally, the LDC Board retains adequate scope for the exercise of independent judgment within the overall framework of good corporate governance of the Company. The LDC Board oversees the operations of the utility and its regulatory and public policy activities, asset planning, customer relations functions, and compliance activities. It retains decision-making authority related to approval of any dividends by the LDC and approves its financial statements. The LDC Board also reviews and approves, in a manner consistent with the overall business plan and budget approved by the THC Board, significant corporate plans and initiatives, major acquisitions and dispositions and other significant matters of corporate strategy or policy.

This multi-layered corporate structure allows for matters of material importance to be dealt with at the most appropriate organizational level. A corporate entities relationship chart, showing the extent to which THC is represented on the LDC's Board of Directors, is shown in Figure 2 below.

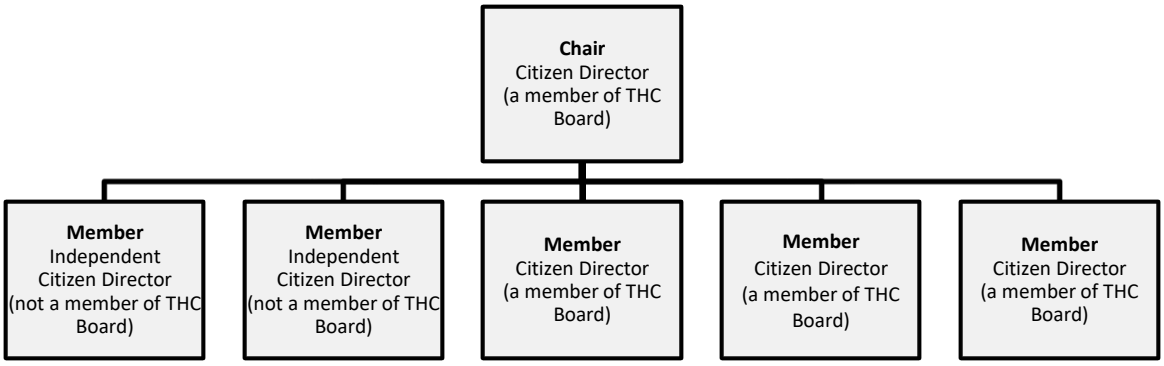


Figure 2: Toronto Hydro Corporate Entities Relationship Chart

1.2 Executive Team

THC's executive team is comprised of the Executive Vice-President and Chief Financial Officer ("CFO") and Executive Vice-President External Affairs, Corporate Development and Chief Legal Officer, both of whom are accountable to the President and Chief Executive Officer ("CEO") of THC. The CEO of THC is also the President and CEO of the LDC and of TH Energy.

The LDC's executive management team consists of the following positions that are overseen directly by the CEO:

- Executive Vice-President and Chief Financial Officer, who is also an executive member of THC and of TH Energy;
- Executive Vice-President, Planning and Chief Engineering and Modernization Officer;
- Executive Vice-President and Chief Operating Officer;
- Executive Vice-President, Customer Care and Chief Information Officer;
- Executive Vice-President and Chief Human Resources, Environment and Safety Officer; and

- Executive Vice-President, External Affairs, Corporate Development and Chief Legal Officer, who is also an executive officer of THC and of TH Energy.

2. CORPORATE GOVERNANCE

2.1 Securities Law Requirements

THC is a reporting issuer in each province of Canada and issues debentures pursuant to a short form base shelf prospectus (dated July 28, 2023). For purposes of Canadian securities regulations, THC is a "venture issuer" (i.e. a reporting issuer that does not have any of its securities listed or quoted on the TSX or other marketplace specified under the Canadian Securities Administrators' National Instrument 51-102 – *Continuous Disclosure Obligations*) and must comply with certain corporate governance and public disclosure requirements under applicable securities legislation. These requirements make the Company's operations, finances, and governance practices, on a consolidated basis, subject to scrutiny from the Ontario Securities Commission ("OSC"), the investor marketplace, and the broader public in a way not applicable to other privately-owned companies.

THC has filed an Annual Information Form ("AIF") in respect of each of the financial years ended December 31, 2004 through December 31, 2022, in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations*. THC's AIF discloses material information about THC and its business to the public, including information about operations, prospects, risks, and other factors that impact the business of the Company as a whole. A copy of THC's 2022 AIF is filed at Exhibit 1C, Tab 3, Schedule 5.

In addition, to comply with National Instrument 58-101 – *Disclosure of Corporate Governance Practices*, THC provides extensive corporate governance disclosure in its AIF and

annual Management Discussion and Analysis ("MD&A"). Such disclosure includes, amongst others, details about the following:

1) How the Board of Directors facilitates its exercise of independent supervision over management, including the identity and independence of its directors, and whether its directors are directors of any other reporting issuers and their identity;
2) Board of Directors' written mandate or a description of how the board delineates its roles and responsibilities;
3) Written descriptions for the chair of the Board of Directors, the chair of each board committee and the CEO;
4) Board of Directors' orientation and continuing education;
5) The promotion of a culture of ethical business conduct, including adoption of a written code for the directors, officers and employees;
6) The process for nominating new directors;
7) The process of determining CEO and director compensation;
8) Standing committees and their functions;
9) How the Board of Directors assesses whether it is performing effectively; and
10) Director term limits and other mechanisms of board renewal.

THC also provides disclosure in its AIF on the make-up of the Board of Directors (including the percentage of female directors) and attendance of directors at the Board of Directors and Committee meetings. The enhanced level of disclosure, in particular with respect to governance practices, required under securities legislation increases the transparency of the Company's operations and affairs and facilitates effective monitoring of management by the Board and stakeholders.

As a financial oversight measure, and to comply with certification requirements in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings*, all of THC's interim consolidated financial statements (i.e. including LDC's financial results), interim MD&As, AIFs, annual financial statements, and annual MD&As are certified by the CEO and CFO. The CEO and CFO certify that the filings do not contain any misrepresentations and fairly present the financial condition, results of operations, and cash flows of THC as of the date of and for the periods presented in the filings. The certification process is one example of the Company's system of internal checks and balances that fosters a culture of accountability amongst senior management. THC and LDC also maintain a significant system of internal financial controls which are subject to internal and external audit to ensure that these certifications are accurate.

2.2 Shareholder Direction

As the sole shareholder of THC, the City has adopted a Shareholder Direction which establishes, amongst other things, the following objectives and fundamental principles that govern the operations of the Company:

1) To operate the Company on an efficient and commercially prudent basis;
2) To optimize the Shareholder's return on equity and operate the Company with a view to meeting the financial performance objectives of the Shareholder as set out in the Shareholder Direction;
3) To provide a reliable, effective and efficient electricity distribution system that supports the electricity demands of residents and businesses in the City;
4) To operate the Company in an environmentally responsible manner consistent with the City's energy, climate change and urban forestry objectives and, as appropriate, utilizing emerging green technologies;
5) To ensure that the business is managed in material compliance with all law; and

6) To engage in recruitment and procurement practices designed to attract employees and suppliers from the City's diverse community.

The Shareholder Direction recognizes the central role of the Board of Directors under law, and does not operate as a unanimous shareholder declaration under the Ontario's *Business Corporations Act* ("OBCA").[2] Though it reiterates the items for which shareholder approval is required under the OBCA as well as restricting some financial activities of THC, it emphasizes that the Board of Directors is responsible for determining and implementing the appropriate balance among the objectives and fundamental principles specified in the Shareholder Direction. Ultimately, the City requires THC to operate on a commercially prudent and profitable basis in compliance with law and expects the Board of Directors to provide stewardship and independently oversee management and operations in accordance with best corporate governance practices.

THC's economic relationship with the City is governed principally by a dividend policy (the "Dividend Policy"), contained within the Shareholder Direction. The Dividend Policy sets an expectation, but does not create a legal requirement, for the Board of Directors of THC to declare dividends. The LDC and THC Board of Directors keep a detailed record of the processes surrounding decisions relating to dividends paid by the respective corporation. In that regard, dividend checklists for each of the THC Board of Directors and the LDC Board of Directors have been developed (the "Dividend Checklists"). The Dividend Checklists specify that, before declaring a dividend, the directors must ensure that the applicable corporation meets statutory solvency and capital impairment tests.

[2] Business Corporations Act, RSO 1990, c B.16.

At all times, Directors are required to exercise their discretion honestly and in good faith with a view to the best interests of the relevant corporation (fiduciary duty) and exercise the care, diligence, and skill that a reasonably prudent person would exercise in comparable circumstances (duty of care). When considering the best interests of the relevant corporation, directors are may take into account the interests of various stakeholders, including shareholders, ratepayers, employees, and creditors. In the case of dividends paid by the LDC, regulated utilities are obligated to operate in a manner that balances the interests of the utility's shareholders against those of its ratepayers.

2.3 Board of Directors

THC's Board of Directors members are appointed by THC's sole shareholder, the City. No members of management sit on the THC Board. Of the eleven directors currently on the THC Board of Directors, three are Councillors of the City (including one director who is the Mayor of the City or a member of City Council whom the Mayor recommends as his or her designate and who is appointed by City Council) and are not considered independent because of their positions. Eight of the eleven directors are not elected officials or employees of the City, and have no direct or indirect material relationship with THC and are independent within the meaning of applicable Canadian securities law. The Chair of the THC Board is an independent citizen director. As at September 13, 2023, female directors constituted 54.5 percent (six of eleven) of the members of the THC Board of Directors.

No members of management sit on the LDC Board of Directors. Two of the six directors are independent, i.e. they are not elected officials or employees of the City or members of the Board of any affiliate of the LDC. Currently, four of the directors on the LDC Board of Directors are citizen directors who are also members of the Board of Directors of THC.

2.3.1 Nomination of Directors

Pursuant to the Shareholder Direction, the City appoints directors who collectively represent a range of expertise including:

1) Experience on a public utility commission or board of a major corporation or other commercial enterprise;
2) Experience or knowledge with respect to:
    a) Corporate finance;
    b) Corporate governance;
    c) Market development;
    d) Large system operation and management;
    e) Urban energy industries;
    f) Public policy issues and the law relating to the Company and the electricity industry;
    g) Environmental matters;
    h) Labour relations;
    i) Occupational health and safety issues;
3) Commercial sensitivity and acumen;
4) Independence of judgment;
5) Personal integrity; and
6) At least three directors with financial management expertise.

The Corporate Governance and Nominating Committee of the THC Board of Directors reviews a skills matrix for evaluation of all potential THC and LDC Board of Directors members. In the case of appointment of THC Directors, the matrix is provided to the City by the THC Board. The matrix's design reflects best practices for requirements for directors as recommended by the Institute of Corporate Directors.

THC appoints the LDC's Board of Directors from among the directors of THC and independent residents of Toronto who are not elected officials or employees of the City or any of its agencies or corporations. The Corporate Governance and Nominating Committee nominates independent candidates for appointment to the LDC Board of Directors for approval by the THC Board of Directors as required by the Affiliate Relationships Code, utilizing the board skills and competencies matrix developed by the Committee as well as expert external recruitment services. This ensures that the directors have a mix of competencies and skills necessary to enable LDC's Board of Directors to properly discharge their responsibilities. Pursuant to the LDC's Board of Directors Mandate, the LDC's Board of Directors is required to give due regard to the qualifications of the candidates including:

1) Experience on a public utility commission or board of a major corporation or other commercial enterprise and/or the completion of formal training in directorship / governance;
2) Experience in a regulated electricity utility sector at a senior management level;
3) Experience at an executive level in resource and performance management / compensation, including ability to appoint and evaluate the performance of the CEO and senior executives; oversee strategic human resource management, including workforce planning, compensation models, and labour relations; and oversee large scale organizational change;
4) Educational background, including university degrees and professional designations;
5) Experience or knowledge with respect to:
    a) Strategic planning, including ability to identify and critically assess strategic opportunities and threats to the organization;
    b) Risk management, including ability to assess key risks to the organization on an enterprise basis and monitor the risk management framework systems;

c) Corporate finance / accounting / audit / securities, including ability to analyze financial statements, assess financial viability, contribute to financial planning, oversee budgets, and oversee funding arrangements;
d) Corporate governance;
e) Market development, innovation and development of new strategic business lines;
f) Large system operation and management, including large-scale procurement and supply chain management;
g) Engineering and construction;
h) Urban energy industries;
i) Decarbonization and energy systems transition;
j) Public policy issues and laws relating to the Corporation and its subsidiary entities and the electricity industry;
k) Environmental matters, including experience in environmental management;
l) Occupational health and safety issues;
m) Information technology governance, including privacy, data management, digitization strategies and security;
n) Legal and regulatory compliance, including ability to monitor compliance of legal and regulatory requirements;
o) Stakeholder engagement / advocacy / communications, including ability to effectively engage and communicate to industry stakeholders and advocate on behalf of the organization; and
p) corporate governance;

6) The following interpersonal skills and attributes:
a) Leadership, including ability to make, and take responsibility for, decisions and take necessary actions in the best interest of the organization, set

appropriate Board and organizational culture and represent the organization favourably;

b) Personal integrity / ethics, including understanding and fulfilling the duties and responsibilities of a director, being transparent and declaring any activities or conduct that might be a potential conflict, and maintaining Board confidentiality;

c) Communications skills, including ability to listen constructively and appropriately debate others' viewpoints, develop and deliver cogent arguments, and communicate effectively with a broad range of stakeholders;

d) Constructive questioning, including preparedness to ask questions and challenge management and peer directors in a constructive and appropriate manner;

e) Critical and innovative thinking/decision making, including ability to critically analyze complex and detailed information, readily distill key issues, and develop innovative approaches and solutions to problems;

f) Influencing and negotiating, including ability to negotiate outcomes and influence others to agree with those outcomes and gain stakeholder support for the Board's decisions;

g) Crisis management, including ability to constructively manage crises, provide leadership around solutions and contribute to communications strategy with stakeholders;

h) Individual and team contribution, including ability to work as part of a team, and demonstrate the passion and time to make a genuine and active contribution to the Board and the organization;

i) Commercial sensitivity and acumen; and

j) Independence of judgement;

7) At least one director with financial management expertise.

2.3.2 Exercise of Independent Judgment

No members of management sit on the Boards of THC or LDC. The Board of Directors for each of THC and LDC has a number of practices and policies in place to facilitate its ability to act independently of senior management and to ensure that its behaviour and decision-making processes are objective, responsible, and effective.

- ***In Camera* Board Meetings:** Each of the Boards of Directors meets regularly in the absence of management to discuss the management of the Company. A portion of each Board and Board committee meeting is reserved for Directors to meet without management present.
- **Board of Directors Mandates:** Each the THC and LDC Board of Directors has adopted a written mandate providing clear direction on the appropriate expectations and standards to be met by Directors, including with respect to independence. For example, the mandates specifically require the Directors, in undertaking their responsibilities and overseeing and authorizing the activities of the Company, to consider the interests of its customers as well as considering and balancing the interests of such other stakeholders as appropriate in the circumstances.
- **Outside Advisors:** Under their respective mandates, each of the Board of Directors of THC and LDC is authorized to retain independent legal counsel and other outside advisors if it considers this appropriate. Each of the LDC and THC Boards also has unrestricted access to the officers of the Company and are authorized to invite officers and employees of the Company and others to attend or participate in its meetings and proceedings if it considers this appropriate.
- **Internal Audit Function***:* The internal audit department provides independent, objective assurance and consulting services designed to add value and improve the

Company's operations. The internal audit department's work is overseen by the Audit Committee of the Board of Directors of THC. To facilitate independence, the Director of Internal Audit and Compliance of LDC has unrestricted access to the President and Chief Executive Officer. Director of Internal Audit and Compliance of LDC has unrestricted access to, and ability to communicate and interact directly with, the Audit Committee, including in private meetings without management present. The Director of Internal Audit and Compliance of LDC meets independently with the members of the Audit Committee on a regular basis. The Director of Internal Audit and Compliance of LDC reports functionally to the Audit Committee and administratively (i.e. day-to-day operations) to the Chief Financial Officer.

- **Corporate Governance and Nominating Committee***:* The Corporate Governance and Nominating Committee facilitates the periodic assessment of the performance of the Board of Directors of THC and LDC and Board committees and reports the results of that assessment to the Boards.
- **Position Descriptions***:* A written position description has been developed for the Chair of each of the THC and LDC Boards which provides direction in the undertaking of these roles. In each case, the Chair is responsible for reporting to the Board, leading the directors and managing the day-to-day activities of the Board. The Chair of the Board of THC is also responsible for engaging in discussions with the Shareholder and its representatives as are necessary and desirable, maintaining an active and cooperative relationship with the affiliate Boards, the CEO and other senior management, acting as the principal interface between the Board and the CEO, and providing advice and counsel to the CEO and other senior management. The THC Board has also developed written position descriptions for the chair of each of the standing committees and the CEO.

2.3.3 Board of Directors Mandate

The Company have adopted written mandates for each of the Boards of THC, LDC and TH Energy, which are reviewed periodically and revised as required. The mandates set out the composition, responsibilities and authority of each of the Boards.

2.3.4 Orientation and Continuing Education

Upon joining the Board of Directors of THC and/or LDC, each new director is given an orientation session with a comprehensive set of materials designed to provide him/her with a summary of the key organizational, financial, regulatory, reporting, planning, and operational aspects of the Company. Orientation also engages Directors of THC and/or LDC with organizational representatives in these key areas and a key executive is appointed for ongoing responsibility with each Board and standing Committee. Directors have access to a variety of internal and external resources on topics related to THC's and LDC's businesses, as well as relating to the responsibilities of directors such as fiduciary obligations, issues of confidentiality and privilege, and public disclosure and whistleblowing requirements. Directors also have the opportunity to attend continuing education programs run by external or internal service providers such as the Institute of Corporate Directors and energy industry organizations.

2.3.5 Ethical Business Conduct

All employees, officers and directors of THC and LDC are required to comply with the principles set out in the written Code of Business Conduct and Whistleblower Procedure (the "Code"). The Code was implemented in 2004 and is periodically reviewed and re-approved by the Board of Directors of THC. The Code of Business Conduct is included in new directors' orientation materials and each director completes training connected therewith and signs an acknowledgement that he or she will comply with the Code.

2.3.6 Board Committees

THC's Board of Directors has established three standing committees to assist the THC and LDC Boards in fulfilling their responsibilities: the Audit Committee, the Corporate Governance and Nominating Committee, and the Human Resources and Environment Committee. The standing committees are each composed of at least three directors of THC.

Each committee has a written charter that establishes the committee's purpose, composition and responsibilities.

- **Audit Committee:** oversees the adequacy and effectiveness of financial reporting, accounting systems, internal financial control structures, and financial risk management systems. Among other things, the Audit Committee reviews THC's and LDC's quarterly and annual financial statements, reviews the audit plans of the external auditors, and oversees the internal audit of THC and LDC. The composition of the Audit Committee complies with the rules applicable to venture issuers as set out in National Instrument 52-110 – *Audit Committees*.
- **Corporate Governance and Nominating Committee:** advises the THC and LDC Boards of Directors with respect to matters relating to the corporate governance of the Company, including but not limited to Board and committee composition and mandates and facilitates the periodic assessment of the performance and effectiveness of the THC and LDC Boards and the standing Board committees. The Corporate Governance and Nominating Committee also nominates independent candidates for appointment to the LDC Board of Directors for approval by THC's Board of Directors. The Corporate Governance and Nominating Committee also reviews and approves all orientation and education materials and programs for new and current directors undertaken by management. The majority of the members of

the Corporate Governance and Nominating Committee are independent citizen directors who are not elected officials or employees of the City.

- **Human Resources and Environment Committee:** assists the THC and LDC Boards of Directors with the recruitment, assessment, and compensation of the CEO, oversees succession planning, reviews and approves the compensation of the executive officers, oversees executive compensation disclosure under applicable securities laws, and advises the Boards of Directors regarding the compensation structure, benefit plans and programs of the Company. The Human Resources and Environment Committee is also responsible for, among other things, reviewing and making recommendations with respect to the parameters of collective bargaining negotiations, the oversight of health and safety related functions, oversight of human resources related matters, and the oversight of environmental related matters and processes of the Company. The majority of members of the Human Resources and Environment Committee are independent citizen directors who are not elected officials or employees of the City.

FINANCIAL INFORMATION OVERVIEW

In accordance with section 2.1.8 of the OEB's Filing Requirements,[1] Exhibit 1C, Tab 3 provides the following financial information:

- Accounting standards used for general purpose financial statements and adoption date for those standards (Schedule 2);
- Toronto Hydro's audited financial statements for 2020, 2021, and 2022 (Schedule 3);
- Toronto Hydro Corporation's Management's Discussion & Analysis for 2022 (Schedule 4);
- Toronto Hydro Corporation's Annual Information Form for 2022 (Schedule 5);
- Public debt offering information (Schedule 6);
- Rating agency reports (Schedule 7);
- Existing accounting orders and departures from the Uniform System of Accounts ("USoA") (Schedule 8); and
- Toronto Hydro's Annual Report for 2022 (Schedule 9).

[1] Ontario Energy Board Filing Requirements for Electricity Distributor Rate Applications, Chapter 2 (December 15, 2022).

ACCOUNTING STANDARDS

Toronto Hydro adopted International Financial Reporting Standards ("IFRS") for financial reporting purposes in the year beginning on January 1, 2015, and the utility continues to apply these standards. The Audited Financial Statements provided in Exhibit 1C, Tab 3, Schedule 3 have been prepared in accordance with IFRS.

The OEB Accounting Procedures Handbook ("APH") directs distributors to use Modified IFRS ("MIFRS") for regulatory purposes. Toronto Hydro adopted MIFRS for regulatory purposes in the year beginning on January 1, 2015, and the utility continues to use MIFRS. This application represents Toronto Hydro's third rebasing application under MIFRS.

Toronto Hydro confirms that it has segregated the accounting of all its non-rate regulated business activities from rate regulated activities. Toronto Hydro has updated its capitalization policy since the last rebasing application, as discussed in Exhibit 2A, Tab 4, Schedule 1. The relevant changes simplify aspects of the policy, reflect updated accounting pronouncements, revise the frequency of reviews, and reflect updated titles of responsible persons.

In response to the OEB's direction in the 2020-2024 CIR Application,[1] Toronto Hydro engaged an independent expert to conduct a new depreciation study and assess the financial life estimates related to the Toronto Hydro distribution system assets. This study resulted in changes to the useful lives for certain assets. Please refer to Exhibit 2A, Tab 2, Schedule 1 and the appendices thereto for more information on these changes to depreciation and amortization practices and the study itself.

[1] EB-2018-0165, Decision and Order (December 19, 2019) at page 146.

1. Definition of Accounting Estimates [Amendments to IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors ["IAS 8"]]

In February 2021, the International Accounting Standards Board ("IASB") issued amendments to IAS 8 to introduce a definition of "accounting estimates" and include other amendments to help entities distinguish changes in accounting estimates from changes in accounting policies. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted. The amendments are to be applied prospectively.

Toronto Hydro applied the amendment effective January 1, 2023 on a prospective basis. This did not have an impact on its Consolidated Financial Statements or on the revenue requirement.

2. Disclosure of Accounting Policies [Amendments to IAS 1]

In February 2021, the IASB issued amendments to IAS 1 requiring an entity to disclose its material accounting policies, rather than its significant accounting policies. Additional amendments were made to explain how an entity can identify a material accounting policy. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted.

Toronto Hydro applied the amendment effective January 1, 2023 on a prospective basis. This did not have an impact on its Consolidated Financial Statements or on the revenue requirement.

3. Deferred Tax related to Assets and Liabilities arising from a Single Transaction [Amendments to IAS 12 Income Taxes ["IAS 12"]]

In May 2021, the IASB issued amendments to IAS 12. The amendments clarify how companies should account for deferred tax on certain transactions such as leases and decommissioning obligations. The amendments narrow the scope of the initial recognition exemption, so that it does not apply to transactions that give rise to equal and offsetting temporary differences. As a result, companies will need to recognize both a deferred tax asset and a deferred tax liability when accounting for such transactions. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted.

Toronto Hydro determined that there was no retrospective impact as the utility had interpreted the IAS 12 requirements as clarified in the amendments. Toronto Hydro applied the amendment effective January 1, 2023. This did not have an impact on its Consolidated Financial Statements or on the revenue requirement.

The IASB has issued a number of standards and amendments to existing standards that are not yet effective. Toronto Hydro determined that the following amendments could have an impact on the Corporation's consolidated financial statements when adopted.

4. Classification of Liabilities as Current or Non-current (Amendments to IAS 1)

In January 2020, the IASB issued amendments to IAS 1 relating to the classification of liabilities as current or non-current. Specifically, the amendments clarify one of the criteria in IAS 1 for classifying a liability as non-current, that is, the requirement for an entity to have the right to defer settlement of the liability for at least 12 months after the reporting period. This right may be subject to compliance with covenants. After reconsidering certain aspects

of the 2020 amendments, in October 2022, the IASB issued Non-current Liabilities with Covenants (Amendments to IAS 1), reconfirming that only covenants with which a company must comply on or before the reporting date affect the classification of a liability as current or non-current. The amendments are effective for annual reporting periods beginning on or after January 1, 2024, with early adoption permitted. The amendments are to be applied retrospectively.

The Corporation anticipates that the adoption of these accounting pronouncements on January 1, 2024 will not have a material impact on the Corporation's consolidated financial statements or on the revenue requirement.

AUDITED FINANCIAL STATEMENTS

In accordance with s. 2.1.8 of the OEB's Filing Requirements,[1] this schedule provides Toronto Hydro-Electric System Limited's Audited Financial Statements, as follows:

- Appendix A: 2020 Audited Financial Statements
- Appendix B: 2021 Audited Financial Statements
- Appendix C: 2022 Audited Financial Statements

[1] Ontario Energy Board, Filing Requirements for Electricity Distributor Rate Applications, Chapter 2 (December 15, 2022).

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2020 and 2019

KPMG LLP
Bay Adelaide Centre
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Toronto, ON M5H 2S5
Canada
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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Toronto Hydro-Electric System Limited

Opinion

We have audited the accompanying financial statements of Toronto Hydro-Electric System Limited (the Entity), which comprise:

- the balance sheet as at December 31, 2020
- the statement of income for the year then ended
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended

and notes to the financial statements, including a summary of significant accounting policies (Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2020, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Financial Statements" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity.
KPMG Canada provides services to KPMG LLP.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards (IFRS), and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.
- The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
Toronto, Canada
March 3, 2021

BALANCE SHEETS

[in millions of Canadian dollars]

As at December 31	Note	2020 $	2019 $
ASSETS			
Current			
Cash and cash equivalents		**142.0**	75.4
Accounts receivable and unbilled revenue	*4, 14[b]*	**464.7**	538.1
Income tax receivable		**11.7**	0.9
Materials and supplies		**9.8**	7.8
Other assets	*5*	**16.5**	14.0
Total current assets		**644.7**	636.2
Property, plant and equipment	*6*	**4,987.5**	4,654.5
Intangible assets	*7*	**343.1**	339.7
Other assets	*5*	**8.2**	9.4
Total assets		**5,983.5**	5,639.8
Regulatory balances	*8*	**170.4**	165.0
Total assets and regulatory balances		**6,153.9**	5,804.8
LIABILITIES AND EQUITY			
Current			
Accounts payable and accrued liabilities	*9*	**401.5**	504.0
Customer deposits		**44.9**	49.1
Deferred revenue	*10*	**17.8**	13.2
Deferred conservation credit	*3[c]*	**16.0**	9.5
Notes payable to related party	*11, 22*	**359.8**	60.0
Total current liabilities		**840.0**	635.8
Notes payable to related party	*11, 22*	**2,083.6**	2,183.9
Customer deposits		**18.7**	18.9
Deferred revenue	*10*	**537.9**	397.9
Post-employment benefits	*12*	**332.7**	334.9
Deferred tax liabilities	*20*	**47.1**	23.1
Other liabilities		**3.4**	0.5
Total liabilities		**3,863.4**	3,595.0
Equity			
Share capital	*16*	**556.3**	556.3
Retained earnings		**1,538.0**	1,422.5
Contributed surplus		**12.8**	12.8
Total equity		**2,107.1**	1,991.6
Total liabilities and equity		**5,970.5**	5,586.6
Regulatory balances	*8*	**183.4**	218.2
Total liabilities, equity and regulatory balances		**6,153.9**	5,804.8

Commitments, contingencies and subsequent events *2, 23, 24*

See accompanying notes to the financial statements.

STATEMENTS OF INCOME

[in millions of Canadian dollars]

Year ended December 31	Note	2020 $	2019 $
Revenues			
Energy sales	*17*	**3,142.5**	2,779.7
Distribution revenue	*17*	**694.4**	799.2
Other	*17*	**79.8**	79.4
		3,916.7	3,658.3
Expenses			
Energy purchases		**3,150.5**	2,779.6
Operating expenses	*18*	**313.9**	295.7
Depreciation and amortization	*6, 7*	**271.2**	252.1
		3,735.6	3,327.4
Finance costs	*19*	**(80.4)**	(82.4)
Gain on disposals of property, plant and equipment		**-**	2.2
Income before income taxes		**100.7**	250.7
Income tax expense	*20*	**(28.5)**	(66.7)
Net income		**72.2**	184.0
Net movements in regulatory balances	*8*	**18.8**	(62.4)
Net movements in regulatory balances arising from deferred taxes	*8*	**25.2**	33.4
Net income after net movements in regulatory balances		**116.2**	155.0

STATEMENTS OF COMPREHENSIVE INCOME

[in millions of Canadian dollars]

Year ended December 31	Note	2020 $	2019 $
Net income after net movements in regulatory balances		**116.2**	155.0
Other comprehensive income			
Items that will not be reclassified to income or loss			
Remeasurements of post-employment benefits, net of tax [2020 - ($1.3), 2019 - $10.1]	*12*	**3.8**	(28.1)
Net movements in regulatory balances related to OCI, net of tax [2020 - ($1.3), 2019 - $10.1]	*8, 12*	**(3.8)**	28.1
Other comprehensive income, net of tax		**-**	-
Total comprehensive income		**116.2**	155.0

See accompanying notes to the financial statements.

STATEMENTS OF CHANGES IN EQUITY

[in millions of Canadian dollars]

Year ended December 31	Note	2020 $	2019 $
Share capital	*16*	**556.3**	556.3
Retained earnings, beginning of year		**1,422.5**	1,267.5
Net income after net movements in regulatory balances		**116.2**	155.0
Dividends	*16, 22*	**(0.7)**	-
Retained earnings, end of year		**1,538.0**	1,422.5
Contributed surplus		**12.8**	12.8
Total equity		**2,107.1**	1,991.6

See accompanying notes to the financial statements.

STATEMENTS OF CASH FLOWS

[in millions of Canadian dollars]

Year ended December 31	Note	2020 $	2019 $
OPERATING ACTIVITIES			
Net income after net movements in regulatory balances		**116.2**	155.0
Net movements in regulatory balances	*8*	**(18.8)**	62.4
Net movements in regulatory balances arising from deferred taxes	*8*	**(25.2)**	(33.4)
Adjustments			
Depreciation and amortization	*6, 7*	**271.2**	252.1
Amortization of deferred revenue	*10*	**(8.2)**	(5.9)
Finance costs		**80.4**	82.4
Income tax expense		**28.5**	66.7
Post-employment benefits		**2.9**	20.8
Gain on disposals of property, plant and equipment		**-**	(2.2)
Other		**0.3**	0.9
Capital contributions received	*10*	**151.7**	127.8
Net change in other non-current assets and liabilities		**0.8**	(5.6)
Decrease in customer deposits		**(4.4)**	(11.8)
Changes in non-cash operating working capital balances	*21*	**46.0**	(83.0)
Income tax paid		**(15.0)**	(36.2)
Net cash provided by operating activities		**626.4**	590.0
INVESTING ACTIVITIES			
Purchase of property, plant and equipment	*21*	**(633.5)**	(509.5)
Purchase of intangible assets	*21*	**(40.8)**	(53.0)
Proceeds on disposals of property, plant and equipment		**0.5**	2.3
Net cash used in investing activities		**(673.8)**	(560.2)
FINANCING ACTIVITIES			
Issuance of notes payable to related party	*11*	**198.6**	397.5
Repayment of notes payable to related party	*11*	**-**	(245.1)
Repayment of lease liability		**-**	(0.2)
Dividends paid	*16*	**(0.7)**	-
Interest received		**0.7**	1.0
Interest paid		**(84.6)**	(86.1)
Net cash provided by financing activities		**114.0**	67.1
Net change in cash and cash equivalents during the year		**66.6**	96.9
Cash and cash equivalents (bank indebtedness), beginning of year		**75.4**	(21.5)
Cash and cash equivalents, end of year		**142.0**	75.4

See accompanying notes to the financial statements.

1. NATURE OF BUSINESS

Toronto Hydro-Electric System Limited was incorporated on June 23, 1999 under the *Business Corporations Act* (Ontario) in accordance with the Electricity Act. LDC is wholly-owned by the Corporation and is domiciled in Canada, with its registered office located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

LDC distributes electricity to customers located in the city of Toronto and is subject to rate regulation.

2. BASIS OF PRESENTATION

LDC's audited financial statements for the years ended December 31, 2020 and 2019 have been prepared in accordance with IFRS as issued by the IASB.

The financial statements are presented in Canadian dollars, LDC's functional currency, and have been prepared on the historical cost basis, except for post-employment benefits which are recorded at actuarial value.

LDC has evaluated the events and transactions occurring after the balance sheet date through March 3, 2021 when LDC's financial statements were authorized for issuance by LDC's Board of Directors, and identified the events and transactions which required recognition in the LDC's financial statements and/or disclosure in the notes to the LDC's financial statements *[note 3[a]]*.

The summary of significant accounting policies has been disclosed in note 25.

3. REGULATION

The OEB has regulatory oversight of electricity matters in Ontario. The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to approve the amounts paid to non-contracted generators, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

- *Commodity Charge* – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO back to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- *Retail Transmission Rate* – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are a pass-through to operators of transmission facilities.

- *WMS Charge* – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are a pass-through to the IESO.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable (usage-based) components, based on a forecast of LDC's customers and load.

a) COVID-19 Pandemic Considerations

On March 11, 2020, the World Health Organization declared that the COVID-19 outbreak was a global pandemic. On March 17, 2020, the Ontario Government declared a State of Emergency pursuant to the *Emergency Management and Civil Protection Act*. The Ontario Government renewed the declaration, as required by the legislation, until July 24, 2020. During the State of Emergency, the Ontario Government issued emergency orders under the legislation and extended them as required by the legislation. On July 24, 2020, the *Reopening Ontario (A Flexible Response to COVID-19) Act, 2020* came into effect, bringing the declared State of Emergency to an end. The *Reopening Ontario Act* also enabled the Ontario Government to extend, amend, and revoke the remaining emergency orders in order to facilitate a flexible response to the ongoing COVID-19 risks.

On March 19, 2020, the OEB extended the ban on disconnecting residential customers to July 31, 2020, in light of the COVID-19 pandemic. For the same reason, at the same time, the OEB also banned the disconnection of other low volume customers (as defined in the OEB Act) prior to July 31, 2020. In addition, LDC extended its ban on disconnecting residential and low volume customers until the transition back into the OEB's annual recurring winter disconnection ban on November 15, 2020 *[note 14[b]]*.

On March 24, 2020, the Ontario Government issued an emergency order setting TOU rates for on-peak, mid-peak, and off-peak at 10.1 cents per kWh, which prior to the emergency order was the TOU off-peak rate. That emergency order was effective through May 7, 2020. On May 6, 2020, the Ontario Government issued an emergency order extending those TOU rates through May 31, 2020. On May 30, 2020, the Ontario Government announced the COVID-19 Recovery Rate, setting a fixed TOU electricity price at 12.8 cents per kWh, 24 hours a day, seven days a week, effective June 1, 2020 until October 31, 2020. On October 13, 2020, the OEB announced new TOU rates for on-peak, mid-peak, and off-peak, that once again vary according to when electricity is used, effective November 1, 2020. There was no impact to net income to LDC.

On March 25, 2020, the OEB established a deferral account for regulatory balances to record the costs of changes to billing systems resulting from the Ontario Government's TOU emergency order, other incremental costs and lost revenues associated with the COVID-19 pandemic. On May 14, 2020, the OEB launched a consultation process to inform its decision-making with respect to how the account will operate, including eligibility requirements, and the process and timing for the disposition. On December 16, 2020, OEB staff issued a proposal with respect to the deferral account and related consultation *[note 8]*.

On August 20, 2020, the Ontario Government amended O. Reg. 95/05 *Classes of Consumers and Determination of Rates*. Accordingly, customers on the RPP have the choice to pay TOU rates or tiered rates, effective November 1, 2020. By default, RPP customers will pay TOU rates. RPP customers who choose to pay tiered rates will pay a lower rate for consumption below a monthly threshold, and a higher rate for consumption above that threshold. The tiered rates and the threshold are set by the OEB twice per year, at the same time as the OEB sets TOU rates. There was no impact to net income to LDC.

On December 15, 2020, the OEB announced new RPP TOU and tiered rates to reflect a decrease in supply cost resulting from the Ontario Government's decision to remove certain renewable generation costs from the global adjustment and funding them directly through the tax base. The reduction was accompanied by a corresponding reduction to the Ontario Electricity Rebate. There was no net income impact to LDC.

On December 22, 2020, the Ontario Government amended O. Reg. 95/05 *Classes of Consumers and Determination of Rates*, setting both the TOU rates for on-peak, mid-peak, and off-peak and tiered rates at the TOU off-peak rate of 8.5 cents per kWh. That regulatory amendment was effective through January 28, 2021, and most recently extended until February 22, 2021. On February 23, 2021, residential and small business customers resumed paying TOU and tiered pricing under the RPP at prices that were set by the OEB on December 15, 2020. There was no net income impact to LDC.

b) Electricity Distribution Rates

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and custom index adjustments similar to IRM. A cost of service review uses a future test-year to establish rates, and provides for revenues required to recover the forecasted costs of providing the regulated service, and a fair and reasonable return on rate base. Custom index adjustments are typically used for one or more years following a cost of service review and provide for adjustments to rates based on an inflationary factor net of a productivity factor and an efficiency factor as determined relative to other electricity distributors.

On July 31, 2014, LDC filed its first CIR application. The CIR mechanism is an OEB ratemaking methodology that utilizes a cost of service approach in the first year and a custom index approach in the subsequent years, for a given period. On December 29, 2015, the OEB issued a Decision approving the CIR application, and on March 1, 2016 issued a Final Rate Order ["2015-2019 CIR decision and rate order"] which began the process of LDC receiving revenue to fund its 2015-2019 investment plan and operations. Pursuant to the Decision, for each subsequent year during that period, LDC was required to file rate applications to finalize annual distribution rates on a custom index basis.

On August 31, 2018, LDC filed its 2019 rate application seeking OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2019 and ending on December 31, 2019. On December 13, 2018, the OEB issued a Decision and Rate Order approving LDC's 2019 rates and providing for other deferral and variance account dispositions. This was the final annual rate application to finalize distribution rates in the 2015-2019 period.

On December 19, 2019, the OEB issued its 2020-2024 CIR Decision and on February 20, 2020, the OEB issued its CIR Final Rate Order, both in relation to the rate application filed on August 15, 2018 ["2020-2024 CIR decision and rate order"]. The 2020-2024 CIR decision and rate order approved a revenue requirement of $750.2 million for 2020, and rates calculated on that basis. The rates for 2020 were implemented on March 1, 2020, with an effective date of January 1, 2020. The financial considerations of the OEB's 2020-2024 CIR decision and rate order are reflected in the financial statements including disclosure of approved disposition for a number of requested rate riders *[note 8]*.

c) CDM Activities

On March 21, 2019, the Government of Ontario issued ministerial directives to the IESO related to the delivery of CDM programs. Previously, LDC and other distributors delivered the CDM programs; under the new directives, the IESO became responsible for delivering the CDM programs.

Under its ECA with the IESO, LDC had a joint CDM plan with Oakville Hydro Electricity Distribution Inc. for the delivery of CDM programs over the 2015-2020 period. As part of implementing its new mandate, the IESO terminated the ECA effective June 20, 2019. LDC was required to cease marketing and business development for all CDM programs immediately and make commercially reasonable efforts to wind down the delivery of programs. Under the ECA, LDC was entitled to reimbursement from the IESO of its eligible expenses and administrative costs relating to the wind-down of its role in the CDM programs. Participant agreements with customers for many of the CDM programs that were in effect before April 1, 2019 remained in effect notwithstanding the termination of the ECA and LDC remains responsible for its obligations under such agreements. On July 22, 2020, the Government of Ontario issued ministerial directives to the IESO directing it to extend the deadline by which participants are to complete the projects from December 31, 2020 to June 30, 2021. Amounts received from the IESO for the funding of the projects under the participant agreements, but not yet spent, are presented on the balance sheets under current liabilities as deferred conservation credit.

4. ACCOUNTS RECEIVABLE AND UNBILLED REVENUE

Accounts receivable and unbilled revenue consist of the following:

	2020 $	2019 $
Unbilled revenue	**228.0**	267.7
Trade receivables	**183.0**	215.6
Due from related parties *[note 22]*	**39.1**	44.8
Other	**14.6**	10.0
	464.7	538.1

5. OTHER ASSETS

Other assets consist of the following:

	2020 $	2019 $
Prepaid expenses	**15.2**	12.8
Deferred financing costs	**1.2**	1.5
Other	**8.3**	9.1
Total other assets	**24.7**	23.4
Less: Current portion of other assets relating to:		
Prepaid expenses	**15.2**	12.8
Deferred financing costs	**0.4**	0.4
Other	**0.9**	0.8
Current portion of other assets	**16.5**	14.0
Non-current portion of other assets	**8.2**	9.4

6. PROPERTY, PLANT AND EQUIPMENT

PP&E consist of the following:

	Distribution assets	Land and buildings	Equipment and other	Construction in progress	Total
	$	$	$	$	$
Cost					
Balance as at January 1, 2019	4,080.8	409.6	226.1	422.2	5,138.7
Additions/(Transfers), net	414.6	19.1	35.1	57.2	526.0
Disposals and retirements	(30.3)	(1.8)	(13.0)	—	(45.1)
Balance as at December 31, 2019	4,465.1	426.9	248.2	479.4	5,619.6
Additions/(Transfers), net	**486.0**	**13.5**	**38.4**	**31.0**	**568.9**
Disposals and retirements	**(31.2)**	**(0.6)**	**(1.2)**	**—**	**(33.0)**
Balance as at December 31, 2020	**4,919.9**	**439.8**	**285.4**	**510.4**	**6,155.5**
Accumulated depreciation					
Balance as at January 1, 2019	618.7	51.0	119.1	—	788.8
Depreciation	156.4	15.3	25.1	—	196.8
Disposals and retirements	(7.0)	(0.5)	(13.0)	—	(20.5)
Balance as at December 31, 2019	768.1	65.8	131.2	—	965.1
Depreciation	**169.9**	**15.6**	**26.9**	**—**	**212.4**
Disposals and retirements	**(8.1)**	**(0.2)**	**(1.2)**	**—**	**(9.5)**
Balance as at December 31, 2020	**929.9**	**81.2**	**156.9**	**—**	**1,168.0**
Carrying amount					
Balance as at December 31, 2019	3,697.0	361.1	117.0	479.4	4,654.5
Balance as at December 31, 2020	**3,990.0**	**358.6**	**128.5**	**510.4**	**4,987.5**

As at December 31, 2020, "Land and buildings" included right-of-use assets related to leases of land and office space with cost of $7.6 million [December 31, 2019 - $7.6 million], accumulated depreciation of $0.8 million [December 31, 2019 - $0.6 million], and carrying amount of $6.8 million [December 31, 2019 - $7.0 million]. For the year ended December 31, 2020, LDC recorded depreciation expense of $0.2 million [2019 - $0.3 million] related to the right-of-use assets.

For the year ended December 31, 2020, borrowing costs in the amount of $2.9 million [2019 - $3.2 million] were capitalized to PP&E with an average interest rate of 3.19% [2019 - 3.57%].

"Construction in progress" additions are net of transfers to the other PP&E categories.

7. INTANGIBLE ASSETS

Intangible assets consist of the following:

	Computer software	Contributions	Software in development	Contributions for work in progress	Total
	$	$	$	$	$
Cost					
Balance as at January 1, 2019	207.8	164.1	15.0	39.5	426.4
Additions/(Transfers), net	27.8	25.2	6.7	6.4	66.1
Other	—	(12.7)	—	—	(12.7)
Balance as at December 31, 2019	235.6	176.6	21.7	45.9	479.8
Additions/(Transfers), net	**29.1**	**(0.3)**	**(1.1)**	**12.1**	**39.8**
Balance as at December 31, 2020	**264.7**	**176.3**	**20.6**	**58.0**	**519.6**
Accumulated amortization					
Balance as at January 1, 2019	96.8	10.7	—	—	107.5
Amortization	25.8	6.8	—	—	32.6
Balance as at December 31, 2019	122.6	17.5	—	—	140.1
Amortization	**29.3**	**7.1**	**—**	**—**	**36.4**
Balance as at December 31, 2020	**151.9**	**24.6**	**—**	**—**	**176.5**
Carrying amount					
Balance as at December 31, 2019	113.0	159.1	21.7	45.9	339.7
Balance as at December 31, 2020	**112.8**	**151.7**	**20.6**	**58.0**	**343.1**

For the year ended December 31, 2020, borrowing costs in the amount of $1.7 million [2019 - $0.5 million] were capitalized to intangible assets with an average interest rate of 3.19% [2019 - 3.57%].

"Software in development" and "Contributions for work in progress" additions are net of transfers to the other intangible asset categories.

"Contributions" represent payments made to HONI for dedicated infrastructure in order to receive connections to transmission facilities. The remaining amortization period for computer software ranges from less than one year to eight years. The remaining amortization period for contributions ranges from eight to 24 years.

8. REGULATORY BALANCES

Debit balances consist of the following:

	January 1, 2020	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2020	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
OPEB net actuarial loss	**86.3**	**(5.1)**	**(5.7)**	**—**	**75.5**	note 8[a]	—
Deferred taxes	**21.4**	**26.5**	**—**	**—**	**47.9**	note 8[b]	—
LRAM	**35.9**	**(1.8)**	**(0.9)**	**—**	**33.2**	note 8[c]	(1)
Settlement variances	**—**	**8.2**	**4.1**	**(8.9)**	**3.4**	note 8[d]	(1)
OPEB cash versus accrual	**7.1**	**—**	**(6.2)**	**—**	**0.9**	note 8[e]	—
Foregone revenue	**2.8**	**—**	**—**	**(2.8)**	**—**	note 8[f]	—
IFRS transitional adjustments	**—**	**—**	**0.8**	**(0.8)**	**—**	note 8[g]	—
Other	**11.5**	**1.2**	**(3.2)**	**—**	**9.5**	24	(1)
	165.0	**29.0**	**(11.1)**	**(12.5)**	**170.4**		

	January 1, 2019	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2019	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
OPEB net actuarial loss	48.1	38.2	—	—	86.3	note 8[a]	—
LRAM	29.0	18.8	(11.9)	—	35.9	note 8[c]	(1)
Deferred taxes	—	23.3	—	(1.9)	21.4	note 8[b]	—
OPEB cash versus accrual	5.4	1.7	—	—	7.1	note 8[e]	—
Foregone revenue	23.2	—	(20.4)	—	2.8	note 8[f]	—
IFRS transitional adjustments	7.0	—	—	(7.0)	—	note 8[g]	—
Stranded meters	3.6	—	—	(3.6)	—	note 8[n]	(1)
Named properties	1.6	—	(1.5)	—	0.1	note 8[o]	—
Capital contributions	0.5	—	(0.5)	—	—	note 8[p]	—
Other	7.5	3.9	—	—	11.4	34	(1)
	125.9	85.9	(34.3)	(12.5)	165.0		

(1) Carrying charges were added to the regulatory balance in accordance with the OEB's direction, at a rate of 2.18% for January 1, 2020 to June 30, 2020 and 0.57% for July 1, 2020 to December 31, 2020 [January 1, 2019 to March 31, 2019 - 2.45%, April 1, 2019 to December 31, 2019 - 2.18%].

Credit balances consist of the following:

	January 1, 2020	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2020	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Capital-related revenue requirement	**77.1**	**0.8**	**—**	**—**	**77.9**	note 8[h]	(1)
Gain on disposal	**61.8**	**0.8**	**(25.1)**	**—**	**37.5**	note 8[i]	(1)
Derecognition	**32.8**	**0.4**	**—**	**—**	**33.2**	note 8[j]	(1)
Development charges	**10.9**	**3.9**	**—**	**—**	**14.8**	note 8[k]	(1)
Tax-related variances	**11.4**	**(0.2)**	**—**	**—**	**11.2**	note 8[l]	(1)
Settlement variances	**8.9**	**—**	**—**	**(8.9)**	**—**	note 8[d]	(1)
Accounts receivable credits	**3.4**	**0.1**	**—**	**—**	**3.5**	note 8[m]	(1)
Foregone revenue	**—**	**4.0**	**(0.3)**	**(2.8)**	**0.9**	note 8[f]	—
IFRS transitional adjustments	**0.8**	**—**	**—**	**(0.8)**	**—**	note 8[g]	—
Other	**11.1**	**2.3**	**(9.0)**	**—**	**4.4**	12 - 48	(1)
	218.2	**12.1**	**(34.4)**	**(12.5)**	**183.4**		

	January 1, 2019	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2019	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Capital-related revenue requirement	56.5	20.6	—	—	77.1	note 8[h]	(1)
Gain on disposal	61.8	1.3	(1.3)	—	61.8	note 8[i]	(1)
Derecognition	21.8	11.0	—	—	32.8	note 8[j]	(1)
Tax-related variances	1.1	10.9	(0.6)	—	11.4	note 8[l]	(1)
Development charges	7.9	3.0	—	—	10.9	note 8[k]	(1)
Settlement variances	19.2	(0.4)	(9.9)	—	8.9	note 8[d]	(1)
Accounts receivable credits	—	3.4	—	—	3.4	note 8[m]	(1)
IFRS transitional adjustments	—	—	7.8	(7.0)	0.8	note 8[g]	—
Stranded meters	—	—	4.0	(3.6)	0.4	note 8[n]	(1)
Deferred taxes	1.9	—	—	(1.9)	—	note 8[b]	—
Smart meters	0.3	—	(0.3)	—	—	—	—
Other	7.7	3.0	—	—	10.7	1 - 48	(1)
	178.2	52.8	(0.3)	(12.5)	218.2		

(1) Carrying charges were added to the regulatory balance in accordance with the OEB's direction, at a rate of 2.18% for January 1, 2020 to June 30, 2020 and 0.57% for July 1, 2020 to December 31, 2020 [January 1, 2019 to March 31, 2019 - 2.45%, April 1, 2019 to December 31, 2019 - 2.18%].

The "Balances arising in the period" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery/reversal" column consists of amounts disposed through OEB-approved rate riders. The "Other movements" column consists of impairment and reclassification between the regulatory debit and credit

balances. In addition, the "Other movements" column includes reclassification of regulatory deferral accounts considered to be insignificant into the "Other" categories. There was no impairment recorded for the year ended December 31, 2020.

Reconciliation between the net movements in regulatory balances shown in the regulatory debit and credit balances tables and the net movements presented on the statements of income and the statements of comprehensive income is as follows:

	2020 $	2019 $
Total movements per regulatory debit balances table	**5.4**	39.1
Total movements per regulatory credit balances table	**34.8**	(40.0)
Total net movements	**40.2**	(0.9)
Net movements per financial statements:		
Net movements in regulatory balances	**18.8**	(62.4)
Net movements in regulatory balances arising from deferred taxes	**25.2**	33.4
Net movements in regulatory balances related to OCI, net of tax	**(3.8)**	28.1
Total net movements per financial statements	**40.2**	(0.9)

Regulatory developments in Ontario's electricity industry and other governmental policy changes may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. There is a risk that the OEB may disallow the recovery of a portion of certain costs incurred in the current period through future rates or disagree with the proposed recovery period. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, any impairment will be recorded in the period when the assessment is made.

The regulatory balances of LDC consist of the following:

a) OPEB net actuarial loss

This regulatory balance accumulates the actuarial gains and losses arising from changes in actuarial assumptions and experience adjustments recognized in OCI. The balance arising during the year ended December 31, 2020 of $5.1 million is related to the actuarial gain recorded for the year [2019 - $38.2 million actuarial loss] *[note 12[a]]*. The net position is an actuarial loss recoverable in future rates.

In the 2020-2024 CIR decision and rate order, the OEB approved partial recovery of the balance amounting to $6.4 million over a 10-month period commencing on March 1, 2020.

b) Deferred taxes

This regulatory balance relates to both deferred tax amounts reclassified under IFRS 14 *Regulatory Deferral Accounts* ["IFRS 14"] *[note 25[a]]* and the expected future electricity distribution rate impact to customers arising from timing differences in the recognition of deferred tax assets and liabilities. LDC does not apply for disposition of the balance since it is reversed through timing differences in the recognition of deferred tax assets and liabilities.

The amounts reclassified under IFRS 14 include the deferred tax asset related to regulatory balances of $8.3 million (debits) as at December 31, 2020 [December 31, 2019 - $6.1 million (debits)], and the recognition of a regulatory balance in respect of additional temporary differences for which a deferred tax amount was recognized of $14.3 million (credits) as at December 31, 2020 [December 31, 2019 - $5.5 million (credits)].

The deferred tax amount related to the expected future impact to electricity distribution rates was $53.9 million (debits) as at December 31, 2020 [December 31, 2019 - $20.8 million (debits)].

c) Lost revenue adjustment mechanism

This regulatory balance relates to the difference between the level of CDM program activities included in LDC's load forecast used to set approved rates and the actual impact of CDM activities achieved. Approved variances for 2017 were recovered through OEB-approved rate riders over 12 months commencing on January 1, 2019.

As part of OEB's decision and rate order approving LDC's 2021 rates, OEB approved recovery of $33.1 million related to 2018 and 2019 variances over a 12-month period commencing January 1, 2021.

d) Settlement variances

This account includes the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by LDC. LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. Approved variances up to 2017, including carrying charges forecasted to the end of 2018, were disposed through OEB-approved rate riders over 12 months commencing on January 1, 2019.

In the 2020-2024 CIR decision and rate order, the OEB approved disposition of $7.5 million related to the 2018 settlement variances over a 22-month period commencing on March 1, 2020. As part of OEB's decision and rate order approving LDC's 2021 rates, OEB approved recovery of $25.3 million related to 2019 settlement variances over a 12-month period commencing January 1, 2021.

e) OPEB cash versus accrual

This regulatory balance relates to the difference between LDC's forecasted OPEB costs determined on an accrual basis and the cash payments made under the OPEB plans. In the 2015-2019 CIR decision and rate order, the OEB directed LDC to track the difference as a temporary arrangement, pending the OEB's conclusion on the sector-wide policy consultation it initiated on the regulatory treatment of pension and OPEB costs. On September 14, 2017, the OEB issued its final report on the consultation and established the use of the accrual accounting method as the default method on which to set rates for OPEB costs.

In the 2020-2024 CIR decision and rate order, the OEB approved recovery of the 2019 balance over a 10-month period commencing on March 1, 2020 and recovery of OPEB costs on an accrual basis.

f) Foregone revenue

This regulatory balance relates to the revenue that LDC would have recovered in 2015 and 2016 if new OEB-approved rates were implemented as of May 1, 2015 and January 1, 2016, respectively. In the 2015-2019 CIR decision and rate order, the OEB approved foregone revenue rate riders over 46 months commencing on March 1, 2016 for May 1, 2015 to December 31, 2015 based on approved 2015 rates and for January 1, 2016 to February 29, 2016 based on approved 2016 rates.

The 2020 balance arising of $4.0 million is revenue to be returned to customers, related to January and February 2020 as a result of implementing new OEB-approved rates on March 1, 2020. In the 2020-2024 CIR decision and rate order, the OEB approved the disposition of 2020 foregone revenue over a 22-month period commencing on March 1, 2020.

g) IFRS transitional adjustments

This regulatory balance relates to the differences arising from accounting policy changes for PP&E and intangible assets due to the transition from US GAAP to IFRS in 2014, primarily related to derecognition of certain assets and additional capitalized borrowing costs. In the 2015-2019 CIR decision and rate order, the OEB approved recovery of the forecasted balance over 46 months commencing on March 1, 2016.

In the 2020-2024 CIR decision and rate order, the OEB approved disposition of the 2019 balance for the difference between the forecasted and actual IFRS transitional adjustments over a 10-month period commencing on March 1, 2020.

h) Capital-related revenue requirement

This regulatory balance relates to the asymmetrical variance between the cumulative 2015 to 2019 capital-related revenue requirement included in rates and the actual capital-related revenue requirement over the same period. The cumulative 2015 to 2019 capital-related revenue requirement included in rates exceeded the actual capital-related revenue requirement over the same rate period. LDC applied for disposition of this account in order to return the balance to customers through a rate rider.

In the 2020-2024 CIR decision and rate order, the OEB approved disposition of the 2019 balance over a 24-month period commencing on January 1, 2023.

i) Gain on disposal

This regulatory balance consists of the net of amounts disposed through the OEB-approved rate riders offset by the related tax savings (credits) and the after-tax gain realized on three significant LDC properties (credits).

As part of the 2015-2019 CIR decision and rate order, LDC agreed to a rate rider that would pass the total forecasted net gains along with future tax savings on the first two properties back to customers, effective from March 1, 2016 to December 31, 2018. The gain on disposal of the two properties was realized by LDC in 2015 and 2018, respectively. In the second quarter of 2017, LDC realized a gain in connection with the disposal of the third property.

In the 2020-2024 CIR decision and rate order, the incremental balance related to the actual realized gain and tax savings that exceeded the approved rate riders in connection with the disposal of the first two LDC properties was approved for disposition over a 22-month period commencing on March 1, 2020. The OEB also approved disposition of the actual realized gain and tax savings in connection with the disposal of the third property over a 22-month period commencing on March 1, 2020.

j) Derecognition

This regulatory balance relates to the difference between the revenue requirement on derecognition of PP&E and intangible assets included in the OEB-approved rates and the actual amounts of derecognition.

In the 2020-2024 CIR decision and rate order, the OEB approved disposition of the 2019 balance over a 12-month period commencing on January 1, 2022.

k) Development charges

This regulatory balance relates to excess expansion deposits retained by LDC where the requested number of connections or electricity demand were not met by the connecting customer. Pursuant to the OEB's Distribution System Code, LDC may collect expansion deposits from specific customers to guarantee the payment of additional costs relating to expansion projects. During the customer connection horizon, LDC has an obligation to annually return the expansion deposit to the connecting customer in proportion to the actual connections or electricity demand that occurred in that year. If the number of connections or electricity demand requested by the customer do not

materialize by the end of the connection horizon, LDC retains the excess expansion deposit not otherwise returned to the connecting customer.

In the 2020-2024 CIR decision and rate order, the OEB approved disposition of the 2019 balance over a 48-month period commencing on January 1, 2021.

l) Tax-related variance accounts

The regulatory balance arose primarily from the revenue requirement impact of accelerated capital cost allowance deductions from the Accelerated Investment Incentive tax measure which received Royal Assent on June 21, 2019. In the 2020-2024 CIR decision and rate order, the OEB approved the disposition of the 2019 balance over a 24-month period commencing on January 1, 2023.

In addition, the balance includes a residual credit balance that arose from favourable income tax reassessments on certain prior year tax positions received, which differed from those assumed in previous applications for electricity distribution rates.

m) Accounts receivable credits

This regulatory account relates to closed customer accounts with unclaimed credit balances.

In the 2020-2024 CIR decision and rate order, the OEB approved disposition of the 2019 balance over a 48-month period commencing on January 1, 2021.

n) Stranded meters and smart meters

These regulatory balances relate to the provincial government's decision to install smart meters throughout Ontario.

In the 2015-2019 CIR decision and rate order, the OEB approved LDC's request for recovery of the forecasted net book value of the stranded meters as at December 31, 2014 over 46 months commencing on March 1, 2016.

The OEB ruling on smart meters permitted the recovery in principle of LDC's allowed cost of capital on smart meters since 2008, with a rate order issued to this effect. This allowed LDC to recover the incremental revenue requirement associated with these assets for the period during which they remained outside of rate base.

In the 2020-2024 CIR decision and rate order, the OEB approved disposition of the 2019 balance for the difference between the forecasted and actual net book value of stranded meters as at December 31, 2014 over a 48-month period commencing on January 1, 2021.

o) Named properties

As part of 2010 rates, LDC had forecasted net gains on certain properties which were planned for sale between 2007 and 2011. This regulatory balance relates to the excess of those forecasted net gains over the actual net gains realized upon the sale of the named properties. In the 2015-2019 CIR decision and rate order, the OEB approved disposition of this variance over 46 months commencing on March 1, 2016.

p) Capital contributions

This regulatory balance relates to the difference between amounts included in rates for HONI capital contributions and actual contributions made in 2010 and 2011. In the 2015-2019 CIR decision and rate order, the OEB approved disposition of this variance over 46 months commencing on March 1, 2016.

q) COVID-19 emergency

On March 25, 2020, the OEB established the COVID-19 Emergency Deferral Account in recognition that distributors will incur incremental costs and lost revenues resulting from the COVID-19 pandemic. The OEB accounting guidance specified that incremental bad debt expense can be included in COVID-19 Emergency Deferral Account. On May 14, 2020, the OEB launched a consultation process to inform its decision-making with respect to how the account will operate, including eligibility requirements, and the process and timing for the disposition. As at September 30, 2020 the balance recorded as a regulatory debit balance in the COVID-19 Emergency Deferral Account was $17.7 million and represented management's best estimate of the incremental bad debt expense as a result of the COVID-19 pandemic expected to be probable of recovery.

On December 16, 2020, OEB staff issued a proposal, which provided an update on the OEB's most recent orientation in the policy consultation. Based on this information, management believes there is high uncertainty in regards to the recoverability of costs and lost revenues related to government and OEB customer relief actions, and therefore a low probability of recovery. Consequently, the balance of $17.7 million that was previously deferred to the COVID-19 Emergency Deferral Account for incremental bad debt expense was reversed such that no amount was deferred as at December 31, 2020. LDC continues to track lost revenues related to lower commercial electricity consumption, direct relief provided to customers through reduction of late payment charges, incremental bad debt expense and costs directly related to the implementation of safety measures as a result of the COVID-19 pandemic but no amounts have been recorded in the COVID-19 Emergency Deferral Account as at December 31, 2020.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities consist of the following:

	2020 $	2019 $
Trade payables	**250.2**	306.4
Accrued liabilities	**104.9**	150.3
Due to related parties *[note 22]*	**45.0**	45.8
Other	**1.4**	1.5
	401.5	504.0

10. DEFERRED REVENUE

Deferred revenue consists of the following:

	2020 $	2019 $
Capital contributions, beginning of year	**410.0**	288.2
Capital contributions received	**151.7**	127.8
Amortization	**(8.2)**	(5.9)
Other	**(0.1)**	(0.1)
Capital contributions, end of year	**553.4**	410.0
Other deferred revenue, beginning of year	**1.1**	1.9
Other deferred revenue received	**15.6**	10.0
Revenue recognized	**(14.4)**	(10.8)
Other deferred revenue, end of year	**2.3**	1.1
Total deferred revenue	**555.7**	411.1
Less: Current portion of deferred revenue relating to:		
Capital contributions	**15.5**	12.1
Other deferred revenue	**2.3**	1.1
Current portion of deferred revenue	**17.8**	13.2
Non-current portion of deferred revenue	**537.9**	397.9

11. NOTES PAYABLE TO RELATED PARTY

Notes payable to related party consist of the following:

	2020 $	2019 $
Notes payable to related party:		
5.59% Long-term note payable to the Corporation due May 21, 2040	**200.0**	200.0
3.59% Long-term note payable to the Corporation due November 18, 2021	**300.0**	300.0
2.96% Long-term note payable to the Corporation due April 10, 2023	**250.0**	250.0
4.01% Long-term note payable to the Corporation due April 9, 2063	**200.0**	200.0
4.13% Long-term note payable to the Corporation due September 16, 2044	**200.0**	200.0
3.60% Long-term note payable to the Corporation due July 28, 2045	**200.0**	200.0
3.988% Long-term note payable to the Corporation due April 9, 2063	**45.0**	45.0
2.572% Long-term note payable to the Corporation due August 25, 2026	**200.0**	200.0
3.535% Long-term note payable to the Corporation due February 28, 2048	**200.0**	200.0
2.488% Long-term note payable to the Corporation due December 11, 2029	**200.0**	200.0
3.042% Long-term note payable to the Corporation due December 10, 2049	**200.0**	200.0
1.55% Long-term note payable to the Corporation due October 15, 2030	**200.0**	—
6.16% Demand note payable to the Corporation due on demand	**45.0**	45.0
3.32% Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	15.0
Total notes payable to related party	**2,455.0**	2,255.0
Less: Unamortized debt issuance costs	**11.6**	11.1
Current portion of notes payable to related party *[note 22]*	**359.8**	60.0
Long-term portion of notes payable to related party *[note 22]*	**2,083.6**	2,183.9

All notes payable to the Corporation are unsecured, rank equally and will be settled in cash.

On November 12, 2019, LDC issued two promissory notes to the Corporation. The principal amounts of the promissory notes are $200.0 million payable on December 11, 2029, which bears interest at a rate of 2.488% per annum, and $200.0 million payable on December 10, 2049, which bears interest at a rate of 3.042% per annum. Interest is calculated and payable semi-annually in arrears on June 11 and December 11, and June 10 and December 10 of each year, respectively for both promissory notes.

On October 15, 2020, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $200.0 million payable on October 15, 2030, which bears interest at a rate of 1.55% per annum. Interest is calculated and payable semi-annually in arrears on April 15 and October 15.

12. EMPLOYEE FUTURE BENEFITS

Multi-employer pension plan

LDC's eligible employees participate in a defined benefit pension plan through OMERS. As at December 31, 2020, the OMERS plan was 97.0% funded [December 31, 2019 - 97.0%]. OMERS has a strategy to return the plan to a fully funded position. LDC is not able to assess the implications, if any, of this strategy or of the withdrawal of other participating entities from the OMERS plan on its future contributions. For the year ended December 31, 2020, LDC's contributions were $17.6 million [2019 - $18.0 million], representing less than five percent of total contributions to the OMERS plan. LDC expects to contribute approximately $18.1 million to the OMERS plan in 2021.

Post-employment benefits

a) Benefit obligation

	2020 $	2019 $
Balance, beginning of year	**334.9**	275.9
Current service cost	**4.2**	3.0
Interest cost	**9.8**	10.2
Benefits paid	**(11.7)**	(10.6)
Past service cost [(1)]	**1.0**	11.2
Experience loss (gain) [(2)]	**(6.3)**	1.4
Actuarial gain arising from changes in demographic assumptions [(2)]	**(27.2)**	—
Actuarial loss arising from changes in financial assumptions [(2)] [(3)]	**28.0**	39.6
Transfer from related parties	**—**	4.2
Balance, end of year	**332.7**	334.9

[(1)] An arbitration process was ongoing prior to December 31, 2019 with respect to certain employees of LDC. As a result of the arbitrator's decision received on March 3, 2020, LDC recorded an estimated past service cost relating to the existence of a post-employment benefit obligation as at December 31, 2019. The plan amendment details were finalized in 2020 and were included as a component of the past service cost as at December 31, 2020. The related obligations will be supported by a letter of credit.
[(2)] Actuarial loss (gain) on accumulated sick leave credits of ($0.5) million [2019 - $2.8 million] is recognized in benefit cost *[note 12[c]]* and $0.1 million in transfer from related parties [2019 - $nil], and actuarial loss (gain) on medical, dental and life insurance benefits of ($5.1) million [2019 - $38.2 million] is recognized in OCI *[note 12[d]]*.
[(3)] Reflects the impact of change in discount rate *[note 12[e]]*.

b) Amounts recognized in regulatory balances

As at December 31, 2020, the amount recognized in regulatory balances related to accumulated net actuarial loss was $75.5 million [December 31, 2019 - $86.3 million] *[note 8[a]]*.

c) Benefit cost recognized

	2020 $	2019 $
Current service cost	**4.2**	3.0
Interest cost	**9.8**	10.2
Past service cost *[note 12[a]]*	**1.0**	11.2
Actuarial loss (gain) on other employee benefits *[note 12[a]]*	**(0.5)**	2.8
Benefit cost	**14.5**	27.2
Capitalized to PP&E and intangible assets	**6.4**	7.6
Charged to operating expenses	**8.1**	19.6

d) Amounts recognized in OCI

	2020 $	2019 $
Actuarial loss (gain) *[note 12[a]]*	**(5.1)**	38.2
Income tax expense (recovery) in OCI *[note 20]*	**1.3**	(10.1)
Remeasurements of post-employment benefits, net of tax	**(3.8)**	28.1
Net movements in regulatory balances related to OCI, net of tax	**3.8**	(28.1)
OCI, net of tax	**—**	—

e) Significant assumptions

	2020 %	2019 %
Discount rate used in the calculation of:		
Benefit obligation as at December 31	**2.50**	3.00
Assumed medical and dental cost trend rates as at December 31:		
Rate of increase in dental costs assumed for next year	**4.00**	4.00
Rate of increase in medical costs assumed for next year	**5.00**	5.00

f) Sensitivity analysis

Significant actuarial assumptions for benefit obligation measurement purposes are discount rate and assumed medical and dental cost trend rates. The weighted average duration of the benefit obligation as at December 31, 2020 was 17.0 [2019 - 17.3]. The sensitivity analysis below has been determined based on reasonably possible changes of the assumptions, in isolation of one another, occurring at the end of the reporting period. This analysis may not be representative of the actual change since it is unlikely that changes in the assumptions would occur in isolation of one another as some of the assumptions may be correlated.

Changes in key assumptions would have had the following effect on the benefit obligation:

	Change in assumption	2020 $	2019 $
Benefit obligation		**332.7**	334.9
Discount rate	1% ↑	**(49.9)**	(50.5)
	1% ↓	**64.0**	64.9
Medical and dental cost trend rate	1% ↑	**40.6**	41.4
	1% ↓	**(35.9)**	(37.0)

13. CAPITAL MANAGEMENT

LDC's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain, refurbish and expand the electricity distribution system;
- ensure sufficient liquidity is available (either through cash and cash equivalents or borrowings from TH Energy or the Corporation) to meet the needs of the business; and
- minimize finance costs while taking into consideration current and future industry, market and economic risks and conditions.

LDC monitors forecasted cash flows, capital expenditures, debt repayment and key credit ratios similar to those used by key rating agencies. LDC manages capital by preparing short-term and long-term cash flow forecasts. In addition, LDC borrows from TH Energy or the Corporation as required to help fund some of the periodic net cash outflows and to maintain available liquidity. There have been no changes in LDC's approach to capital management during the year. As at December 31, 2020, LDC's definition of capital included equity, bank indebtedness, borrowings through the Corporation and obligations under leases, including the current portion thereof, and has remained unchanged from the definition as at December 31, 2019. As at December 31, 2020, equity amounted to $2,107.1 million [December 31, 2019 - $1,991.6 million], and bank indebtedness, borrowings through the Corporation and obligations under leases, including the current portion thereof, amounted to $2,443.7 million [December 31, 2019 - $2,244.2 million].

14. FINANCIAL INSTRUMENTS

a) Recognition and measurement

As at December 31, 2020 and December 31, 2019, the fair values of cash and cash equivalents, accounts receivable and unbilled revenue, and accounts payable and accrued liabilities approximated their carrying amounts due to the short maturity of these instruments *[note 25[j]]*. The fair value of customer deposits approximates their carrying amounts taking into account interest accrued on the outstanding balance. Obligations under leases are measured based on a discounted cash flow analysis and approximate the carrying amounts as management believes that the fixed interest rates are representative of current market rates.

The carrying amounts and fair values of LDC's notes payable to related party consist of the following:

	2020 $		2019 $	
	Carrying amount	**Fair value [1]**	**Carrying amount**	**Fair value [1]**
Notes payable to the Corporation				
5.59% due May 21, 2040	**198.9**	**292.9**	198.9	277.8
3.59% due November 18, 2021	**299.8**	**308.3**	299.6	308.3
2.96% due April 10, 2023	**249.6**	**263.8**	249.5	256.4
4.01% due April 9, 2063	**198.8**	**272.5**	198.7	242.6
4.13% due September 16, 2044	**198.5**	**256.3**	198.5	238.4
3.60% due July 28, 2045	**198.8**	**238.5**	198.7	220.5
3.988% due April 9, 2063	**44.7**	**61.0**	44.7	54.3
2.572% due August 25, 2026	**199.2**	**217.7**	199.1	203.6
3.535% due February 28, 2048	**198.7**	**238.7**	198.7	219.4
2.488% due December 11, 2029	**199.0**	**197.6**	198.9	200.4
3.042% due December 10, 2049	**198.7**	**220.4**	198.6	200.8
1.55% due October 15, 2030	**198.7**	**200.8**	—	—
Demand note payable to the Corporation due on demand	**45.0**	**45.0**	45.0	45.0
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	**15.4**	15.0	15.4
	2,443.4	**2,828.9**	2,243.9	2,482.9

[1] The fair value measurement of financial instruments for which the fair value has been disclosed is included in Level 2 of the fair value hierarchy *[note 25[k]]*.

b) Financial risks

The following is a discussion of financial risks and related mitigation strategies that have been identified by LDC for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

Credit risk

LDC is exposed to the risk of counterparties defaulting on their obligations. LDC monitors and limits its exposure to credit risk on a continuous basis. The credit risk related to cash and cash equivalents is mitigated by LDC's treasury policies on assessing and monitoring the credit exposures of counterparties.

LDC's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. LDC is subject to credit risk with respect to customer non-payment of electricity bills. As a result of the COVID-19 pandemic and material disruptions to businesses and the economy, LDC's credit risk has increased due to some customers not being able to pay their electricity bills when due, and LDC's security interest or other protective measures, if any, provided to LDC, such as letters of credit, cash deposits or pre-authorized payments may not be sufficient. LDC considers the current economic and credit conditions to determine the loss allowance of its accounts receivable and unbilled revenue. Given the high degree of uncertainty caused by the COVID-19 pandemic, the estimates and judgments made by management in the preparation of the expected credit loss allowance are subject to a high degree of estimation uncertainty. Based on LDC's current estimates and assumptions, including but not limited to recent trend for customer collections and current and forecasted economic conditions, LDC adjusted the expected credit loss provision to account for the higher level of expected customer defaults at the balance sheet date. LDC continues to actively monitor its exposure to credit risk and as at December 31, 2020, recorded an incremental provision of $17.2 million to its expected credit loss allowance as a result of the COVID-19 pandemic.

LDC obtains security instruments from certain customers in accordance with direction provided by the OEB. As at December 31, 2020, LDC held security deposits in the amount of $63.6 million [December 31, 2019 - $68.0 million], of which $33.4 million [December 31, 2019 - $35.2 million] was related to security deposits on offers to connect to guarantee the payment of additional costs related to expansion projects. LDC's security instruments may not provide sufficient protection from counterparties defaulting on their obligations. As at December 31, 2020, there were no significant concentrations of credit risk with respect to any customer. The credit risk and mitigation strategies with respect to unbilled revenue are the same as those for accounts receivable.

LDC did not have any single customer that generated more than 10% of total revenue for the years ended December 31, 2020 and December 31, 2019.

Credit risk associated with accounts receivable and unbilled revenue is as follows:

	2020 $	2019 $
Accounts receivable, gross		
Outstanding for not more than 30 days	**164.9**	200.3
Outstanding for more than 30 days and not more than 120 days	**51.2**	44.3
Outstanding for more than 120 days	**25.5**	13.1
Total accounts receivable, gross	**241.6**	257.7
Unbilled revenue, gross	**253.3**	292.0
Loss allowance	**(30.2)**	(11.6)
Total accounts receivable and unbilled revenue	**464.7**	538.1

Unbilled revenue represents amounts for which LDC has a contractual right to receive cash through future billings and are unbilled at period-end. Unbilled revenue is considered in conjunction with accounts receivable and is included in the loss allowance as at December 31, 2020 and December 31, 2019.

LDC has a broad base of customers. As at December 31, 2020 and December 31, 2019, LDC's accounts receivable and unbilled revenue which were not past due or impaired were assessed by management to have no significant collection risk.

Reconciliation between the opening and closing loss allowance balances for accounts receivable and unbilled revenue is as follows:

	2020 $	2019 $
Balance, beginning of year	**(11.6)**	(10.6)
Loss allowance	**(22.7)**	(6.0)
Write-offs	**4.4**	5.2
Recoveries of previously written-off balances	**(0.3)**	(0.2)
Balance, end of year	**(30.2)**	(11.6)

For the year ended December 31, 2020, LDC recorded an incremental loss allowance primarily related to commercial electricity customers as a result of the COVID-19 pandemic.

c) Market risks

Interest rate risk

LDC is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations *[note 12[f]]*. LDC is also exposed to short-term interest rate risk on the net of cash and cash equivalents and customer deposits. Notes payable to related party bear interest based on the prevailing market conditions at the time of issuance.

As at December 31, 2020, aside from the valuation of its post-employment benefit obligations, LDC was exposed to interest rate risk predominately from cash and cash equivalents and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. LDC estimates that a 25 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $0.2 million to annual finance costs.

Liquidity risk

LDC is exposed to liquidity risk related to its ability to fund its obligations as they become due. LDC monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. LDC has access to credit facilities and borrowings through the Corporation and monitors cash balances daily. LDC's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing finance costs. LDC relies on debt financing from borrowings through the Corporation and existing credit facilities to finance its daily operations, repay existing indebtedness, and fund capital expenditures. The current challenging economic climate affected by factors including but not limited to the effects of the COVID-19 pandemic may lead to material adverse changes in cash flows, working capital levels and/or debt balances, which may also have a direct negative impact on LDC's operating results and financial position in the future. Accordingly, LDC continues to monitor and adapt its response plan as the economic climate evolves.

Liquidity risks associated with financial commitments are as follows:

2020	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Accounts payable and accrued liabilities [1]	**382.3**	—	—	—	—	—
Obligations under leases	—	—	**0.1**	**0.1**	**0.1**	—
Long-term notes payable to the Corporation						
5.59% due May 21, 2040	—	—	—	—	—	**200.0**
3.59% due November 18, 2021	**300.0**	—	—	—	—	—
2.96% due April 10, 2023	—	—	**250.0**	—	—	—
4.01% due April 9, 2063	—	—	—	—	—	**200.0**
4.13% due September 16, 2044	—	—	—	—	—	**200.0**
3.60% due July 28, 2045	—	—	—	—	—	**200.0**
3.988% due April 9, 2063	—	—	—	—	—	**45.0**
2.572% due August 25, 2026	—	—	—	—	—	**200.0**
3.535% due February 28, 2048	—	—	—	—	—	**200.0**
2.488% due December 11, 2029	—	—	—	—	—	**200.0**
3.042% due December 10, 2049	—	—	—	—	—	**200.0**
1.55% due October 15, 2030	—	—	—	—	—	**200.0**
Demand note payable to the Corporation due on demand	**45.0**	—	—	—	—	—
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	—	—	—	—	—
Interest payments on long-term notes payable and demand notes payable	**82.9**	**70.5**	**66.5**	**62.8**	**62.8**	**1,176.7**
	825.2	**70.5**	**316.6**	**62.9**	**62.9**	**3,021.7**

[1] Accounts payable and accrued liabilities exclude $19.2 million of accrued interest on long-term notes payable and demand notes payable included within "Interest payments on long-term notes payable and demand notes payable".

Foreign exchange risk

As at December 31, 2020, LDC had limited exposure to the changing values of foreign currencies. While LDC purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions is not material to the financial statements.

15. FINANCIAL ASSISTANCE

As at December 31, 2020, $32.9 million [December 31, 2019 - $33.2 million] of letters of credit had been issued by the Corporation, on behalf of LDC, under its $75.0 million demand facility mainly to support LDC's prudential requirements with the IESO.

16. SHARE CAPITAL

Share capital consists of the following:

	2020 $	2019 $
Authorized		
The authorized share capital of LDC consists of an unlimited number of common shares without par value.		
Issued and outstanding		
1,000 common shares, of which all were fully paid.	**556.3**	556.3

Dividends

During the year ended December 31, 2020, the Board of Directors of LDC declared and paid dividends to the Corporation totalling $0.7 million [2019 - $nil].

17. REVENUES

Revenues consist of the following:

	2020 $	2019[(1)] $
Revenue from contracts with customers		
Energy sales	**3,142.5**	2,779.7
Distribution revenue	**694.4**	799.2
Pole and duct rentals	**20.4**	19.3
Ancillary services revenue	**13.8**	17.5
Other regulatory service charges	**7.5**	10.2
Street lighting services	**6.9**	6.5
Miscellaneous	**14.1**	8.0
Revenue from other sources		
Capital contributions	**8.2**	5.9
Other	**8.9**	12.0
	3,916.7	3,658.3

(1) Includes reclassification from amounts previously reported.

Energy sales and distribution revenue by customer class are as follows:

	2020 $	2019 $
Residential service [1]	**1,120.7**	917.2
General service [2]	**2,512.4**	2,443.6
Large users [3]	**203.8**	218.1
Total energy sales and distribution revenue	**3,836.9**	3,578.9

[1] "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multifamily units and seasonal occupancy.
[2] "General Service" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a 12-month period.
[3] "Large Users" means a service provided to a customer with a monthly peak demand of 5,000 kW or greater averaged over a 12-month period.

18. OPERATING EXPENSES

Operating expenses consist of the following:

	2020 $	2019 $
Salaries and benefits	**224.0**	239.9
External services	**135.7**	138.6
Other support costs [1]	**45.4**	22.0
Materials and supplies	**26.6**	18.1
Less: Capitalized costs	**(117.8)**	(122.9)
	313.9	295.7

[1] Includes bad debt expense, taxes other than income taxes, utilities, rental, communication, insurance, and other general and administrative expenses.

For the year ended December 31, 2020, LDC recognized operating expenses of $16.3 million related to materials and supplies used to service electricity distribution assets [2019 - $9.3 million].

19. FINANCE COSTS

Finance costs consist of the following:

	2020 $	2019 $
Interest income	**(0.7)**	(1.0)
Interest expense		
Interest on long-term debt [1]	**82.7**	81.9
Interest on short-term debt	**2.6**	4.4
Other interest	**0.4**	0.8
Capitalized borrowing costs	**(4.6)**	(3.7)
	80.4	82.4

[1] Includes amortization of debt issuance costs, discounts and premiums.

20. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined statutory Canadian federal and provincial income tax rate. Reconciliation of income tax expense computed at the statutory income tax rate to the income tax provision is set out below:

	2020 $	2019 $
Rate reconciliation before net movements in regulatory balances		
Income before income taxes	**100.7**	250.7
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**26.7**	66.4
Non-taxable amounts	**(0.3)**	(0.9)
Gain on disposal	**—**	0.4
Other	**2.1**	0.8
Income tax expense	**28.5**	66.7
Effective tax rate	**28.3%**	26.6%
Rate reconciliation after net movements in regulatory balances		
Net income after net movements in regulatory balances, before income tax [(1)]	**119.5**	188.3
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**31.7**	49.9
Temporary differences recoverable in future rates	**(29.4)**	(15.7)
Gain on disposal	**—**	0.4
Other	**1.0**	(1.3)
Income tax expense and income tax recorded in net movements in regulatory balances	**3.3**	33.3
Effective tax rate	**2.8%**	17.7%

[(1)] Income tax includes income tax expense and income tax recorded in net movements in regulatory balances.

Income tax expense as presented in the statements of income and statements of comprehensive income are as follows:

	2020 $	2019 $
Income tax expense	**28.5**	66.7
Income tax recorded in net movements in regulatory balances	**(25.2)**	(33.4)
Income tax expense and income tax recorded in net movements in regulatory balances	**3.3**	33.3
Income tax expense (recovery) in OCI *[note 12[d]]*	**1.3**	(10.1)
Income tax expense (recovery) in OCI recorded in net movements in regulatory balances	**(1.3)**	10.1
Income tax expense in OCI	**—**	—

Components of income tax expense and income tax recorded in net movements in regulatory balances are as follows:

	2020 $	2019 $
Current tax expense		
Current year	**5.8**	33.2
Deferred tax expense		
Origination and reversal of temporary differences	**(2.5)**	0.1
Income tax expense and income tax recorded in net movements in regulatory balances	**3.3**	33.3

Deferred tax assets (liabilities) consist of the following:

	Net balance January 1, 2020 $	Recognized in net income $	Recognized in OCI $	Net balance December 31, 2020 $
PP&E and intangible assets	**(83.3)**	**(30.7)**	**—**	**(114.0)**
Post-employment benefits	**88.7**	**0.7**	**(1.3)**	**88.1**
Tax credit carryforward	**—**	**2.5**	**—**	**2.5**
Other taxable temporary differences	**(28.5)**	**4.8**	**—**	**(23.7)**
	(23.1)	**(22.7)**	**(1.3)**	**(47.1)**

	Net balance January 1, 2019 $	Recognized in net income $	Recognized in OCI $	Net balance December 31, 2019 $
PP&E and intangible assets	(45.9)	(37.4)	—	(83.3)
Post-employment benefits	73.0	5.6	10.1	88.7
Other taxable temporary differences	(26.8)	(1.7)	—	(28.5)
	0.3	(33.5)	10.1	(23.1)

21. STATEMENTS OF CASH FLOWS

Changes in non-cash operating working capital provided (used) cash as follows:

	2020 $	2019 $
Accounts receivable and unbilled revenue	**72.7**	(49.0)
Income tax receivable	**(10.8)**	(0.9)
Materials and supplies	**(2.0)**	0.3
Other current assets	**(2.5)**	(3.3)
Accounts payable and accrued liabilities	**(22.5)**	(27.1)
Income tax payable	**—**	(4.8)
Deferred revenue	**4.6**	0.8
Deferred conservation credit	**6.5**	1.3
Other current liabilities	**—**	(0.3)
	46.0	(83.0)

Reconciliation between the amounts presented on the statements of cash flows and total additions to PP&E and intangible assets is as follows:

	2020 $	2019 $
Purchase of PP&E, cash basis	**633.5**	509.5
Net change in accruals related to PP&E	**(65.5)**	15.6
Other	**0.9**	0.9
Total additions to PP&E	**568.9**	526.0
Purchase of intangible assets, cash basis	**40.8**	53.0
Net change in accruals related to intangible assets	**(1.0)**	0.4
Other	**—**	12.7
Total additions to intangible assets	**39.8**	66.1

Summary of changes in liabilities arising from financing activities:

	2019 $	Cash flows [(1)] $	Non-cash changes $	2020 $
Year ended December 31				
Notes payable to related party *[note 11]*	**2,243.9**	**198.6**	**0.9**	**2,443.4**
Accrued interest [(2)]	**19.4**	**(84.6)**	**84.4**	**19.2**
Dividends payable	**—**	**(0.7)**	**0.7**	**—**
Lease liability [(3)]	**0.3**	**—**	**—**	**0.3**
	2,263.6	**113.3**	**86.0**	**2,462.9**

	2018 $	Cash flows [1] $	Non-cash changes $	2019 $
Year ended December 31				
Notes payable to related party *[note 11]*	2,090.6	152.4	0.9	2,243.9
Accrued interest [2]	19.4	(86.1)	86.1	19.4
Lease liability [3]	1.3	(0.2)	(0.8)	0.3
	2,111.3	66.1	86.2	2,263.6

[1] Cash inflows and cash outflows arising from notes payable to related party are presented on a net basis.
[2] Included within accounts payable and accrued liabilities *[note 9]*.
[3] Included within other liabilities.

22. RELATED PARTY TRANSACTIONS

For LDC, transactions with related parties include transactions with the City, which is the sole shareholder of the Corporation, the Corporation, and TH Energy, a wholly-owned subsidiary of the Corporation.

	City $	Corporation $	TH Energy $
For year ended December 31, 2020			
Revenues	**285.5**	**—**	**7.0**
Operating expenses (recoveries) and capital expenditures	**10.5**	**1.2**	**(0.9)**
Finance costs	**—**	**82.9**	**—**
Dividends declared and paid	**—**	**0.7**	**—**
As at December 31, 2020			
Accounts receivable and unbilled revenue	**39.1**	**—**	**—**
Accounts payable and accrued liabilities	**25.7**	**19.1**	**0.2**
Current portion of notes payable to related party	**—**	**359.8**	**—**
Long-term portion of notes payable to related party	**—**	**2,083.6**	**—**
Customer deposits	**12.6**	**—**	**—**

	City $	Corporation $	TH Energy $
For year ended December 31, 2019			
Revenues	279.2	—	6.6
Operating expenses (recoveries) and capital expenditures	7.3	4.9	(1.0)
Finance costs	—	83.5	—
As at December 31, 2019			
Accounts receivable and unbilled revenue	41.9	—	2.9
Accounts payable and accrued liabilities	23.9	21.9	—
Current portion of notes payable to related party	—	60.0	—
Long-term portion of notes payable to related party	—	2,183.9	—
Customer deposits	14.1	—	—

Revenues represent amounts charged to the City primarily for electricity and ancillary services, and to TH Energy for street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged

by the City for purchased road cut repairs, property taxes and other services, and the Corporation for purchased corporate and management services. Operating expense recoveries represent amounts charged to TH Energy for the provision of goods and services. Finance costs represent interest charged by the Corporation on the notes payable *[note 11]*. Dividends are paid to the Corporation *[note 16]*.

Accounts receivable and unbilled revenue represent receivables from the City primarily for electricity and ancillary services, and TH Energy for the provision of goods and services, including amounts not yet billed. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services. Included in the accounts payable and accrued liabilities are amounts payable to the Corporation for purchased corporate and management services and interest accruing on the notes payable to the Corporation and amounts payable to TH Energy for provision of goods and services. Notes payable to related party represent amounts borrowed from the Corporation *[note 11]*. Customer deposits represent amounts received from the City for future expansion projects.

Key management personnel include LDC's senior executive officers and members of the Board of Directors. The compensation costs associated with the key management personnel are as follows:

	2020 $	2019 $
Short-term employee benefits	**4.9**	4.4
Post-employment benefits	**2.8**	0.9
Termination benefits	**2.6**	—
	10.3	5.3

23. COMMITMENTS

Capital projects

As at December 31, 2020, the future minimum payments for capital projects and other commitments were as follows:

	Capital projects [1] and other $
Less than one year	**36.3**
Between one and five years	**39.1**
Total amount of future minimum payments [2]	**75.4**

[1] Mainly commitments for construction services.
[2] Refer to note 14 for financial commitments excluded from the table above.

24. CONTINGENCIES

Legal Proceedings

In the ordinary course of business, LDC is subject to various legal actions and claims from customers, suppliers, and other parties. On an ongoing basis, LDC assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, LDC would make a claim under any applicable liability insurance policies which LDC believes would cover any damages which may become payable by LDC in connection with these actions, subject to such claim not being disputed by the insurers.

25. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from those prescribed by IFRS for enterprises operating in an unregulated environment and regulated entities that did not adopt IFRS 14.

Regulatory Balances

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of continuing to recognize regulatory balances according to their previous GAAP. Regulatory balances provide useful information about LDC's financial position, financial performance and cash flows. IFRS 14 is restricted to first-time adopters of IFRS and remains in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB.

LDC has determined that certain debit and credit balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14. Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding LDC's regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory debit and credit balances on LDC's balance sheets, and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. Regulatory balances can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is determined by management to be probable. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, the balances are recorded in LDC's statements of income in the period when the assessment is made. Regulatory balances, which do not meet the definition of an asset or liability under any other IFRS, are segregated on the balance sheets and are presented on the statements of income and the statements of comprehensive income as net movements in regulatory balances and net movements in regulatory balances related to OCI, net of tax. The netting of regulatory debit and credit balances is not permitted. The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions.

b) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition. On the statements of cash flows, cash and cash equivalents (bank indebtedness) include bank overdrafts that are repayable on demand and form an integral part of LDC's cash management.

c) Accounts receivable and unbilled revenue

Accounts receivable are recorded at the invoiced amount and overdue amounts bear interest at OEB-approved rates. Unbilled revenue is recorded based on an estimated amount for electricity delivered and for other services provided and not yet billed. The estimate is primarily based on the customers' previous billings with adjustments mainly for assumptions related to seasonality and weighted average price. The carrying amount of accounts receivable and unbilled revenue is reduced through a loss allowance, if applicable, and the amount of the related impairment loss is recognized in the statements of income. The impairment loss is the difference between an asset's carrying amount and the estimated future cash flows. When LDC considers that there are no realistic prospects of recovery of the financial assets, the relevant amounts are written off. If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Accounts receivable and unbilled revenue are assessed at each reporting date to determine whether there is objective evidence of impairment, which includes default or delinquency by a debtor, indications that a debtor or issuer will

enter bankruptcy, and adverse changes in the payment status of borrowers or issuers. Accounts receivable and unbilled revenue that are not individually assessed for impairment are collectively assessed for impairment by grouping together receivables with similar risk characteristics, and LDC considers historical trends on the timing of recoveries and the amount of loss incurred, adjusted for forward-looking factors specific to the current economic and credit conditions.

LDC measures the loss allowance at an amount equal to the lifetime expected credit losses ["ECL"] for all trade receivables that result from transactions with customers and do not contain a significant financing component. A provision matrix is used by LDC to measure the lifetime ECL of accounts receivable from individual customers. Loss rates are calculated using a 'roll rate' method based on the probability of a trade receivable progressing through successive stages of delinquency to write-off and are based on the average of actual credit loss experience over the past three years, as it more accurately reflects anticipated credit loss. Roll rates are calculated separately for exposures based on customer account status. LDC also adjusts the ECL in efforts to account for current economic conditions and events (including forward-looking macroeconomic data) and historical information (including credit agency reports, if available). LDC considers the reasons for the accounts being past due, the characteristics of existing accounts, reasonable and supportable forecasts and other considerations that may affect the collectability of the reported amounts.

d) Materials and supplies

Materials and supplies consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. LDC classifies all major construction related components of its electricity distribution infrastructure to PP&E. Materials and supplies are carried at the lower of cost and net realizable value, with cost determined on a weighted average cost basis net of a provision for obsolescence.

e) Property, plant and equipment

PP&E are measured at cost less accumulated depreciation and any accumulated impairment losses, if applicable. The cost of PP&E represents the original cost, consisting of direct materials and labour, contracted services, borrowing costs, and directly attributable overhead. Subsequent costs are capitalized only if it is probable that the future economic benefits associated with the expenditure will flow to LDC and the costs can be measured reliably. If significant parts of an item of PP&E have different useful lives, then they are accounted for as separate major components of PP&E. The carrying amount of an item of PP&E is derecognized on disposal of the asset or when no future economic benefits are expected to accrue to LDC from its continued use. Any gain or loss arising on derecognition is recorded in the statements of income in the period in which the asset is derecognized. The gain or loss on disposal of an item of PP&E is determined as the sale proceeds less the carrying amount of the asset and costs of removal and is recognized in the statements of income.

Depreciation begins when an asset becomes available for use. Depreciation is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Distribution assets:	
Distribution lines	1.7% to 5.0%
Transformers	3.3% to 5.0%
Meters	2.5% to 6.7%
Stations	2.0% to 10.0%
Buildings	1.3% to 5.0%
Equipment and other:	
Other capital assets	4.0% to 25.0%
Right-of-use assets	1.0% to 11.1%

Right-of-use assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that LDC will obtain ownership by the end of the lease term, in which case they are depreciated to the end of the useful life of the underlying assets. Right-of-use assets are recognized for contracts that are, or contain, leases. Construction in progress relates to assets not currently available for use and therefore is not depreciated. The

depreciation method and useful lives are reviewed at each financial year-end and adjusted if appropriate. There are no residual values for items of PP&E.

f) Intangible assets

Intangible assets are measured at cost less accumulated amortization and any accumulated impairment losses, if applicable.

Amortization begins when an asset becomes available for use. Amortization is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Computer software	10.0% to 25.0%
Contributions	4.0%

Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized. Contributions represent payments made to HONI for dedicated infrastructure in order to receive connections to transmission facilities. The amortization method and useful lives are reviewed at each financial year-end and adjusted if appropriate.

g) Impairment of non-financial assets

LDC reviews the carrying amounts of its non-financial assets other than materials and supplies and deferred tax assets at each reporting date to determine whether there is any indication of impairment, in which case the assets' recoverable amounts are estimated. For impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent on the cash inflows of other assets or CGUs. LDC has determined that its assets are a single CGU due to interdependencies of its assets to generate cash flows. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount. Impairment losses are recognized in the statements of income, and are allocated to reduce the carrying amounts of assets in the CGU on a pro rata basis. An impairment loss recognized in prior periods is reversed when an asset's recoverable amount has increased, but not exceeding the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

h) Capitalized borrowing costs

Borrowing costs directly attributable to the acquisition, construction or development of qualifying assets that necessarily take a substantial period of time to get ready for their intended use are capitalized, until such time as the assets are substantially ready for their intended use. The interest rate for capitalization is LDC's weighted average cost of borrowing, and is applied to the carrying amount of the construction-in-progress assets or assets under development including borrowing costs previously capitalized, net of capital contributions received. Capitalization commences immediately as the expenditure on a qualifying asset is incurred. Borrowing costs are included in the cost of PP&E and intangible assets for financial reporting purposes, and charged to operations through depreciation and amortization expense over the useful lives of the related assets.

i) Revenue recognition

LDC assesses each contract with the customer to identify the performance obligation. The transaction price and the payment terms are agreed upon in the contract between LDC and the customer.

Revenues from energy sales and electricity distribution are recorded on the basis of cyclical billings and include an estimated amount for electricity delivered and not yet billed. The performance obligation is satisfied over time when the electricity is simultaneously received and consumed by the customer. The majority of billing cycles and payment terms are on a monthly basis. These revenues are impacted by energy demand primarily driven by outside temperature, and customer class usage patterns and composition.

Energy sales arise from charges to customers for electricity consumed, based on regulated rates. Energy sales include amounts billed or billable to customers for commodity charges, retail transmission charges, and WMS charges at current rates. These charges are passed through to customers over time and are considered revenue by LDC due to the collection risk of the related balances. LDC applies judgment to determine whether revenues are recorded on a gross or net basis. LDC has primary responsibility for the delivery of electricity to the customer. For any given period, energy sales should be equal to the cost of energy purchased. However, a difference between energy sales and energy purchases arises when there is a timing difference between the amounts charged by LDC to customers, based on regulated rates, and the electricity and non-competitive electricity service costs billed monthly by the IESO to LDC. This difference is recorded as a settlement variance, representing future amounts to be recovered from or refunded to customers through future billing rates approved by the OEB. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the balance sheets and within net movements in regulatory balances on the statements of income.

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by LDC in delivering electricity to customers. Distribution revenue also includes revenue related to the collection of OEB-approved rate riders.

Other revenue includes revenue from services ancillary to the electricity distribution, delivery of street lighting services, pole and duct rentals, other regulatory service charges, capital contributions and CDM programs.

Capital contributions received in advance from electricity customers and developers to construct or acquire PP&E for the purpose of connecting a customer to a network are recorded as deferred revenue and amortized into other revenue at an equivalent rate to that used for the depreciation of the related PP&E. Capital contributions received from developers to construct or acquire PP&E for the purpose of connecting future customers to the distribution network are considered out of scope of IFRS 15 *Revenue from Contracts with Customers*. Contributions received from customers to construct or acquire PP&E to deliver services other than those related to delivery of electricity are recorded as deferred revenue and amortized into other revenue over the term of the contract with the customer.

Revenues and costs associated with CDM programs are presented using the net basis of accounting and are recorded in accordance with IAS 20 *Accounting for Government Grants and Disclosure of Government Assistance*. Cost efficiency incentives related to the CDM programs, included as part of other revenue, are recognized when it is probable that future economic benefits will flow to the entity and the amount can be reasonably measured.

LDC has not incurred any additional costs to obtain or fulfill contracts with its customers nor any kind of variable considerations from the above-mentioned revenue generating activities.

j) Financial instruments

All financial assets and financial liabilities are classified as "Amortized cost". These financial instruments are recognized initially at fair value adjusted for any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties.

LDC uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the balance sheets:

- Cash and cash equivalents are classified as "Amortized cost" and are initially measured at fair value. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Bank indebtedness is classified as "Amortized cost" and is initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts payable are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Customer deposits are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at cost plus accrued interest. The carrying amounts approximate fair value taking into account interest accrued on the outstanding balance.

- Obligations under leases are classified as "Amortized cost" and are initially measured at fair value, or at the present value of the minimum lease payments, if lower. Subsequent measurements are based on a discounted cash flow analysis and approximate the carrying amount as management believes that the fixed interest rates are representative of current market rates.

- Notes payable to related party are classified as "Amortized cost" and are initially measured at fair value. The carrying amounts of notes payable are carried at amortized cost, based on the fair value of the notes payable at issuance, which was the fair value of the consideration received adjusted for transaction costs. The fair values of the notes payable are based on the present value of contractual cash flows, discounted at LDC's current borrowing rate for similar debt instruments *[note 14[a]]*. Debt issuance costs incurred in connection with LDC's debt offerings are capitalized as part of the carrying amount of the notes payable and amortized over the term of the related notes payable, using the effective interest method, and the amortization is included in finance costs.

k) Fair value measurements

LDC utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect LDC's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;

- Level 2: Other than quoted prices included within Level 1 that are observable for the assets or liabilities, either directly or indirectly; and

- Level 3: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

l) Employee benefits

(i) Short-term employee benefits

Short-term employee benefit obligations that are due to be settled wholly within twelve months after the end of the annual reporting period in which the employees render the related service are measured on an undiscounted basis and are expensed as the related service is provided. A liability is recognized for the amount expected to be paid if LDC has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

(ii) Multi-employer pension plan

LDC's full-time employees participate in a pension plan through OMERS. The OMERS plan is a jointly sponsored, multi-employer defined benefit pension plan established in 1962 by the province of Ontario for employees of municipalities, school boards, libraries, police and fire departments, and other local agencies in communities across Ontario. Both participating employers and employees are required to make plan contributions equally based on participating employees' contributory earnings, and share equally in funding gains or losses. The plan assets and pension obligations are not segregated in separate accounts for each member entity. The OMERS plan is accounted for as a defined contribution plan and the contribution payable is recognized as an employee benefit expense in the statements of income in the period when the service is rendered by the employee, since it is not practicable to determine LDC's portion of pension obligations or of the fair value of plan assets.

(iii) Post-employment benefits

LDC has a number of unfunded benefit plans providing post-employment benefits to its employees, including certain retirement, medical, dental and life insurance benefits. LDC also pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The cost of providing benefits under the benefit plans is actuarially determined using the projected unit credit method, which incorporates management's best estimate of future salary levels, retirement ages of employees, health care costs, and other actuarial factors. Past service cost is recognized when a plan amendment or curtailment occurs. Changes in actuarial assumptions and experience adjustments give rise to actuarial gains and losses. Actuarial gains and losses on post-employment benefits other than sick leave credits are recognized in OCI as they arise, and are subsequently reclassified from OCI to a regulatory balance on the balance sheets. Actuarial gains and losses on accumulated sick leave credits are recognized in the statements of income in the period in which they arise.

The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest actuarial valuation was performed as at January 1, 2020.

m) Customer deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits that are refundable upon demand are classified as a current liability.

Security deposits on offers to connect are cash collections from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits are classified as a current liability when LDC no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

n) Income taxes

Under the Electricity Act, LDC is required to make PILs to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the ITA and the TA as modified by regulations made under the Electricity Act and related regulations. This effectively results in LDC paying income taxes equivalent to what would be imposed under the Federal and Ontario Tax Acts.

LDC uses the liability method of accounting for income taxes. Under the liability method, current income taxes payable are recorded based on taxable income. LDC recognizes deferred tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheets and their respective tax basis, using the tax rates enacted or substantively enacted by the balance sheet date that are in effect for the year in which the differences are expected to reverse. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when it is probable that they will be realized, and are measured at the best estimate of the tax amount expected to be paid to or recovered from

the taxation authorities. Deferred tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable that the related tax benefits will be realized. The calculation of current and deferred taxes requires management to make certain judgments with respect to changes in tax interpretations, regulations and legislation, and to estimate probable outcomes on the timing and reversal of temporary differences and tax authority audits of income tax.

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates. A gross up to reflect the income tax benefits or liabilities associated with the revenue impact resulting from the realization of deferred taxes is recorded within regulatory balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the statements of income.

The benefits of the refundable and non-refundable apprenticeship and other ITCs are credited against the related expense in the statements of income.

o) Use of judgments and estimates

The preparation of LDC's financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions which affect the application of accounting policies, reported assets, liabilities and regulatory balances, and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the IESO, the Ontario Ministry of Energy, Northern Development and Mines or the Ontario Ministry of Finance. The assessment of the duration and severity of the COVID-19 pandemic is subject to significant uncertainty; accordingly, judgments, estimates and assumptions related to the impact of the pandemic made by management in the preparation of the LDC's financial statements are also subject to significant uncertainty. Management has analyzed the impact of the COVID-19 pandemic on its estimates and adjusted the expected credit loss provision to account for the higher level of expected customer defaults as at December 31, 2020 *[note 14[b]]*. The extent of the future impact of the pandemic on the LDC's financial results and business operations is not known at this time.

Information about judgments in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in note 25[a] relating to recognition of regulatory balances and note 25[i] relating to principal versus agent determination for recording revenue on a gross or net basis.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively. Assumptions and estimates with a significant risk of resulting in a material adjustment within the next financial year are used in the following:

- Note 24 – Recognition and measurement of provisions and contingencies;
- Note 25[a] – Recognition and measurement of regulatory balances;
- Note 25[c] – Recognition and measurement of loss allowance for accounts receivable and unbilled revenue;
- Notes 25[e] and 25[f] – Determination of useful lives of depreciable assets;
- Note 25[i] – Revenue recognition – measurement of unbilled revenue;
- Notes 25[l] and 12 – Measurement of post-employment benefits – key actuarial assumptions; and
- Notes 25[n] and 20 – Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and tax loss carryforwards can be used.

p) Changes in accounting standards

Definition of Material (Amendments to IAS 1 *Presentation of Financial Statements* ["IAS 1"] and IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors* ["IAS 8"])

On October 31, 2018, the IASB issued amendments to IAS 1 and IAS 8 - the amendments clarify the definition of 'material' and align the definition used in the Conceptual Framework for Financial Reporting and the standards themselves. The amendments are effective for annual reporting periods beginning on or after January 1, 2020.

Effective January 1, 2020, LDC has applied the definition of 'material' as amended, with no impact on the financial statements.

q) Future accounting pronouncements

The IASB has issued a number of standards and amendments to existing standards that are not yet effective. LDC continues to analyze these pronouncements and has determined that the following amendments could have an impact on LDC's financial statements when adopted.

Classification of Liabilities as Current or Non-current (Amendments to IAS 1)

In January 2020, the IASB issued amendments to IAS 1 relating to the classification of liabilities as current or non-current. Specifically, the amendments clarify one of the criteria in IAS 1 for classifying a liability as non-current - that is, the requirement for an entity to have the right to defer settlement of the liability for at least 12 months after the reporting period. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted. The amendments are to be applied retrospectively.

Onerous Contracts - Cost of Fulfilling a Contract (Amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets ["IAS 37"])

In May 2020, the IASB issued amendments to IAS 37 regarding costs that should be included as the cost of fulfilling a contract when assessing whether a contract is onerous. The amendments clarify that the cost of fulfilling the contract comprises all costs that relate directly to the contract. Such costs include both the incremental costs of fulfilling that contract and an allocation of other costs that relate directly to fulfilling contracts. The amendments apply to contracts existing at the date when the amendments are first applied. The amendments are effective for annual periods beginning on or after January 1, 2022, with early adoption permitted.

LDC is currently assessing the impact of the above amendments on LDC's financial statements.

GLOSSARY

CDM – Conservation and demand management

CGU – Cash generating unit

CIR – Custom Incentive Rate-setting

City – City of Toronto

Corporation – Toronto Hydro Corporation

COVID-19 – Coronavirus disease 2019

ECA – Energy Conservation Agreement

Electricity Act – *Electricity Act, 1998* (Ontario), as amended

GAAP – Generally Accepted Accounting Principles

HONI – Hydro One Networks Inc.

IAS – International Accounting Standard

IASB – International Accounting Standards Board

IESO – Independent Electricity System Operator

IFRS – International Financial Reporting Standards

IRM – Incentive Regulation Mechanism

ITA – *Income Tax Act* (Canada), as amended

ITC – Investment tax credit

kW – Kilowatt

kWh – Kilowatt hour

LDC – Toronto Hydro-Electric System Limited

LRAM – Lost revenue adjustment mechanism

OCI – Other comprehensive income

OEB – Ontario Energy Board

OEB Act – *Ontario Energy Board Act, 1998* (Ontario), as amended

OMERS – Ontario Municipal Employees Retirement System

OPEB – Other post-employment benefits

PILs – Payments in lieu of corporate taxes

PP&E – Property, plant and equipment

RPP – Regulated Price Plan

TA – *Taxation Act, 2007* (Ontario), as amended

TH Energy – Toronto Hydro Energy Services Inc.

TOU – Time-of-use

US GAAP – United States Generally Accepted Accounting Principles

WMS – Wholesale Market Service

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2021 and 2020

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Toronto Hydro-Electric System Limited

Opinion

We have audited the accompanying financial statements of Toronto Hydro-Electric System Limited (the Entity), which comprise:

- the balance sheet as at December 31, 2021
- the statement of income for the year then ended
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended

and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2021, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Financial Statements" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity.
KPMG Canada provides services to KPMG LLP.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards (IFRS), and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.
- The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
Toronto, Canada
March 1, 2022

BALANCE SHEETS

[in millions of Canadian dollars]

As at December 31	Note	2021 $	2020 $
ASSETS			
Current			
Cash and cash equivalents		**102.6**	142.0
Accounts receivable and unbilled revenue	*4, 14[b]*	**445.4**	464.7
Income tax receivable		**3.0**	11.7
Materials and supplies		**9.9**	9.8
Other assets	*5*	**18.8**	16.5
Total current assets		**579.7**	644.7
Property, plant and equipment	*6*	**5,322.6**	4,987.5
Intangible assets	*7*	**358.0**	343.1
Other assets	*5*	**6.9**	8.2
Total assets		**6,267.2**	5,983.5
Regulatory balances	*8*	**181.4**	170.4
Total assets and regulatory balances		**6,448.6**	6,153.9
LIABILITIES AND EQUITY			
Current			
Accounts payable and accrued liabilities	*9*	**422.9**	401.5
Customer deposits		**62.3**	44.9
Deferred revenue	*10*	**24.4**	17.8
Deferred conservation credit	*3[c]*	**11.7**	16.0
Notes payable to related party	*11, 22*	**60.0**	359.8
Total current liabilities		**581.3**	840.0
Notes payable to related party	*11, 22*	**2,432.0**	2,083.6
Customer deposits		**10.1**	18.7
Deferred revenue	*10*	**642.8**	537.9
Post-employment benefits	*12*	**306.6**	332.7
Deferred tax liabilities	*20*	**63.8**	47.1
Other liabilities		**17.4**	3.4
Total liabilities		**4,054.0**	3,863.4
Equity			
Share capital	*16*	**556.3**	556.3
Retained earnings		**1,674.3**	1,538.0
Contributed surplus		**12.8**	12.8
Total equity		**2,243.4**	2,107.1
Total liabilities and equity		**6,297.4**	5,970.5
Regulatory balances	*8*	**151.2**	183.4
Total liabilities, equity and regulatory balances		**6,448.6**	6,153.9

Commitments, contingencies and subsequent events *2, 23, 24*

See accompanying notes to the financial statements.

STATEMENTS OF INCOME

[in millions of Canadian dollars]

Year ended December 31	Note	2021 $	2020 $
Revenues			
Energy sales	*17*	**2,702.4**	3,142.5
Distribution revenue	*17*	**759.1**	694.4
Other	*17*	**88.1**	79.8
		3,549.6	3,916.7
Expenses			
Energy purchases		**2,775.2**	3,150.5
Operating expenses	*18*	**310.7**	313.9
Depreciation and amortization	*6, 7*	**289.3**	271.2
		3,375.2	3,735.6
Finance costs	*19*	**(82.8)**	(80.4)
Gain on disposals of property, plant and equipment		**2.7**	-
Income before income taxes		**94.3**	100.7
Income tax expense	*20*	**(20.4)**	(28.5)
Net income		**73.9**	72.2
Net movements in regulatory balances	*8*	**54.1**	18.8
Net movements in regulatory balances arising from deferred taxes	*8*	**8.9**	25.2
Net income after net movements in regulatory balances		**136.9**	116.2

STATEMENTS OF COMPREHENSIVE INCOME

[in millions of Canadian dollars]

Year ended December 31	Note	2021 $	2020 $
Net income after net movements in regulatory balances		**136.9**	116.2
Other comprehensive income			
Items that will not be reclassified to income or loss			
Remeasurements of post-employment benefits, net of tax [2021 - ($7.1), 2020 - ($1.3)]	*12*	**19.8**	3.8
Net movements in regulatory balances related to OCI, net of tax [2021 - ($7.1), 2020 - ($1.3)]	*8, 12*	**(19.8)**	(3.8)
Other comprehensive income, net of tax		**-**	-
Total comprehensive income		**136.9**	116.2

See accompanying notes to the financial statements.

STATEMENTS OF CHANGES IN EQUITY

[in millions of Canadian dollars]

Year ended December 31	Note	2021 $	2020 $
Share capital	*16*	**556.3**	556.3
Retained earnings, beginning of year		**1,538.0**	1,422.5
Net income after net movements in regulatory balances		**136.9**	116.2
Dividends	*16, 22*	**(0.6)**	(0.7)
Retained earnings, end of year		**1,674.3**	1,538.0
Contributed surplus		**12.8**	12.8
Total equity		**2,243.4**	2,107.1

See accompanying notes to the financial statements.

STATEMENTS OF CASH FLOWS

[in millions of Canadian dollars]

Year ended December 31	Note	2021 $	2020 $
OPERATING ACTIVITIES			
Net income after net movements in regulatory balances		**136.9**	116.2
Net movements in regulatory balances	*8*	**(54.1)**	(18.8)
Net movements in regulatory balances arising from deferred taxes	*8*	**(8.9)**	(25.2)
Adjustments			
Depreciation and amortization	*6, 7*	**289.3**	271.2
Amortization of deferred revenue	*10*	**(12.3)**	(8.2)
Finance costs		**82.8**	80.4
Income tax expense		**20.4**	28.5
Post-employment benefits		**0.8**	2.9
Gain on disposals of property, plant and equipment		**(2.7)**	-
Other		**1.0**	0.3
Capital contributions received	*10*	**101.2**	138.7
Net change in other non-current assets and liabilities		**11.1**	0.8
Increase (decrease) in customer deposits		**8.8**	(4.4)
Changes in non-cash operating working capital balances	*21*	**17.4**	46.0
Income tax paid		**-**	(15.0)
Net cash provided by operating activities		**591.7**	613.4
INVESTING ACTIVITIES			
Purchase of property, plant and equipment	*21*	**(548.0)**	(620.5)
Purchase of intangible assets	*21*	**(47.6)**	(40.8)
Proceeds on disposals of property, plant and equipment		**2.8**	0.5
Net cash used in investing activities		**(592.8)**	(660.8)
FINANCING ACTIVITIES			
Issuance of notes payable to related party	*11*	**347.7**	198.6
Repayment of notes payable to related party	*11*	**(300.0)**	-
Dividends paid	*16*	**(0.6)**	(0.7)
Interest received		**0.9**	0.7
Interest paid		**(86.3)**	(84.6)
Net cash provided by (used in) financing activities		**(38.3)**	114.0
Net change in cash and cash equivalents during the year		**(39.4)**	66.6
Cash and cash equivalents, beginning of year		**142.0**	75.4
Cash and cash equivalents, end of year		**102.6**	142.0

See accompanying notes to the financial statements.

1. NATURE OF BUSINESS

Toronto Hydro-Electric System Limited was incorporated on June 23, 1999 under the *Business Corporations Act* [Ontario] in accordance with the Electricity Act. LDC is wholly owned by the Corporation and is domiciled in Canada, with its registered office located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

LDC distributes electricity to customers located in the city of Toronto and is subject to rate regulation.

2. BASIS OF PRESENTATION

LDC's audited financial statements for the years ended December 31, 2021 and 2020 have been prepared in accordance with IFRS as issued by the IASB.

The financial statements are presented in Canadian dollars, LDC's functional currency, and have been prepared on the historical cost basis, except for post-employment benefits which are measured at the present value of the post-employment benefit obligation.

LDC has evaluated the events and transactions occurring after the balance sheet date through March 1, 2022 when LDC's financial statements were authorized for issuance by LDC's Board of Directors, and identified the events and transactions which required recognition in LDC's financial statements and/or disclosure in the notes to LDC's financial statements *[notes 3[a] and 11]*.

The summary of significant accounting policies has been disclosed in note 25.

3. REGULATION

The OEB has regulatory oversight of electricity matters in Ontario. The OEB's authority and responsibilities include the power to approve and set rates for the transmission and distribution of electricity, the power to approve the amounts paid to non-contracted generators, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts [all of which, other than distribution rates, represent a pass-through of amounts payable to third parties]:

- *Commodity Charge* – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO back to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- *Retail Transmission Rate* – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are a pass-through to operators of transmission facilities.

- *WMS Charge* – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are a pass-through to the IESO.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable [usage-based] components, based on a forecast of LDC's customers and load.

a) COVID-19 Pandemic Considerations

On March 11, 2020, the World Health Organization declared that the COVID-19 outbreak was a global pandemic. The COVID-19 pandemic has had, and as at the date of the financial statements continues to have, a significant impact on LDC.

On April 21, 2021, the OEB extended the existing ban on disconnecting residential customers until May 19, 2021, which was further extended on May 14, 2021 until June 2, 2021, in light of the stay-at-home order issued by the Ontario Government under its State of Emergency declaration. The restriction also applied to the issuance of any post-dated disconnection notices during that period.

On November 15, 2021, the OEB's standard winter disconnection ban commenced and will remain in effect until May 1, 2022. LDC continues to voluntarily extend its ban on disconnecting residential and low volume customers, which has been in place since the beginning of the pandemic, until further notice.

On January 7, 2022, the Ontario Government announced further targeted relief measures setting both the TOU rates for on-peak, mid-peak, and off-peak and tiered rates at the TOU off-peak rate of 8.2 cents per kWh, 24 hours a day, seven days a week, effective January 18, 2022 until February 7, 2022.

b) Electricity Distribution Rates

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and custom index adjustments similar to IRM. A cost of service review uses a future test-year to establish rates, and provides for revenues required to recover the forecasted costs of providing the regulated service, and a fair and reasonable return on rate base. Custom index adjustments are typically used for one or more years following a cost of service review and provide for adjustments to rates based on an inflationary factor net of a productivity factor and an efficiency factor as determined relative to other electricity distributors.

On December 19, 2019, the OEB issued its 2020-2024 CIR Decision and on February 20, 2020, the OEB issued its CIR Final Rate Order, both in relation to the rate application filed on August 15, 2018 ["2020-2024 CIR decision and rate order"]. The 2020-2024 CIR decision and rate order approved a revenue requirement of $750.2 million for 2020, and rates calculated on that basis. The rates for 2020 were implemented on March 1, 2020, with an effective date of January 1, 2020. In addition, the 2020-2024 CIR decision and rate order approved subsequent annual rate adjustments based on a custom index for the period commencing on January 1, 2021 and ending on December 31, 2024. The financial considerations of the OEB's 2020-2024 CIR decision and rate order are reflected in the financial statements including disclosure of approved disposition for a number of requested rate riders *[note 8]*.

On August 24, 2020, LDC filed its 2021 rate application seeking the OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2021 and ending on December 31, 2021. On December 10, 2020, the OEB issued a decision and rate order approving LDC's 2021 rates and providing for other deferral and variance account dispositions.

On August 20, 2021, LDC filed its 2022 rate application seeking the OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2022 and ending on December 31, 2022. On December 9, 2021, the OEB issued a decision and rate order approving LDC's 2022 rates and providing for other deferral and variance account dispositions.

c) CDM Activities

On March 21, 2019, the Government of Ontario issued ministerial directives to the IESO related to the delivery of CDM programs. Previously, LDC and other distributors delivered the CDM programs; under the new directives, the IESO became responsible for delivering the CDM programs.

Under its ECA with the IESO, LDC had a joint CDM plan with Oakville Hydro Electricity Distribution Inc. for the delivery of CDM programs over the 2015-2020 period. As part of implementing its new mandate, the IESO terminated the ECA effective June 20, 2019. LDC was required to cease marketing and business development for all CDM programs immediately and make commercially reasonable efforts to wind down the delivery of programs. Under the ECA, LDC was reimbursed from the IESO for its eligible expenses and administrative costs relating to the wind-down of its role in the CDM programs. Participant agreements with customers for many of the CDM programs that were in effect before April 1, 2019 remained in effect notwithstanding the termination of the ECA and LDC remains responsible for its obligations under such agreements. On June 10, 2021, the Government of Ontario issued ministerial directives to the IESO directing it to extend the deadline by which participants are to complete the projects from June 30, 2021 to December 31, 2021, and on December 9, 2021, it was further extended to August 31, 2022. The directive also allows for the completion deadline to be further extended to December 31, 2022, if certain conditions are met. Amounts received from the IESO for the funding of the projects under the participant agreements, but not yet spent, are presented on the balance sheets under current liabilities as deferred conservation credit.

4. ACCOUNTS RECEIVABLE AND UNBILLED REVENUE

Accounts receivable and unbilled revenue consist of the following:

	2021 $	2020 $
Unbilled revenue	**211.6**	228.0
Trade receivables	**175.6**	183.0
Due from related parties *[note 22]*	**39.9**	39.1
Other	**18.3**	14.6
	445.4	464.7

5. OTHER ASSETS

Other assets consist of the following:

	2021 $	2020 $
Prepaid expenses	**18.4**	15.2
Deferred financing costs	**1.4**	1.2
Other	**5.9**	8.3
Total other assets	**25.7**	24.7
Less: Current portion of other assets relating to:		
Prepaid expenses	**18.4**	15.2
Deferred financing costs	**0.4**	0.4
Other	**—**	0.9
Current portion of other assets	**18.8**	16.5
Non-current portion of other assets	**6.9**	8.2

6. PROPERTY, PLANT AND EQUIPMENT

PP&E consist of the following:

	Distribution assets	Land and buildings	Equipment and other	Construction in progress	Total
	$	$	$	$	$
Cost					
Balance as at January 1, 2020	4,465.1	426.9	248.2	479.4	5,619.6
Additions	—	—	—	568.9	568.9
Transfers into service	486.0	13.5	38.4	(537.9)	—
Disposals and retirements	(31.2)	(0.6)	(1.2)	—	(33.0)
Balance as at December 31, 2020	4,919.9	439.8	285.4	510.4	6,155.5
Additions	**—**	**—**	**—**	**587.9**	**587.9**
Transfers into service	**519.5**	**23.3**	**55.5**	**(598.3)**	**—**
Disposals and retirements	**(33.2)**	**(0.2)**	**(2.7)**	**—**	**(36.1)**
Balance as at December 31, 2021	**5,406.2**	**462.9**	**338.2**	**500.0**	**6,707.3**
Accumulated depreciation					
Balance as at January 1, 2020	768.1	65.8	131.2	—	965.1
Depreciation	169.9	15.6	26.9	—	212.4
Disposals and retirements	(8.1)	(0.2)	(1.2)	—	(9.5)
Balance as at December 31, 2020	929.9	81.2	156.9	—	1,168.0
Depreciation	**183.3**	**16.1**	**28.9**	**—**	**228.3**
Disposals and retirements	**(8.9)**	**(0.1)**	**(2.6)**	**—**	**(11.6)**
Balance as at December 31, 2021	**1,104.3**	**97.2**	**183.2**	**—**	**1,384.7**
Carrying amount					
Balance as at December 31, 2020	3,990.0	358.6	128.5	510.4	4,987.5
Balance as at December 31, 2021	**4,301.9**	**365.7**	**155.0**	**500.0**	**5,322.6**

As at December 31, 2021, "Land and buildings" included right-of-use assets related to leases of land and office space with cost of $7.6 million [December 31, 2020 - $7.6 million], accumulated depreciation of $0.9 million [December 31, 2020 - $0.8 million], and carrying amount of $6.7 million [December 31, 2020 - $6.8 million]. For the year ended December 31, 2021, LDC recorded depreciation expense of $0.1 million [2020 - $0.2 million] related to the right-of-use assets.

For the year ended December 31, 2021, borrowing costs in the amount of $2.8 million [2020 - $2.9 million] were capitalized to PP&E with an average interest rate of 3.07% [2020 - 3.19%].

7. INTANGIBLE ASSETS

Intangible assets consist of the following:

	Computer software	Contributions	Software in development	Contributions for work in progress	Total
	$	$	$	$	$
Cost					
Balance as at January 1, 2020	235.6	176.6	21.7	45.9	479.8
Additions	—	—	28.0	11.8	39.8
Transfers into service	29.1	(0.3)	(29.1)	0.3	—
Balance as at December 31, 2020	264.7	176.3	20.6	58.0	519.6
Additions	**—**	**—**	**32.3**	**21.0**	**53.3**
Transfers into service	**25.5**	**18.6**	**(25.5)**	**(18.6)**	**—**
Balance as at December 31, 2021	**290.2**	**194.9**	**27.4**	**60.4**	**572.9**
Accumulated amortization					
Balance as at January 1, 2020	122.6	17.5	—	—	140.1
Amortization	29.3	7.1	—	—	36.4
Balance as at December 31, 2020	151.9	24.6	—	—	176.5
Amortization	**30.7**	**7.7**	**—**	**—**	**38.4**
Balance as at December 31, 2021	**182.6**	**32.3**	**—**	**—**	**214.9**
Carrying amount					
Balance as at December 31, 2020	112.8	151.7	20.6	58.0	343.1
Balance as at December 31, 2021	**107.6**	**162.6**	**27.4**	**60.4**	**358.0**

For the year ended December 31, 2021, borrowing costs in the amount of $1.9 million [2020 - $1.7 million] were capitalized to intangible assets with an average interest rate of 3.07% [2020 - 3.19%].

“Contributions” represent payments made to HONI for dedicated infrastructure in order to receive connections to transmission facilities. The remaining amortization period for computer software ranges from less than one year to seven years. The remaining amortization period for contributions ranges from seven to 25 years.

8. REGULATORY BALANCES

Debit balances consist of the following:

	January 1, 2021 $	Balances arising in the period $	Recovery/ reversal $	Other movements $	December 31, 2021 $	Remaining recovery/ reversal period (months)	Carrying charges applicable
Deferred taxes	**47.9**	**16.0**	**—**	**—**	**63.9**	note 8[a]	**—**
Settlement variances	**3.4**	**73.2**	**(18.1)**	**—**	**58.5**	note 8[b]	(1)
OPEB net actuarial loss	**75.5**	**(26.9)**	**(0.5)**	**—**	**48.1**	note 8[c]	**—**
LRAM	**33.2**	**0.1**	**(29.1)**	**—**	**4.2**	note 8[d]	(1)
Other	**10.4**	**(0.5)**	**(2.3)**	**(0.9)**	**6.7**	12	(1)
	170.4	**61.9**	**(50.0)**	**(0.9)**	**181.4**		

	January 1, 2020 $	Balances arising in the period $	Recovery/ reversal $	Other movements $	December 31, 2020 $	Remaining recovery/ reversal period (months)	Carrying charges applicable
OPEB net actuarial loss	86.3	(5.1)	(5.7)	—	75.5	note 8[c]	—
Deferred taxes	21.4	26.5	—	—	47.9	note 8[a]	—
LRAM	35.9	(1.8)	(0.9)	—	33.2	note 8[d]	(1)
Settlement variances	—	8.2	4.1	(8.9)	3.4	note 8[b]	(1)
OPEB cash versus accrual	7.1	—	(6.2)	—	0.9	note 8[k]	—
Foregone revenue	2.8	—	—	(2.8)	—	note 8[l]	—
IFRS transitional adjustments	—	—	0.8	(0.8)	—	—	—
Other	11.5	1.2	(3.2)	—	9.5	24	(1)
	165.0	29.0	(11.1)	(12.5)	170.4		

(1) Carrying charges were added to the regulatory balance in accordance with the OEB's direction, at a rate of 0.57% for January 1, 2021 to December 31, 2021 [January 1, 2020 to June 30, 2020 - 2.18%; July 1, 2020 to December 31, 2020 - 0.57%].

Credit balances consist of the following:

	January 1, 2021	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2021	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Capital-related revenue requirement	**77.9**	**0.4**	**—**	**—**	**78.3**	note 8[e]	(1)
Derecognition	**33.2**	**0.2**	**—**	**—**	**33.4**	note 8[f]	(1)
Development charges	**14.8**	**2.8**	**(2.4)**	**—**	**15.2**	note 8[g]	(1)
Tax-related variances	**11.2**	**—**	**—**	**—**	**11.2**	note 8[h]	(1)
Gain on disposal	**37.5**	**0.1**	**(32.9)**	**—**	**4.7**	note 8[i]	(1)
Accounts receivable credits	**3.5**	**0.1**	**(0.8)**	**—**	**2.8**	note 8[j]	(1)
Other	**5.3**	**2.3**	**(1.1)**	**(0.9)**	**5.6**	36	(1)
	183.4	**5.9**	**(37.2)**	**(0.9)**	**151.2**		

	January 1, 2020	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2020	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Capital-related revenue requirement	77.1	0.8	—	—	77.9	note 8[e]	(1)
Gain on disposal	61.8	0.8	(25.1)	—	37.5	note 8[i]	(1)
Derecognition	32.8	0.4	—	—	33.2	note 8[f]	(1)
Development charges	10.9	3.9	—	—	14.8	note 8[g]	(1)
Tax-related variances	11.4	(0.2)	—	—	11.2	note 8[h]	(1)
Settlement variances	8.9	—	—	(8.9)	—	note 8[b]	(1)
Accounts receivable credits	3.4	0.1	—	—	3.5	note 8[j]	(1)
Foregone revenue	—	4.0	(0.3)	(2.8)	0.9	note 8[l]	—
IFRS transitional adjustments	0.8	—	—	(0.8)	—	—	—
Other	11.1	2.3	(9.0)	—	4.4	12 - 48	(1)
	218.2	12.1	(34.4)	(12.5)	183.4		

(1) Carrying charges were added to the regulatory balance in accordance with the OEB's direction, at a rate of 0.57% for January 1, 2021 to December 31, 2021 [January 1, 2020 to June 30, 2020 - 2.18%; July 1, 2020 to December 31, 2020 - 0.57%].

The "Balances arising in the period" column consists of new additions to regulatory balances (for both debits and credits). The "Recovery/reversal" column consists of amounts disposed through OEB-approved rate riders. The "Other movements" column consists of impairment and reclassification between the regulatory debit and credit balances. In addition, the "Other movements" column includes reclassification of regulatory deferral accounts considered to be insignificant into the "Other" categories. There was no impairment recorded for the year ended December 31, 2021.

Reconciliation between the net movements in regulatory balances shown in the regulatory debit and credit balances tables and the net movements presented on the statements of income and the statements of comprehensive income is as follows:

	2021 $	2020 $
Total movements per regulatory debit balances table	**11.0**	5.4
Total movements per regulatory credit balances table	**32.2**	34.8
Total net movements	**43.2**	40.2
Net movements per financial statements:		
Net movements in regulatory balances	**54.1**	18.8
Net movements in regulatory balances arising from deferred taxes	**8.9**	25.2
Net movements in regulatory balances related to OCI, net of tax	**(19.8)**	(3.8)
Total net movements per financial statements	**43.2**	40.2

Regulatory developments in Ontario's electricity industry and other governmental policy changes may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. There is a risk that the OEB may disallow the recovery of a portion of certain costs incurred in the current period through future rates or disagree with the proposed recovery period. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, any impairment will be recorded in the period when the assessment is made.

The regulatory balances of LDC consist of the following:

a) Deferred taxes

This regulatory balance relates to both deferred tax amounts recorded under IFRS 14 *Regulatory Deferral Accounts* ["IFRS 14"] *[note 25[a]]* and the expected future electricity distribution rate impact to customers arising from timing differences in the recognition of deferred tax assets and liabilities. LDC does not apply for disposition of the balance since it is reversed through timing differences in the recognition of deferred tax assets and liabilities.

The amounts recorded under IFRS 14 include the deferred tax asset related to regulatory balances of $15.5 million [debits] as at December 31, 2021 [December 31, 2020 - $8.3 million [debits]], and the recognition of a regulatory balance in respect of additional temporary differences for which a deferred tax amount was recognized of $17.5 million [credits] as at December 31, 2021 [December 31, 2020 - $14.3 million [credits]].

The deferred tax amount related to the expected future impact to electricity distribution rates was $65.9 million [debits] as at December 31, 2021 [December 31, 2020 - $53.9 million [debits]].

b) Settlement variances

This account includes the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by LDC. LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB.

In the 2020-2024 CIR decision and rate order, the OEB approved disposition of $7.5 million related to the 2018 settlement variances over a 22-month period commencing on March 1, 2020. As part of OEB's decision and rate order approving LDC's 2021 rates, OEB approved recovery of $25.3 million related to 2019 settlement variances over a 12-month period commencing January 1, 2021. Settlement variances pertaining to 2020 did not exceed the disposition threshold in accordance with OEB policy and will be aggregated with 2021 settlement variances which are yet to be applied for disposition.

c) OPEB net actuarial loss

This regulatory balance accumulates the actuarial gains and losses arising from changes in actuarial assumptions and experience adjustments recognized in OCI. The balance arising during the year ended December 31, 2021 of $26.9 million is related to the actuarial gain recorded for the year [2020 - $5.1 million actuarial gain] *[note 12[a]]*. The net position is an actuarial loss recoverable in future rates.

In the 2020-2024 CIR decision and rate order, the OEB approved partial recovery of the balance amounting to $6.4 million over a 10-month period commencing on March 1, 2020.

d) Lost revenue adjustment mechanism

This regulatory balance relates to the difference between the level of CDM program activities included in LDC's load forecast used to set approved rates and the actual impact of CDM activities achieved.

As part of OEB's decision and rate order approving LDC's 2021 rates, OEB approved recovery of $33.1 million related to 2018 and 2019 variances over a 12-month period commencing January 1, 2021.

e) Capital-related revenue requirement

This regulatory balance relates to the asymmetrical variance between the cumulative 2015 to 2019 capital-related revenue requirement included in rates and the actual capital-related revenue requirement over the same period. The cumulative 2015 to 2019 capital-related revenue requirement included in rates exceeded the actual capital-related revenue requirement over the same rate period. LDC applied for disposition of this account in order to return the balance to customers through a rate rider.

In the 2020-2024 CIR decision and rate order, the OEB approved disposition of the 2019 balance over a 24-month period commencing on January 1, 2023.

f) Derecognition

This regulatory balance relates to the difference between the revenue requirement on derecognition of PP&E and intangible assets included in the OEB-approved rates and the actual amounts of derecognition.

In the 2020-2024 CIR decision and rate order, the OEB approved disposition of the 2019 balance over a 12-month period commencing on January 1, 2022.

g) Development charges

This regulatory balance relates to excess expansion deposits retained by LDC where the requested number of connections or electricity demand were not met by the connecting customer. Pursuant to the OEB's Distribution System Code, LDC may collect expansion deposits from specific customers to guarantee the payment of additional costs relating to expansion projects. During the customer connection horizon, LDC has an obligation to annually return the expansion deposit to the connecting customer in proportion to the actual connections or electricity demand that occurred in that year. If the number of connections or electricity demand requested by the customer do not materialize by the end of the connection horizon, LDC retains the excess expansion deposit not otherwise returned to the connecting customer.

In the 2020-2024 CIR decision and rate order, the OEB approved disposition of the 2019 balance over a 48-month period commencing on January 1, 2021.

h) Tax-related variance accounts

The regulatory balance arose primarily from the revenue requirement impact of accelerated capital cost allowance deductions from the Accelerated Investment Incentive tax measure which received Royal Assent on June 21, 2019. In the 2020-2024 CIR decision and rate order, the OEB approved disposition of the 2019 balance over a 24-month period commencing on January 1, 2023.

In addition, the balance includes a residual credit balance that arose from favourable income tax reassessments on certain prior year tax positions received, which differed from those assumed in previous applications for electricity distribution rates.

i) Gain on disposal

This regulatory balance consists of the net of amounts disposed through the OEB-approved rate riders offset by the related tax savings [credits] and the after-tax gain realized on the sale of three significant LDC properties between 2015 and 2018.

As part of the 2015-2019 CIR decision and rate order, LDC agreed to a rate rider that would pass the total forecasted net gains along with future tax savings on the first two properties back to customers, effective from March 1, 2016 to December 31, 2018. The gain on disposal of the two properties was realized by LDC in 2015 and 2018, respectively. In the second quarter of 2017, LDC realized a gain in connection with the disposal of the third property.

In the 2020-2024 CIR decision and rate order, the incremental balance related to the actual realized gain and tax savings that exceeded the approved rate riders in connection with the disposal of the first two LDC properties was approved for disposition over a 22-month period commencing on March 1, 2020. The OEB also approved disposition of the actual realized gain and tax savings in connection with the disposal of the third property over a 22-month period commencing on March 1, 2020.

j) Accounts receivable credits

This regulatory account relates to closed customer accounts with unclaimed credit balances.

In the 2020-2024 CIR decision and rate order, the OEB approved disposition of the 2019 balance over a 48-month period commencing on January 1, 2021.

k) OPEB cash versus accrual

This regulatory balance relates to the difference between LDC's forecasted OPEB costs determined on an accrual basis and the cash payments made under the OPEB plans.

In the 2020-2024 CIR decision and rate order, the OEB approved recovery of the 2019 balance over a 10-month period commencing on March 1, 2020 and recovery of OPEB costs on an accrual basis.

l) Foregone revenue

The 2020 balance arising of $4.0 million is revenue to be returned to customers, related to January and February 2020 as a result of implementing new OEB-approved rates on March 1, 2020. In the 2020-2024 CIR decision and rate order, the OEB approved disposition of 2020 foregone revenue over a 22-month period commencing on March 1, 2020.

m) COVID-19 emergency

On March 25, 2020, the OEB established the COVID-19 Emergency Deferral Account for regulatory balances to record the costs of changes to billing systems resulting from the Ontario Government's TOU emergency order, other incremental costs and lost revenues associated with the COVID-19 pandemic. On May 14, 2020, the OEB launched a consultation process to inform its decision-making with respect to how the account will operate, including eligibility requirements, and the process and timing for the disposition.

On December 16, 2020, OEB staff issued a proposal which provided an update on the OEB's orientation in the policy consultation. Based on this information, management believed that there was high uncertainty in regard to the recoverability of costs and lost revenues related to government and OEB-mandated customer relief actions and therefore a low probability of recovery. On June 17, 2021, the OEB issued the final report on the COVID-19 Emergency Deferral Account consultation. The assessment on the recoverability of costs and lost revenues associated with the pandemic remains unchanged. Consequently, no amounts have been recorded in the COVID-19 Emergency Deferral Account as at December 31, 2021.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities consist of the following:

	2021 $	2020 $
Trade payables	**261.3**	250.2
Accrued liabilities	**123.8**	104.9
Due to related parties *[note 22]*	**36.4**	45.0
Other	**1.4**	1.4
	422.9	401.5

10. DEFERRED REVENUE

Deferred revenue consists of the following:

	2021 $	2020 $
Capital contributions, beginning of year	**553.4**	410.0
Capital contributions received [(1)]	**123.1**	151.7
Amortization	**(12.3)**	(8.2)
Other	**(0.4)**	(0.1)
Capital contributions, end of year	**663.8**	553.4
Other deferred revenue, beginning of year	**2.3**	1.1
Other deferred revenue received	**16.7**	15.6
Revenue recognized	**(15.6)**	(14.4)
Other deferred revenue, end of year	**3.4**	2.3
Total deferred revenue	**667.2**	555.7
Less: Current portion of deferred revenue relating to:		
Capital contributions	**21.0**	15.5
Other deferred revenue	**3.4**	2.3
Current portion of deferred revenue	**24.4**	17.8
Non-current portion of deferred revenue	**642.8**	537.9

[(1)] Includes non-cash contributions of $21.9 million [2020 - $13.0 million].

11. NOTES PAYABLE TO RELATED PARTY

Notes payable to related party consist of the following:

	2021 $	2020 $
Notes payable to related party:		
5.59% Long-term note payable to the Corporation due May 21, 2040	**200.0**	200.0
3.59% Long-term note payable to the Corporation due November 18, 2021	**—**	300.0
2.96% Long-term note payable to the Corporation due April 10, 2023	**250.0**	250.0
4.01% Long-term note payable to the Corporation due April 9, 2063	**200.0**	200.0
4.13% Long-term note payable to the Corporation due September 16, 2044	**200.0**	200.0
3.60% Long-term note payable to the Corporation due July 28, 2045	**200.0**	200.0
3.988% Long-term note payable to the Corporation due April 9, 2063	**45.0**	45.0
2.572% Long-term note payable to the Corporation due August 25, 2026	**200.0**	200.0
3.535% Long-term note payable to the Corporation due February 28, 2048	**200.0**	200.0
2.488% Long-term note payable to the Corporation due December 11, 2029	**200.0**	200.0
3.042% Long-term note payable to the Corporation due December 10, 2049	**200.0**	200.0
1.55% Long-term note payable to the Corporation due October 15, 2030	**200.0**	200.0
2.52 % Long-term note payable to the Corporation due October 20, 2031	**150.0**	—
3.32 % Long-term note payable to the Corporation due October 18, 2051	**200.0**	—
6.16% Demand note payable to the Corporation due on demand	**45.0**	45.0
3.32% Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	15.0
Total notes payable to related party	**2,505.0**	2,455.0
Less: Unamortized debt issuance costs	**13.0**	11.6
Current portion of notes payable to related party *[note 22]*	**60.0**	359.8
Long-term portion of notes payable to related party *[note 22]*	**2,432.0**	2,083.6

All notes payable to the Corporation are unsecured, rank equally and will be settled in cash.

On October 15, 2020, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $200.0 million payable on October 15, 2030, which bears interest at a rate of 1.55% per annum. Interest is calculated and payable semi-annually in arrears on April 15 and October 15.

On October 18, 2021, LDC issued two promissory notes to the Corporation. The principal amounts of the promissory notes are $150.0 million payable on October 20, 2031, which bears interest at a rate of 2.52% per annum, and $200.0 million payable on October 18, 2051, which bears interest at a rate of 3.32% per annum. Interest is calculated and payable semi-annually in arrears on April 20 and October 20, and April 18 and October 18 of each year, respectively for both promissory notes.

On November 18, 2021, LDC repaid its $300.0 million promissory note to the Corporation.

Subsequent to December 31, 2021, LDC repaid its $15.0 million promissory note to the Corporation.

12. EMPLOYEE FUTURE BENEFITS

Multi-employer pension plan

LDC's eligible employees participate in a defined benefit pension plan through OMERS. As at December 31, 2021, OMERS had disclosed that the plan was 97.0% funded [December 31, 2020 - 97.0%]. LDC is not able to assess the implications, if any, of OMERS' strategy to address the funding shortfall or of the withdrawal of other participating entities from the OMERS plan on its future contributions. For the year ended December 31, 2021, LDC's

contributions were $16.1 million [2020 - $17.6 million], representing less than five percent of total contributions to the OMERS plan. LDC expects to contribute approximately $18.1 million to the OMERS plan in 2022.

Post-employment benefits

a) Benefit obligation

	2021 $	2020 $
Balance, beginning of year	**332.7**	334.9
Current service cost	**3.0**	4.2
Interest cost	**8.1**	9.8
Benefits paid	**(12.7)**	(11.7)
Past service cost [1]	**—**	1.0
Experience loss (gain) [2]	**3.2**	(6.3)
Actuarial gain arising from changes in demographic assumptions [2]	**—**	(27.2)
Actuarial loss (gain) arising from changes in financial assumptions [2] [3]	**(28.2)**	28.0
Transfer from related parties	**0.5**	—
Balance, end of year	**306.6**	332.7

[1] An arbitration process was ongoing prior to December 31, 2019 with respect to certain employees of LDC. As a result of the arbitrator's decision received on March 3, 2020, LDC recorded an estimated past service cost relating to the existence of a post-employment benefit obligation as at December 31, 2019. The plan amendment details were finalized in 2020 and were included as a component of the past service cost as at December 31, 2020. On August 9, 2021, $26.2 million of letters of credit were issued to support the related obligations.
[2] Actuarial loss [gain] on accumulated sick leave credits of $2.0 million [2020 - ($0.5) million] is recognized in benefit cost *[note 12[c]]* and ($0.1) million in transfer from related parties [2020 - $0.1 million], and actuarial gain on medical, dental and life insurance benefits of $26.9 million [2020 - $5.1 million] is recognized in OCI *[note 12[d]]*.
[3] Reflects the impact of change in discount rate *[note 12[e]]*.

b) Amounts recognized in regulatory balances

As at December 31, 2021, the amount recognized in regulatory balances related to accumulated net actuarial loss was $48.1 million [December 31, 2020 - $75.5 million] *[note 8[c]]*.

c) Benefit cost recognized

	2021 $	2020 $
Current service cost	**3.0**	4.2
Interest cost	**8.1**	9.8
Past service cost *[note 12[a]]*	**—**	1.0
Actuarial loss (gain) on other employee benefits *[note 12[a]]*	**2.0**	(0.5)
Benefit cost	**13.1**	14.5
Capitalized to PP&E and intangible assets	**5.5**	6.4
Charged to operating expenses	**7.6**	8.1

d) Amounts recognized in OCI

	2021 $	2020 $
Actuarial gain *[note 12[a]]*	**(26.9)**	(5.1)
Income tax expense in OCI *[note 20]*	**7.1**	1.3
Remeasurements of post-employment benefits, net of tax	**(19.8)**	(3.8)
Net movements in regulatory balances related to OCI, net of tax	**19.8**	3.8
OCI, net of tax	**—**	—

e) Significant assumptions

	2021 %	2020 %
Discount rate used in the calculation of:		
Benefit obligation as at December 31	**3.00**	2.50
Assumed medical and dental cost trend rates as at December 31:		
Rate of increase in dental costs assumed for next year	**4.00**	4.00
Rate of increase in medical costs assumed for next year	**5.00**	5.00

f) Sensitivity analysis

Significant actuarial assumptions for benefit obligation measurement purposes are discount rate and assumed medical and dental cost trend rates. The weighted average duration of the benefit obligation as at December 31, 2021 was 16.5 [2020 - 17.0]. The sensitivity analysis below has been determined based on reasonably possible changes of the assumptions, in isolation of one another, occurring at the end of the reporting period. This analysis may not be representative of the actual change since it is unlikely that changes in the assumptions would occur in isolation of one another as some of the assumptions may be correlated.

Changes in key assumptions would have had the following effect on the benefit obligation:

	Change in assumption	2021 $	2020 $
Benefit obligation		**306.6**	332.7
Discount rate	1% ↑	**(46.0)**	(49.9)
	1% ↓	**59.0**	64.0
Medical and dental cost trend rate	1% ↑	**37.4**	40.6
	1% ↓	**(33.1)**	(35.9)

13. CAPITAL MANAGEMENT

LDC's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain, refurbish and expand the electricity distribution system;
- ensure sufficient liquidity is available [either through cash and cash equivalents or borrowings from TH Energy or the Corporation] to meet the needs of the business; and

- minimize finance costs while taking into consideration current and future industry, market and economic risks and conditions.

LDC monitors forecasted cash flows, capital expenditures, debt repayment and key credit ratios similar to those used by key rating agencies. LDC manages capital by preparing short-term and long-term cash flow forecasts. In addition, LDC borrows from TH Energy or the Corporation as required to help fund some of the periodic net cash outflows and to maintain available liquidity. There have been no changes in LDC's approach to capital management during the year. As at December 31, 2021, LDC's definition of capital included equity, bank indebtedness, borrowings through the Corporation and obligations under leases, including the current portion thereof, and has remained unchanged from the definition as at December 31, 2020. As at December 31, 2021, equity amounted to $2,243.4 million [December 31, 2020 - $2,107.1 million], and bank indebtedness, borrowings through the Corporation and obligations under leases, including the current portion thereof, amounted to $2,492.2 million [December 31, 2020 - $2,443.7 million].

14. FINANCIAL INSTRUMENTS

a) Fair value

As at December 31, 2021 and December 31, 2020, the fair values of cash and cash equivalents, accounts receivable and unbilled revenue, and accounts payable and accrued liabilities approximated their carrying amounts due to the short maturity of these instruments *[note 25[j]]*. The fair value of customer deposits approximates their carrying amount taking into account interest accrued on the outstanding balance. Obligations under leases are measured based on a discounted cash flow analysis and fair values approximate the carrying amounts as management believes that the fixed interest rates are representative of current market rates.

The carrying amounts and fair values of LDC's notes payable to related party consist of the following:

	2021 $		2020 $	
	Carrying amount	**Fair value [1]**	**Carrying amount**	**Fair value [1]**
Notes payable to the Corporation				
5.59% due May 21, 2040	**199.0**	**274.7**	198.9	292.9
3.59% due November 18, 2021	—	—	299.8	308.3
2.96% due April 10, 2023	**249.7**	**255.6**	249.6	263.8
4.01% due April 9, 2063	**198.8**	**249.5**	198.8	272.5
4.13% due September 16, 2044	**198.6**	**238.7**	198.5	256.3
3.60% due July 28, 2045	**198.8**	**221.4**	198.8	238.5
3.988% due April 9, 2063	**44.7**	**56.2**	44.7	61.0
2.572% due August 25, 2026	**199.4**	**207.0**	199.2	217.7
3.535% due February 28, 2048	**198.7**	**220.6**	198.7	238.7
2.488% due December 11, 2029	**199.1**	**205.4**	199.0	197.6
3.042% due December 10, 2049	**198.7**	**202.8**	198.7	220.4
1.55% due October 15, 2030	**198.8**	**189.0**	198.7	200.8
2.52% due October 20, 2031	**149.1**	**152.1**	—	—
3.32% due October 18, 2051	**198.6**	**214.0**	—	—
Demand note payable to the Corporation due on demand	**45.0**	**45.0**	45.0	45.0
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	**15.0**	15.0	15.4
	2,492.0	**2,747.0**	2,443.4	2,828.9

[1] The fair value measurement of financial instruments for which the fair value has been disclosed is included in Level 2 of the fair value hierarchy *[note 25[k]]*.

b) Financial risks

The following is a discussion of certain financial risks and related mitigation strategies that have been identified by LDC for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

Credit risk

LDC is exposed to the risk of counterparties defaulting on their obligations. LDC monitors and limits its exposure to credit risk on a continuous basis. The credit risk related to cash and cash equivalents is mitigated by LDC's treasury policies on assessing and monitoring the credit exposures of counterparties.

LDC's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. LDC is subject to credit risk with respect to customer non-payment of electricity bills. As a result of the COVID-19 pandemic and material disruptions to businesses and the economy, LDC's credit risk has increased due to some customers not being able to pay their electricity bills when due, and LDC's security interest or other protective measures, if any, provided to LDC, such as letters of credit, cash deposits or pre-authorized payments may not be sufficient. LDC considers the current economic and credit conditions to determine the loss allowance of its accounts receivable and unbilled revenue. Given the high degree of uncertainty caused by the COVID-19 pandemic, the estimates and judgments made by management in the preparation of the expected credit loss allowance are subject to a high degree of estimation uncertainty. Based on LDC's current estimates and assumptions, including but not limited to recent trends for customer collections and current and forecasted economic conditions, LDC adjusted the expected credit loss provision to account for the higher level of expected customer defaults at the balance sheet date. LDC continues to actively monitor its exposure to credit risk and for the year ended December 31, 2021, recorded an incremental provision of $1.2 million [2020 - $17.2 million] to its expected credit loss allowance as a result of the COVID-19 pandemic.

LDC obtains security instruments from certain customers in accordance with direction provided by the OEB. As at December 31, 2021, LDC held security deposits in the amount of $72.4 million [December 31, 2020 - $63.6 million], of which $39.4 million [December 31, 2020 - $33.4 million] was related to security deposits on offers to connect to guarantee the payment of additional costs related to expansion projects. LDC's security instruments may not provide sufficient protection from counterparties defaulting on their obligations. As at December 31, 2021, there were no significant concentrations of credit risk with respect to any customer. The credit risk and mitigation strategies with respect to unbilled revenue are the same as those for accounts receivable.

LDC did not have any single customer that generated more than 10% of total revenue for the years ended December 31, 2021 and December 31, 2020.

Credit risk associated with accounts receivable and unbilled revenue is as follows:

	2021 $	2020 $
Accounts receivable, gross		
Outstanding for not more than 30 days	**183.8**	164.9
Outstanding for more than 30 days and not more than 120 days	**20.2**	51.2
Outstanding for more than 120 days	**36.7**	25.5
Total accounts receivable, gross	**240.7**	241.6
Unbilled revenue, gross	**237.9**	253.3
Credit loss allowance	**(33.2)**	(30.2)
Total accounts receivable and unbilled revenue	**445.4**	464.7

Unbilled revenue represents amounts for which LDC has a contractual right to receive cash through future billings and are unbilled at period-end. Unbilled revenue is considered in conjunction with accounts receivable and is included in the loss allowance as at December 31, 2021 and December 31, 2020.

LDC has a broad base of customers. As at December 31, 2021 and December 31, 2020, LDC's accounts receivable for non-commercial customers and unbilled revenue which were not past due or impaired were assessed by management to have no significant collection risk. Accounts receivable balances related to commercial customers are assessed on a holistic basis and the entire billed balance, including amounts not past due, is assessed for significant collection risk.

Reconciliation between the opening and closing credit loss allowance balances for accounts receivable and unbilled revenue is as follows:

	2021 $	2020 $
Balance, beginning of year	**(30.2)**	(11.6)
Additional credit loss allowance	**(6.8)**	(22.7)
Write-offs	**4.0**	4.4
Recoveries of previously written-off balances	**(0.2)**	(0.3)
Balance, end of year	**(33.2)**	(30.2)

c) Market risks

Interest rate risk

LDC is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations *[note 12[f]]*. LDC is also exposed to short-term interest rate risk on the net of cash and cash equivalents and customer deposits. Notes payable to related party bear interest based on the prevailing market conditions at the time of issuance.

As at December 31, 2021, aside from the valuation of its post-employment benefit obligations, most of LDC's remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing. LDC estimates that a 25-basis point increase [decrease] in short-term interest rates, with all other variables held constant, would result in an increase [decrease] of approximately $0.1 million to annual finance costs.

Liquidity risk

LDC is exposed to liquidity risk related to its ability to fund its obligations as they become due. LDC monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. LDC has access to credit facilities and borrowings through the Corporation and monitors cash balances daily. LDC's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing finance costs. LDC relies on debt financing from borrowings through the Corporation and existing credit facilities to finance its daily operations, repay existing indebtedness, and fund capital expenditures. The current challenging economic climate affected by factors including but not limited to the effects of the COVID-19 pandemic may lead to material adverse changes in cash flows, working capital levels and/or debt balances, which may also have a direct negative impact on LDC's operating results and financial position in the future. Accordingly, LDC continues to monitor and adapt its response plan as the economic climate evolves.

Liquidity risks associated with financial commitments are as follows:

2021	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Accounts payable and accrued liabilities [1]	**402.8**	**—**	**—**	**—**	**—**	**—**
Obligations under leases	**—**	**—**	**0.1**	**0.1**	**—**	**—**
Long-term notes payable to the Corporation						
5.59% due May 21, 2040	**—**	**—**	**—**	**—**	**—**	**200.0**
2.96% due April 10, 2023	**—**	**250.0**	**—**	**—**	**—**	**—**
4.01% due April 9, 2063	**—**	**—**	**—**	**—**	**—**	**200.0**
4.13% due September 16, 2044	**—**	**—**	**—**	**—**	**—**	**200.0**
3.60% due July 28, 2045	**—**	**—**	**—**	**—**	**—**	**200.0**
3.988% due April 9, 2063	**—**	**—**	**—**	**—**	**—**	**45.0**
2.572% due August 25, 2026	**—**	**—**	**—**	**—**	**200.0**	**—**
3.535% due February 28, 2048	**—**	**—**	**—**	**—**	**—**	**200.0**
2.488% due December 11, 2029	**—**	**—**	**—**	**—**	**—**	**200.0**
3.042% due December 10, 2049	**—**	**—**	**—**	**—**	**—**	**200.0**
1.55% due October 15, 2030	**—**	**—**	**—**	**—**	**—**	**200.0**
2.52% due October 20, 2031	**—**	**—**	**—**	**—**	**—**	**150.0**
3.32% due October 18, 2051	**—**	**—**	**—**	**—**	**—**	**200.0**
Demand note payable to the Corporation due on demand	**45.0**	**—**	**—**	**—**	**—**	**—**
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15.0**	**—**	**—**	**—**	**—**	**—**
Interest payments on long-term notes payable and demand notes payable	**81.0**	**77.0**	**73.2**	**73.2**	**73.2**	**1,298.8**
	543.8	**327.0**	**73.3**	**73.3**	**273.2**	**3,293.8**

[1] Accounts payable and accrued liabilities exclude $20.1 million of accrued interest on long-term notes payable and demand notes payable included within "Interest payments on long-term notes payable and demand notes payable".

Foreign exchange risk

As at December 31, 2021, LDC had limited exposure to the changing values of foreign currencies. While LDC purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions is not material to the financial statements.

15. FINANCIAL ASSISTANCE

As at December 31, 2021, $51.5 million [December 31, 2020 - $32.9 million] of letters of credit had been issued by the Corporation, on behalf of LDC, under its $100.0 million demand facility mainly to support LDC's prudential requirements with the IESO.

16. SHARE CAPITAL

Share capital consists of the following:

	2021 $	2020 $
Authorized		
The authorized share capital of LDC consists of an unlimited number of common shares without par value.		
Issued and outstanding		
1,000 common shares, of which all were fully paid.	**556.3**	556.3

Dividends

During the year ended December 31, 2021, the Board of Directors of LDC declared and paid dividends to the Corporation totalling $0.6 million [2020 - $0.7 million].

17. REVENUES

Revenues consist of the following:

	2021 $	2020 $
Revenue from contracts with customers		
Energy sales	**2,702.4**	3,142.5
Distribution revenue	**759.1**	694.4
Pole and duct rentals	**18.2**	20.4
Ancillary services revenue	**16.7**	13.8
Other regulatory service charges	**7.8**	7.5
Street lighting services	**7.8**	6.9
Miscellaneous	**17.6**	14.1
Revenue from other sources		
Capital contributions	**12.3**	8.2
Other	**7.7**	8.9
	3,549.6	3,916.7

Energy sales and distribution revenue by customer class are as follows:

	2021 $	2020 $
Residential service [1]	**1,000.5**	1,120.7
General service [2]	**2,270.6**	2,512.4
Large users [3]	**190.4**	203.8
Total energy sales and distribution revenue	**3,461.5**	3,836.9

[1] "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multi-family units and seasonal occupancy.
[2] "General Service" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a 12-month period.
[3] "Large Users" means a service provided to a customer with a monthly peak demand of 5,000 kW or greater averaged over a 12-month period.

18. OPERATING EXPENSES

Operating expenses consist of the following:

	2021 $	2020 $
Salaries and benefits	**203.6**	224.0
External services	**156.3**	135.7
Other support costs [1]	**30.8**	45.4
Materials and supplies	**27.0**	26.6
Less: Capitalized costs	**(107.0)**	(117.8)
	310.7	313.9

[1] Includes expected credit loss, taxes other than income taxes, utilities, rental, communication, insurance, and other general and administrative expenses.

For the year ended December 31, 2021, LDC recognized operating expenses of $17.6 million related to materials and supplies used to service electricity distribution assets [2020 - $16.3 million].

19. FINANCE COSTS

Finance costs consist of the following:

	2021 $	2020 $
Interest income	**(0.9)**	(0.7)
Interest expense		
Interest on long-term debt [1]	**85.9**	82.7
Interest on short-term debt	**2.2**	2.6
Other interest	**0.3**	0.4
Capitalized borrowing costs	**(4.7)**	(4.6)
	82.8	80.4

[1] Includes amortization of debt issuance costs, discounts and premiums.

20. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined statutory Canadian federal and provincial income tax rate. Reconciliation of income tax expense computed at the statutory income tax rate to the income tax provision is set out below:

	2021 $	2020 $
Rate reconciliation before net movements in regulatory balances		
Income before income taxes	**94.3**	100.7
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**25.0**	26.7
Non-taxable amounts	**(5.5)**	(0.3)
Gain on disposals of PP&E	**0.1**	—
Other	**0.8**	2.1
Income tax expense	**20.4**	28.5
Effective tax rate	**21.6%**	28.3%
Rate reconciliation after net movements in regulatory balances		
Net income after net movements in regulatory balances, before income tax [(1)]	**148.4**	119.5
Statutory Canadian federal and provincial income tax rate	**26.5%**	26.5%
Expected income tax expense	**39.3**	31.7
Temporary differences recoverable in future rates	**(27.1)**	(29.4)
Gain on disposals of PP&E	**0.1**	—
Other	**(0.8)**	1.0
Income tax expense and income tax recorded in net movements in regulatory balances	**11.5**	3.3
Effective tax rate	**7.7%**	2.8%

[(1)] Income tax includes income tax expense and income tax recorded in net movements in regulatory balances.

Income tax expense as presented in the statements of income and statements of comprehensive income are as follows:

	2021 $	2020 $
Income tax expense	**20.4**	28.5
Income tax recorded in net movements in regulatory balances	**(8.9)**	(25.2)
Income tax expense and income tax recorded in net movements in regulatory balances	**11.5**	3.3
Income tax expense in OCI *[note 12[d]]*	**7.1**	1.3
Income tax recovery in OCI recorded in net movements in regulatory balances	**(7.1)**	(1.3)
Income tax expense in OCI	**—**	—

Components of income tax expense and income tax recorded in net movements in regulatory balances are as follows:

	2021 $	2020 $
Current tax expense		
Current year	**10.9**	5.8
Deferred tax expense		
Origination and reversal of temporary differences	**0.6**	(2.5)
Income tax expense and income tax recorded in net movements in regulatory balances	**11.5**	3.3

Deferred tax assets [liabilities] consist of the following:

	Net balance January 1, 2021 $	Recognized in net income $	Recognized in OCI $	Net balance December 31, 2021 $
PP&E and intangible assets	**(114.0)**	**(29.6)**	—	**(143.6)**
Post-employment benefits	**88.1**	**0.3**	**(7.1)**	**81.3**
Tax credit carryforward	**2.5**	**(0.7)**	—	**1.8**
Other taxable temporary differences	**(23.7)**	**20.4**	—	**(3.3)**
	(47.1)	**(9.6)**	**(7.1)**	**(63.8)**

	Net balance January 1, 2020 $	Recognized in net income $	Recognized in OCI $	Net balance December 31, 2020 $
PP&E and intangible assets	(83.3)	(30.7)	—	(114.0)
Post-employment benefits	88.7	0.7	(1.3)	88.1
Tax credit carryforward	—	2.5	—	2.5
Other taxable temporary differences	(28.5)	4.8	—	(23.7)
	(23.1)	(22.7)	(1.3)	(47.1)

21. STATEMENTS OF CASH FLOWS

Changes in non-cash operating working capital provided [used] cash as follows:

	2021 $	2020 $
Accounts receivable and unbilled revenue	**18.4**	72.7
Income tax receivable	**8.7**	(10.8)
Materials and supplies	**(0.1)**	(2.0)
Other current assets	**(2.3)**	(2.5)
Accounts payable and accrued liabilities	**(8.2)**	(22.5)
Deferred revenue	**5.2**	4.6
Deferred conservation credit	**(4.3)**	6.5
	17.4	46.0

Reconciliation between the amounts presented on the statements of cash flows and total additions to PP&E and intangible assets is as follows:

	2021 $	2020 $
Purchase of PP&E, cash basis	**548.0**	620.5
Net change in accounts payable and accruals related to PP&E	**16.6**	(65.5)
Non-cash contributed assets [1]	**21.9**	13.0
Other	**1.4**	0.9
Total additions to PP&E	**587.9**	568.9
Purchase of intangible assets, cash basis	**47.6**	40.8
Net change in accounts payable and accruals related to intangible assets	**5.7**	(1.0)
Total additions to intangible assets	**53.3**	39.8

[1] Includes reclassification from amounts previously reported due to change in presentation of the statements of cash flows for amounts between purchase of PP&E and capital contributions received of $13.0 million for the year ended December 31, 2020.

Summary of changes in liabilities arising from financing activities:

	2020 $	Cash flows [1] $	Non-cash changes $	2021 $
Year ended December 31				
Notes payable to related party *[note 11]*	**2,443.4**	**47.7**	**0.9**	**2,492.0**
Accrued interest [2]	**19.2**	**(86.3)**	**87.2**	**20.1**
Dividends payable	**—**	**(0.6)**	**0.6**	**—**
Lease liability [3]	**0.3**	**—**	**(0.1)**	**0.2**
	2,462.9	**(39.2)**	**88.6**	**2,512.3**

	2019 $	Cash flows [1] $	Non-cash changes $	2020 $
Year ended December 31				
Notes payable to related party *[note 11]*	2,243.9	198.6	0.9	2,443.4
Accrued interest [2]	19.4	(84.6)	84.4	19.2
Dividends payable	—	(0.7)	0.7	—
Lease liability [3]	0.3	—	—	0.3
	2,263.6	113.3	86.0	2,462.9

[1] Cash inflows and cash outflows arising from notes payable to related party are presented on a net basis.
[2] Included within accounts payable and accrued liabilities *[note 9]*.
[3] Included within other liabilities.

22. RELATED PARTY TRANSACTIONS

For LDC, transactions with related parties include transactions with the City, which is the sole shareholder of the Corporation, the Corporation, and TH Energy, a wholly owned subsidiary of the Corporation.

	City $	Corporation $	TH Energy $
For year ended December 31, 2021			
Revenues	**259.3**	**—**	**7.8**
Operating expenses (recoveries) and capital expenditures (recoveries)	**(1.5)**	**0.5**	**(1.7)**
Finance costs	**—**	**85.5**	**—**
Dividends declared and paid	**—**	**0.6**	**—**
As at December 31, 2021			
Accounts receivable and unbilled revenue	**39.5**	**—**	**0.4**
Accounts payable and accrued liabilities	**15.0**	**21.4**	**—**
Current portion of notes payable to related party	**—**	**60.0**	**—**
Long-term portion of notes payable to related party	**—**	**2,432.0**	**—**
Customer deposits	**12.8**	**—**	**—**

	City $	Corporation $	TH Energy $
For year ended December 31, 2020			
Revenues	285.5	—	7.0
Operating expenses (recoveries) and capital expenditures	10.5	1.2	(0.9)
Finance costs	—	82.9	—
Dividends declared and paid	—	0.7	—
As at December 31, 2020			
Accounts receivable and unbilled revenue	39.1	—	—
Accounts payable and accrued liabilities	25.7	19.1	0.2
Current portion of notes payable to related party	—	359.8	—
Long-term portion of notes payable to related party	—	2,083.6	—
Customer deposits	12.6	—	—

Revenues represent amounts charged to the City primarily for electricity and ancillary services, and to TH Energy for street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services, and the Corporation for purchased corporate and management services. Operating expense recoveries represent amounts charged to TH Energy for the provision of goods and services. Capital expense recoveries represent amounts reversed by the City for closed road cut repair accruals. Finance costs represent interest charged by the Corporation on the notes payable *[note 11]*. Dividends are paid to the Corporation *[note 16]*.

Accounts receivable and unbilled revenue represent receivables from the City primarily for electricity and ancillary services, and TH Energy for the provision of goods and services, including amounts not yet billed. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services. Included in the accounts payable and accrued liabilities are amounts payable to the Corporation for purchased corporate and management services and interest accruing on the notes payable to the Corporation and amounts payable to TH Energy for provision of goods and services. Notes payable to related party represent amounts borrowed from the Corporation *[note 11]*. Customer deposits represent amounts received from the City for future expansion projects.

Key management personnel include LDC's senior executive officers and members of the Board of Directors. The compensation costs associated with the key management personnel are as follows:

	2021 $	2020 $
Short-term employee benefits	**4.6**	4.9
Post-employment benefits	**4.9**	2.8
Termination benefits	**—**	2.6
	9.5	10.3

23. COMMITMENTS

As at December 31, 2021, the future minimum payments for capital projects and other commitments were as follows:

	Capital projects [1] and other $
Less than one year	**32.6**
Between one and five years	**10.1**
Total amount of future minimum payments [2]	**42.7**

[1] Mainly commitments for construction services.
[2] Refer to note 14 for financial commitments excluded from the table above.

24. CONTINGENCIES

Legal Proceedings

In the ordinary course of business, LDC is subject to various legal proceedings, actions and claims from customers, suppliers, regulators and other parties. As at the date hereof, LDC believes that none of these legal proceedings, actions and claims from customers, suppliers, regulators and other parties in which it is currently involved or has been involved since the beginning of the most recently completed financial year, would be expected to have a material adverse effect on LDC. On an ongoing basis, LDC assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, LDC would make a claim under any liability or other insurance policies, to the extent applicable, subject to such claim not being disputed by the insurers.

25. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from those prescribed by IFRS for enterprises operating in an unregulated environment and regulated entities that did not adopt IFRS 14.

Regulatory Balances

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of continuing to recognize regulatory balances according to their previous GAAP. Regulatory balances provide useful information about LDC's financial position, financial performance and cash flows. IFRS 14 is

restricted to first-time adopters of IFRS and remains in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB.

LDC has determined that certain debit and credit balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14. Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding LDC's regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory debit and credit balances on LDC's balance sheets, and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. Regulatory balances can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is determined by management to be probable. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, the balances are recorded in LDC's statements of income in the period when the assessment is made. Regulatory balances, which do not meet the definition of an asset or liability under any other IFRS, are segregated on the balance sheets and are presented on the statements of income and the statements of comprehensive income as net movements in regulatory balances and net movements in regulatory balances related to OCI, net of tax. The netting of regulatory debit and credit balances is not permitted. The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions.

b) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition. On the statements of cash flows, cash and cash equivalents [bank indebtedness] include bank overdrafts that are repayable on demand and form an integral part of LDC's cash management.

c) Accounts receivable and unbilled revenue

Accounts receivable are recorded at the invoiced amount and overdue amounts bear interest at OEB-approved rates. Unbilled revenue is recorded based on an estimated amount for electricity delivered and for other services provided and not yet billed. The estimate is primarily based on the customers' previous billings with adjustments mainly for assumptions related to seasonality and weighted average price. The carrying amount of accounts receivable and unbilled revenue is reduced through a loss allowance, if applicable, and the amount of the related impairment loss is recognized in the statements of income. The impairment loss is the difference between an asset's carrying amount and the estimated future cash flows. When LDC considers that there are no realistic prospects of recovery of the financial assets, the relevant amounts are written off. If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Accounts receivable and unbilled revenue are assessed at each reporting date to determine whether there is objective evidence of impairment, which includes default or delinquency by a debtor, indications that a debtor or issuer will enter bankruptcy, and adverse changes in the payment status of borrowers or issuers. Accounts receivable and unbilled revenue that are not individually assessed for impairment are collectively assessed for impairment by grouping together receivables with similar risk characteristics, and LDC considers historical trends on the timing of recoveries and the amount of loss incurred, adjusted for forward-looking factors specific to the current economic and credit conditions.

LDC measures the loss allowance at an amount equal to the lifetime expected credit losses ["ECL"] for all trade receivables that result from transactions with customers and do not contain a significant financing component. A provision matrix is used by LDC to measure the lifetime ECL of accounts receivable from individual customers. Loss rates are calculated using a 'roll rate' method based on the probability of a trade receivable progressing through successive stages of delinquency to write-off and are based on the average of actual credit loss experience over the past three years, as it more accurately reflects anticipated credit loss. Roll rates are calculated separately for exposures based on customer account status. LDC also adjusts the ECL in efforts to account for current economic

conditions and events (including forward-looking macroeconomic data) and historical information (including credit agency reports, if available), including the impact of the COVID-19 pandemic *[note 14[b]]*. LDC considers the reasons for the accounts being past due, the characteristics of existing accounts, reasonable and supportable forecasts and other considerations that may affect the collectability of the reported amounts.

d) Materials and supplies

Materials and supplies consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. LDC classifies all major construction related components of its electricity distribution infrastructure to PP&E. Materials and supplies are carried at the lower of cost and net realizable value, with cost determined on a weighted average cost basis net of a provision for obsolescence.

e) Property, plant and equipment

PP&E are measured at cost less accumulated depreciation and any accumulated impairment losses, if applicable. The cost of PP&E represents the original cost, consisting of direct materials and labour, contracted services, borrowing costs, and directly attributable overhead. Subsequent costs are capitalized only if it is probable that the future economic benefits associated with the expenditure will flow to LDC and the costs can be measured reliably. If significant parts of an item of PP&E have different useful lives, then they are accounted for as separate major components of PP&E. The carrying amount of an item of PP&E is derecognized on disposal of the asset or when no future economic benefits are expected to accrue to LDC from its continued use. Any gain or loss arising on derecognition is recorded in the statements of income in the period in which the asset is derecognized. The gain or loss on disposal of an item of PP&E is determined as the sale proceeds less the carrying amount of the asset and costs of removal and is recognized in the statements of income.

Depreciation begins when an asset becomes available for use. Depreciation is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Distribution assets:	
Distribution lines	1.7% to 5.0%
Transformers	3.3% to 5.0%
Meters	2.5% to 6.7%
Stations	2.0% to 10.0%
Buildings	1.3% to 5.0%
Equipment and other:	
Other capital assets	4.0% to 25.0%
Right-of-use assets	1.0% to 11.1%

Right-of-use assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that LDC will obtain ownership by the end of the lease term, in which case they are depreciated to the end of the useful life of the underlying assets. Right-of-use assets are recognized for contracts that are, or contain, leases. Construction in progress relates to assets not currently available for use and therefore is not depreciated. The depreciation method and useful lives are reviewed at each financial year-end and adjusted if appropriate. There are no residual values for items of PP&E.

f) Intangible assets

Intangible assets are measured at cost less accumulated amortization and any accumulated impairment losses, if applicable.

Amortization begins when an asset becomes available for use. Amortization is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Computer software	10.0% to 25.0%
Contributions	4.0%

Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized. Contributions represent payments made to HONI for dedicated infrastructure in order to receive connections to transmission facilities. The amortization method and useful lives are reviewed at each financial year-end and adjusted if appropriate.

g) Impairment of non-financial assets

LDC reviews the carrying amounts of its non-financial assets other than materials and supplies and deferred tax assets at each reporting date to determine whether there is any indication of impairment, in which case the assets' recoverable amounts are estimated. For impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent on the cash inflows of other assets or CGUs. LDC has determined that its assets are a single CGU due to interdependencies of its assets to generate cash flows. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount. Impairment losses are recognized in the statements of income, and are allocated to reduce the carrying amounts of assets in the CGU on a pro rata basis. An impairment loss recognized in prior periods is reversed when an asset's recoverable amount has increased, but not exceeding the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

h) Capitalized borrowing costs

Borrowing costs directly attributable to the acquisition, construction or development of qualifying assets that necessarily take a substantial period of time to get ready for their intended use are capitalized, until such time as the assets are substantially ready for their intended use. The interest rate for capitalization is LDC's weighted average cost of borrowing, and is applied to the carrying amount of the construction-in-progress assets or assets under development including borrowing costs previously capitalized, net of capital contributions received. Capitalization commences immediately as the expenditure on a qualifying asset is incurred. Borrowing costs are included in the cost of PP&E and intangible assets for financial reporting purposes, and charged to operations through depreciation and amortization expense over the useful lives of the related assets.

i) Revenue recognition

LDC assesses each contract with the customer to identify the performance obligation. The transaction price and the payment terms are agreed upon in the contract between LDC and the customer.

Revenues from energy sales and electricity distribution are recorded on the basis of cyclical billings and include an estimated amount for electricity delivered and not yet billed. The performance obligation is satisfied over time when the electricity is simultaneously received and consumed by the customer. The majority of billing cycles and payment terms are on a monthly basis. These revenues are impacted by energy demand primarily driven by outside temperature, and customer class usage patterns and composition.

Energy sales arise from charges to customers for electricity consumed, based on regulated rates. Energy sales include amounts billed or billable to customers for commodity charges, retail transmission charges, and WMS charges at current rates. These charges are passed through to customers over time and are considered revenue by LDC due to

the collection risk of the related balances. LDC applies judgment to determine whether revenues are recorded on a gross or net basis. LDC has primary responsibility for the delivery of electricity to the customer. For any given period, energy sales should be equal to the cost of energy purchased. However, a difference between energy sales and energy purchases arises when there is a timing difference between the amounts charged by LDC to customers, based on regulated rates, and the electricity and non-competitive electricity service costs billed monthly by the IESO to LDC. This difference is recorded as a settlement variance, representing future amounts to be recovered from or refunded to customers through future billing rates approved by the OEB. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the balance sheets and within net movements in regulatory balances on the statements of income.

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by LDC in delivering electricity to customers. Distribution revenue also includes revenue related to the collection of OEB-approved rate riders.

Other revenue includes revenue from services ancillary to the electricity distribution, delivery of street lighting services, pole and duct rentals, other regulatory service charges, capital contributions and CDM programs.

Capital contributions received in advance from electricity customers and developers to construct or acquire PP&E for the purpose of connecting a customer to a network are recorded as deferred revenue and amortized into other revenue at an equivalent rate to that used for the depreciation of the related PP&E. Capital contributions received from developers to construct or acquire PP&E for the purpose of connecting future customers to the distribution network are considered out of scope of IFRS 15 *Revenue from Contracts with Customers*. Contributions received from customers to construct or acquire PP&E to deliver services other than those related to delivery of electricity are recorded as deferred revenue and amortized into other revenue over the term of the contract with the customer.

Revenues and costs associated with CDM programs are presented using the net basis of accounting and are recorded in accordance with IAS 20 *Accounting for Government Grants and Disclosure of Government Assistance*. Cost efficiency incentives related to the CDM programs, included as part of other revenue, are recognized when it is probable that future economic benefits will flow to the entity and the amount can be reasonably measured.

LDC has not incurred any additional costs to obtain or fulfill contracts with its customers from the above-mentioned revenue generating activities. Variable consideration under a contract is recorded only to the extent that it is highly probable that a significant reversal in the amount of cumulative revenue recognized will not occur when the associated uncertainty is subsequently resolved.

j) Financial instruments

All financial assets and financial liabilities are classified as "Amortized cost". These financial instruments are recognized initially at fair value adjusted for any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties.

LDC uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the balance sheets:

- Cash and cash equivalents are classified as "Amortized cost" and are initially measured at fair value. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Bank indebtedness is classified as "Amortized cost" and is initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts payable are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Customer deposits are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at cost plus accrued interest. The carrying amounts approximate fair value taking into account interest accrued on the outstanding balance.

- Obligations under leases are classified as "Amortized cost" and are initially measured at fair value, or at the present value of the minimum lease payments, if lower. Subsequent measurements are based on a discounted cash flow analysis and approximate the carrying amount as management believes that the fixed interest rates are representative of current market rates.

- Notes payable to related party are classified as "Amortized cost" and are initially measured at fair value. The carrying amounts of notes payable are carried at amortized cost, based on the fair value of the notes payable at issuance, which was the fair value of the consideration received adjusted for transaction costs. The fair values of the notes payable are based on the present value of contractual cash flows, discounted at LDC's current borrowing rate for similar debt instruments *[note 14[a]]*. Debt issuance costs incurred in connection with LDC's debt offerings are capitalized as part of the carrying amount of the notes payable and amortized over the term of the related notes payable, using the effective interest method, and the amortization is included in finance costs.

k) Fair value measurements

LDC utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect LDC's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;

- Level 2: Other than quoted prices included within Level 1 that are observable for the assets or liabilities, either directly or indirectly; and

- Level 3: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

l) Employee benefits

(i) Short-term employee benefits

Short-term employee benefit obligations that are due to be settled wholly within twelve months after the end of the annual reporting period in which the employees render the related service are measured on an undiscounted basis and are expensed as the related service is provided. A liability is recognized for the amount expected to be paid if LDC has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

(ii) Multi-employer pension plan

LDC's full-time employees participate in a pension plan through OMERS. The OMERS plan is a jointly sponsored, multi-employer defined benefit pension plan established in 1962 by the province of Ontario for employees of municipalities, school boards, libraries, police and fire departments, and other local agencies in communities across Ontario. Both participating employers and employees are required to make plan contributions equally based on participating employees' contributory earnings, and share equally in funding gains or losses. The plan assets and pension obligations are not segregated in separate accounts for each member entity. The OMERS plan is accounted for as a defined contribution plan and the contribution payable is recognized as an employee benefit expense in the statements of income in the period when the service is rendered by the employee, since it is not practicable to determine LDC's portion of pension obligations or of the fair value of plan assets.

(iii) Post-employment benefits

LDC has a number of unfunded benefit plans providing post-employment benefits to its employees, including certain retirement, medical, dental and life insurance benefits. LDC also pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The cost of providing benefits under the benefit plans is actuarially determined using the projected unit credit method, which incorporates management's best estimate of future salary levels, retirement ages of employees, health care costs, and other actuarial factors. Past service cost is recognized when a plan amendment or curtailment occurs. Changes in actuarial assumptions and experience adjustments give rise to actuarial gains and losses. Actuarial gains and losses on post-employment benefits other than sick leave credits are recognized in OCI as they arise, and are subsequently reclassified from OCI to a regulatory balance on the balance sheets. Actuarial gains and losses on accumulated sick leave credits are recognized in the statements of income in the period in which they arise.

The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest actuarial valuation was performed as at January 1, 2020.

m) Customer deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits that are refundable upon demand are classified as a current liability.

Security deposits on offers to connect are cash collections from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits are classified as a current liability when LDC no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

n) Income taxes

Under the Electricity Act, LDC is required to make PILs to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the ITA and the TA as modified by regulations made under the Electricity Act and related regulations. This effectively results in LDC paying income taxes equivalent to what would be imposed under the Federal and Ontario Tax Acts.

LDC uses the liability method of accounting for income taxes. Under the liability method, current income taxes payable are recorded based on taxable income. LDC recognizes deferred tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheets and their respective tax basis, using the tax rates enacted or substantively enacted by the balance sheet date that are in effect for the year in which the differences are expected to reverse. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when it is probable that they will be realized, and are measured at the best estimate of the tax amount expected to be paid to or recovered from

the taxation authorities. Deferred tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable that the related tax benefits will be realized. The calculation of current and deferred taxes requires management to make certain judgments with respect to changes in tax interpretations, regulations and legislation, and to estimate probable outcomes on the timing and reversal of temporary differences and tax authority audits of income tax.

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates. A gross up to reflect the income tax benefits or liabilities associated with the revenue impact resulting from the realization of deferred taxes is recorded within regulatory balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the statements of income.

The benefits of the refundable and non-refundable apprenticeship and other ITCs are credited against the related expense in the statements of income.

o) Lessor arrangements

When LDC acts as a lessor, it determines at lease inception whether each lease is a finance lease or an operating lease.

To classify each lease, LDC makes an overall assessment of whether the lease transfers substantially all of the risks and rewards incidental to ownership of the underlying asset. If this is the case, then the lease is a finance lease; if not, then it is an operating lease.

p) Use of judgments and estimates

The preparation of LDC's financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions which affect the application of accounting policies, reported assets, liabilities and regulatory balances, and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the IESO, the Ontario Ministry of Energy or the Ontario Ministry of Finance. The assessment of the duration and severity of the COVID-19 pandemic is subject to significant uncertainty; accordingly, judgments, estimates and assumptions related to the impact of the COVID-19 pandemic made by management in the preparation of LDC's financial statements are also subject to significant uncertainty. Management has analyzed the impact of the COVID-19 pandemic on its estimates and adjusted the expected credit loss provision to account for the higher level of expected customer defaults as at December 31, 2021 *[note 14[b]]*. The extent of the future impact of the COVID-19 pandemic on LDC's financial results and business operations is not known at this time.

Information about judgments in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in note 25[a] relating to recognition of regulatory balances and note 25[i] relating to principal versus agent determination for recording revenue on a gross or net basis.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively. Assumptions and estimates with a significant risk of resulting in a material adjustment within the next financial year are used in the following:

- Note 24 – Recognition and measurement of provisions and contingencies;
- Note 25[a] – Recognition and measurement of regulatory balances;
- Note 25[c] – Recognition and measurement of loss allowance for accounts receivable and unbilled revenue;

- Notes 25[e] and 25[f] – Determination of useful lives of depreciable assets;
- Note 25[i] – Revenue recognition – measurement of unbilled revenue;
- Notes 25[l] and 12 – Measurement of post-employment benefits – key actuarial assumptions; and
- Notes 25[n] and 20 – Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and tax loss carryforwards can be used.

q) Future accounting pronouncements

The IASB has issued a number of standards and amendments to existing standards that are not yet effective. LDC continues to analyze these pronouncements and has determined that the following amendments could have an impact on LDC's financial statements when adopted.

Classification of Liabilities as Current or Non-current [Amendments to IAS 1 Presentation of Financial Statements ["IAS 1"]]

In January 2020, the IASB issued amendments to IAS 1 relating to the classification of liabilities as current or non-current. Specifically, the amendments clarify one of the criteria in IAS 1 for classifying a liability as non-current - that is, the requirement for an entity to have the right to defer settlement of the liability for at least 12 months after the reporting period. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted. The amendments are to be applied retrospectively.

Onerous Contracts - Cost of Fulfilling a Contract [Amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets ["IAS 37"]]

In May 2020, the IASB issued amendments to IAS 37 regarding costs that should be included as the cost of fulfilling a contract when assessing whether a contract is onerous. The amendments clarify that the cost of fulfilling the contract comprises all costs that relate directly to the contract. Such costs include both the incremental costs of fulfilling that contract and an allocation of other costs that relate directly to fulfilling contracts. The amendments apply to contracts existing at the date when the amendments are first applied. The amendments are effective for annual reporting periods beginning on or after January 1, 2022, with early adoption permitted.

Definition of Accounting Estimates [Amendments to IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors ["IAS 8"]]

In February 2021, the IASB issued amendments to IAS 8 to introduce a definition of "accounting estimates" and include other amendments to help entities distinguish changes in accounting estimates from changes in accounting policies. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted. The amendments are to be applied prospectively.

Disclosure of Accounting Policies [Amendments to IAS 1]

In February 2021, the IASB issued amendments to IAS 1 requiring an entity to disclose its material accounting policies, rather than its significant accounting policies. Additional amendments were made to explain how an entity can identify a material accounting policy. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted.

Deferred Tax related to Assets and Liabilities arising from a Single Transaction [Amendments to IAS 12 Income Taxes ["IAS 12"]]

In May 2021, the IASB issued amendments to IAS 12. The amendments clarify how companies should account for deferred tax on certain transactions such as leases and decommissioning obligations. The amendments narrow the scope of the initial recognition exemption, so that it does not apply to transactions that give rise to equal and offsetting temporary differences. As a result, companies will need to recognize both a deferred tax asset and a deferred tax

liability when accounting for such transactions. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted.

LDC is currently assessing the impact of the above amendments on LDC's financial statements.

GLOSSARY

CDM – Conservation and demand management

CGU – Cash generating unit

CIR – Custom Incentive Rate-setting

City – City of Toronto

Corporation – Toronto Hydro Corporation

COVID-19 – Coronavirus disease 2019 and its variants

ECA – Energy Conservation Agreement

Electricity Act – *Electricity Act, 1998* [Ontario], as amended

GAAP – Generally Accepted Accounting Principles

HONI – Hydro One Networks Inc.

IAS – International Accounting Standard

IASB – International Accounting Standards Board

IESO – Independent Electricity System Operator

IFRS – International Financial Reporting Standards

IRM – Incentive Regulation Mechanism

ITA – *Income Tax Act* [Canada], as amended

ITC – Investment tax credit

kW – Kilowatt

kWh – Kilowatt hour

LDC – Toronto Hydro-Electric System Limited

LRAM – Lost revenue adjustment mechanism

OCI – Other comprehensive income

OEB – Ontario Energy Board

OMERS – Ontario Municipal Employees Retirement System

OPEB – Other post-employment benefits

PILs – Payments in lieu of corporate taxes

PP&E – Property, plant and equipment

TA – *Taxation Act, 2007* [Ontario], as amended

TH Energy – Toronto Hydro Energy Services Inc.

TOU – Time-of-use

WMS – Wholesale Market Service

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2022 and 2021

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INDEPENDENT AUDITOR'S REPORT

To the Shareholder of Toronto Hydro-Electric System Limited

Opinion

We have audited the accompanying financial statements of Toronto Hydro-Electric System Limited (the Entity), which comprise:

- the balance sheet as at December 31, 2022
- the statement of income for the year then ended
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended

and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2022, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditor's Responsibilities for the Audit of the Financial Statements" section of our auditor's report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity.
KPMG Canada provides services to KPMG LLP.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS as issued by the IASB, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.
- The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
Toronto, Canada
March 1, 2023

Toronto Hydro-Electric System Limited

BALANCE SHEETS

[in millions of Canadian dollars]

As at December 31	Note	2022 $	2021 $
ASSETS			
Current			
Cash and cash equivalents		**91.5**	102.6
Accounts receivable and unbilled revenue	*4, 14[b]*	**495.5**	445.4
Income tax receivable		**—**	3.0
Materials and supplies		**8.2**	9.9
Other assets	*5*	**16.3**	18.8
Total current assets		**611.5**	579.7
Property, plant and equipment	*6*	**5,698.2**	5,322.6
Intangible assets	*7*	**387.3**	358.0
Other assets	*5*	**14.1**	6.9
Total assets		**6,711.1**	6,267.2
Regulatory balances	*8*	**262.9**	181.4
Total assets and regulatory balances		**6,974.0**	6,448.6
LIABILITIES AND EQUITY			
Current			
Accounts payable and accrued liabilities	*9*	**460.9**	422.9
Income tax payable		**2.1**	—
Customer deposits		**54.8**	62.3
Deferred revenue	*10*	**28.7**	24.4
Deferred conservation credit	*3[c]*	**16.8**	11.7
Notes payable to related party	*11, 22*	**294.9**	60.0
Total current liabilities		**858.2**	581.3
Notes payable to related party	*11, 22*	**2,480.6**	2,432.0
Customer deposits		**15.2**	10.1
Deferred revenue	*10*	**736.7**	642.8
Post-employment benefits	*12*	**230.0**	306.6
Deferred tax liabilities	*20*	**84.6**	63.8
Other liabilities		**6.4**	17.4
Total liabilities		**4,411.7**	4,054.0
Equity			
Share capital	*16*	**556.3**	556.3
Retained earnings		**1,843.1**	1,674.3
Contributed surplus		**12.8**	12.8
Total equity		**2,412.2**	2,243.4
Total liabilities and equity		**6,823.9**	6,297.4
Regulatory balances	*8*	**150.1**	151.2
Total liabilities, equity and regulatory balances		**6,974.0**	6,448.6

Commitments, contingencies and subsequent events 23, 24, 26

See accompanying notes to the financial statements.

STATEMENTS OF INCOME

[in millions of Canadian dollars]

Year ended December 31	Note	2022 $	2021 $
Revenues			
Energy sales	*17*	**2,737.8**	2,702.4
Distribution revenue	*17*	**754.2**	759.1
Other	*17*	**96.2**	88.1
		3,588.2	3,549.6
Expenses			
Energy purchases		**2,846.7**	2,775.2
Operating expenses	*18*	**310.6**	310.7
Depreciation and amortization	*6, 7*	**307.8**	289.3
		3,465.1	3,375.2
Finance costs	*19*	**(83.2)**	(82.8)
Gain on disposals of property, plant and equipment		**—**	2.7
Income before income taxes		**39.9**	94.3
Income tax expense	*20*	**(10.0)**	(20.4)
Net income		**29.9**	73.9
Net movements in regulatory balances	*8*	**136.5**	54.1
Net movements in regulatory balances arising from deferred taxes	*8*	**2.4**	8.9
Net income after net movements in regulatory balances		**168.8**	136.9

STATEMENTS OF COMPREHENSIVE INCOME

[in millions of Canadian dollars]

Year ended December 31	Note	2022 $	2021 $
Net income after net movements in regulatory balances		**168.8**	136.9
Other comprehensive income			
Items that will not be reclassified to income or loss			
Remeasurements of post-employment benefits, net of tax [2022 - ($20.3), 2021 - ($7.1)]	*12*	**56.3**	19.8
Net movements in regulatory balances related to OCI, net of tax [2022 - ($20.3), 2021 - ($7.1)]	*8, 12*	**(56.3)**	(19.8)
Other comprehensive income, net of tax		**—**	—
Total comprehensive income		**168.8**	136.9

See accompanying notes to the financial statements.

STATEMENTS OF CHANGES IN EQUITY

[in millions of Canadian dollars]

Year ended December 31	Note	2022 $	2021 $
Share capital	*16*	**556.3**	556.3
Retained earnings, beginning of year		**1,674.3**	1,538.0
Net income after net movements in regulatory balances		**168.8**	136.9
Dividends	*16, 22*	**—**	(0.6)
Retained earnings, end of year		**1,843.1**	1,674.3
Contributed surplus		**12.8**	12.8
Total equity		**2,412.2**	2,243.4

See accompanying notes to the financial statements.

STATEMENTS OF CASH FLOWS

[in millions of Canadian dollars]

Year ended December 31	Note	2022 $	2021 $
OPERATING ACTIVITIES			
Net income after net movements in regulatory balances		**168.8**	136.9
Net movements in regulatory balances	*8*	**(136.5)**	(54.1)
Net movements in regulatory balances arising from deferred taxes	*8*	**(2.4)**	(8.9)
Adjustments			
Depreciation and amortization	*6, 7*	**307.8**	289.3
Amortization of deferred revenue	*10*	**(18.1)**	(12.3)
Finance costs		**83.2**	82.8
Income tax expense		**10.0**	20.4
Post-employment benefits		**—**	0.8
Gain on disposals of property, plant and equipment		**—**	(2.7)
Other		**0.2**	1.0
Capital contributions received	*10*	**85.8**	101.2
Net change in other non-current assets and liabilities		**(20.9)**	11.1
Increase (decrease) in customer deposits		**(2.4)**	8.8
Changes in non-cash operating working capital balances	*21*	**(15.4)**	7.3
Income tax paid		**(1.7)**	—
Net cash provided by operating activities		**458.4**	581.6
INVESTING ACTIVITIES			
Purchase of property, plant and equipment	*21*	**(607.3)**	(548.0)
Purchase of intangible assets	*21*	**(59.6)**	(37.5)
Proceeds on disposals of property, plant and equipment		**0.4**	2.8
Net cash used in investing activities		**(666.5)**	(582.7)
FINANCING ACTIVITIES			
Issuance of notes payable to related party	*11*	**297.9**	347.7
Repayment of notes payable to related party	*11*	**(15.0)**	(300.0)
Dividends paid	*16*	**—**	(0.6)
Interest received		**1.8**	0.9
Interest paid		**(87.7)**	(86.3)
Net cash provided by (used in) financing activities		**197.0**	(38.3)
Net change in cash and cash equivalents during the year		**(11.1)**	(39.4)
Cash and cash equivalents, beginning of year		**102.6**	142.0
Cash and cash equivalents, end of year		**91.5**	102.6

See accompanying notes to the financial statements.

1. NATURE OF BUSINESS

Toronto Hydro-Electric System Limited was incorporated on June 23, 1999 under the *Business Corporations Act* [Ontario] in accordance with the Electricity Act. LDC is wholly owned by the Corporation and is domiciled in Canada, with its registered office located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

LDC distributes electricity to customers located in the city of Toronto and is subject to rate regulation.

2. BASIS OF PRESENTATION

LDC's audited financial statements for the years ended December 31, 2022 and 2021 have been prepared in accordance with IFRS as issued by the IASB.

The financial statements are presented in Canadian dollars, LDC's functional and presentation currency. The financial statements have been prepared on the historical cost basis, except for post-employment benefits which are measured at the present value of the post-employment benefit obligation.

The summary of significant accounting policies has been disclosed in note 25.

3. REGULATION

The OEB has regulatory oversight of electricity matters in Ontario. The OEB's authority and responsibilities include the power to approve and set rates for the transmission and distribution of electricity, the power to approve the amounts paid to non-contracted generators, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts [all of which, other than distribution rates, represent a pass-through of amounts payable to third parties]:

- *Commodity Charge* – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO back to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- *Retail Transmission Rate* – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are a pass-through to operators of transmission facilities.

- *WMS Charge* – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market and maintain reliable operation of the provincial grid. Wholesale charges are a pass-through to the IESO.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable [usage-based] components, based on a forecast of LDC's customers and load.

a) COVID-19 Pandemic Considerations

On March 11, 2020, the World Health Organization declared that the COVID-19 outbreak was a global pandemic. The COVID-19 pandemic has not had a significant impact on the financial statements of LDC for the year ended December 31, 2022.

On November 15, 2021, the OEB's standard winter disconnection ban commenced and remained in effect until May 1, 2022. Concurrent with the effective end date of the OEB's standard winter disconnection ban, LDC ended its voluntary ban on disconnections, which had been in place since the beginning of the pandemic. LDC's disconnection practices remain subject to the applicable OEB rules.

On January 7, 2022, the Ontario Government announced further targeted relief measures setting both the TOU rates for on-peak, mid-peak, and off-peak and tiered rates at the TOU off-peak rate of 8.2 cents per kWh, 24 hours a day, seven days a week, effective January 18, 2022 until February 7, 2022. There was no net income impact to LDC.

b) Electricity Distribution Rates

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and custom index adjustments similar to IRM. A cost of service review uses a future test-year to establish rates, and provides for revenues required to recover the forecasted costs of providing the regulated service, and a fair and reasonable return on rate base. Custom index adjustments are typically used for one or more years following a cost of service review and provide for adjustments to rates based on an inflationary factor net of a productivity factor and an efficiency factor as determined relative to other electricity distributors.

On December 19, 2019, the OEB issued its 2020-2024 CIR Decision and on February 20, 2020, the OEB issued its CIR Final Rate Order, both in relation to the rate application filed on August 15, 2018 [together, the "2020-2024 CIR Decision and Rate Order"]. The 2020-2024 CIR Decision and Rate Order approved subsequent annual rate adjustments based on a custom index for the period commencing on January 1, 2021 and ending on December 31, 2024. The financial considerations of the OEB's 2020-2024 CIR Decision and Rate Order are reflected in the financial statements including disclosure of approved disposition for a number of requested rate riders *[note 8]*.

On August 20, 2021, LDC filed the 2022 rate application seeking the OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2022 and ending on December 31, 2022. On December 9, 2021, the OEB issued a decision and rate order approving LDC's 2022 rates and providing for other deferral and variance account dispositions.

On August 23, 2022, LDC filed the 2023 rate application seeking the OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2023 and ending on December 31, 2023. On December 8, 2022, the OEB issued a decision and rate order approving LDC's 2023 rates and providing for other deferral and variance account dispositions.

c) CDM Activities

The IESO is responsible for delivery of CDM programs; however, LDC remains responsible for its obligations under participant agreements with customers for many of the programs under its previous joint CDM plan with Oakville Hydro Electricity Distribution Inc. that were in effect before April 1, 2019. On June 10, 2021, the Government of Ontario issued ministerial directives to the IESO to extend the deadline by which participants were to complete the projects from June 30,

2021 to December 31, 2021, and on December 9, 2021, the deadline was further extended to August 31, 2022. The ministerial directives also allowed for the completion deadline to be further extended for participants who completed projects prior to December 31, 2022 to be eligible for funding upon submission of their claims, if certain conditions were met. Amounts received from the IESO for the funding of the projects under the participant agreements, but not yet spent, are presented on the balance sheets under current liabilities as deferred conservation credit.

4. ACCOUNTS RECEIVABLE AND UNBILLED REVENUE

Accounts receivable and unbilled revenue consist of the following:

	2022 $	2021 $
Unbilled revenue	**254.3**	211.6
Trade receivables	**187.0**	175.6
Due from related parties *[note 22]*	**36.2**	39.9
Other	**18.0**	18.3
Total accounts receivable and unbilled revenue	**495.5**	445.4

5. OTHER ASSETS

Other assets consist of the following:

	2022 $	2021 $
Prepaid expenses	**29.0**	24.3
Deferred financing costs	**1.4**	1.4
Total other assets	**30.4**	25.7
Less: Current portion of other assets relating to:		
Prepaid expenses	**16.0**	18.4
Deferred financing costs	**0.3**	0.4
Current portion of other assets	**16.3**	18.8
Non-current portion of other assets	**14.1**	6.9

6. PROPERTY, PLANT AND EQUIPMENT

PP&E consist of the following:

	Distribution assets	Land and buildings	Equipment and other	Construction in progress	Total
	$	$	$	$	$
Cost					
Balance as at January 1, 2021	4,919.9	439.8	285.4	510.4	6,155.5
Additions	—	—	—	587.9	587.9
Transfers into service	519.5	23.3	55.5	(598.3)	—
Disposals and retirements	(33.2)	(0.2)	(2.7)	—	(36.1)
Balance as at December 31, 2021	5,406.2	462.9	338.2	500.0	6,707.3
Additions	**—**	**—**	**—**	**644.2**	**644.2**
Transfers into service	**525.0**	**22.2**	**46.9**	**(594.1)**	**—**
Disposals and retirements	**(34.2)**	**—**	**(1.1)**	**—**	**(35.3)**
Balance as at December 31, 2022	**5,897.0**	**485.1**	**384.0**	**550.1**	**7,316.2**
Accumulated depreciation					
Balance as at January 1, 2021	929.9	81.2	156.9	—	1,168.0
Depreciation	183.3	16.1	28.9	—	228.3
Disposals and retirements	(8.9)	(0.1)	(2.6)	—	(11.6)
Balance as at December 31, 2021	1,104.3	97.2	183.2	—	1,384.7
Depreciation	**195.2**	**16.9**	**30.6**	**—**	**242.7**
Disposals and retirements	**(8.3)**	**—**	**(1.1)**	**—**	**(9.4)**
Balance as at December 31, 2022	**1,291.2**	**114.1**	**212.7**	**—**	**1,618.0**
Carrying amount					
Balance as at December 31, 2021	4,301.9	365.7	155.0	500.0	5,322.6
Balance as at December 31, 2022	**4,605.8**	**371.0**	**171.3**	**550.1**	**5,698.2**

As at December 31, 2022, “Land and buildings” included right-of-use assets related to leases of land and office space with cost of $7.6 million [December 31, 2021 - $7.6 million], accumulated depreciation of $1.0 million [December 31, 2021 - $0.9 million], and carrying amount of $6.6 million [December 31, 2021 - $6.7 million]. For the year ended December 31, 2022, LDC recorded depreciation expense of $0.1 million [2021 - $0.1 million] related to the right-of-use assets.

For the year ended December 31, 2022, borrowing costs in the amount of $5.5 million [2021 - $2.8 million] were capitalized to PP&E with an average interest rate of 3.13% [2021 - 3.07%].

7. INTANGIBLE ASSETS

Intangible assets consist of the following:

	Computer software	Contributions	Software in development	Contributions for work in progress	Total
	$	$	$	$	$
Cost					
Balance as at January 1, 2021	264.7	176.3	20.6	58.0	519.6
Additions	—	—	32.3	21.0	53.3
Transfers into service	25.5	18.6	(25.5)	(18.6)	—
Balance as at December 31, 2021	290.2	194.9	27.4	60.4	572.9
Additions	**—**	**—**	**46.1**	**25.1**	**71.2**
Transfers into service	**29.4**	**72.8**	**(29.4)**	**(72.8)**	**—**
Balance as at December 31, 2022	**319.6**	**267.7**	**44.1**	**12.7**	**644.1**
Accumulated amortization					
Balance as at January 1, 2021	151.9	24.6	—	—	176.5
Amortization	30.7	7.7	—	—	38.4
Balance as at December 31, 2021	182.6	32.3	—	—	214.9
Amortization	**31.8**	**10.1**	**—**	**—**	**41.9**
Balance as at December 31, 2022	**214.4**	**42.4**	**—**	**—**	**256.8**
Carrying amount					
Balance as at December 31, 2021	107.6	162.6	27.4	60.4	358.0
Balance as at December 31, 2022	**105.2**	**225.3**	**44.1**	**12.7**	**387.3**

For the year ended December 31, 2022, borrowing costs in the amount of $1.3 million [2021 - $1.9 million] were capitalized to intangible assets with an average interest rate of 3.13% [2021 - 3.07%].

“Contributions” represent payments made to HONI for dedicated infrastructure in order to receive connections to transmission facilities. The remaining amortization period for computer software ranges from less than one year to six years. The remaining amortization period for contributions ranges from six to 25 years.

8. REGULATORY BALANCES

Debit balances consist of the following:

	January 1, 2022	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2022	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Settlement variances	**58.5**	**111.6**	**(1.5)**	**(0.2)**	**168.4**	note 8[a]	[1]
Deferred taxes	**63.9**	**22.7**	**—**	**—**	**86.6**	note 8[b]	—
LRAM	**4.2**	**—**	**(2.3)**	**—**	**1.9**	note 8[c]	[1]
OPEB net actuarial loss	**48.1**	**—**	**—**	**(48.1)**	**—**	note 8[d]	—
Other	**6.7**	**3.4**	**(3.9)**	**(0.2)**	**6.0**	—	[1]
Total	**181.4**	**137.7**	**(7.7)**	**(48.5)**	**262.9**		

	January 1, 2021	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2021	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Settlement variances	3.4	73.2	(18.1)	—	58.5	note 8[a]	[1]
Deferred taxes	47.9	16.0	—	—	63.9	note 8[b]	—
LRAM	33.2	0.1	(29.1)	—	4.2	note 8[c]	[1]
OPEB net actuarial loss	75.5	(26.9)	(0.5)	—	48.1	note 8[d]	—
Other	10.4	(0.5)	(2.3)	(0.9)	6.7	12	[1]
Total	170.4	61.9	(50.0)	(0.9)	181.4		

[1] Carrying charges were added to the regulatory balances in accordance with the OEB's direction, at a rate of 0.57% for January 1, 2022 to March 31, 2022, 1.02% for April 1, 2022 to June 30, 2022, 2.20% for July 1, 2022 to September 30, 2022 and 3.87% for October 1, 2022 to December 31, 2022 [January 1, 2021 to December 31, 2021 – 0.57%].

Credit balances consist of the following:

	January 1, 2022	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2022	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Capital-related revenue requirement	**78.3**	**1.4**	**—**	**—**	**79.7**	note 8[e]	[1]
OPEB net actuarial gain	**—**	**76.6**	**—**	**(48.1)**	**28.5**	note 8[d]	—
Development charges	**15.2**	**1.2**	**(2.6)**	**(0.1)**	**13.7**	note 8[f]	[1]
Tax-related variances	**11.2**	**1.3**	**—**	**—**	**12.5**	note 8[g]	[1]
Derecognition	**33.4**	**1.0**	**(31.2)**	**—**	**3.2**	note 8[h]	[1]
Gain on disposals	**4.7**	**—**	**(2.5)**	**—**	**2.2**	note 8[i]	[1]
Accounts receivable credits	**2.8**	**0.1**	**(0.9)**	**(0.1)**	**1.9**	note 8[j]	[1]
Other	**5.6**	**3.5**	**(0.5)**	**(0.2)**	**8.4**	24	[1]
Total	**151.2**	**85.1**	**(37.7)**	**(48.5)**	**150.1**		

	January 1, 2021	Balances arising in the period	Recovery/ reversal	Other movements	December 31, 2021	Remaining recovery/ reversal period (months)	Carrying charges applicable
	$	$	$	$	$		
Capital-related revenue requirement	77.9	0.4	—	—	78.3	note 8[e]	[1]
Development charges	14.8	2.8	(2.4)	—	15.2	note 8[f]	[1]
Tax-related variances	11.2	—	—	—	11.2	note 8[g]	[1]
Derecognition	33.2	0.2	—	—	33.4	note 8[h]	[1]
Gain on disposals	37.5	0.1	(32.9)	—	4.7	note 8[i]	[1]
Accounts receivable credits	3.5	0.1	(0.8)	—	2.8	note 8[j]	[1]
Other	5.3	2.3	(1.1)	(0.9)	5.6	36	[1]
Total	183.4	5.9	(37.2)	(0.9)	151.2		

[1] Carrying charges were added to the regulatory balances in accordance with the OEB's direction, at a rate of 0.57% for January 1, 2022 to March 31, 2022, 1.02% for April 1, 2022 to June 30, 2022, 2.20% for July 1, 2022 to September 30, 2022 and 3.87% for October 1, 2022 to December 31, 2022 [January 1, 2021 to December 31, 2021 – 0.57%].

The "Balances arising in the period" column consists of new additions to regulatory balances [for both debits and credits]. The "Recovery/reversal" column consists of amounts disposed through OEB-approved rate riders. The "Other movements" column consists of impairment and reclassification between the regulatory debit and credit balances and other regulatory deferral accounts considered to be insignificant. There was no impairment recorded for the year ended December 31, 2022.

Reconciliation between the net movements in regulatory balances shown in the regulatory debit and credit balances tables and the net movements presented on the statements of income and the statements of comprehensive income is as follows:

	2022 $	2021 $
Total movements per regulatory debit balances table	**81.5**	11.0
Total movements per regulatory credit balances table	**1.1**	32.2
Total net movements	**82.6**	43.2
Net movements per financial statements:		
Net movements in regulatory balances	**136.5**	54.1
Net movements in regulatory balances arising from deferred taxes	**2.4**	8.9
Net movements in regulatory balances related to OCI, net of tax	**(56.3)**	(19.8)
Total net movements per financial statements	**82.6**	43.2

Regulatory developments in Ontario's electricity industry and other governmental policy changes may affect the electricity distribution rates charged by LDC and the costs LDC is permitted to recover. There is a risk that the OEB may disallow the recovery of a portion of certain costs incurred in the current period through future rates or disagree with the proposed recovery period. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, any impairment will be recorded in the period when the assessment is made.

The regulatory balances of LDC consist of the following:

a) Settlement Variances

This account includes the variances between amounts charged by LDC to customers, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by LDC. LDC has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB.

In the 2020-2024 CIR Decision and Rate Order, the OEB approved disposition of $7.5 million related to the 2018 settlement variances over a 22-month period commencing on March 1, 2020. As part of the OEB's decision and rate order approving LDC's 2021 rates, the OEB approved recovery of $25.3 million related to 2019 settlement variances over a 12-month period commencing January 1, 2021. As part of the OEB's decision and rate order approving LDC's 2023 rates, the OEB approved recovery of $53.1 million related to 2020 and 2021 settlement variances over a 12-month period commencing January 1, 2023.

b) Deferred taxes

This regulatory balance relates to both deferred tax amounts recorded under IFRS 14 *Regulatory Deferral Accounts* ["IFRS 14"] *[note 25[a]]* and the expected future electricity distribution rate impact to customers arising from timing differences in the recognition of deferred tax assets and liabilities. LDC does not apply for disposition of the balance since it is reversed through timing differences in the recognition of deferred tax assets and liabilities.

The amounts recorded under IFRS 14 include the deferred tax asset related to regulatory balances of $29.6 million [debits] as at December 31, 2022 [December 31, 2021 - $15.5 million [debits]] and the recognition of a regulatory balance in respect of additional temporary differences for which a deferred tax amount was recognized of $20.6 million [credits] as at December 31, 2022 [December 31, 2021 - $17.5 million [credits]]. The deferred tax amount related to the expected future impact to

electricity distribution rates was $77.6 million [debits] as at December 31, 2022 [December 31, 2021 - $65.9 million [debits]].

c) Lost revenue adjustment mechanism

This regulatory balance relates to the difference between the level of CDM program activities included in LDC's load forecast used to set approved rates and the actual impact of CDM activities achieved. As part of the OEB's decision and rate order approving LDC's 2021 rates, the OEB approved recovery of $33.1 million related to 2018 and 2019 variances over a 12-month period commencing January 1, 2021.

d) OPEB net actuarial gain/loss

This regulatory balance accumulates the actuarial gains and losses arising from changes in actuarial assumptions and experience adjustments recognized in OCI. The balance arising during the year ended December 31, 2022 of $76.6 million is related to the actuarial gain recorded for the year [2021 - $26.9 million actuarial gain] *[note 12[d]]*. The net position is an actuarial gain to be disposed in future rates. As a result of the increase in actuarial gains, the balance changed from a debit balance as at January 1, 2022 to a credit balance as at December 31, 2022, with the reclassification of $48.1 million shown in "Other movements". In the 2020-2024 CIR Decision and Rate Order, the OEB approved partial recovery of the balance amounting to $6.4 million which has been fully recovered.

e) Capital-related revenue requirement

This regulatory balance relates to the asymmetrical variance between the cumulative 2015 to 2019 capital-related revenue requirement included in rates and the actual capital-related revenue requirement over the same period. The cumulative 2015 to 2019 capital-related revenue requirement included in rates exceeded the actual capital-related revenue requirement over the same rate period. LDC applied for disposition of this account in order to return the balance to customers through a rate rider. In the 2020-2024 CIR Decision and Rate Order, the OEB approved disposition of $81.8 million related to the 2019 balance over a 24-month period commencing on January 1, 2023.

f) Development charges

This regulatory balance relates to excess expansion deposits retained by LDC where the requested number of connections or electricity demand were not met by the connecting customer. Pursuant to the OEB's Distribution System Code, LDC may collect expansion deposits from specific customers to guarantee the payment of additional costs relating to expansion projects. During the customer connection horizon, LDC has an obligation to annually return the expansion deposit to the connecting customer in proportion to the actual connections or electricity demand that occurred in that year. If the number of connections or electricity demand requested by the customer do not materialize by the end of the connection horizon, LDC retains the excess expansion deposit not otherwise returned to the connecting customer. In the 2020-2024 CIR Decision and Rate Order, the OEB approved disposition of $11.1 million related to the 2019 balance over a 48-month period commencing on January 1, 2021.

g) Tax-related variance accounts

The regulatory balance arose primarily from the revenue requirement impact of accelerated capital cost allowance deductions from the Accelerated Investment Incentive tax measure which received Royal Assent on June 21, 2019. In the 2020-2024 CIR Decision and Rate Order, the OEB approved disposition of $11.6 million related to the 2019 balance over a 24-month period commencing on January 1, 2023. In addition, the balance includes the revenue requirement impact of additional capital cost allowance deductions from the Immediate Expensing tax measure which received Royal Assent in June 2022, and

a residual credit balance that arose from favourable income tax reassessments on certain prior year tax positions received, which differed from those assumed in previous applications for electricity distribution rates.

h) Derecognition

This regulatory balance relates to the difference between the revenue requirement on derecognition of PP&E and intangible assets included in the OEB-approved rates and the actual amounts of derecognition. In the 2020-2024 CIR Decision and Rate Order, the OEB approved disposition of $34.2 million related to the 2019 balance over a 12-month period commencing on January 1, 2022.

i) Gain on disposals

This regulatory balance consists of the net of amounts disposed through the OEB-approved rate riders offset by the related tax savings [credits] and the after-tax gain realized on the sale of three significant LDC properties between 2015 and 2018.

As part of the 2015-2019 CIR decision and rate order, LDC agreed to a rate rider that would pass the total forecasted net gain along with future tax savings on the first two properties back to customers, effective from March 1, 2016 to December 31, 2018. The gain on disposals of the two properties was realized by LDC in 2015 and 2018, respectively. In the second quarter of 2017, LDC realized a gain in connection with the disposal of the third property.

In the 2020-2024 CIR Decision and Rate Order, the incremental balance related to the actual realized gain and tax savings that exceeded the approved rate riders in connection with the disposal of the first two LDC properties amounting to $73.7 million was approved for disposition over a 22-month period commencing on March 1, 2020. The OEB also approved disposition of $11.8 million related to the actual realized gain and tax savings in connection with the disposal of the third property over a 22-month period commencing on March 1, 2020.

j) Accounts receivable credits

This regulatory account relates to closed customer accounts with unclaimed credit balances. In the 2020-2024 CIR Decision and Rate Order, the OEB approved disposition of $3.5 million related to the 2019 balance over a 48-month period commencing on January 1, 2021.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities consist of the following:

	2022 $	2021 $
Trade payables	**259.2**	261.3
Accrued liabilities	**169.2**	123.8
Due to related parties *[note 22]*	**31.8**	36.4
Other	**0.7**	1.4
Total accounts payable and accrued liabilities	**460.9**	422.9

10. DEFERRED REVENUE

Deferred revenue consists of the following:

	2022 $	2021 $
Capital contributions, beginning of year	**663.8**	553.4
Capital contributions received [(1)]	**115.7**	123.1
Amortization	**(18.1)**	(12.3)
Other	**0.1**	(0.4)
Capital contributions, end of year	**761.5**	663.8
Other deferred revenue, beginning of year	**3.4**	2.3
Other deferred revenue	**15.1**	16.7
Revenue recognized	**(14.6)**	(15.6)
Other deferred revenue, end of year	**3.9**	3.4
Total deferred revenue	**765.4**	667.2
Less: Current portion of deferred revenue relating to:		
Capital contributions	**24.8**	21.0
Other deferred revenue	**3.9**	3.4
Current portion of deferred revenue	**28.7**	24.4
Non-current portion of deferred revenue	**736.7**	642.8

[(1)] Includes non-cash contributions of $29.9 million [2021 – $21.9 million].

11. NOTES PAYABLE TO RELATED PARTY

Notes payable to related party consist of the following:

	2022 $	2021 $
Notes payable to related party:		
5.59% Long-term note payable to the Corporation due May 21, 2040	**200.0**	200.0
2.96% Long-term note payable to the Corporation due April 10, 2023	**250.0**	250.0
4.01% Long-term note payable to the Corporation due April 9, 2063	**200.0**	200.0
4.13% Long-term note payable to the Corporation due September 16, 2044	**200.0**	200.0
3.60% Long-term note payable to the Corporation due July 28, 2045	**200.0**	200.0
3.988% Long-term note payable to the Corporation due April 9, 2063	**45.0**	45.0
2.572% Long-term note payable to the Corporation due August 25, 2026	**200.0**	200.0
3.535% Long-term note payable to the Corporation due February 28, 2048	**200.0**	200.0
2.488% Long-term note payable to the Corporation due December 11, 2029	**200.0**	200.0
3.042% Long-term note payable to the Corporation due December 10, 2049	**200.0**	200.0
1.55% Long-term note payable to the Corporation due October 15, 2030	**200.0**	200.0
2.52% Long-term note payable to the Corporation due October 20, 2031	**150.0**	150.0
3.32% Long-term note payable to the Corporation due October 18, 2051	**200.0**	200.0
5.00% Long-term note payable to the Corporation due October 13, 2052	**300.0**	—
6.16% Demand note payable to the Corporation due on demand	**45.0**	45.0
3.32% Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**—**	15.0
Total notes payable to related party	**2,790.0**	2,505.0
Less: Unamortized debt issuance costs	**14.5**	13.0
Current portion of notes payable to related party *[note 22]*	**294.9**	60.0
Long-term portion of notes payable to related party *[note 22]*	**2,480.6**	2,432.0

All notes payable to the Corporation are unsecured, rank equally and will be settled in cash.

On October 18, 2021, LDC issued two promissory notes to the Corporation. The principal amounts of the promissory notes are $150.0 million payable on October 20, 2031, which bears interest at a rate of 2.52% per annum, and $200.0 million payable on October 18, 2051, which bears interest at a rate of 3.32% per annum. Interest is calculated and payable semi-annually in arrears on April 20 and October 20, and April 18 and October 18 of each year, respectively for both promissory notes.

On November 18, 2021, LDC repaid its $300.0 million promissory note to the Corporation.

During 2022, LDC repaid its $15.0 million promissory note to the Corporation.

On October 13, 2022, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $300.0 million payable on October 13, 2052, which bears interest at a rate of 5.00% per annum. Interest is calculated and payable semi-annually in arrears on April 13 and October 13 of each year.

12. EMPLOYEE FUTURE BENEFITS

Multi-employer pension plan

LDC's eligible employees participate in a defined benefit pension plan through OMERS. As at December 31, 2022, OMERS had disclosed that the plan was 95.0% funded [December 31, 2021 - 97.0%]. LDC is not able to assess the implications, if any, of OMERS' strategy to address the funding shortfall or of the withdrawal of other participating entities from the OMERS plan on its future contributions. For the year ended December 31, 2022, LDC's contributions were $16.6 million [2021 - $16.1 million], representing less than five percent of total contributions to the OMERS plan. LDC expects to contribute approximately $20.3 million to the OMERS plan in 2023.

Post-employment benefits

a) Benefit obligation

	2022 $	2021 $
Balance, beginning of year	**306.6**	332.7
Current service cost	**2.7**	3.0
Interest cost	**9.0**	8.1
Benefits paid	**(10.4)**	(12.7)
Past service cost	**1.3**	—
Experience loss [(1)]	**2.9**	3.2
Actuarial loss arising from changes in demographic assumptions [(1)]	**1.9**	—
Actuarial gain arising from changes in financial assumptions [(1) (2)]	**(85.2)**	(28.2)
Transfer from related parties	**1.2**	0.5
Balance, end of year	**230.0**	306.6

(1) Actuarial gain on accumulated sick leave credits of $3.7 million [2021 - $2.0 million loss] is recognized in benefit cost *[note 12[c]]* and $0.1 million in transfer from related parties [2021 - $0.1 million], and actuarial gain on medical, dental and life insurance benefits of $76.6 million [2021 - $26.9 million] is recognized in OCI *[note 12[d]]*.
(2) Reflects the impact of the change in discount rate from 3.0% to 5.1% *[note 12[e]]*.

b) Amounts recognized in regulatory balances

As at December 31, 2022, the amount recognized in regulatory balances related to accumulated net actuarial gain/loss was $28.5 million [credits] [December 31, 2021 - $48.1 million [debits]] *[note 8[d]]*.

c) Benefit cost recognized

	2022 $	2021 $
Current service cost	**2.7**	3.0
Interest cost	**9.0**	8.1
Past service cost	**1.3**	—
Actuarial (gain) loss on other employee benefits *[note 12[a]]*	**(3.7)**	2.0
Benefit cost	**9.3**	13.1
Capitalized to PP&E and intangible assets	**3.6**	5.5
Charged to operating expenses	**5.7**	7.6

d) Amounts recognized in OCI

	2022 $	2021 $
Actuarial gain *[note 12[a]]*	**76.6**	26.9
Income tax expense in OCI *[note 20]*	**(20.3)**	(7.1)
Remeasurements of post-employment benefits, net of tax	**56.3**	19.8
Net movements in regulatory balances related to OCI, net of tax	**(56.3)**	(19.8)
OCI, net of tax	**—**	—

e) Significant assumptions

	2022 %	2021 %
Discount rate used in the calculation of:		
Benefit obligation as at December 31	**5.10**	3.00
Assumed medical and dental cost trend rates as at December 31:		
Rate of increase in dental costs assumed for next year	**4.00**	4.00
Rate of increase in medical costs assumed for next year	**5.10**	5.00

f) Sensitivity analysis

Significant actuarial assumptions for benefit obligation measurement purposes are discount rate and assumed medical and dental cost trend rates. The weighted average duration of the benefit obligation as at December 31, 2022 was 13.0 [2021 - 16.5]. The sensitivity analysis below has been determined based on reasonably possible changes of the assumptions, in isolation of one another, occurring at the end of the reporting period. This analysis may not be representative of the actual change since it is unlikely that changes in the assumptions would occur in isolation of one another as some of the assumptions may be correlated.

Changes in key assumptions would have had the following effect on the benefit obligation:

	Change in assumption	2022 $	2021 $
Benefit obligation		**230.0**	306.6
Discount rate	1% ↑	**(27.1)**	(46.0)
	1% ↓	**33.3**	59.0
Medical and dental cost trend rate	1% ↑	**25.0**	37.4
	1% ↓	**(21.7)**	(33.1)

13. CAPITAL MANAGEMENT

LDC's main objectives when managing capital are to:

- ensure ongoing access to funding to maintain, refurbish and expand the electricity distribution system;
- ensure sufficient liquidity is available [either through cash and cash equivalents or borrowings from TH Energy or the Corporation] to meet the needs of the business; and
- minimize finance costs while taking into consideration current and future industry, market and economic risks and conditions.

LDC monitors forecasted cash flows, capital expenditures, debt repayment and key credit ratios similar to those used by key rating agencies. LDC manages capital by preparing short-term and long-term cash flow forecasts. In addition, LDC borrows from TH Energy or the Corporation as required to help fund some of the periodic net cash outflows and to maintain available liquidity. There have been no changes in LDC's approach to capital management during the year. As at December 31, 2022, LDC's definition of capital included equity, bank indebtedness, borrowings through the Corporation and obligations under leases, including the current portion thereof, and has remained unchanged from the definition as at December 31, 2021. As at December 31, 2022, equity amounted to $2,412.2 million [December 31, 2021 - $2,243.4 million], and bank indebtedness, borrowings through the Corporation and obligations under leases, including the current portion thereof, amounted to $2,775.7 million [December 31, 2021 - $2,492.2 million].

14. FINANCIAL INSTRUMENTS

a) Fair value

As at December 31, 2022 and December 31, 2021, the fair values of cash and cash equivalents, accounts receivable and unbilled revenue, and accounts payable and accrued liabilities approximated their carrying amounts due to the short maturity of these instruments *[note 25[j]]*. The fair value of customer deposits approximates their carrying amount taking into account interest accrued on the outstanding balance. Obligations under leases are measured based on a discounted cash flow analysis and fair values approximate the carrying amounts as management believes that the fixed interest rates are representative of current market rates. Notes payable are measured at amortized cost, based on the fair value of the notes payable at issuance, which was the fair value of the consideration received adjusted for transaction costs. The fair values of the notes payable are based on the present value of contractual cash flows, discounted at LDC's current borrowing rate for similar debt instruments.

The carrying amounts and fair values of LDC's notes payable to related party consist of the following:

	2022 $		2021 $	
	Carrying amount	Fair value [1]	Carrying amount	Fair value [1]
Notes payable to the Corporation				
5.59% due May 21, 2040	**199.0**	**214.2**	199.0	274.7
2.96% due April 10, 2023	**249.9**	**248.6**	249.7	255.6
4.01% due April 9, 2063	**198.8**	**165.4**	198.8	249.5
4.13% due September 16, 2044	**198.6**	**178.2**	198.6	238.7
3.60% due July 28, 2045	**198.8**	**163.7**	198.8	221.4
3.988% due April 9, 2063	**44.7**	**37.2**	44.7	56.2
2.572% due August 25, 2026	**199.5**	**186.9**	199.4	207.0
3.535% due February 28, 2048	**198.7**	**160.6**	198.7	220.6
2.488% due December 11, 2029	**199.2**	**176.6**	199.1	205.4
3.042% due December 10, 2049	**198.7**	**145.1**	198.7	202.8
1.55% due October 15, 2030	**198.9**	**160.5**	198.8	189.0
2.52% due October 20, 2031	**149.2**	**126.9**	149.1	152.1
3.32% due October 18, 2051	**198.6**	**152.1**	198.6	214.0
5.00% due October 13, 2052	**297.9**	**305.4**	—	—
Demand note payable to the Corporation due on demand	**45.0**	**45.0**	45.0	45.0
Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	—	—	15.0	15.0
Total	**2,775.5**	**2,466.4**	2,492.0	2,747.0

[1] The fair value measurement of financial instruments for which the fair value has been disclosed is included in Level 2 of the fair value hierarchy *[note 25[k]]*.

b) Financial risks

The following is a discussion of certain financial risks and related mitigation strategies that have been identified by LDC for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

Credit risk

LDC is exposed to the risk of counterparties defaulting on their obligations. LDC monitors and limits its exposure to credit risk on a continuous basis. The credit risk related to cash and cash equivalents is mitigated by LDC in assessing and monitoring the credit exposures of counterparties.

LDC's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. As a result of current uncertain economic conditions, LDC may be exposed to credit risk with respect to customer non-payment of electricity bills, and LDC's security interest or other protective measures, if any, provided to LDC, such as letters of credit, cash deposits or pre-authorized payments may not be sufficient. LDC considers the current economic and credit conditions to determine the expected credit loss allowance of its accounts receivable and unbilled revenue. Due to current uncertain economic conditions, the estimates and judgments made by management in the preparation of the expected credit loss allowance are subject to an estimation uncertainty. LDC determines the expected credit loss allowance based on current estimates and

assumptions, including but not limited to recent trends for customer collections and current and forecasted economic conditions. LDC continues to actively monitor its exposure to credit risk.

LDC obtains security instruments from certain customers in accordance with direction provided by the OEB. As at December 31, 2022, LDC held security deposits in the amount of $70.0 million [December 31, 2021 - $72.4 million], of which $36.7 million [December 31, 2021 - $39.4 million] was related to security deposits on offers to connect to guarantee the payment of additional costs related to expansion projects. LDC's security instruments may not provide sufficient protection from counterparties defaulting on their obligations. As at December 31, 2022, there were no significant concentrations of credit risk with respect to any customer. The credit risk and mitigation strategies with respect to unbilled revenue are the same as those for accounts receivable.

LDC did not have any single customer that generated more than 10% of total revenue for the years ended December 31, 2022 and December 31, 2021.

Credit risk associated with accounts receivable and unbilled revenue is as follows:

	2022 $	2021 $
Accounts receivable, gross		
Outstanding for not more than 30 days	**184.6**	183.8
Outstanding for more than 30 days and not more than 120 days	**30.0**	20.2
Outstanding for more than 120 days	**35.9**	36.7
Total accounts receivable, gross	**250.5**	240.7
Unbilled revenue, gross	**276.7**	237.9
Expected credit loss allowance	**(31.7)**	(33.2)
Total accounts receivable and unbilled revenue	**495.5**	445.4

Unbilled revenue represents amounts for which LDC has a contractual right to receive cash through future billings and are unbilled at period-end. Unbilled revenue is considered in conjunction with accounts receivable and is included in the expected credit loss allowance as at December 31, 2022 and December 31, 2021.

LDC has a broad base of customers. As at December 31, 2022 and December 31, 2021, LDC's accounts receivable for non-commercial customers and unbilled revenue which were not past due or impaired were assessed by management to have no significant collection risk. Accounts receivable balances related to commercial customers are assessed on a holistic basis and the entire billed balance, including amounts not past due, is assessed for significant collection risk.

Reconciliation between the opening and closing expected credit loss allowance balances for accounts receivable and unbilled revenue is as follows:

	2022 $	2021 $
Balance, beginning of year	**(33.2)**	(30.2)
Additional expected credit loss allowance	**(4.4)**	(6.8)
Write-offs	**6.1**	4.0
Recoveries of previously written-off balances	**(0.2)**	(0.2)
Balance, end of year	**(31.7)**	(33.2)

c) Market risks

Interest rate risk

LDC is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations *[note 12[f]]*. LDC is also exposed to short-term interest rate risk on the net of cash and cash equivalents and customer deposits. Notes payable to related party bear interest based on the prevailing market conditions at the time of issuance.

As at December 31, 2022, aside from the valuation of its post-employment benefit obligations, most of LDC's remaining obligations were either non-interest bearing or bear fixed interest rates. Its financial assets were predominately short-term in nature and mostly non-interest bearing. LDC estimates that a 25-basis point increase [decrease] in short-term interest rates, with all other variables held constant, would result in an increase [decrease] of approximately $0.1 million to annual finance costs.

Liquidity risk

LDC is exposed to liquidity risk related to its ability to fund its obligations as they become due. LDC monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. LDC has access to credit facilities and borrowings through the Corporation and monitors cash balances daily. LDC's objective is to ensure that sufficient liquidity is on hand to meet obligations as they become due while minimizing finance costs. LDC relies on debt financing from borrowings through the Corporation and existing credit facilities to finance its daily operations, repay existing indebtedness and fund capital expenditures. The current challenging economic climate affected by factors including but not limited to uncertain macroeconomic conditions like a global recession may lead to material adverse changes in cash flows, working capital levels and/or debt balances, which may also have a direct negative impact on LDC's operating results and financial position in the future. Accordingly, LDC continues to monitor liquidity risk and adapt its plans as the economic climate evolves.

Liquidity risks associated with financial commitments are as follows:

	2022					
	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Accounts payable and accrued liabilities [1]	**437.8**	—	—	—	—	—
Obligations under leases	—	**0.1**	**0.1**	—	—	—
Long-term notes payable to the Corporation						
5.59% due May 21, 2040	—	—	—	—	—	**200.0**
2.96% due April 10, 2023	**250.0**	—	—	—	—	—
4.01% due April 9, 2063	—	—	—	—	—	**200.0**
4.13% due September 16, 2044	—	—	—	—	—	**200.0**
3.60% due July 28, 2045	—	—	—	—	—	**200.0**
3.988% due April 9, 2063	—	—	—	—	—	**45.0**
2.572% due August 25, 2026	—	—	—	**200.0**	—	—
3.535% due February 28, 2048	—	—	—	—	—	**200.0**
2.488% due December 11, 2029	—	—	—	—	—	**200.0**
3.042% due December 10, 2049	—	—	—	—	—	**200.0**
1.55% due October 15, 2030	—	—	—	—	—	**200.0**
2.52% due October 20, 2031	—	—	—	—	—	**150.0**
3.32% due October 18, 2051	—	—	—	—	—	**200.0**
5.00% due October 13, 2052						**300.0**
Demand note payable to the Corporation due on demand	**45.0**	—	—	—	—	—
Interest payments on long-term notes payable and demand notes payable	**93.3**	**88.3**	**88.3**	**88.3**	**83.1**	**1,606.0**
Total	**826.1**	**88.4**	**88.4**	**288.3**	**83.1**	**3,901.0**

[1] Accounts payable and accrued liabilities exclude $23.1 million of accrued interest on long-term notes payable and demand notes payable included within "Interest payments on long-term notes payable and demand notes payable".

Inflation risk

The general rate of inflation in Canada and many other countries saw a significant increase during 2021 and continuing throughout 2022, with some regions experiencing multi-decade highs. Certain underlying factors include, but are not limited to, global supply chain disruptions, shipping restrictions, labour market constraints, geopolitical instability and side effects from monetary policies and fiscal expansions. The global economic recovery remains uncertain. Prices for certain services and materials continue to evolve in response to fast-changing commodity markets, industry activities, supply chain dynamics, and government policies impacting operating and capital costs. The global economic recovery and rising inflationary trends are widely expected to result in elevated interest rates. In 2022, the Bank of Canada began raising its benchmark interest rates for the first time since 2018 and further interest rate increases continue to occur. LDC closely monitors market trends and seeks to mitigate cost impacts through various measures, including project management, procurement and other management actions.

Foreign exchange risk

As at December 31, 2022, LDC had limited exposure to the changing values of foreign currencies. While LDC purchases goods and services which are payable in United States dollars, and purchases United States currency to meet the related commitments when required, the impact of these transactions is not material to the financial statements.

15. FINANCIAL ASSISTANCE

As at December 31, 2022, $50.4 million [December 31, 2021 - $51.5 million] of letters of credit had been issued by the Corporation, on behalf of LDC, under its $100.0 million demand facility mainly to support LDC's prudential requirements with the IESO.

16. SHARE CAPITAL

Share capital consists of the following:

	2022 $	2021 $
Authorized		
The authorized share capital of LDC consists of an unlimited number of common shares without par value.		
Issued and outstanding		
1,000 common shares, of which all were fully paid.	**556.3**	556.3

Dividends

During the year ended December 31, 2022, the Board of Directors of LDC declared and paid dividends to the Corporation totalling $nil [2021 - $0.6 million].

17. REVENUES

Revenues consist of the following:

	2022 $	2021 $
Revenue from contracts with customers		
Energy sales	**2,737.8**	2,702.4
Distribution revenue	**754.2**	759.1
Ancillary services revenue	**19.7**	16.7
Pole and duct rentals	**17.9**	18.2
Other regulatory service charges	**9.2**	7.8
Street lighting services	**8.3**	7.8
Capital contributions - energy storage systems	**1.4**	—
Miscellaneous	**11.0**	17.6
Revenue from other sources		
Capital contributions - developers and other	**16.7**	12.3
Other	**12.0**	7.7
Total revenues	**3,588.2**	3,549.6

Energy sales and distribution revenue by customer class are as follows:

	2022 $	2021 $
Residential service [(1)]	**1,007.8**	1,000.5
General service [(2)]	**2,309.8**	2,270.6
Large users [(3)]	**174.4**	190.4
Total energy sales and distribution revenue	**3,492.0**	3,461.5

[(1)] "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multi-family units and seasonal occupancy.
[(2)] "General Service" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a 12-month period.
[(3)] "Large Users" means a service provided to a customer with a monthly peak demand of 5,000 kW or greater averaged over a 12-month period.

18. OPERATING EXPENSES

Operating expenses consist of the following:

	2022 $	2021 $
Salaries and benefits	**210.8**	203.6
External services	**162.7**	156.3
Other support costs [1]	**29.9**	30.8
Materials and supplies	**25.9**	27.0
Less: Capitalized costs	**(118.7)**	(107.0)
Total operating expenses	**310.6**	310.7

[1] Includes expected credit loss allowance, taxes other than income taxes, utilities, rental, communication, insurance, and other general and administrative expenses.

For the year ended December 31, 2022, LDC recognized operating expenses of $16.0 million related to materials and supplies used to service electricity distribution assets [2021 - $17.6 million].

19. FINANCE COSTS

Finance costs consist of the following:

	2022 $	2021 $
Interest income	**2.7**	0.9
Interest expense		
Interest on long-term debt [1]	**(87.4)**	(85.9)
Interest on short-term debt	**(3.4)**	(2.2)
Other interest	**(1.9)**	(0.3)
Capitalized borrowing costs	**6.8**	4.7
Total finance costs	**(83.2)**	(82.8)

[1] Includes amortization of debt issuance costs, discounts and premiums.

20. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined statutory Canadian federal and provincial income tax rate. Reconciliation of income tax expense computed at the statutory income tax rate to the income tax provision is set out below:

	2022 $	2021 $
Rate reconciliation before net movements in regulatory balances		
Income before income taxes	**39.9**	94.3
Statutory Canadian federal and provincial income tax rate	**26.5 %**	26.5 %
Expected income tax expense	**(10.6)**	(25.0)
Non-taxable amounts	**1.0**	5.5
Gain on disposals of PP&E	**—**	(0.1)
Other	**(0.4)**	(0.8)
Income tax expense	**(10.0)**	(20.4)
Effective tax rate	**25.1 %**	21.6 %
Rate reconciliation after net movements in regulatory balances		
Net income after net movements in regulatory balances, before income tax [(1)]	**176.4**	148.4
Statutory Canadian federal and provincial income tax rate	**26.5 %**	26.5 %
Expected income tax expense	**(46.7)**	(39.3)
Temporary differences recoverable in future rates	**37.6**	27.1
Gain on disposals of PP&E	**—**	(0.1)
Other	**1.5**	0.8
Income tax expense and income tax recorded in net movements in regulatory balances	**(7.6)**	(11.5)
Effective tax rate	**4.3 %**	7.7 %

[(1)] Income tax includes income tax expense and income tax recorded in net movements in regulatory balances.

Income tax expense as presented in the statements of income and statements of comprehensive income are as follows:

	2022 $	2021 $
Income tax expense	**(10.0)**	(20.4)
Income tax recorded in net movements in regulatory balances	**2.4**	8.9
Income tax expense and income tax recorded in net movements in regulatory balances	**(7.6)**	(11.5)
Income tax expense in OCI *[note 12[d]]*	**(20.3)**	(7.1)
Income tax recovery in OCI recorded in net movements in regulatory balances	**20.3**	7.1
Income tax in OCI	**—**	—

Components of income tax expense and income tax recorded in net movements in regulatory balances are as follows:

	2022 $	2021 $
Current tax expense		
Current year	**(9.4)**	(10.9)
Deferred tax (expense) recovery		
Origination and reversal of temporary differences	**1.8**	(0.6)
Income tax expense and income tax recorded in net movements in regulatory balances	**(7.6)**	(11.5)

Deferred tax assets [liabilities] consist of the following:

	Net balance January 1, 2022 $	Recognized in net income $	Recognized in OCI $	Net balance December 31, 2022 $
PP&E and intangible assets	**(143.6)**	**(29.9)**	**—**	**(173.5)**
Post-employment benefits	**81.3**	**—**	**(20.3)**	**61.0**
Tax credit carryforward	**1.8**	**1.7**	**—**	**3.5**
Other taxable temporary differences	**(3.3)**	**27.7**	**—**	**24.4**
Total	**(63.8)**	**(0.5)**	**(20.3)**	**(84.6)**

	Net balance January 1, 2021 $	Recognized in net income $	Recognized in OCI $	Net balance December 31, 2021 $
PP&E and intangible assets	(114.0)	(29.6)	—	(143.6)
Post-employment benefits	88.1	0.3	(7.1)	81.3
Tax credit carryforward	2.5	(0.7)	—	1.8
Other taxable temporary differences	(23.7)	20.4	—	(3.3)
Total	(47.1)	(9.6)	(7.1)	(63.8)

21. STATEMENTS OF CASH FLOWS

Changes in non-cash operating working capital provided [used] cash as follows:

	2022 $	2021 $
Accounts receivable and unbilled revenue	**(51.9)**	18.4
Income tax receivable	**3.0**	8.7
Materials and supplies	**1.7**	(0.1)
Other current assets	**2.5**	(2.3)
Accounts payable and accrued liabilities [(1)]	**17.8**	(18.3)
Income tax payable	**2.1**	—
Deferred revenue	**4.3**	5.2
Deferred conservation credit	**5.1**	(4.3)
Total changes in non-cash operating working capital	**(15.4)**	7.3

Reconciliation between the amount presented on the statements of cash flows and total additions to PP&E and intangible assets is as follows:

	2022 $	2021 $
Purchase of PP&E, cash basis	**607.3**	548.0
Net change in accounts payable and accruals related to PP&E	**5.6**	16.6
Non-cash contributed assets	**29.9**	21.9
Other	**1.4**	1.4
Total additions to PP&E	**644.2**	587.9
Purchase of intangible assets, cash basis	**59.6**	37.5
Net change in accounts payable and accruals related to intangible assets [(1)]	**11.6**	15.8
Total additions to intangible assets	**71.2**	53.3

[(1)] Includes reclassification from amounts previously reported due to change in presentation on the statements of cash flows for amounts between purchase of intangible assets and changes in non-cash operating working capital balances of $10.1 million for the year ended December 31, 2021.

Summary of changes in liabilities arising from financing activities:

	2021 $	Cash flows [1] $	Non-cash changes $	2022 $
Year ended December 31,				
Notes payable to related party *[note 11]*	**2,492.0**	**282.9**	**0.6**	**2,775.5**
Accrued interest [2]	**20.1**	**(87.7)**	**90.7**	**23.1**
Lease liability [3]	**0.2**	**—**	**—**	**0.2**
Total	**2,512.3**	**195.2**	**91.3**	**2,798.8**

	2020 $	Cash flows [1] $	Non-cash changes $	2021 $
Year ended December 31,				
Notes payable to related party *[note 11]*	2,443.4	47.7	0.9	2,492.0
Accrued interest [2]	19.2	(86.3)	87.2	20.1
Dividends payable	—	(0.6)	0.6	—
Lease liability [3]	0.3	—	(0.1)	0.2
Total	2,462.9	(39.2)	88.6	2,512.3

[1] Cash inflows and cash outflows arising from notes payable to related party are presented on a net basis.
[2] Included within accounts payable and accrued liabilities *[note 9]*.
[3] Included within other liabilities.

22. RELATED PARTY TRANSACTIONS

For LDC, transactions with related parties include transactions with the City, which is the sole shareholder of the Corporation, the Corporation, and TH Energy, a wholly-owned subsidiary of the Corporation.

	City $	Corporation $	TH Energy $
For year ended December 31, 2022			
Revenues	**250.2**	**—**	**8.5**
Operating expenses (recoveries) and capital expenditures (recoveries)	**0.6**	**1.8**	**(1.2)**
Finance costs	**—**	**86.9**	**—**
As at December 31, 2022			
Accounts receivable and unbilled revenue	**34.8**	**0.2**	**1.2**
Accounts payable and accrued liabilities	**6.7**	**25.1**	**—**
Current portion of notes payable to related party	**—**	**294.9**	**—**
Long-term portion of notes payable to related party	**—**	**2,480.6**	**—**
Customer deposits	**9.8**	**—**	**—**

	City $	Corporation $	TH Energy $
For year ended December 31, 2021			
Revenues	259.3	—	7.8
Operating expenses (recoveries) and capital expenditures (recoveries)	(1.5)	0.5	(1.7)
Finance costs	—	85.5	—
Dividends declared and paid	—	0.6	—
As at December 31, 2021			
Accounts receivable and unbilled revenue	39.5	—	0.4
Accounts payable and accrued liabilities	15.0	21.4	—
Current portion of notes payable to related party	—	60.0	—
Long-term portion of notes payable to related party	—	2,432.0	—
Customer deposits	12.8	—	—

Revenues represent amounts charged to the City primarily for electricity and ancillary services, and to TH Energy for street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and other services, and the Corporation for purchased corporate and management services. Operating expense recoveries represent amounts charged to TH Energy for the provision of goods and services. Capital expense recoveries represent amounts reversed by the City for closed road cut repair accruals. Finance costs represent interest charged by the Corporation on the notes payable *[note 11]*. Dividends are paid to the Corporation *[note 16]*.

Accounts receivable and unbilled revenue represent receivables from the City primarily for electricity and ancillary services, and TH Energy for the provision of goods and services, including amounts not yet billed. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services. Included in the accounts payable and accrued liabilities are amounts payable to the Corporation for purchased corporate and management services and interest accruing on the notes payable to the Corporation and amounts payable to TH Energy for provision of goods and services. Notes payable to related party represent amounts borrowed from the Corporation *[note 11]*. Customer deposits represent amounts received from the City for future expansion projects.

Key management personnel include LDC's senior executive officers and members of the Board of Directors. The compensation costs associated with the key management personnel are as follows:

	2022 $	2021 $
Short-term employee benefits	**4.6**	4.6
Post-employment benefits	**2.2**	4.9
Total	**6.8**	9.5

23. COMMITMENTS

As at December 31, 2022, the future minimum payments for capital projects and other commitments were as follows:

	Capital projects [1] and other $
Less than one year	**16.7**
Between one and five years	**5.4**
More than five years	**2.2**
Total amount of future minimum payments [2]	**24.3**

[1] Mainly commitments for construction services.
[2] Refer to note 14 for financial commitments excluded from the table above.

24. CONTINGENCIES

Legal Proceedings

In the ordinary course of business, LDC is subject to various legal proceedings, actions and claims from customers, suppliers, regulators and other parties. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and could materially adversely affect LDC. As at the date hereof, LDC believes that none of these legal proceedings, actions and claims from customers, suppliers, regulators and other parties in which it is currently involved or has been involved since the beginning of the most recently completed financial year, would be expected to have a material adverse effect on LDC. On an ongoing basis, LDC assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, LDC would make a claim under any liability or other insurance policies, to the extent applicable, subject to such claim not being disputed by the insurers.

25. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from those prescribed by IFRS for enterprises operating in an unregulated environment and regulated entities that did not adopt IFRS 14.

Regulatory Balances

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of continuing to recognize regulatory balances according to their previous GAAP. Regulatory balances provide useful information about LDC's financial position, financial performance and cash flows. IFRS 14 is restricted to first-time adopters of IFRS and remains in force until either repealed or replaced by permanent guidance on rate-regulated accounting from the IASB.

LDC has determined that certain debit and credit balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14. Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect

the economic impact of regulatory decisions regarding LDC's regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory debit and credit balances on LDC's balance sheets, and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB. Regulatory balances can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is determined by management to be probable. In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, the balances are recorded in LDC's statements of income in the period when the assessment is made. Regulatory balances, which do not meet the definition of an asset or liability under any other IFRS, are segregated on the balance sheets and are presented on the statements of income and the statements of comprehensive income as net movements in regulatory balances and net movements in regulatory balances related to OCI, net of tax. The netting of regulatory debit and credit balances is not permitted. The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions.

b) Cash and cash equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition. On the statements of cash flows, cash and cash equivalents [bank indebtedness] include bank overdrafts that are repayable on demand and form an integral part of LDC's cash management.

c) Accounts receivable and unbilled revenue

Accounts receivable are recorded at the invoiced amount and overdue amounts bear interest at OEB-approved rates. Unbilled revenue is recorded based on an estimated amount for electricity delivered and for other services provided and not yet billed. The estimate is primarily based on the customers' previous billings with adjustments mainly for assumptions related to seasonality and weighted average price. The carrying amount of accounts receivable and unbilled revenue is reduced through a loss allowance, if applicable, and the amount of the related impairment loss is recognized in the statements of income. The impairment loss is the difference between an asset's carrying amount and the estimated future cash flows. When LDC considers that there are no realistic prospects of recovery of the financial assets, the relevant amounts are written off. If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Accounts receivable and unbilled revenue are assessed at each reporting date to determine whether there is objective evidence of impairment, which includes default or delinquency by a debtor, indications that a debtor or issuer will enter bankruptcy, and adverse changes in the payment status of borrowers or issuers. Accounts receivable and unbilled revenue that are not individually assessed for impairment are collectively assessed for impairment by grouping together receivables with similar risk characteristics, and LDC considers historical trends on the timing of recoveries and the amount of loss incurred, adjusted for forward-looking factors specific to the current economic and credit conditions.

LDC measures the expected credit loss allowance at an amount equal to the lifetime expected credit losses for all trade receivables that result from transactions with customers and do not contain a significant financing component. A provision matrix is used by LDC to measure the lifetime expected credit losses of accounts receivable from individual customers. Loss rates are calculated using a 'roll rate' method based on the probability of a trade receivable progressing through successive stages of delinquency to write-off and are based on the average of actual credit loss experience over the past three years, as it more accurately reflects anticipated credit loss. Roll rates are calculated separately for exposures based on customer account status. LDC also adjusts the expected credit loss allowance in efforts to account for current economic conditions and events (including forward-looking macroeconomic data) and historical information (including credit agency reports, if available) *[note 14[b]]*. LDC considers the reasons for the accounts being past due, the characteristics of existing accounts, reasonable and supportable forecasts and other considerations that may affect the collectability of the reported amounts.

d) Materials and supplies

Materials and supplies consist primarily of small consumable materials mainly related to the maintenance of the electricity distribution infrastructure. LDC classifies all major construction related components of its electricity distribution infrastructure to PP&E. Materials and supplies are carried at the lower of cost and net realizable value, with cost determined on a weighted average cost basis net of a provision for obsolescence.

e) Property, plant and equipment

PP&E are measured at cost less accumulated depreciation and any accumulated impairment losses, if applicable. The cost of PP&E represents the original cost, consisting of direct materials and labour, contracted services, borrowing costs and directly attributable overhead. Subsequent costs are capitalized only if it is probable that the future economic benefits associated with the expenditure will flow to LDC and the costs can be measured reliably. If significant parts of an item of PP&E have different useful lives, then they are accounted for as separate major components of PP&E. The carrying amount of an item of PP&E is derecognized on disposal of the asset or when no future economic benefits are expected to accrue to LDC from its continued use. Any gain or loss arising on derecognition is recorded in the statements of income in the period in which the asset is derecognized. The gain or loss on disposal of an item of PP&E is determined as the sale proceeds less the carrying amount of the asset and costs of removal and is recognized in the statements of income.

Depreciation begins when an asset becomes available for use. Depreciation is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Distribution assets:	
Distribution lines	1.7% to 5.0%
Transformers	3.3% to 5.0%
Meters	2.5% to 6.7%
Stations	2.0% to 10.0%
Buildings	1.3% to 5.0%
Equipment and other:	
Other capital assets	4.0% to 25.0%
Right-of-use assets	1.0% to 11.1%

Right-of-use assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that LDC will obtain ownership by the end of the lease term, in which case they are depreciated to the end of the useful life of the underlying assets. Right-of-use assets are recognized for contracts that are, or contain, leases. Construction in progress relates to assets not currently available for use and therefore is not depreciated. The depreciation method and useful lives are reviewed at each financial year-end and adjusted if appropriate. There are no residual values for items of PP&E.

f) Intangible assets

Intangible assets are measured at cost less accumulated amortization and any accumulated impairment losses, if applicable.

Amortization begins when an asset becomes available for use. Amortization is provided on a straight-line basis over the estimated useful lives at the following annual rates:

Computer software	10.0% to 25.0%
Contributions	4.0%

Software in development and contributions for work in progress relate to assets not currently available for use and therefore are not amortized. Contributions represent payments made to HONI for dedicated infrastructure in order to receive connections to transmission facilities. The amortization method and useful lives are reviewed at each financial year-end and adjusted if appropriate.

g) Impairment of non-financial assets

LDC reviews the carrying amounts of its non-financial assets other than materials and supplies and deferred tax assets at each reporting date to determine whether there is any indication of impairment, in which case the assets' recoverable amounts are estimated. For impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent on the cash inflows of other assets or CGUs. LDC has determined that its assets are a single CGU due to interdependencies of its assets to generate cash flows. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount. Impairment losses are recognized in the statements of income, and are allocated to reduce the carrying amounts of assets in the CGU on a pro rata basis. An impairment loss recognized in prior periods is reversed when an asset's recoverable amount has increased, but not exceeding the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

h) Capitalized borrowing costs

Borrowing costs directly attributable to the acquisition, construction or development of qualifying assets that necessarily take a substantial period of time to get ready for their intended use are capitalized, until such time as the assets are substantially ready for their intended use. The interest rate for capitalization is LDC's weighted average cost of borrowing, and is applied to the carrying amount of the construction-in-progress assets or assets under development including borrowing costs previously capitalized, net of capital contributions received. Capitalization commences immediately as the expenditure on a qualifying asset is incurred. Borrowing costs are included in the cost of PP&E and intangible assets for financial reporting purposes and charged to operations through depreciation and amortization expense over the useful lives of the related assets.

i) Revenue recognition

LDC assesses each contract with the customer to identify the performance obligation. The transaction price and the payment terms are agreed upon in the contract between LDC and the customer.

Revenues from energy sales and electricity distribution are recorded on the basis of cyclical billings and include an estimated amount for electricity delivered and not yet billed. The performance obligation is satisfied over time when the electricity is simultaneously received and consumed by the customer. The majority of billing cycles and payment terms are on a monthly basis. These revenues are impacted by energy demand primarily driven by outside temperature, and customer class usage patterns and composition.

Energy sales arise from charges to customers for electricity consumed, based on regulated rates. Energy sales include amounts billed or billable to customers for commodity charges, retail transmission charges, and WMS charges at current rates. These charges are passed through to customers over time and are considered revenue by LDC due to the collection risk of the related balances. LDC applies judgment to determine whether revenues are recorded on a gross or net basis. LDC has primary responsibility for the delivery of electricity to the customer. For any given period, energy sales should be equal to the cost of energy purchased. However, a difference between energy sales and energy purchases arises when there is a timing difference between the amounts charged by LDC to customers, based on regulated rates, and the electricity and non-competitive electricity service costs billed monthly by the IESO to LDC. This difference is recorded as a settlement variance, representing future amounts to be recovered from or refunded to customers through future billing rates approved by the OEB. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the balance sheets and within net movements in regulatory balances on the statements of income.

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by LDC in delivering electricity to customers. Distribution revenue also includes revenue related to the collection of OEB-approved rate riders.

Other revenue includes revenue from services ancillary to the electricity distribution, delivery of street lighting services, pole and duct rentals, other regulatory service charges, capital contributions and CDM programs.

Capital contributions received in advance from electricity customers and developers to construct or acquire PP&E for the purpose of connecting a customer to a network are recorded as deferred revenue and amortized into other revenue at an equivalent rate to that used for the depreciation of the related PP&E. Capital contributions received from developers to construct or acquire PP&E for the purpose of connecting future customers to the distribution network are considered out of scope of IFRS 15 *Revenue from Contracts with Customers*. Contributions received from customers to construct or acquire PP&E to deliver services other than those related to delivery of electricity are recorded as deferred revenue and amortized into other revenue over the term of the contract with the customer.

Revenues and costs associated with CDM programs are presented using the net basis of accounting and are recorded in accordance with IAS 20 *Accounting for Government Grants and Disclosure of Government Assistance*. Cost efficiency incentives related to the CDM programs, included as part of other revenue, are recognized when it is probable that future economic benefits will flow to the entity and the amount can be reasonably measured.

LDC has not incurred any additional costs to obtain or fulfill contracts with its customers from the above-mentioned revenue generating activities. Variable consideration under a contract is recorded only to the extent that it is highly probable that a significant reversal in the amount of cumulative revenue recognized will not occur when the associated uncertainty is subsequently resolved.

j) Financial instruments

All financial assets and financial liabilities are classified as "Amortized cost". These financial instruments are recognized initially at fair value adjusted for any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties.

LDC uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the balance sheets:

- Cash and cash equivalents are classified as "Amortized cost" and are initially measured at fair value. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts receivable and unbilled revenue are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method, less expected credit loss allowance. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Bank indebtedness is classified as "Amortized cost" and is initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Accounts payable are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value due to the short maturity of these instruments.

- Customer deposits are classified as "Amortized cost" and are initially measured at fair value. Subsequent measurements are recorded at cost plus accrued interest. The carrying amounts approximate fair value taking into account interest accrued on the outstanding balance.

- Obligations under leases are classified as "Amortized cost" and are initially measured at fair value, or at the present value of the minimum lease payments, if lower. Subsequent measurements are based on a discounted cash flow analysis and fair values approximate the carrying amounts as management believes that the fixed interest rates are representative of current market rates.

- Notes payable to related party are classified as "Amortized cost" and are initially measured at fair value. The carrying amounts of notes payable are carried at amortized cost, based on the fair value of the notes payable at issuance, which was the fair value of the consideration received adjusted for transaction costs. The fair values of the notes payable are based on the present value of contractual cash flows, discounted at LDC's current borrowing rate for similar debt instruments *[note 14[a]]*. Debt issuance costs incurred in connection with LDC's debt offerings are capitalized as part of the carrying amount of the notes payable and amortized over the term of the related notes payable, using the effective interest method, and the amortization is included in finance costs.

k) Fair value measurements

LDC utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. A fair value hierarchy exists that prioritizes observable and unobservable inputs used to measure fair value. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect LDC's assumptions with respect to how market participants would price an asset or liability. The fair value hierarchy includes three levels of inputs that may be used to measure fair value:

- Level 1: Unadjusted quoted prices in active markets for identical assets or liabilities. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis;

- Level 2: Other than quoted prices included within Level 1 that are observable for the assets or liabilities, either directly or indirectly; and

- Level 3: Unobservable inputs, supported by little or no market activity, used to measure the fair value of the assets or liabilities to the extent that observable inputs are not available.

l) Employee benefits

(i) Short-term employee benefits

Short-term employee benefit obligations that are due to be settled wholly within twelve months after the end of the annual reporting period in which the employees render the related service are measured on an undiscounted basis and are expensed as the related service is provided. A liability is recognized for the amount expected to be paid if LDC has a present legal or

constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

(ii) Multi-employer pension plan

LDC's full-time employees participate in a pension plan through OMERS. The OMERS plan is a jointly sponsored, multi-employer defined benefit pension plan established in 1962 by the province of Ontario for employees of municipalities, school boards, libraries, police and fire departments, and other local agencies in communities across Ontario. Both participating employers and employees are required to make plan contributions equally based on participating employees' contributory earnings, and share equally in funding gains or losses. The plan assets and pension obligations are not segregated in separate accounts for each member entity. The OMERS plan is accounted for as a defined contribution plan and the contribution payable is recognized as an employee benefit expense in the statements of income in the period when the service is rendered by the employee, since it is not practicable to determine LDC's portion of pension obligations or of the fair value of plan assets.

(iii) Post-employment benefits

LDC has a number of unfunded benefit plans providing post-employment benefits to its employees, including certain retirement, medical, dental and life insurance benefits. LDC also pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The cost of providing benefits under the benefit plans is actuarially determined using the projected unit credit method, which incorporates management's best estimate of future salary levels, retirement ages of employees, health care costs, and other actuarial factors. Past service cost is recognized when a plan amendment or curtailment occurs. Changes in actuarial assumptions and experience adjustments give rise to actuarial gains and losses. Actuarial gains and losses on post-employment benefits other than sick leave credits are recognized in OCI as they arise, and are subsequently reclassified from OCI to a regulatory balance on the balance sheets. Actuarial gains and losses on accumulated sick leave credits are recognized in the statements of income in the period in which they arise.

The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest actuarial valuation was performed as at January 1, 2022.

m) Customer deposits

Security deposits from electricity customers are cash collections to guarantee the payment of electricity bills. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits that are refundable upon demand are classified as a current liability.

Security deposits on offers to connect are cash collections from specific customers to guarantee the payment of additional costs relating to expansion projects. This liability includes related interest amounts owed to the customers with a corresponding amount charged to finance costs. Deposits are classified as a current liability when LDC no longer has an unconditional right to defer payment of the liability for at least 12 months after the reporting period.

n) Income taxes

LDC is exempt from tax under the ITA and the TA, if not less than 90% of its capital is owned by the Corporation, an MEU, and not more than 10% of its income is derived from activities carried on outside the municipal geographical boundaries of the City.

LDC is an MEU for purposes of the PILs regime contained in the Electricity Act. The Electricity Act provides that an MEU that is exempt from tax under the ITA and the TA is required to make PILs to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the ITA and the TA as modified by regulations made under the Electricity Act and related regulations. This effectively results in LDC paying income taxes equivalent to what would be imposed under the ITA and the TA.

LDC uses the liability method of accounting for income taxes. Under the liability method, current income taxes payable are recorded based on taxable income. LDC recognizes deferred tax assets and liabilities for the future tax consequences of events that have been included in the financial statements or income tax returns. Deferred tax assets and liabilities are determined based on the difference between the carrying value of assets and liabilities on the balance sheets and their respective tax basis, using the tax rates enacted or substantively enacted by the balance sheet date that are in effect for the year in which the differences are expected to reverse. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when it is probable that they will be realized, and are measured at the best estimate of the tax amount expected to be paid to or recovered from the taxation authorities. Deferred tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable that the related tax benefits will be realized. The calculation of current and deferred taxes requires management to make certain judgments with respect to changes in tax interpretations, regulations and legislation, and to estimate probable outcomes on the timing and reversal of temporary differences and tax authority audits of income tax.

Rate-regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates. A gross up to reflect the income tax benefits or liabilities associated with the revenue impact resulting from the realization of deferred taxes is recorded within regulatory balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the statements of income.

The benefits of the refundable and non-refundable apprenticeship and other ITCs are credited against the related expense in the statements of income.

o) Lessor arrangements

When LDC acts as a lessor, it determines at lease inception whether each lease is a finance lease or an operating lease.

To classify each lease, LDC makes an overall assessment of whether the lease transfers substantially all of the risks and rewards incidental to ownership of the underlying asset. If this is the case, then the lease is a finance lease; if not, then it is an operating lease.

p) Use of judgments and estimates

The preparation of LDC's financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions which affect the application of accounting policies, reported assets, liabilities and regulatory balances, and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future

decisions made by the OEB, the IESO, the Ontario Ministry of Energy, or the Ontario Ministry of Finance. The assessment of the COVID-19 pandemic recovery is subject to uncertainty; accordingly, judgments, estimates and assumptions related to the impact of the uncertain economic conditions made by management in the preparation of LDC's financial statements are also subject to uncertainty. Management has analyzed the impact of the uncertain economic conditions on its estimates and adjusted the expected credit loss allowance as at December 31, 2022 *[note 14[b]]*. The extent of the future impact of the uncertain economic conditions on LDC's financial results and business operations is not known at this time.

Information about judgments in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in note 25[a] relating to recognition of regulatory balances and note 25[i] relating to principal versus agent determination for recording revenue on a gross or net basis.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively. Assumptions and estimates with a significant risk of resulting in a material adjustment within the next financial year are used in the following:

- *Note 24* – Recognition and measurement of provisions and contingencies;
- *Note 25[a]* – Recognition and measurement of regulatory balances;
- *Note 25[c]* – Recognition and measurement of expected credit loss allowance for accounts receivable and unbilled revenue;
- *Notes 25[e] and 25[f]* – Determination of useful lives of depreciable assets;
- *Note 25[i]* – Revenue recognition – measurement of unbilled revenue;
- *Notes 25[l] and 12* – Measurement of post-employment benefits – key actuarial assumptions; and
- *Notes 25[n] and 20* – Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and tax loss carryforwards can be used.

q) Changes in accounting standards

Onerous Contracts - Cost of Fulfilling a Contract [Amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets ["IAS 37"]]

In May 2020, the IASB issued amendments to IAS 37 regarding costs that should be included as the cost of fulfilling a contract when assessing whether a contract is onerous. The amendments clarify that the cost of fulfilling the contract comprises all costs that relate directly to the contract. Such costs include both the incremental costs of fulfilling that contract and an allocation of other costs that relate directly to fulfilling contracts. The amendments apply to contracts existing at the date when the amendments are first applied. The amendments are effective for annual reporting periods beginning on or after January 1, 2022, with early adoption permitted.

Effective January 1, 2022, LDC adopted these amendments, with no impact on LDC's financial statements.

r) Future accounting pronouncements

The IASB has issued a number of standards and amendments to existing standards that are not yet effective. LDC has determined that the following amendments could have an impact on LDC's financial statements when adopted.

Classification of Liabilities as Current or Non-current [Amendments to IAS 1 Presentation of Financial Statements ["IAS 1"]]

In January 2020, the IASB issued amendments to IAS 1 relating to the classification of liabilities as current or non-current. Specifically, the amendments clarify one of the criteria in IAS 1 for classifying a liability as non-current - that is, the requirement for an entity to have the right to defer settlement of the liability for at least 12 months after the reporting period. This right may be subject to compliance with covenants. After reconsidering certain aspects of the 2020 amendments, in October 2022, the IASB issued Non-current Liabilities with Covenants [Amendments to IAS 1], reconfirming that only covenants with which a company must comply on or before the reporting date affect the classification of a liability as current or non-current. The amendments are effective for annual reporting periods beginning on or after January 1, 2024, with early adoption permitted. The amendments are to be applied retrospectively.

Definition of Accounting Estimates [Amendments to IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors ["IAS 8"]]

In February 2021, the IASB issued amendments to IAS 8 to introduce a definition of "accounting estimates" and include other amendments to help entities distinguish changes in accounting estimates from changes in accounting policies. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted. The amendments are to be applied prospectively.

Disclosure of Accounting Policies [Amendments to IAS 1]

In February 2021, the IASB issued amendments to IAS 1 requiring an entity to disclose its material accounting policies, rather than its significant accounting policies. Additional amendments were made to explain how an entity can identify a material accounting policy. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted.

Deferred Tax related to Assets and Liabilities arising from a Single Transaction [Amendments to IAS 12 Income Taxes ["IAS 12"]]

In May 2021, the IASB issued amendments to IAS 12. The amendments clarify how companies should account for deferred tax on certain transactions such as leases and decommissioning obligations. The amendments narrow the scope of the initial recognition exemption, so that it does not apply to transactions that give rise to equal and offsetting temporary differences. As a result, companies will need to recognize both a deferred tax asset and a deferred tax liability when accounting for such transactions. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted.

LDC anticipates that the adoption of these accounting pronouncements will not have a material impact on LDC's financial statements.

26. SUBSEQUENT EVENTS

LDC has evaluated the events and transactions occurring after the balance sheet date through to February 28, 2023 when LDC's financial statements were authorized for issuance by LDC's Board of Directors, and has identified no events and transactions which required recognition in LDC's financial statements and/or disclosure in the notes to LDC's financial statements.

GLOSSARY

CDM – Conservation and demand management

CGU – Cash generating unit

CIR – Custom Incentive Rate-setting

City – City of Toronto

Corporation – Toronto Hydro Corporation

COVID-19 – Coronavirus disease 2019 and its variants

Electricity Act – *Electricity Act, 1998* [Ontario], as amended

GAAP – Generally Accepted Accounting Principles

HONI – Hydro One Networks Inc.

IAS – International Accounting Standards

IASB – International Accounting Standards Board

IESO – Independent Electricity System Operator

IFRS – International Financial Reporting Standards

IRM – Incentive Regulation Mechanism

ITA – *Income Tax Act, 1985* [Canada], as amended

ITC – Investment tax credit

kW – Kilowatt

kWh – Kilowatt hour

LDC – Toronto Hydro-Electric System Limited

LRAM – Lost revenue adjustment mechanism

MEU – Municipal electricity utility

OCI – Other comprehensive income

OEB – Ontario Energy Board

OMERS – Ontario Municipal Employees Retirement System

OPEB – Other post-employment benefits

PILs – Payments in lieu of corporate taxes

PP&E – Property, plant and equipment

TA – *Taxation Act, 2007* [Ontario], as amended

TH Energy – Toronto Hydro Energy Services Inc.

TOU – Time-of-use

WMS – Wholesale Market Service



FINANCIAL REPORT
DECEMBER 31, 2022

TORONTO HYDRO CORPORATION

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GLOSSARY

CDM – Conservation and demand management

CEO – President and Chief Executive Officer

CFO – Executive Vice-President and Chief Financial Officer

CGU – Cash generating unit

CIR – Custom Incentive Rate-setting

City – *City incorporated under the City of Toronto Act, 1997* [Ontario]

Copeland Station – The Clare R. Copeland transformer station, formerly called "Bremner Station"

Corporation – Toronto Hydro Corporation

COVID-19 – Coronavirus disease 2019 and its variants

ECA – Energy Conservation Agreement

Electricity Act – *Electricity Act, 1998* [Ontario], as amended

ERM – Enterprise Risk Management

GAAP – Generally Accepted Accounting Principles

GHG – Greenhouse Gas

HONI – Hydro One Networks Inc.

IAS – International Accounting Standards

IASB – International Accounting Standards Board

IESO – Independent Electricity System Operator

IFRS – International Financial Reporting Standards

IRM – Incentive Regulation Mechanism

ISO 45001 – 2018 Occupational Health and Safety Management Systems

ISO 55001 – 2014 Asset Management System

ITA – *Income Tax Act, 1985* [Canada], as amended

ITC – Investment tax credit

kW – Kilowatt

kWh – Kilowatt hour

LDC – The Corporation's wholly-owned subsidiary, Toronto Hydro-Electric System Limited

LRAM – Lost revenue adjustment mechanism

MD&A – Management's Discussion and Analysis

MEU – Municipal electricity utility

MTN Program – Medium term note program established by the Corporation under which the Corporation issues debentures

OCI – Other comprehensive income

OEB – Ontario Energy Board

OEB Act – *Ontario Energy Board Act, 1998* [Ontario], as amended

OHSAS – Occupational Health and Safety Assessment Series

OHSAS 18001 – BS OHSAS 18001:2007, British Standard Occupational Health and Safety Assessment Series

OMERS – Ontario Municipal Employees Retirement System

OPEB – Other post-employment benefits

PILs – Payments in lieu of corporate taxes

PP&E – Property, plant and equipment

PWU – Power Workers' Union

TA – *Taxation Act, 2007* [Ontario], as amended

TH Energy – Toronto Hydro Energy Services Inc

Toronto Hydro – Toronto Hydro Corporation and its subsidiaries

TOU – Time-of-use

TransformTO – The City's TransformTO Net Zero Strategy, which outlines a pathway to achieve net zero emissions in Toronto by 2040

WMS – Wholesale Market Service



MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEARS ENDED DECEMBER 31, 2022 AND 2021

Executive Summary

- Net income after net movements in regulatory balances for the three months and year ended December 31, 2022 was $16.0 million and $163.9 million, respectively, compared to $19.5 million and $141.0 million for the comparable periods in 2021;
- Capital expenditures were primarily related to the renewal of the electricity infrastructure of LDC and were $239.7 million and $722.7 million for the three months and year ended December 31, 2022, respectively, compared to $184.9 million and $647.4 million for the comparable periods in 2021;
- Effective April 6, 2022, the City Council appointed James Hinds and Annie Ropar to the Board of the Corporation. All then-current citizen directors were re-appointed to the Board of the Corporation other than Tamara Kronis and Juliana Lam who ceased to be directors of the Corporation;
- On August 23, 2022, LDC filed the 2023 rate application seeking the OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2023 and ending on December 31, 2023;
- Effective September 15, 2022, Annie Ropar resigned from the Board of Directors of the Corporation and as a member of the Audit and Human Resources and Environment Committees. Concurrently, Michael Eubanks was appointed to the Audit Committee and David McFadden was appointed to the Human Resources and Environment Committee;
- On October 13, 2022, the Corporation issued $300.0 million of 4.95% senior unsecured debentures due October 13, 2052 ["Series 19"] at a price of $999.22 per $1,000 principal amount. The Series 19 debentures bear interest payable semi-annually in arrears;
- On November 14, 2022, Deputy Mayor Denzil Minnan-Wong's term as a director of the Corporation ended with the expiry of his term as City Councillor;
- On November 22, 2022, Councillor Paul Ainslie's term as a director of the Corporation ended;
- On November 23, 2022, the City Council appointed the following Councillor directors to the Corporation's Board: Councillor Stephen Holyday, Deputy Mayor Jennifer McKelvie, and Councillor Jaye Robinson as the Mayor's designate;
- On December 8, 2022, the OEB issued a decision and rate order approving LDC's 2023 rates and providing for other deferral and variance account dispositions; and
- On March 1, 2023, the Board of Directors of the Corporation declared a dividend in the amount of $24.6 million with respect to the first quarter of 2023 [first quarter of 2022 - $21.2 million], payable to the City by March 31, 2023.

Introduction

This MD&A should be read in conjunction with the Corporation's audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2022 and 2021, which were prepared in accordance with IFRS [the "Consolidated Financial Statements"].

Copies of these documents are available on the System for Electronic Document Analysis and Retrieval website at www.sedar.com.

Business of Toronto Hydro Corporation

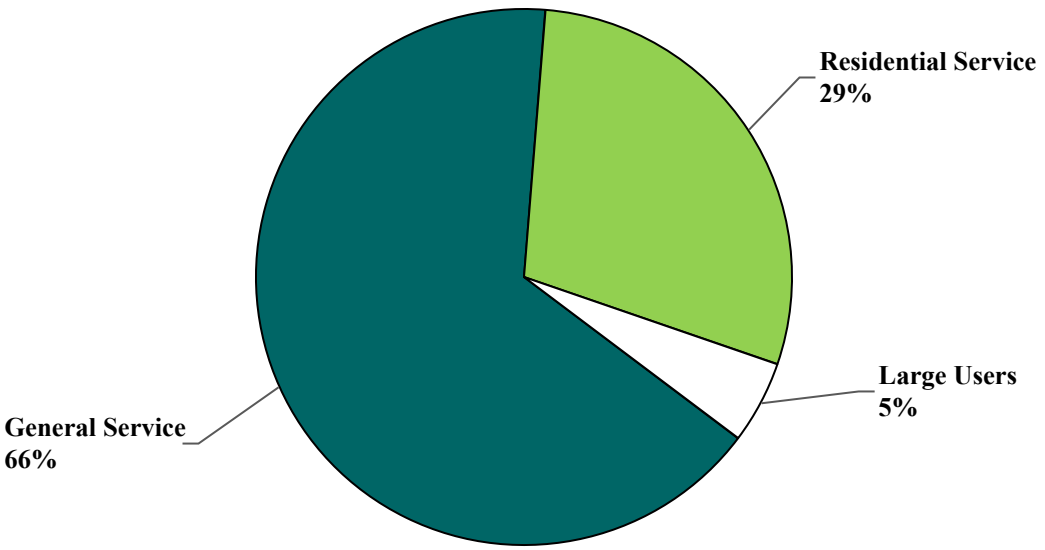
The Corporation is a holding company which wholly owns two subsidiaries:

- LDC – distributes electricity; and
- TH Energy – provides street lighting and expressway lighting services in the city of Toronto.

The Corporation supervises the operations of, and provides corporate, management services and strategic direction to its subsidiaries. The City is the sole shareholder of the Corporation.

The principal business of the Corporation and its subsidiaries is the distribution of electricity by LDC. LDC owns and operates an electricity distribution system that delivers electricity to approximately 790,000 customers located in the city of Toronto. LDC serves the largest city in Canada and distributes approximately 18% of the electricity consumed in Ontario. The business of LDC is regulated by the OEB, which has broad powers relating to licensing, standards of conduct and service, and the regulation of electricity distribution rates charged by electricity distributors in Ontario. For the year ended December 31, 2022, LDC recognized energy sales and distribution revenue of $3,492.0 million from general service users[1], residential service users[2] and large users[3].

LDC Energy Sales and Distribution Revenue by Class
Year ended December 31, 2022



[1] "General Service" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a 12-month period.

[2] "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multi-family units and seasonal occupancy.

[3] "Large Users" means a service provided to a customer with a monthly peak demand of 5,000 kW or greater averaged over a 12-month period.

Electricity Distribution – Industry Overview

Under provincial laws, LDC and other electricity distributors purchase electricity from the wholesale market administered by the IESO and recover the costs of electricity and certain other costs from customers in accordance with rate-setting procedures mandated by the OEB.

The OEB has regulatory oversight of electricity matters in Ontario. The OEB Act sets out the OEB's authority to issue a distribution licence that must be obtained by owners or operators of an electricity distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for distribution and other activities, and requirements for rate-setting and other legal filings.

The OEB's authority and responsibilities include the power to approve and set rates for the transmission and distribution of electricity, the power to approve the amounts paid to non-contracted generators, the responsibility to provide rate protection for rural or remote electricity customers, and the responsibility for ensuring that electricity distribution companies fulfill their obligations to connect and service customers.

LDC is required to charge its customers for the following amounts [all of which, other than distribution rates, represent a pass-through of amounts payable to third parties]:

- *Commodity Charge* – The commodity charge represents the market price of electricity consumed by customers and is passed through the IESO back to operators of generating stations. It includes the global adjustment, which represents the difference between the market price of electricity and the rates paid to regulated and contracted generators.

- *Retail Transmission Rate* – The retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are a pass-through to operators of transmission facilities.

- *WMS Charge* – The WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are a pass-through to the IESO.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable [usage-based] components, based on a forecast of LDC's customers and load.

LDC is required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

The Corporation is exempt from tax under the ITA if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income of the Corporation is derived from activities carried on outside the municipal geographical boundaries of the City. In addition, the Corporation's subsidiaries are also exempt from tax under the ITA provided that all of their capital is owned by the Corporation and not more than 10% of their respective income is from activities carried on outside the municipal geographical boundaries of the City. A corporation exempt from tax under the ITA is also exempt from tax under the TA.

The Electricity Act provides that an MEU that is exempt from tax under the ITA and the TA is required to make, for each taxation year, a PILs payment to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the TA if it were not exempt from tax. The Corporation and each of its subsidiaries are MEUs for purposes of the PILs regime contained in the Electricity Act, and therefore, the Corporation is required to make PILs to the Ontario Electricity Financial Corporation.

Results of Operations

Net Income after Net Movements in Regulatory Balances

Consolidated Statements of Income
Three months ended December 31, 2022
[in millions of Canadian dollars]

	2022 $	2021 $	Change $
Revenues			
Energy sales	**601.7**	625.0	(23.3)
Distribution revenue	**185.4**	186.6	(1.2)
Other	**32.0**	32.4	(0.4)
	819.1	844.0	(24.9)
Expenses			
Energy purchases	**643.1**	653.3	(10.2)
Operating expenses	**91.9**	92.6	(0.7)
Depreciation and amortization	**88.7**	79.2	9.5
	823.7	825.1	(1.4)
Finance costs	**(25.4)**	(20.3)	(5.1)
Gain on disposals of property, plant and equipment	**—**	0.4	(0.4)
Loss before income taxes	**(30.0)**	(1.0)	(29.0)
Income tax recovery	**0.6**	9.2	(8.6)
Net income (loss)	**(29.4)**	8.2	(37.6)
Net movements in regulatory balances	**48.1**	23.3	24.8
Net movements in regulatory balances arising from deferred taxes	**(2.7)**	(12.0)	9.3
Net income after net movements in regulatory balances	**16.0**	19.5	(3.5)

For the three months ended December 31, 2022, net income after net movements in regulatory balances was lower by $3.5 million. The decrease was mainly due to higher depreciation and amortization [$9.5 million] related to in-service asset additions and higher finance costs [$5.1 million] mostly driven by an increase in the rate of funding from commercial paper, partially offset by higher consumption and electricity distribution rates [$7.4 million].

The variances in energy sales and energy purchases do not impact net income after net movements in regulatory balances as there is a corresponding offset in net movements in regulatory balances. The difference between energy sales and energy purchases is recorded as a settlement variance within regulatory balances on the Corporation's consolidated balance sheets and represents amounts to be recovered from or refunded to customers through future rates approved by the OEB.

Consolidated Statements of Income
Year ended December 31, 2022
[in millions of Canadian dollars]

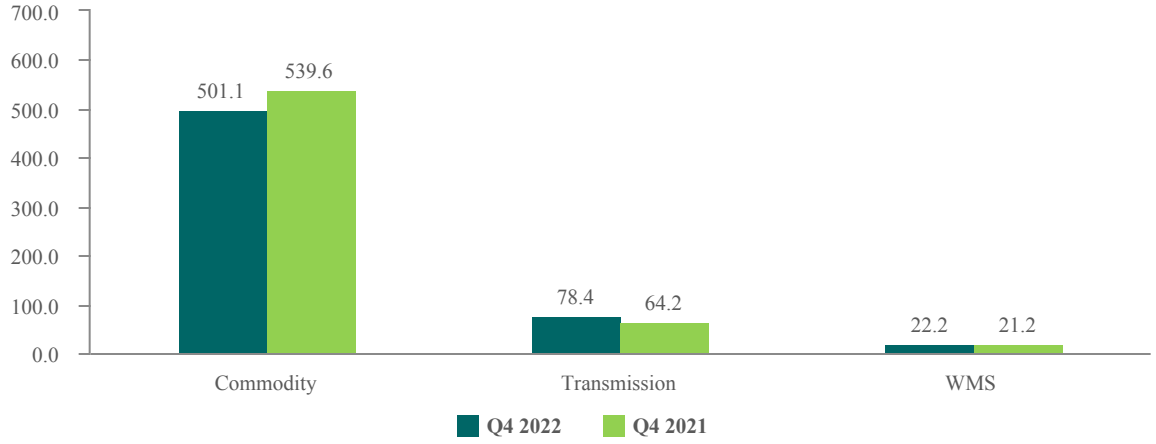
	2022 $	2021 $	Change $
Revenues			
Energy sales	**2,737.8**	2,702.4	35.4
Distribution revenue	**754.2**	759.1	(4.9)
Other	**109.7**	105.6	4.1
	3,601.7	3,567.1	34.6
Expenses			
Energy purchases	**2,846.7**	2,775.2	71.5
Operating expenses	**322.5**	323.0	(0.5)
Depreciation and amortization	**311.4**	292.7	18.7
	3,480.6	3,390.9	89.7
Finance costs	**(87.6)**	(79.1)	(8.5)
Gain on disposals of property, plant and equipment	**—**	2.7	(2.7)
Income before income taxes	**33.5**	99.8	(66.3)
Income tax expense	**(8.5)**	(21.8)	13.3
Net income	**25.0**	78.0	(53.0)
Net movements in regulatory balances	**136.5**	54.1	82.4
Net movements in regulatory balances arising from deferred taxes	**2.4**	8.9	(6.5)
Net income after net movements in regulatory balances	**163.9**	141.0	22.9

For the year ended December 31, 2022, net income after net movements in regulatory balances was higher by $22.9 million. The increase was mainly due to higher consumption and electricity distribution rates [$26.4 million], lower income taxes including regulatory balances arising from deferred taxes [$6.8 million] and higher other revenue [$4.1 million] primarily due to higher amortization of capital contributions. This was partially offset by higher depreciation and amortization [$18.7 million] related to in-service asset additions and higher finance costs [$8.5 million] primarily driven by an increase in the rate of funding from commercial paper.

Energy Sales

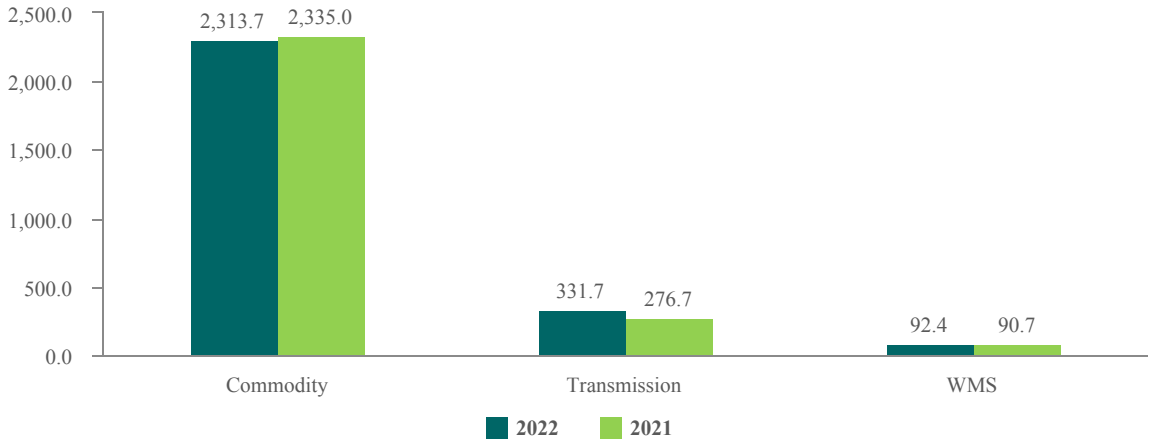
LDC's energy sales arise from charges to customers for electricity consumed, based on regulated rates. Energy sales include amounts billed or billable to customers for commodity charges, retail transmission charges, and WMS charges at current rates. These charges are passed through to customers over time and are considered revenue by LDC. For any given period, energy sales should be equal to the cost of energy purchased. However, a difference between energy sales and energy purchases arises when there is a timing difference between the amounts charged by LDC to customers, based on regulated rates, and the electricity and non-competitive electricity service costs billed monthly by the IESO to LDC. This difference is recorded as a settlement variance, representing amounts to be recovered from or refunded to customers through future rates approved by the OEB. In accordance with IFRS 14 *Regulatory Deferral Accounts* ["IFRS 14"], this settlement variance is presented within regulatory balances on the Corporation's consolidated balance sheets ["Consolidated Balance Sheets"] and within net movements in regulatory balances on the Corporation's consolidated statements of income ["Consolidated Statements of Income"].

Energy Sales
Three months ended December 31, 2022
[in millions of Canadian dollars]



Energy sales for the three months ended December 31, 2022 were $601.7 million, compared to $625.0 million for the comparable period in 2021. The decrease was primarily due to lower commodity charges [$38.5 million], partially offset by higher retail transmission charges [$14.2 million].

Energy Sales
Year ended December 31, 2022
[in millions of Canadian dollars]



Energy sales for the year ended December 31, 2022 were $2,737.8 million, compared to $2,702.4 million for the comparable period in 2021. The increase was primarily due to higher retail transmission charges [$55.0 million], partially offset by lower commodity charges [$21.3 million].

Distribution Revenue

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by LDC in delivering electricity to customers and includes revenue collected through OEB-approved rate riders.

Distribution revenue for the three months and year ended December 31, 2022 was $185.4 million and $754.2 million, respectively, compared to $186.6 million and $759.1 million for the comparable periods in 2021.

The decrease in distribution revenue [$1.2 million] for the three months ended December 31, 2022 was primarily due to lower revenue collected through OEB-approved rate riders [$8.6 million], partially offset by higher electricity consumption [$4.5 million] and higher 2022 distribution rates [$2.8 million].

The decrease in distribution revenue [$4.9 million] for the year ended December 31, 2022 was primarily due to lower revenue collected through OEB-approved rate riders [$31.5 million], partially offset by higher electricity consumption [$15.4 million] and higher 2022 distribution rates [$11.0 million].

Other Revenue

Other revenue includes revenue from services ancillary to electricity distribution, delivery of street lighting services, pole and duct rentals, other regulatory service charges and capital contributions.

Other revenue for the three months and year ended December 31, 2022 was $32.0 million and $109.7 million, respectively, compared to $32.4 million and $105.6 million for the comparable periods in 2021.

Other revenue for the three months ended December 31, 2022 was in line with the comparable period in 2021.

The increase in other revenue for the year ended December 31, 2022 was primarily due to higher amortization of capital contributions and higher revenue in connection with ancillary services, partially offset by streetlighting cost recoveries received in 2021.

Energy Purchases

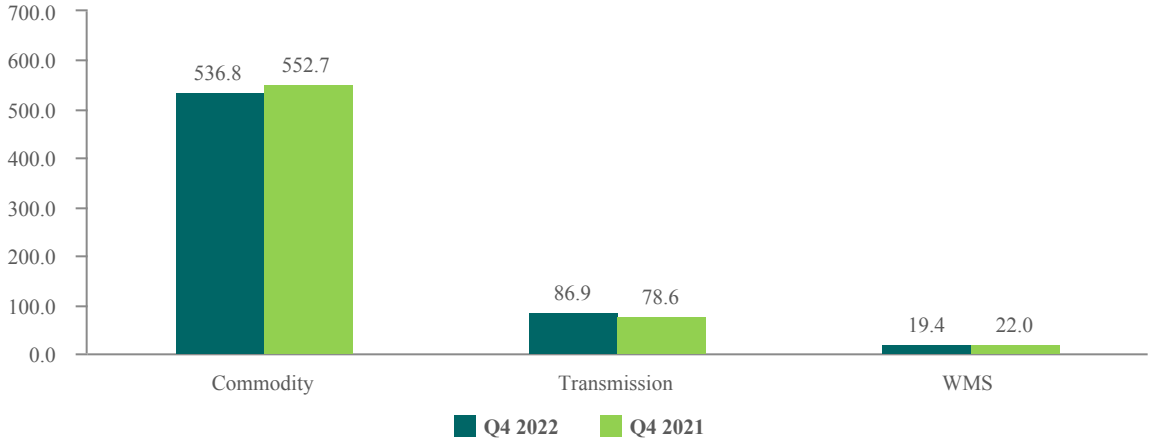
LDC's energy purchases consist of actual charges for electricity generated by third parties, which are passed through to customers over time in the form of energy sales. Energy purchases are billed monthly by the IESO and include commodity charges, retail transmission charges and WMS charges.

Energy Purchases, Energy Sales, and Settlement Variances
Three months ended December 31, 2022
[in millions of Canadian dollars]

	Energy Purchases $	Energy Sales $	Settlement Variances $
Commodity charges	536.8	501.1	35.7
Retail transmission charges	86.9	78.4	8.5
WMS charges	19.4	22.2	(2.8)
Total	643.1	601.7	41.4

For the three months ended December 31, 2022, LDC recognized $601.7 million in energy sales to customers and was billed $643.1 million for energy purchases from the IESO. The difference between energy sales and energy purchases represents a $41.4 million settlement variance for the period. The settlement variance was recorded as an increase to the regulatory debit balance [$43.1 million including carrying charges on the accumulated settlement variance balance] on the Consolidated Balance Sheets, and presented within net movements in regulatory balances on the Consolidated Statements of Income.

LDC Energy Purchases
Three months ended December 31, 2022
[in millions of Canadian dollars]



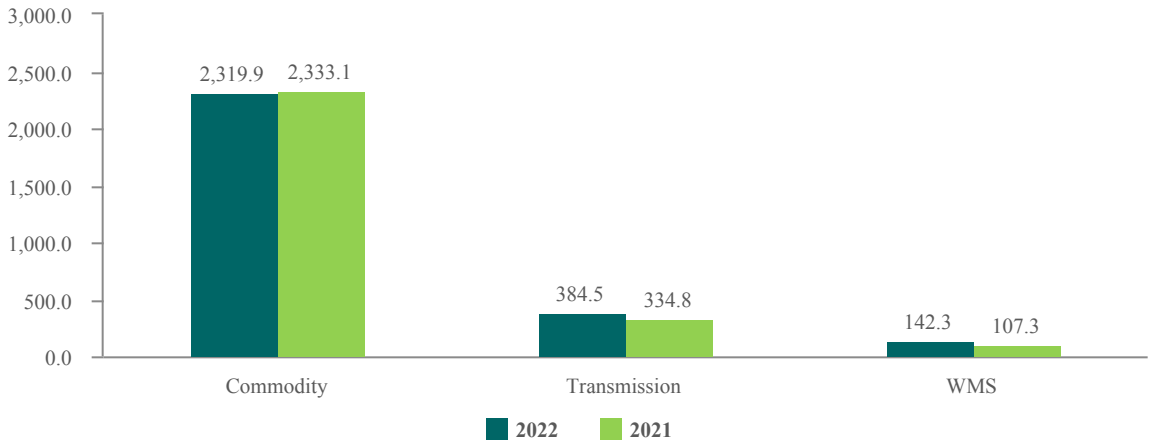
Energy purchases for the three months ended December 31, 2022 were $643.1 million compared to $653.3 million for the comparable period in 2021. The decrease was primarily due to lower commodity charges [$15.9 million], partially offset by higher retail transmission charges [$8.3 million].

Energy Purchases, Energy Sales, and Settlement Variances
Year ended December 31, 2022
[in millions of Canadian dollars]

	Energy Purchases $	Energy Sales $	Settlement Variances $
Commodity charges	2,319.9	2,313.7	6.2
Retail transmission charges	384.5	331.7	52.8
WMS charges	142.3	92.4	49.9
Total	2,846.7	2,737.8	108.9

For the year ended December 31, 2022, LDC recognized $2,737.8 million in energy sales to customers and was billed $2,846.7 million for energy purchases from the IESO. The difference between energy sales and energy purchases represents a $108.9 million settlement variance for the period. The settlement variance was recorded as an increase to the regulatory debit balance [$111.6 million including carrying charges on the accumulated settlement variance balance; refer to the regulatory debit balance table in note 8 to the Consolidated Financial Statements] on the Consolidated Balance Sheets, and presented within net movements in regulatory balances on the Consolidated Statements of Income.

LDC Energy Purchases
Year ended December 31, 2022
[in millions of Canadian dollars]



Energy purchases for the year ended December 31, 2022 were $2,846.7 million compared to $2,775.2 million for the comparable period in 2021. The increase was primarily due to higher retail transmission charges [$49.7 million], higher wholesale market service charges [$35.0 million], partially offset by lower commodity charges [$13.2 million].

Operating Expenses

Operating expenses for the three months and year ended December 31, 2022 were $91.9 million and $322.5 million, respectively, and were in line with $92.6 million and $323.0 million for the comparable periods in 2021.

Depreciation and Amortization

Depreciation and amortization expense, which includes derecognition of assets removed from service, for the three months and year ended December 31, 2022 was $88.7 million and $311.4 million, respectively, compared to $79.2 million and $292.7 million for the comparable periods in 2021.

The increases in depreciation and amortization for the three months and year ended December 31, 2022 were primarily due to in-service asset additions and higher derecognition of assets removed from service, partially offset by certain assets being fully depreciated.

Finance Costs

Finance costs for the three months and year ended December 31, 2022 were $25.4 million and $87.6 million, respectively, compared to $20.3 million and $79.1 million for the comparable periods in 2021.

The increases in finance costs for the three months and year ended December 31, 2022 were primarily due to a higher rate of funding with a weighted average interest rate of 2.15% [2021 - 0.28%] for commercial paper and higher average amount of outstanding debentures, partially offset by an increase in investment income due to higher short-term rates.

Gain on Disposals of PP&E

Gain on disposals of PP&E for the three months and year ended December 31, 2022 was $nil, compared to $0.4 million and $2.7 million for the comparable periods in 2021.

The decrease in gain on disposals of PP&E for the year ended December 31, 2022 was primarily related to the gain realized in connection with the sale of a property in the first quarter of 2021 [$1.5 million].

Income Tax Expense and Income Tax Recorded in Net Movements in Regulatory Balances

Income tax expense and income tax recorded in net movements in regulatory balances for the three months and year ended December 31, 2022 was $2.1 million and $6.1 million, respectively, compared to $2.8 million and $12.9 million for the comparable periods in 2021.

The decrease in income tax expense and income tax recorded in net movements in regulatory balances for the three months ended December 31, 2022 was primarily due to lower income before taxes, partially offset by lower net deductions in permanent and temporary differences between accounting and tax treatments.

The decrease in income tax expense and income tax recorded in net movements in regulatory balances for the year ended December 31, 2022 was primarily due to higher net deductions in permanent and temporary differences between accounting and tax treatments, and lower tax recognized on property dispositions, partially offset by higher income before taxes.

Net Movements in Regulatory Balances

In accordance with IFRS 14, the Corporation separately presents regulatory balances and related net movements on the Consolidated Balance Sheets and the Consolidated Statements of Income.

The increase in the regulatory debit [$81.5 million] and decrease in the regulatory credit [$1.1 million] balances for the year ended December 31, 2022 equals the sum [$82.6 million] of net movements in regulatory balances, net movements in regulatory balances arising from deferred taxes and net movements in regulatory balances related to OCI for the period [refer to “Financial Position” below]. Energy purchases record the actual cost of power purchased, which varies from month to month. Since the selling price of power within energy sales is fixed for set periods of time, a gain or loss usually results and is part of the calculation of net income. However, per OEB regulations, such gains or losses on energy sales are deferred within regulatory variance accounts for later disposition to or from rate payers via rate riders after approval by the OEB. Deferrals of gains or losses on energy sales [refer to discussion on settlement variance under “Results of Operations” above], or disposition of past deferrals in electricity rates will usually represent the largest single element of the net movements in regulatory balances for a given period.

Net movements in regulatory balances for the three months and year ended December 31, 2022 were a recovery of $48.1 million and $136.5 million, respectively, compared to a recovery of $23.3 million and $54.1 million for the comparable periods in 2021. The recovery of $48.1 million and $136.5 million for the three months and year ended December 31, 2022 was primarily due to the settlement variance between the electricity costs billed monthly by the IESO and LDC’s billing to customers and amounts disposed through OEB-approved rate riders. The recovery of $23.3 million and $54.1 million for the

three months and year ended December 31, 2021 was primarily due to the settlement variance between the electricity costs billed monthly by the IESO and LDC's billing to customers, partially offset by amounts disposed through OEB-approved rate riders.

Summary of Quarterly Results of Operations

The table below presents a summary of the Corporation's results of operations for eight quarters including and immediately preceding December 31, 2022.

Summary of Quarterly Results of Operations
[in millions of Canadian dollars]

	December 31, 2022	September 30, 2022	June 30, 2022	March 31, 2022
	$	$	$	$
Energy sales	**601.7**	815.3	646.5	674.3
Distribution revenue	**185.4**	194.8	187.1	186.9
Other	**32.0**	26.2	25.8	25.7
Revenues	**819.1**	1,036.3	859.4	886.9
Net income after net movements in regulatory balances	**16.0**	55.0	45.4	47.5

	December 31, 2021	September 30, 2021	June 30, 2021	March 31, 2021
	$	$	$	$
Energy sales	625.0	756.9	643.3	677.2
Distribution revenue	186.6	201.4	188.5	182.6
Other	32.4	25.2	26.2	21.8
Revenues	844.0	983.5	858.0	881.6
Net income after net movements in regulatory balances	19.5	47.8	37.9	35.8

The Corporation's revenues, all other things being equal, are impacted by temperature fluctuations and unexpected weather conditions, including increased frequency of extreme weather events as a result of climate change, such as heat waves, intense rain events, snow storms and higher average temperatures. Generally, revenues would tend to be higher in the first quarter as a result of higher energy consumption for winter heating, and in the third quarter due to air conditioning/cooling. The Corporation's revenues are also impacted by fluctuations in electricity prices and the timing and recognition of regulatory decisions.

Financial Position

The following table outlines the significant changes in the Consolidated Balance Sheet as at December 31, 2022 as compared to the Consolidated Balance Sheet as at December 31, 2021.

Consolidated Balance Sheet Data
[in millions of Canadian dollars]

Balance Sheet Account	Increase (Decrease) $	Explanation of Significant Change
Assets		
Accounts receivable and unbilled revenue	**42.6**	The increase was primarily due to higher pass-through electricity costs, higher electricity consumption and timing of billing and collection activities.
PP&E and intangible assets	**408.6**	The increase was primarily due to capital expenditures [refer to "Investing Activities" below], partially offset by depreciation and amortization including derecognition.
Liabilities and Equity		
Commercial paper	**80.0**	The increase was primarily due to the issuances of commercial paper required for general corporate purposes [refer "Liquidity and Capital Resources" below].
Accounts payable and accrued liabilities	**37.9**	The increase was primarily due to timing differences in payments, partially offset by lower pass-through electricity costs payable to the IESO.
Debentures	**298.4**	The increase was primarily due to the issuance of $300.0 million of Series 19 debentures, net of issuance costs [refer to "Liquidity and Capital Resources" and "Financing Activities" below].
Deferred revenue	**98.4**	The increase was primarily due to capital contributions received.
Post-employment benefits	**(76.6)**	The decrease was primarily due to the recognized actuarial gain incurred as a result of the increase in discount rate from 3.0% to 5.1% as at December 31, 2022.
Deferred tax liabilities	**20.8**	The increase was primarily due to lower tax values as compared to accounting values of PP&E and intangible assets, and the impact of the actuarial gain on post-employment benefit obligation.
Other Liabilities	**(11.0)**	The decrease was mainly due to the settlement of a HONI liability in 2022 related to the connection of Copeland station to transmission facilities.

Consolidated Balance Sheet Data
[in millions of Canadian dollars]

Balance Sheet Account	Increase (Decrease) $	Explanation of Significant Change
Retained earnings	**79.3**	The increase was due to net income after net movements in regulatory balances [$163.9 million], offset by dividends paid [$84.6 million].
Regulatory Balances		
Regulatory debit balances	**81.5**	The increase was primarily related to the settlement variance between the electricity costs billed monthly by the IESO and LDC's billing to customers and deferred taxes, partially offset by the reclassification of the post-employment net actuarial loss from regulatory debit to regulatory credit balance resulting from the remeasurement of post-employment benefit obligations to reflect the higher discount rate.
Regulatory credit balances	**(1.1)**	The decrease was primarily due to the recognized actuarial gain resulting from the remeasurement of post-employment benefit obligations to reflect the higher discount rate, partially offset by amounts disposed through OEB-approved rate riders.

Liquidity and Capital Resources

The Corporation is a party to a credit agreement with a syndicate of Canadian chartered banks which established a revolving credit facility ["Revolving Credit Facility"], pursuant to which it may borrow up to $800.0 million, of which up to $210.0 million is available in the form of letters of credit. On September 2, 2021, the maturity date of the Revolving Credit Facility was extended from October 10, 2024 to September 2, 2026. On November 18, 2022, the maturity date of the Revolving Credit Facility was extended from September 2, 2026 to September 17, 2027. As at December 31, 2022, the Corporation was in compliance with all covenants included in its Revolving Credit Facility agreement.

The Corporation has a commercial paper program allowing up to $750.0 million of unsecured short-term promissory notes ["Commercial Paper Program"] to be issued in various maturities of no more than one year. The Commercial Paper Program is supported by liquidity facilities available under the Revolving Credit Facility; hence, available borrowing under the Revolving Credit Facility is reduced by the amount of commercial paper outstanding at any point in time. Proceeds from the Commercial Paper Program are used for general corporate purposes. Borrowings under the Commercial Paper Program bear interest based on the prevailing market conditions at the time of issuance.

Additionally, the Corporation is a party to a demand facility with a Canadian chartered bank for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO ["Prudential Facility"]. As at December 31, 2022, $57.6 million of letters of credit had been issued against the Prudential Facility.

The Corporation is a party to a $20.0 million demand facility with a Canadian chartered bank for the purpose of working capital management ["Working Capital Facility"]. As at December 31, 2022, $12.8 million had been drawn under the Working Capital Facility, compared to $8.8 million as at December 31, 2021. On the consolidated statements of cash flows, cash and cash equivalents [working capital facility] includes bank overdrafts that are repayable on demand and form an integral part of the Corporation's cash management.

The Corporation's current assets and current liabilities amounted to $526.2 million and $1,182.5 million, respectively, as at December 31, 2022, resulting in a working capital deficit of $656.3 million. The deficit is primarily attributable to the Corporation's preference for utilizing its Commercial Paper Program and Working Capital Facility before issuing additional debentures to fulfill the Corporation's ongoing liquidity requirements, including funding of significant capital spending and the reclassification of Series 8 debenture to current liabilities due on April 10, 2023. The Corporation seeks to maintain an optimal mix of short-term and long-term debt in order to lower overall financing costs and to enhance borrowing flexibility.

The Corporation's primary sources of liquidity and capital resources are cash provided by operating activities, issuance of commercial paper, amounts available to be drawn against its credit facilities, and borrowings from debt capital markets. On October 13, 2022, the Corporation issued $300.0 million of 4.95% senior unsecured debentures [see "Financing Activities" below]. The Corporation's liquidity and capital resource requirements are mainly for capital expenditures to maintain and improve the electricity distribution system of LDC, for energy purchases and to meet financing obligations.

The amount available under the Revolving Credit Facility as well as the outstanding borrowings under the Revolving Credit Facility and the Commercial Paper Program are as follows:

[in millions of Canadian dollars]	Revolving Credit Facility Limit $	Revolving Credit Facility Borrowings $	Commercial Paper Outstanding $	Revolving Credit Facility Availability $
Balance as at December 31, 2022	**800.0**	**—**	**355.0**	**445.0**
Balance as at December 31, 2021	800.0	—	275.0	525.0

Consolidated Statements of Cash Flow Data
[in millions of Canadian dollars]

	Three months ended December 31,		Year ended December 31,	
	2022 $	2021 $	**2022** $	2021 $
Cash and cash equivalents (working capital facility), beginning of period	**(6.4)**	1.1	**(8.8)**	(6.2)
Net cash provided by operating activities	**196.3**	220.6	**469.1**	577.9
Net cash used in investing activities	**(198.2)**	(163.4)	**(674.6)**	(590.5)
Net cash provided by (used in) financing activities	**(4.5)**	(67.1)	**201.5**	10.0
Working capital facility, end of period	**(12.8)**	(8.8)	**(12.8)**	(8.8)

In addition, the Corporation continues to monitor the impacts of recent interest rate increases on the Corporation, and any further increases that may occur.

Operating Activities

Net cash provided by operating activities for the three months and year ended December 31, 2022 was $196.3 million and $469.1 million, respectively, compared to $220.6 million and $577.9 million for the comparable periods in 2021.

The decrease in net cash provided by operating activities for the three months ended December 31, 2022 was primarily due to lower net income before net movements in regulatory balances, lower net other non-current assets and liabilities and lower customer deposits, partially offset by timing differences in the settlement of receivables and payables.

The decrease in net cash provided by operating activities for the year ended December 31, 2022 was primarily due to timing differences in the settlement of receivables and payables, lower net income before net movements in regulatory balances, lower net other non-current assets and liabilities and lower customer deposits.

Investing Activities

Net cash used in investing activities for the three months and year ended December 31, 2022 was $198.2 million and $674.6 million, respectively, compared to $163.4 million and $590.5 million for the comparable periods in 2021.

Electricity distribution is a capital-intensive business. As LDC is the municipal electricity distribution company serving the largest city in Canada, it continues to invest in the renewal of existing aging infrastructure to address safety, reliability and customer service requirements.

The following table summarizes the Corporation's capital expenditures [on an accrual basis] for the periods indicated [refer to note 21 to the Consolidated Financial Statements for cash basis].

Capital Expenditures
[in millions of Canadian dollars]

	Three months ended December 31,		Year ended December 31,	
	2022	2021	**2022**	2021
	$	$	**$**	$
Regulated LDC				
Distribution system				
Planned [1]	**175.0**	148.1	**560.5**	517.8
Reactive [2]	**18.2**	13.3	**51.1**	46.5
Technology assets	**20.0**	13.9	**58.3**	45.2
Other [3]	**23.9**	7.2	**43.8**	23.7
Regulated capital expenditures	**237.1**	182.5	**713.7**	633.2
Unregulated capital expenditures [4]	**2.6**	2.4	**9.0**	14.2
Total capital expenditures	**239.7**	184.9	**722.7**	647.4

[1] Includes, among other initiatives, the replacement of underground and overhead infrastructures, station programs, delivery of customer connections and customer-initiated plant relocations and expansions.
[2] Non-discretionary replacement of failed or failing assets across the distribution system.
[3] Includes fleet capital and building enhancements.
[4] Primarily relates to behind-the-meter battery storage projects, street lighting and generation equipment.

The total regulated capital expenditures for the three months and year ended December 31, 2022 were $237.1 million and $713.7 million, respectively, compared to $182.5 million and $633.2 million for the comparable periods in 2021.

For the three months ended December 31, 2022, the increase in regulated capital expenditures was primarily due to higher spending on underground infrastructure [$18.7 million], fleet capital [$12.3 million], technology assets [$6.1 million], network infrastructure [$5.6 million], control operations and reinforcement program [$5.1 million], reactive capital [$4.9 million] and customer-initiated plant relocations and expansions [$4.8 million].

For the year ended December 31, 2022, the increase in regulated capital expenditures was primarily due to higher spending on underground infrastructure [$28.7 million], fleet capital [$13.2 million], technology assets [$13.1 million], network infrastructure [$10.1 million], control operations and reinforcement program [$8.9 million], critical capital equipment [$4.9 million], and reactive capital [$4.6 million].

For the year ended December 31, 2022, the decrease in unregulated capital expenditures was primarily due to lower behind-the-meter battery storage.

The largest capital initiatives in 2022 include the delivery of customer connections, replacement of underground and overhead infrastructures, station programs, customer-initiated plant relocations and expansions, and technology assets.

The delivery of customer connections includes spending related to new service and upgrades to existing service for specific commercial customers. For the year ended December 31, 2022, capital expenditures for the delivery of customer connections were $137.2 million.

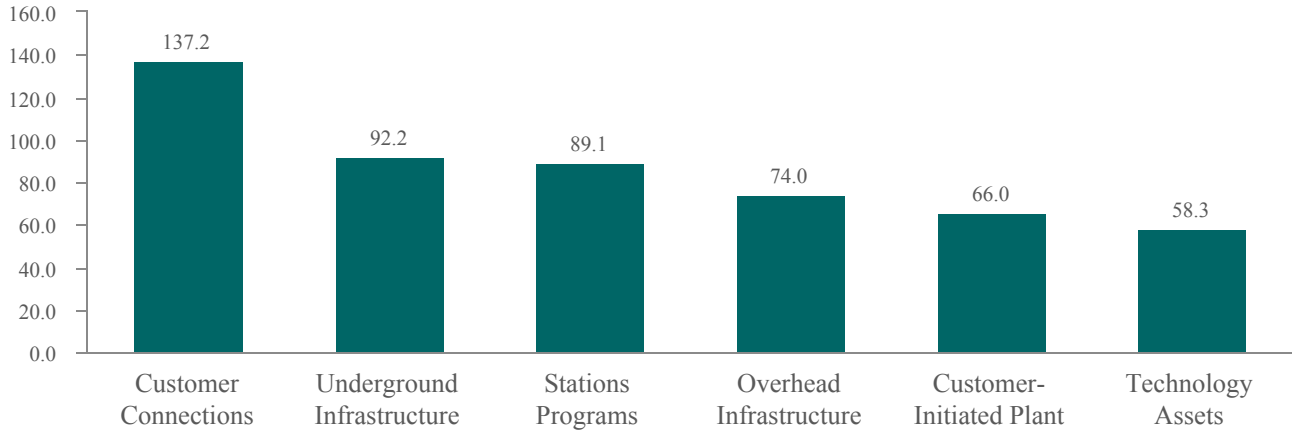
The replacement of underground infrastructure includes replacing direct buried cables, transformers, switches and other aging underground infrastructure. The replacement of overhead infrastructure includes replacing poles, overhead transformers, conductors, overhead switches and other aging overhead infrastructure and equipment. Both initiatives will allow LDC to continue to provide ongoing safe and reliable service to its customers. For the year ended December 31, 2022, capital expenditures for underground and overhead infrastructure were $92.2 million and $74.0 million, respectively.

The station programs focus on station renewal and station expansion. Station renewal targets the aging station infrastructure to reduce the risk of power outages and to maximize useful life. Station expansion addresses medium to long-term system capacity needs on the distribution system. For the year ended December 31, 2022, capital expenditures for station programs were $89.1 million.

Customer-initiated plant relocations and expansions include relocating infrastructure to accommodate construction by third parties. For the year ended December 31, 2022, capital expenditures for customer-initiated plant relocations and expansions were $66.0 million.

Technology assets include software, hardware and communication infrastructure to provide reliable technology solutions and services to support the Corporation's business activities. For the year ended December 31, 2022, capital expenditures for technology assets were $58.3 million.

Expenditures on Most Significant Regulated Capital Initiatives
Year ended December 31, 2022
[in millions of Canadian dollars]



Financing Activities

Net cash provided by [used in] financing activities for the three months and year ended December 31, 2022 was $4.5 million and $201.5 million, respectively, compared to $67.1 million and $10.0 million for the comparable periods in 2021.

The decrease in net cash used in financing activities for the three months ended and year ended December 31, 2022 was primarily due to lower debenture issuances in the fourth quarter of 2022.

For the three months and year ended December 31, 2022, the average aggregate outstanding borrowings under the Corporation's Revolving Credit Facility, Working Capital Facility and Commercial Paper Program were $397.2 million and $459.5 million, respectively, with a weighted average interest rate of 3.87% and 2.15% [compared to $219.0 million and $288.3 million, respectively, with a weighted average interest rate of 0.31% and 0.28% for the comparable periods in 2021].

As at December 31, 2022, the Corporation had debentures outstanding in the principal amount of $2.7 billion. These debentures will mature between 2023 and 2063. As at December 31, 2022, the Corporation was in compliance with all covenants included in its trust indenture and supplemental trust indentures.

On October 13, 2022, the Corporation issued $300.0 million of 4.95% senior unsecured debentures due on October 13, 2052 at a price of $999.22 per $1,000 principal amount. The Series 19 debentures bear interest payable semi-annually in arrears. The net proceeds have been used to reduce indebtedness of the Corporation, including, but not limited to, indebtedness that the Corporation may have with bank affiliates of one or more dealers, to refinance the Corporation's outstanding debentures upon maturity, to finance the Corporation's capital expenditure program and for general corporate purposes. Debt issuance costs of $2.1 million relating to the Series 19 debentures were recorded against the carrying amount of the debentures in the fourth quarter of 2022 and are amortized to finance costs using the effective interest method.

The following table sets out the current credit ratings of the Corporation.

Credit Ratings
As at December 31, 2022

	DBRS		Standard & Poor's	
	Credit Rating	Trend	Credit Rating	Outlook
Issuer rating	A	Stable	A	Positive
Senior unsecured debentures	A	Stable	A	—
Commercial paper	R-1 [low]	Stable	—	—

The Corporation believes that it has sufficient available sources of liquidity and capital to satisfy working capital requirements for the next 12 months.

During the year ended December 31, 2022, the Board of Directors of the Corporation declared and paid dividends to the City totalling $84.6 million [2021 - $70.3 million].

On March 1, 2023, the Board of Directors of the Corporation declared a dividend in the amount of $24.6 million, payable to the City by March 31, 2023.

Summary of Contractual Obligations and Other Commitments

The following table presents a summary of the Corporation's debentures, major contractual obligations and other commitments.

Summary of Contractual Obligations and Other Commitments
As at December 31, 2022
[in millions of Canadian dollars]

	Total $	2023 $	2024 / 2025 $	2026 / 2027 $	After 2027 $
Commercial paper [1]	**355.0**	355.0	—	—	—
Debentures - principal repayment	**2,745.0**	250.0	—	200.0	2,295.0
Debentures - interest payments	**2,019.6**	90.6	174.0	169.0	1,586.0
Capital projects [2] and other	**24.3**	16.7	3.7	1.7	2.2
Leases	**0.2**	—	0.2	—	—
Total contractual obligations and other commitments	**5,144.1**	712.3	177.9	370.7	3,883.2

[1] The notes under the Commercial Paper Program were issued at a discount and are repaid at their principal amount.
[2] Primarily commitments for construction services.

Corporate Developments

Changes to the Corporation's Board of Directors.

Effective April 6, 2022, the City Council appointed James Hinds and Annie Ropar to the Board of the Corporation. All then-current citizen directors were re-appointed to the Board of the Corporation other than Tamara Kronis and Juliana Lam who ceased to be directors of the Corporation.

Effective September 15, 2022, Annie Ropar resigned from the Board of the Corporation and as a member of the Audit and Human Resources and Environment Committees. Concurrently, Michael Eubanks was appointed to the Audit Committee and David McFadden was appointed to the Human Resources and Environment Committee.

On November 14, 2022, Deputy Mayor Denzil Minnan-Wong's term as a director of the Corporation ended with the expiry of his term as City Councillor.

On November 22, 2022, Councillor Paul Ainslie's term as a director of the Corporation ended.

On November 23, 2022, the City Council appointed the following Councillor directors to the Corporation's Board: Councillor Stephen Holyday, Deputy Mayor Jennifer McKelvie, and Councillor Jaye Robinson as the Mayor's designate.

COVID-19 Pandemic Considerations

On March 11, 2020, the World Health Organization declared that the COVID-19 outbreak was a global pandemic. The COVID-19 pandemic has not had a significant impact on the Consolidated Financial Statements of the Corporation for the year ended December 31, 2022.

On November 15, 2021, the OEB's standard winter disconnection ban commenced and remained in effect until May 1, 2022. Concurrent with the effective end date of the OEB's standard winter disconnection ban, the Corporation ended its voluntary

ban on disconnections, which had been in place since the beginning of the pandemic. The Corporation's disconnection practices remain subject to the applicable OEB rules.

On January 7, 2022, the Ontario Government announced further targeted relief measures setting both the TOU rates for on-peak, mid-peak, and off-peak and tiered rates at the TOU off-peak rate of 8.2 cents per kWh, 24 hours a day, seven days a week, effective January 18, 2022 until February 7, 2022. There was no net income impact to the Corporation.

On October 1, 2022, Toronto Hydro transitioned to a hybrid work arrangement, which enabled employees who could perform their work from home the flexibility to attend their assigned work centre a minimum number of days a week, with flexibility as to work location on other days.

Toronto Hydro Climate Action Plan

At its meeting held on April 7-8, 2021, a resolution was passed by City Council that requested the City Manager and Toronto Hydro report back to City Council with respect to Toronto Hydro's ongoing work and an action plan with opportunities to achieve outcomes associated with climate action matters, including electric vehicle chargers, outdoor lighting, renewable energy, energy storage, and related grants, funding, and financing.

Toronto Hydro submitted its Climate Action Plan to the City Manager on September 30, 2021 concerning current work and an action plan setting out opportunities, in accordance with the City Council resolution.

At its meeting held on December 15-17, 2021, a resolution was passed by City Council that requested the City Manager and Toronto Hydro report back to City Council with additional information related to the Climate Action Plan and its interplay with the City of Toronto TransformTO Net Zero Strategy approved at that same meeting.

At its meeting held on July 19-22, 2022, City Council received reports from the City Manager and Toronto Hydro in accordance with the December 2021 direction. City Council adopted the recommendations of those reports, as well as additional motions from City Councillors. The resolutions include a request that Toronto Hydro establish a new climate advisory services business in keeping with the proposal set out in Toronto Hydro's Climate Action Plan and Toronto Hydro's Climate Action Plan Status Report filed with the City in June 2022. City Council directed that a memorandum of understanding between the City and Toronto Hydro with respect to climate advisory services implementation targets and coordination details return to City Council in the first quarter of 2023.

Climate Advisory Services is designed to facilitate reductions in greenhouse gas emissions via electrification by reducing stakeholder-identified barriers that prevent or inhibit customers from participating in the energy transition. The Climate Action Plan sets out examples of these services to customers, including to: identify their situation-specific opportunities; help in choosing particular climate actions and the timing of implementation; provide recommendations on potential clean tech products and services to vendors; assist in applying for government or institutional funding such as grants and/or loans; remove barriers faced by low income customers; as well as assist with monitoring the implementation and evaluating the results. Toronto Hydro employees would then use the knowledge obtained from this work to ease and support the energy transition of other customers.

The annual costs for the Climate Advisory Services are anticipated to be approximately $8.0 million in 2023, and are expected to increase each year until reaching approximately $15 million in 2026. Actual costs will depend on the nature and scope of services provided. Specifically, the operating costs set out above are expected to be funded through revenues and net income within LDC, not from electricity distribution rates.

Other adopted City Council resolutions support in principle a city-wide LED conversion of streetlights and reinvestment in the enabling infrastructure, and request a report back in the second quarter of 2023 with implementation options and a recommendation from City Transportation Services. City Council requested additional information in future annual reports to the City with respect to the expansion of the electricity grid to help the City achieve its TransformTO Net Zero Strategy goals, and directed the City Manager to submit TransformTO targets to Toronto Hydro to consider in its local capacity planning and rate application processes. City Council requested a report on potential future opportunities to proceed with the climate capital investments proposal set out in Toronto Hydro's Climate Action Plan. To date, City Council is yet to provide approval of the funding required to support the implementation of city-wide LED street light conversion or the climate capital investments proposal.

Electricity Distribution Rates

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and custom index adjustments similar to IRM. A cost of service review uses a future test-year to establish rates, and provides for revenues required to recover the forecasted costs of providing the regulated service, and a fair and reasonable return on rate base. Custom index adjustments are typically used for one or more years following a cost of service review and provide for adjustments to rates based on an inflationary factor net of a productivity factor and an efficiency factor as determined relative to other electricity distributors.

On December 19, 2019, the OEB issued its 2020-2024 CIR Decision and on February 20, 2020, the OEB issued its CIR Final Rate Order, both in relation to the rate application filed on August 15, 2018 [together, the "2020-2024 CIR Decision and Rate Order"]. The 2020-2024 CIR Decision and Rate Order approved funding for capital and operating expenditures of approximately $3.8 billion for the 2020-2024 period. The 2020-2024 CIR Decision and Rate Order approved subsequent annual rate adjustments based on a custom index for the period commencing on January 1, 2021 and ending on December 31, 2024.

The financial considerations of the OEB's 2020-2024 CIR Decision and Rate Order are reflected in the Consolidated Financial Statements including disclosure of approved disposition for a number of requested rate riders [see note 8 to the Consolidated Financial Statements].

On August 20, 2021, LDC filed the 2022 rate application seeking the OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2022 and ending on December 31, 2022. On December 9, 2021, the OEB issued a decision and rate order approving LDC's 2022 rates and providing for other deferral and variance account dispositions.

On August 23, 2022, LDC filed the 2023 rate application seeking the OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2023 and ending on December 31, 2023. On December 8, 2022, the OEB issued a decision and rate order approving LDC's 2023 rates and providing for other deferral and variance account dispositions.

CDM Activities

The IESO is responsible for delivery of CDM programs; however, LDC remains responsible for its obligations under participant agreements with customers for many of the programs under its previous joint CDM plan with Oakville Hydro Electricity Distribution Inc. that were in effect before April 1, 2019. On June 10, 2021, the Government of Ontario issued ministerial directives to the IESO to extend the deadline by which participants were to complete the projects from June 30, 2021 to December 31, 2021, and on December 9, 2021, the deadline was further extended to August 31, 2022. The ministerial directives also allowed for the completion deadline to be further extended for participants who completed projects prior to December 31, 2022 to be eligible for funding upon submission of their claims, if certain conditions were met. Amounts received from the IESO for the funding of the projects under the participant agreements, but not yet spent, are presented on the Corporation's consolidated balance sheets under current liabilities as deferred conservation credit.

Legal Proceedings

In the ordinary course of business, the Corporation and its subsidiaries are subject to various legal proceedings, actions and claims from customers, suppliers, regulators and other parties. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and could materially adversely affect the Corporation. As at the date hereof, the Corporation believes that none of these legal proceedings, actions and claims from customers, suppliers, regulators and other parties in which it is currently involved or has been involved since the beginning of the most recently completed financial year, would be expected to have a material adverse effect on the Corporation. On an ongoing basis, the Corporation and its subsidiaries assess the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual

issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, the Corporation and its subsidiaries would make a claim under any liability or other insurance policies, to the extent applicable, subject to such claim not being disputed by the insurers.

Share Capital

Share capital consists of the following:

[in millions of Canadian dollars]	**2022 $**	2021 $
Authorized		
The authorized share capital of the Corporation consists of an unlimited number of common shares without par value.		
Issued and outstanding		
1,200 common shares, of which all were fully paid.	**817.8**	817.8

Transactions with Related Parties

As the City is the sole shareholder of the Corporation, the Corporation and the City are considered related parties. The Corporation provides electricity, street lighting and ancillary services to the City. All transactions with the City are conducted on terms similar to those offered to unrelated parties.

Summary of Transactions with Related Parties
[in millions of Canadian dollars]

	Year ended December 31,	
	2022 $	2021 $
Revenues	**271.4**	284.4
Operating expenses and capital expenditures (recoveries)	**0.6**	(1.5)
Dividends declared and paid	**84.6**	70.3

Summary of Amounts Due to/from Related Parties
[in millions of Canadian dollars]

	As at December 31,	
	2022 $	2021 $
Accounts receivable and unbilled revenue	**40.0**	52.2
Accounts payable and accrued liabilities	**6.7**	15.0
Customer deposits	**9.8**	12.8

Revenues represent amounts charged to the City primarily for electricity, street lighting and ancillary services. Operating expenses and capital expenditures represent amounts charged by the City for purchased road cut repairs, property taxes and

other services. Capital expense recoveries represent amounts reversed by the City for closed road cut repair accruals. Dividends are paid to the City.

Accounts receivable and unbilled revenue represent receivables from the City primarily for electricity, street lighting and ancillary services including amounts not yet billed. Accounts payable and accrued liabilities represent amounts payable to the City related to road cut repairs and other services. Customer deposits represent amounts received from the City for future expansion projects.

Controls and Procedures

For purposes of certain Canadian securities regulations, the Corporation is a "Venture Issuer". As such, it is exempt from certain requirements of National Instrument 52-109 – *Certification of Disclosure in Issuers*' Annual and Interim Filings. The CEO and CFO have reviewed the Consolidated Financial Statements and the MD&A for the three months and year ended December 31, 2022 and 2021. Based on their knowledge and exercise of reasonable diligence, they have concluded that these documents fairly present in all material respects the financial condition, financial performance and cash flows of the Corporation as at the date of and for the period presented.

Risk Management and Risk Factors

Toronto Hydro faces various risks that could impact the achievement of its strategic objectives. It adopts an enterprise-wide approach to risk management, based on an overall enterprise risk philosophy, and achieved through a process of consolidating and aligning the various views of risk across the enterprise via a risk governance structure.

Toronto Hydro's ERM framework utilizes industry best practices and international guidelines tailored to meet Toronto Hydro's circumstances, and focuses on identifying emerging trends in risks and related opportunities particular to Toronto Hydro through a comprehensive evaluation of Toronto Hydro's business and the electricity industry generally. Toronto Hydro views ERM as a management activity undertaken to add value and improve overall operations and has made it an important part of its decision-making processes. The ERM framework helps Toronto Hydro by enabling the attainment of its strategic goals and objectives through a systematic, disciplined approach towards identifying, evaluating, treating, monitoring and reporting of risks. Accordingly, ERM is an integral part of the strategic management of Toronto Hydro and is routinely considered in forecasting, planning and executing key aspects of the business.

The ERM framework is operationalized by a consistent and disciplined methodology that clearly defines the risk management process and which incorporates judgment of subject matter experts within Toronto Hydro, risk quantification, risk trends and risk interdependencies. The risk criteria used to assess each enterprise risk relate to: strategic, reputational, financial, stakeholder management, distribution system, information system, compliance, occupational health and safety, and public safety impacts.

Toronto Hydro has assigned a designated responsible member of senior management for each enterprise risk [and several key component risks] to seek to ensure that such risks are being monitored through qualitative and quantitative risk indicators and that short interval controls and medium to long-term mitigation plans are in place. Each designated responsible person provides regular risk reporting and briefings to the executive team on their enterprise risk and the key components of such risk. Additionally, Toronto Hydro's risk governance structure includes internal coordination efforts to align outreach to key external stakeholders, both from a strategic and consistency perspective, to help reduce risks and identify opportunities for engagement.

Internal ERM professionals meet regularly with the designated responsible persons to gather and review risk indicators and trends, and identify potential emerging facts that could impact Toronto Hydro, augment other risks or curtail opportunities. Such risk management processes and tools help Toronto Hydro prioritize its mitigation efforts, strengthen its planning efforts, and identify areas for improvement.

While Toronto Hydro's philosophy is that ERM is the responsibility of all business units at all levels, in strategic and functional matters, the ERM governance structure is comprised of three key levels.

At the first level is the Board, which maintains a general understanding of Toronto Hydro's risk profile, the risk categories and the types of risks to which Toronto Hydro may be exposed, and the practices used to identify, assess, measure and

manage those risks. The risk profile is a list of key areas that may impede Toronto Hydro from achieving certain or all of its strategic objectives, and which are most material to its operational success. The Board also reviews Toronto Hydro's risk philosophy on an annual basis and is responsible for approving any new enterprise risk areas.

The second level is the executive team, which ensures systems are in place to identify, manage, and monitor risks and trends. Through input from the business and other considerations, the executive team assesses the appropriateness and consistent application of systems to manage risks within Toronto Hydro. The executive team also ensures that key risks are brought forward to the attention of the Board for discussion and action, as required.

Finally, the third level is the senior leadership team. The senior leadership team supports the executive team and is a collection of subject matter experts from across Toronto Hydro who actively engage in the day-to-day management of risks. Members of the senior leadership team have been assigned to be the designated responsible person for managing and reporting upon enterprise risks. Understanding the critical linkages between external stakeholder management and the impact and likelihood of the emergence of enterprise risk, members of this group are among those that have also been assigned as stakeholder coordinators to ensure that Toronto Hydro is working effectively with external stakeholders to mitigate risks. Working with the executive team, the senior leadership team oversees Toronto Hydro's risk profile and its performance against the defined risk philosophy. This group understands changes in risk status and trends, identifies potential opportunities, and determines responses and action plans that are then implemented by the organization. These senior leaders also work to ensure effective, efficient, complete and transparent risk reporting to the executive team.

Toronto Hydro reviews its risk philosophy and enterprise risks areas continuously for alignment with business and industry conditions and regularly updates and enhances its ERM program to ensure that Toronto Hydro is focused upon and responsive to risks of the greatest significance, likelihood and impact. Toronto Hydro's ERM program is focused on the key strategic and functional risk categories facing the organization. This allows Toronto Hydro's executive team and responsible business units to concentrate on these risks, focus on key data points and undertake deeper dives into root causes and risk trends in these areas on both a short-interval and long-term basis. By focusing in particular on the strategic risks to the organization, decision-making is strengthened and Toronto Hydro has a greater ability to realize opportunities central to its interests.

Toronto Hydro's business is subject to a variety of risks including those key risk areas described in the following sections. The strategic risk areas of Toronto Hydro are identified as the governance, oversight and franchise risks, while the key functional risks of the organization are the cybersecurity, safety, financial, operations, human capital and compliance risks. There can be no assurance that any steps Toronto Hydro may take to manage risks will avoid future loss resulting from the occurrence of the identified key enterprise risk areas or any other risks.

Governance Risk

Risk that municipal activity [laws, policies, or intervention] impedes Toronto Hydro's effective performance, and ability to meet its objectives and serve its customers.

The Corporation is a government-controlled enterprise whose sole shareholder is the City. The operations of Toronto Hydro are influenced by the broad by-law enactment and enforcement powers of the City. The City is also responsible for developing policies and municipal initiatives of general application and there is no guarantee that such policies, including climate change and energy policies, will align with Toronto Hydro's strategic objectives or long-term financial health. The City may also implement additional requirements relating to reduction in GHG emissions and adaptation to climate change as part of initiatives such as the City's TransformTO. In this respect, in response to resolutions passed by City Council in 2021, Toronto Hydro proposed a climate action plan to assist the City in meeting its 2040 net zero GHG emission objective. In July, 2022, City Council passed resolutions to support the implementation of the climate action plan. The City, as sole shareholder, may require Toronto Hydro to make additional investments in infrastructure and/or undertake activities which necessitate additional time, money and effort to be expended related to compliance with the City's TransformTO that are inconsistent with Toronto Hydro's proposed climate action plan. Additionally, due to its authority to put in place oversight bodies which may have or be given jurisdiction over Toronto Hydro as a government-controlled enterprise, the City may also empower certain of its agencies to investigate or audit Toronto Hydro, which could lead to significant reputational, operational or financial harm.

The City also plays a role as a municipal asset manager and construction entity and could substantially impact Toronto Hydro's operations and impose material costs through its infrastructure work plans and policies [e.g., asset relocation costs, work restrictions, climate change adaptation, etc.]. The City may also impact Toronto Hydro when elected officials take actions as community representatives whereby such actions are contrary to the strategic objectives or necessary operational functions of Toronto Hydro.

As the Corporation's sole shareholder, the City has set out the governing objectives and principles, including financial objectives, for the Corporation through the Shareholder Direction. Under the Shareholder Direction, the City has the power to direct Toronto Hydro to conduct its affairs and govern its operations in accordance with such rules, policies, directives or objectives as are directed by City Council from time to time, subject to applicable law. Certain conflicts may arise where the City's goals and objectives in implementing such rules, policies, directives or objectives differ from or amend the Shareholder Direction principles, create new governing objectives and principles, or restrict the ability of the Board to oversee the operations of the Corporation and management's ability to take strategic or functional action, and therefore could materially adversely affect Toronto Hydro's business, operations, financial condition or prospects. The City may not provide or support equity investment or net income reinvestment in the Corporation to enable Toronto Hydro to maintain the financial objectives under the Shareholder Direction as it undertakes its strategic plan and implements OEB-approved rate decisions and orders.

Toronto Hydro engages on a systematic basis with the City Mayor, City Councillors, the City Manager's office, and other departments and agencies to ensure a sharing of perspectives on the vital interests of Toronto Hydro and its customers. Through such engagements the parties review and consider the challenges to Toronto Hydro achieving the objectives and principles set out under the Shareholder Direction, and in particular the impact that proposed changes in city by-laws, municipal policies or directions by the shareholder may create for Toronto Hydro's ability to meet its business objectives and serve its customers.

Oversight Risk

Risk that provincial government or regulator activity [laws, frameworks or policies] impedes Toronto Hydro's effective performance, and its ability to meet its objectives and serve its customers.

Toronto Hydro is subject to the risk that its business activities may be impeded through the actions of governmental or regulatory authorities or by changes in regulation. There is a risk that future changes to Ontario's electricity regulatory model, manner of regulation, application of regulatory principles, and/or broader climate change and energy policy framework does not align with Toronto Hydro's business direction and could materially adversely affect Toronto Hydro's strategic goals and financial results.

Ontario's electricity industry regulatory and other energy policy developments may affect the electricity distribution rates charged by LDC, the costs LDC is permitted to recover and the activities LDC and others, including those parties offering alternative or additional services to the electricity distribution grid, may undertake and how such activities are supported. This may in turn have a material adverse effect on the financial performance of the Corporation and/or LDC's ability to deliver effective and efficient operations and reliable service to its customers, as well as create barriers to LDC achieving its strategic objectives. Among other things, there can be no assurance that:

- the OEB will approve LDC's electricity distribution rates at levels that will permit LDC to maintain safe and reliable service to its customers and earn a commercially reasonable rate of return on the investment in the business;
- the OEB will approve and permit recovery through rates of past and future expenditures incurred by LDC in providing distribution services to customers, including costs arising from an increased inflationary environment, in a timely manner or at all;
- governmental authorities will pursue net zero GHG policies that optimally utilize electrification or adequately support local distribution companies in facilitating electrification;
- the OEB will approve and permit recovery through rates of past and future expenditures incurred by LDC in preparing for or expanding electricity distribution service to meet increased electricity demand or other requirements resulting from net zero GHG emission policies;

- the OEB will adopt other rate-setting principles, formulae, inputs and cost recovery methodologies in a manner consistent with well-established regulatory principles that result in rates that properly support LDC's activities;

- the regulatory instruments that are made available to LDC will be sufficient to address LDC's operations, needs and circumstances in respect of future applications for electricity distribution rates; and

- the OEB, IESO or other governmental authority will not permit, enable or facilitate other parties in providing distribution services in LDC's licensed area, or permit loads within LDC's service area to become served by a means other than through LDC's electricity distribution system.

Any future regulatory decision to disallow or limit the recovery of costs could lead to potential asset impairment and charges to results from operations, which could have a material adverse effect on Toronto Hydro.

Toronto Hydro actively participates in industry engagement efforts in order to mitigate the above risks and realize potential opportunities in regulatory, climate change and energy policy development. Through these types of engagements, Toronto Hydro monitors proposed regulatory, climate change and energy policy changes that may support or impede its business. LDC also employs a comprehensive organizational regulatory application program, which includes a risk assessment, to ensure that all applications to the OEB achieve the highest utility standard of evidence gathering, preparation and presentation, and most accurately reflects the needs of LDC. The preparation of the LDC distribution rates application to the OEB for the 2025-2029 rate period is currently underway. Successful completion and implementation of the project work plan related to the application is expected to yield long-term results for Toronto Hydro: specifically, funding certainty and flexibility to invest in the modernization and renewal of the distribution system and to prepare for growth and electrification driven by the City's TransformTO. However, there can be no assurance that the OEB will substantially approve the activities, plans and methodologies set out therein or the revenue requirement related thereto.

Additionally, the policy priorities of provincial and federal governments and regulatory bodies beyond those specifically applicable to the climate change and energy space, including policies of more general application, and the implementation of policies by such bodies, may impact Toronto Hydro's ability to deliver effective and efficient operations, meet business objectives, report on its activities and capitalize upon new opportunities. Developments and changes in any of the laws, rules, regulations, policies, permits, or directives applicable to the businesses carried on by Toronto Hydro, and the manner of implementation and application of the same, could materially adversely affect Toronto Hydro. This may include developments with respect to labour and employment laws, changes to accounting standards and financial reporting requirements and environmental obligations, among others. This may also include changes to public safety rules, such as restrictive measures affecting the mobility or availability of human and/or non-human resources associated with infectious diseases such as COVID-19 or other adverse public health developments. Toronto Hydro actively engages with government entities and participates in industry organizations to monitor emerging policies and where possible plays an advocacy role.

Franchise Risk

Risk that restrictions in LDC's business model and/or external conditions impede its ability to maintain and grow its legal right to be the sole provider of electricity distribution and connection services in the city of Toronto [its franchise] and serve electricity customers. Toronto Hydro is subject to the risk that it is displaced from its strategic position or fails to gain a strategic advantage to effectively facilitate local electricity demand, which could materially adversely affect Toronto Hydro's strategic goals and financial results.

The OEB has the authority to grant municipal distribution licences, has issued to LDC a licence stipulating a service area that reflects the territory within the City, and has not granted any other distribution licence that permits distribution within LDC's service area. In addition, there is a legal framework in place that establishes LDC, as the holder of the municipal distribution licence in the City, to be the sole provider of distribution activities across municipal rights of way. There is no assurance that these frameworks will continue to exist sufficiently or at all in order to provide LDC the opportunity to be the comprehensive distribution provider in the city of Toronto.

Other regulated and unregulated entities have and continue to compete with LDC and its predecessors, and new parties continue to emerge to provide customers with other sources of energy, including electricity and energy services. Additionally, customers have made choices to provide their own electricity or other sources of energy for their use and/or sale

back into the distribution grid. The pervasiveness of this competition and the presence of alternatives to Toronto Hydro's distribution services, and the resultant effects on LDC's distribution business, have varied over time and continue to vary based on many factors. These factors may include the relative price and relevant costs of energy source [e.g., natural gas, solar photovoltaic, grid-supplied electricity, behind-the-meter generation, district energy], climate change policy, technology development [e.g., energy storage, energy efficiency, demand response], ability of customers to access transmission-direct connections, economic trends, real estate prices, workplace arrangements, government-based incentives, regulatory frameworks and compliance frameworks especially for non-utility entities, load development, and the state of the marketplace and economy in general. Toronto Hydro also faces the risk of its franchise being diminished by the possibility of an overall reduction in the use of electricity in its service territory.

There can be no assurance that the future nature, prevalence, or effects of these forms of competition, from the transition to net zero GHG emissions or otherwise, will be comparable to current or historic experience. Failure to effectively review and understand our external and internal environment and take appropriate action could lead to missed business opportunities and loss of competitive advantage. In particular, the clean energy transition to net zero GHG emitting energy sources may create both risks and opportunities and there can be no guarantee that Toronto Hydro has the correct strategic direction to capitalize on the associated policy changes or technological advancements or that it will be able to effectively mitigate losses from these developments.

Risks to Toronto Hydro's franchise interests may also result from impairment to Toronto Hydro's image in the community, public confidence or brand. Toronto Hydro is committed to delivering safe and reliable electricity to its customers in an environmentally responsible manner at optimal costs. Negative views regarding this commitment and the cost of electrification and energy transition, could impact the public's perception of Toronto Hydro. In addition, events and/or external factors that draw negative media attention to Toronto Hydro could cause reputational damage and impact Toronto Hydro's business and relationship with its stakeholders. These factors could lead customers, governments and regulators to look more favourably to alternative services and service providers as compared to utility-based electricity distribution.

Toronto Hydro is focused on monitoring external competitive factors and industry developments, including alternative service providers and technologies, through indicators such as customer engagements related to innovative technologies and pre-assessment requests and connection applications for energy storage. Toronto Hydro is also focused on enhancing the intelligence, automation and interactivity of LDC's electricity distribution grid, including utilizing developing technology and facilitating customer use of technology and business models, to support the reliability of its core infrastructure grid operations, prepare for increased electricity demand from net zero GHG emission policies, promote greater value, and deliver solutions for its customers. Additionally, Toronto Hydro takes measures to maintain relationships with its customers to better understand the specific needs and expectations of each class of customer, and develop or enhance service offerings to address those needs. Toronto Hydro conducts customer research and consultations in the ordinary course of its operations, and as part of the development of its rate application whereby it directly considers customer preferences and feedback, in addition to other inputs, as part of developing its business plan. Toronto Hydro also has dedicated personnel focused on the utility's key account customers, who respond to issues raised by large commercial, industrial and institutional customers and assist with their energy management needs. Toronto Hydro also provides climate advisory services as part of its climate action plan to facilitate customers in developing their own climate action plans and reduce stakeholder-identified barriers that prevent or inhibit customers from participating in the energy transition. Through these types of engagements, Toronto Hydro can monitor its customers' specific needs and can work with them to develop energy solutions.

Cyber Security Risk

Risk that Toronto Hydro is unable to adequately safeguard digital information assets, connections to digital infrastructure, physical assets and people from threats or vulnerabilities.

Toronto Hydro's ability to operate effectively is also in part dependent on the development, maintenance and management of complex information technology and operational technology systems. Computer systems are employed to operate LDC's electricity distribution system, and Toronto Hydro's financial, customer billing and business systems to capture data and to produce timely and accurate information.

LDC's electricity distribution infrastructure and technology systems are potentially vulnerable to damage or interruption from cyber-attacks, breaches or other compromises, which could result in business interruption, service disruptions, theft of intellectual property and confidential information [about customers, suppliers, counterparties and employees], additional

regulatory scrutiny, litigation and reputational damage. The cybersecurity threat landscape is continually evolving and actors are using more sophisticated methods to penetrate information technology systems. In particular, the utilities sector, as operators of critical infrastructure and providers of essential services with large customer bases, has become an increasing target for cybersecurity activity. Toronto Hydro has implemented security controls substantially aligned with industry best practices and standards, including the National Institute of Standards and Technology Cybersecurity Framework and the OEB's Ontario Cyber Security Framework, and maintains cyber insurance. Cyber-attacks, breaches or other compromises of electricity distribution infrastructure and technology systems could result in service disruptions and system failures, including as a result of a failure to provide electricity to customers, property damage, data corruption, and/or loss of confidential employee, supplier, counterparty or customer information. A significant breach could materially adversely affect the financial performance of Toronto Hydro or its reputation and standing with customers, regulators and in the financial markets. It could also expose Toronto Hydro to third-party claims. Overseeing the management of these risks, Toronto Hydro's Audit Committee receives comprehensive updates on the cybersecurity environment and the organization's cybersecurity program and responses.

Toronto Hydro must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information [including the personal information of customers], as well as information provided by suppliers, employees, counterparties, and others. Such information could be exposed in the event of a cybersecurity incident or other unauthorized access, which could materially adversely affect Toronto Hydro and also result in third-party claims against Toronto Hydro.

Preventative controls are employed to protect information and technology assets against cyber-attacks and mitigate their effects. Toronto Hydro maintains close coordination with industry partners and agencies and technology vendors who provide near real-time threat intelligence. Detective controls are employed to continuously monitor information systems so that Toronto Hydro can respond appropriately to minimize the damage in the event of a cyber-attack. Additionally, in respect of Toronto Hydro's operational technology systems in general, controls are in place which mitigate against wider systemic risk to business systems. Toronto Hydro has also developed robust processes for assessment of third-party providers and contractors that interact with its information technology systems, and has contractual protection and technical safeguards in place to safeguard against third-party risks. Even with these measures in place, since the techniques used to obtain unauthorized access, disable or degrade service, or sabotage systems change frequently and may only be detected once a cyber incident has initiated, Toronto Hydro may be unable to anticipate these techniques or to implement adequate preventative measures.

As Toronto Hydro focuses on increasing the intelligence, automation and interactive nature of its distribution system, the incorporation of a greater level of technology and information systems into its infrastructure, makes the distribution system inherently more prone to external cyberattack. As such, there can be no assurance that the measures taken will be effective in protecting LDC's electricity distribution infrastructure or assets, or the personal information of its customers or employees, from a cyber-attack or the effects therefrom.

As public health measures and pandemic restrictions have lifted, Toronto Hydro has transitioned to a hybrid work arrangement. Threat vectors related to remote working (i.e. scams, spams, phishing, vishing, etc.) are expected to persist to exploit hybrid work infrastructure and target employees' home networks and personal devices to gain access to Toronto Hydro's networks. As such, the Corporation will continue to deploy preventative and detective controls to protect and continuously monitor information systems and technology assets to help minimize damage in the event of a cyber-attack, breach or other compromise. The Corporation also has internal cybersecurity and technology use policies in place, as well as a cybersecurity training program for its employees.

Despite the proactive steps taken to adapt to the current environment, the Corporation's ability to operate effectively is dependent on the security, development, maintenance, and management of complex information technology systems.

Safety Risk

Risk to Toronto Hydro employees or the general public of critical/fatal injuries and illnesses relating to or impacting upon Toronto Hydro activities.

Potential and existing health and safety risks related to worksites and tasks being performed by Toronto Hydro are regularly assessed and where identified, hazards are removed and/or mitigated to continually improve health and safety for Toronto

Hydro employees, customers and members of the public. The most serious workplace incidents arising from workplace hazards can cause and/or contribute to critical injuries, fatal injuries, and occupational illnesses, as defined by provincial health and safety legislation.

The nature of the work performed in electrical utilities operations requires that employees receive extensive training on health and safety, including on personal protective equipment and the implementation of workplace safety procedures and protocols. This is due to the hazards inherent to electrical utilities work, which, depending on the required task, can include electrical contact, arc flash, working in confined spaces, fires or explosions, slips, trips and falls, motor vehicle incidents, occupational illnesses, and biological hazards such as infectious diseases. On occasion, hazards can result in personal injury, operational interruptions, and loss or damage to equipment, property, or information technology systems. In an active and ongoing manner, Toronto Hydro further mitigates health and safety risks to employees, customers and members of the public through equipment inspection, replacement and maintenance, employee training, communications programs and reactive and emergency work. "Safety by Design" principles are applied in the development of construction standards and design practices. New products for use in the distribution system go through a thorough review and introduction process. The selection process for new products and the development of standards promotes employee, customer, and public health and safety.

Toronto Hydro is subject to compliance with provincial health and safety legislation. Toronto Hydro's management approach to occupational health and safety is to meet, and often where possible, exceed legal compliance requirements and eliminate or safeguard known occupational hazards and risks. Toronto Hydro also follows the internal responsibility system to clearly define responsibility and accountability for every workplace party at each level within the organization. There are processes in place to develop and nurture good leadership practices through recruitment, education, training and performance management practices that encourage the application of Toronto Hydro's corporate values, including health and safety.

Toronto Hydro also has in place an infectious disease plan, which was activated by the COVID-19 emergency, as well as previous pandemics and epidemics. This plan has been a significant part of Toronto Hydro's emergency response to COVID-19 and has been used to seek to limit health and safety exposures to employees, members of the public, and the communities serviced by Toronto Hydro.

In 2013, LDC received OHSAS 18001 certification which was the international standard for occupational health and safety management systems. OHSAS was later replaced by ISO 45001:2018 which Toronto Hydro successfully migrated to in 2019 and was subsequently re-certified in 2021. LDC conducts annual third-party audits to maintain ISO 45001:2018 certification. In addition, occupational health and safety legal compliance audits are conducted by an external third party every two years. The ISO 45001:2018 certificate expires on February 4, 2025.

Financial Risk

Risk that Toronto Hydro is unable to maintain its financial health and performance at acceptable levels.

Toronto Hydro is directly and indirectly subject to various macroeconomic and local market forces, which could have material adverse impacts. As a consequence of uncertainties in the recovery of economic and market conditions, Toronto Hydro remains exposed to inflationary pressures, an increased interest rate cost environment, indeterminate levels of customer consumption, credit risk with respect to customer non-payment of electricity bills and increased supply chain, operating and infrastructure development costs. The general rate of inflation in Canada and many other countries saw a significant increase during 2021 and continuing throughout 2022, with some regions experiencing multi-decade highs. Certain underlying factors include, but are not limited to, global supply chain disruptions, shipping restrictions, labour market constraints, geopolitical instability and side effects from monetary policies and fiscal expansions. The global economic recovery remains uncertain. Prices for certain services and materials continue to evolve in response to fast-changing commodity markets, industry activities, supply chain dynamics, and government policies impacting operating and capital costs. The global economic recovery and rising inflationary trends are widely expected to result in elevated interest rates. In 2022, the Bank of Canada began raising its benchmark interest rates for the first time since 2018 and further interest rate increases may occur. The Corporation closely monitors market trends and seeks to mitigate cost impacts through various

measures, including project management, procurement and other management actions. There can be no assurance that the OEB will allow full recovery of increased costs relating to these factors.

As a result of the uncertain economic conditions, Toronto Hydro also may be exposed to the risk of counterparties defaulting on their obligations. The Corporation monitors and limits its exposure to credit risk on a continuous basis. The credit risk related to cash and cash equivalents is mitigated by the Corporation in assessing and monitoring the credit exposures of counterparties. The Corporation's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. As a result of current uncertain economic conditions, the Corporation may be exposed to credit risk with respect to customer non-payment of electricity bills, and LDC's security interest or other protective measures, if any, provided to LDC, such as letters of credit, cash deposits or pre-authorized payments may not be sufficient. The Corporation considers the current economic and credit conditions to determine the expected credit loss allowance of its accounts receivable and unbilled revenue. Due to current uncertain economic conditions, the estimates and judgments made by management in the preparation of the expected credit loss allowance are subject to an estimation uncertainty. The Corporation determines the expected credit loss allowance based on current estimates and assumptions, including but not limited to recent trends for customer collections and current and forecasted economic conditions. The Corporation continues to actively monitor its exposure to credit risk.

Actions by the provincial government or regulatory authorities may impede LDC's ability to mitigate the risk of customer non-payment using means normally permitted by law at certain times of the year, including security deposits [i.e., letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB], late payment penalties, pre-payment, pre-authorized payment, load limiters or disconnection. LDC may have no option in certain cases but to assume the amount of any default, whether in whole or in part, and LDC's security interest or other measures, if any, may not provide sufficient protection. While LDC would be liable for the full amount of the default, there can be no assurance that the OEB would allow recovery of the expected credit loss allowance or of the increased operating or construction costs, and such expenses and costs could have a material adverse effect on the Corporation's business, operations, financial condition or prospects. The OEB would examine any electricity distributor's application for recovery of extraordinary expected credit loss allowance and other expenses on a case-by-case basis. Increases in outstanding receivables due to reduced or delayed customer payments as a result of economic conditions could also contribute to liquidity risk for LDC as it continues to be charged for electricity commodity, transmission and other charges, which are intended to be flow-through items to customers. If the level of customer payment delays or non-payment, or increased costs contribute to liquidity challenges, the Corporation expects that it would utilize various mitigation tools at its disposal in seeking to improve its liquidity, including accessing further debt under, or increasing limits in, any of its MTN Program, Commercial Paper Program, or its credit facilities, or by reducing costs and delaying payments. The global economic situation continues to be dynamic and uncertain and the ultimate duration and magnitude of the impact on Toronto Hydro's business cannot be determined with certainty at this time.

The Corporation is exposed to liquidity risk related to its ability to fund its obligations as they become due. The Corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. The Corporation has access to credit facilities and debt capital markets and monitors cash balances daily. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they become due while minimizing finance costs. The Corporation relies on debt financing through the debt capital markets and existing credit facilities to finance its daily operations, repay existing indebtedness, and fund capital expenditures. The current challenging economic climate affected by factors including but not limited to uncertain macroeconomic conditions like a global recession may lead to material adverse changes in cash flows, working capital levels and/or debt balances, which may also have a direct negative impact on the Corporation's operating results and financial position in the future. Accordingly, the Corporation continues to monitor liquidity risk and adapt its plans as the economic climate evolves.

Toronto Hydro seeks to target an optimal capital structure and cash to debt range to access capital markets at the lowest interest rates to finance its capital plans, including those related to meeting increased electricity demand resulting from net zero GHG emission policies [such as the City's TransformTO]. The Corporation's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by a number of factors, including financial market conditions, inflationary pressure, Bank of Canada monetary policy decisions, regulatory processes that affect the timeliness for the approval and clearance of variance accounts, and macroeconomic concerns around the health of the economy in general and consumers. In addition, any of the above factors can also be affected by financial or geopolitical events in the global economy, Toronto Hydro's business, operations, financial condition or prospects, compliance with contractual debt covenants, the ratings assigned to the Corporation or the debentures issued under the Corporation's MTN Program by credit rating agencies, the rating assigned to short-term borrowings under the Commercial Paper Program by a credit rating agency, the availability of the commercial paper market, and the interest rates and availability of borrowing capacity under its

Revolving Credit Facility, Working Capital Facility and other credit arrangements. In the event the Corporation is unable to maintain a required credit rating for its Commercial Paper Program, the Corporation's cost to access short-term capital could be materially adversely affected. In addition, if the Corporation cannot maintain attractive credit ratings for its MTN Program, debt capital under such program may become too costly or unavailable, which could materially adversely affect the Corporation's capital and operational programs, and its financial health and performance. There can be no assurance that debt or equity financing will be available or sufficient to meet Toronto Hydro's requirements, objectives, or strategic opportunities. If and when financing is available, there can be no assurance that it will be on acceptable terms to Toronto Hydro. As the City is the sole shareholder of the Corporation, it is dependent on the City for new equity, the timing and amount of which is subject to uncertainty. Therefore, as further indebtedness is incurred to finance Toronto Hydro's capital program and its climate action plan, the Corporation's debt to equity capital structure may not be maintained at a level in alignment with the OEB's deemed capital structure for rate making purposes (60% debt:40% equity). The Corporation regularly reviews the external market environment and has regular engagements with its credit rating agencies, securities dealers and investor community to monitor capital structure risk.

Generally, Toronto Hydro is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations. As at December 31, 2022, Toronto Hydro estimates that a 1% [100 basis point] increase in the discount rate used to value these obligations would decrease the accrued benefit obligation by $27.1 million, and a 1% [100 basis point] decrease in the discount rate would increase the accrued benefit obligation by $33.3 million.

Toronto Hydro is also exposed to short-term interest rate risk on the short-term borrowings under its Commercial Paper Program and Working Capital Facility, as well as customer deposits, while most of its remaining obligations for the most recently completed financial year were either non-interest bearing or bear fixed interest rates, and its financial assets for the most recently completed financial year were predominately short-term in nature and mostly non-interest bearing. Toronto Hydro manages interest rate risk by monitoring its mix of fixed and floating rate instruments, and taking action as necessary to maintain an appropriate balance as established under its treasury policies. Toronto Hydro estimates that a 25-basis point increase [decrease] in short-term interest rates, with all other variables held constant, would result in an increase [decrease] of approximately $1.1 million to annual finance costs.

Toronto Hydro typically has limited exposure to the changing values of foreign currencies. While Toronto Hydro purchases goods and services which are payable in US dollars, and purchases US currency to meet the related commitments when required, the impact of these transactions as at December 31, 2022 was not material.

Toronto Hydro's financial health and performance may also be adversely affected by events or measures, as well as changes in economic, policy, customer preference or technological conditions, that reduce the demand for electricity. Such events or measures may include, but are not limited to, closures of businesses and other institutions such as schools and government operations as a result of extreme storms and other weather conditions, natural disasters, terrorism, and pandemics such as COVID-19. A reduction in demand for grid-supplied electricity distribution may also arise from conservation measures. Additionally, the adoption by customers of new technologies in the electricity industry, including those related to self-generation, could reduce customer demand for grid-supplied electricity distribution. Toronto Hydro is focused on investing in its infrastructure to modernize the grid to drive resiliency, reliability, customer effectiveness and efficiency.

Operations Risk

Risk that Toronto Hydro is not able to effectively meet the needs of its customers and a growing city, and maintain the security and reliability of the distribution grid at acceptable levels. The primary factors driving Toronto Hydro's operations risk relate to asset management, supply chain, customer management, physical security, and business interruption.

Toronto Hydro may be unable to maintain reasonable levels of reliability for its customers due to failure of existing distribution infrastructure and assets [including assets not directly involved in electricity distribution such as facilities and computer systems], access to the supply of electricity from the provincial and local generation and transmission systems, and the inability to replace or expand distribution infrastructure in an optimal timeframe. Electricity distribution is a capital-intensive business. As the municipal electricity distribution company serving the largest city in Canada, LDC continues to invest in the renewal of existing aging infrastructure and in the development of new infrastructure to address safety, reliability, hardening the resiliency of the distribution system against the effects of climate change, and customer service requirements now and in the future. As well, infrastructure investments will be made to increase the capacity and resilience

of the grid required to facilitate the electrification of the economy and people's daily lives in order to achieve government net zero GHG emissions targets.

LDC estimates that over a quarter of its electricity distribution assets have already exceeded or will reach the end of their expected operating lives over the next five years [i.e., by 2028]. Asset condition assessment demographics also indicate substantial asset investment needs for a number of critical assets during this period. At the same time, Toronto is one of the fastest growing cities in North America and LDC must make upgrades to keep pace with urban intensification and electrification, optimize flexibility of connection to generation and transmission systems, including distributed energy resources; and ensure good stewardship of the distribution system in a manner that accounts for a changing climate. Further, extreme weather is no longer an infrequent experience, and has instead become a regular condition of operating a distribution system. Toronto Hydro has experienced several extreme weather events in recent years, including ice storms, freezing rain, extreme wind and flooding, that have led to a significant number of customers experiencing electricity outages and challenges to maintaining access to electricity supply from the transmission system.

In addition, as the City, provincial government and the Government of Canada implement policies and programs to respond and adapt to climate change, including greater electrification through the adoption of electric vehicles, distributed energy resources, building heating and cooling retrofits and energy efficiency/demand management technologies, the pressures on Toronto Hydro's system are expected to increase. Such factors may drive a need for incremental capital expenditures for system upgrades and new technologies to increase grid capacity and resilience in order to reliably handle increased loads, higher power quality requirements and multi-directional flows. As Toronto Hydro adopts novel technologies or equipment to enhance the capabilities of its electricity distribution grid, despite system contingency, there can be no guarantee that these technologies or equipment will be effective or that they will not increase the incidence or duration of outages.

LDC's ability to continue to provide a safe work environment for its employees and a reliable and safe distribution service to its customers and the general public will depend on, among other things, the ability of Toronto Hydro to fund additional infrastructure investments, and the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment, expansion and replacement.

LDC is focused on overcoming the above challenges and executing its capital and maintenance programs. It uses a variety of asset and project management tools to implement its plans, measures progress on a recurring short interval basis, and regularly monitors and manages the health of its assets. Toronto Hydro continues to align its asset management system to the ISO 55001: Asset Management standard and has commenced a formal process which is expected to lead to certification under the standard and to cause the lifecycle of assets to be managed more effectively, reduce system costs and improve system visibility and reliability. Toronto Hydro employs sophisticated, granular scenarios analysis based upon customer preferences to support its investment planning programs at the local level. LDC is also extensively engaged in regional planning activities and processes with the IESO to ensure the adequacy of the regional transmission system serving the City. Toronto Hydro also utilizes a diverse set of contractors and suppliers through its rigorous procurement practices and monitors market conditions closely. However, if LDC is unable to carry out these plans in a timely and optimal manner, becomes subject to significant unforeseen equipment failures, or is unable to access sufficient supplies or human resources, equipment performance will degrade. Such degradation may compromise the reliability of distribution assets, climate change readiness, the ability to deliver sufficient electricity and/or customer supply security, including in response to government net zero GHG policies and public goals, and increase the costs of operating and maintaining these assets. Similarly, there is no certainty that regional planning efforts controlled by external governing agencies and regulators will address all electricity supply matters as identified by LDC.

Additionally, Toronto Hydro's ability to operate effectively is in part dependent upon timely access to equipment, materials and service suppliers. Loss or delay of key equipment, materials and service suppliers and the reputational and financial risk exposures of key vendors could affect the Corporation's operations and execution of capital projects. Disruptions to the Corporation's supply chain, driven by the geopolitical environment, inflation, shifts in demand, and labour shortages, have resulted in increased lead times, increased costs, and more variability in on-time and in-full deliveries for key assets like transformers, cables, and switchgear. These capacity concerns may affect grid reliability, storm management and recovery, or lead to delays or cancellation of electrification projects. Uncertainty and disruption resulting from international conflicts and military operations may also affect Toronto Hydro, including by contributing to supply chain or financial markets disruption. Toronto Hydro has a number of mitigation plans in place, including purchasing material requirements beyond lead times, sourcing and approving new suppliers to alleviate single point of supply issues, adjusting re-order points to increase certain stock codes, extending planning horizons, and re-using/repairing existing equipment where possible.

Toronto Hydro utilizes its procurement processes and a diverse supplier and contractor base to mitigate against supply chain risks and costs.

Toronto Hydro may also fail to accurately measure customer electricity consumption, respond to and address customer service issues or bill customers correctly or on time [including meter to cash management]. In order to provide timely and accurate billing and customer service, Toronto Hydro has implemented a number of policies, procedures and guidelines including those related to metering, accounts receivable and connections/disconnections. Toronto Hydro monitors metering/billing accuracy, customer communications and customer service quality on an ongoing basis. The Corporation has also commenced a multi-phase customer enhancement program to harmonize the customer experience by delivering a digital enablement of customer interactions, seamless meter to cash process, updating customer billing technology and other customer service processes in a cost-effective and unified manner. As noted above under "COVID-19 Pandemic Considerations", Toronto Hydro has implemented a number of provincial government and OEB-based programs, including changes to commodity prices, as well as its own initiatives such as extensions of disconnect moratoriums and reductions in late payment charges, in order to assist customers. The wind-down and removal of these supports for customers may lead to negative customer sentiment toward Toronto Hydro. As a result of net zero GHG emissions policies, LDC may need to accelerate capital investments to accommodate increasing electrification. These system enhancements may lead to material customer bill increases and a more challenging customer relationship environment for Toronto Hydro, as well as customer backlash against the energy transition and related expenditures by Toronto Hydro.

Toronto Hydro also faces external threats to its physical and perimeter security. This includes the security of Toronto Hydro's facilities including office buildings and distribution stations. In order to safeguard its assets and staff, Toronto Hydro has developed policies and guidelines around physical and perimeter security and facilities related emergency preparedness. Toronto Hydro has also implemented electronic security technologies to ensure that only authorized personnel have access to Toronto Hydro facilities.

Similarly, Toronto Hydro may be unable to maintain continuing and sustainable business operations, or recover from business interruption after an incident that is beyond normal operations. Toronto Hydro's operations are exposed to the effects of natural and other unexpected occurrences such as extreme storm and other weather conditions, natural disasters, loss of the supply of electricity from the provincial and local generation and transmission system, as well as terrorism and pandemics, such as COVID-19. LDC is also exposed to risks that informational and operational technology systems may not operate as anticipated and could result in sustained interruptions to key corporate systems that would have a substantial impact on continuing normal business operations. Costs and operational changes, associated with such business interruption events may have a material and adverse effect on Toronto Hydro's business and operations in both its short and longer term. These impacts may also include limiting Toronto Hydro's ability to build, repair and maintain capital infrastructure, with resultant impacts on reliability and revenue. Toronto Hydro has implemented various initiatives aimed at improving the system's resiliency to increasingly frequent extreme weather events caused by climate change. These initiatives include updating major equipment specifications, revising planning guidelines, reviewing the load forecast impacts, revising design practices, and enhancing maintenance programs.

Toronto Hydro has also implemented an emergency and business continuity management program to support organizational-wide resiliency and build measures in response to major threats to operations such as the COVID-19 pandemic, and major power outage events. Although Toronto Hydro's facilities and operations are constructed, operated and maintained with such occurrences in mind, there can be no assurance that they will successfully withstand such occurrences in all circumstances. Any major damage to Toronto Hydro's facilities or interruption of Toronto Hydro's operations arising from these occurrences could result in lost revenues and repair costs that can be substantial. Although Toronto Hydro has continued to place insurance which it considers to be consistent with industry practice, there is no guarantee that insurance will continue to be available at reasonable rates for certain types of coverage and policy limits. If Toronto Hydro sustained a large uninsured loss caused by natural or other unexpected occurrences, LDC may apply to the OEB for the recovery of the loss related to the electricity distribution system. There can be no assurance that the OEB would approve, in whole or in part, such an application.

Human Capital Risk

Risk that Toronto Hydro is unable to maintain necessary resource talent and skilled resources.

Toronto Hydro is subject to the risk that human resources may not be available with the necessary knowledge, skills and education to support Toronto Hydro's future talent requirements and, as a result, its strategic activities and business objectives. This risk could be heightened in economic conditions where inflation rates are rising as this may result in pressure on wages and salaries, and where employee expectations with respect to work-life balance and flexibility are evolving. Furthermore, Toronto Hydro expects that labour force availability for certain positions will continue to tighten, resulting in increased competition and turnover for certain skilled employees, which may negatively impact knowledge management and business continuity at Toronto Hydro.

Development and retention of talent to meet the evolving needs of the business, particularly those related to the adoption of new technologies central to electrification and implementation of grid-connected energy resources to enable the clean energy transition and other needs of a modernized distribution grid requires Toronto Hydro to focus on a series of proactive activities and programs to mitigate these risks, such as strategic workforce planning, promotion of apprenticeship programs, diversity and inclusiveness awareness and training, investments in colleges and universities, succession planning, knowledge transfer and a robust training program.

Constraints on executive compensation may hinder Toronto Hydro's ability to attract and retain executive level talent. Failure to attract and retain executive level talent that have the skills and experience necessary to help Toronto Hydro achieve its strategic goals could have a material adverse effect on Toronto Hydro's business and operations.

Toronto Hydro's ability to operate successfully in the electricity industry in Ontario will continue to depend in part on its ability to make changes to existing work processes and conditions in order to adapt to changing circumstances, including limitations and restrictions placed on human resources as a result of external environment factors such as infectious diseases or erosion of social cohesion. Toronto Hydro's ability to make such changes or adapt, in turn, will continue to depend in part on its relationship with its labour unions, including negotiating collective bargaining agreements with the Society of United Professionals and PWU. There can be no assurance that Toronto Hydro will be able to secure the support of its labour unions. There can also be no assurance that Toronto Hydro will be able to secure collective agreements without work stoppages by its unionized work forces.

Toronto Hydro's ability to develop its work processes to meet changing circumstances, deliver upon grid modernization and address electrification, also depends on its ability to access adequate resources from its external contractor community with advanced developed skills. Toronto Hydro's ability to successfully access and benefit from third party service providers will depend, in part, on minimizing any disruption that may be caused by infectious diseases or other factors. If such disruption occurs, there may be a material adverse effect on Toronto Hydro's business and operations. One way in which Toronto Hydro seeks to mitigate this risk is through its use of business practices and internal procedures to identify a diverse group of reputable third-party service providers with access to advanced skill sets and entering into contracts with, and monitoring the performance of, these third-party service providers.

Compliance Risk

Risk that Toronto Hydro does not meet its material compliance obligations under legal and regulatory instruments.

Toronto Hydro is committed to complying with applicable legal and regulatory requirements and other requirements to which the organization subscribes. Toronto Hydro has a Corporate Compliance program that strengthens the organization's culture of compliance and aims to provide reasonable assurance, to Toronto Hydro's senior leadership and Toronto Hydro's Board of Directors, of adherence with material compliance requirements. Regular senior leadership reporting on the completion status of planned mitigation actions, monitoring of compliance issue turnover rates, and a responsible employee attestation process assist with ensuring effective management of identified compliance risks. Despite these mitigations, there can be no certainty that Toronto Hydro will be in material compliance with applicable future laws, rules, regulations and policies at all times. Constraints on access to human and materials resources due to global supply chain challenges may create risk of completion of compliance activities in accordance with mandated timelines. Failure by Toronto Hydro to comply with applicable laws, rules, regulations and policies may subject Toronto Hydro to civil or regulatory proceedings that could have a material

adverse effect on Toronto Hydro. The OEB may not allow recovery in rates for the costs of coming into or maintaining compliance with these laws, rules, regulations and policies.

Use of Judgements and Estimates

The preparation of the Corporation's Consolidated Financial Statements in accordance with IFRS requires management to make judgments, estimates and assumptions which affect the application of accounting policies, reported assets, liabilities and regulatory balances, and the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported revenues and expenses for the year. The estimates are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as for identifying and assessing the accounting treatment with respect to commitments and contingencies. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the IESO, the Ontario Ministry of Energy, or the Ontario Ministry of Finance. The assessment of the COVID-19 pandemic recovery is subject to uncertainty; accordingly, judgments, estimates and assumptions related to the impact of the uncertain economic conditions made by management in the preparation of the Corporation's Consolidated Financial Statements are also subject to uncertainty. Management has analyzed the impact of the uncertain economic conditions on its estimates and adjusted the expected credit loss allowance as at December 31, 2022 *[note 15[b]]*. The extent of the future impact of the uncertain economic conditions on the Corporation's financial results and business operations is not known at this time.

Information about judgments in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in note 25[b] relating to recognition of regulatory balances and note 25[j] relating to principal versus agent determination for recording revenue on a gross or net basis.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively. Assumptions and estimates with a significant risk of resulting in a material adjustment within the next financial year are used in the following notes to the Consolidated Financial Statements:

Note 24 – Recognition and measurement of provisions and contingencies;
Note 25[b] – Recognition and measurement of regulatory balances;
Note 25[d] – Recognition and measurement of loss allowance for accounts receivable and unbilled revenue;
Notes 25[f] and 25[g] – Determination of useful lives of depreciable assets;
Note 25[j] – Revenue recognition – measurement of unbilled revenue;
Notes 25[m] and 13 – Measurement of post-employment benefits – key actuarial assumptions; and
Notes 25[o] and 20 – Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and tax loss carryforwards can be used.

Significant Accounting Policies

The Corporation's Consolidated Financial Statements have been prepared in accordance with IFRS with respect to the preparation of financial information. The Consolidated Financial Statements are presented in Canadian dollars, which is the Corporation's functional currency. The significant accounting policies of the Corporation are summarized in note 25 to the Consolidated Financial Statements.

Changes in Accounting Standards

Onerous Contracts - Cost of Fulfilling a Contract [Amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets ["IAS 37"]]

In May 2020, the IASB issued amendments to IAS 37 regarding costs that should be included as the cost of fulfilling a contract when assessing whether a contract is onerous. The amendments clarify that the cost of fulfilling the contract comprises all costs that relate directly to the contract. Such costs include both the incremental costs of fulfilling that contract and an allocation of other costs that relate directly to fulfilling contracts. The amendments apply to contracts existing at the date when the amendments are first applied. The amendments are effective for annual reporting periods beginning on or after January 1, 2022, with early adoption permitted. Effective January 1, 2022, the Corporation adopted these amendments, with no impact on the Consolidated Financial Statements.

Future Accounting Pronouncements

The IASB has issued a number of standards and amendments to existing standards that are not yet effective. The Corporation has determined that the following amendments could have an impact on the Corporation's consolidated financial statements when adopted.

Classification of Liabilities as Current or Non-current [Amendments to IAS 1 Presentation of Financial Statements ["IAS 1"]]

In January 2020, the IASB issued amendments to IAS 1 relating to the classification of liabilities as current or non-current. Specifically, the amendments clarify one of the criteria in IAS 1 for classifying a liability as non-current - that is, the requirement for an entity to have the right to defer settlement of the liability for at least 12 months after the reporting period. This right may be subject to compliance with covenants. After reconsidering certain aspects of the 2020 amendments, in October 2022, the IASB issued Non-current Liabilities with Covenants [Amendments to IAS 1], reconfirming that only covenants with which a company must comply on or before the reporting date affect the classification of a liability as current or non-current. The amendments are effective for annual reporting periods beginning on or after January 1, 2024, with early adoption permitted. The amendments are to be applied retrospectively.

Definition of Accounting Estimates [Amendments to IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors ["IAS 8"]]

In February 2021, the IASB issued amendments to IAS 8 to introduce a definition of "accounting estimates" and include other amendments to help entities distinguish changes in accounting estimates from changes in accounting policies. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted. The amendments are to be applied prospectively.

Disclosure of Accounting Policies [Amendments to IAS 1]

In February 2021, the IASB issued amendments to IAS 1 requiring an entity to disclose its material accounting policies, rather than its significant accounting policies. Additional amendments were made to explain how an entity can identify a material accounting policy. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted.

Deferred Tax related to Assets and Liabilities arising from a Single Transaction [Amendments to IAS 12 Income Taxes ["IAS 12"]]

In May 2021, the IASB issued amendments to IAS 12. The amendments clarify how companies should account for deferred tax on certain transactions such as leases and decommissioning obligations. The amendments narrow the scope of the initial recognition exemption, so that it does not apply to transactions that give rise to equal and offsetting temporary differences. As a result, companies will need to recognize both a deferred tax asset and a deferred tax liability when accounting for such transactions. The amendments are effective for annual reporting periods beginning on or after January 1, 2023, with early adoption permitted.

The Corporation anticipates that the adoption of these accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements.

Forward-Looking Information

Certain information included in this MD&A constitutes "forward-looking information" within the meaning of applicable securities legislation. The purpose of the forward-looking information is to provide the Corporation's current expectations regarding future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All information, other than statements of historical fact, which address activities, events or developments that we expect or anticipate may or will occur in the future, are forward-looking information. The words "anticipates", "believes", "can", "committed", "continue", "could", "estimates", "expects", "focus", "forecasts", "future", "further-notice", "impact", "intends", "may", "once", "plans", "propose", "projects", "seek", "should", "trend", "will", "would", "objective", "ongoing", "outlook", or the negative or other variations of these words or other comparable words or phrases, are intended to identify

forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects the Corporation's current beliefs and is based on information currently available to the Corporation.

Specific forward-looking information in the MD&A includes, but is not limited to, the statements regarding the settlement variance and other regulatory balance variances as described in the section entitled "Results of Operations"; the effect of changes in weather conditions and energy consumption on future revenue as described in the section entitled "Summary of Quarterly Results of Operations"; the Corporation's plans to lower overall financing costs and enhance borrowing flexibility as described in the section entitled "Liquidity and Capital Resources"; the effect of overhead and underground infrastructure initiatives on LDC's ability to provide service to its customers, as described in the section entitled "Liquidity and Capital Resources"; the Corporation's available sources of liquidity and capital resources and the sufficiency thereof to satisfy working capital requirements for the next 12 months as described in the section entitled "Liquidity and Capital Resources"; the City's climate-related objectives, including TransformTO, and the Corporation's climate action plan and relevant City strategies and programs, including Toronto Hydro's climate change advisory services business and anticipated costs, as described in the section entitled "Corporate Developments"; risk that the City may require the Corporation to make additional investments in infrastructure to assist in achieving the City's climate-related objectives as described in the section entitled "Governance Risk"; risk that future changes to Ontario's electricity regulatory model, manner of regulation, and/or broader climate change and energy policy framework does not align with Toronto Hydro's business direction and could materially adversely affect Toronto Hydro's strategic goals and financial results as described in the section entitled "Oversight Risk"; the expected results of successful completion and implementation of the project work plan related to the 2025-2029 rates application as described in the section entitled "Oversight Risk"; Toronto Hydro's monitoring of external competitive factors as described in the section entitled "Franchise Risk"; the pervasiveness of competition and the presence of alternatives to Toronto Hydro's distribution services, and the resultant effects on LDC's distribution business as described in the section entitled "Franchise Risk"; Toronto Hydro's focus on increasing the intelligence, automation and interactive nature of its distribution system, and the incorporation of a greater level of technology and information systems into its infrastructure as described in the section entitled "Cyber Security Risk"; Toronto Hydro's hybrid work arrangement as described in the section entitled "Cyber Security Risk"; risk that serious workplace incidents arising from workplace hazards can cause and/or contribute to critical injuries, fatal injuries, and occupational illnesses as described in the section entitled "Safety Risk"; the Corporation's reliance on debt financing through its MTN Program, Commercial Paper Program or existing credit facilities to finance Toronto Hydro's daily operations, repay existing indebtedness, and fund capital expenditures as described in the section entitled "Financial Risk"; the impact on Toronto Hydro's operating results and financial position in the future due to uncertain economic factors, including macroeconomic factors such as a global recession, as described in the section entitled "Financial Risk"; increases in liquidity risk due to reduced or delayed customer payments as a result of economic conditions as described in the section entitled "Financial Risk"; Toronto Hydro's ability to monitor its exposure to credit risk and risk of counterparties defaulting on their obligations as described in the section entitled "Financial Risk"; the continued ability of the Corporation to arrange sufficient and cost-effective debt financing in order to meet its short and long term obligations as described in the section entitled "Financial Risk"; the effect of changes in interest rates and discount rates on future revenue requirements and future post-employment benefit obligations, respectively, as described in the section entitled "Financial Risk"; the effect of inflation on the Corporation's costs for supplies and materials as well as general employee and overhead costs, as described in the section entitled "Financial Risk"; risk that Toronto Hydro is not able to effectively meet the needs of its customers and a growing city, and maintain the security and reliability of the distribution grid at acceptable levels as described in the section entitled "Operations Risk"; future infrastructure investments to increase the capacity and resilience of the grid as described in the section entitled "Operations Risk"; the estimation that over a quarter of Toronto Hydro's electricity distribution assets have already exceeded or will reach the end of their expected operating lives over the next five years [i.e., by 2028] as described in the section entitled "Operations Risk"; risk that Toronto Hydro may not be able to acquire or obtain necessary equipment, materials or service supplies on-time due to global supply chain disruptions as described in the section entitled "Operations Risk"; risk that Toronto Hydro is unable to maintain necessary resource talent and skilled resources as described in the section entitled "Human Capital Risk"; and risk that Toronto Hydro does not meet its material compliance obligations under legal and regulatory instruments as described in the section entitled "Compliance Risk"; constraints on access to human and materials resources due to global supply chain challenges as described in the section entitled "Compliance Risk"; the expectation that none of the legal actions and claims as described further in the section entitled "Legal Proceedings" would have a material adverse effect on the Corporation and the ability to claim under applicable liability insurance policies and/or pay any damages with respect to legal actions and claims as described in the section entitled "Legal Proceedings", and the Corporation's assessment of the impact on adoption of the amendments to IAS 1, IAS 8, IAS 12, and IAS 37, if any, as described in the sections entitled "Changes in Accounting Standards" and "Future Accounting Pronouncements".

The forward-looking information is based on estimates and assumptions made by the Corporation's management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management believes to be reasonable in the circumstances, including, but not limited to, the amount of indebtedness of the Corporation, changes in funding requirements, the future course of the economy and financial markets, no unforeseen delays and costs in the Corporation's capital projects, no unforeseen changes to project plans, no significant changes to the seasonal weather patterns in accordance with historical seasonal trends because of climate change, no unforeseen changes in the legislative and operating framework for electricity distribution in Ontario, the receipt of applicable regulatory approvals and requested rate orders, no unexpected delays in obtaining required approvals, the ability of the Corporation to obtain and retain qualified staff, materials, equipment and services in a timely and cost efficient manner, continued contractor performance, compliance with covenants, the receipt of favourable judgments, no unforeseen changes in electricity distribution rate orders or rate setting methodologies, no unfavourable changes in environmental regulation, the ratings issued by credit rating agencies, the level of interest rates and the Corporation's ability to borrow and assumptions regarding general business and economic conditions.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to, risks associated with the execution of LDC's capital and maintenance programs necessary to maintain the performance of aging distribution assets and make required infrastructure improvements, including to deliver a modernized grid and meet electrification requirements to achieve government net zero GHG emissions targets; risks associated with capital projects; risks associated with electricity industry regulatory developments and other governmental policy changes including factors relating to LDC's distribution activities and to climate change; risks associated with increased competition from regulated and unregulated entities; risks associated with the timing and results of regulatory decisions regarding LDC's revenue requirements, cost recovery and rates; risks associated with information system security and with maintaining complex information technology systems; risks associated with maintaining the security of Toronto Hydro's information assets, including but not limited to the collection, use and disclosure of personal information; risks associated with the failure of critical IT systems; risk of external threats to LDC's facilities and operations posed by unexpected weather conditions caused by climate change and other factors; risks associated with changing weather patterns due to climate change and resultant impacts to electricity consumption based on historic seasonal trends, terrorism and pandemics, including but not limited to COVID-19, and LDC's limited insurance coverage for losses resulting from these events; risks related to COVID-19, including but not limited to restrictive measures affecting the mobility and availability of human and non-human resources, operational disruptions and the availability of financing; risk to Toronto Hydro's employees or the general public of serious/fatal injuries and illnesses relating to or impacting upon Toronto Hydro's activities; risks of municipal government activity, including the risk that the City could introduce rules, policies or directives, including those relating to net zero GHG emissions targets, that can potentially limit Toronto Hydro's ability to meet its business objectives as laid out in the Shareholder Direction principles; risks related to LDC's work force demographic, the available labour markets and the changing expectations of potential employees, and Toronto Hydro's potential inability to attract, train and retain skilled employees; risks of being unable to retain necessary qualified external contracting forces relating to its capital, maintenance and reactive infrastructure program; risks associated with possible labour disputes and LDC's ability to negotiate appropriate collective agreements; related to the approval of the rate application to the OEB for the 2025-2029 rate period; risk that Toronto Hydro may fail to monitor the external environment and or develop and pursue strategies through appropriate business models, thus failing to gain a strategic advantage; risk that Toronto Hydro is not able to arrange sufficient and cost-effective debt financing to repay maturing debt and to fund capital expenditures and other obligations; risk that the Corporation is unable to maintain its financial health and performance at acceptable levels; risk that insufficient debt or equity financing will be available to meet the Corporation's requirements, objectives, or strategic opportunities; risk of downgrades to the Corporation's credit rating; risks related to the timing and extent of changes in prevailing interest rates and discount rates and their effect on future revenue requirements and future post-employment benefit obligations; risks arising from inflation, the course of the economy and other general macroeconomic factors; risk associated with the impairment to the Corporation's image in the community, public confidence or brand; risk associated with the Corporation failing to meet its material compliance obligations under legal and regulatory instruments; risk of substantial and currently undetermined or underestimated environmental costs and liabilities; risk that assumptions that form the basis of LDC's recorded environmental liabilities and related regulatory balances may change; risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders; risk concerning the renewal of the LDC's distribution licence and other factors which are discussed in more detail under the section entitled "Risk Management and Risk Factors" in the 2022 Annual MD&A.

Please review the section "Risk Management and Risk Factors" in the 2022 Annual MD&A in detail. All of the forward-looking information included in this MD&A is qualified by the cautionary statements in this "Forward-Looking Information" section and the "Risk Management and Risk Factors" section in the 2022 Annual MD&A. These factors are not intended to represent a complete list of the factors that could affect the Corporation; however, these factors should be considered carefully and readers should not place undue reliance on forward-looking information made herein. Furthermore, the forward-looking information contained herein is dated as of the date of this MD&A or as of the date specified in this MD&A, as the case may be, and the Corporation has no intention and undertakes no obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

Selected Annual Information

The following table sets forth selected annual financial information for the three years ended December 31, 2022, 2021 and 2020. This information has been derived from the Corporation's consolidated financial statements.

Selected Annual Consolidated Financial Information
[in millions of Canadian dollars]

	2022 **$**	2021 $	2020 $
Year Ended December 31			
Total revenues [1]	**3,601.7**	3,567.1	3,929.6
Net income after net movements in regulatory balances [1]	**163.9**	141.0	117.1
As at December 31			
Total assets and regulatory balances [2]	**6,947.0**	6,413.8	6,069.0
Total debentures [2,3]	**2,729.1**	2,430.7	2,382.2
Other non-current financial liabilities [4]	**21.6**	27.5	22.1
Total equity [2]	**2,062.0**	1,982.7	1,912.0
Dividends [5]	**84.6**	70.3	92.6

[1] See "Results of Operations" for further details on distribution revenue, other revenue, and net income after net movements in regulatory balances.

[2] See "Financial Position" for further details of significant changes in assets, debentures and shareholder's equity.

[3] Total debentures include current and long-term debentures.

[4] Other non-current financial liabilities include primarily non-current obligations under capital lease and non-current customer deposits. Under IFRS, deposits that are due or will be due on demand within one year from the end of the reporting period have been reclassified to other current financial liabilities.

[5] See "Liquidity and Capital Resources" for further details on dividends.

Additional Information

Additional information with respect to the Corporation [including its annual information form] is available on the System for Electronic Document Analysis and Retrieval website at www.sedar.com.

Toronto, Canada

March 1, 2023



ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2022

March 28, 2023

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PART 1 - FORWARD-LOOKING INFORMATION

Certain information included in this AIF constitutes "forward-looking information" within the meaning of applicable securities legislation. The purpose of the forward-looking information is to provide the Corporation's current expectations regarding future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All information, other than statements of historical fact, which address activities, events or developments that we expect or anticipate may or will occur in the future, are forward-looking information. The words "anticipates", "believes", "budgets", "can", "committed", "continual", "could", "estimates", "expects", "focus", "forecasts", "further notice", "future", "impact", "intends", "may", "might", "once", "plans", "propose", "projects", "schedule", "seek", "should", "trend", "will", "would", "objective", "ongoing", "outlook" or the negative or other variations of these words or other comparable words or phrases, are intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects the Corporation's current beliefs and is based on information currently available to the Corporation.

Specific forward-looking information in this AIF includes, but is not limited to, the statements regarding: certain regulated and unregulated entities competing with LDC to provide customers with sources of energy as described in the section entitled "Competitive Conditions"; the validity of the ISO 14001:2015 certificate as described in the section entitled "Environmental Policy and Oversight"; the audit, review and approval of environmental policies, programs and procedures by management as described in the section entitled "Environmental Policy and Oversight"; the gender diverse talent pipeline to fulfill short and long-term workforce staffing and succession management requirements as described in the section entitled "Environmental, Social and Governance"; Toronto Hydro's new metrics aimed at managing climate related risks and opportunities as described in the section entitled "Environmental, Social and Governance"; the terms of existing collective agreements with unionized staff and expected collective bargaining between Toronto Hydro and Society of United Professionals for IT professionals as described in the section entitled "Employees"; continual updates to the infectious disease plan as described in the section entitled "Health and Safety"; the undertaking of surveillance audits to verify the ISO 45001:2018 requirements and the ISO 14001:2015 requirements continue to be met as described in the sections entitled "Health and Safety" and "Environmental Policy and Oversight", respectively; the current coverage, amounts, and terms of the Corporation's insurance policies being consistent with industry practice as described in the section entitled "Insurance"; the effect of changes in energy consumption on future revenue as described in the section entitled "Seasonal Effects"; the hybrid work arrangement as described in the section entitled "COVID-19 Pandemic Considerations"; electricity distribution rates and rate applications as described in the section entitled "Rate Applications"; the termination of the ECA, the continuance of participant agreements that were in effect before April 1, 2019, the extension of the date by which participants are to complete the projects thereunder and LDC's continued responsibility for its obligations under the participant agreements as described in the section entitled "Conservation and Demand Management"; the City's climate-related objectives, including TransformTO, and Toronto Hydro's climate action plan and relevant City strategies and programs as described in the section entitled "Toronto Hydro Climate Action Plan"; the climate advisory service and its ability to facilitate reductions in GHG emissions by reducing stakeholder-identified barriers and the expected annual costs of the climate advisory services business as described in the section entitled "Toronto Hydro Climate Action Plan"; the effects of the Corporation or a subsidiary ceasing to be exempt from tax under the ITA and the TA and the payment of transfer taxes and the prescribed transfer tax rate for any future transfer of interest by the Corporation and its subsidiaries, or any changes to tax rates, as described in the section entitled "Tax Regime"; risk that the City may require the Corporation to make additional investments in infrastructure to assist in achieving the City's climate-related objectives as described in the section entitled "Governance Risk"; risk that future changes to Ontario's electricity regulatory model, manner of regulation, and/or broader climate change and energy policy framework does not align with Toronto Hydro's business direction and could materially adversely affect Toronto Hydro's strategic goals and financial results as described in the section entitled "Oversight Risk"; the expected results of successful completion and implementation of the project work plan related to the 2025-2029 rates application as described in the section entitled "Oversight Risk"; Toronto Hydro's monitoring of external competitive factors as described in the section entitled "Franchise Risk"; the pervasiveness of competition and the presence of alternatives to Toronto Hydro's distribution services, and the resultant effects on LDC's distribution business as described in the section entitled "Franchise Risk"; Toronto Hydro's focus on increasing the intelligence, automation and interactive nature of its distribution system, and the incorporation of a greater level of technology and information systems into its infrastructure as described in the

section entitled “Cyber Security Risk”; Toronto Hydro’s hybrid work arrangement as described in the section entitled “Cyber Security Risk”; risk that serious workplace incidents arising from workplace hazards can cause and/or contribute to critical injuries, fatal injuries, and occupational illnesses as described in the section entitled “Safety Risk”; the Corporation’s reliance on debt financing through its MTN Program, CP Program or existing credit facilities to finance Toronto Hydro’s daily operations, repay existing indebtedness, and fund capital expenditures as described in the section entitled “Financial Risk”; the impact on Toronto Hydro’s operating results and financial position in the future due to uncertain economic factors, including macroeconomic factors such as a global recession, as described in the section entitled “Financial Risk”; increases in liquidity risk due to reduced or delayed customer payments as a result of economic conditions as described in the section entitled “Financial Risk”; Toronto Hydro’s ability to monitor its exposure to credit risk and risk of counterparties defaulting on their obligations as described in the section entitled “Financial Risk”; the continued ability of the Corporation to arrange sufficient and cost-effective debt financing in order to meet its short and long term obligations as described in the section entitled “Financial Risk”; the effect of changes in interest rates and discount rates on future revenue requirements and future post-employment benefit obligations, respectively, as described in the section entitled “Financial Risk”; the effect of inflation on the Corporation’s costs for supplies and materials as well as general employee and overhead costs, as described in the section entitled “Financial Risk”; risk that Toronto Hydro is not able to effectively meet the needs of its customers and a growing city, and maintain the security and reliability of the distribution grid at acceptable levels as described in the section entitled “Operations Risk”; future infrastructure investments to increase the capacity and resilience of the grid as described in the section entitled “Operations Risk”; the estimation that over a quarter of Toronto Hydro’s electricity distribution assets have already exceeded or will reach the end of their expected operating lives over the next five years [i.e., by 2028] as described in the section entitled “Operations Risk”; risk that Toronto Hydro may not be able to acquire or obtain necessary equipment, materials or service supplies on-time due to global supply chain disruptions as described in the section entitled “Operations Risk”; risk that Toronto Hydro is unable to maintain necessary resource talent and skilled resources as described in the section entitled “Human Capital Risk”; risk that Toronto Hydro does not meet its material compliance obligations under legal and regulatory instruments as described in the section entitled “Compliance Risk”; constraints on access to human and materials resources due to global supply chain challenges as described in the section entitled “Compliance Risk”; the specific details and amounts of such compensation that certain Toronto Hydro executives will receive as described in the section entitled “Compensation of NEOs in 2022 – Narrative Discussion”, and the expectation that none of the legal actions and claims as described further in the section entitled “Legal Proceedings” would have a material adverse effect on the Corporation and the ability to claim under applicable liability insurance policies and/or pay any damages with respect to legal actions and claims as described in the section entitled “Legal Proceedings”.

The forward-looking information is based on estimates and assumptions made by the Corporation’s management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management believes to be reasonable in the circumstances, including, but not limited to, the amount of indebtedness of the Corporation, changes in funding requirements, the future course of the economy and financial markets, no unforeseen delays and costs in the Corporation’s capital projects, no unforeseen changes to project plans, no significant changes to the seasonal weather patterns in accordance with historical seasonal trends because of climate change, no unforeseen changes in the legislative and operating framework for electricity distribution in Ontario, the receipt of applicable regulatory approvals and requested rate orders, no unexpected delays in obtaining required approvals, the ability of the Corporation to obtain and retain qualified staff, materials, equipment and services in a timely and cost efficient manner, continued contractor performance, compliance with covenants, the receipt of favourable judgments, no unforeseen changes in electricity distribution rate orders or rate setting methodologies, no unfavourable changes in environmental regulation, the ratings issued by credit rating agencies, the level of interest rates and the Corporation’s ability to borrow and assumptions regarding general business and economic conditions.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to, risks associated with the execution of LDC’s capital and maintenance programs necessary to maintain the performance of aging distribution assets and make required infrastructure improvements, including to deliver a modernized grid and meet electrification requirements to achieve government net zero GHG emissions targets; risks associated with capital

projects; risks associated with electricity industry regulatory developments and other governmental policy changes including factors relating to LDC's distribution activities and to climate change; risks associated with increased competition from regulated and unregulated entities; risks associated with the timing and results of regulatory decisions regarding LDC's revenue requirements, cost recovery and rates; risks associated with information system security and with maintaining complex information technology systems; risks associated with maintaining the security of Toronto Hydro's information assets, including but not limited to the collection, use and disclosure of personal information; risks associated with the failure of critical IT systems; risk of external threats to LDC's facilities and operations posed by unexpected weather conditions caused by climate change and other factors; risks associated with changing weather patterns due to climate change and resultant impacts to electricity consumption based on historic seasonal trends, terrorism and pandemics, including but not limited to COVID-19, and LDC's limited insurance coverage for losses resulting from these events; risks related to COVID-19, including but not limited to restrictive measures affecting the mobility and availability of human and non-human resources, operational disruptions and the availability of financing; risk to Toronto Hydro's employees or the general public of serious/fatal injuries and illnesses relating to or impacting upon Toronto Hydro's activities; risks of municipal government activity, including the risk that the City could introduce rules, policies or directives, including those relating to net zero GHG emissions targets, that can potentially limit Toronto Hydro's ability to meet its business objectives as laid out in the Shareholder Direction principles; risks related to LDC's work force demographic, the available labour markets and the changing expectations of potential employees, and Toronto Hydro's potential inability to attract, train and retain skilled employees; risks of being unable to retain necessary qualified external contracting forces relating to its capital, maintenance and reactive infrastructure program; risks associated with possible labour disputes and LDC's ability to negotiate appropriate collective agreements; risk related to the approval of the rate application to the OEB for the 2025-2029 rate period; risk that Toronto Hydro may fail to monitor the external environment and or develop and pursue strategies through appropriate business models, thus failing to gain a strategic advantage; risk that Toronto Hydro is not able to arrange sufficient and cost-effective debt financing to repay maturing debt and to fund capital expenditures and other obligations; risk that the Corporation is unable to maintain its financial health and performance at acceptable levels; risk that insufficient debt or equity financing will be available to meet the Corporation's requirements, objectives, or strategic opportunities; risk of downgrades to the Corporation's credit rating; risks related to the timing and extent of changes in prevailing interest rates and discount rates and their effect on future revenue requirements and future post-employment benefit obligations; risks arising from inflation, the course of the economy and other general macroeconomic factors; risk associated with the impairment to the Corporation's image in the community, public confidence or brand; risk associated with the Corporation failing to meet its material compliance obligations under legal and regulatory instruments; risk of substantial and currently undetermined or underestimated environmental costs and liabilities; risk that assumptions that form the basis of LDC's recorded environmental liabilities and related regulatory balances may change; risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders; risk concerning the renewal of the LDC's distribution licence, and other factors which are discussed in more detail under Part 8 "Risk Factors" in this AIF.

All of the forward-looking information included in this AIF is qualified by the cautionary statements in this "Forward-Looking Information" section and the "Risk Factors" section of this AIF. These factors are not intended to represent a complete list of the factors that could affect the Corporation; however, these factors should be considered carefully and readers should not place undue reliance on forward-looking information made herein. Furthermore, the forward-looking information contained herein is dated as of the date of this AIF or as of the date specified in this AIF, as the case may be, and the Corporation has no intention and undertakes no obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

PART 2 - GLOSSARY OF DEFINED TERMS

In addition to terms defined elsewhere in this AIF, the below defined terms shall have the following meanings:

"2020-2024 CIR Decision and Rate Order" has the meaning set forth under section 5.3 entitled "Rate Applications".

"Affiliate Relationships Code" refers to the Affiliate Relationships Code for Electricity Distributors and Transmitters that was published by the OEB and became effective on April 1, 1999, as amended.

"AIF" refers to the Corporation's Annual Information Form for the year ended December 31, 2022.

"Board" refers to the board of directors of the Corporation.

"BOMA BEST" refers to the Canadian environmental assessment and certification program launched by BOMA Canada in 2005.

"BOMA Canada" refers to the Building Owners and Managers Association of Canada.

"Building Emissions Reduction" refers to a measure of the reduction of GHG emissions from Toronto Hydro occupied work centres [measured in tonnes of carbon dioxide equivalent].

"CAIDI" refers to the Customer Average Interruption Duration Index and is a measure [in hours] of the average duration of interruptions experienced by customers, not including MED. CAIDI represents the quotient obtained by dividing SAIDI by SAIFI.

"Canadian Environmental Protection Act" refers to the *Canadian Environmental Protection Act, 1999* [Canada], as amended.

"Capital Assets" refers to the sum of property, plant and equipment and intangible assets, net of accumulated depreciation and amortization. See note 6 and note 7 to the Consolidated Financial Statements.

"CDM" refers to conservation and demand management.

"CDS" refers to CDS Clearing and Depository Services Inc.

"CEO" refers to the President and Chief Executive Officer of the Corporation.

"CFO" refers to the Executive Vice-President and Chief Financial Officer.

"CIR" refers to Custom Incentive Rate-setting.

"City" refers to the *city incorporated under the City of Toronto Act, 1997* [Ontario], as amended.

"City Council" refers to Toronto City Council.

"City Councillor" refers to a councillor of Toronto City Council.

"**Climate Advisory Services**" refer to a new, unregulated business of the Corporation to support the realization of the City's net zero strategy by facilitating and stimulating the growth of emerging local cleantech markets.

"Consolidated Financial Statements" refers to the audited consolidated financial statements of the Corporation together with the auditors' report thereon and the notes thereto as at and for the years ended December 31, 2022 and December 31, 2021, a copy of which is available on the SEDAR website at www.sedar.com.

"Consumer Price Index" refers to the index measuring price movements published by Statistics Canada.

"Copeland Station" refers to the Clare R. Copeland transformer station, formerly called "Bremner Station".

"Corporation" refers to Toronto Hydro Corporation.

"COVID-19" refers to Coronavirus Disease 2019 and its variants.

"CPAB" refers to Canadian Public Accountability Board.

"CP Program" refers to the commercial paper program established by the Corporation under which the Corporation issues commercial paper. See section 9.3 entitled "Credit Facilities".

"DBRS" refers to DBRS Limited.

"Debentures" has the meaning set forth under section 9.2 entitled "Debentures".

"Distribution System Code" refers to the Distribution System Code that was published by the OEB on July 14, 2000, as amended.

"EBITDA" refers to earnings before interest, taxes, depreciation and amortization.

"EC" refers to Electricity Canada (formerly the Canadian Electricity Association).

"ECA" refers to the Energy Conservation Agreement between Toronto Hydro and IESO, dated July 1, 2017.

"EHSMS" refers to the Environment, Health and Safety Management System.

"Electricity Act" refers to the *Electricity Act, 1998* [Ontario], as amended.

"Electricity Property" refers to a municipal corporation's or an MEU's interest in real or personal property used in connection with generating, transmitting, distributing or retailing electricity.

"Energy Competition Act" refers to the *Energy Competition Act, 1998* [Ontario], as amended.

"Energy Consumer Protection Act" refers to the *Energy Consumer Protection Act, 2010* [Ontario], as amended.

"Environmental Policy" refers to the policy applicable to all Toronto Hydro employees and contractors performing work on behalf of Toronto Hydro covering, amongst other things, core environmental principles by which Toronto Hydro is committed to conducting its business, as approved by the Board most recently at August 24, 2022 meeting.

"Environmental Protection Act" refers to the *Environmental Protection Act, 1990* [Ontario], as amended.

"ERM" refers to Enterprise Risk Management.

"ESG" refers to environmental, social, and governance criteria that are factored into LDC's investment processes and decision-making.

"Fire Protection and Prevention Act" refers to the *Fire Protection and Prevention Act, 1997* [Ontario], as amended.

"Fleet Electrification" refers to the percentage of Toronto Hydro's fleet that is an electric vehicle, plug-in hybrid electric vehicle, or hybrid vehicle.

"GAAP" refers to Generally Accepted Accounting Principles.

"GHG" refers to Greenhouse Gas.

"GRI" refers to Global Reporting Initiative.

"Hydro One" refers to Hydro One Limited, Hydro One Inc. or Hydro One Networks Inc. and their respective subsidiaries, as appropriate.

"ICD.D" refers to the designation granted by the Institute of Corporate Directors, through the Directors Education Program jointly developed by the Institute of Corporate Directors and the University of Toronto's Rotman School of Management.

"ICM" refers to Incremental Capital Module. See section 4.3(e)(i) entitled "Rate Setting Mechanism" for more information.

"Idling Time" refers to the number of hours Toronto Hydro vehicles spend idling without a power take-off engaged.

"IEEE" refers to the Institute of Electrical and Electronic Engineers.

"IESO" refers to the Independent Electricity System Operator. Through amendments to the Electricity Act, the operations of the IESO and the OPA were merged under the name Independent Electricity System Operator on January 1, 2015, bringing together real-time operations of the grid with long-term planning, procurement and conservation efforts.

"IRM" refers to Incentive Regulation Mechanism. See section 4.3(e)(i) entitled "Rate Setting Mechanism" for more information.

"ISO" refers to the International Organization for Standardization.

"ISO 14001:2015" refers to ISO 14001:2015 Environmental Management Systems.

"ISO 26000" refers to ISO 26000 Social Responsibility.

"ISO 45001:2018" refers to ISO 45001:2018 Occupational Health and Safety Management Systems.

"ISO 55001" refers to ISO 55001:2014 Asset Management Systems.

"IT" refers to Information Technology.

"ITA" refers to the *Income Tax Act, 1985* [Canada], as amended.

"J.D." refers to the Juris Doctor degree.

"KPI" refers to Key Performance Indicator.

"kW" refers to a kilowatt, a common measure of electrical power equal to 1,000 Watts.

"kWh" refers to a kilowatt-hour, a standard unit for measuring electrical energy produced or consumed over time. One kWh is the amount of electricity consumed by ten 100-Watt light bulbs burning for one hour.

"LDC" refers to the Corporation's wholly-owned subsidiary, Toronto Hydro-Electric System Limited.

"LED" refers to a light-emitting diode.

"LL.B." refers to the Bachelor of Laws degree.

"LL.M." refers to the Master of Laws degree.

"Management's Discussion and Analysis" or **"MD&A"** refers to Management's Discussion and Analysis of Financial Condition and Results of Operations of the Corporation for the year ended December 31, 2022, a copy of which is available on the SEDAR website at www.sedar.com.

"MED" refers to Major Event Days as defined by IEEE Std 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices.

"MEU" refers to a Municipal Electricity Utility in the Province of Ontario.

"Moody's" refers to Moody's Canada Inc.

"MTN Program" refers to the medium term note program established by the Corporation under which the Corporation issues debentures. See section 9.2 entitled "Debentures" for the debentures currently outstanding.

"Named Executive Officer" or **"NEO"** means, collectively, the Corporation's CEO, the CFO, and/or a person serving in either of those capacities during the year and the three most highly compensated executive officers of Toronto Hydro who were serving as executive officers as at December 31, 2022, and each individual who would be amongst the three most highly compensated executive officers for Toronto Hydro, but for the fact that such individual was not an executive officer on December 31, 2022, if any.

"Oakville Hydro" refers to Oakville Hydro Electricity Distribution Inc.

"OBCA" refers to the *Business Corporations Act, 1990* [Ontario], as amended.

"Occupational Health and Safety Policy" refers to the policy applicable to all Toronto Hydro employees and contractors performing work on behalf of Toronto Hydro covering, amongst other things, a commitment to providing safe and healthy working conditions, as approved by the Board most recently at its August 24, 2022 meeting.

"OEB" refers to the Ontario Energy Board.

"OEB Act" refers to the *Ontario Energy Board Act, 1998* [Ontario], as amended.

"**OEFC"** refers to the Ontario Electricity Financial Corporation.

"OHSAS" refers to the Occupational Health and Safety Assessment Series.

"**OHSAS 18001"** refers to BS OHSAS 18001:2007, British Standard Occupational Health and Safety Assessment Series.

"OMERS" refers to the Ontario Municipal Employees Retirement System, a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario.

"OPA" refers to the Ontario Power Authority. Through amendments to the Electricity Act, the operations of the IESO and the OPA were merged under the name Independent Electricity System Operator on January 1, 2015, bringing together real-time operations of the grid with long-term planning, procurement and conservation efforts.

"Open Access" refers to the opening of the Province's wholesale and retail electricity markets to competition pursuant to the requirement under the Electricity Act that transmitters and distributors of electricity in the Province provide generators, retailers and consumers with non-discriminatory access to their transmission and electricity distribution systems. Open Access commenced on May 1, 2002.

"OPG" refers to Ontario Power Generation Inc.

"OREC Act" refers to *Ontario Rebate for Electricity Consumers Act, 2016* [Ontario].

"OSC" refers to the Ontario Securities Commission.

"PCBs" refers to polychlorinated biphenyls, a synthetic chemical compound consisting of chlorine, carbon and hydrogen. PCBs are used primarily as insulating and cooling elements in electrical equipment. Secondary uses include hydraulic and heat transfer fluids, flame proofing adhesives, paints, sealants and cable insulating paper.

"PILs" refers to the Payments In Lieu of Corporate Taxes regime contained in the Electricity Act pursuant to which MEUs that are exempt from tax under the ITA and the TA are required to make, for each taxation year, payments in lieu of corporate taxes to the OEFC. See note 25[o] and note 20 to the Consolidated Financial Statements.

"PP&E" refers to property, plant and equipment.

"Province" refers to the Province of Ontario.

"Prudential Facility" refers to a $100.0 million demand facility that the Corporation entered into with a Canadian chartered bank for the purpose of issuing letters of credit mainly to support LDC's prudential requirements with the IESO. See section 9.3 entitled "Credit Facilities".

"PWU" refers to the Power Workers' Union.

"Recycling Rate" refers to the percentage amount of solid, non-hazardous waste diverted from the landfill through recycling at work centres and stations.

"Retail Settlement Code" refers to the Retail Settlement Code that was published by the OEB on December 13, 2000 and became effective on the commencement of Open Access [except with respect to "Service Agreements", as that term is defined in the Retail Settlement Code, which came into effect on March 1, 2001], as amended.

"Revolving Credit Facility" refers to the Corporation's credit agreement with a syndicate of Canadian chartered banks which established a revolving credit facility. See section 9.3 entitled "Credit Facilities".

"S&P" refers to Standard & Poor's Financial Services LLC, a subsidiary of S&P Global Inc.

"SAIDI" means System Average Interruption Duration Index and is a measure [in hours] of the annual system average interruption duration for customers served, not including MED. SAIDI represents the quotient obtained by dividing the total customer hours of interruptions longer than one minute by the number of customers served.

"SAIFI" means System Average Interruption Frequency Index and is a measure of the frequency of service interruptions for customers served, not including MED. SAIFI represents the quotient obtained by dividing the total number of customer interruptions longer than one minute by the number of customers served.

"SEDAR" refers to the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval. SEDAR's website is www.sedar.com.

"Shareholder Direction" refers to the Shareholder Direction adopted by the Council of the City with respect to the Corporation, as amended and/or restated from time to time, pursuant to which the City has set out certain corporate governance principles with respect to the Corporation.

"Smart Meter" refers to a metering device capable of recording and transmitting hourly consumption information of a residential or general service customer.

"Standard Supply Customers" refers to persons connected to an electricity distributor's distribution system who are not served by retailers or whose retailer is unable to sell them electricity or who request the distributor to sell electricity to them.

"Standard Supply Service" refers to an electricity distributor's obligation to sell electricity to Standard Supply Customers, or to give effect to such rates as determined by the OEB under section 79.16 of the OEB Act.

"Standard Supply Service Code" refers to the Standard Supply Service Code for Electricity Distributors that was published by the OEB on December 8, 1999 and became effective on the commencement of Open Access, as amended.

"Stewardship Ontario" refers to a not-for-profit organization which operates the Blue Box and Orange Drop Programs under the authority of the *Waste-Free Ontario Act, 2016* [Ontario].

"TA" refers to the *Taxation Act, 2007* [Ontario], as amended.

"Technical Standards and Safety Act" refers to the *Technical Standards and Safety Act, 2000* [Ontario], as amended.

"TH Energy" refers to the Corporation's wholly-owned subsidiary, Toronto Hydro Energy Services Inc.

"Toronto Hydro" refers to Toronto Hydro Corporation and its subsidiaries.

"Total Recordable Injury Frequency" refers to the number of recordable injuries multiplied by 200,000 divided by exposure hours, as per EC standards.

"TOU" refers to Time-Of-Use.

"Transfer By-law" refers to By-law No. 374-1999 of the City made under section 145 of the Electricity Act pursuant to which the Toronto Hydro-Electric Commission and the City transferred their assets and liabilities and employees in respect of the electricity distribution system to LDC and in respect of electricity generation, co-generation and energy services to TH Energy. The Transfer By-law permits the Treasurer of the City to adjust the fair market value of the assets and the consideration paid in respect of the electricity distribution assets transferred to LDC as a consequence of OEB rate orders and permitted rates of return for 2000 or any subsequent year.

"TransformTO" refers to the City's TransformTO Net Zero Strategy, which outlines a pathway to achieve net zero emissions in Toronto by 2040.

"Transportation of Dangerous Goods Act" refers to the *Transportation of Dangerous Goods Act, 1992* [Canada], as amended.

"Unit Smart Meter" refers to a unit Smart Meter installed by LDC in a unit of a multi-unit complex where the multi-unit complex is not connected solely to a bulk meter, and includes such other meters as may be prescribed by the Energy Consumer Protection Act.

"Watt" or **"W"** refers to a common measure of electrical power. One Watt equals the power used when one ampere of current flows through an electrical circuit with a potential of one volt.

"Working Capital Facility" refers to a $20.0 million demand facility the Corporation entered into with a Canadian chartered bank for the purpose of working capital management. See section 9.3 entitled "Credit Facilities".

Unless otherwise specified, all references to statutes are to statutes of the Province and all references to dollars are to Canadian dollars.

PART 3 - CORPORATE STRUCTURE

3.1 Name, Address, Incorporation

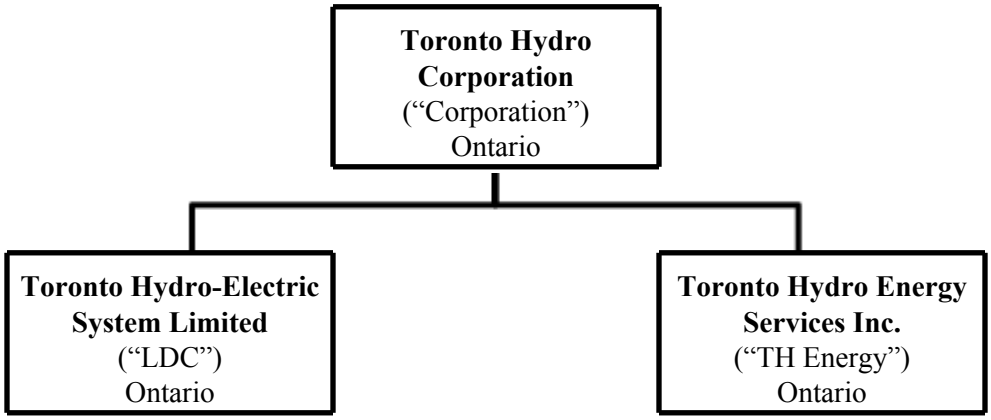
On January 1, 1998, the former municipalities of Metropolitan Toronto, Toronto, East York, Etobicoke, North York, Scarborough and York amalgamated to form the City. At the same time, the electric commissions of Toronto, East York, Etobicoke, North York, Scarborough and York were combined to form the Toronto Hydro-Electric Commission. Toronto Hydro is the successor to the Toronto Hydro-Electric Commission.

The Corporation, LDC and TH Energy were incorporated under the OBCA on June 23, 1999. Pursuant to the Transfer By-law, the Toronto Hydro-Electric Commission and the City transferred their assets and liabilities in respect of the electricity distribution system to LDC and electricity generation, co-generation and energy services to TH Energy.

The registered and head office of the Corporation is located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

3.2 Inter-corporate Relationships

The sole shareholder of the Corporation is the City. The Corporation, in turn, owns 100% of the shares of the subsidiaries listed below:



PART 4 - BUSINESS OF TORONTO HYDRO

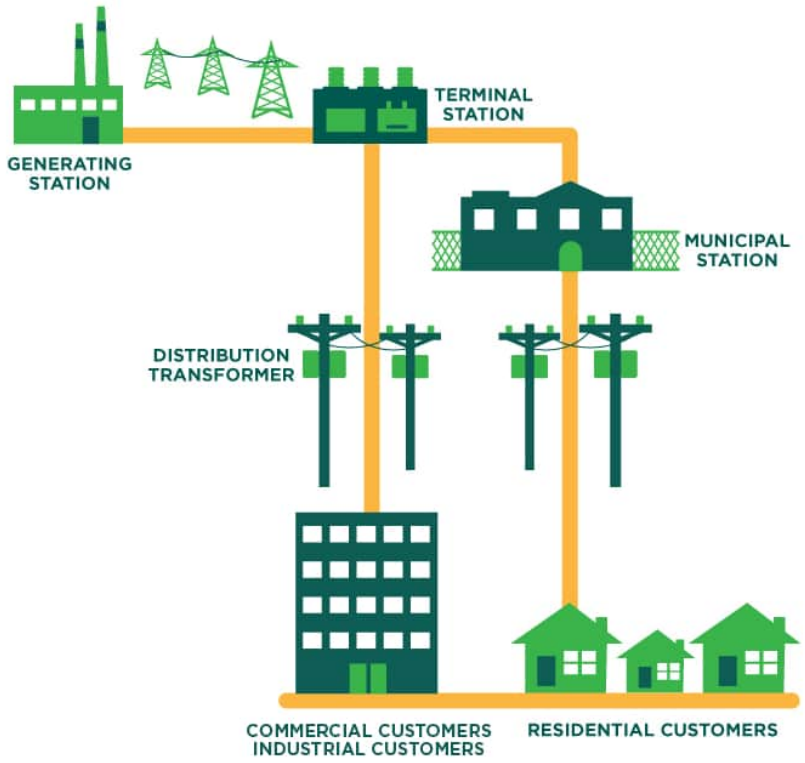
4.1 Industry Structure

The electricity industry in the Province is generally comprised of three principal segments:

- Generation - the production of electricity at generating stations using nuclear, natural gas, hydro, solar, wind, biofuel or other sources of energy;
- Transmission - the transfer of electricity from generating stations to local areas using large, high-voltage power lines; and
- Distribution - the delivery of electricity to homes and businesses within local areas using relatively low-voltage power lines.

Electricity produced at generating stations is boosted to high voltages by nearby transformers so that the electricity can be transmitted long distances over transmission lines with limited power loss. The voltage is then reduced [stepped down] at terminal stations for supply to electricity distributors or large customers. Electricity distributors carry the electricity to distribution transformers that further reduce the voltage for supply to local customers. Electricity is distributed in the Province through a network of local electricity distributors that includes municipal electricity distributors, privately owned electricity distributors and Hydro One. This traditional structure is evolving and has the potential to become more decentralized as local customers invest in distributed energy resources such as behind-the-meter generation facilities and energy storage systems. Distributed energy resources connected directly to local electricity distribution grids can serve various functions ranging from selling power to the bulk or local electricity grid to providing reliability services and voltage control.

The following diagram illustrates the basic structure of an electricity infrastructure system:



4.2 Toronto Hydro Corporation

Toronto Hydro Corporation is a holding company which wholly owns two subsidiaries:

- LDC – distributes electricity; and
- TH Energy – provides street lighting and expressway lighting services in the city of Toronto.

The Corporation supervises the operations of, and provides corporate, management services and strategic direction to its subsidiaries.

4.3 Toronto Hydro-Electric System Limited ["LDC"]

The principal business of Toronto Hydro is the distribution of electricity by LDC. LDC owns and operates $6.1 billion of Capital Assets comprised primarily of an electricity distribution system that delivers electricity to approximately 790,000 customers located in the city of Toronto. LDC serves the largest city in Canada and distributes approximately 18% of the electricity consumed in the Province.

(a) LDC's Electricity Distribution System

Electricity produced at generating stations is transmitted through transmission lines owned by Hydro One to terminal stations, at which point the voltage is then reduced [or stepped down] to distribution-level voltages. Distribution-level voltages are then distributed across LDC's electricity distribution system to distribution class transformers, at which point the voltage is further reduced [or stepped down] for supply to end use customers. Electricity typically passes through a meter before reaching a distribution board or service panel that directs the electricity to end use customers [and their circuits].

LDC's electricity distribution system is serviced from one control centre and 37 terminal stations, and is comprised of approximately 17,060 primary switches, approximately 61,300 distribution transformers, 139 in-service municipal substations, approximately 15,393 circuit kilometres of overhead wires supported by approximately 183,620 poles, and approximately 13,765 circuit kilometres of underground wires.

(i) *Control Centre*

LDC has one control centre. The control centre co-ordinates and monitors the distribution of electricity throughout LDC's electricity distribution assets, and provides isolation and work protection for LDC's construction and maintenance crews and external customers. LDC's control centre utilizes supervisory control and data acquisition [SCADA] systems to monitor, operate, sectionalize and restore the electricity distribution system.

(ii) *Terminal Stations*

LDC receives electricity at its terminal stations which contain power transformers, high-voltage switching equipment, and lower-voltage equipment such as circuit breakers, switches and station busses.

One of LDC's largest capital initiatives, the construction of which was completed in 2019, is Copeland Station, which was constructed in response to the developing need for distribution solutions in the downtown core of the city of Toronto. Copeland Station is the first transformer station built in downtown Toronto since the 1960's and is the second underground transformer station in Canada. It provides electricity to buildings and neighbourhoods in the central-southwest area of downtown Toronto.

(iii) *Distribution Transformers and Municipal Substations*

Electricity at distribution voltages is distributed from the terminal stations to distribution transformers that are typically located in buildings or vaults or mounted on poles or surface pads that are used to reduce or step down

voltages to utilization levels for supply to customers. The electricity distribution system also includes in-service municipal substations that are located in various parts of the city of Toronto and are used to reduce or step down electricity voltage prior to delivery to distribution transformers. LDC also delivers electricity at distribution voltages directly to certain commercial and industrial customers that own their own substations.

(iv) *Wires*

LDC distributes electricity through a network of electrical circuits made up of a combination of overhead and underground wires.

(v) *Metering*

LDC provides its customers with meters through which electricity passes before reaching a distribution board or service panel that directs the electricity to end use circuits on the customer's premises. The meters are used to measure electricity consumption and/or demand. LDC owns the meters and is responsible for their maintenance and accuracy.

As part of its metering services, LDC also installs Unit Smart Meters in multi-unit complexes that fall within the OEB's Competitive Sector Multi-Unit Residential rate class. As at December 31, 2022, LDC had installed approximately 92,000 Unit Smart Meters in these types of multi-unit complexes.

(vi) *Reliability of Distribution System*

The table below sets forth certain industry recognized measurements of system reliability with respect to LDC's electricity distribution system and the composite measures reported by LDC and EC for the 12-month periods ending December 31 in the years indicated below.

	LDC 2022	**LDC 2021**	**EC 2021 (1)**
SAIDI	0.97	0.99	4.50
SAIFI	1.63	1.55	2.28
CAIDI	0.59	0.64	1.97

Note:

(1) Data was extracted from the EC's 2021 Service Continuity Report on Distribution System Performance in Electrical Utilities, for all Canadian utilities, excluding significant events. At the date of this AIF, such report for the year 2022 has not been published by EC.

(b) LDC's Service Area and Customers

LDC is the sole provider of electricity distribution services in the city of Toronto, and serves approximately 790,000 customers. The City is the largest city in Canada with a population of approximately 3.0 million. The City is a financial centre with large and diversified service and industrial sectors.

The table below sets out LDC's customer classes and certain operating data with respect to each class for each of the years in the two-year period ended December 31, 2022:

	Year ended December 31	
	2022	**2021**
Residential Service [1]		
Number of customers	707,178	703,947
kWh	5,394,320,650	5,427,336,381
Revenue	$1,007,806,243	$1,000,471,911
% of total service revenue	28.9%	28.9%
General Service [2]		
Number of customers	82,820	82,711
kWh	16,853,764,874	16,265,446,850
Revenue	$2,309,827,994	$2,270,659,641
% of total service revenue	66.1%	65.6%
Large Users [3]		
Number of customers	42	46
kWh	1,722,691,956	1,680,085,796
Revenue	$174,411,972	$190,381,458
% of total service revenue	5.0%	5.5%
Total		
Number of customers	790,040	786,704
kWh	23,970,777,480	23,372,869,027
Revenue	$3,492,046,209	$3,461,513,010

Notes:

(1) "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multi-family units and seasonal occupancy.

(2) "General Service" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a 12-month period.

(3) "Large Users" means a service provided to a customer with a monthly peak demand of 5,000 kW or greater averaged over a 12-month period.

(c) LDC's Real Property

The following table sets forth summary information with respect to the principal real property owned, leased or otherwise used by LDC as at December 31, 2022:

Property	Total
Terminal stations	37 sites
Municipal substations	139 sites
Decommissioned municipal substations	33 sites
Control centre [(1)]	1 site
Operation centres [(2)]	4 sites
Other [(3)]	36 sites

Notes:

(1) LDC's control centre is located within one of its operation centres.

(2) LDC's operation centres accommodate office, staff, crews, vehicles, equipment and material necessary to operate and monitor the electricity distribution system.

(3) Other properties include locations under construction, small work centres and surplus properties.

Under the OEB Act, electricity distributors may apply to the OEB for authority to expropriate land required in connection with new or expanded electricity distribution lines or interconnections. If, after a hearing, the OEB is of the opinion that the expropriation of land is in the public interest, the OEB may make an order authorizing expropriation upon payment of specified compensation. The Electricity Act grandfathered thousands of existing unregistered easements, principally for distribution over third-party lands. The Electricity Act also authorizes electricity distributors to locate assets on, over or under public streets and highways.

(d) Regulation of LDC

(i) *Legislative Framework*

The Electricity Act and the OEB Act provide the broad legislative framework for the Province's electricity market.

The Electricity Act requires electricity distributors to provide generators, retailers, market participants, and consumers with non-discriminatory access to distribution systems in Ontario in accordance with distribution licences. Furthermore, an electricity distributor is required to connect to its distribution system any building that lies along its distribution lines upon request. The Electricity Act also requires an electricity distributor to sell electricity to every person connected to its distribution system, effectively acting as the electricity supplier of last resort, except where the person connected opts out of such supply by the distributor.

Additionally, the Electricity Act requires electricity distributors in the Province to keep their distribution businesses separate from their other businesses.

The business of LDC and other electricity distributors is regulated by the OEB, which has broad powers relating to licensing, standards of conduct and service, the regulation of electricity distribution rates charged by LDC and other electricity distributors, and transmission rates charged by Hydro One and other transmitters. The OEB Act states that, subject to certain exceptions, LDC and other electricity distributors shall not carry on any business activity other than the distribution of electricity, except through affiliated companies. As exceptions to the general restriction on its business activities, the OEB Act permits LDC to own and operate alternative, cleaner and renewable sources of energy and energy storage and provide additional services related to the promotion of CDM activities. See section 5.4 entitled "Conservation and Demand Management" for more information on LDC's CDM

activities. As well, the OEB may in particular cases and circumstances authorize LDC to carry on a non-distribution business activity.

The Energy Consumer Protection Act, which came into force in 2011, enables and sets out the requirements relating to LDC's installation of Unit Smart Meters in multi-unit complexes and provides the rules regarding the manner in which Unit Smart Metered consumers are to be billed for their electricity consumption.

Since 2017, LDC has been providing financial assistance to eligible electricity consumers in accordance with the OREC Act. Pursuant to the applicable legislative requirements, LDC applies a credit [rebate] to the bills of eligible consumers and is reimbursed by the IESO for monthly total assistance amounts provided.

(ii) *Licences*

Distribution Licence

The OEB has granted LDC a distribution licence. The term of the current licence is until October 16, 2023. LDC expects to apply for the renewal of its distribution licence by the second quarter of 2023 to retain the licence and continue operations in the normal course of business. The licence allows LDC to own and operate an electricity distribution system in the city of Toronto. Amongst other things, the licence provides that LDC must allow non-discriminatory access to its distribution system by a consumer, generator or retailer upon request and sell electricity in accordance with the Electricity Act, must keep financial records associated with distributing electricity separate from its financial records associated with other activities, may not impose charges for the distribution of electricity except in accordance with distribution rate orders approved by the OEB, and must comply with industry codes established by the OEB.

Electricity Generation Licence

On December 18, 2002, the OEB issued an electricity generation licence to TH Energy and TREC Windpower Co-operative [No.1] Incorporated [the "Co-Venturers"], in connection with a wind turbine located at Exhibition Place in the city of Toronto. The licence allows the Co-Venturers to generate electricity or provide ancillary services for sale through the IESO-administered markets, or directly to another person, subject to certain terms and conditions. On August 19, 2022, TH Energy applied to the OEB to have its interest in the generation licence transferred to a new entity in accordance with the sale of TH Energy's interest in the wind turbine to Rankin Integrated Energy Inc., which assumed TH Energy's role as one of the Co-Venturers of TREC Windpower Co-operative [No.1] Incorporated [see Section 4.4 entitled "Toronto Hydro Energy Services Inc."]. On October 6, 2022, the OEB authorized the transfer of the generation licence, which took effect as of October 27, 2022.

(iii) *Industry Codes*

The OEB has established the Affiliate Relationships Code, the Distribution System Code, the Retail Settlement Code, and the Standard Supply Service Code. These codes prescribe minimum standards of conduct, as well as standards of service, for electricity distributors in the non-competitive electricity market, and have been assigned the following ranking in the event there is a conflict between them:

(1) Affiliate Relationships Code
(2) Distribution System Code
(3) Retail Settlement Code
(4) Standard Supply Service Code

These codes are summarized below.

Affiliate Relationships Code

The Affiliate Relationships Code establishes standards and conditions for the interaction between electricity distributors and their affiliated companies. It is intended to minimize the potential for an electricity distributor to cross-subsidize competitive or non-monopoly activities, protect the confidentiality of consumer information collected by an electricity distributor and ensure that there is no preferential access to regulated services. The Affiliate Relationships Code prescribes standards of conduct for an electricity distributor with respect to the following: the degree of separation from affiliates; sharing of services and resources; transfer pricing; financial transactions with affiliates; equal access to services; and confidentiality of customer information.

Distribution System Code

The Distribution System Code establishes the minimum conditions that an electricity distributor must meet in carrying out its obligations to distribute electricity under its licence and under the Energy Competition Act [which enacted the Electricity Act and the OEB Act], and has been amended as the regulatory environment has evolved. Generally, the Distribution System Code prescribes the rights and responsibilities of electricity distributors and electricity distribution customers with respect to the following: connections; connection agreements and conditions of service; expansion projects; alternative bids [available to customers for work otherwise done by an electricity distributor]; metering; billing; distribution operations; disconnections and reconnections; customer service standards; security deposits; certain financial assistance programs; and regional planning.

Retail Settlement Code

The Retail Settlement Code outlines the minimum obligations of an electricity distributor with respect to its relationship with retail market participants such as retailers and consumers and the administration of service transaction requests where a competitive retailer provides service to a consumer, in accordance with the Electricity Act and the distribution licence. Under the terms of the Retail Settlement Code, an electricity distributor is required to do the following: unbundle the costs of competitive electricity services and non-competitive electricity services; record, in variance accounts, the difference between amounts billed by the IESO to the electricity distributor for competitive and non-competitive electricity services, and the aggregate amounts billed by the electricity distributor to consumers, retailers and others for the same services; provide electricity billing and settlement services to retailers and customers; process service transaction requests; and provide access to consumer information to retailers and consumers as prescribed.

Standard Supply Service Code

The Standard Supply Service Code requires an electricity distributor to act as a default supplier and provide Standard Supply Service to persons connected to the electricity distributor's distribution system in accordance with the Electricity Act. The Standard Supply Service Code also specifies the conditions and manner by which OEB approved Standard Supply Service rates are to be charged and billed to customers. Under the Standard Supply Service Code, an electricity distributor's rates for Standard Supply Service must be approved by the OEB and must consist of the price of electricity and an administrative charge that will allow the electricity distributor to cover its costs of providing the service.

(e) Distribution Rates

(i) *Rate Setting Mechanism*

The OEB's regulatory framework for electricity distributors is designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB typically regulates the electricity rates for distributors using a combination of detailed cost of service reviews and custom index adjustments similar to IRM. A cost of service review uses a future test-year to establish rates, and provides for revenues required to recover the forecasted costs of providing the regulated service, and a fair and reasonable return on rate base [i.e., the aggregate of approved investment in PP&E and intangible assets excluding work in progress, less accumulated depreciation and amortization and unamortized capital contributions from customers, plus an allowance for working capital]. Custom index adjustments are typically used for one or more years following a cost of service review and provide for adjustments to rates based on an inflationary factor net of a productivity factor and an efficiency factor as determined relative to other electricity distributors.

Administratively, the OEB currently regulates the electricity rates for distributors through one of three specific rate-setting methods: Price Cap Incentive Rate-setting [typically applicable to most distributors], CIR [typically applicable to distributors with large or highly variable capital requirements], and the Annual Incentive Rate-setting Index [typically applicable to distributors requiring limited rate adjustments]. Under each of these methods, the OEB also allows recovery of costs arising from significant events satisfying certain criteria which are considered external to the regulatory regime and beyond the control of management.

Under the Price Cap Incentive Rate-setting method, rates are set on a single forward test-year cost of service basis for the first year and indexed for four subsequent years through an industry-standard IRM adjustment. Under this method, the ICM is available to apply for incremental funding to address any additional capital investment needs that may arise during the term.

Under the CIR method, rates are set for a minimum period of five years, typically on a forward test-year cost of service basis for the first year with subsequent annual adjustments based on a distributor-specific custom index. The particular mechanics through which rates are set and adjusted are proposed by utilities and determined by the OEB on a case-by-case basis.

The Annual Incentive Rate-setting Index method sets a distributor's rates through an industry-standard IRM adjustment [using a limited form of the industry standard IRM formula] for one or more years.

Under each method, actual operating conditions may vary from forecasts such that actual achieved returns can differ from approved returns. Approved electricity rates are generally not adjusted as a result of actual costs or revenues being different from forecasted amounts, other than for certain prescribed costs that are eligible for deferral for future collection from, or refund to, customers.

See section 5.3 entitled "Rate Applications" for more information on LDC's rate applications.

(f) Competitive Conditions

The OEB distribution licence issued to LDC stipulates a service area that reflects the territory within the city of Toronto. By law, only the OEB can grant such a licence for a service area and only an entity with such a licence can provide licenced services to the public-at-large within a service area. The OEB has not granted any other distribution licence that permits distribution within LDC's service area. In addition to this regulatory barrier to entry, there are other barriers to entry, including the cost of constructing an electricity distribution system, physical space limitations within and legal access to the right-of-way, the specialized skills associated with the distribution business, the level of expertise required to achieve operational and regulatory compliance, and LDC's relationships with its customers. Notwithstanding the existing barriers to entry, other regulated and unregulated entities have competed with LDC and its predecessors to provide customers with other sources of energy, including electricity. The pervasiveness of this competition and its particular effects on LDC's distribution business have varied over time and are expected to continue to vary based on many factors, including the relative price of energy sources [e.g., natural gas, grid-supplied electricity, behind-the-meter generation], government-based policy and incentives [e.g., green energy generation], and technology advancements [e.g., micro-grids, behind-the-meter generation facilities, energy storage systems, virtual power].

4.4 Toronto Hydro Energy Services Inc.

TH Energy owns and operates $58.3 million of Capital Assets as of December 31, 2022. TH Energy owns certain street lighting assets located in the city of Toronto, and has an agreement with the City to provide street lighting system maintenance and capital improvement services to the City. TH Energy sub-contracts street lighting services to LDC.

From December 18, 2002 to October 27, 2022, TH Energy also operated a wind turbine located at the Better Living Centre [Exhibition Place] in a joint venture with TREC Windpower Co-operative [No.1] Incorporated. Effective October 27, 2022 TH Energy transferred its interest in the wind turbine to Rankin Integrated Energy Inc. for nominal consideration.

4.5 Environmental Matters

(a) Environmental Protection Requirements

Toronto Hydro is subject to extensive federal, provincial and local regulation relating to the protection of the environment. The principal federal legislation is the Canadian Environmental Protection Act which regulates the use, import, export and storage of toxic substances, including PCBs and ozone-depleting substances. Toronto Hydro is also subject to the federal Transportation of Dangerous Goods Act which prescribes safety standards and requirements for the handling and transportation of hazardous goods including PCBs and sets reporting, training and inspection requirements relating thereto.

The principal provincial legislation is the Environmental Protection Act which regulates releases and spills of contaminants, including PCBs, ozone-depleting substances and other halocarbons, contaminated sites, waste management, and the monitoring and reporting of airborne contaminant discharge. The provincial Technical Standards and Safety Act also applies to Toronto Hydro's operations with respect to the handling of and training related to compressed gas, propane and liquid fuels. The provincial Fire Protection and Prevention Act requires Toronto Hydro to incorporate procedures and training for dealing with any spills of flammable or combustible liquids. The provincial Transportation of Dangerous Goods Act prescribes safety standards and requirements for the transportation of dangerous goods on provincial highways and sets out inspection requirements related thereto.

Municipal by-laws regulate discharges of industrial sewage and storm water run-off to the municipal sewer system and the reporting of the release of certain toxic substances into the environment.

(b) Financial and Operational Effects of Environmental Protection Requirements

In 2022, LDC spent approximately $2.1 million to meet environmental protection requirements. This includes costs for hazardous and non-hazardous waste disposal, testing, asbestos abatement, site remediation, wood and concrete pole removal, manifest and tonnage fees, and Stewardship Ontario fees.

Toronto Hydro recognizes a liability for its best estimate of the future removal and handling costs for contamination in electricity distribution equipment in service. The liability is recognized when there is a present obligation, a probable outflow of resources and the amount can be estimated reliably. Actual future environmental costs may vary from the estimates used in the calculation.

(c) Environmental Policy and Oversight

Toronto Hydro has a strong commitment to the environment through the enforcement of a well-defined Environmental Policy. Conformance with the Environmental Policy is managed by Toronto Hydro's Environment, Health and Safety department led by the Executive Vice-President and Chief Human Resources & Safety Officer. The content of the Environmental Policy is reviewed and approved annually by the Board.

Toronto Hydro's Environmental Policy identifies several core environmental principles, which include:

- Mitigation of the potential adverse effects of climate change and other environmental conditions on the organization, and action to eliminate or reduce, as far as practicable, any potentially adverse environmental impacts through the implementation of policies, programs and procedures;
- Commitment to achieve net zero direct greenhouse gas emissions by 2040;
- Commitment from leadership to provide suitable and sufficient resources for the environmental management system;
- Compliance with all applicable laws, codes and standards;
- Continual improvement of environmental performance through the establishment of annual objectives, targets and programs;
- Employee engagement through education, training and providing general awareness of the Environmental Policy requirements and the environmental management system;
- Stakeholder engagement including consultation and engagement of environmental issues within the community and various stakeholders such as suppliers, customers, regulators, industry and the public; and
- Integration of environmental considerations into Toronto Hydro business processes.

LDC manages its environmental aspects in conformance with ISO 14001:2015 and was re-certified on December 6, 2021 as meeting the requirements of the ISO 14001:2015 standard by a third-party auditor. The certificate is valid until February 4, 2025. Throughout the certification period, Toronto Hydro undertakes annual third-party surveillance audits to verify the ISO 14001:2015 requirements continue to be met. The latest verification occurred on November 23, 2022, with the auditors confirming the management system remained in conformance with the requirements.

Legislative environmental reporting for federal, provincial and municipal governments is compiled and submitted in accordance with applicable obligations and authorities. Third party environmental compliance audits are also conducted biennially in conformance with LDC's environment, health and safety audit plan.

Toronto Hydro's environmental policies, programs and procedures are reviewed and approved by management. Information on environmental performance, environmental risks, mitigation strategies and other material environmental matters are presented to the Human Resources and Environment Committee of the Board as part of Toronto Hydro's regular update on ESG performance.

(d) Environmental, Social and Governance

Toronto Hydro operates substantially in conformance with ISO 26000, an internationally recognized social responsibility standard. The focus of Toronto Hydro's ESG and sustainability actions is guided in part by an external materiality study and may be supplemented with information obtained through customer surveys. Toronto Hydro's Board receives updates on Toronto Hydro's ESG performance through the Human Resources and Environment Committee of the Board. This includes updates on performance on climate change metrics and targets and progress towards Toronto Hydro ESG-related goals, including those that are climate-related.

In 2022, the key areas of Toronto Hydro's ESG and sustainability activities were:

- Climate change mitigation and adaptation;
- Reduction of GHG emissions;
- Occupational health, safety and wellness;
- Transportation electrification;
- Ethics and integrity;
- Diversity, equity and inclusion;
- Service reliability; and
- Customer relationships and support.

In 2014, Toronto Hydro was one of the earliest Canadian electrical utilities to receive the prestigious "Sustainable Electricity Leader" designation. This designation is issued by EC to organizations following a successful third-party assessment of documented evidence that demonstrates an organization's conformance to ISO 26000, ISO 14001:2015, and integration of ESG and sustainability requirements into the organization's supply chain. Toronto Hydro has maintained this designation continuously since 2014. Further details on Toronto Hydro's activities in respect of ISO 14001:2015 can be found in section 4.5(c) entitled "Environmental Policy and Oversight".

Starting in 2013-2014, Toronto Hydro has reported publicly on its ESG and sustainability performance, substantially in conformance with the requirements of the GRI and electric utility sector-specific guidelines. The GRI Sustainability Reporting Standards are generally considered to be the most widely adopted global standards for sustainability reporting. In 2020, Toronto Hydro began reporting substantially in conformance with the requirements of the GRI on an annual basis and has begun to include metrics from the Sustainability Accounting Standards Board.

Specifically, with respect to its environmental objectives, these reports aim to aid stakeholders in understanding how oversight processes may translate into tangible climate-related accomplishments and details the Corporation's activities in:

- Enabling climate action;
- Reducing GHG emissions;
- Leading environmental initiatives;
- Renewable energy [and enabling infrastructure];
- Energy security;
- Climate change adaptation; and
- Emergency preparedness.

Toronto Hydro has a robust process for establishing and approving key metrics to challenge the performance of the organization and support the drive for continual improvement. Toronto Hydro has met the established targets for the following ESG metrics since 2017: Recycling Rate, Total Recordable Injury Frequency, Idling Time and SAIDI. Beginning in 2022, Toronto Hydro has developed two new metrics aimed at managing climate related risks and opportunities: Building Emissions Reduction and Fleet Electrification. Two of the largest sources of GHG emissions at Toronto Hydro are the buildings and vehicle fleet. The new metrics are expected to support Toronto Hydro's target of net-zero GHG emissions by 2040.

Since 2018, Toronto Hydro has been a signatory to Electricity Human Resources Canada's Leadership Accord on Diversity, Equity and Inclusion to affirm the organization's commitment to advance governance, education and practices that support women to both understand the opportunities available in the electricity industry and achieve equal opportunities for growth and development. In 2022, Toronto Hydro developed and implemented an unconscious bias training program and engagement events for front-line leaders. The training program and engagement events aimed to support leaders to improve the identification of unconscious bias and promote a more inclusive workplace. The program and events built on the success of an unconscious bias program for executives and senior leaders was implemented in 2021.

Through collaborations with EC and local colleges and universities, the focus of Toronto Hydro's continuous efforts has been on the promotion and mentorship of women to pursue educational programs in electrical engineering fields of study to avail a gender diverse talent pipeline to fulfill short and long-term workforce staffing and succession management requirements.

As at the date of this AIF, 40% [4 of 10] of the members of the Corporation's Board, 67% [2 out of 3] of the executive officers of the Corporation and 38% [3 out of 8] of the executive officers of LDC are female. As of December 31, 2022, 27% of the workforce is female, inclusive of the executive officers.

Toronto Hydro has received recognition for its leadership in ESG and sustainability and climate change adaptation from multiple sources for several years, including being recognized ninth in 2022 on the Corporate Knights' Best 50 Corporate Citizens in Canada list and first overall amongst electricity transmission and distribution companies.

Also, three of Toronto Hydro's four work centres have been certified as meeting BOMA Canada's requirements for building environmental standards [BOMA BEST].

Overall, Toronto Hydro continues to strive to achieve zero injuries and remain a sustainable electricity company. Toronto Hydro regularly monitors and assesses aspects of its environmental performance in an effort to reduce its environmental footprint and improve efficiency. Toronto Hydro also enables customers to be part of the shift to a sustainable economy by connecting renewable power and energy storage to the grid; facilitating the use of electrified transportation; and offering online billing to reduce paper consumption.

4.6 Additional Information Regarding Toronto Hydro

(a) Employees

At December 31, 2022, Toronto Hydro had approximately 1,245 employees. Included in Toronto Hydro's employees are 517 members of bargaining units represented by PWU and 79 professional engineers and 70 IT professionals represented by the Society of United Professionals. The Society of United Professionals Engineers Collective Agreement covers a four-year period, from January 1, 2020 and expiring December 31, 2023. On June 9, 2022, the PWU ratified collective agreements governing inside and outside employees for a five-year period beginning February 1, 2022 and expiring January 31, 2027. On October 7, 2022, the IT professionals ratified a five-year collective agreement for a period beginning January 1, 2021 and expiring December 31, 2025.

Full time employees of Toronto Hydro are required to participate in the OMERS pension plan. Both participating employers and participating employees are required to make equal plan contributions based on participating employees' eligible contributory earnings. Optional participation has been expanded by OMERS to all fixed term contract employees, including students of Toronto Hydro. Plan benefits are determined based on a formula that considers the highest 5-year average contributory earnings and the number of years of service. The pension benefits at retirement are indexed to increases in the Consumer Price Index, subject to an annual maximum of 6%. Any increase in the Consumer Price Index above 6% per year is carried forward for later years. All obligations to make payments to retirees under the OMERS pension plan are the responsibility of OMERS.

In addition to OMERS, Toronto Hydro provides other employment and post-employment benefits to employees, including medical, dental and life insurance benefits. See note 25[m] and note 13 to the Consolidated Financial Statements.

(b) Specialized Skills and Knowledge

Certified and skilled trades and designated and technical professional roles are important in the safe and reliable design, construction, maintenance, restoration and customer connections to support the LDC's electricity distribution system operations. Toronto Hydro hires a mix of experienced workers and new graduates to perform a variety of technician, technologist, engineering, information technology and corporate professional roles. Technician and technologist apprenticeships require between 4 and 6 years to become fully competent and capable of performing all aspects of their job. LDC provides specialized knowledge and technical programs, on the job learning and legislative and compliance training to support entry to the organization and throughout the apprenticeship program for required skills and knowledge outcomes.

(c) Health and Safety

Toronto Hydro is committed to a healthy, safe and injury free work environment for all employees, contractors, visitors and the public. LDC manages its health and safety management system in conformance with ISO 45001:2018 and was re-certified on December 6, 2021 as meeting the requirements of the ISO 45001:2018 standard by a third-party auditor. The certificate is valid until February 4, 2025. Throughout the certification period, Toronto Hydro undertakes annual third-party surveillance audits to verify the ISO 45001:2018 requirements continue to be met. The latest verification occurred on November 23, 2022, with the auditors confirming the management system remained in conformance with the requirements.

Through LDC's EHSMS, LDC maintains and reviews procedures, programs and the Occupational Health and Safety Policy which outlines several core principles including:

- Compliance
- Continual improvement
- Engagement and consultation
- Communication
- Accountability
- Risk management
- Contractor management
- Incident investigation
- Performance monitoring
- Wellness

The content of the Occupational Health and Safety Policy is reviewed and approved annually by the Board.

Toronto Hydro's health and safety performance, occupational health and safety risks, mitigation strategies and other occupational health and safety matters are reviewed periodically by the Human Resources and Environment Committee of the Board as part of Toronto Hydro's regular update on ESG performance.

Despite the ongoing COVID-19 pandemic in 2022, the Total Recordable Injury Frequency rate was 0.47 recordable injuries per 200,000 hours which was our most successful performance on record and 16% better than the previous year.

Toronto Hydro also has in place an infectious disease plan, which continues to be reviewed regularly as the COVID-19 emergency continues to evolve. This plan contains rigorous measures that often exceed applicable minimum public health standards and guidelines, which have been a significant part of Toronto Hydro's emergency response to COVID-19 and has been used to seek to limit exposure within its workforce. The plan continues to be updated and enhanced for use in the current conditions of the COVID-19 pandemic, as well as future potential infectious disease emergencies.

LDC's legislated occupational health and safety requirements come under provincial jurisdiction exclusively and all legislated occupational health and safety reporting requirements are complied with. Management assurance that these requirements are met is accomplished by commissioning third party health and safety compliance and management system audits conducted in conformance with LDC's environmental, health and safety audit plan.

Toronto Hydro's occupational health and safety policies, programs and procedures are reviewed and approved by management.

(d) Code of Business Conduct and Whistleblower Procedure

All employees, officers and directors of Toronto Hydro are required to comply with the principles set out in the Code of Business Conduct and Whistleblower Procedure [the "Code"], which was originally implemented by Toronto Hydro in 2003, and is reviewed, revised and approved by the Board from time to time. The Code provides guidance to all employees in situations of potential perceived conflict of interest. All employees, officers and directors of Toronto Hydro are required to complete training in respect of the Code and sign an attestation in accordance with the Code upon commencement of employment and every three years thereafter.

The Code provides for the appointment of an Ethics Officer and establishes a direct hotline to the Ethics Officer by which perceived violations of the principles set out in the Code may be reported, anonymously or otherwise. Where the complaint involves the conduct of a director or officer of Toronto Hydro, the Ethics Officer is required to report it to the Chair of the Human Resources and Environment Committee of the Board, or, where such conduct relates to questionable auditing or accounting matters, to the Chair of the Audit Committee of the Board, who oversees the investigation of that complaint. In addition to the provisions of the Code, the Ethics Officer reports quarterly to the Human Resources and Environment Committee of the Board on the nature of complaints received and the Director,

Internal Audit and Compliance reports quarterly to the Audit Committee on matters related to audit and accounting. A copy of Toronto Hydro's Code of Business Conduct and Whistleblower Procedure is available on the SEDAR website at www.sedar.com.

(e) Insurance

Toronto Hydro's current insurance policies provide coverage for a variety of losses and expenses which might arise from time to time, including:

- comprehensive general liability insurance;
- all risk property, boiler and machinery insurance;
- automobile liability insurance;
- directors and officers' liability insurance;
- cyber insurance;
- crime insurance; and
- insurance covering loss or damage on certain physical assets.

Toronto Hydro believes that the coverage, amounts and terms of its insurance arrangements are consistent with industry practice.

(f) Intangible Property

The Corporation owns various intangible assets, such as computer software systems used in the course of business, and intellectual property, including the "Toronto Hydro" brand name and the trademark Toronto Hydro & Star Design. The Corporation also owns the trademark POWERSHIFT®.

(g) Seasonal Effects

Toronto Hydro's revenues, all other things being equal, are impacted by temperature fluctuations and unexpected weather conditions, including increased frequency of extreme weather events as a result of climate change, such as heat waves, intense rain events, snow storms and higher average temperatures. Generally, revenues would tend to be higher in the first quarter as a result of higher energy consumption for winter heating, and in the third quarter due to air conditioning/cooling. Toronto Hydro's revenues are also impacted by fluctuations in electricity prices and the timing and recognition of regulatory decisions.

PART 5 - GENERAL DEVELOPMENT OF THE BUSINESS

5.1 Business Operations

(a) Three Year History

The following table sets forth selected annual financial information of the Corporation for the three years ended December 31, 2022, 2021 and 2020. This information has been derived from the Consolidated Financial Statements and is presented in millions of dollars.

	Year ended December 31		
	2022	**2021**	**2020**
Net income after net movements in regulatory balances	$163.9	$141.0	$117.1
Capital expenditures	$722.7	$647.4	$617.2
Total assets and regulatory balances	$6,947.0	$6,413.8	$6,069.0
Total equity	$2,062.0	$1,982.7	$1,912.0

(b) Business Operations

Over the past three years, Toronto Hydro continues to focus its business operations on LDC's core business of distributing electricity.

5.2 COVID-19 Pandemic Considerations

On March 11, 2020, the World Health Organization declared that the COVID-19 outbreak was a global pandemic. The COVID-19 pandemic has not had a significant impact on the Consolidated Financial Statements.

On November 15, 2021, the OEB's standard winter disconnection ban commenced and remained in effect until May 1, 2022. Concurrent with the effective end date of the OEB's standard winter disconnection ban, the Corporation ended its voluntary ban on disconnections, which had been in place since the beginning of the pandemic. The Corporation's disconnection practices remain subject to the applicable OEB rules.

On January 7, 2022, the Ontario Government announced further targeted relief measures setting both the TOU rates for on-peak, mid-peak, and off-peak and tiered rates at the TOU off-peak rate of 8.2 cents per kWh, 24 hours a day, seven days a week, effective January 18, 2022 until February 7, 2022. There was no net income impact to the Corporation.

On October 1, 2022, Toronto Hydro transitioned to a hybrid work arrangement, which enabled employees who could perform their work from home the flexibility to attend their assigned work centre a minimum number of days a week, with flexibility as to work location on other days.

5.3 Rate Applications

On December 19, 2019, the OEB issued its 2020-2024 CIR Decision and on February 20, 2020, the OEB issued its CIR Final Rate Order, both in relation to the rate application filed on August 15, 2018 [together, the "2020-2024 CIR Decision and Rate Order"]. The 2020-2024 CIR Decision and Rate Order approved funding for capital and operating expenditures of approximately $3.8 billion for the 2020-2024 period. The 2020-2024 CIR Decision and Rate Order approved subsequent annual rate adjustments based on a custom index for the period commencing on January 1, 2021 and ending on December 31, 2024. The financial considerations of the OEB's 2020-2024 CIR Decision and Rate Order are reflected in the Consolidated Financial Statements including disclosure of approved disposition for a number of requested rate riders. See note 8 to the Consolidated Financial Statements.

On August 24, 2020, LDC filed the 2021 rate application seeking the OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2021 and ending on December 31, 2021. On December 10, 2020, the OEB issued a decision and rate order approving LDC's 2021 rates and providing for other deferral and variance account dispositions.

On August 20, 2021, LDC filed the 2022 rate application seeking the OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2022 and ending on December 31, 2022. On December 9, 2021, the OEB issued a decision and rate order approving LDC's 2022 rates and providing for other deferral and variance account dispositions.

On August 23, 2022, LDC filed the 2023 rate application seeking the OEB's approval to finalize distribution rates and other charges for the period commencing on January 1, 2023 and ending on December 31, 2023. On December 8, 2022, the OEB issued a decision and rate order approving LDC's 2023 rates and providing for other deferral and variance account dispositions.

5.4 Conservation and Demand Management

The IESO is responsible for delivery of CDM programs; however, LDC remains responsible for its obligations under participant agreements with customers for many of the programs under its previous joint CDM plan with Oakville Hydro Electricity Distribution Inc. that were in effect before April 1, 2019. On June 10, 2021, the Government of Ontario issued ministerial directives to the IESO to extend the deadline by which participants were to complete the projects from June 30, 2021 to December 31, 2021, and on December 9, 2021, the deadline was further extended to August 31, 2022. The ministerial directives also allowed for the completion deadline to be further extended for participants who completed projects prior to December 31, 2022 to be eligible for funding upon submission of their claims, if certain conditions were met. Amounts received from the IESO for the funding of the projects under the participant agreements, but not yet spent, are presented on the Corporation's consolidated balance sheets under current liabilities as deferred conservation credit.

5.5 Toronto Hydro Climate Action Plan

At its meeting held on April 7-8, 2021, a resolution was passed by City Council that requested the City Manager and Toronto Hydro report back to City Council with respect to Toronto Hydro's ongoing work and an action plan with opportunities to achieve outcomes associated with climate action matters, including electric vehicle chargers, outdoor lighting, renewable energy, energy storage, and related grants, funding, and financing.

Toronto Hydro submitted its Climate Action Plan to the City Manager on September 30, 2021 concerning current work and an action plan setting out opportunities, in accordance with the City Council resolution.

At its meeting held on December 15-17, 2021, a resolution was passed by City Council that requested the City Manager and Toronto Hydro report back to City Council with additional information related to the Climate Action Plan and its interplay with the City of Toronto TransformTO Net Zero Strategy approved at that same meeting.

At its meeting held on July 19-22, 2022, City Council received reports from the City Manager and Toronto Hydro in accordance with the December 2021 direction. City Council adopted the recommendations of those reports, as well as additional motions from City Councillors. The resolutions include a request that Toronto Hydro establish a new climate advisory services business in keeping with the proposal set out in Toronto Hydro's Climate Action Plan and Toronto Hydro's Climate Action Plan Status Report filed with the City in June 2022. City Council directed that a memorandum of understanding between the City and Toronto Hydro with respect to climate advisory services implementation targets and coordination details return to City Council in the first quarter of 2023.

Climate Advisory Services is designed to facilitate reductions in greenhouse gas emissions via electrification by reducing stakeholder-identified barriers that prevent or inhibit customers from participating in the energy transition. The Climate Action Plan sets out examples of these services to customers, including to: identify their situation-specific opportunities; help in choosing particular climate actions and the timing of implementation; provide recommendations on potential clean tech products and services to vendors; assist in applying for government or

institutional funding such as grants and/or loans; remove barriers faced by low income customers; as well as assist with monitoring the implementation and evaluating the results. Toronto Hydro employees would then use the knowledge obtained from this work to ease and support the energy transition of other customers.

The annual costs for the Climate Advisory Services are anticipated to be approximately $8.0 million in 2023, and are expected to increase each year until reaching approximately $15 million in 2026. Actual costs will depend on the nature and scope of services provided. Specifically, the operating costs set out above are expected to be funded through revenues and net income within LDC, not from electricity distribution rates.

Other adopted City Council resolutions support in principle a city-wide LED conversion of streetlights and reinvestment in the enabling infrastructure, and request a report back in the second quarter of 2023 with implementation options and a recommendation from City Transportation Services. City Council requested additional information in future annual reports to the City with respect to the expansion of the electricity grid to help the City achieve its TransformTO Net Zero Strategy goals, and directed the City Manager to submit TransformTO targets to Toronto Hydro to consider in its local capacity planning and rate application processes. City Council requested a report on potential future opportunities to proceed with the climate capital investments proposal set out in Toronto Hydro's Climate Action Plan. To date, City Council is yet to provide approval of the funding required to support the implementation of city-wide LED street light conversion or the climate capital investments proposal.

PART 6 - RELATIONSHIP WITH THE CITY

6.1 Shareholder Direction

As sole shareholder of the Corporation, the City has adopted the Shareholder Direction that sets out the following corporate governance principles with respect to Toronto Hydro:

- the objectives and principles that govern the operations of Toronto Hydro;
- the matters in addition to those set out in the OBCA that require the approval of the City as the sole shareholder of the Corporation; and
- certain financial and administrative arrangements between the Corporation and the City.

The Shareholder Direction requires Toronto Hydro to conduct its affairs and govern its operations in accordance with such rules, policies, directives or objectives as directed by City Council from time to time, subject to Toronto Hydro's requirements under law.

(a) Shareholder Objectives and Principles

The Shareholder Direction provides that the following objectives and principles shall govern the operations of Toronto Hydro:

- to operate Toronto Hydro on an efficient and commercially prudent basis;
- to optimize the City's return on equity as the sole shareholder of the Corporation and operate Toronto Hydro with a view to meeting the financial performance objectives of the City as set out in the Shareholder Direction;
- to provide a reliable, effective and efficient electricity distribution system that supports the electricity demands of residents and businesses in the City;
- to operate Toronto Hydro in an environmentally responsible manner consistent with the City's energy, climate change and urban forestry objectives and, as appropriate, utilizing emerging green technologies;

- to ensure that the business is managed in material compliance with all law; and
- to engage in recruitment and procurement practices designed to attract employees and suppliers from the City's diverse community.

The Shareholder Direction provides that the Board is responsible for determining and implementing the appropriate balance among these objectives and principles and for causing Toronto Hydro to conduct its affairs in accordance with the same.

(b) Shareholder Approval

In addition to those matters set out in the OBCA, the following matters, among others, require the approval of the City as the sole shareholder of the Corporation:

- subject to certain exceptions in the case of LDC, creating any security over the assets of the Corporation or LDC;
- in the case of LDC, providing any financial assistance to any person other than in accordance with the Shareholder Direction;
- in the case of the Corporation and LDC, making any investment in or providing any financial assistance to any subsidiary of the Corporation [other than LDC], other than trade payables incurred in the ordinary course of business on customary terms and an investment in or financial assistance to a subsidiary that originally was an investment in or financial assistance to LDC, in excess of 12% of the shareholder's equity of LDC as shown in its most recent financial statements; and
- acquiring any interest in the electricity distribution system, undertaking or securities of a distributor operating outside the City unless, among other things, the acquisition does not adversely affect the dividend payable to the City and there is no dilution of the City's shareholding in the Corporation.

The City has authorized the Corporation to provide financial assistance to its subsidiaries for the purpose of enabling them to carry on their respective businesses, including, in the case of LDC, for the purpose of satisfying the prudential requirements of the IESO. The Shareholder Direction limits the financial assistance that may be provided by the Corporation to its subsidiaries to an aggregate amount of $500.0 million, except in the case of LDC, which financial assistance is unlimited.

(c) Financial Performance

The Shareholder Direction provides that the Board will use its best efforts to ensure that Toronto Hydro meets certain financial performance standards, including those relating to the credit rating and dividends.

(d) Credit Rating

The Shareholder Direction provides that the Corporation will obtain and maintain a rating of A minus or higher [or its equivalent rating, depending on the credit rating agency] on its senior debt securities, as rated by two accredited credit rating agencies in Ontario [which include S&P, DBRS and Moody's]. See section 9.4 entitled "Credit Rating" for more information on the Corporation's credit ratings as at December 31, 2022.

(e) Dividends

Subject to applicable law, the Shareholder Direction provides that the Corporation will pay dividends to the City each year amounting to 60% of the Corporation's consolidated net income after net movements in regulatory

balances for the prior fiscal year. The dividend is declared in quarterly instalments, subject to the discretion of the Board and payable to the City by the last business day of each fiscal quarter.

The Corporation declared and paid dividends to the City totaling $92.6 million in 2020, $70.3 million in 2021, and $84.6 million in 2022.

On March 1, 2023, the Board declared a dividend in the amount of $24.6 million, payable to the City by March 31, 2023.

LDC declared and paid dividends to the Corporation of $0.7 million in 2020, $0.6 million in 2021 and $nil in 2022.

TH Energy declared and paid $nil dividends to the Corporation in 2020, 2021, and 2022.

6.2 Services Provided to the City

Toronto Hydro provides certain services to the City at commercial and regulated rates, including street lighting services. Ongoing street lighting services are provided by TH Energy and sub-contracted to LDC. See section 4.4 entitled "Toronto Hydro Energy Services Inc." for more information. See note 22 to the Consolidated Financial Statements.

6.3 Shareholder Engagement

The Corporation believes that regular and constructive engagement with the City, its sole shareholder, is an important part of creating an open, candid and informed dialogue. In addition to the Corporation's annual shareholder meetings, representatives of the Corporation engage with the City through formal attendance at City Council meetings and other engagements with the Mayor, City Councillors and City management throughout the year as required. Other means of communications with the City include the Corporation's annual and quarterly financial and management reports, and ward-specific updates.

PART 7 - TAXATION

7.1 Tax Regime

The Corporation is exempt from tax under the ITA, if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income of the Corporation is derived from activities carried on outside the municipal geographical boundaries of the City. In addition, the Corporation's subsidiaries are also exempt from tax under the ITA provided that all of their capital is owned by the Corporation and not more than 10% of their respective income is from activities carried on outside the municipal geographical boundaries of the City. A corporation exempt from tax under the ITA is also exempt from tax under the TA.

The Electricity Act provides that an MEU that is exempt from tax under the ITA and the TA is required to make, for each taxation year, a PILs payment to the OEFC in an amount equal to the tax that it would be liable to pay under the ITA and the TA if it were not exempt from tax. The Corporation and each of its subsidiaries are MEUs for purposes of the PILs regime contained in the Electricity Act, and therefore, the Corporation is required to make PILs to the OEFC.

If the Corporation or a subsidiary ceases to be exempt from tax under the ITA and the TA, it will become subject to tax under those statutes, will no longer be required to make PILs payments to the OEFC, and will be deemed to have disposed of its assets for proceeds of disposition equal to their fair market value at that time and to have reacquired its assets at the same amount with the result that:

- such corporation would become liable to make a PILs payment in respect of any income or gains arising as a result of these deemed dispositions; and

- the amount of annual taxes payable by the corporation under the ITA, and the TA may be different from the PILs payment that would be payable without a loss of tax-exempt status to reflect, among other things, the consequences of these deemed dispositions and acquisitions.

The Electricity Act also provides that a municipal corporation or an MEU is required to pay a transfer tax when it transfers Electricity Property. An interest in Electricity Property includes any interest in a corporation, partnership or other entity that derives its value in whole or in part from Electricity Property. The transfer tax is the prescribed percentage [22% for transfers occurring between January 1, 2016 and December 31, 2024 (originally set to expire in December 2018 and extended to December 2022 as part of the 2018 Ontario Economic Outlook and Fiscal Review, further extended to December 2024 as set out in the 2022 Ontario Budget), and 33% for transfers occurring thereafter] of the fair market value of the interest transferred. The amount of transfer tax payable where the interest that is transferred is an interest in a corporation, partnership or other entity, is calculated in accordance with a special rule. The amount of transfer tax payable by an MEU on a transfer of Electricity Property may be reduced by:

- any PILs payment made by the MEU in respect of the part of the taxation year up to and including the date that the transfer takes place or a previous taxation year;

- any amount that the MEU has paid as tax under Part III of the TA in respect of the part of the taxation year up to and including the date of the transfer or a previous taxation year; and

- any amounts that the MEU would be liable to pay as tax under Part I of the ITA in respect of the taxation year if that tax were computed on the basis that the MEU had no income other than the capital gain realized on the transfer of its interest in the property.

Transfers of Electricity Property will be an excluded transfer and thereby exempt from the transfer tax if made to an MEU, Hydro One or OPG, or a subsidiary of either of them if the transferee is exempt from tax under the ITA at the time of transfer. Capital gains arising from a transfer of Electricity Property occurring between January 1, 2016 and December 31, 2024 are also exempt from the transfer tax.

In addition, a refund of transfer tax may be made where such tax had been paid on the sale or transfer of Electricity Property and where the proceeds of that transfer were reinvested in certain other capital or depreciable assets used in connection with generating, transmitting, distributing or retailing electricity in Ontario and, subject to certain deeming rules, before the end of the second taxation year following the taxation year in which the liability to pay the transfer tax arose.

PILs payments are deductible in computing the transfer tax only to the extent that they have not been previously applied to reduce transfer tax payable by a municipal corporation or an MEU.

7.2 PILs Recoveries through Rates

The OEB's Filing Requirements for Electricity Distribution Rate Applications provides for electricity distribution rate adjustments to permit recoveries relating to PILs payments. These recoveries are recalculated and submitted for recovery by LDC in each cost of service or rebasing distribution rate application. LDC is also generally at risk for variances between forecasted and actual PILs paid, excluding variances arising from changes in tax legislation not assumed in the setting of rates for the period in question, which variances are disposed of through deferral accounts under cost of service, IRM or CIR. See note 8[g] to the Consolidated Financial Statements.

PART 8 - RISK FACTORS

Risk Management

Toronto Hydro faces various risks that could impact the achievement of its strategic objectives. It adopts an enterprise-wide approach to risk management, based on an overall enterprise risk philosophy, and achieved through a process of consolidating and aligning the various views of risk across the enterprise via a risk governance structure.

Toronto Hydro's ERM framework utilizes industry best practices and international guidelines tailored to meet Toronto Hydro's circumstances, and focuses on identifying emerging trends in risks and related opportunities particular to Toronto Hydro through a comprehensive evaluation of Toronto Hydro's business and the electricity industry generally. Toronto Hydro views ERM as a management activity undertaken to add value and improve overall operations and has made it an important part of its decision-making processes. The ERM framework helps Toronto Hydro by enabling the attainment of its strategic goals and objectives through a systematic, disciplined approach towards identifying, evaluating, treating, monitoring and reporting of risks. Accordingly, ERM is an integral part of the strategic management of Toronto Hydro and is routinely considered in forecasting, planning and executing key aspects of the business.

The ERM framework is operationalized by a consistent and disciplined methodology that clearly defines the risk management process and which incorporates judgment of subject matter experts within Toronto Hydro, risk quantification, risk trends and risk interdependencies. The risk criteria used to assess each enterprise risk relate to: strategic, reputational, financial, stakeholder management, distribution system, information system, compliance, occupational health and safety, and public safety impacts.

Toronto Hydro has assigned a designated responsible member of senior management for each enterprise risk [and several key component risks] to seek to ensure that such risks are being monitored through qualitative and quantitative risk indicators and that short interval controls and medium to long-term mitigation plans are in place. Each designated responsible person provides regular risk reporting and briefings to the executive team on their enterprise risk and the key components of such risk. Additionally, Toronto Hydro's risk governance structure includes internal coordination efforts to align outreach to key external stakeholders, both from a strategic and consistency perspective, to help reduce risks and identify opportunities for engagement.

Internal ERM professionals meet regularly with the designated responsible persons to gather and review risk indicators and trends, and identify potential emerging facts that could impact Toronto Hydro, augment other risks or

curtail opportunities. Such risk management processes and tools help Toronto Hydro prioritize its mitigation efforts, strengthen its planning efforts, and identify areas for improvement.

While Toronto Hydro's philosophy is that ERM is the responsibility of all business units at all levels, in strategic and functional matters, the ERM governance structure is comprised of three key levels.

At the first level is the Board, which maintains a general understanding of Toronto Hydro's risk profile, the risk categories and the types of risks to which Toronto Hydro may be exposed, and the practices used to identify, assess, measure and manage those risks. The risk profile is a list of key areas that may impede Toronto Hydro from achieving certain or all of its strategic objectives, and which are most material to its operational success. The Board also reviews Toronto Hydro's risk philosophy on an annual basis and is responsible for approving any new enterprise risk areas.

The second level is the executive team, which ensures systems are in place to identify, manage, and monitor risks and trends. Through input from the business and other considerations, the executive team assesses the appropriateness and consistent application of systems to manage risks within Toronto Hydro. The executive team also ensures that key risks are brought forward to the attention of the Board for discussion and action, as required.

Finally, the third level is the senior leadership team. The senior leadership team supports the executive team and is a collection of subject matter experts from across Toronto Hydro who actively engage in the day-to-day management of risks. Members of the senior leadership team have been assigned to be the designated responsible person for managing and reporting upon enterprise risks. Understanding the critical linkages between external stakeholder management and the impact and likelihood of the emergence of enterprise risk, members of this group are among those that have also been assigned as stakeholder coordinators to ensure that Toronto Hydro is working effectively with external stakeholders to mitigate risks. Working with the executive team, the senior leadership team oversees Toronto Hydro's risk profile and its performance against the defined risk philosophy. This group understands changes in risk status and trends, identifies potential opportunities, and determines responses and action plans that are then implemented by the organization. These senior leaders also work to ensure effective, efficient, complete and transparent risk reporting to the executive team.

Toronto Hydro reviews its risk philosophy and enterprise risks areas continuously for alignment with business and industry conditions and regularly updates and enhances its ERM program to ensure that Toronto Hydro is focused upon and responsive to risks of the greatest significance, likelihood and impact. Toronto Hydro's ERM program is focused on the key strategic and functional risk categories facing the organization. This allows Toronto Hydro's executive team and responsible business units to concentrate on these risks, focus on key data points and undertake deeper dives into root causes and risk trends in these areas on both a short-interval and long-term basis. By focusing in particular on the strategic risks to the organization, decision-making is strengthened and Toronto Hydro has a greater ability to realize opportunities central to its interests.

Toronto Hydro's business is subject to a variety of risks including those key risk areas described in the following sections. The strategic risk areas of Toronto Hydro are identified as the governance, oversight and franchise risks, while the key functional risks of the organization are the cybersecurity, safety, financial, operations, human capital and compliance risks. There can be no assurance that any steps Toronto Hydro may take to manage risks will avoid future loss resulting from the occurrence of the identified key enterprise risk areas or any other risks.

Governance Risk

Risk that municipal activity [laws, policies, or intervention] impedes Toronto Hydro's effective performance, and ability to meet its objectives and serve its customers.

The Corporation is a government-controlled enterprise whose sole shareholder is the City. The operations of Toronto Hydro are influenced by the broad by-law enactment and enforcement powers of the City. The City is also responsible for developing policies and municipal initiatives of general application and there is no guarantee that such policies, including climate change and energy policies, will align with Toronto Hydro's strategic objectives or long-term financial health. The City may also implement additional requirements relating to reduction in GHG

emissions and adaptation to climate change as part of initiatives such as the City's TransformTO. In this respect, in response to resolutions passed by City Council in 2021, Toronto Hydro proposed a climate action plan to assist the City in meeting its 2040 net zero GHG emission objective. In July, 2022, City Council passed resolutions to support the implementation of the climate action plan [see section 5.5 entitled "Toronto Hydro Climate Action Plan"]. The City, as sole shareholder, may require Toronto Hydro to make additional investments in infrastructure and/or undertake activities which necessitate additional time, money and effort to be expended related to compliance with the City's TransformTO that are inconsistent with Toronto Hydro's proposed climate action plan. Additionally, due to its authority to put in place oversight bodies which may have or be given jurisdiction over Toronto Hydro as a government-controlled enterprise, the City may also empower certain of its agencies to investigate or audit Toronto Hydro, which could lead to significant reputational, operational or financial harm.

The City also plays a role as a municipal asset manager and construction entity and could substantially impact Toronto Hydro's operations and impose material costs through its infrastructure work plans and policies [e.g., asset relocation costs, work restrictions, climate change adaptation, etc.]. The City may also impact Toronto Hydro when elected officials take actions as community representatives whereby such actions are contrary to the strategic objectives or necessary operational functions of Toronto Hydro.

As the Corporation's sole shareholder, the City has set out the governing objectives and principles, including financial objectives, for the Corporation through the Shareholder Direction, as described in section 6.1 entitled "Shareholder Direction". Under the Shareholder Direction, the City has the power to direct Toronto Hydro to conduct its affairs and govern its operations in accordance with such rules, policies, directives or objectives as are directed by City Council from time to time, subject to applicable law. Certain conflicts may arise where the City's goals and objectives in implementing such rules, policies, directives or objectives differ from or amend the Shareholder Direction principles, create new governing objectives and principles, or restrict the ability of the Board to oversee the operations of the Corporation and management's ability to take strategic or functional action, and therefore could materially adversely affect Toronto Hydro's business, operations, financial condition or prospects. The City may not provide or support equity investment or net income reinvestment in the Corporation to enable Toronto Hydro to maintain the financial objectives under the Shareholder Direction as it undertakes its strategic plan and implements OEB-approved rate decisions and orders.

Toronto Hydro engages on a systematic basis with the City Mayor, City Councillors, the City Manager's office, and other departments and agencies to ensure a sharing of perspectives on the vital interests of Toronto Hydro and its customers. Through such engagements the parties review and consider the challenges to Toronto Hydro achieving the objectives and principles set out under the Shareholder Direction, and in particular the impact that proposed changes in city by-laws, municipal policies or directions by the shareholder may create for Toronto Hydro's ability to meet its business objectives and serve its customers.

Oversight Risk

Risk that provincial government or regulator activity [laws, frameworks or policies] impedes Toronto Hydro's effective performance, and its ability to meet its objectives and serve its customers.

Toronto Hydro is subject to the risk that its business activities may be impeded through the actions of governmental or regulatory authorities or by changes in regulation. There is a risk that future changes to Ontario's electricity regulatory model, manner of regulation, application of regulatory principles, and/or broader climate change and energy policy framework does not align with Toronto Hydro's business direction and could materially adversely affect Toronto Hydro's strategic goals and financial results.

Ontario's electricity industry regulatory and other energy policy developments may affect the electricity distribution rates charged by LDC, the costs LDC is permitted to recover and the activities LDC and others, including those parties offering alternative or additional services to the electricity distribution grid, may undertake and how such activities are supported. This may in turn have a material adverse effect on the financial performance of the Corporation and/or LDC's ability to deliver effective and efficient operations and reliable service to its customers, as well as create barriers to LDC achieving its strategic objectives. Among other things, there can be no assurance that:

- the OEB will approve LDC's electricity distribution rates at levels that will permit LDC to maintain safe and reliable service to its customers and earn a commercially reasonable rate of return on the investment in the business;

- the OEB will approve and permit recovery through rates of past and future expenditures incurred by LDC in providing distribution services to customers, including costs arising from an increased inflationary environment, in a timely manner or at all;

- governmental authorities will pursue net zero GHG policies that optimally utilize electrification or adequately support local distribution companies in facilitating electrification;

- the OEB will approve and permit recovery through rates of past and future expenditures incurred by LDC in preparing for or expanding electricity distribution service to meet increased electricity demand or other requirements resulting from net zero GHG emission policies;

- the OEB will adopt other rate-setting principles, formulae, inputs and cost recovery methodologies in a manner consistent with well-established regulatory principles that result in rates that properly support LDC's activities;

- the regulatory instruments that are made available to LDC will be sufficient to address LDC's operations, needs and circumstances in respect of future applications for electricity distribution rates; and

- the OEB, IESO or other governmental authority will not permit, enable or facilitate other parties in providing distribution services in LDC's licensed area, or permit loads within LDC's service area to become served by a means other than through LDC's electricity distribution system.

Any future regulatory decision to disallow or limit the recovery of costs could lead to potential asset impairment and charges to results from operations, which could have a material adverse effect on Toronto Hydro.

Toronto Hydro actively participates in industry engagement efforts in order to mitigate the above risks and realize potential opportunities in regulatory, climate change and energy policy development. Through these types of engagements, Toronto Hydro monitors proposed regulatory, climate change and energy policy changes that may support or impede its business. LDC also employs a comprehensive organizational regulatory application program, which includes a risk assessment, to ensure that all applications to the OEB achieve the highest utility standard of evidence gathering, preparation and presentation, and most accurately reflects the needs of LDC. The preparation of the LDC distribution rates application to the OEB for the 2025-2029 rate period is currently underway. Successful completion and implementation of the project work plan related to the application is expected to yield long-term results for Toronto Hydro: specifically, funding certainty and flexibility to invest in the modernization and renewal of the distribution system and to prepare for growth and electrification driven by the City's TransformTO. However, there can be no assurance that the OEB will substantially approve the activities, plans and methodologies set out therein or the revenue requirement related thereto.

Additionally, the policy priorities of provincial and federal governments and regulatory bodies beyond those specifically applicable to the climate change and energy space, including policies of more general application, and the implementation of policies by such bodies, may impact Toronto Hydro's ability to deliver effective and efficient operations, meet business objectives, report on its activities and capitalize upon new opportunities. Developments and changes in any of the laws, rules, regulations, policies, permits, or directives applicable to the businesses carried on by Toronto Hydro, and the manner of implementation and application of the same, could materially adversely affect Toronto Hydro. This may include developments with respect to labour and employment laws, changes to accounting standards and financial reporting requirements and environmental obligations, among others. This may also include changes to public safety rules, such as restrictive measures affecting the mobility or availability of human and/or non-human resources associated with infectious diseases such as COVID-19 or other adverse public health developments. Toronto Hydro actively engages with government entities and participates in industry organizations to monitor emerging policies and where possible plays an advocacy role.

Franchise Risk

Risk that restrictions in LDC's business model and/or external conditions impede its ability to maintain and grow its legal right to be the sole provider of electricity distribution and connection services in the city of Toronto [its franchise] and serve electricity customers. Toronto Hydro is subject to the risk that it is displaced from its strategic position or fails to gain a strategic advantage to effectively facilitate local electricity demand, which could materially adversely affect Toronto Hydro's strategic goals and financial results.

The OEB has the authority to grant municipal distribution licences, has issued to LDC a licence stipulating a service area that reflects the territory within the City, and has not granted any other distribution licence that permits distribution within LDC's service area. In addition, there is a legal framework in place that establishes LDC, as the holder of the municipal distribution licence in the City, to be the sole provider of distribution activities across municipal rights of way. There is no assurance that these frameworks will continue to exist sufficiently or at all in order to provide LDC the opportunity to be the comprehensive distribution provider in the city of Toronto.

Other regulated and unregulated entities have and continue to compete with LDC and its predecessors, and new parties continue to emerge to provide customers with other sources of energy, including electricity and energy services. Additionally, customers have made choices to provide their own electricity or other sources of energy for their use and/or sale back into the distribution grid. The pervasiveness of this competition and the presence of alternatives to Toronto Hydro's distribution services, and the resultant effects on LDC's distribution business, have varied over time and continue to vary based on many factors. These factors may include the relative price and relevant costs of energy source [e.g., natural gas, solar photovoltaic, grid-supplied electricity, behind-the-meter generation, district energy], climate change policy, technology development [e.g., energy storage, energy efficiency, demand response], ability of customers to access transmission-direct connections, economic trends, real estate prices, workplace arrangements, government-based incentives, regulatory frameworks and compliance frameworks especially for non-utility entities, load development, and the state of the marketplace and economy in general. Toronto Hydro also faces the risk of its franchise being diminished by the possibility of an overall reduction in the use of electricity in its service territory.

There can be no assurance that the future nature, prevalence, or effects of these forms of competition, from the transition to net zero GHG emissions or otherwise, will be comparable to current or historic experience. Failure to effectively review and understand our external and internal environment and take appropriate action could lead to missed business opportunities and loss of competitive advantage. In particular, the clean energy transition to net zero GHG emitting energy sources may create both risks and opportunities and there can be no guarantee that Toronto Hydro has the correct strategic direction to capitalize on the associated policy changes or technological advancements or that it will be able to effectively mitigate losses from these developments.

Risks to Toronto Hydro's franchise interests may also result from impairment to Toronto Hydro's image in the community, public confidence or brand. Toronto Hydro is committed to delivering safe and reliable electricity to its customers in an environmentally responsible manner at optimal costs. Negative views regarding this commitment and the cost of electrification and energy transition, could impact the public's perception of Toronto Hydro. In addition, events and/or external factors that draw negative media attention to Toronto Hydro could cause reputational damage and impact Toronto Hydro's business and relationship with its stakeholders. These factors could lead customers, governments and regulators to look more favourably to alternative services and service providers as compared to utility-based electricity distribution.

Toronto Hydro is focused on monitoring external competitive factors and industry developments, including alternative service providers and technologies, through indicators such as customer engagements related to innovative technologies and pre-assessment requests and connection applications for energy storage. Toronto Hydro is also focused on enhancing the intelligence, automation and interactivity of LDC's electricity distribution grid, including utilizing developing technology and facilitating customer use of technology and business models, to support the reliability of its core infrastructure grid operations, prepare for increased electricity demand from net zero GHG emission policies, promote greater value, and deliver solutions for its customers. Additionally, Toronto Hydro takes measures to maintain relationships with its customers to better understand the specific needs and

expectations of each class of customer, and develop or enhance service offerings to address those needs. Toronto Hydro conducts customer research and consultations in the ordinary course of its operations, and as part of the development of its rate application whereby it directly considers customer preferences and feedback, in addition to other inputs, as part of developing its business plan. Toronto Hydro also has dedicated personnel focused on the utility's key account customers, who respond to issues raised by large commercial, industrial and institutional customers and assist with their energy management needs. Toronto Hydro also provides climate advisory services as part of its climate action plan to facilitate customers in developing their own climate action plans and reduce stakeholder-identified barriers that prevent or inhibit customers from participating in the energy transition [see section 5.5 entitled "Toronto Hydro Climate Action Plan"]. Through these types of engagements, Toronto Hydro can monitor its customers' specific needs and can work with them to develop energy solutions.

Cyber Security Risk

Risk that Toronto Hydro is unable to adequately safeguard digital information assets, connections to digital infrastructure, physical assets and people from threats or vulnerabilities.

Toronto Hydro's ability to operate effectively is also in part dependent on the development, maintenance and management of complex information technology and operational technology systems. Computer systems are employed to operate LDC's electricity distribution system, and Toronto Hydro's financial, customer billing and business systems to capture data and to produce timely and accurate information.

LDC's electricity distribution infrastructure and technology systems are potentially vulnerable to damage or interruption from cyber-attacks, breaches or other compromises, which could result in business interruption, service disruptions, theft of intellectual property and confidential information [about customers, suppliers, counterparties and employees], additional regulatory scrutiny, litigation and reputational damage. The cybersecurity threat landscape is continually evolving and actors are using more sophisticated methods to penetrate information technology systems. In particular, the utilities sector, as operators of critical infrastructure and providers of essential services with large customer bases, has become an increasing target for cybersecurity activity. Toronto Hydro has implemented security controls substantially aligned with industry best practices and standards, including the National Institute of Standards and Technology Cybersecurity Framework and the OEB's Ontario Cyber Security Framework, and maintains cyber insurance. Cyber-attacks, breaches or other compromises of electricity distribution infrastructure and technology systems could result in service disruptions and system failures, including as a result of a failure to provide electricity to customers, property damage, data corruption, and/or loss of confidential employee, supplier, counterparty or customer information. A significant breach could materially adversely affect the financial performance of Toronto Hydro or its reputation and standing with customers, regulators and in the financial markets. It could also expose Toronto Hydro to third-party claims. Overseeing the management of these risks, Toronto Hydro's Audit Committee receives comprehensive updates on the cybersecurity environment and the organization's cybersecurity program and responses.

Toronto Hydro must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information [including the personal information of customers], as well as information provided by suppliers, employees, counterparties, and others. Such information could be exposed in the event of a cybersecurity incident or other unauthorized access, which could materially adversely affect Toronto Hydro and also result in third-party claims against Toronto Hydro.

Preventative controls are employed to protect information and technology assets against cyber-attacks and mitigate their effects. Toronto Hydro maintains close coordination with industry partners and agencies and technology vendors who provide near real-time threat intelligence. Detective controls are employed to continuously monitor information systems so that Toronto Hydro can respond appropriately to minimize the damage in the event of a cyber-attack. Additionally, in respect of Toronto Hydro's operational technology systems in general, controls are in place which mitigate against wider systemic risk to business systems. Toronto Hydro has also developed robust processes for assessment of third-party providers and contractors that interact with its information technology systems, and has contractual protection and technical safeguards in place to safeguard against third-party risks. Even with these measures in place, since the techniques used to obtain unauthorized access, disable or degrade

service, or sabotage systems change frequently and may only be detected once a cyber incident has initiated, Toronto Hydro may be unable to anticipate these techniques or to implement adequate preventative measures.

As Toronto Hydro focuses on increasing the intelligence, automation and interactive nature of its distribution system, the incorporation of a greater level of technology and information systems into its infrastructure, makes the distribution system inherently more prone to external cyberattack. As such, there can be no assurance that the measures taken will be effective in protecting LDC's electricity distribution infrastructure or assets, or the personal information of its customers or employees, from a cyber-attack or the effects therefrom.

As public health measures and pandemic restrictions have lifted, Toronto Hydro has transitioned to a hybrid work arrangement. Threat vectors related to remote working (i.e. scams, spams, phishing, vishing, etc.) are expected to persist to exploit hybrid work infrastructure and target employees' home networks and personal devices to gain access to Toronto Hydro's networks. As such, the Corporation will continue to deploy preventative and detective controls to protect and continuously monitor information systems and technology assets to help minimize damage in the event of a cyber-attack, breach or other compromise. The Corporation also has internal cybersecurity and technology use policies in place, as well as a cybersecurity training program for its employees.

Despite the proactive steps taken to adapt to the current environment, the Corporation's ability to operate effectively is dependent on the security, development, maintenance, and management of complex information technology systems.

Safety Risk

Risk to Toronto Hydro employees or the general public of critical/fatal injuries and illnesses relating to or impacting upon Toronto Hydro activities.

Potential and existing health and safety risks related to worksites and tasks being performed by Toronto Hydro are regularly assessed and where identified, hazards are removed and/or mitigated to continually improve health and safety for Toronto Hydro employees, customers and members of the public. The most serious workplace incidents arising from workplace hazards can cause and/or contribute to critical injuries, fatal injuries, and occupational illnesses, as defined by provincial health and safety legislation.

The nature of the work performed in electrical utilities operations requires that employees receive extensive training on health and safety, including on personal protective equipment and the implementation of workplace safety procedures and protocols. This is due to the hazards inherent to electrical utilities work, which, depending on the required task, can include electrical contact, arc flash, working in confined spaces, fires or explosions, slips, trips and falls, motor vehicle incidents, occupational illnesses, and biological hazards such as infectious diseases. On occasion, hazards can result in personal injury, operational interruptions, and loss or damage to equipment, property, or information technology systems. In an active and ongoing manner, Toronto Hydro further mitigates health and safety risks to employees, customers and members of the public through equipment inspection, replacement and maintenance, employee training, communications programs and reactive and emergency work. "Safety by Design" principles are applied in the development of construction standards and design practices. New products for use in the distribution system go through a thorough review and introduction process. The selection process for new products and the development of standards promotes employee, customer, and public health and safety.

Toronto Hydro is subject to compliance with provincial health and safety legislation. Toronto Hydro's management approach to occupational health and safety is to meet, and often where possible, exceed legal compliance requirements and eliminate or safeguard known occupational hazards and risks. Toronto Hydro also follows the internal responsibility system to clearly define responsibility and accountability for every workplace party at each level within the organization. There are processes in place to develop and nurture good leadership practices through recruitment, education, training and performance management practices that encourage the application of Toronto Hydro's corporate values, including health and safety.

Toronto Hydro also has in place an infectious disease plan, which was activated by the COVID-19 emergency, as well as previous pandemics and epidemics. This plan has been a significant part of Toronto Hydro's emergency

response to COVID-19 and has been used to seek to limit health and safety exposures to employees, members of the public, and the communities serviced by Toronto Hydro.

In 2013, LDC received OHSAS 18001 certification which was the international standard for occupational health and safety management systems. OHSAS was later replaced by ISO 45001:2018 which Toronto Hydro successfully migrated to in 2019 and was subsequently re-certified in 2021. LDC conducts annual third-party audits to maintain ISO 45001:2018 certification. In addition, occupational health and safety legal compliance audits are conducted by an external third party every two years. The ISO 45001:2018 certificate expires on February 4, 2025.

Financial Risk

Risk that Toronto Hydro is unable to maintain its financial health and performance at acceptable levels.

Toronto Hydro is directly and indirectly subject to various macroeconomic and local market forces, which could have material adverse impacts. As a consequence of uncertainties in the recovery of economic and market conditions, Toronto Hydro remains exposed to inflationary pressures, an increased interest rate cost environment, indeterminate levels of customer consumption, credit risk with respect to customer non-payment of electricity bills and increased supply chain, operating and infrastructure development costs. The general rate of inflation in Canada and many other countries saw a significant increase during 2021 and continuing throughout 2022, with some regions experiencing multi-decade highs. Certain underlying factors include, but are not limited to, global supply chain disruptions, shipping restrictions, labour market constraints, geopolitical instability and side effects from monetary policies and fiscal expansions. The global economic recovery remains uncertain. Prices for certain services and materials continue to evolve in response to fast-changing commodity markets, industry activities, supply chain dynamics, and government policies impacting operating and capital costs. The global economic recovery and rising inflationary trends are widely expected to result in elevated interest rates. In 2022, the Bank of Canada began raising its benchmark interest rates for the first time since 2018 and further interest rate increases may occur. The Corporation closely monitors market trends and seeks to mitigate cost impacts through various measures, including project management, procurement and other management actions. There can be no assurance that the OEB will allow full recovery of increased costs relating to these factors.

As a result of the uncertain economic conditions, Toronto Hydro also may be exposed to the risk of counterparties defaulting on their obligations. The Corporation monitors and limits its exposure to credit risk on a continuous basis. The credit risk related to cash and cash equivalents is mitigated by the Corporation in assessing and monitoring the credit exposures of counterparties. The Corporation's exposure to credit risk primarily relates to accounts receivable and unbilled revenue. As a result of current uncertain economic conditions, the Corporation may be exposed to credit risk with respect to customer non-payment of electricity bills, and LDC's security interest or other protective measures, if any, provided to LDC, such as letters of credit, cash deposits or pre-authorized payments may not be sufficient. The Corporation considers the current economic and credit conditions to determine the expected credit loss allowance of its accounts receivable and unbilled revenue. Due to current uncertain economic conditions, the estimates and judgments made by management in the preparation of the expected credit loss allowance are subject to an estimation uncertainty. The Corporation determines the expected credit loss allowance based on current estimates and assumptions, including but not limited to recent trends for customer collections and current and forecasted economic conditions. The Corporation continues to actively monitor its exposure to credit risk.

Actions by the provincial government or regulatory authorities may impede LDC's ability to mitigate the risk of customer non-payment using means normally permitted by law at certain times of the year, including security deposits [i.e., letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB], late payment penalties, pre-payment, pre-authorized payment, load limiters or disconnection. LDC may have no option in certain cases but to assume the amount of any default, whether in whole or in part, and LDC's security interest or other measures, if any, may not provide sufficient protection. While LDC would be liable for the full amount of the default, there can be no assurance that the OEB would allow recovery of the expected credit loss allowance or of the increased operating or construction costs, and such expenses and costs could have a material adverse effect on the Corporation's business, operations, financial condition or prospects. The OEB would examine any electricity distributor's application for recovery of extraordinary expected credit loss allowance and other

expenses on a case-by-case basis. Increases in outstanding receivables due to reduced or delayed customer payments as a result of economic conditions could also contribute to liquidity risk for LDC as it continues to be charged for electricity commodity, transmission and other charges, which are intended to be flow-through items to customers. If the level of customer payment delays or non-payment, or increased costs contribute to liquidity challenges, the Corporation expects that it would utilize various mitigation tools at its disposal in seeking to improve its liquidity, including accessing further debt under, or increasing limits in, any of its MTN Program, CP Program, or its credit facilities, or by reducing costs and delaying payments. The global economic situation continues to be dynamic and uncertain and the ultimate duration and magnitude of the impact on Toronto Hydro's business cannot be determined with certainty at this time.

The Corporation is exposed to liquidity risk related to its ability to fund its obligations as they become due. The Corporation monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and financial requirements. The Corporation has access to credit facilities and debt capital markets and monitors cash balances daily. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they become due while minimizing finance costs. The Corporation relies on debt financing through the debt capital markets and existing credit facilities to finance its daily operations, repay existing indebtedness, and fund capital expenditures. The current challenging economic climate affected by factors including but not limited to uncertain macroeconomic conditions like a global recession may lead to material adverse changes in cash flows, working capital levels and/or debt balances, which may also have a direct negative impact on the Corporation's operating results and financial position in the future. Accordingly, the Corporation continues to monitor liquidity risk and adapt its plans as the economic climate evolves.

Toronto Hydro seeks to target an optimal capital structure and cash to debt range to access capital markets at the lowest interest rates to finance its capital plans, including those related to meeting increased electricity demand resulting from net zero GHG emission policies [such as the City's TransformTO]. The Corporation's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by a number of factors, including financial market conditions, inflationary pressure, Bank of Canada monetary policy decisions, regulatory processes that affect the timeliness for the approval and clearance of variance accounts, and macroeconomic concerns around the health of the economy in general and consumers. In addition, any of the above factors can also be affected by financial or geopolitical events in the global economy, Toronto Hydro's business, operations, financial condition or prospects, compliance with contractual debt covenants, the ratings assigned to the Corporation or the debentures issued under the Corporation's MTN Program by credit rating agencies, the rating assigned to short-term borrowings under the CP Program by a credit rating agency, the availability of the commercial paper market, and the interest rates and availability of borrowing capacity under its Revolving Credit Facility, Working Capital Facility and other credit arrangements. In the event the Corporation is unable to maintain a required credit rating for its CP Program, the Corporation's cost to access short-term capital could be materially adversely affected. In addition, if the Corporation cannot maintain attractive credit ratings for its MTN Program, debt capital under such program may become too costly or unavailable, which could materially adversely affect the Corporation's capital and operational programs, and its financial health and performance. There can be no assurance that debt or equity financing will be available or sufficient to meet Toronto Hydro's requirements, objectives, or strategic opportunities. If and when financing is available, there can be no assurance that it will be on acceptable terms to Toronto Hydro. As the City is the sole shareholder of the Corporation, it is dependent on the City for new equity, the timing and amount of which is subject to uncertainty. Therefore, as further indebtedness is incurred to finance Toronto Hydro's capital program and its climate action plan, the Corporation's debt to equity capital structure may not be maintained at a level in alignment with the OEB's deemed capital structure for rate making purposes (60% debt:40% equity). The Corporation regularly reviews the external market environment and has regular engagements with its credit rating agencies, securities dealers and investor community to monitor capital structure risk.

Generally, Toronto Hydro is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations. As at December 31, 2022, Toronto Hydro estimates that a 1% [100 basis point] increase in the discount rate used to value these obligations would decrease the accrued benefit obligation by $27.1 million, and a 1% [100 basis point] decrease in the discount rate would increase the accrued benefit obligation by $33.3 million.

Toronto Hydro is also exposed to short-term interest rate risk on the short-term borrowings under its CP Program and Working Capital Facility, as well as customer deposits, while most of its remaining obligations for the most

recently completed financial year were either non-interest bearing or bear fixed interest rates, and its financial assets for the most recently completed financial year were predominately short-term in nature and mostly non-interest bearing. Toronto Hydro manages interest rate risk by monitoring its mix of fixed and floating rate instruments, and taking action as necessary to maintain an appropriate balance as established under its treasury policies. Toronto Hydro estimates that a 25-basis point increase [decrease] in short-term interest rates, with all other variables held constant, would result in an increase [decrease] of approximately $1.1 million to annual finance costs.

Toronto Hydro typically has limited exposure to the changing values of foreign currencies. While Toronto Hydro purchases goods and services which are payable in United States dollars, and purchases United States currency to meet the related commitments when required, the impact of these transactions as at December 31, 2022 was not material.

Toronto Hydro's financial health and performance may also be adversely affected by events or measures, as well as changes in economic, policy, customer preference or technological conditions, that reduce the demand for electricity. Such events or measures may include, but are not limited to, closures of businesses and other institutions such as schools and government operations as a result of extreme storms and other weather conditions, natural disasters, terrorism, and pandemics such as COVID-19. A reduction in demand for grid-supplied electricity distribution may also arise from conservation measures. Additionally, the adoption by customers of new technologies in the electricity industry, including those related to self-generation, could reduce customer demand for grid-supplied electricity distribution. Toronto Hydro is focused on investing in its infrastructure to modernize the grid to drive resiliency, reliability, customer effectiveness and efficiency. See section 4.5(d) entitled "Environmental, Social and Governance" for more information on Toronto Hydro's ESG and sustainability activities.

Operations Risk

Risk that Toronto Hydro is not able to effectively meet the needs of its customers and a growing city, and maintain the security and reliability of the distribution grid at acceptable levels. The primary factors driving Toronto Hydro's operations risk relate to asset management, supply chain, customer management, physical security, and business interruption.

Toronto Hydro may be unable to maintain reasonable levels of reliability for its customers due to failure of existing distribution infrastructure and assets [including assets not directly involved in electricity distribution such as facilities and computer systems], access to the supply of electricity from the provincial and local generation and transmission systems, and the inability to replace or expand distribution infrastructure in an optimal timeframe. Electricity distribution is a capital-intensive business. As the municipal electricity distribution company serving the largest city in Canada, LDC continues to invest in the renewal of existing aging infrastructure and in the development of new infrastructure to address safety, reliability, hardening the resiliency of the distribution system against the effects of climate change, and customer service requirements now and in the future. As well, infrastructure investments will be made to increase the capacity and resilience of the grid required to facilitate the electrification of the economy and people's daily lives in order to achieve government net zero GHG emissions targets.

LDC estimates that over a quarter of its electricity distribution assets have already exceeded or will reach the end of their expected operating lives over the next five years [i.e., by 2028]. Asset condition assessment demographics also indicate substantial asset investment needs for a number of critical assets during this period. At the same time, Toronto is one of the fastest growing cities in North America and LDC must make upgrades to keep pace with urban intensification and electrification, optimize flexibility of connection to generation and transmission systems, including distributed energy resources; and ensure good stewardship of the distribution system in a manner that accounts for a changing climate. Further, extreme weather is no longer an infrequent experience, and has instead become a regular condition of operating a distribution system. Toronto Hydro has experienced several extreme weather events in recent years, including ice storms, freezing rain, extreme wind and flooding, that have led to a significant number of customers experiencing electricity outages and challenges to maintaining access to electricity supply from the transmission system.

In addition, as the City, provincial government and the Government of Canada implement policies and programs to respond and adapt to climate change, including greater electrification through the adoption of electric vehicles, distributed energy resources, building heating and cooling retrofits and energy efficiency/demand management technologies, the pressures on Toronto Hydro's system are expected to increase. Such factors may drive a need for incremental capital expenditures for system upgrades and new technologies to increase grid capacity and resilience in order to reliably handle increased loads, higher power quality requirements and multi-directional flows. As Toronto Hydro adopts novel technologies or equipment to enhance the capabilities of its electricity distribution grid, despite system contingency, there can be no guarantee that these technologies or equipment will be effective or that they will not increase the incidence or duration of outages.

LDC's ability to continue to provide a safe work environment for its employees and a reliable and safe distribution service to its customers and the general public will depend on, among other things, the ability of Toronto Hydro to fund additional infrastructure investments, and the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment, expansion and replacement.

LDC is focused on overcoming the above challenges and executing its capital and maintenance programs. It uses a variety of asset and project management tools to implement its plans, measures progress on a recurring short interval basis, and regularly monitors and manages the health of its assets. Toronto Hydro continues to align its asset management system to the ISO 55001: Asset Management standard and has commenced a formal process which is expected to lead to certification under the standard and to cause the lifecycle of assets to be managed more effectively, reduce system costs and improve system visibility and reliability. Toronto Hydro employs sophisticated, granular scenarios analysis based upon customer preferences to support its investment planning programs at the local level. LDC is also extensively engaged in regional planning activities and processes with the IESO to ensure the adequacy of the regional transmission system serving the City. Toronto Hydro also utilizes a diverse set of contractors and suppliers through its rigorous procurement practices and monitors market conditions closely. However, if LDC is unable to carry out these plans in a timely and optimal manner, becomes subject to significant unforeseen equipment failures, or is unable to access sufficient supplies or human resources, equipment performance will degrade. Such degradation may compromise the reliability of distribution assets, climate change readiness, the ability to deliver sufficient electricity and/or customer supply security, including in response to government net zero GHG policies and public goals, and increase the costs of operating and maintaining these assets. Similarly, there is no certainty that regional planning efforts controlled by external governing agencies and regulators will address all electricity supply matters as identified by LDC.

Additionally, Toronto Hydro's ability to operate effectively is in part dependent upon timely access to equipment, materials and service suppliers. Loss or delay of key equipment, materials and service suppliers and the reputational and financial risk exposures of key vendors could affect the Corporation's operations and execution of capital projects. Disruptions to the Corporation's supply chain, driven by the geopolitical environment, inflation, shifts in demand, and labour shortages, have resulted in increased lead times, increased costs, and more variability in on-time and in-full deliveries for key assets like transformers, cables, and switchgear. These capacity concerns may affect grid reliability, storm management and recovery, or lead to delays or cancellation of electrification projects. Uncertainty and disruption resulting from international conflicts and military operations may also affect Toronto Hydro, including by contributing to supply chain or financial markets disruption. Toronto Hydro has a number of mitigation plans in place, including purchasing material requirements beyond lead times, sourcing and approving new suppliers to alleviate single point of supply issues, adjusting re-order points to increase certain stock codes, extending planning horizons, and re-using/repairing existing equipment where possible. Toronto Hydro utilizes its procurement processes and a diverse supplier and contractor base to mitigate against supply chain risks and costs.

Toronto Hydro may also fail to accurately measure customer electricity consumption, respond to and address customer service issues or bill customers correctly or on time [including meter to cash management]. In order to provide timely and accurate billing and customer service, Toronto Hydro has implemented a number of policies, procedures and guidelines including those related to metering, accounts receivable and connections/disconnections. Toronto Hydro monitors metering/billing accuracy, customer communications and customer service quality on an ongoing basis. The Corporation has also commenced a multi-phase customer enhancement program to harmonize the customer experience by delivering a digital enablement of customer interactions, seamless meter to cash process, updating customer billing technology and other customer service processes in a cost-effective and unified manner.

As noted above under "COVID-19 Pandemic Considerations", Toronto Hydro has implemented a number of provincial government and OEB-based programs, including changes to commodity prices, as well as its own initiatives such as extensions of disconnect moratoriums and reductions in late payment charges, in order to assist customers. The wind-down and removal of these supports for customers may lead to negative customer sentiment toward Toronto Hydro. As a result of net zero GHG emissions policies, LDC may need to accelerate capital investments to accommodate increasing electrification. These system enhancements may lead to material customer bill increases and a more challenging customer relationship environment for Toronto Hydro, as well as customer backlash against the energy transition and related expenditures by Toronto Hydro.

Toronto Hydro also faces external threats to its physical and perimeter security. This includes the security of Toronto Hydro's facilities including office buildings and distribution stations. In order to safeguard its assets and staff, Toronto Hydro has developed policies and guidelines around physical and perimeter security and facilities related emergency preparedness. Toronto Hydro has also implemented electronic security technologies to ensure that only authorized personnel have access to Toronto Hydro facilities.

Similarly, Toronto Hydro may be unable to maintain continuing and sustainable business operations, or recover from business interruption after an incident that is beyond normal operations. Toronto Hydro's operations are exposed to the effects of natural and other unexpected occurrences such as extreme storm and other weather conditions, natural disasters, loss of the supply of electricity from the provincial and local generation and transmission system, as well as terrorism and pandemics, such as COVID-19. LDC is also exposed to risks that informational and operational technology systems may not operate as anticipated and could result in sustained interruptions to key corporate systems that would have a substantial impact on continuing normal business operations. Costs and operational changes, associated with such business interruption events may have a material and adverse effect on Toronto Hydro's business and operations in both its short and longer term. These impacts may also include limiting Toronto Hydro's ability to build, repair and maintain capital infrastructure, with resultant impacts on reliability and revenue. Toronto Hydro has implemented various initiatives aimed at improving the system's resiliency to increasingly frequent extreme weather events caused by climate change. These initiatives include updating major equipment specifications, revising planning guidelines, reviewing the load forecast impacts, revising design practices, and enhancing maintenance programs.

Toronto Hydro has also implemented an emergency and business continuity management program to support organizational-wide resiliency and build measures in response to major threats to operations such as the COVID-19 pandemic, and major power outage events. Although Toronto Hydro's facilities and operations are constructed, operated and maintained with such occurrences in mind, there can be no assurance that they will successfully withstand such occurrences in all circumstances. Any major damage to Toronto Hydro's facilities or interruption of Toronto Hydro's operations arising from these occurrences could result in lost revenues and repair costs that can be substantial. Although Toronto Hydro has continued to place insurance which it considers to be consistent with industry practice, there is no guarantee that insurance will continue to be available at reasonable rates for certain types of coverage and policy limits. If Toronto Hydro sustained a large uninsured loss caused by natural or other unexpected occurrences, LDC may apply to the OEB for the recovery of the loss related to the electricity distribution system. There can be no assurance that the OEB would approve, in whole or in part, such an application.

Human Capital Risk

Risk that Toronto Hydro is unable to maintain necessary resource talent and skilled resources.

Toronto Hydro is subject to the risk that human resources may not be available with the necessary knowledge, skills and education to support Toronto Hydro's future talent requirements and, as a result, its strategic activities and business objectives. This risk could be heightened in economic conditions where inflation rates are rising as this may result in pressure on wages and salaries, and where employee expectations with respect to work-life balance and flexibility are evolving. Furthermore, Toronto Hydro expects that labour force availability for certain positions will continue to tighten, resulting in increased competition and turnover for certain skilled employees, which may negatively impact knowledge management and business continuity at Toronto Hydro.

Development and retention of talent to meet the evolving needs of the business, particularly those related to the adoption of new technologies central to electrification and implementation of grid-connected energy resources to enable the clean energy transition and other needs of a modernized distribution grid requires Toronto Hydro to focus on a series of proactive activities and programs to mitigate these risks, such as strategic workforce planning, promotion of apprenticeship programs, diversity and inclusiveness awareness and training, investments in colleges and universities, succession planning, knowledge transfer and a robust training program. See section 4.5(d) entitled "Environmental, Social and Governance" for more information on Toronto Hydro's ESG and diversity activities.

Constraints on executive compensation may hinder Toronto Hydro's ability to attract and retain executive level talent. Failure to attract and retain executive level talent that have the skills and experience necessary to help Toronto Hydro achieve its strategic goals could have a material adverse effect on Toronto Hydro's business and operations.

Toronto Hydro's ability to operate successfully in the electricity industry in Ontario will continue to depend in part on its ability to make changes to existing work processes and conditions in order to adapt to changing circumstances, including limitations and restrictions placed on human resources as a result of external environment factors such as infectious diseases or erosion of social cohesion. Toronto Hydro's ability to make such changes or adapt, in turn, will continue to depend in part on its relationship with its labour unions, including negotiating collective bargaining agreements with the Society of United Professionals and PWU. There can be no assurance that Toronto Hydro will be able to secure the support of its labour unions. There can also be no assurance that Toronto Hydro will be able to secure collective agreements without work stoppages by its unionized work forces.

Toronto Hydro's ability to develop its work processes to meet changing circumstances, deliver upon grid modernization and address electrification, also depends on its ability to access adequate resources from its external contractor community with advanced developed skills. Toronto Hydro's ability to successfully access and benefit from third party service providers will depend, in part, on minimizing any disruption that may be caused by infectious diseases or other factors. If such disruption occurs, there may be a material adverse effect on Toronto Hydro's business and operations. One way in which Toronto Hydro seeks to mitigate this risk is through its use of business practices and internal procedures to identify a diverse group of reputable third-party service providers with access to advanced skill sets and entering into contracts with, and monitoring the performance of, these third-party service providers.

Compliance Risk

Risk that Toronto Hydro does not meet its material compliance obligations under legal and regulatory instruments.

Toronto Hydro is committed to complying with applicable legal and regulatory requirements and other requirements to which the organization subscribes. Toronto Hydro has a Corporate Compliance program that strengthens the organization's culture of compliance and aims to provide reasonable assurance, to Toronto Hydro's senior leadership and Toronto Hydro's Board of Directors, of adherence with material compliance requirements. Regular senior leadership reporting on the completion status of planned mitigation actions, monitoring of compliance issue turnover rates, and a responsible employee attestation process assist with ensuring effective management of identified compliance risks. Despite these mitigations, there can be no certainty that Toronto Hydro will be in material compliance with applicable future laws, rules, regulations and policies at all times. Constraints on access to human and materials resources due to global supply chain challenges may create risk of completion of compliance activities in accordance with mandated timelines. Failure by Toronto Hydro to comply with applicable laws, rules, regulations and policies may subject Toronto Hydro to civil or regulatory proceedings that could have a material adverse effect on Toronto Hydro. The OEB may not allow recovery in rates for the costs of coming into or maintaining compliance with these laws, rules, regulations and policies.

PART 9 - CAPITAL STRUCTURE

9.1 Share Capital

The authorized capital of the Corporation consists of an unlimited number of common shares without par value, of which 1,200 common shares are issued and outstanding as at the date of this AIF. See note 16 to the Consolidated Financial Statements.

9.2 Debentures

As at December 31, 2022, the Corporation had the following debentures [the "Debentures"] outstanding, which have been issued pursuant to its MTN Program:

- $200.0 million of 5.54% Series 6 senior unsecured debentures due May 21, 2040;
- $250.0 million of 2.91% Series 8 senior unsecured debentures due April 10, 2023;
- $245.0 million of 3.96% Series 9 senior unsecured debentures due April 9, 2063;
- $200.0 million of 4.08% Series 10 senior unsecured debentures due September 16, 2044;
- $200.0 million of 3.55% Series 11 senior unsecured debentures due July 28, 2045;
- $200.0 million of 2.52% Series 12 senior unsecured debentures due August 25, 2026;
- $200.0 million of 3.485% Series 13 senior unsecured debentures due February 28, 2048;
- $200.0 million of 2.43% Series 14 senior unsecured debentures due December 11, 2029;
- $200.0 million of 2.99% Series 15 senior unsecured debentures due December 10, 2049;
- $200.0 million of 1.50% Series 16 senior unsecured debentures due October 15, 2030;
- $150.0 million of 2.47% Series 17 senior unsecured debentures due October 20, 2031;
- $200.0 million of 3.27% Series 18 senior unsecured debentures due October 18, 2051; and
- $300.0 million of 4.95% Series 19 senior unsecured debentures due October 13, 2052

The Debentures are not listed, posted for trading or quoted on any stock exchange or quotation system.

The Debentures have been issued under the CDS book entry system administered by CDS with BNY Trust Company of Canada as trustee. Accordingly, a nominee of CDS is the registered holder of the Debentures and beneficial ownership of the Debentures is evidenced through book entry credits to securities accounts of CDS participants [e.g., banks, trust companies and securities dealers], who act as agents on behalf of beneficial owners who are their customers, rather than by physical certificates representing the Debentures.

9.3 Credit Facilities

The Corporation has a Revolving Credit Facility, pursuant to which it may borrow up to $800.0 million, of which up to $210.0 million is available in the form of letters of credit. On September 2, 2021, the maturity date of the Revolving Credit Facility was extended from October 10, 2024 to September 2, 2026. On November 18, 2022, the maturity date of the Revolving Credit Facility was extended from September 2, 2026 to September 17, 2027. Borrowings under the Revolving Credit Facility bear interest at fluctuating rates plus an applicable margin based on the Corporation's credit rating. On March 17, 2023, the amount available for borrowing under the Revolving Credit Facility was increased by $200.0 million from $800.0 million to $1.0 billion.

The Revolving Credit Facility contains certain covenants, including a requirement that the Corporation's debt to capitalization ratio not exceed 75%. As at December 31, 2022, the Corporation was in compliance with all covenants included in its Revolving Credit Facility agreement.

The Corporation has a CP Program allowing up to $750.0 million of unsecured short-term promissory notes to be issued in various maturities of no more than one year. The CP Program is supported by liquidity facilities available under the Revolving Credit Facility; hence, available borrowing under the Revolving Credit Facility is reduced by the amount of commercial paper outstanding at any point in time. Proceeds from the CP Program are used for general corporate purposes. Borrowings under the CP Program bear interest based on the prevailing market

conditions at the time of issuance. On March 24, 2023, the amount available for issuance under the Commercial Paper Program was increased by $250.0 million from $750.0 million to $1.0 billion.

The amount available under the Revolving Credit Facility as well as outstanding borrowings under the Revolving Credit Facility and CP Program are as follows:

	Revolving Credit Facility Limit	Revolving Credit Facility Borrowings	Commercial Paper Outstanding	Revolving Credit Facility Availability
December 31, 2022	$ 800.0 million	—	$ 355.0 million	$ 445.0 million
December 31, 2021	$ 800.0 million	—	$ 275.0 million	$ 525.0 million

Additionally, the Corporation has a Prudential Facility and a Working Capital Facility. On September 2, 2021, the amount which can be issued against the Prudential Facility was increased from $75.0 million to $100.0 million. For the year ended December 31, 2022, the average aggregate outstanding borrowings under the Corporation's Revolving Credit Facility, Working Capital Facility and CP Program were $459.5 million with a weighted average interest rate of 2.15%.

As at December 31, 2022, $12.8 million had been drawn under the Working Capital Facility and letters of credit in the amount of $57.6 million were issued against the Prudential Facility.

9.4 Credit Rating

As at December 31, 2022, the credit ratings of the Corporation were as follows:

	DBRS		S&P	
	Credit Rating	Trend	Credit Rating	Outlook
Issuer rating	A	Stable	A	Positive
Debentures	A	Stable	A	-
Commercial paper	R-1 (low)	Stable	-	-

DBRS rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". All rating categories other than AAA and D also contain the subcategories "(high)" and "(low)" to indicate relative standing within the major rating categories. The absence of either a "(high)" or "(low)" designation indicates the rating is in the middle of the category. An A rating is the third highest of the ten rating categories. Long-term debt instruments which are rated in the "A" category by DBRS are considered to be of good credit quality, with substantial capacity for the payment of financial obligations. Entities in the "A" category may be vulnerable to future events, but qualifying negative factors are considered manageable.

DBRS rates short-term debt instruments by rating categories ranging from a high of "R-1 (high)" to a low of "D". An R-1 (low) rating is the third highest of the ten rating categories. Short-term debt instruments which are rated in the "R-1 (low)" category by DBRS are considered to be of good credit quality, with substantial capacity for the payment of financial obligations. Entities in the "R-1 (low)" category may be vulnerable to future events, but qualifying negative factors are considered manageable.

S&P rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". Ratings from "AA" to "CCC" may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. An A rating is the third highest of the ten rating categories. Long-term debt instruments which are rated in the "A" category by S&P are considered somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories; however, the obligor's capacity to meet its financial commitment on the obligation is still strong.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. A rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating agency.

For the years ended December 31, 2022 and 2021, payments were made to both DBRS and S&P for credit rating services only.

PART 10 - DIRECTORS AND OFFICERS

10.1 Changes to the Corporation's Board of Directors

Effective April 6, 2022, the City Council appointed James Hinds and Annie Ropar to the Board of the Corporation. Also effective on April 6, 2022, all then-current citizen directors were re-appointed to the Board of the Corporation other than Tamara Kronis and Juliana Lam who ceased to be directors of the Corporation.

Effective September 15, 2022, Annie Ropar resigned from the Board of the Corporation and as a member of the Audit and Human Resources and Environment Committees. Concurrently, Michael Eubanks was appointed to the Audit Committee and David McFadden was appointed to the Human Resources and Environment Committee.

On November 14, 2022, Deputy Mayor Denzil Minnan-Wong's term as a director of the Corporation ended with the expiry of his term as City Councillor.

On November 22, 2022, Councillor Paul Ainslie's term as a director of the Corporation ended.

On November 23, 2022, the City Council appointed the following Councillor directors to the Corporation's Board: Councillor Stephen Holyday, Deputy Mayor Jennifer McKelvie, and Councillor Jaye Robinson as the Mayor's designate.

10.2 Nomination of Directors

As at the date of this AIF, the Board consists of ten directors all of whom are appointed by the sole shareholder of the Corporation, the City. There is one vacancy on the Board, which is to be filled upon the appointment of a citizen director by City Council.

Pursuant to the Shareholder Direction, in electing directors to the Board, the City gives due regard to the qualifications of a candidate, including: experience or knowledge; commercial sensitivity and acumen; independence of judgment; and personal integrity. The City seeks candidates with experience and knowledge in: public utility commissions or boards of major corporations or other commercial enterprises; corporate finance; corporate governance; market development; large system operation and management; urban energy industries; and public policy issues and laws relating to Toronto Hydro, the electricity industry, environmental matters, labour relations and occupational health and safety issues. The City may also utilize the skills matrix prepared by Toronto Hydro as referenced in section 10.3(b) below. Each citizen director is elected to serve for a term of up to two years or until his or her successor is appointed, and may be elected for a maximum of four consecutive terms for a maximum of eight consecutive years or such longer term until a successor is appointed. The terms of all current citizen directors expire upon the effective date of the appointment of their successors unless re-appointed. Each City Councillor director is elected to serve for two years or until his or her successor is elected. The terms of the current City Councillor directors expire on December 31, 2024 or upon the effective date of the appointment of their successors. As at the date of this AIF, female directors constituted 40% [4 of 10] of the members of the Corporation's Board.

10.3 Committees of the Board of Directors

The Board had established three standing committees [Audit Committee, Corporate Governance and Nominating Committee, and Human Resources and Environment Committee] as shown in the following chart.



(a) Audit Committee

The Audit Committee is responsible for overseeing the adequacy and effectiveness of financial reporting, accounting systems, internal financial control structures and financial risk management systems. The Audit Committee reviews the Corporation's quarterly and annual financial statements as well as financial statements prepared in connection with the requirements of applicable regulatory authorities, reviews the audit plans of the external auditors, oversees the internal audit of the Corporation, reviews and makes recommendations to the Board with respect to the payment of dividends or distribution of capital by the Corporation, and recommends the external auditor to the Board for appointment by the Corporation's sole shareholder. The Audit Committee also receives updates on cyber security related matters including management reporting on the Corporation's cyber security programs. See Part 11 entitled "Audit Committee" below for further information on the Audit Committee.

(b) Corporate Governance and Nominating Committee

The Corporate Governance and Nominating Committee is responsible for considering and making recommendations to the Board with respect to matters relating to the corporate governance of Toronto Hydro, including board and committee composition and mandates, and guidelines for assessing the effectiveness of the Board and its committees and procedures to ensure that the Board functions independently from management.

As part of its governance function, the Corporate Governance and Nominating Committee develops and reviews a skills matrix for all potential director candidates, which is then forwarded to the Corporation's sole shareholder by the Board for use in its director appointment process. The skills matrix incorporates best practice elements while considering the unique requirements of Toronto Hydro in order to identify key skills required of directors and help to ensure that these skills are accounted for among current and prospective directors. The skills matrix also takes into account diversity considerations, with a view to ensuring that the Board benefits from the broader exchange of perspectives made possible by diversity of backgrounds, as well as thought, skills and experience.

The Corporate Governance and Nominating Committee also nominates independent candidates for appointment to the Board of Directors of LDC for approval by the Corporation's Board as required by the Affiliate Relationships Code. The Corporate Governance and Nominating Committee reviews and approves orientation and education materials and programs for new and current directors undertaken by management.

Each of the current members of the Corporate Governance and Nominating Committee is independent within the meaning of applicable Canadian securities laws.

(c) Human Resources and Environment Committee

The Human Resources and Environment Committee is responsible for reviewing and assisting the Board in overseeing the recruitment and assessment of the CEO and the compensation of the CEO, reviewing and approving the compensation of the executive officers, reviewing and making recommendations to the Board concerning executive compensation disclosure under applicable securities laws, and reviewing and making recommendations to the Board regarding the compensation structure and benefit plans and programs of Toronto Hydro. The Human Resources and Environment Committee is also responsible for reviewing and approving the parameters of collective bargaining negotiations, the oversight of health and safety related matters and processes, and the oversight of environmental and climate change-related matters, processes and reporting of Toronto Hydro. Reporting on ESG performance and activities is also regularly provided to the Human Resources and Environment Committee. See section 12.1(a) entitled "Human Resources and Environment Committee" for further information on the Human Resources and Environment Committee.

(d) Other Committees

The Board also has a Steering Committee, consisting of the Chair of the Board and the Chairs of the respective standing committees, to assist the Board and its standing committees in fulfilling their responsibilities by providing timely guidance on emerging, time-sensitive, significant issues arising with respect to matters that overlap with the mandates of the standing Board committees. The Steering Committee does not replace any of the functions of the Board or its standing committees unless otherwise expressly delegated by the Board from time to time. The role of the Steering Committee is to provide advice and recommendations to the respective Board committees(s) that will enable them to successfully carry out their responsibilities and ultimately properly advise and make recommendations to the Board.

Further, the Board may establish ad-hoc committees from time to time for a specific task or subject matter.

10.4 Directors

The following summaries set forth, for each of the directors of the Corporation, the director's name, province and country of residence, the date on which the person became a director and the expiry date of the director's current term, the director's relevant education and experience, principal occupations within the five preceding years and board memberships with other reporting issuers. The following tables also summarize the attendance of individual directors at the Board and standing committee meetings held during 2022 and 2023 as of the date of this AIF. See section 10.1 entitled "Changes to the Corporation's Board of Directors" for more information on the Corporation's Board of Directors.

David McFadden, Chair of the Board
Ontario, Canada

Director since: December 10, 2015
Expiry of current term: April 8, 2024, or effective date of appointment of a successor director

Mr. McFadden is a former Partner and Counsel at Gowling WLG where his practice focused on the energy, infrastructure and financial services industries. He is a former member of Gowling's Board of Trustees and Executive Committee. Mr. McFadden currently serves as Chair of the Board of Directors of 407 International Inc., Makwa Development Corp. and PCI Geomatics Inc. He is a member of the MaRS Energy Board and of the Council for Clean & Reliable Energy. In the past, Mr. McFadden served as the Chair of the Board of Directors of the Ontario Energy Association. Mr. McFadden served as Chair of the Energy Transformation Network of the Independent Electricity System Operator and of the Electricity Transition Committee of the Ontario Government, and as a member of the Ontario Government's Electricity Distribution Sector Review Panel and the Electricity Conservation and Supply Task Force. Mr. McFadden was named the Energy Leader of the Year by the Ontario Energy Association in 2013. Mr. McFadden has been active in the higher education sector. He served as Chair of the Ontario Centres of Excellence from 2004-2010 and as a member of the Board of Governors of York University from 2013 to 2020. Mr. McFadden is the Chair of the Board of Directors of the Yonge Street Mission. Mr. McFadden holds a Bachelor of Laws at Osgoode Hall Law School and a Bachelor of Arts at the University of Toronto, and is a member of the Law Society of Ontario. Mr. McFadden received an Honorary Doctor of Laws from York University in 2012.

Mr. McFadden currently serves as Chair of the Board. He is also an ex-officio member of the Audit Committee, and Corporate Governance and Nominating Committee and has been appointed as a member of the Human Resources and Environment Committee effective November 5, 2022. Mr. McFadden has considerable experience in policy matters relating to renewable energy, decarbonization and climate change mitigation strategies through his work with the Energy Transformation Network and other bodies. Mr. McFadden also has considerable experience in executive compensation matters from his various Chair and Director roles. Through these roles at major organizations, he is familiar with the structure of compensation systems and related benefit programs, and is experienced in executive performance evaluation.

Principal Occupation:
Corporate Director

Board/Committee Membership	**2022 Attendance**	
Board	9 of 9	100%
Human Resources and Environment Committee	1 of 1 [(1)]	100%
	2023 Attendance [(2)]	
Board	1 of 1	100%
Human Resources and Environment Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
407 International Inc. [Reporting Jurisdictions: All provinces]

Notes:

(1) Mr. McFadden was appointed to the Human Resources and Environment Committee on November 15, 2022. 2022 attendance was reported for the period Mr. McFadden was actively serving on the Committee.
(2) 2023 attendance is for the period of January 1, 2023 to the date of this AIF.

Heather Zordel
Ontario, Canada

Director since: December 10, 2015
Expiry of current term: April 8, 2024, or effective date of appointment of a successor director

Ms. Zordel is a lawyer with extensive experience in corporate finance, securities regulatory compliance and corporate governance. A Lawyer of Counsel in the Securities Group at Gardiner Roberts LLP, she is also Chair of the Condominium Authority of Ontario. Ms. Zordel is a former non-executive Chair of the OSC's Board of Directors and a past OSC Commissioner. She previously was a Bencher of the Law Society of Ontario and part-time adjudicator for the Law Society Tribunal and part-time adjudicator for the OSC Tribunal. Ms. Zordel is a former member of the federally-appointed Expert Panel on Securities Regulation and a past Chair of the Securities Advisory Committee to the Ontario Securities Commission. Academically, she is a past Co-Director and a current Course Director for the Osgoode Professional LL.M. program in securities law. Ms. Zordel has a Bachelor of Commerce from the University of Saskatchewan and a LL.B./J.D./LL.M. [Securities] from Osgoode Hall Law School.

Ms. Zordel currently serves as Chair of the Board of Directors of TH Energy.

Principal Occupation:
Lawyer of Counsel, Gardiner Roberts LLP

Board/Committee Membership	**2022 Attendance**	
Board	9 of 9	100%
Audit Committee	1 of 1 (1)	100%
Corporate Governance and Nominating Committee	5 of 6	83%
	2023 Attendance (2)	
Board	1 of 1	100%
Corporate Governance and Nominating Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Notes:

(1) Ms. Zordel ceased to be a member of the Audit Committee on April 27, 2022. 2022 attendance was reported for the period Ms. Zordel was actively serving on the Committee.
(2) 2023 attendance is for the period of January 1, 2023 to the date of this AIF.

The Honourable Howard Wetston
Ontario, Canada

Director since:	December 10, 2015
Expiry of current term:	April 8, 2024, or effective date of appointment of a successor director

The Honourable Mr. Wetston is a distinguished lawyer with a breadth of experience and expertise in competition law and policy, securities regulation, energy regulation and administrative law. In 2016, Mr. Wetston was awarded the Order of Canada for his significant contributions as a public servant, jurist and regulator. Mr. Wetston is a former Canadian Senator between November 10, 2016 and June 3, 2022. Mr. Wetston has served as Chair and Chief Executive Officer of the OSC, as Vice-Chair of the OSC, and as Chair and Chief Executive Officer of the OEB. During his time as Chair and Chief Executive Officer of the OSC, Mr. Wetston played a significant role in Canadian and international securities regulatory bodies by serving as a senior member of the Canadian Securities Administrators and as a Vice Chair of the International Organization of Securities Commissions. Mr. Wetston has served as a Judge of the Federal Court of Canada, Trial Division, an ex-officio member of the Federal Court's Appeal Division, and Director of Investigations and Research at the Bureau of Competition Policy. Mr. Wetston is a Senior Fellow of the C.D. Howe Institute and has served on several Advisory Boards, including the Program on Ethics in Law and Business at the University of Toronto, and the Shannon School of Business at Cape Breton University. Mr. Wetston is a former Trustee of the International Valuations Standards Council. Mr. Wetston is a Member of the C.D. Howe Institute's Competition Policy Council. Mr. Wetston holds a Bachelor of Laws from Dalhousie University and a Bachelor of Science from Mount Allison University, and holds an ICD.D designation from the Institute of Corporate Directors. He has received special recognition as a Board Diversity Champion from Catalyst Canada Honours. Mr. Wetston holds honorary doctorate degrees from Cape Breton University and Dalhousie University and he is a recipient of the Queen Elizabeth II Diamond Jubilee Medal.

Mr. Wetston currently serves as Chair of the Board of Directors of LDC.

Principal Occupation:
Corporate Director

Board/Committee Membership	**2022 Attendance**	
Board	7 of 9	78%
Corporate Governance and Nominating Committee	6 of 6	100%
	2023 Attendance [(1)]	
Board	1 of 1	100%
Corporate Governance and Nominating Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Note:

(1) 2023 attendance is for the period of January 1, 2023 to the date of this AIF.

Mary Ellen Richardson
Ontario, Canada

Director since:	December 11, 2016
Expiry of current term:	April 8, 2024, or effective date of appointment of a successor director

Ms. Richardson is a retired energy executive and independent board director in the energy sector, with extensive experience in the oil, natural gas, district energy and electricity industries. Ms. Richardson currently serves as Vice-Chair of the Board of Directors and Chair of the Human Resources and Governance Committee of Markham District Energy Inc. In the past, Ms. Richardson has served as President of the Canadian District Energy Association, Vice-President, Corporate Affairs and Vice-President, Conservation Programs and External Relations at the OPA, President of the Association of Major Power Consumers in Ontario, and was a member of the Board of Directors and Human Resources Committee of Guelph Municipal Holdings Inc. Ms. Richardson has also served on the management board of the Ontario Centre of Excellence in Energy, on the Board of Directors of Environmental Careers Organization of Canada, on the Ontario Government's Electricity Conservation and Supply Task Force, on the Executive of the Stakeholders' Alliance for Competition and Customer Choice, and on Hydro One's Customer Advisory Board. Ms. Richardson holds an Honours degree in Economics from the University of Calgary, and the ICD.D designation.

Ms. Richardson currently serves as a member of the Board of Directors of LDC.

Principal Occupation:
President, Mary Ellen Richardson Inc.

Board/Committee Membership	**2022 Attendance**	
Board	9 of 9	100%
Corporate Governance and Nominating Committee	6 of 6	100%
	2023 Attendance [(1)]	
Board	1 of 1	100%
Corporate Governance and Nominating Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Note:

(1) 2023 attendance is for the period of January 1, 2023 to the date of this AIF.

Michael Anthony Eubanks
Ontario, Canada

Director since: November 27, 2020
Expiry of current term: April 8, 2024, or effective date of appointment of a successor director

Mr. Eubanks is an executive with significant experience in technology leadership. He is currently the Senior Vice-President Operations Support and Chief Information Officer of goeasy Ltd., a reporting issuer in all Canadian provinces, which provides leasing and lending services. Mr. Eubanks is also a member of the Board of Directors of Allstate Insurance Company of Canada. Prior to his employment with goeasy Ltd., Mr. Eubanks was the Chief Information Officer at the Liquor Control Board of Ontario [LCBO] and the Ontario Cannabis Store. Prior to that Mr. Eubanks served in progressive leadership roles focused on technology in the retail industry having worked for Canadian Tire Corporation and Best Buy International. Through his executive leadership roles at major organizations, he is familiar with the structure of compensation systems and related benefit programs, and is experienced in executive performance evaluation. Mr. Eubanks is a graduate of York University, ICD-Rotman Directors Education Program.

Mr. Eubanks is currently a member of the Board of Directors of TH Energy.

Principal Occupation:
Senior Vice-President Operations Support and Chief Information Officer of goeasy Ltd.
Former Senior Vice- President and Chief Information Officer of LCBO [Liquor Control Board of Ontario]

Board/Committee Membership	**2022 Attendance**	
Board	8 of 9	89%
Audit Committee	2 of 2 (1)	100%
Human Resources and Environment Committee	5 of 5	100%
	2023 Attendance (2)	
Board	1 of 1	100%
Audit Committee	1 of 1	100%
Human Resources and Environment Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Notes:

(1) Mr. Eubanks ceased to be a member of the Audit Committee on April 27, 2022, but was reappointed as an Audit Committee member on November 16, 2022. 2022 attendance was reported for the periods Mr. Eubanks was actively serving on the Committee.
(2) 2023 attendance is for the period of January 1, 2023 to the date of this AIF.

Michael Nobrega, Vice-Chair of the Board
Ontario, Canada

Director since: May 10, 2016
Expiry of current term: April 8, 2024, or effective date of appointment of a successor director

Mr. Nobrega is a Chartered Professional Accountant with extensive experience in finance and business. Mr. Nobrega has served as President & Chief Executive Officer of OMERS, Chief Investment Officer of OMERS, and as President & Chief Executive Officer of Borealis [OMERS] Infrastructure. Mr. Nobrega acted as interim President and Chief Executive Officer of Waterfront Toronto, and is the former Chair of Ontario Centres of Excellence. Mr. Nobrega has served as the Chair of the Board of Directors of IBI Group Inc. In the past, Mr. Nobrega was also president of a merchant bank, a tax partner at Arthur Anderson, Chartered Accountants, and a member of the Board of Directors of the Global Risk Institute. Mr. Nobrega is the Chair of the Centre for the Commercialization of Regenerative Medicine. Mr. Nobrega earned an Honours Bachelor of Arts [Economics and Mathematics] from the University of Toronto, where, in 2002, he was honoured with the Arbor Award for outstanding community service. He holds a chartered accountancy designation from the Chartered Professional Accountants of Ontario [formerly the Institute of Chartered Accountants of Ontario] and Chartered Professional Accountants of Canada, and was named a Fellow of Chartered Professional Accountants of Ontario [formerly the Institute of Chartered Accountants of Ontario] in 2009. Mr. Nobrega has considerable experience in executive compensation matters from his years as the Chief Executive Officer of OMERS and Borealis [OMERS] Infrastructure. Through his executive leadership roles at major organizations, he is familiar with the structure of compensation systems and related benefit programs, and is experienced in executive performance evaluation. Mr. Nobrega also has considerable experience in climate change matters and developing climate-resilient strategies, including through his involvement in formalizing investment policies and supporting green energy projects at OMERS and participation on committees focusing on investments in technologies aimed at reducing the carbon footprint.

Mr. Nobrega currently serves as a member of the Board of Directors of LDC.

Principal Occupation:
Corporate Director
Former Interim President and CEO, Waterfront Toronto
Former Chair, Ontario Centres of Excellence

Board/Committee Membership	**2022 Attendance**	
Board	8 of 9	89%
Audit Committee	4 of 4	100%
Human Resources and Environment Committee	1 of 1 (1)	100%
	2023 Attendance (2)	
Board	1 of 1	100%
Audit Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Notes:

(1) Mr. Nobrega ceased to be a member of the Human Resources and Environment Committee on April 27, 2022. 2022 attendance was reported for the period Mr. Nobrega was actively serving on the Committee.
(2) 2023 attendance is for the period of January 1, 2023 to the date of this AIF.

James Hinds
Ontario, Canada

Director since:	April 6, 2022
Expiry of current term:	April 8, 2024, or effective date of appointment of a successor director

Mr. Hinds has many years of public service in Ontario's electricity sector, most recently as a director of Hydro One (2015-2018). Prior to that, he was Chair of the IESO and has also served as Chair of the former OPA (until its merger with the IESO in 2015). Prior to joining the OPA Board (2010-2015), he served as a Director on and as Chair of the IESO Board (2005-2010). Mr. Hinds is a retired investment banker, having specialized in public equity markets underwriting and advice. He previously served as Managing Director of TD Securities Inc. and has also held positions with CIBC Wood Gundy Inc. and Newcrest Capital Inc.

Mr. Hinds received an undergraduate degree in political economy from the University of Toronto, a Masters of Business Administration from the Wharton School of Business at the University of Pennsylvania, and a law degree from the University of Toronto.

Mr. Hinds currently serves as a member of the Board of Directors of LDC.

Principal Occupation:
Corporate Director

Board/Committee Membership	**2022 Attendance**	
Board [(1)]	6 of 6 [(2)]	100%
Audit Committee	3 of 3 [(3)]	100%
	2023 Attendance [(4)]	
Board	1 of 1	100%
Audit Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Notes:

(1) Mr. Hinds was appointed to the Board on April 6, 2022.
(2) Six Board meetings occurred since the date of Mr. Hinds' appointment to the Board.
(3) Three Audit Committee meetings occurred in 2022 since the date of Mr. Hinds' appointment to the Committee.
(4) 2023 attendance is for the period of January 1, 2023 to the date of this AIF.

Jaye Robinson
Ontario, Canada

Director since:	November 23, 2022
Expiry of current term:	December 31, 2024, or effective date of appointment of a successor director

Councillor Robinson is the Mayor's designate to the Board. Councillor Robinson is the City Councillor for Ward 15 - Don Valley West and was previously City Councillor for Ward 25 - Don Valley West since 2010. Currently, Councillor Robinson serves as Vice-Chair of the Economic and Community Development Committee and on the Board of Directors for the Art Gallery of Ontario, Leaside Memorial Gardens Arena, and Toronto Symphony Orchestra. Councillor Robinson has also been named to a special role leading the 2026 FIFA World Cup in Toronto. Before running for municipal office, Councillor Robinson was a senior manager in economic development at the City of Toronto for over 20 years. With an entrepreneurial approach, Councillor Robinson successfully merged arts and community building initiatives with economic development strategies to launch a vibrant roster of annual events that generated significant financial benefits for the City. Her resume includes Nuit Blanche, Summerlicious, and Winterlicious.

From 2018-2022, Councillor Robinson served as Chair of the Toronto Transit Commission (TTC) and during the 2014-2018 City Council term, as Chair of the Public Works and Infrastructure Committee.

Principal Occupation:
Councillor, City of Toronto

Board/Committee Membership	**2022 Attendance**	
Board [1]	1 of 1 [2]	100%
	2023 Attendance [3]	
Board	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Notes:

(1) Ms. Robinson was appointed to the Board on November 23, 2022.
(2) One Board meeting occurred since the date of Ms. Robinson's appointment to the Board.
(3) 2023 attendance is for the period of January 1, 2023 to the date of this AIF.

Jennifer McKelvie
Ontario, Canada

Director since: November 23, 2022
Expiry of current term: December 31, 2024, or effective date of appointment of a successor director

Deputy Mayor McKelvie is a graduate of the University of Toronto Scarborough (B.Sc. Environmental Science) and a Professional Geoscientist (P. Geo. non-practicing). Her graduate (Ph.D. 2006) and postgraduate research was supported by numerous provincial, national and international awards, including the Natural Sciences and Engineering Research Council (NSERC) Canada Graduate Scholarship and the L'Oréal/United Nations Educational Scientific Organization (UNESCO) Women in Science Fellowship. Deputy Mayor McKelvie is currently serving as Chair of City Council's Infrastructure and Environment Committee, Striking Committee, Vice-Chair of City Council's Executive Committee, member of the Scarborough Community Council, and City Council's Committee of Revision. She is also a member of the Board of Management of the Toronto Zoo. Prior to becoming Councillor for Scarborough-Rouge Park, Deputy Mayor McKelvie managed industrial-academic partnerships and environmental research in the non-profit sector. Deputy Mayor McKelvie has a long-record of community service. She served as first President of the Scarborough Community Renewal Organization (2016-2018), and as President of the Centennial Community & Recreation Association (2015 to 2017). In this capacity, Deputy Mayor McKelvie worked collaboratively with stakeholders and residents to advocate for investment in Scarborough. Deputy Mayor McKelvie has also served as a member of the University of Toronto Scarborough Campus Council (2015-2018), as a citizen member of the Toronto Region Conservation Authority (2015-2018) and as a member of the Scarborough Women of Philanthropy (2015-2018), council in support of the Scarborough & Rouge Hospital Foundation.

Principal Occupation:
Deputy Mayor and Councillor, City of Toronto

Board/Committee Membership	**2022 Attendance**	
Board [1]	1 of 1 [2]	100%
	2023 Attendance [3]	
Board	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Notes:

(1) Ms. McKelvie was appointed to the Board on November 23, 2022.
(2) One Board meeting occurred since the date of Ms. McKelvie's appointment to the Board.
(3) 2023 attendance is for the period of January 1, 2023 to the date of this AIF.

Stephen Holyday
Ontario, Canada

Director since:	December 3, 2014
Expiry of current term:	December 31, 2024, or effective date of appointment of a successor director

Councillor Stephen Holyday has been the City Councillor for Ward 2 - Etobicoke Centre since 2018, and was previously City Councillor for Ward 3 - Etobicoke Centre since December 2014. Councillor Holyday is currently serving as Chair of City Council's Audit Committee, Chair of the Etobicoke York Community Council, Chair of City Council's Corporations Nominating Panel, and Vice Chair of City Council's General Government Committee. Councillor Holyday is a member of the Toronto Transit Commission, the Board of Directors of the Hockey Hall of Fame, and the Board of Directors of the Canadian National Exhibition Association. Before being elected to public office, Stephen Holyday was Manager, Service Management at the Ontario Ministry of Energy. He holds a Bachelor of Technology in Architectural Science from Ryerson University. Through his previous experience as Vice-Chair of City Council's Employee and Labour Relations Committee, Mr. Holyday is familiar with compensation systems and related benefit programs at all levels. Formerly a member of the Board of Directors of The Atmospheric Fund, Councillor Holyday was engaged in various issues and mitigation programs relating to climate change matters and actions to combat climate change and improve regional air quality through collaborative work with private, public and non-profit sectors.

Principal Occupation:
Councillor, City of Toronto

Board/Committee Membership	**2022 Attendance**	
	9 of 9	100%
Human Resources and Environment Committee	5 of 5	100%
	2023 Attendance [(1)]	
Board	1 of 1	100%
Human Resources and Environment Committee	1 of 1	100%

Board Memberships for other Reporting Issuers:
None

Note:

(1) 2023 attendance is for the period of January 1, 2023 to the date of this AIF.

10.5 Executive Officers

The following table sets forth the name, province and country of residence, office, and principal occupation for each of the executive officers of the Corporation as of December 31, 2022.

Name	Residence	Office	Principal Occupation
Anthony Haines[(1)]	Ontario, Canada	President and Chief Executive Officer	President and Chief Executive Officer, Toronto Hydro Corporation
Celine Arsenault[(2)]	Ontario, Canada	Executive Vice-President, Chief Financial Officer	Executive Vice-President, Chief Financial Officer, Toronto Hydro Corporation
Amanda Klein[(3)]	Ontario, Canada	Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer	Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer, Toronto Hydro Corporation

Notes:

(1) Mr. Haines has been the President of LDC since September 2006. He was also appointed the CEO of the Corporation effective October 1, 2009.

(2) Ms. Arsenault was appointed the Executive Vice President, Chief Financial Officer of the Corporation effective June 6, 2022.

(3) Ms. Klein was Vice-President, Regulatory Affairs and General Counsel of the Corporation [from January 1, 2015 to August 31, 2016] and then Executive Vice-President, Regulatory Affairs and General Counsel of the Corporation [from September 1, 2016 to September 30, 2018]. Ms. Klein was appointed as the Corporation's Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer effective as of October 1, 2018.

10.6 Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Mr. Nobrega was a director of CellCube Energy Storage Systems Inc. (now Saltbae Capital Corp.) when its shareholders, directors and officers were subject to a cease trade order. The cease trade order was issued by the Ontario Securities Commission on November 1, 2019 for the company's failure to file its corporation's annual audited financial statements, management's discussion and analysis and certification of the annual filings by the filing deadline under applicable law. The cease trade order remains in effect.

1. Except as noted above, no director or executive officer of the Corporation is, as at the date of this AIF, or has within ten years prior to the date of this AIF:

    (a) been a director, chief executive officer or chief financial officer of any company [including the Corporation] that was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation for a period of more than 30 consecutive days, where such order was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer;

    (b) been a director, chief executive officer or chief financial officer of any company [including the Corporation] that was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation for a period of more than 30 consecutive days, where such order was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer;

2. No director, executive officer of the Corporation or, to the Corporation's knowledge, the City is, as at the date of this AIF, or has within ten years prior to the date of this AIF:

(a) been a director or executive officer of any company [including the Corporation] that, while that person was acting in that capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(b) become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of such director or executive officer.

3. No director, executive officer of the Corporation or, to the Corporation's knowledge, the City, has been subject to:

(a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

10.7 Independence

As at the date of this AIF, the Board consists of ten directors, all of whom are appointed by the City in its capacity as sole shareholder of the Corporation. Three of the directors are Councillors of the City and are not considered independent because of their positions. None of the other directors have a direct or indirect material relationship with the Corporation and are independent within the meaning of applicable Canadian securities law.

No members of management sit on the Board. The Board meets regularly to discuss the management of the Corporation. A portion of each Board and Board committee meeting is reserved for Directors to meet without management present. Under its mandate, the Board is authorized to retain independent legal counsel and other advisors if it considers this appropriate. The mandate also provides that the Board shall have unrestricted access to the officers of the Corporation and is authorized to invite officers and employees of the Corporation and others to attend or participate in its meetings and proceedings if it considers this appropriate. The full text of the Board's written mandate is attached as Annex B.

The Corporation has developed a written position description for the Chair of the Board. The Chair is responsible for reporting to the Board, leading the directors and managing the day-to-day activities of the Board. The Chair is also responsible for engaging in discussions with the shareholder and its representatives as are necessary and desirable, maintaining an active and cooperative relationship with the CEO and other senior management of the Corporation, acting as the principal interface between the Board and the CEO of the Corporation, and providing advice and counsel to the CEO and other senior management of the Corporation.

The Board has also developed written position descriptions for the Chair of each Board committee and the CEO.

10.8 Board Orientation and Continuing Education

Each new director, upon joining the Board, is given an orientation session with access to a comprehensive set of materials designed to provide a summary of the key organizational, financial, regulatory and operational aspects of Toronto Hydro. These materials also contain information on the various Toronto Hydro boards and committees.

On an ongoing basis, as part of regular and special board meetings, directors receive presentations, reports and training on topics related to Toronto Hydro's businesses and the obligations and responsibilities of directors. Topics covered are either suggested by management or requested by the directors. As well, directors receive information

from management in response to any actions arising at a board meeting or otherwise. Educational programs through external service providers are also made available to the directors and the directors have access to an on-line resource centre populated with materials relating to Toronto Hydro which is updated regularly.

10.9 Board, Committee and Director Assessments

The Corporate Governance and Nominating Committee oversees a process used to evaluate the effectiveness of the Board as a whole, its committees and the individual directors. The process may be facilitated by an independent consultant with expertise in board assessments as selected by the Board. Alternatively, the Board may complete an internal assessment. The process may consist of an in-person interview and/or a written evaluation questionnaire that are completed periodically by each director. The directors' responses to the questionnaire and/or interviews related to the operation of the Board and its committees are compiled into a summary report that is reviewed by the Chair of the Board. This report and recommended remedial actions are presented to the Board for review, consideration and implementation.

10.10 Board Oversight and Management of Risks

In accordance with its mandate, the Board is responsible for overseeing the identification of the principal risks of the business and implementation of appropriate systems to manage these risks. Toronto Hydro has an ERM program which is focused upon improving the Corporation's operations through enabling the attainment of its strategic goals and objectives. The ERM program helps the Corporation achieve this by bringing a systematic and disciplined approach towards identifying, evaluating, treating, monitoring and reporting of risks applicable to Toronto Hydro. Accordingly, ERM is an integral part of the strategic management of the Corporation's business and is routinely considered in forecasting, planning and executing key aspects of Toronto Hydro's operations.

See Part 8 entitled "Risk Factors – Risk Management" above for further information on ERM.

10.11 Indebtedness of Directors and Executive Officers

No director, executive officer, employee, former director, former executive officer or former employee or associate of any director or executive officer of the Corporation or any of its subsidiaries had any outstanding indebtedness to the Corporation or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Corporation or any of its subsidiaries.

PART 11 - AUDIT COMMITTEE

11.1 Composition, Independence and Financial Literacy

The Audit Committee comprises Michael Nobrega [Chair], James Hinds and Michael Eubanks, each of whom is independent and financially literate within the meaning of applicable Canadian securities laws.

For a description of the relevant education and experience of each member of the Audit Committee, please refer to each member's profile under the section entitled "Directors and Officers – Directors".

11.2 Audit Committee Charter

Under the terms of its charter, the Audit Committee is responsible for: managing the relationship between Toronto Hydro and its external auditors; overseeing the external audit; overseeing the internal audit; reviewing and recommending to the Board for approval the financial statements, management's discussion and analysis and interim reports of the Corporation and its subsidiaries, the annual information form and other public disclosure of financial information extracted from the financial statements of the Corporation; overseeing internal financial control structure and financial risk management systems; establishing and reviewing certain procedures and policies; reviewing policy reporting; and reviewing and making recommendations to the Board with respect to the payment of dividends or distribution of capital by the Corporation.

The full text of the Corporation's Audit Committee Charter is attached as Annex A.

11.3 Policy on the Provision of Services by the External Auditors

The Audit Committee has developed a Policy on the Provision of Services by the External Auditors. Under the terms of the Policy:

- the external auditors may not provide services to Toronto Hydro that impair or have the potential to impair the independence and objectivity of the external auditors in relation to the external audit function [generally, prohibited services include services where the external auditors participate in activities that are normally undertaken by management of Toronto Hydro, are remunerated through a "success fee" structure, act in an advocacy role for Toronto Hydro or may be required to audit their own work];

- the Audit Committee has pre-approved certain audit and permitted non-audit services as services that the auditors may provide to Toronto Hydro, including: services that constitute the agreed scope of the external audit or interim reviews of Toronto Hydro; services that are outside the agreed scope of, but are consistent with, the external audit or interim reviews of Toronto Hydro; tax services that do not compromise the independence and objectivity of the external auditors in relation to the external audit; and other services of an advisory nature that do not compromise the independence and objectivity of the external auditors in relation to the external audit work; and

- an authorization process has been established which provides, among other things: the Chief Financial Officer may authorize in advance all engagements of the external auditors to provide pre-approved services [other than audit services] to Toronto Hydro up to a maximum of $50,000 for any engagement and up to a maximum of $100,000 for all engagements in any fiscal year [the Chief Financial Officer must report all such authorized engagements to the Audit Committee at its next meeting]; the Chair of the Audit Committee may authorize in advance all engagements of the external auditors to provide pre-approved services [other than audit services] to Toronto Hydro up to a maximum of $100,000 for any engagement and up to a maximum of $250,000 for all engagements in any fiscal year [the Chair must report all such authorized engagements to the Audit Committee at its next meeting]; and the Audit Committee must authorize in advance all engagements of the external auditors to provide pre-approved services to Toronto Hydro above the

prescribed thresholds and all engagements to provide services that are not pre-approved services regardless of the dollar value of the services.

Exceptions can be made to this Policy where the exceptions are in the interests of Toronto Hydro and appropriate arrangements are established to ensure the independence and objectivity of the external auditors in relation to the external audit. Any exception must be authorized by the Audit Committee and must be reported to the Board.

11.4 External Auditors Service Fees

The table below sets out the fees charged by Toronto Hydro's external auditor, KPMG LLP, on an accrual basis, for each of last two fiscal years in respect of the services noted below.

	Year ended December 31	
	2022	**2021**
Audit fees [(1)]	$725,257	$759,427
Audit-related fees [(2)]	$40,660	$45,766
Tax fees [(3)]	$50,000	—
All other fees [(4)]	$5,549	—

Notes:

(1) Fees for audit services and interim reviews, excluding CPAB levy.
(2) Fees for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported under (1) above, specifically French translation.
(3) Fees for tax compliance services.
(4) Fees for compilation report.

PART 12 - EXECUTIVE COMPENSATION

12.1 Compensation Governance

(a) Human Resources and Environment Committee

(i) *Composition and Independence*

The Human Resources and Environment Committee, under the direction of the Board has oversight for Toronto Hydro's senior executive compensation program. The Human Resources and Environment Committee is comprised of Michael Eubanks (Chair), David McFadden, and Stephen Holyday. Michael Eubanks and David McFadden are each independent within the meaning of applicable Canadian securities laws. Since the City is the sole shareholder of the Corporation, Stephen Holyday is not independent within the meaning of applicable Canadian securities laws. The appointment of one of the Corporation's City Councillor directors to the Human Resources and Environment Committee is a requirement under the Shareholder Direction.

(ii) *Human Resources and Environment Committee Charter*

The Human Resources and Environment Committee operates under a written charter adopted by the Board. One of the primary functions of the Human Resources and Environment Committee is to advise and assist the Board in overseeing Toronto Hydro's compensation program and assessing the performance and compensation of the CEO and the other officers of Toronto Hydro. Specifically, under the terms of its charter, the Human Resources and Environment Committee is responsible for assisting the Board in fulfilling its responsibilities with respect to: the recruitment and assessment of the performance of the CEO; the review and approval of the compensation of the CEO and the other senior executive officers of Toronto Hydro; the review and approval of senior executive compensation policies; the review and approval of senior executive compensation disclosure; the review of the

alignment of compensation programs with Toronto Hydro's strategic plans and risk profile; and the general oversight of the compensation structure and benefit plans and programs for Toronto Hydro.

(b) Compensation Risk Oversight

Toronto Hydro has a rigorous risk management and governance structure in place to assist the Board with its oversight and management of all of Toronto Hydro's risks, including risks related to Toronto Hydro's compensation policies and practices. While the Board and the Human Resources and Environment Committee have not conducted a formal assessment of the implications of risks specifically associated with Toronto Hydro's compensation policies and practices, the Human Resources and Environment Committee has and continues to consider the Corporation's strategic objectives, plans and risk strategy in its review and recommendations regarding Toronto Hydro's compensation program. In addition to Toronto Hydro's ERM program, the practices, processes and systems in place to identify and mitigate compensation policies and practices that could encourage an executive officer to take inappropriate or excessive risks include: the periodic review and audit of Toronto Hydro's senior executive compensation program by Toronto Hydro's internal auditor; the development and application of a management control reporting system providing transparency and control to compensation measures; the use of a balanced scorecard of corporate, divisional and individual performance objectives; the periodic benchmarking of Toronto Hydro's compensation program; the review of Toronto Hydro's compensation program by an independent compensation consultant and, from time to time, the OEB; and the application of maximum payout amounts for achievement of individual performance goals. See Part 8 under the heading "Risk Factors – Risk Management" and section 10.10 under the heading "Board Oversight and Management of Risks" for more information on Toronto Hydro's ERM program, section 12.2(c)(ii) under the heading "Benchmarking" for more information on Toronto Hydro's benchmarking of its compensation program, section 12.2(c)(iii) under the heading "Compensation Consultants and Advisors" for more information on the Corporation's compensation consultant and section 12.2(d)(ii) under the heading "Performance-Based Incentive Compensation" for more information on Toronto Hydro's performance-based incentive compensation program.

12.2 Compensation Discussion and Analysis

(a) Named Executive Officers

This Compensation Discussion and Analysis describes and explains all significant elements of compensation awarded to, earned by, paid to, or payable to the NEOs for the financial year ended December 31, 2022. The NEOs are:

(i) **Anthony Haines**
President and Chief Executive Officer, Toronto Hydro Corporation

(ii) **Aida Cipolla** [(1)]
Former Executive Vice-President and Chief Financial Officer, Toronto Hydro Corporation

(iii) **Federico Zeni** [(2)]
Former Interim, Chief Financial Officer, Toronto Hydro Corporation

(iv) **Celine Arsenault** [(3)]
Executive Vice-President and Chief Financial Officer, Toronto Hydro Corporation

(v) **Amanda Klein**
Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer, Toronto Hydro-Electric System Limited

(vi) **Sheikh Nahyaan**
Executive Vice-President, Customer Care and Chief Information Officer, Toronto Hydro-Electric System Limited

(vii) **Elias Lyberogiannis**
Executive Vice-President, Planning and Chief Engineering and Modernization Officer, Toronto Hydro-Electric System Limited

Notes:

(1) Effective March 5, 2022, Ms. Cipolla resigned from her role as Executive Vice-President and Chief Financial Officer.
(2) Effective March 5, 2022, Mr. Zeni began acting in the capacity of Interim, Chief Financial Officer of the Corporation until June 6, 2022 when he resumed his role of Controller.
(3) Effective June 6, 2022, Ms. Arsenault began her role as Executive Vice-President and Chief Financial Officer.

(b) General Objectives of Compensation Program

Toronto Hydro's senior executive compensation program is designed to attract and retain executives who have the skills and experience to help Toronto Hydro achieve its strategic goals, to motivate executives to achieve such corporate goals and to reward senior executives for superior performance and achievement of corporate, divisional and individual objectives.

(c) Process for Establishing Compensation

(i) *Policies and Practices*

Toronto Hydro's overall senior executive compensation policy, structure and program is developed and supervised by the Human Resources and Environment Committee with the assistance of a compensation consultant, and approved by the Board. The senior executive compensation policy was reviewed and approved November 2021. See section 12.2(c)(iii) under the heading "Compensation Consultants and Advisors" for more information on the compensation consultant.

Pursuant to the terms of its charter, the Human Resources and Environment Committee has the responsibility to annually, and more frequently if appropriate, review and make recommendations to the Board with respect to the individual performance-based incentive compensation goals and objectives related to the compensation of the CEO and to assess the CEO's performance against those goals and objectives. The Human Resources and Environment Committee also makes recommendations to the Board with respect to the overall compensation and benefits of the CEO. The Board ultimately sets and approves the CEO's compensation.

The CEO has the responsibility to annually, and more frequently if appropriate, review and approve the individual performance-based incentive compensation goals and objectives related to the compensation of the other senior executive officers, including the NEOs, and assess the other senior executive officers' performance against those goals and objectives. The CEO proposes the other senior executive officers' performance-based incentive compensation and overall compensation, subject to the Human Resources and Environment Committee's review and approval.

(ii) *Benchmarking*

Toronto Hydro periodically benchmarks the compensation it provides to the NEOs to ensure reasonableness, competitiveness and effectiveness of Toronto Hydro's compensation program, including the level and type of compensation provided. The Human Resources and Environment Committee periodically engages a compensation consultant to conduct executive compensation benchmarking for the NEOs, to ensure that Toronto Hydro is able to attract, retain, and motivate high-performing senior executives in the markets in which it competes for talent.

Toronto Hydro's objective is to pay competitively with other Canadian utility and energy industry companies of comparable size and complexity. NEO compensation is generally benchmarked against:

- industry comparators in the public sector of like size: publicly owned utility / energy companies in Canada with revenues of approximately ½ to 2x Toronto Hydro's distribution revenue and / or total revenue;
- publicly and privately owned (including publicly traded) utility / energy companies in Canada with revenues of approximately ½ to 2x Toronto Hydro's distribution revenue and / or total revenue;
- industrial companies in the Greater Toronto Area;
- industrial companies in Canada; and
- public sector organizations in Canada.

The benchmark data comes from proprietary compensation surveys, and publicly disclosed executive compensation information in Canada.

The senior executive compensation information derived from the benchmarking analysis is designed to assist the Human Resources and Environment Committee in establishing, over a reasonable period of time, total cash compensation for NEOs in the range of the median total cash compensation of the benchmark data. Total cash compensation to NEOs may exceed the median of the marketplace when corporate, divisional and individual performance significantly exceeds objectives.

(iii) *Compensation Consultants and Advisors*

The Human Resources and Environment Committee engaged the services of Willis Towers Watson ("WTW") for senior executive compensation consulting services since 2016. The consulting services provided to the Human Resources and Environment Committee include providing advice on the competitiveness and appropriateness of Toronto Hydro's senior executive compensation program, compensation benchmarking services, and other compensation related matters that may arise from time to time. The Corporation also engages Willis Towers Watson for actuarial services. The Human Resources and Environment Committee or the Board is advised of any actuarial services Willis Towers Watson provides to Toronto Hydro in accordance with the Corporation's Policy on the Provision of Services by External Executive Compensation Advisors. The actuarial services provided by Willis Towers Watson do not present any conflicts with the services provided as compensation advisor to the Human Resources and Environment Committee.

The table below sets out the fees billed by Willis Towers Watson and Exec Comp Advisory Services Inc. for each of last two fiscal years in respect of the services noted below.

		Year ended December 31,	
		2022	**2021**
Executive Compensation – Related Fees [1]	Willis Towers Watson	$44,606	—
	Exec Comp Advisory Services Inc. [3]	—	$8,250
All Other Fees [2]	Willis Towers Watson	$122,841	$132,463

Notes:

(1) Aggregate fees billed for consulting services to Toronto Hydro's Human Resources and Environment Committee.
(2) Aggregate fees billed by Willis Towers Watson, or any of its affiliates, for services which include actuarial services that are not reported under note (1) above.
(3) Exec Comp Advisory Services Inc. fees billed for consulting services to Toronto Hydro's Human Resources and Environment Committee in 2021 only.

(d) Elements of Compensation

The principal components of compensation for NEOs are:

- base salary;
- performance-based incentive compensation;
- personal benefits and perquisites;
- pension plan;
- post-employment benefits; and
- retirement allowances.

As the Corporation has a single shareholder that is the registered and beneficial owner of all of its issued and outstanding shares, the Corporation is not able to offer an equity incentive plan or other stock-based compensation to its NEOs.

(i) *Base Salary*

In accordance with the general objectives and process for establishing compensation noted above, Toronto Hydro provides NEOs with a base salary to compensate them for services rendered during the fiscal year. Toronto Hydro provides reasonably competitive market-based base salaries to help attract, motivate, and retain NEOs who are critical to Toronto Hydro's success.

Annually, adjustments to base salaries for NEOs generally are driven by market benchmarking data and the NEO's individual performance rating. In the case of NEOs other than the CEO, the performance rating is determined by the CEO based on the achievement of performance-based incentive compensation objectives, knowledge, skills, and competencies related to day-to-day performance, as well as demonstration of desired corporate behaviours, subject to the Human Resources and Environment Committee's review and approval. In the case of the CEO, in accordance with the retirement arrangement the Human Resources and Environment Committee has set the annual adjustment at 3% annually until his retirement. See "12.3(b)(vii) Termination Payments".

(ii) *Performance-Based Incentive Compensation*

All NEOs receive a portion of their annual compensation in the form of performance-based cash payments. The performance-based incentive compensation is designed to retain, motivate and reward NEOs for reaching corporate, divisional and individual performance objectives established at the beginning of each calendar year.

The annual performance-based incentive compensation is calculated as a percentage of the NEO's base salary for the year and, if earned, paid in one lump sum in the next fiscal year.

In order for an NEO to earn and receive the performance-based incentive compensation, the Corporation and the NEO must each achieve certain pre-determined performance objectives. Each NEO's performance-based incentive compensation is based on a weighting of corporate, divisional and individual performance objectives. Weightings and objectives are determined at the start of each year and vary by role to reflect the performance focus of the role. The weighting and objectives are reviewed and set each year in order to reflect the Corporation's overall strategy and objectives.

Each year the Board reviews and approves the Corporation's objectives. Each performance objective is weighted to reflect its relative importance and includes threshold, target and stretch expectations of performance. Specific performance targets are approved by the Board considering the Corporation's business plans and priorities for the upcoming year, the prior year's performance and a review of forecasted results based on a historical analysis of performance. Similarly, divisional objectives are approved by the CEO and reviewed by the Human Resources and Environment Committee to recognize unique divisional priorities and ensure alignment with the Corporation's overall objectives.

The CEO's individual objectives are reviewed and approved by the Board. The individual objectives of the other NEOs are reviewed and approved by the CEO. Each NEO's individual objectives are based on areas of strategic and operational emphasis related to their respective responsibilities and portfolios.

The NEO's individual objectives are intended to be reasonably difficult to attain and to encourage success in the NEO's performance. Individual objectives are often but not always achieved by an NEO in any given year. NEOs review their objectives and measurements throughout the year, with one formal mid-year review with the Human Resources and Environment Committee (in the case of the CEO), and with the CEO (in the case of the other NEOs), to track achievement to-date and revise performance goals as may be necessary to reflect any change in corporate strategy or priorities.

In the case of each NEO other than the CEO, an annual performance evaluation in respect of the individual objectives for each individual is conducted by the CEO, who proposes the amount of performance-based incentive compensation to be paid to each other NEO. The Human Resources and Environment Committee reviews and approves the amounts of performance-based incentive compensation to be paid to each of the other NEOs. In the case of the CEO, annual performance-based incentive compensation is determined in accordance with his retirement

arrangement. See "12.3(b)(vii) Termination Payments". Mr. Haines' performance will be reviewed with the Board of Directors annually.

(iii) *Personal Benefits and Perquisites*

Toronto Hydro provides NEOs with other personal benefits and perquisites that Toronto Hydro believes are reasonable and consistent with its overall compensation program to better enable Toronto Hydro to attract and retain superior employees for key positions. Benefits include group health, dental, group life insurance, short-term and long-term disability, accidental death & dismemberment, a gym subsidy, and educational reimbursements, all of which are generally available to all salaried employees.

(iv) *Pension Plan*

All full-time employees of Toronto Hydro, including the NEOs, are required to participate in the OMERS pension plan. The OMERS pension plan is generally available to all other salaried employees. See section 4.6(a) under the heading "Employees" for more information on the OMERS pension plan.

Pursuant to the terms of the OMERS pension plan, NEOs are required to make equal plan contributions based on their eligible pensionable earnings. In 2022, Toronto Hydro and each NEO was required to contribute 9% equally of the first $64,900 of pensionable earnings and thereafter 14.6% equally on all earnings over $64,900 and up to $180,944. From $180,944 and up to a maximum of $454,300, contributions continue equally at 14.6% towards a Retirement Compensation Arrangement (RCA), which is governed separately under the Canadian Income Tax Act. See section 12.3(b)(iv) under the heading "Pension Plan" and 12.3(b)(vi) under the heading "Retirement Allowance" for more information related to the pension plan for NEOs**.**

(v) *Post-employment Benefits*

NEOs are eligible to receive post-employment health, dental and life insurance benefits. The post-employment benefits provided to eligible NEOs are the same as are generally available to all other salaried employees. Post-employment benefits aid in attracting and retaining key executives to ensure the long-term success of Toronto Hydro.

(vi) *Retirement Allowances*

From time to time, in certain circumstances, Toronto Hydro enters into retirement allowance agreements with its NEOs. The retirement allowance agreements are designed to recognize service, and to promote retention, stability and continuity, of the NEOs. These agreements are made on a case-by-case basis based on an NEO's years of service and position. Any retirement allowance provided to the CEO is approved by the Board after review of the recommendation of the Human Resources and Environment Committee. In the case of each of the other NEOs, any retirement allowance agreement is proposed by the CEO and reviewed and amended or approved by the Human Resources and Environment Committee.

12.3 Compensation of Named Executive Officers

(a) Summary Compensation Table

The following table provides a summary of the compensation earned during the years ended December 31, 2022, 2021 and 2020, by the NEOs:

Summary Compensation Table [1]

NEO Name and Principal Position	Year	Salary [2] ($)	Non-Equity Incentive Plan Compensation [3] ($)	All Other Compensation [4] ($)	Total Compensation ($)
Anthony Haines [5] President and Chief Executive Officer, Toronto Hydro Corporation	2022	$706,949	$680,846	$18,045	$1,405,840
	2021	$686,433	$661,015	$30,630	$1,378,078
	2020	$666,464	$641,763	$23,208	$1,331,435
Aida Cipolla [6] Former Executive Vice-President and Chief Financial Officer, Toronto Hydro Corporation	2022	$112,439	$—	$2,921	$115,360
	2021	$327,862	$194,709	$18,216	$540,787
	2020	$298,391	$176,949	$9,223	$484,563
Federico Zeni [7] Former Interim, Chief Financial Officer, Toronto Hydro Corporation	2022	$196,189	$74,582	$1,374	$272,145
Celine Arsenault [8] Executive Vice-President and Chief Financial Officer, Toronto Hydro Corporation	2022	$166,923	$97,629	$1,687	$266,239
Amanda Klein Executive Vice-President, Public and Regulatory Affairs and Chief Legal Officer, Toronto Hydro-Electric System Limited	2022	$358,177	$208,914	$10,909	$578,000
	2021	$338,029	$203,184	$10,452	$551,665
	2020	$320,459	$192,592	$3,283	$516,334
Sheikh Nahyaan [9] Executive Vice-President, Customer Care and Chief Information Officer, Toronto Hydro-Electric System Limited	2022	$271,553	$158,428	$16,040	$446,021
	2021	$255,000	$153,000	$3,428	$411,428
	2020	$214,380	$84,897	$500	$299,777
Elias Lyberogiannis [9] Executive Vice-President, Planning and Chief Engineering and Modernization Officer, Toronto Hydro-Electric System Limited	2022	$268,489	$151,523	$11,029	$431,041
	2021	$255,000	$146,772	$6,526	$408,298
	2020	$214,380	$84,897	$5,610	$304,887

Notes:

(1) Amounts shown in this table are in Canadian dollars and have been rounded to the nearest dollar.
(2) Amounts shown reflect actual amounts paid during the year.
(3) Each NEO's annual performance-based incentive compensation for a fiscal year is determined and paid in the next fiscal year. Accordingly, amounts reflected in respect of a particular year (e.g. 2020) represent the annual performance-based incentive compensation earned by the NEO for the achievement of performance objectives in respect of that fiscal year (e.g. 2020) but which amounts are paid in the following fiscal year (e.g. 2021).
(4) Amounts shown in this column reflect all other compensation earned by the NEO during the year. The amounts shown include the aggregate value of perquisites and other personal benefits provided to the NEO, where such perquisites and personal benefits are not generally available to all employees and have been calculated by using the actual cost. In 2022, 2021 and 2020, perquisites were not worth $50,000 or more for any NEO, nor were they worth 10% or more of any NEO's total salary for the year.
(5) Mr. Haines was awarded a top-up benefit as a result of the changes to the OMERS pension plan. As a result of this award, a current service cost of $246,600 was recognized in 2022. [see sections 12.3(b)(iv) and 12.3(b)(vi) of "Compensation of NEOs in 2022 – Narrative Discussion" below.]
(6) Effective March 5, 2022, Ms. Cipolla resigned from the Executive Vice-President and Chief Financial Officer role.
(7) Effective March 5, 2022, Mr. Zeni began acting in the capacity of Interim, Chief Financial Officer of the Corporation until June 6, 2022 when he resumed his role of Controller. During the period in which Mr. Zeni was acting in the capacity of Interim, Chief Financial Officer, his annual base salary was increased to $215,000, and his target performance-based incentive was 30% of salary.
(8) Effective June 6, 2022 Ms. Arsenault is the Executive Vice-President and Chief Financial Officer, Toronto Hydro Corporation, and her annual base salary was $310,000.
(9) Mr. Nahyaan and Mr. Lyberogiannis were promoted into executive roles effective December 1, 2020. Their 2020 compensation figures are reflective of their non-executive vice president positions.

(b) Compensation of NEOs in 2022 – Narrative Discussion

(i) *Base Salaries*

The NEOs' annual base salaries for 2022 were: $707,740 in the case of Mr. Haines, $344,523 in the case of Ms. Cipolla, $310,000 in the case of Ms. Arsenault, $358,958 in the case of Ms. Klein, $272,213 in the case of Mr Nahyaan, and $269,025 in the case of Mr. Lyberogiannis. While serving as Interim, Chief Financial Officer Mr. Zeni's annualized base salary was $215,000.

(ii) *Performance-Based Incentive Compensation*

The targets and component weightings for the 2022 performance-based incentive compensation were as follows:

Position	Target Performance-Based Incentive (% of salary)	Individual Performance (% weighting)	Divisional Performance (% weighting)	Corporate Performance (% weighting)
CEO	65%	20%	—	80%
CFO	40%	20%	20%	60%
Other NEOs	40%	20%	20%	60%

The performance-based incentive compensation amount payable to each NEO may exceed the respective target percentage of base salary indicated above when results exceed corporate, divisional and individual objectives and may be below the respective target percentage of base salary indicated above when the corporate, divisional and individual objectives are not achieved. The component weightings outlined above have been unchanged since 2011.

The performance objectives of the Corporation for 2022 were as follows:

Corporate Key Performance Indicators	Definition	Target	Weight (%)
Consolidated Net Income ($M) [(1)]	Net income after net movements in regulatory balances per the Corporation's financial statements adjusted for COVID-19.	$156.0	25%
In-Service Assets ($M) [(2)]	Total value of the fully allocated costs to construct assets available for use in a given year (as per IFRS and OEB-approved definitions), net of capital contributions and pre-approved program exclusions	$434.1	10%
Outage Frequency - Defective Equipment Only	Average number of interruptions per customer in a given year caused by defective equipment	0.50	10%
Outage Duration – Defective Equipment Only	Average duration of interruptions (in minutes) per customer in a given year caused by defective equipment	26.47	10%
Total Recordable Injury Frequency Rate	Recordable Injury Frequency Rate as per Canadian Electricity Association (CEA) Standard	1.10	10%
New Services Connected on Time	Percentage of connections for new low-voltage (<750 volts) service requests completed within five business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to by the customer	98%	5%
Estimated Time of Restoration (ETOR)	Composite percentage of outage events with an accurate ETOR populated within 1 hour of event creation	85%	5%
First Contact Resolution	Percentage of telephone and email enquiries resolved in one contact, within a 21-day time period	86%	5%
Employee Engagement	Average number of engagement sessions attended per employee per year	7.5	5%
Cash Flow Management ($M)[(3)]	The amount of short and long-term indebtedness under existing or new facilities, as measured at December 31, 2022.	$532.0	5%
Building Emissions Reduction (tons of Carbon Dioxide equivalent)	Measures the reduction of emissions from Toronto Hydro occupied work centres.	2,213.6	5%
Fleet Electrification	Percentage of fleet (driving vehicles) that is either electric vehicle or hybrid.	5%	5%

Notes:

(1) This is a non-GAAP measure based on Net Income after net movements in regulatory balances as per the Financial Statements, modified based on Board approved adjustments to remove the impact of COVID-19. These adjustments include: a) the addition of $85.4 million, being the amount by which budgeted EBITDA exceeded actual EBITDA; b) the addition of $6.1 million for the change to taxes as a result of a); c) the reduction of $104.4 million, being the decrease in net movements in regulatory balances as a result of a) and b); and d) the addition of $18.0 million pre-tax ($13.2 million post-tax) in respect of increased operating expenses.

(2) This is a non-GAAP measure based on in-service assets as at year end as calculated under GAAP of $554.5 million, net of reported capital contributions and net of $104.0 million in pre-approved program exclusions related to initiatives significantly impacted by external factors or subject to OEB-approved variance accounts.

(3) This is a non-GAAP measure that aggregates reported amounts for Commercial Paper and Debentures as at year end.

Corporate key performance indicators ("KPIs") are cascaded down in the organization to create appropriate divisional performance objectives with strong line of sight.

Weightings for these KPIs ranged from 5% to 20% of divisional performance. All divisional KPIs support achievement in the Corporation's five areas of focus: Customer, People, Operations, Environment and Financial. These measures are aimed at increasing customer satisfaction, improving reliability, accomplishing LDC's work program safely and meeting regulatory requirements. Prioritization of these KPIs is determined based on divisional accountabilities. Some examples of Divisional measures are Customer Connection Index, Safety Inspections per Leader, Emergency & Outage Response and Operating Expenses.

Performance-based incentives also include individual performance objectives which are set annually and are tied to business priorities and each individual's particular accountabilities. The number and weighting of individual objectives vary by individual and from year to year. Examples of the 2022 individual performance objectives for the NEOs include, but are not limited to, continuous improvement of operational processes to enhance performance.

In 2022, the Corporation exceeded the majority of its KPI targets at the Corporate and Divisional levels, with the NEOs exceeding the majority of their individual performance targets. Each of the corporate, divisional and individual performance targets were reasonably difficult to attain and served to encourage success in the NEOs performance and in the Corporation's overall results.

Toronto Hydro has a Climate Action Plan as part of its commitment to environmental sustainability, and is committed to achieving net zero greenhouse gas emissions in its operations by 2040. Toronto Hydro's net zero commitment focuses on reducing emissions from two of its largest sources of greenhouse gas emissions, by targeting (i) its building operations and (ii) its vehicle fleet operations. To help track its progress towards net zero, and incent progress in these areas starting in 2022, Toronto Hydro introduced two KPIs; Building Emissions Reduction and Fleet Electrification. Toronto Hydro was able to exceed its target on both measures in 2022.

(iii) *Personal Benefits and Perquisites*

In 2022, the NEOs received personal benefits and perquisites as described in section 12.2(d)(iii) under the heading "Personal Benefits and Perquisites". Personal benefits other than group health, dental, group life insurance, short-term, and long-term disability, accidental death & dismemberment are quantified in the Summary Compensation Table in section 12.3(a) above. Perquisites did not exceed the threshold for any NEO of $50,000 or 10% or more of any NEO's total salary for the year.

(iv) *Pension Plan*

In 2022, each of the NEOs participated in the OMERS pension plan. The OMERS pension plan is a group pension plan that is generally available to all salaried employees. See section 4.6(a) under the heading "Employees" and section12.2(d)(iv) under the heading "Pension Plan" for further information on the OMERS pension plan.

In 2016, OMERS pension plan introduced a cap on pensionable earnings resulting in a significant reduction in the benefit and accordingly, at retirement Mr. Haines will receive top-up benefit payment from the Corporation through a retirement compensation arrangement of $286,900. The retirement compensation arrangement is secured by a letter of credit with a face amount equal to the applicable actuarial value of the obligation plus 30%, and the face value is remeasured and adjusted annually in light of changes in actuarial assumptions and payments made [see section 9.3 Credit Facilities].

(v) *Post-employment Benefits*

Mr. Haines, Ms. Arsenault, Mr. Zeni, Ms. Klein, Mr. Nahyaan, and Mr. Lyberogiannis are eligible for post-employment medical, dental and life insurance benefits if they retire from Toronto Hydro and begin collecting under the OMERS pension plan upon retirement.

(vi) *Retirement Allowance*

Mr. Haines is the only NEO entitled to a retirement allowance. Under the terms of Mr. Haines' retirement allowance if Mr. Haines had terminated (without cause) or retired from the Corporation on December 31, 2022, he would have received a $1,250,000 retirement allowance. The amount of the existing allowance payable to Mr. Haines will thereafter be increased by an additional $125,000 per year (from 2022 to 2024) for each full calendar year of service completed. The maximum existing allowance payable to Mr. Haines is $1,500,000, which Mr. Haines will earn if he remains in active service for the Corporation until December 31, 2024 and payable at his election in one or two lump sum instalments following termination of his employment. Mr. Haines will receive a top-up benefit payment as outlined in 12.3(b)(iv) as a result of the significant changes to pension arrangements introduced by OMERS in 2016.

(vii) *Termination Payments*

The table below summarizes the treatment of compensation for the NEOs under various termination scenarios. Each of the NEOs is eligible for retirement under the OMERS pension plan. No changes are contemplated in the event of a change of control of the Corporation.

Compensation element	**Resignation**	**Termination w/o cause** (1)	**Termination with cause**
Salary	Salary ends	Salary ends	Salary ends
Performance Pay	Current year award forfeited	Current year award	Current year award forfeited
Benefits	Benefits end	Benefits continue	Benefits end
Pension	Entitled to OMERS pension	Entitled to OMERS pension	Entitled to OMERS pension
Top-up benefit payment (2)	Entitled to top-up	Entitled to top-up	Entitled to top-up
Retirement Allowance (2)	Entitled to lump sum	Entitled to lump sum	Entitled to lump sum
Severance (3)	Not applicable	Base salary and performance pay for (i) 24 months of salary continuation for Mr. Haines and (ii) up to 18 months of salary continuation for Ms. Arsenault	Not applicable

Notes:

(1) Mr. Haines' performance pay is determined in accordance with his retirement arrangement. His performance will continue to be reviewed annually. For Ms. Arsenault, performance pay is based on target.
(2) Only applies to Mr. Haines.
(3) For Mr. Haines, base salary during the severance period will be determined in accordance with his retirement arrangement.

Under the terms of their employment agreements, if their employment had terminated without cause on December 31, 2022, Mr. Haines would have received severance of $2,744,378 and Ms. Arsenault would have received severance of $226,003. Ms. Cipolla resigned and did not receive any severance payment. The severance amount that would have been payable had the employment of Mr. Zeni, Ms. Klein, Mr. Nahyaan and Mr. Lyberogiannis been terminated without cause on December 31, 2022 would have been determined at common law.

Mr. Haines has entered into a retirement arrangement pursuant to which his active service will cease on December 31, 2024 and he will receive compensation consistent with a termination without cause plus vacation pay calculated based on pre-determined base salary and performance pay, and prior to such date, and during the severance period shall receive base pay increases of 3% each year and performance pay set at 148% of target.

12.4 Compensation of Directors

(a) Director Compensation Table

Director Name	Total [1] ($)
David McFadden	$75,000
Michael Anthony Eubanks	$30,000
Heather Zordel	$30,000
Howard Wetston	$28,500
James Hinds [2]	$Nil
Juliana Lam	$8,125
Mary Ellen Richardson	$30,000
Michael Nobrega	$28,500
Tamara Kronis	$8,125
Annie Ropar [3]	$13,514
Deputy Mayor Denzil Minnan-Wong	$Nil
Councillor Paul Ainslie	$Nil
Deputy Mayor Stephen Holyday	$Nil
Councillor Jaye Robinson	$Nil
Councillor Jennifer McKelvie	$Nil

Notes:

(1) There was no compensation paid to directors during 2022 other than in respect of director retainer fees and meeting attendance fees.
(2) James Hinds elected to receive no compensation in 2022.
(3) Annie Ropar's compensation reflects the meeting attendance fees and pro-rated retainer fees due until Ms. Ropar's last day as a director on September 15, 2022.

(b) Compensation of Directors – Narrative Discussion

Directors of the Corporation, other than Councillors of the City, are compensated for their services as directors through a combination of retainer fees and meeting attendance fees. These fees are set by the sole shareholder of the Corporation, the City. The annual retainer fees are as follows: Chair of the Board – $75,000 and each of the other directors up to a maximum of – $12,500 (based on quarterly retainer fee of $3,125). The meeting attendance fees are as follows: each meeting of the Board and the subsidiaries attended – $1,000 and each meeting of the Audit Committee, Corporate Governance and Nominating Committee, Human Resources and Environment Committee, or other Board committee attended – $1,000, subject to annual maximum fees per committee member of $5,000 for the Audit Committee, Corporate Governance Committee, Human Resources and Environment Committee or any other committee of the Board. The Board does, from time to time and in the normal course, strike ad hoc committees to streamline and expedite certain matters as they come before the Board. Any compensation Directors have earned from their attendance at these committees has been included in the table above. The Chair receives no meeting attendance fees. Councillors receive no remuneration for their services as directors of the Corporation. The other directors, other than the Chair, are subject to a maximum annual total retainer and attendance fees of $30,000.

PART 13 - LEGAL PROCEEDINGS

In the ordinary course of business, Toronto Hydro is subject to various legal proceedings, actions and claims from customers, suppliers, regulators and other parties. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and could materially adversely affect Toronto Hydro. As at the date hereof, the Corporation believes that none of these legal proceedings, actions and claims from customers, suppliers, regulators and other parties in which it is currently involved or has been involved since the beginning of the most recently completed financial year, would be expected to have a material adverse effect on the Corporation. On an ongoing basis, Toronto Hydro assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual issue. The provision may change in the future due to new developments in each matter or changes in approach, such as a change in settlement strategy. If damages were awarded under these actions, Toronto Hydro would make a claim under any liability or other insurance policies, to the extent applicable, subject to such claim not being disputed by the insurers.

PART 14 - MATERIAL CONTRACTS

The following are material contracts [other than contracts entered into in the ordinary course of business] that the Corporation has entered into in the most recently completed financial year, or before the most recently completed financial year if such material contract is still in effect:

(a) trust indenture dated as of May 7, 2003 between Toronto Hydro Corporation and CIBC Mellon Trust Company [now BNY Trust Company of Canada] [the "Trust Indenture"];

(b) a sixth supplemental trust indenture dated as of May 20, 2010 relating to the issuance of Series 6 senior unsecured debentures in the aggregate principal amount of $200,000,000;

(c) a seventh supplemental trust indenture made as of September 20, 2011 amending the definition of "GAAP" under the Trust Indenture;

(d) a ninth supplemental trust indenture dated as of April 9, 2013 relating to the issuance of Series 8 senior unsecured debentures in the aggregate principal amount of $250,000,000;

(e) a tenth supplemental trust indenture dated as of April 9, 2013, as amended and restated as of September 2, 2015, relating to the issuance of Series 9 senior unsecured debentures in the aggregate principal amount of $245,000,000;

(f) an eleventh supplemental trust indenture dated as of September 16, 2014 relating to the issuance of Series 10 senior unsecured debentures in the aggregate principal amount of $200,000,000;

(g) a twelfth supplemental trust indenture dated as of March 16, 2015 relating to the issuance of Series 11 senior unsecured debentures in the aggregate principal amount of $200,000,000;

(h) a thirteenth supplemental trust indenture dated as of June 14, 2016 relating to the issuance of Series 12 senior unsecured debentures in the aggregate principal amount of $200,000,000;

(i) a fourteenth supplemental trust indenture dated as of November 14, 2017 relating to the issuance of Series 13 senior unsecured debentures in the aggregate principal amount of $200,000,000;

(j) a fifteenth supplemental trust indenture dated as of November 12, 2019 relating to the issuance of Series 14 senior unsecured debentures in the aggregate principal amount of $200,000,000;

(k) a sixteenth supplemental trust indenture dated as of November 12, 2019 relating to the issuance of Series 15 senior unsecured debentures in the aggregate principal amount of $200,000,000;

(l) a seventeenth supplemental trust indenture dated as of October 15, 2020 relating to the issuance of Series 16 senior unsecured debentures in the aggregate principal amount of $200,000,000;

(m) an eighteenth supplemental trust indenture dated as of October 18, 2021 relating to the issuance of Series 17 senior unsecured debentures in the aggregate principal amount of $150,000,000;

(n) a nineteenth supplemental trust indenture dated as of October 18, 2021 relating to the issuance of Series 18 senior unsecured debentures in the aggregate principal amount of $200,000,000; and

(o) a twentieth supplemental trust indenture dated as of October 13, 2022 relating to the issuance of Series 19 senior unsecured debentures in the aggregate principal amount of $300,000,000.

Each of these supplemental trust indentures supplement the terms of the Trust Indenture, which contains customary covenants and representations by the Corporation for the public issuance of debt securities in the Canadian capital market.

Copies of these material contracts are available on the SEDAR website at www.sedar.com.

PART 15 - NAMED AND INTERESTS OF EXPERTS

The external auditor of the Corporation is KPMG LLP. KPMG LLP is independent within the meaning of the Chartered Professional Accountants of Ontario Code of Professional Conduct.

PART 16 - TRANSFER AGENTS AND REGISTRARS

The trustee and registrar for the outstanding Debentures of the Corporation is BNY Trust Company of Canada, located in Toronto, Ontario.

PART 17 - ADDITIONAL INFORMATION

Additional information relating to the Corporation, including additional financial information provided in the Consolidated Financial Statements and Management's Discussion and Analysis, is available on the SEDAR website at www.sedar.com.

ANNEX A- CHARTER – AUDIT COMMITTEE

1. General

(1) The board of directors (Board) of Toronto Hydro Corporation (Corporation) has established the Audit Committee (Committee) to assist the Board and the boards of directors of the Corporation's subsidiary entities in fulfilling their respective corporate governance and oversight responsibilities with respect to financial reporting, internal financial control structure, financial risk management systems, internal audit and external audit functions.

(2) The composition, responsibilities and authority of the Committee are set out in this Charter.

(3) This Charter and the by-laws of the Corporation and such other procedures, not inconsistent therewith, as the Committee may adopt from time to time shall govern the meetings and procedures of the Committee.

2. Composition

(1) The Committee shall be composed of at least three persons who are directors of the Corporation (Members):

(a) all Members must be independent, (as determined by the Board in accordance with the meaning of "independence", as the context requires, given to it in the Canadian Securities Administrators' National Instrument 52-110 Audit Committees, as the same may be amended and/or replaced from time to time); and

(b) at least one of whom, including the chair of the Committee (Chair) is financially literate (ie, have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the accounting issues that can reasonably be expected to be raised by the financial statements of the Corporation).

(2) Members shall be appointed by the Board on the recommendation of the Chair of the Board, and shall serve until they resign, cease to be a director of the respective board, as applicable, or are removed or replaced by the Board.

(3) The Board shall designate one of the Members as Chair. The Committee shall periodically review the position description of the Chair and make recommendations to the Board.

(4) The Executive Vice-President and Chief Financial Officer (Designated Representative) shall be appointed from time to time to act as the principal interface between the Committee and other senior management of the Corporation and its subsidiary entities.

(5) The Secretary of the Corporation shall be secretary of the Committee (Secretary).

(6) The Chair of the Corporation's Board of Directors shall be an ex-officio Member of the Committee with all of the responsibilities and privileges thereof, but shall only count towards meeting quorum if he or she is present at the meeting.

3. Responsibilities

The Committee shall assist the Board and the boards of directors of the Corporation's subsidiary entities in fulfilling their corporate governance and oversight responsibilities with respect to financial reporting, internal financial control structure, financial risk management systems, internal audit functions, external audit functions, and the payment of dividends by the Corporation and its subsidiary entities.

The Committee has specifically recognized its responsibilities for overseeing the identification of the principal financial and audit risks of the Corporation and its subsidiary entities and overseeing the implementation of appropriate systems to manage these risks. In particular, the Committee shall have the responsibilities set out below.

(1) ***Managing the Relationship between the Corporation and its Subsidiaries and their External Auditors***

The Committee shall be responsible for managing the relationship between the Corporation and its subsidiary entities and their external auditors, including:

(a) appointing and replacing the external auditors, subject to the Boards of Directors and shareholder approval;

(b) setting the compensation of the external auditors subject to the approval of the board of directors or shareholder, as applicable;

(c) overseeing the work of the external auditors, including resolving disagreements between management and the external auditors with respect to financial reporting;

(d) pre-approving all audit services and permitted non-audit services to be provided to the Corporation and its subsidiary entities by the external auditors in accordance with the "Policy on the Provision of Services by the External Auditors";

(e) having the external auditors report to the Committee in a timely manner with respect to all required matters, including those set out in paragraph 3(2);

(f) ensuring the rotation of the audit partner having primary responsibility for the external audits of the Corporation and its subsidiary entities, the audit partner responsible for reviewing the external audit and the external auditors at such intervals as may be required; and

(g) reviewing and assessing the performance, independence and objectivity of the external auditors.

(2) ***Overseeing the External Audits***

The Committee shall be responsible for overseeing the external audits of the Corporation and its subsidiary entities, including:

(a) reviewing and approving the engagement letters and the audit plans, including financial risk areas identified by the external auditors and management;

(b) reviewing and assessing the accounting and reporting practices and principles used by the Corporation and its subsidiary entities in preparing their financial statements, including:

(1) all significant accounting policies and practices used, including changes from preceding years and any proposed changes for future years;

(2) all significant financial reporting issues, estimates and judgments made;

(3) all alternative treatments of financial information discussed by the external auditors and management, the results of such discussions and the treatments preferred by the external auditors;

(4) any major issues identified by the external auditors with respect to the adequacy of internal control systems and procedures and any special audit steps adopted in light of material deficiencies and weaknesses;

(5) the effect of regulatory and accounting initiatives and off-balance sheet transactions or structures on the financial statements;

(6) any errors or omissions in, and any required restatement of, the financial statements for preceding years;

(7) all significant tax issues;

(8) the reporting of all material contingent liabilities; and

(9) any material written communications between the external auditors and management;

(c) reviewing and assessing the results of the external audit and the external auditors' opinion on the financial statements;

(d) reviewing and discussing with the external auditors and management any management or internal control letters issued or proposed to be issued by the external auditors;

(e) reviewing and discussing with the external auditors any problems or difficulties encountered by them in the course of their audit work and management's response (including any restrictions on the scope of activities or access to requested information and any significant disagreements with management); and

(f) reviewing and discussing with legal counsel any legal matters that may have a material impact on the financial statements, operations, assets or compliance policies of the Corporation and its subsidiary entities and any material reports or enquiries received by the Corporation and its subsidiary entities from regulators or government agencies.

(3) ***Overseeing the Internal Audits***

The Committee shall be responsible for overseeing the internal audits of the Corporation and its subsidiary entities, including:

(a) periodically reviewing the Internal Audit Charter and making recommendations to the Board;

(b) reviewing and approving the audit plans, including significant risk exposures identified by the internal auditor and management;

(c) reviewing and discussing with the internal auditor and management the results of any internal audits;

(d) reviewing and discussing with the internal auditors any problems or difficulties encountered by them in the course of their audit work and management's response (including any restrictions on the scope of activities or access to requested information and any significant disagreements with management);

(e) appointing and replacing the internal auditor;

(f) reviewing and assessing the performance of the internal auditor;

(g) ensuring the Committee is kept informed of emerging trends and successful practices in internal auditing; and

(h) confirming there is effective and efficient coordination of activities between internal and external auditors.

(4) ***Reviewing and Recommending to the Respective Boards for Approval the Financial Statements, MD&A and Interim Reports of the Corporation and its Subsidiaries***

The Committee shall review and recommend to each respective board of directors, as applicable, for approval, the financial statements, management's discussion and analysis of financial condition and results of operations (MD&A) and interim financial reports of the Corporation and its subsidiaries, annual information form (AIF) (other than executive compensation) of the Corporation and other public disclosure of financial information extracted from the financial statements of the Corporation and its subsidiaries with particular focus on:

(a) the quality and appropriateness of accounting and reporting practices and principles and any changes thereto;

(b) major estimates or judgments, including alternative treatments of financial information discussed by management and the external auditors, the results of such discussions and the treatment preferred by the external auditors;

(c) material financial risks;

(d) material transactions;

(e) material adjustments;

(f) compliance with loan agreements;

(g) material off-balance sheet transactions and structures;

(h) compliance with accounting standards;

(i) compliance with legal and regulatory requirements;

(j) controls; and

(k) disagreements with management.

(5) ***Overseeing Internal Financial Control Structure and Financial Risk Management Systems***

The Committee shall be responsible for overseeing the internal financial control structure and financial risk management systems of the Corporation and its subsidiary entities, including:

(a) reviewing and discussing with management and the external auditors the quality and adequacy of internal control over financial reporting structures of the Corporation and its subsidiary entities, including any major deficiencies or weakness and the steps taken by management to rectify these deficiencies or weaknesses;

(b) reviewing and discussing with management, the internal auditor and the external auditors the risk assessment and risk management policies of the Corporation and its subsidiary entities, the major financial risk exposures of the Corporation and its subsidiary entities, and the steps taken by management to monitor and control these exposures;

(c) reviewing and discussing with the Chief Executive Officer and the Chief Financial Officer of the Corporation the procedures undertaken by them in connection with the certifications required to be

given by them in connection with annual and other filings required to be made by the Corporation under applicable securities laws; and

(d) periodically reviewing the Treasury Policy Register and making recommendations to the Board in respect of such policy and reviewing performance under this policy with Management.

(6) ***Establish and Review Certain Procedures and Policies***

The Committee shall establish adequate policies and procedures, or require that adequate policies and procedures are established, with respect to the following, and shall annually, or on such other schedule as stated herein, assess the adequacy of these procedures:

(a) the review of the public disclosure of financial information extracted from the financial statements of the Corporation;

(b) the receipt, retention and treatment of complaints received by the Corporation with respect to accounting, internal controls or auditing matters;

(c) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters;

(d) the approval by the Committee of the hiring policies for any present or former partner or employee of the current and former external auditor into a position of senior management with the Corporation or its subsidiaries; and

(e) the periodic review of the Policy on the Provision of Services by the External Auditors and Expense Reimbursement Policy, and provision of recommendations to the Board in respect of the same.

(7) ***Review of Policy Reporting***

(a) The Committee shall be responsible, on a quarterly basis, for reviewing and reporting to the Board in respect of the report of Internal Audit with respect to incidents regarding questionable accounting or auditing matters investigated under the Code of Business Conduct and Whistleblower Procedure during the previous quarter.

(b) The Committee shall be responsible for reviewing, on an annual basis, the report of Internal Audit concerning executive and Board expense reimbursements made in accordance with the Corporation's Expense Reimbursement Policy.

(8) ***Review and Recommendations for Dividend Payment***

(a) The Committee shall be responsible for reviewing and making recommendations to each respective board of directors, as applicable, with respect to the declaration of dividends or distribution of capital by the Corporation or its subsidiary entities.

4. Authority

(1) The Committee is authorized to carry out its responsibilities as set out in this Charter and to make recommendations to the Board and the boards of directors of the Corporation's subsidiaries arising therefrom.

(2) The Committee may delegate by written policy to the Chair and the Executive Vice-President and Chief Financial Officer of the Corporation (CFO) the authority, within specified limits, to authorize in advance all engagements of the external auditors to provide pre-approved services to the Corporation and its subsidiary

entities. The Chair and the CFO shall report all engagements authorized by them to the Committee at its next meeting.

(3) The Committee shall have direct and unrestricted access to the external and internal auditors, officers and employees and information and records of the Corporation and its subsidiary entities.

(4) The Committee is authorized to retain, and to set and pay the compensation of, independent legal counsel and other advisors if it considers this appropriate.

(5) The Committee is authorized to invite officers and employees of the Corporation and its subsidiaries and outsiders with relevant experience and expertise to attend or participate in its meetings and proceedings if it considers this appropriate.

(6) The external auditors shall have direct and unrestricted access to the Committee and shall report directly to the Committee.

(7) The Corporation shall pay directly or reimburse the Committee for the expenses incurred by the Committee in carrying out its responsibilities, in accordance with the Corporation's Expense Reimbursement Policy.

5. Meetings and Proceedings

(1) The Committee shall meet as frequently as required but not less frequently than four times each year.

(2) Any Member or the Secretary may call a meeting of the Committee. The external auditors or the CFO may ask a Member to call a meeting of the Committee. The Chair, along with the Designated Representative, is responsible for the agenda of each meeting of the Committee, including input from the officers and employees of the Corporation and its subsidiary entities, external auditors, other Members, and other directors of the Corporation as appropriate. Meetings will include presentations by management and others when appropriate and allow sufficient time to permit a full and open discussion of agenda items.

(3) Unless waived by all Members, a notice of each meeting of the Committee confirming the date, time, place and agenda of the meeting, together with any supporting materials, shall be forwarded, electronically or otherwise, to each Member at least three days before the date of the meeting.

(4) The quorum for each meeting of the Committee is at least 50% of the Members. In the absence of the Chair, the other Members may appoint one of their number as chair of a meeting. The Chair of a meeting shall not have a second or casting vote.

(5) The Chair or a delegate of the Chair shall report to the Board following each meeting of the Committee.

(6) The Secretary or a delegate of the Secretary shall keep minutes of all meetings of the Committee, including all resolutions passed by the Committee. Minutes of all meetings shall be distributed to the Members. The minutes shall be available for review by the other directors of the Corporation after approval thereof by the Committee.

(7) An individual who is not a Member may be invited to attend a meeting of the Committee for all or part of the meeting. A standing invitation to all meetings shall be given to the President and Chief Executive Officer of the Corporation and the CFO, except where the meeting, or part of the meeting, is for Members only or a private session with the internal auditor or the external auditors. A standing invitation should be given to the internal auditor and the engagement partners of the external auditors for all meetings where financial information is reviewed and approved.

(8) The Committee shall meet regularly alone and in private sessions with the internal auditor, the external auditors and management of the Corporation to facilitate full communication.

6. Review

(1) This Charter shall be reviewed by the Corporate Governance and Nominating Committee of the Corporation every three (3) years and any recommended changes shall be referred first to the Audit Committee for review and comment and second, after consideration of the input from the Audit Committee, to the Board of the Corporation for consideration and disposition.

(2) In addition to the triennial review, the Audit Committee may at any time review the Charter and make recommendations to the Corporate Governance and Nominating Committee for their review and recommendations to the Board with respect thereto.

ANNEX B - MANDATE – BOARD OF DIRECTORS

1. General

(1) The board of directors (Board) of Toronto Hydro Corporation (Corporation) is responsible for supervising the management of the business and affairs of the Corporation and its subsidiary entities (Group).

(2) The composition, responsibilities, and authority of the Board are set out in this Mandate.

(3) This Mandate, the Shareholder Direction issued by the City of Toronto (Shareholder) and the by-laws of the Corporation and such other procedures, not inconsistent therewith, as the Board may adopt from time to time shall govern the meetings and procedures of the Board.

(4) The addendum attached hereto is hereby incorporated into this Mandate and made a part hereof.

2. Composition

(1) The directors of the Corporation (Directors) should have a mix of competencies and skills necessary to enable the Board and Board committees to properly discharge their responsibilities.

(2) All of the Directors shall be residents of Canada.

(3) The Shareholder shall appoint Directors every two years.

(4) In appointing Directors the Shareholder shall give due regard to the qualifications of the candidates including:

(a) experience on a public utility commission or board of a major corporation or other commercial enterprise and/or the completion of formal training in directorship / governance;

(b) experience in regulated electricity utility sector at a senior management level;

(c) experience at an executive level in resource and performance management / compensation, including ability to appoint and evaluate the performance of the CEO and senior executives; oversee strategic human resource management, including workforce planning, compensation models, and labour relations; and oversee large scale organizational change;

(d) educational background, including university degrees and professional designations;

(e) experience or knowledge with respect to:

i) strategic planning, including ability to identify and critically assess strategic opportunities and threats to the organization;

ii) risk management, including ability to assess key risks to the organization on an enterprise basis and monitor the risk management framework systems;

iii) corporate finance / accounting / audit / securities, including ability to analyze financial statements, assess financial viability, contribute to financial planning, oversee budgets, and oversee funding arrangements;

iv) corporate governance;

v) market development, innovation and development of new strategic business lines;

vi) large system operation and management;

vii) urban energy industries;

viii) public policy issues and laws relating to the Corporation and its subsidiary entities and the electricity industry;

ix) environmental matters, including experience in environmental management;

x) labour relations;

xi) occupational health and safety issues;

xii) information technology governance, including privacy, data management and security;

xiii) legal and regulatory compliance, including ability to monitor compliance of legal and regulatory requirements;

xiv) stakeholder engagement / advocacy / communications, including ability to effectively engage and communicate to industry stakeholders and advocate on behalf of the organization;

(f) the following interpersonal skills and attributes:

i) leadership, including ability to make, and take responsibility for, decisions and take necessary actions in the best interest of the organization, set appropriate Board and organizational culture and represent the organization favourably;

ii) personal integrity / ethics, including understanding and fulfilling the duties and responsibilities of a director, being transparent and declaring any activities or conduct that might be a potential conflict, and maintaining Board confidentiality;

iii) communications skills, including ability to listen constructively and appropriately debate others' viewpoints, develop and deliver cogent arguments, and communicate effectively with a broad range of stakeholders;

iv) constructive questioning, including preparedness to ask questions and challenge management and peer directors in a constructive and appropriate manner;

v) critical and innovative thinking / decision making, including ability to critically analyze complex and detailed information, readily distill key issues, and develop innovative approaches and solutions to problems;

vi) influencing and negotiating, including ability to negotiate outcomes and influence others to agree with those outcomes and gain stakeholder support for the Board's decisions;

vii) crisis management, including ability to constructively manage crises, provide leadership around solutions and contribute to communications strategy with stakeholders;

viii) individual and team contribution, including ability to work as part of a team, and demonstrate the passion and time to make a genuine and active contribution to the Board and the organization;

ix) commercial sensitivity and acumen; and

x) independence of judgement

(g) at least three directors with financial management expertise.

(5) To support the review of candidates for director roles and the assessment of the existing Board, the Corporation has also developed a Board skills/competencies matrix, which may be modified from time to time by the Board, and which provides a mechanism for determining the key skills required of directors and the Board as a whole and ensuring these skills are accounted for among current and prospective directors. The Board makes this document available to the Shareholder as guidance and a tool to be employed in the selection of director candidates.

(6) The Board shall appoint a Chair of the Board upon the nomination of the Shareholder from time to time.

(7) The Secretary of the Corporation shall be secretary of the Board (Secretary).

3. Responsibilities

(1) The Board is responsible for supervising the management of the business and affairs of the Group, including the following specific matters:

(a) establishing sound financial principles and performance objectives;

(b) approving any dividend payment or distribution of capital;

(c) appointing the officers of the Corporation;

(d) approving the overall business strategy and related business plan;

(e) approving the financing strategy, including the selection of financial institutions and related banking authorities;

(f) directing labour and employee relations matters; and

(g) approving the financial statements in accordance with the requirements of the Business Corporations Act (Ontario).

(2) In discharging their responsibilities, the Directors owe the following duties to the Corporation:

a fiduciary duty: they must act honestly and in good faith with a view to the best interests of the Corporation; and

a duty of care: they must exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

In discharging their responsibilities, the Directors are entitled to rely on the honesty and integrity of the senior officers of the Corporation and the auditors and other professional advisors of the Corporation.

In discharging their responsibilities, the Directors are also entitled to directors and officers liability insurance purchased by the Corporation and indemnification from the Corporation to the fullest extent permitted by law and the constating documents of the Corporation.

(3) The Board has specifically recognized its responsibilities for:

(a) to the extent feasible, satisfying itself as to the integrity of the President and Chief Executive Officer (CEO) and other senior officers of the Group and that the CEO and other senior officers of the Group create a culture of integrity throughout the Group;

(b) adopting a strategic planning process and approving annually (or more frequently if appropriate) a strategic plan which takes into account, among other things, the opportunities and risks of the business of the Group;

(c) considering and overseeing the strategic development of new business opportunities and innovation;

(d) overseeing the identification of the principal risks of the business of the Group and overseeing the implementation of appropriate systems to manage these risks;

(e) interaction of the Board with the Shareholder in accordance with the Shareholder Direction subject to the duties of the Directors at law;

(f) overseeing the integrity of the internal control and management information systems of the Group;

(g) succession planning (including appointing, training and monitoring the senior officers of the Corporation);

(h) recruiting and assessing the performance of the CEO, the compensation of the CEO and other officers of the Group, executive compensation disclosure and oversight of the compensation structure and benefit plans and programs of the Group;

(i) assessing the effectiveness of the Board;

(j) adopting a disclosure policy for the Group;

(k) developing and overseeing the orientation of new Directors, and the continuing education of existing Directors, of the Group; and

(l) developing the approach of the Corporation to corporate governance including a periodic review of the Code of Business Conduct and Whistleblower Procedure of the Group.

(4) In addition to those matters which must by law be approved by the Board, the Board oversees the development of, and reviews and approves, significant corporate plans and initiatives, including the annual business plan and budget, major acquisitions and dispositions and other significant matters of corporate strategy or policy, including the Environmental Policy, Occupational Health and Safety Policy, Code of Business Conduct and Whistleblower Procedure, Disclosure Policy, Signing Policy and Treasury Policy.

(5) In undertaking its responsibilities and overseeing and authorizing the activities of the Corporation, the Board shall consider the interests of its customers, as well as considering and balancing the interests of such other stakeholders as appropriate in the circumstances.

(6) The Board shall periodically review the Shareholder Direction and make recommendations to the Shareholder to facilitate and clarify interaction and communication between the Shareholder and the Board.

(7) The Board shall periodically review the performance of the Board and the Corporation's subsidiary entities against the Shareholder Direction.

(8) The Board shall periodically review the structure and mandate of each Board committee, the effectiveness of each committee, and the appointment and removal of committee members.

(9) The Board shall periodically review performance under the Environmental Policy with management.

(10) To assist the Directors in discharging their responsibilities, the Board expects management of the Corporation to:

(a) review and update annually (or more frequently if appropriate) the strategic plan and report regularly to the Board on the implementation of the strategic plan in light of evolving conditions;

(b) prepare and present to the Board annually (or more frequently if appropriate) a business plan and budget and report regularly to the Board on the Group's performance against the business plan and budget; and

(c) report regularly to the Board on the Corporation's business and affairs and on any matters of material consequence for the Corporation and its Shareholder.

Additional expectations are developed and communicated during the annual strategic planning and budgeting process and during regular Board and Board committee meetings.

(11) The Board considers that generally management should speak for the Corporation in its communications with securities holders and the public. The Board reviews the Corporation's continuous and timely material disclosure with securities holders and the public. All disclosures on behalf of the Corporation are to be made in compliance with the Corporation's disclosure policy.

(12) Directors are expected to attend Board meetings and meetings of Board committees of which they are members. Directors are also expected to spend the time needed, and to meet as frequently as necessary, to discharge their responsibilities.

(13) Directors are expected to undertake such activities as are required from them to remain current in their knowledge of issues relating to the business of the Group and matters relating to any Board committee of which they are members.

(14) Directors are expected to comply with the Code of Business Conduct and Whistleblower Procedure of the Group.

4. Authority

(1) The Board is authorized to carry out its responsibilities as set out in this Mandate.

(2) The Board is authorized to retain, and to set and pay the compensation of, independent legal counsel and other advisors if it considers this appropriate.

(3) The Board is authorized to invite officers and employees of the Group and others to attend or participate in its meetings and proceedings if it considers this appropriate.

(4) The Directors have unrestricted access to the officers of the Corporation. The Directors will use their judgment to ensure that any such contact is not disruptive to the operations of the Corporation and, except for the chair of any committee established by the Board, will advise the Chair and the CEO of the Corporation of any direct communications between them and the officers of the Corporation.

(5) The Board and the Directors have unrestricted access to the advice and services of the Secretary.

(6) The Board may delegate certain of its functions to Board committees, each of which will have its own charter.

5. Meetings and Proceedings

(1) The Board shall meet as frequently as is determined to be necessary but not less than four times each year.

(2) Any Director or the Secretary may call a meeting of the Board.

(3) The Chair is responsible for the agenda of each meeting of the Board, including input from other Directors and the officers and employees of the Group as appropriate. Meetings will include presentations by management and others when appropriate and allow sufficient time to permit a full and open discussion of agenda items.

(4) Unless waived by all Directors, a notice of each meeting of the Board confirming the date, time, place and agenda of the meeting, together with any supporting materials, shall be forwarded to each Director at least 48 hours before the date of the meeting.

(5) The quorum for each meeting of the Board is a majority of the number of Directors. In the absence of the Chair, the other Directors shall appoint one of their number as chair of a meeting. The chair of a meeting shall not have a second or casting vote.

(6) The Secretary or his delegate shall keep minutes of all meetings of the Board, including all resolutions passed by the Board. Minutes of meetings shall be distributed to the Directors.

(7) An individual who is not a Director may be invited to attend a meeting of the Board for all or part of the meeting.

(8) The Directors shall meet alone regularly to facilitate full communication.

6. Review

(1) This Mandate shall be reviewed by the Corporate Governance Committee every 3 years and any recommended changes shall be brought to the Board of the Corporation for consideration and disposition.

TORONTO HYDRO CORPORATION

Addendum to Board of Directors Mandate

1. General

(1) The composition, responsibilities, and authority of the board of directors ***(Board***) of Toronto Hydro Corporation (***Corporation***) are set out in the Board of Directors Mandate (***Mandate***), as amended from time to time.

(2) This addendum (***Addendum***), the Corporation's Code of Business Conduct and Whistle Blower Procedure (***Code***) and such other procedures, not inconsistent therewith, as the Board may adopt from time to time, is intended to:

(a) guide directors as how to identify and bring forward potential conflicts of interest in respect of: (i) other governance-level appointments as directors, officers, board members, adjudicators, commissioners or similar governing roles (***Governance-Level Roles***), and (ii) employee engagements, consulting arrangements, volunteer engagements and relationships where the director is likely to have access to confidential or strategic information or otherwise be in a position where the interests of Toronto Hydro may intersect or conflict from time to time with the interests of the organizations involved (***Material Engagements***), and

(b) outline the Board process for reviewing and constructively dealing with such situations in a manner that maximizes the participation of all directors in Board discussions and decisions.

(3) This addendum forms part of, and does not replace the Mandate.

2. Meaning of Conflict of Interest

(1) In accordance with the Code, a ***conflict of interest*** occurs when a director's direct or indirect personal interests, activities, or relationships could compromise, or could reasonably appear to compromise his or her ability to perform his or her responsibilities objectively and in the best interest of the Corporation and its subsidiaries (collectively, ***Toronto Hydro***). Conflicts include any activity (even when it is unpaid), interest, or association that might compromise, or appear to compromise the independent exercise of a director's judgment in the best interests of Toronto Hydro.

(2) As examples for purposes of this Addendum, situations that might give rise conflicts of interest or the appearance of a conflict of interest with respect to outside interests include situations where a director:

(a) Holds a Governance-Level Role or Material Engagement for any competitor or any actual or current, active potential business partner (including as a supplier or vendor to Toronto Hydro or its shareholder, or a key account customer);

(b) Is hired for, nominated for, or accepts an appointment to a board or as executive of any business or enterprise that might benefit from, or be in conflict with, the activities of Toronto Hydro or the Board;

(c) Holds a Governance-Level Roles or Material Engagement with regulators of material significance to Toronto Hydro (***Material Regulators***). For greater certainty, Material Regulators include, without limitation, the Ontario Ministry of Energy, the Ontario Energy Board, the Independent Electricity System Operator and the Ontario Securities Commission; or

(d) Any other situation of conflict of interest or potential conflict of interest relating to Governance-Level Roles or Material Engagements set out in the Code.

3. Reporting conflict of interest

(1) Where a director finds himself or herself in a conflict of interest, or identifies a potential situation where he or she may find himself or herself in a conflict of interest, that director should contact the Chair of the Corporate Governance and Nominating Committee (CGNC). If the Chair of the CGNC finds himself or herself in such a situation, the Chair of the CGNC should contact the Chair of the Board, who will then conduct the activities of the Chair of the CGNC described below in place of the Chair of the CGNC.

(2) For greater certainty, where a director receives an offer for nomination to a Governance-Level Role or a Material Engagement, they should contact the Chair of the CGNC once any obligations of confidentiality with respect to that offer permit them to do so.

4. Board process for reviewing conflicts of interest

(1) Upon being notified by a director of an existing or potential conflict of interest, the Chair of the Corporate Governance and Nominating Committee will meet with that director to consider and discuss whether:

(a) the conflict of interest exists;

(b) if the conflict of interest exists, whether it might compromise or appear to compromise the independent exercise of judgment by the director and his or her ability to act in the best interests of Toronto Hydro; and

(c) if such a compromise exists, whether there are administrative processes (***Administrative Processes***), including without limitation, processes for the director to recuse him or herself from related discussions that can be put in place to limit or eliminate the conflict while maximizing the participation of all directors in Board discussions and decisions; or whether the compromise is so pervasive as to lead the director to voluntarily resign from the Board.

(2) In the course of considering whether a conflict of interest exists, and what actions, if any, are to be taken, the Chair of the CGNC may consult with the Chair of the Board, other members of the CGNC and the Board, relevant members of management of Toronto Hydro including the Chief Executive Officer and Chief Legal Officer, and shareholder, outside legal counsel and other advisors, all in confidence as the Chair of the CGNC feels is necessary to resolve the issue.

(3) If the director and the Chair of the CGNC are able to agree on a course of action, the Chair of the CGNC will record the arrangement and provide a copy of it to the Chair of the Board who may disseminate it as necessary. In addition, Administrative Processes will be made known to the balance of the Board as it relates to future Board discussions and decisions.

(4) If the director and the Chair of the CGNC are unable to agree on a course of action, the matter will be escalated to the Steering Committee of the Board for further discussion and consideration which may include a recommendation to the Shareholder that the director be removed from the Board.

(5) For greater certainty, nothing in this policy detracts from or absolves a director of his or her responsibility to review their own potential conflicts and make declarations as to the same as they arise, including at each Board or Committee meeting which he or she attends.

PUBLIC DEBT OFFERING

In accordance with s. 2.1.8 of the Ontario Energy Board's ("OEB") Filing Requirements,[1] this schedule provides Toronto Hydro Corporation's public debt offering information, as follows:

- Appendix A: Base Shelf Prospectus, July 2023
- Appendix B: 15th Supplemental Trust Indenture, November 2019
- Appendix C: 16th Supplemental Trust Indenture, November 2019
- Appendix D: 17th Supplemental Trust Indenture, October 2020
- Appendix E: 18th Supplemental Trust Indenture, October 2021
- Appendix F: 19th Supplemental Trust Indenture, October 2021
- Appendix G: 20th Supplemental Trust Indenture, October 2022
- Appendix H: 21st Supplemental Trust Indenture, June 2023

[1] Ontario Energy Board, Filing Requirements for Electricity Distributor Rate Applications, Chapter 2 (December 15, 2022).

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

This short form prospectus is a base shelf prospectus which has been filed under legislation in each of the provinces of Canada that permits certain information about these securities to be determined after this prospectus has become final and that permits the omission from this prospectus of that information. The legislation requires the delivery to purchasers of a prospectus supplement containing the omitted information within a specified period of time after agreeing to purchase any of these securities. All shelf information omitted from this shelf prospectus will be contained in one or more prospectus supplements that will be delivered to purchasers together with the base shelf prospectus. This short form base shelf prospectus has been filed in reliance on an exemption from the preliminary base shelf prospectus requirement for a well-known seasoned issuer.

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. These securities have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act") or any state securities laws, and, subject to certain exceptions, may not be offered or sold within the United States or to, or for the account or benefit of, U.S. Persons (as such term is defined in Regulation S under the U.S. Securities Act). See "Plan of Distribution".

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. *Copies of the documents incorporated herein by reference may be obtained* on request without charge from the Corporate Secretary of Toronto Hydro Corporation at 14 Carlton Street, Toronto, Ontario, M5B 1K5, (416) 542-3100 *and are also available electronically at www.sedar.com.*

SHORT FORM BASE SHELF PROSPECTUS

New Issue July 27, 2023

TORONTO HYDRO CORPORATION

$1,500,000,000 DEBENTURES

(unsecured)

Toronto Hydro Corporation (the "Corporation") may offer and issue from time to time unsecured debentures (the "Debentures") in one or more series in an aggregate principal amount of up to $1,500,000,000 (or the equivalent thereof in foreign currencies or currency units based on the applicable exchange rate at the time of offering) during the twenty-five months from the date of issuance of the receipt for this prospectus.

As of the date hereof, the Corporation has determined that it qualifies as a “well-known seasoned issuer”, as such term is defined under the WKSI Blanket Orders (as defined below). See "Reliance on Exemptions for Well-Known Seasoned Issuers".

The Debentures will be issued under a trust indenture dated May 7, 2003 (as amended from time to time and as supplemented from time to time by supplemental indentures), will be direct unsecured obligations of the Corporation and will rank *pari passu* (except as to sinking funds and to the extent prescribed by law) with all other unsecured and unsubordinated indebtedness of the Corporation. The Debentures will have a term to maturity of not less than one year and will be issuable in denominations of $1,000 and multiples thereof. The Debentures may be issued in Canadian dollars or any foreign currency or currency unit determined at the time of issue.

The specific terms of an offering of Debentures (including the aggregate principal amount of the Debentures being offered, the currency or currencies, the issue and delivery date, the form, the maturity date, the interest rate, the issue price, the interest payment date(s), any redemption or repayment provisions, any provisions entitling the Corporation to extend the maturity date of the Debentures, the name(s) of the dealer(s) offering the Debentures, the commission payable to such dealer(s), the method of distribution and the net proceeds to the Corporation) will be set forth in a pricing supplement which will be delivered to purchasers together with this

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prospectus. The Corporation reserves the right to set forth in a pricing supplement specific terms of Debentures which are not within the parameters set forth in this prospectus.

The sole shareholder of the Corporation is the City of Toronto. The Debentures will not be obligations of, and will not be guaranteed in any manner by, the City of Toronto.

Investing in the Debentures involves risks. See "Risk Factors" in this prospectus and in the comparable sections of the documents incorporated or deemed to be incorporated by reference in this prospectus, which may be amended or supplemented in any prospectus supplement or pricing supplement.

There is no market through which the Debentures may be sold and purchasers may not be able to resell Debentures purchased under this prospectus. This may affect the pricing of the Debentures in the secondary market, the transparency and availability of trading prices, the liquidity of the Debentures and the extent of issuer regulation. See "Risk Factors". Unless otherwise indicated in a pricing supplement, the Debentures will not be listed on any securities exchange.

RATES ON APPLICATION

Pursuant to the dealer agreement referred to under the heading "Plan of Distribution", the Debentures may be offered for sale severally and on a continuous basis by one or more of BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. and such other dealers as may be selected from time to time by the Corporation (collectively, the "Dealers" and each a "Dealer"), in each case, acting as agent of the Corporation or as principal. Where the Debentures are offered by the Dealer(s) as agent(s), the commissions payable by the Corporation in connection with sales of such Debentures shall be agreed from time to time between the Corporation and any such Dealer(s). Where the Debentures are purchased by the Dealer(s) as principal, the Debentures shall be purchased at such prices and with such commissions as may be agreed from time to time between the Corporation and any such Dealer(s) for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. Each Dealer's compensation will increase or decrease by the amount by which the aggregate price paid for Debentures by purchasers exceeds or is less than the price paid by such Dealer, when purchasing as principal, to the Corporation. The commissions payable in connection with sales of Debentures will be set forth in a pricing supplement which will be delivered to purchasers together with this prospectus. In connection with any offering of Debentures, the Dealers may over-allot or effect transactions which stabilize or maintain the market price of the Debentures offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution". The Corporation may also offer the Debentures directly to potential purchasers pursuant to applicable statutory exemptions at prices and upon terms negotiated between the purchaser and the Corporation, in which case no commissions will be paid to the Dealers. The Corporation and, if applicable, the Dealers, may reject any offer to purchase the Debentures in whole or in part. The Corporation also reserves the right to withdraw, cancel or modify the offering of the Debentures under this prospectus without notice.

The Corporation may be considered to be a connected issuer of BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. within the meaning of Canadian securities legislation. BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. are wholly-owned subsidiaries of banks which are currently lenders to the Corporation. See "Relationship between the Corporation and the Dealers".

The offering of the Debentures is subject to the approval of certain legal matters on behalf of the Corporation by Norton Rose Fulbright Canada LLP and on behalf of the Dealers by Blake, Cassels & Graydon LLP.

The registered and head office of the Corporation is located at 14 Carlton Street, Toronto, Ontario, M5B 1K5.

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Unless otherwise specified, all dollar amounts in this prospectus are expressed in Canadian dollars and references to "$" are to Canadian dollars.

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DOCUMENTS INCORPORATED BY REFERENCE

The following documents of the Corporation filed with the provincial securities regulatory authorities in Canada are incorporated by reference in this prospectus for the purposes of the offering of Debentures hereunder:

(a) the annual information form (the "AIF") of the Corporation for the year ended December 31, 2022 dated March 28, 2023;

(b) the comparative audited consolidated financial statements of the Corporation together with the auditor's report thereon and the notes thereto as at and for the years ended December 31, 2022 and December 31, 2021;

(c) management's discussion and analysis of financial condition and results of operations ("MD&A") for the year ended December 31, 2022;

(d) the comparative unaudited condensed interim consolidated financial statements of the Corporation together with the notes thereto as at and for the three-month periods ended March 31, 2023 and March 31, 2022; and

(e) MD&A for the three-month period ended March 31, 2023.

Updated earnings coverage ratios will be filed quarterly with the provincial securities regulatory authorities in Canada, either as prospectus supplements or as exhibits to the Corporation's unaudited interim and audited consolidated financial statements, and will be deemed to be incorporated by reference in this prospectus for the purposes of the offering of Debentures hereunder.

Any documents of the type required by National Instrument 44-101 – *Short Form Prospectus Distributions* to be incorporated by reference in a short form prospectus, including the documents of the type referred to above, interim financial statements and related MD&A, material change reports (except confidential material change reports) and business acquisition reports filed by the Corporation with the provincial securities regulatory

authorities in Canada after the date of this prospectus and prior to termination of any offering hereunder will be deemed to be incorporated by reference in this prospectus.

Upon a new AIF and new annual financial statements and related MD&A being filed by the Corporation with, and where required, accepted by, the applicable securities regulatory authorities during the currency of this prospectus, the previous AIF, the previous annual financial statements and related MD&A, all previous interim financial statements and related MD&A, previous material change reports filed prior to the commencement of the then current financial year and previous business acquisition reports for acquisitions completed since the beginning of the financial year in respect of which the Corporation's new AIF is filed will be deemed no longer to be incorporated by reference into this prospectus for purposes of future offers and sales of Debentures hereunder. Upon unaudited interim financial statements and the accompanying interim management's discussion and analysis being filed by the Corporation with the applicable securities regulatory authorities during the currency of this prospectus, all unaudited interim financial statements and the accompanying interim management's discussion and analysis filed prior to the new unaudited interim financial reports shall be deemed no longer to be incorporated by reference into this prospectus for purposes of future offers and sales of Debentures hereunder.

A pricing supplement containing the specific variable terms for an offering of Debentures will be delivered to purchasers of such Debentures together with this prospectus and will be deemed to be incorporated by reference in this prospectus as of the date of the pricing supplement, solely for the purposes of the Debentures offered under that pricing supplement.

Certain marketing materials (as that term is defined in applicable securities legislation) may be used in connection with a distribution of Debentures under this prospectus and any applicable pricing supplement. Any template version (as that term is defined in applicable securities legislation) of marketing materials pertaining to a distribution of Debentures, and filed by the Corporation after the date of the applicable pricing supplement for the offering and before termination of the distribution of such Debentures, will be deemed to be incorporated by reference in such pricing supplement for the purposes of the distribution of Debentures to which the pricing supplement pertains.

Any statement contained in this prospectus or in a document incorporated or deemed to be incorporated by reference herein will be deemed to be modified or superseded, for purposes of this prospectus, to the extent that a statement contained herein or in a document incorporated or deemed to be incorporated by reference herein modifies or supersedes such prior statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement will not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded will not constitute a part of this prospectus, except as so modified or superseded.

FORWARD-LOOKING INFORMATION

Certain information included or incorporated by reference in this prospectus constitutes "forward-looking information" within the meaning of applicable securities legislation. The purpose of the forward-looking information is to provide the Corporation's current expectations regarding future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All information, other than statements of historical fact included or incorporated by reference in the prospectus, which address activities, events or developments that the Corporation expects or anticipates may or will occur in the future, are forward-looking information. The words "anticipates", "believes", "budgets", "committed", "can", "could", "estimates", "expects", "focus", "forecasts", "intends", "may", "might", "plans", "propose", "projects", "schedule", "should", "will", "would", "objective", "outlook" or the negative or other variations of these words or other comparable words or phrases, are intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects the Corporation's current beliefs and is based on information currently available to the Corporation.

Specific forward-looking information in this prospectus includes statements under the headings "Use of Proceeds" and "Plan of Distribution". Additional forward-looking information is identified in the various documents incorporated by reference in this prospectus, including, without limitation, the section entitled "Forward-Looking Information" in the Corporation's AIF and the section entitled "Forward-Looking Information" in the Corporation's MD&A.

The forward-looking information is based on estimates and assumptions made by the Corporation's management in light of past experience and perception of historical trends, current conditions and expected future developments, as well as other factors that management believes to be reasonable in the circumstances, including, but not limited to, the completion of issuances of Debentures under this prospectus, the amount of indebtedness of the Corporation at such time, changes in funding requirements, no unforeseen changes in the demand for energy consumption, the future course of the economy and financial markets, no unforeseen delays and costs in the Corporation's capital projects, no unforeseen changes to project plans, no significant changes in weather compared to historical seasonal trends, no unforeseen changes in the legislative and operating framework for electricity distribution in Ontario, no unforeseen changes in public policy relating to electricity distribution in Ontario, the receipt of applicable regulatory approvals and requested rate orders, no unexpected delays in obtaining required approvals, the ability of the Corporation to obtain and retain qualified staff, materials, equipment and services in a timely and cost efficient manner, continued contractor performance, compliance with covenants, the receipt of favourable judgments, no unforeseen changes in electricity distribution rate orders or rate setting methodologies, no unfavourable changes in environmental regulation, the ratings issued by credit rating agencies, the level of interest rates and the Corporation's ability to borrow, and assumptions regarding general business and economic conditions.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information, which are discussed in more detail under "Risk Factors" in this prospectus and in any pricing supplement and in the comparable sections of the documents incorporated or deemed to be incorporated by reference in this prospectus (including the sections entitled "Forward-Looking Information" and "Risk Factors" in the Corporation's AIF and the sections entitled "Forward-Looking Information" and "Risk Management and Risk Factors" in the Corporation's MD&A). All of the forward-looking information included or incorporated by reference in this prospectus is qualified by the cautionary statements in this "Forward-Looking Information" section and the "Risk Factors" section of this prospectus and in the comparable sections of the documents incorporated or deemed to be incorporated by reference in this prospectus (including the sections entitled "Forward-Looking Information" and "Risk Factors" in the Corporation's AIF and the sections entitled "Forward-Looking Information" and "Risk Management and Risk Factors" in the Corporation's MD&A). These factors are not intended to represent a complete list of the factors that could affect the Corporation; however, these factors should be considered carefully and readers should not place undue reliance on forward-looking information made herein or in the documents incorporated by reference. Furthermore, the forward-looking information contained or incorporated by reference herein is dated as of the date of this prospectus or as of the date specified in the documents incorporated by reference into this prospectus, as the case may be, and the Corporation has no intention and undertakes no obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

Capitalized terms used in this section without definition, have the meanings given to them elsewhere in this prospectus.

TORONTO HYDRO

Toronto Hydro Corporation (the "Corporation" and, together with its subsidiaries, "Toronto Hydro") is a holding company which wholly-owns two subsidiaries:

- *Toronto Hydro-Electric System Limited* ("LDC") – distributes electricity; and
- *Toronto Hydro Energy Services Inc.* – provides street lighting and expressway lighting services in the City of Toronto.

The principal business of Toronto Hydro is the distribution of electricity by LDC, which owns and operates the electricity distribution system for Canada's largest city. LDC owns and operates an electricity distribution system, delivering electricity to approximately 791,000 customers located in the City of Toronto. LDC serves the largest city in Canada and distributes approximately 17% of the electricity consumed in Ontario.

The sole shareholder of the Corporation is the City of Toronto.

RECENT DEVELOPMENTS

On June 14, 2023, the Corporation closed an offering of $250 million aggregate principal amount of 4.61% Senior Unsecured Debentures due 2033 (Series 20). The Corporation used the proceeds from the offering to repay certain indebtedness under the Corporation’s commercial paper program which the Corporation incurred to repay its $250 million Series 8 Debentures on April 10, 2023, to finance the Corporation’s capital expenditure program and for general corporate purposes. The Senior Unsecured Debentures were offered pursuant to the short form base shelf prospectus of the Corporation dated July 29, 2021.

USE OF PROCEEDS

The Debentures will be issued from time to time at the discretion of the Corporation in an aggregate principal amount not to exceed $1,500,000,000 (or the equivalent thereof in foreign currencies or currency units based on the applicable exchange rate at the time of offering). Unless otherwise specified in a pricing supplement, the net proceeds from the sale of Debentures will be used by the Corporation to reduce certain indebtedness of the Corporation, including, but not limited to, indebtedness that the Corporation may have with the bank affiliates of one or more of the Dealers, to refinance the Corporation's outstanding Debentures upon maturity, to finance the Corporation's capital expenditure program and for general corporate purposes. The net proceeds from the sale of Debentures cannot be estimated at the date hereof since the amount thereof will depend on the terms and conditions of the Debentures and the extent to which the Debentures are issued under this prospectus. Any commissions payable to the Dealers relating to a particular offering of Debentures will be netted out of the proceeds thereof and all other expenses relating thereto will be paid out of the Corporation's general funds or netted out of the proceeds of such offering.

PLAN OF DISTRIBUTION

Pursuant to the terms of a dealer agreement dated July 27, 2023 (the "Dealer Agreement"), the Debentures may be offered for sale severally and on a continuous basis by one or more of the Dealers, in each case, acting as agent of the Corporation or as principal. Where the Debentures are offered by the Dealer(s) as agent(s), the commissions payable by the Corporation in connection with sales of such Debentures shall be agreed from time to time between the Corporation and any such Dealer(s). Where the Debentures are purchased by the Dealer(s) as principal, the Debentures shall be purchased at such prices and with such commissions as may be agreed from time to time between the Corporation and any such Dealer(s) for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. Each Dealer's compensation will increase or decrease by the amount by which the aggregate price paid for Debentures by purchasers exceeds or is less than the price paid by the Dealer, when purchasing as principal, to the Corporation. The commissions payable in connection with sales of Debentures will be set forth in a pricing supplement which will be delivered to purchasers together with this prospectus. The Corporation may also offer the Debentures directly to potential purchasers pursuant to applicable statutory exemptions at prices

and upon terms negotiated between the purchaser and the Corporation, in which case no commissions will be paid to the Dealers.

The obligations of a Dealer under the Dealer Agreement to purchase any particular issue of Debentures as principal may be terminated at its discretion upon the occurrence of certain stated events. Such events are set out in detail in the Dealer Agreement and include, but are not limited to: (i) an event which prevents or restricts the trading in the Debentures or any other securities of the Corporation or the distribution of the Debentures; (ii) the occurrence of any material change in the business, affairs, operations, assets, liabilities (contingent or otherwise), capital or ownership of Toronto Hydro taken as a whole; (iii) a public announcement by DBRS Limited ("DBRS") or Standard & Poor's ("S&P") that it has placed under surveillance or review, with possible negative or uncertain implications, its rating of any debt securities of the Corporation; and (iv) certain downgrades of the ratings assigned by S&P and DBRS to the long-term debt securities of the Corporation. In addition, the Corporation has agreed under the terms of the Dealer Agreement to reimburse the Dealers for certain expenses and to indemnify the Dealers against certain liabilities.

The Corporation and, if applicable, the Dealers, may reject any offer to purchase the Debentures in whole or in part. The Corporation also reserves the right to withdraw, cancel or modify the offering of the Debentures under this prospectus without notice.

In connection with any offering of Debentures, the Dealers may over-allot or effect transactions which stabilize or maintain the market price of the Debentures offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time. In addition, the Dealers may from time to time purchase and sell the Debentures in the secondary market but are not obliged to do so. Unless otherwise indicated in a prospectus supplement or pricing supplement, there is no market through which Debentures may be resold and purchasers may not be able to resell Debentures purchased under the prospectus. There can be no assurance that there will be a secondary market for the Debentures. The offering price and other terms for such sales in the secondary market may, from time to time, be varied by the Dealers.

The Debentures have not and will not be registered under the U.S. Securities Act, or any state securities laws, and may not be offered or sold within the United States or to U.S. Persons (as such term is defined in Regulation S under the U.S. Securities Act) unless registered under the U.S. Securities Act and applicable state securities laws or an exemption therefrom is available. Each of the Dealers will agree not to buy or offer to buy, to sell or offer to sell, or solicit any offer to buy any Debentures in the United States of America and its territories or possessions, or to, or for the account or benefit of, U.S. Persons, except to "qualified institutional buyers" in accordance with Rule 144A under the U.S. Securities Act. Debentures issued to qualified institutional buyers pursuant to Rule 144A under the U.S. Securities Act will be represented by definitive certificates and will be subject to certain restrictions on transfer set forth therein and in the supplemental indenture and will bear a legend regarding such restrictions as set forth in the supplemental indenture. This prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of the Debentures in the United States. In addition, until 40 days after the commencement of the offering of an issue of Debentures, an offer or sale of that issue within the United States by any Dealer (whether or not participating in the offering) may violate the registration requirements of the U.S. Securities Act if such offer or sale is made otherwise than in accordance with Rule 144A under the U.S. Securities Act or pursuant to an applicable exemption from the registration requirements of the U.S. Securities Act.

RELATIONSHIP BETWEEN THE CORPORATION AND THE DEALERS

The Dealers are wholly-owned subsidiaries of banks which are currently lenders to the Corporation under certain credit facilities, including: (i) a $1.0 billion revolving credit facility (the "THC Revolving Credit Facility"), of which up to $210 million is available in the form of letters of credit; (ii) a $100 million demand facility for the purpose of issuing letters of credit mainly to support LDC's prudential obligations with the IESO (the "Prudential Facility"); and (iii) a $20 million demand facility for the purpose of working capital management (the "Working Capital Facility"). As at March 31, 2023, no borrowings were outstanding under the THC Revolving Credit Facility, $1.7 million had been drawn under the Working Capital Facility and $57.6 million of letters of credit had been issued against the Prudential Facility. The Corporation also reserves capacity under the THC Revolving Credit Facility for amounts of commercial paper outstanding under its commercial paper program; hence, available borrowing under the THC Revolving Credit Facility is reduced by the amount of commercial paper outstanding at any point

in time. As at March 31, 2023, the Corporation had $460 million of commercial paper outstanding. The THC Revolving Credit Facility, the Prudential Facility and the Working Capital Facility are unsecured debt obligations and the Corporation is, and has been since the establishment of such facilities, in compliance with the terms of the respective agreements governing such facilities. As of the date hereof, the Corporation has not been required to obtain a waiver in respect of any breach under such facilities and the Corporation's financial position has not adversely changed in a material manner since such facilities were put in place. Proceeds from the sale of the Debentures may be used to repay indebtedness to the bank affiliates of BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. under the THC Revolving Credit Facility, the Prudential Facility or the Working Capital Facility or other bank facilities, as applicable. Accordingly, the Corporation may be considered to be a connected issuer of BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. within the meaning of Canadian securities legislation. The decision to distribute the Debentures will be made by the Corporation and the terms and conditions of distribution will be determined through negotiations between the Corporation and the Dealers. The lenders will not have any involvement in such decision or determination. Other than payment of their portion of the commissions, if applicable, none of the proceeds of offerings of the Debentures will be applied, directly or indirectly, for the benefit of BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc.

RATINGS

The outstanding senior unsecured debentures of the Corporation have been assigned a rating of "A" with a stable trend by DBRS and "A" by S&P.

DBRS rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". All rating categories other than AAA and D also contain the subcategories "(high)" and "(low)" to indicate relative standing within the major rating categories. The absence of either a "(high)" or "(low)" designation indicates the rating is in the middle of the category. An "A" rating is the third highest of the ten rating categories. Long-term debt instruments which are rated in the "A" category by DBRS are considered to be of good credit quality, with substantial capacity for the payment of financial obligations. Entities in the "A" category, however, may be vulnerable to future events, but qualifying negative factors are considered manageable.

S&P rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". Ratings from "AA" to "CCC" may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. An "A" rating is the third highest of the ten rating categories. Long-term debt instruments which are rated in the "A" category by S&P are considered somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories; however, the obligor's capacity to meet its financial commitment on the obligation is still strong.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. A rating is not a recommendation to buy, sell or hold securities including the Debentures and do not comment as to market price or suitability for a particular investor. There can be no assurance that the ratings will remain in effect for any given period of time or that the ratings will not be revised or withdrawn entirely by the rating agency at any time in the future if in their judgment circumstances so warrant.

The Corporation has made, and anticipates making, payments to each of DBRS and S&P pursuant to the ratings agency services agreements entered into with such credit rating organizations with respect to, among other things, the ratings assigned to the long-term debt of the Corporation, the Corporation's commercial paper rating, the Corporation's rating and ratings assigned to the Debentures of a particular series. There have been no other services provided by any of such credit rating organizations to the Corporation within the last two years.

EARNINGS COVERAGE RATIOS

The consolidated earnings of the Corporation before interest on the consolidated long-term debt of the Corporation and before income taxes was (i) $253.5 million for the twelve-month period ended December 31, 2022, and (ii) $252.6 million for the twelve-month period ended March 31, 2023. Interest expense on the

consolidated long-term debt of the Corporation, without giving effect to the issue of any Debentures that may be distributed under this prospectus, was (i) $83.5 million for the twelve-month period ended December 31, 2022, and (ii) $87.2 million for the twelve-month period ended March 31, 2023.

The earnings coverage ratio for the Corporation for the twelve-month period ended December 31, 2022, based on audited information, without giving effect to the issue of any Debentures that may be distributed under this prospectus, was 3.04. In addition to long-term debt, the Corporation incurred short-term debt which has been disclosed in the consolidated financial statements of the Corporation for the years ended December 31, 2022 and 2021. If this short-term debt were classified as long-term debt the Corporation's earnings coverage ratio for the above period would have been 2.88. The earnings coverage ratio for the Corporation for the twelve-month period ended on March 31, 2023, based on unaudited information, without giving effect to the issue of any Debentures that may be distributed under this prospectus, was 2.90. In addition to long-term debt, the Corporation incurred short-term debt which has been disclosed in the unaudited condensed interim consolidated financial statements of the Corporation for March 31, 2023 and 2022. If this short-term debt were classified as long-term debt the Corporation's earnings coverage ratio for the above period would have been 2.66.

Information in respect of earnings coverage ratios will also be included in the applicable pricing supplement with respect to a specific issuance of Debentures.

CONSOLIDATED CAPITALIZATION

Except as described below, there have been no material changes in the Corporation's share or loan capital on a consolidated basis since March 31, 2023, being the date on which the Corporation's most recently completed quarterly financial period ended, which have not been disclosed in this prospectus or in the documents incorporated by reference herein.

Since March 31, 2023, the Corporation has issued $250 million of debt in the form of Senior Unsecured Debentures. See "Recent Developments".

DESCRIPTION OF THE DEBENTURES

The Debentures will be issued in one or more series under a trust indenture dated May 7, 2003 between the Corporation and BNY Trust Company of Canada (the "Trustee" which term shall include, unless the context requires otherwise, its successors), as amended from time to time and as supplemented from time to time by supplemental indentures (together, the "Indenture"). The Indenture permits the issuance of an unlimited principal amount of debentures of the Corporation in one or more series. The terms of each series of debentures issued pursuant to the Indenture will be specified in a supplemental indenture to the Indenture. A copy of the Indenture is available electronically under the Corporation's profile at www.sedar.com.

The specific terms of an offering of Debentures (including the aggregate principal amount of the Debentures being offered, the currency or currencies, the issue and delivery date, the form, the maturity date, the interest rate, the issue price, the interest payment date(s), any redemption or repayment provisions, any provisions entitling the Corporation to extend the maturity date of the Debentures, the name(s) of the Dealer(s) offering the Debentures, the commission payable to such Dealer(s), the method of distribution and the net proceeds to the Corporation) will be set forth in a pricing supplement which will be delivered to purchasers together with this prospectus. Unless otherwise indicated in a pricing supplement, the Debentures will not be listed on any securities exchange. The Corporation reserves the right to set forth in a pricing supplement specific terms of Debentures which are not within the parameters set forth in this prospectus.

The following is a summary of the material attributes of the Debentures. This summary does not purport to be complete. For a complete description of the Debentures, reference should be made to the Indenture. Certain capitalized terms used in this summary are defined below under "Definitions".

Term, Denomination and Currency

The Debentures will have a term to maturity of not less than one year and will be issuable in denominations of $1,000 and multiples thereof. The Debentures may be issued in Canadian dollars or any foreign currency or currency unit determined at the time of issue.

Interest

The Debentures will bear interest at fixed or floating rates as set out in the applicable pricing supplement to this prospectus.

Rank

The Debentures will be direct unsecured obligations of the Corporation and will rank *pari passu* with all other Debentures from time to time outstanding under the Indenture and, except as to sinking funds and to the extent prescribed by law, with all other unsecured and unsubordinated indebtedness of the Corporation from time to time outstanding, including, but not limited to, indebtedness of the Corporation under the THC Revolving Credit Facility, the Prudential Facility, the Working Capital Facility, its commercial paper program and debentures of every other series from time to time outstanding issued pursuant to the Indenture.

The Debentures will not be obligations of, and will not be guaranteed in any manner by, the City of Toronto.

Redemption

If so specified in the applicable pricing supplement, a series of Debentures may be redeemed, at the Corporation's option, in whole at any time or in part from time to time, prior to maturity, on not more than 60 and not less than 15 business days prior notice, or such other prior notice period as specified in the applicable pricing supplement and permitted by the Indenture, at the redemption price or at par, together in each case with accrued and unpaid interest to, but not including, the date fixed for redemption. The applicable pricing supplement will specify the redemption price (or the manner of calculating the redemption price), if any, for the series of Debentures.

If less than all Debentures of any series of Debentures are to be redeemed, the Debentures to be redeemed will be selected by the Trustee on a *pro rata* basis or by lot or such other means as the Trustee may deem equitable and expedient.

Purchase for Cancellation

The Corporation may, at any time, purchase Debentures for cancellation, in the open market, by tender or by private contract, at any price.

Covenants

Negative Pledge

The Corporation will not, and will not permit any Designated Subsidiary to, create, assume or suffer to exist any Security Interest, other than Permitted Encumbrances, on or over any of its assets (present or future) to secure any Obligation, unless at the same time it shall secure equally and rateably therewith all the debentures issued pursuant to the Indenture then outstanding.

Limitation on Funded Indebtedness

The Corporation will not, and will not permit any Designated Subsidiary to, directly or indirectly, issue, incur, assume or otherwise become liable for or in respect of any Funded Indebtedness unless, after giving effect thereto, Consolidated Funded Indebtedness would not exceed 75% of Total Consolidated Capitalization. This covenant will not operate to prevent the Corporation or a Designated Subsidiary from issuing, incurring, assuming

or otherwise becoming liable for or in respect of any Inter-Company Indebtedness and Non-Speculative Financial Instrument Obligations. This covenant will operate to prevent the Corporation or a Designated Subsidiary from assigning any Inter-Company Indebtedness to a person other than the Corporation or a Designated Subsidiary.

Limitation on Designated Subsidiary Indebtedness

The Corporation will not permit a Designated Subsidiary to, directly or indirectly, issue, incur, assume or otherwise become liable for or in respect of any Indebtedness except:

(a) Inter-Company Indebtedness of the Designated Subsidiary;

(b) Non-Recourse Debt of the Designated Subsidiary;

(c) Non-Speculative Financial Instrument Obligations of the Designated Subsidiary;

(d) Permitted Capital Lease Obligations of the Designated Subsidiary;

(e) Prudential and Bilateral Credit Support Obligations of the Designated Subsidiary;

(f) Purchase Money Obligations of the Designated Subsidiary; and

(g) any other Indebtedness of the Designated Subsidiary (in addition to the Indebtedness referred to in paragraphs (a) to (f)) if, after giving effect to the Indebtedness, the aggregate amount of all Indebtedness of all Designated Subsidiaries permitted by this paragraph (g) only would not exceed 5% of Consolidated Net Worth.

For the purposes of this covenant, the assignment by the Corporation to a third party of Inter-Company Indebtedness owing by a Designated Subsidiary will be considered to be an incurrence of Indebtedness by such Designated Subsidiary.

Designation of Subsidiaries as Designated Subsidiaries

LDC is a Designated Subsidiary. The board of directors of the Corporation may designate a subsidiary of the Corporation in addition to LDC as a Designated Subsidiary if:

(a) at the time of and after giving effect to the designation, no Event of Default or event that, with the passing of time or the giving of notice or both, would constitute an Event of Default has occurred and is continuing;

(b) after giving effect to the designation, the Corporation would be entitled under the Indenture to issue Funded Indebtedness in the amount of at least $1.00; and

(c) none of the shares of the subsidiary is owned by another subsidiary of the Corporation that is not a Designated Subsidiary.

The board of directors of the Corporation may terminate the designation of a subsidiary of the Corporation other than LDC as a Designated Subsidiary if:

(a) at the time of and after giving effect to the termination, no Event of Default or event that, with the passing of time or the giving of notice or both, would constitute an Event of Default has occurred and is continuing;

(b) after giving effect to the termination, the Corporation would be entitled under the Indenture to issue Funded Indebtedness in the amount of at least $1.00; and

(c) the subsidiary does not own any Funded Indebtedness of the Corporation or any shares or Funded Indebtedness of any other Designated Subsidiary.

Restriction on Mergers and Dispositions

The Corporation will not, directly or indirectly through a Designated Subsidiary, enter into a transaction or series of transactions in which all or substantially all of the undertaking, property and assets of the Corporation and its Designated Subsidiaries determined on a consolidated basis would become the property of any other person, whether by way of reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale, lease or otherwise, unless:

(a) the person is a corporation organized and existing under the laws of Canada or a province or territory thereof and expressly assumes, by a supplemental indenture satisfactory in form to the Trustee and its counsel and executed and delivered to the Trustee, all of the covenants and obligations of the Corporation under the Indenture and all debentures issued pursuant to the Indenture; and

(b) at the time of and after giving effect to the reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale, lease or other transaction, no Event of Default or event that, with the passing of time or the giving of notice or both, would constitute an Event of Default has occurred and is continuing.

Events of Default

The following are Events of Default applicable to all series of debentures, including each series of Debentures, issued pursuant to the Indenture:

(a) failure to pay principal or premium (if any) on the debentures when due;

(b) failure to pay interest on the debentures when due if such failure continues for a period of 30 days;

(c) the sale, transfer, lease or other disposition of all or substantially all of the property and assets of the Corporation and its Designated Subsidiaries determined on a consolidated basis other than in accordance with the covenants described above under "Description of the Debentures – Covenants – Restriction on Mergers and Dispositions";

(d) failure to observe or perform any other covenant or condition contained in the Indenture if such failure continues for a period of 60 days after written notice thereof has been given to the Corporation by the Trustee or the holders of at least 25% in principal amount of the debentures of any affected series then outstanding;

(e) failure by the Corporation or any Material Subsidiary to pay principal, premium (if any) or interest due on any Indebtedness, the principal amount of which is more than $50 million in the aggregate, beyond the applicable grace period;

(f) failure by the Corporation or any Material Subsidiary to observe or perform any provision of any agreement under which Indebtedness is created if such failure has the effect of causing more than $50 million of such Indebtedness in the aggregate to become due and payable or to be required to be redeemed or repurchased before its stated maturity;

(g) the rendering by a court of competent jurisdiction of one or more judgments against the Corporation or any Material Subsidiary in an aggregate amount of more than $50 million if the judgments remain undischarged or unstayed for more than 30 days; and

(h) specified events of bankruptcy, insolvency or reorganization affecting the Corporation or any Material Subsidiary.

Default

If an Event of Default described in paragraphs (a) to (g) above occurs and is continuing, the Trustee or the holders of not less than 25% of the principal amount of debentures of a series of debentures issued pursuant to the Indenture then outstanding may declare the principal amount of, and the premium (if any) and accrued and unpaid interest on all debentures of that series then outstanding to be due and payable immediately.

If an Event of Default described in paragraph (h) above occurs and is continuing, the principal amount of and the premium (if any) and accrued and unpaid interest on all debentures issued pursuant to the Indenture then outstanding shall be due and payable immediately without any declaration or other action by the Trustee or the holders of the debentures.

Protection of Trustee

Subject to the provisions of the Indenture relating to the duties of the Trustee, if an event of default applicable to a series of debentures issued pursuant to the Indenture occurs and is continuing, the Trustee will be under no obligation to exercise any of its rights or powers under the Indenture at the request or direction of any holders of such debentures unless the Trustee is sufficiently indemnified in accordance with the provisions of the Indenture. Subject to the provisions of the Indenture providing for the indemnification of the Trustee, the holders of the requisite principal amount of such debentures will have the right to direct the time, method and place of conducting any proceedings for any remedy available to the Trustee or exercising any rights or powers of the Trustee in respect of such debentures.

Modification

The Indenture provides that certain rights, privileges, restrictions and conditions of debentures issued and outstanding under the Indenture may be modified if such modifications are authorized by extraordinary resolution.

The term "extraordinary resolution" is defined in the Indenture to mean:

(a) in the case of modifications which affect a particular series of debentures issued pursuant to the Indenture, a resolution passed by the affirmative votes of the holders of not less than 66⅔% in principal amount of debentures of that series then outstanding represented and voting at a meeting or an instrument in writing signed by the holders of not less than 66⅔% in principal amount of debentures of that series then outstanding; and

(b) in the case of modifications which affect all debentures issued pursuant to the Indenture, a resolution passed by the affirmative votes of the holders of not less than 66⅔% in principal amount of all debentures then outstanding represented and voting at a meeting or an instrument in writing signed by the holders of not less than 66⅔% in principal amount of all debentures then outstanding, treated in each case as a single class.

Defeasance

The Indenture requires the Trustee to release the Corporation from its obligations in respect of a series of debentures issued pursuant to the Indenture if specified conditions are met, including the deposit by the Corporation of cash or certain cash-equivalent securities for the payment of all principal and interest and any other amounts on the debentures of such series and the payment of the expenses of the Trustee.

Form, Transfer and Payment Mechanics

Except as described under "Plan of Distribution" or as set out in a pricing supplement, the Debentures will be represented by one or more global Debentures (collectively, the "Global Debenture") registered in the name of CDS Clearing and Depository Services Inc. or a successor thereof (the "Depository") or its nominee and held by or on behalf of the Depository as custodian for institutions (including the Dealers) which participate directly or indirectly in the Depository's book-entry only registration system ("BEO Participants"). Interests in the Debentures represented by the Global Debenture will be evidenced by credits to book-entry accounts of BEO Participants

maintained with the Depository. Interests of the owners of Debentures represented by the Global Debenture will be evidenced by credits to accounts maintained with such BEO Participants on behalf of such owners.

Except as described under "Plan of Distribution" and as described below or as set out in a pricing supplement, purchasers of Debentures represented by the Global Debenture will not be entitled to certificates or other instruments from the Corporation or the Depository evidencing their ownership of Debentures. Beneficial owners of Debentures represented by the Global Debenture will not be shown on the registers maintained by the Trustee or the records maintained by the Depository but will be shown through book-entry accounts of BEO Participants. The rights of beneficial owners of Debentures represented by the Global Debenture may be exercised only through the BEO Participants with which such book-entry accounts are maintained. Purchasers of Debentures represented by the Global Debenture will receive a customer confirmation of purchase from the selling Dealer.

Purchasers of Debentures represented by the Global Debenture will receive definitive Debentures registered in their name only:

(a) if the Corporation determines that the Depository is no longer willing, able or qualified to discharge properly its responsibilities as holder of the Global Debenture in connection with the Debentures and the Corporation is unable to locate a qualified successor;

(b) if the Corporation elects to terminate the book-entry only registration of Debentures through the Depository; or

(c) in certain other specified circumstances.

Transfers of interests in Debentures represented by the Global Debenture will be effected through records maintained by the Depository or its nominee (with respect to interests of BEO Participants) and on the records of BEO Participants (with respect to interests of persons other than BEO Participants). Beneficial owners of Debentures represented by the Global Debenture who are not BEO Participants but who desire to transfer any interest in Debentures may do so only through BEO Participants.

Payments of interest and principal on the Global Debenture will be made to the Depository or its nominee as registered holder of the Global Debenture. As long as the Depository or its nominee is the registered owner of the Global Debenture, the Depository or its nominee will be considered the sole owner of the Global Debenture for the purposes of receiving payment on the Global Debenture and for all other purposes under the Indenture and the Global Debenture.

The Corporation expects that the Depository or its nominee, upon receipt of any payment of principal or interest in respect of the Global Debenture, will credit the accounts of BEO Participants, on the date principal or interest is payable, with payments in amounts proportionate to their respective interests in the principal amount of the Global Debenture as shown on the records of the Depository or its nominee. The Corporation also expects that payments of principal and interest by BEO Participants to the owners of interests in the Debentures represented by the Global Debenture held through accounts maintained with BEO Participants will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name", and will be the responsibility of BEO Participants. The responsibility and liability of the Corporation and the Trustee in respect of Debentures represented by the Global Debenture is limited to making payment of any principal and interest due on the Global Debenture to the Depository or its nominee.

Governing Law

The Indenture is and the Debentures will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

Definitions

The following defined terms used in this section of the prospectus are defined in the Indenture substantially as set out below.

"**Capital Lease**" means, with respect to a person, a lease or other arrangement in respect of real or personal property that is required to be classified and accounted for as a capital lease on a balance sheet of the person in accordance with GAAP.

"**Capital Lease Obligation**" means, with respect to a person, the obligation of the person to pay rent or other amounts under a Capital Lease.

"**Consolidated Funded Indebtedness**" means the aggregate amount of all Funded Indebtedness of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP.

"**Consolidated Net Worth**" means the shareholder's equity of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP. For greater certainty, the shareholder's equity of a subsidiary of the Corporation that is not a Designated Subsidiary will not be included in making such determination.

"**Contingent Liability**" means, with respect to a person, any agreement, undertaking or arrangement by which the person guarantees, endorses or otherwise becomes or is contingently liable upon (by direct or indirect agreement, contingent or otherwise, to provide funds for payment, to supply funds to, or otherwise to invest in, a debtor, or otherwise to assure a creditor against loss) the obligation, debt or other liability of any other person (other than by endorsements of instruments in the course of collection), or guarantees the payment of dividends or other distributions upon the shares of any other person. The amount of any Contingent Liability will, subject to any limitation contained therein, be deemed to be the outstanding principal amount (or maximum principal amount, if larger) of the obligation, debt or other liability to which the Contingent Liability relates.

"**Deferred Purchase Price Obligation**" means, with respect to a person, an obligation issued, incurred or assumed by the person in connection with the acquisition by the person of an asset in respect of the deferred purchase price of the asset.

"**Designated Subsidiary**" means Toronto Hydro-Electric System Limited and, until such designation is terminated in accordance with the covenants described above under "Description of the Debentures – Covenants – Designation of Subsidiaries as Designated Subsidiaries", any other subsidiary of the Corporation designated as a Designated Subsidiary by the board of directors of the Corporation in accordance with the covenants described above under "Description of the Debentures – Covenants – Designation of Subsidiaries as Designated Subsidiaries".

"**Event of Default**" means an event of default under the Indenture.

"**Financial Instrument Obligations**" means, with respect to any person, obligations arising under:

(a) interest rate swap agreements, forward rate agreements, floor, cap or collar agreements, futures or options, insurance or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is interest rates or the price, value or amount payable thereunder is dependent or based upon interest rates or fluctuations in interest rates in effect from time to time (but excluding conventional floating rate indebtedness);

(b) currency swap agreements, cross-currency agreements, forward agreements, floor, cap or collar agreements, futures or options, insurance or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is currency exchange rates or the price, value or amount payable thereunder is dependent or based upon currency exchange rates or fluctuations in currency exchange rates in effect from time to time; and

(c) any agreement for the making or taking of any commodity (including coal, natural gas, oil and electricity), swap agreement, floor, cap or collar agreement or commodity future or option or other similar agreement or arrangement, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is any commodity or the price, value or amount payable thereunder is dependent or based upon the price or fluctuations in the price of any commodity;

or any other similar transaction, including any option to enter into any of the foregoing, or any combination of the foregoing, in each case to the extent of the net amount due or accruing due by the person under the obligations determined by marking the obligations to market in accordance with their terms.

"**Funded Indebtedness**" means Indebtedness (other than Subordinated Indebtedness) that, on the date of issue or assumption of liability, has a term to maturity (including any right of extension or renewal) greater than 18 months.

"**GAAP**" means, as at any date of determination:

(a) accounting principles which are generally recognized as being generally accepted in Canada, if the Corporation is then preparing its financial statements in accordance with such principles; or

(b) accounting principles which are generally recognized as being generally accepted in the United States, if the Corporation is then preparing its financial statements in accordance with such principles.

"**Indebtedness**" means, with respect to a person, without duplication:

(a) all obligations of the person for borrowed money, including obligations with respect to bankers' acceptances and contingent reimbursement obligations relating to letters of credit and other financial instruments;

(b) all Financial Instrument Obligations of the person;

(c) all Deferred Purchase Price Obligations of the person;

(d) all Capital Lease Obligations and Purchase Money Obligations of the person;

(e) all Prudential and Bilateral Credit Support Obligations of the person; and

(f) all Contingent Liabilities of the person with respect to obligations of another person if such obligations are of the type referred to in paragraphs (a) to (e).

"**Inter-Company Indebtedness**" means, with respect to the Corporation, indebtedness of the Corporation to a Designated Subsidiary and, with respect to a Designated Subsidiary, indebtedness of the Designated Subsidiary to the Corporation or to another Designated Subsidiary.

"**Material Subsidiary**" means a Designated Subsidiary and any other subsidiary of the Corporation:

(a) the total assets of which represent more than 10% of the total assets of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP; or

(b) the total revenues of which represent more than 10% of the total revenues of the Corporation and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP.

For greater certainty, the assets and revenues of a subsidiary of the Corporation that is not a Designated Subsidiary will not be included in making such determinations.

"**Non-Recourse Debt**" means, with respect to a person, any indebtedness incurred to finance the creation, development, construction or acquisition of an asset of the person (and any extensions, renewals or refunding of any such indebtedness) provided that the recourse of the obligee thereof against the person is limited in all circumstances (other than in respect of false or misleading representations or warranties) to the asset (including all rights and benefits related to or arising out of the asset).

"**Non-Speculative Financial Instrument Obligations**" means, with respect to a person, Financial Instrument Obligations of the person entered into by the person in the ordinary course of business for risk management purposes and not for speculative or capital raising purposes.

"**Obligations**" means, with respect to a person, without duplication, all items which, in accordance with GAAP, would be included as liabilities on the liability side of the balance sheet of the person and all Contingent Liabilities of the person.

"**Permitted Capital Lease Obligations**" means, with respect to a Designated Subsidiary, the obligation of the Designated Subsidiary to pay rent or other amounts under a Capital Lease, other than a Capital Lease entered into as part of a Sale and Leaseback Transaction unless:

(a) the property which is the subject matter of the Sale and Leaseback Transaction is recorded as an asset of the Designated Subsidiary on its non-consolidated financial statements in accordance with GAAP;

(b) the proceeds of sale of such property have been determined by the board of directors of the Designated Subsidiary to be at least equal to its fair value; and

(c) either of the following is applicable:

(1) at the time of the Sale and Leaseback Transaction, the cost of acquiring such property could have been financed pursuant to a Purchase Money Obligation; or

(2) within 120 days after completion of the Sale and Leaseback Transaction, the Designated Subsidiary reduces its Indebtedness, other than Indebtedness permitted pursuant to paragraphs (a) to (e) above under "Description of the Debentures – Covenants – Limitation on Designated Subsidiary Indebtedness", by an amount at least equal to the net proceeds from the Sale and Leaseback Transaction.

"**Permitted Encumbrances**" means:

(a) any Security Interest securing Obligations of a Designated Subsidiary that:

(1) exists before and at the time that the Designated Subsidiary becomes a Designated Subsidiary;

(2) was not created or assumed in contemplation or as a result of the Designated Subsidiary becoming a Designated Subsidiary; and

(3) immediately before and after the Designated Subsidiary becomes a Designated Subsidiary, does not attach to the assets or secure Obligations of the Corporation or any other Designated Subsidiary;

(b) any Purchase Money Mortgage or Capital Lease of the Corporation or a Designated Subsidiary;

(c) any Security Interest in an asset created or assumed by the Corporation or a Designated Subsidiary to secure Non-Recourse Debt of the Corporation or the Designated Subsidiary in respect of such asset;

(d) any Security Interest in cash, marketable debt securities or accounts receivable created or assumed by the Corporation or a Designated Subsidiary to or in favour of a bank or other lending institution to secure indebtedness of the Corporation or the Designated Subsidiary that is payable on demand or that, on the date of issue or assumption of liability, has a term to maturity (including any right of extension or renewal) of 18 months or less and that is incurred by the Corporation or the Designated Subsidiary in the ordinary course of business and for the purpose of carrying on the same;

(e) any Security Interest in cash or marketable debt securities created or assumed by the Corporation to secure Non-Speculative Financial Instrument Obligations of the Corporation if the aggregate value of such cash and marketable debt securities is not more than 105% of the aggregate amount of the Non-Speculative Financial Instrument Obligations;

(f) any Security Interest created or assumed by a Designated Subsidiary in favour of the Corporation or any Wholly-Owned Designated Subsidiary;

(g) any Security Interest in an asset acquired by the Corporation or a Designated Subsidiary that secures Obligations of any other person, whether or not such Obligations are assumed by the Corporation or the Designated Subsidiary provided that the Security Interest:

(1) exists before and at the time that the asset is acquired by the Corporation or the Designated Subsidiary;

(2) was not created or assumed in contemplation or as a result of the asset being acquired by the Corporation or the Designated Subsidiary; and

(3) immediately before and after the asset is acquired by the Corporation or the Designated Subsidiary, does not attach to the assets or secure Obligations of the Corporation or any other Designated Subsidiary;

(h) any Security Interest in cash or marketable debt securities in a sinking fund account established by the Corporation in support of a series of debentures issued pursuant to the Indenture;

(i) any Security Interest or deposit under workers' compensation, social security or similar legislation or in connection with bids, tenders, leases, contracts or expropriation proceedings or to secure public or statutory obligations, surety and appeal bonds or costs of litigation where required by law;

(j) any Security Interest or privilege imposed by law, such as builders', mechanics, material men's, carriers', warehousemen's and landlords' liens and privileges; or any Security Interest or privilege arising out of judgments or awards with respect to which the Corporation or a Designated Subsidiary at the time is prosecuting an appeal or proceedings for review and with respect to which it has secured a stay of execution pending such appeal or proceedings for review; or any Security Interest for taxes, assessments or governmental charges or levies not at the time due and delinquent or the validity of which is being contested at the time by the Corporation or a Designated Subsidiary in good faith; or any undetermined or inchoate Security Interest or privilege incidental to current operations that has not been filed pursuant to law against the Corporation or a Designated Subsidiary or that relates to obligations not due or delinquent; or the deposit of cash or securities in connection with any Security Interest or privilege referred to in this paragraph (j);

(k) any right reserved to or vested in any municipality or governmental or other public authority by the terms of any lease, licence, franchise, grant or permit held or acquired by the Corporation or a Designated Subsidiary, or by any statutory provision, to terminate the lease, licence, franchise, grant or permit or to purchase assets used in connection therewith or to require annual or other periodic payments as a condition of the continuance thereof;

(l) any Security Interest or right of distress reserved in or exercisable under any lease for rent to which the Corporation or a Designated Subsidiary is a party and for compliance with the terms of the lease;

(m) any Security Interest created or assumed by the Corporation or a Designated Subsidiary in favour of a public utility or any municipality or governmental or other public authority when required by the utility, municipality or other authority in connection with the operations of the Corporation or a Designated Subsidiary;

(n) any reservations, limitations, provisos and conditions expressed in original grants from the Crown;

(o) any minor encumbrances, such as easements, rights-of-way, servitudes or other similar rights in land granted to or reserved by other persons, rights-of-way for sewers, electric lines, telegraph and telephone lines, oil and natural gas pipelines and other similar purposes, or zoning or other restrictions applicable to the Corporation's or a Designated Subsidiary's use of real property, that do not in the aggregate materially detract from the value of the property or materially impair its use in the operation of the business of the Corporation or the Designated Subsidiary;

(p) any extension, renewal, alteration, substitution or replacement, in whole or in part, of a Security Interest referred to in paragraphs (a) to (o) provided that the Security Interest is limited to all or part of the same assets, the principal amount of the secured Obligations is not increased by that action, the term of the secured Obligations is not shortened and the terms and conditions of the Security Interest are no more restrictive in any material respect than the Security Interest so extended; and

(q) any other Security Interest created or assumed by the Corporation or a Designated Subsidiary (in addition to the Security Interests referred to in paragraphs (a) to (p)) if, after giving effect to the Security Interest, the aggregate amount of all Indebtedness secured by Security Interests permitted by this paragraph only does not at that time exceed 5% of Consolidated Net Worth.

"**Prudential and Bilateral Credit Support Obligations**" means, without duplication, the following obligations:

(a) all contingent reimbursement obligations of the Corporation relating to letters of credit and other financial instruments and all Contingent Liabilities of the Corporation in respect of Obligations of a subsidiary of the Corporation for the purchase or sale of electricity or natural gas; and

(b) all obligations of a Designated Subsidiary for borrowed money, including contingent reimbursement obligations relating to letters of credit and other financial instruments under credit facilities established for participants in the wholesale market for electricity administered by the Independent Electricity System Operator ("IESO"), in respect of the Obligations of the Designated Subsidiary for the purchase or sale of electricity or natural gas;

if such obligations were incurred or assumed to satisfy:

(x) prescribed prudential requirements in the wholesale market for electricity administered by the IESO;

(y) credit support arrangements required by electricity distribution companies under the terms of the Retail Settlement Code established by the Ontario Energy Board; or

(z) credit support requirements of counterparties under bilateral contracts or customers under purchase contracts.

"**Purchase Money Mortgage**" means, with respect to a person, any Security Interest created or assumed by the person to secure a Purchase Money Obligation provided that such Security Interest is limited to the asset financed by such Purchase Money Obligation and is created or assumed not later than three months after such Purchase Money Obligation is issued, incurred or assumed.

"**Purchase Money Obligation**" means, with respect to a person, indebtedness of the person issued, incurred or assumed to finance all or part of the cost of acquiring any asset for the person, other than shares, bonds and other securities, or constructing, installing or improving any real property or fixtures of the person, provided that the indebtedness is issued, incurred or assumed within twelve months after such acquisition, construction, installation or improvement, and includes any extension, renewal or refunding of such indebtedness so long as the principal amount thereof outstanding on the date of such extension, renewal or refunding is not increased.

"**Sale and Leaseback Transaction**" means, with respect to a person, a transaction or series of transactions pursuant to which the person sells or transfers real or personal property owned by the person to a third party and subsequently leases such real or personal property.

"**Security Interest**" means any security interest, assignment by way of security, mortgage, charge (whether fixed or floating), hypothec, pledge, lien or other encumbrance on or interest in property or assets that secures the payment of Obligations.

"**Subordinated Indebtedness**" means all indebtedness of the Corporation in respect of which, upon any distribution of assets of the Corporation upon any dissolution, winding-up, liquidation or reorganization of the Corporation (whether in bankruptcy, insolvency or receivership proceedings or upon an assignment for the benefit of creditors, or any other marshalling of the assets and liabilities of the Corporation or otherwise), the payment of all indebtedness and liabilities of the Corporation in connection with all debentures issued pursuant to the Indenture including principal, interest, fees and expenses, must be satisfied in full prior to any amount being applied to such indebtedness.

"**Total Consolidated Capitalization**" means, without duplication, the sum of:

(a) the principal amount of all Consolidated Funded Indebtedness;

(b) the principal amount of all Subordinated Indebtedness; and

(c) the Consolidated Net Worth;

in each case, as determined by the Corporation and its Designated Subsidiaries.

"**Wholly-Owned Designated Subsidiary**" means a Designated Subsidiary all of the outstanding shares in the capital of which are owned by the Corporation or one or more Wholly-Owned Designated Subsidiaries.

RISK FACTORS

An investment in the Debentures is subject to a variety of risks. Before deciding whether to invest in any Debentures, prospective purchasers of Debentures should consider carefully various risks, including the risk factors described below and contained in the documents incorporated or deemed to be incorporated by reference in this prospectus (including the sections entitled "Forward-Looking Information" and "Risk Factors" in the Corporation's AIF and the sections entitled "Forward-Looking Information" and "Risk Management and Risk Factors" in the Corporation's MD&A). This prospectus, including the documents incorporated or deemed to be incorporated by reference in this prospectus, does not describe all of the risks of an investment in the Debentures. Prospective purchasers should consult their own financial and legal advisors about the risks entailed by an investment in the Debentures and the suitability of such investment in light of their particular circumstances. Debentures will not be an appropriate investment for a prospective purchaser if the purchaser does not understand the terms of the Debentures or financial matters in general. A prospective purchaser should not purchase Debentures unless the prospective purchaser understands, and can bear, all of the investment risks related to the Debentures.

Rank of Debentures and Holding Company Structure

The Debentures will be direct unsecured obligations of the Corporation and will rank *pari passu* with all other unsecured and unsubordinated indebtedness of the Corporation from time to time outstanding, including,

but not limited to, indebtedness of the Corporation under the THC Revolving Credit Facility, the Prudential Facility, the Working Capital Facility, its commercial paper program and debentures of every other series issued pursuant to the Indenture. A default by the Corporation under the Indenture will constitute an event of default under the THC Revolving Credit Facility and an event of default or repayment event under the Working Capital Facility and the Prudential Facility. There can be no assurance that sufficient funds would be available to the Corporation at the time of any such default to make any required payment under the Debentures.

The Corporation is a holding company and substantially all of its business activities are carried on by its subsidiaries. Therefore, the Corporation's ability to meet its financial obligations is dependent primarily upon the receipt of interest and principal, management fees, cash dividends and other payments from its subsidiaries, together with proceeds raised by the Corporation through the issuance of debt. The Corporation is wholly-owned by the City of Toronto and does not currently raise funds through the issuance of share capital to the public. The payment of dividends and the making of loans, advances and other payments to the Corporation by its subsidiaries may be subject to statutory or contractual restrictions, will depend on the earnings of the subsidiaries and will be subject to various business and other considerations.

The Corporation's subsidiaries are separate legal entities and have no legal obligation, contingent or otherwise, to pay any amount due under the Debentures or to make any amounts available to the Corporation, whether by dividends, interest, loans or other payments. In addition, these subsidiaries have not guaranteed the Debentures. Therefore, the Debentures will be effectively subordinated to the current and future liabilities, including trade payables and other indebtedness, of the Corporation's subsidiaries. The creditors of those subsidiaries will have the right to be paid before payment on the Debentures from any cash received or held by those subsidiaries. In the event of any bankruptcy, dissolution, liquidation or reorganization of one of those subsidiaries, following payment by the subsidiary of its liabilities, the subsidiary may not have sufficient assets to make payments to the Corporation in its capacity as an equityholder of such subsidiary.

Absence of Public Market for the Debentures

The Debentures will be newly issued securities for which, unless otherwise indicated in a prospectus supplement or pricing supplement, there is no existing trading market. The Corporation does not intend to list the Debentures on any Canadian, U.S. or other securities exchange. This may affect the pricing of the Debentures in the secondary market, the transparency and availability of trading prices, the liquidity of the Debentures and the extent of issuer regulation. There can be no assurance that a secondary market will develop for the Debentures or that any secondary market that does develop will continue. Accordingly, purchasers may not be able to sell the Debentures. In addition, if a trading market develops for the Debentures, the Debentures could trade at prices that may be higher or lower than their initial offering prices, depending on many factors, including prevailing interest rates, general economic conditions, the Corporation's results of operations and financial position, the ratings assigned to the Debentures and the Corporation's other debt securities and the markets for similar debt securities. If a holder of Debentures sells any Debentures before their maturity, such holder may have to do so at a substantial discount from the issue price, and as a result such holder may suffer substantial losses.

Ratings

The Corporation's perceived creditworthiness and changes in ratings of the Debentures may affect the market price or value and the liquidity of the Debentures. There is no assurance that any rating assigned to the Debentures issued hereunder will remain in effect for any given period of time or that any rating will not be lowered or withdrawn entirely by the relevant rating agency. A lowering or withdrawal of such rating may have an adverse effect on the market value of the Debentures.

Ratings may not reflect all risks associated with an investment in the Debentures. The ratings applied to the Debentures are an assessment of the Corporation's ability to pay its obligations. The ratings, however, may not reflect the potential impact of risks related to structure, market or other factors discussed in this prospectus or documents incorporated or deemed to be incorporated by reference in this prospectus on the value of the Debentures.

Additional Debt Financing

The Corporation expects to borrow to repay the Debentures when required to do so under the terms of the Debentures and to fund capital expenditures, including the renewal of LDC's electricity distribution assets. The Corporation's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including financial market conditions and activity in the global capital markets, the regulatory and public policy environment in Ontario, the Corporation's business, operations, financial condition or prospects, compliance with covenants, the ratings assigned to the Corporation and its debt securities by credit rating agencies, the availability of the commercial paper market, the current timing of debt maturities and general economic conditions.

Interest Rate Risks

Prevailing interest rates will affect the market price or value of the Debentures. Generally, the market price or value of the Debentures will decline as prevailing interest rates for comparable debt instruments rise and increase as prevailing interest rates for comparable debt instruments decline. Fluctuations in interest rates may also impact borrowing costs of the Corporation which may adversely affect its creditworthiness.

Risks Associated with Floating Rate Debentures

The Debentures will bear interest at fixed or floating rates as set out in the applicable pricing supplement to this prospectus. Investments in floating rate Debentures entail risks not associated with investments in fixed rate Debentures. The resetting of the applicable rate on a floating rate Debenture may result in a lower interest rate as compared to a fixed rate Debenture issued at the same time. The applicable rate on a floating rate Debenture will fluctuate in accordance with fluctuations in the instrument or obligation or other measure on which the applicable rate is based, which in turn may fluctuate and be affected by a number of interrelated factors, including economic, financial and political events over which the Corporation has no control.

Foreign Currency Risks

An investment in Debentures that are denominated or payable in a currency other than Canadian dollars entails significant risks that are not associated with a similar investment in a security denominated in Canadian dollars. Such risks include, without limitation, the possibility of significant changes in rates of exchange between the Canadian dollar and the applicable foreign currency unit, the possibility of the imposition or modification of foreign exchange controls by either the Canadian or foreign governments and potential illiquidity in the secondary market. These risks generally depend on circumstances over which the Corporation has no control, including political events, government policy and macroeconomic conditions. These risks will vary depending upon the currency or currencies involved and, where appropriate, will be more fully described in a pricing supplement.

This prospectus does not describe all the risks of an investment in the Debentures denominated or payable other than in Canadian dollars and prospective investors should consult their own financial and legal advisor as to the risk entailed with respect thereto. Debentures denominated in other than Canadian dollars are not appropriate investments for investors who are unfamiliar with foreign currency transactions.

The Debentures will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. A judgment by a Canadian court relating to any Debenture may be awarded only in Canadian currency and such judgment may be based on a rate of exchange in existence on a day other than the day of payment.

Early Redemption of the Debentures

Depending on the terms of the Debentures, the Corporation may have the right to redeem them, or the Debentures may be automatically redeemable under some circumstances. If the Debentures are redeemed, depending on the market conditions at the time of redemption, a holder of Debentures may not be able to reinvest the redemption proceeds in a security with a comparable return.

Shareholder Direction

Council of the City of Toronto has adopted a shareholder direction (the "Shareholder Direction") which sets out certain corporate governance principles with respect to Toronto Hydro. The Shareholder Direction is summarized in the AIF under "Relationship with the City". The Shareholder Direction is not for the benefit of, or enforceable by, the holders of the Debentures.

ELIGIBILITY FOR INVESTMENT

In the opinion of Norton Rose Fulbright Canada LLP, counsel to the Corporation, and Blake, Cassels & Graydon LLP, counsel to the Dealers, unless otherwise specified in the applicable pricing supplement, the Debentures, if issued on the date hereof, would be, as at that date, qualified investments under the *Income Tax Act* (Canada) and the *Income Tax Regulations* (collectively, the "Tax Act") for a trust governed by a registered retirement savings plan ("RRSP"), registered retirement income fund ("RRIF"), registered education savings plan ("RESP"), registered disability savings plan ("RDSP"), deferred profit sharing plan (other than a trust governed by a deferred profit sharing plan to which the Corporation, or an employer with which the Corporation does not deal at arm's length within the meaning of the Tax Act, has made a contribution), first home savings account ("FHSA"), or a tax-free savings account ("TFSA").

Notwithstanding that the Debentures may be a qualified investment for a trust governed by an RRSP, RRIF, RESP, RDSP, TFSA, or FHSA, the annuitant under an RRSP or RRIF, the subscriber of an RESP or the holder of an RDSP, TFSA, or FHSA, as the case may be, will be subject to a penalty tax if such Debentures are a "prohibited investment" for the RRSP, RRIF, RESP, RDSP, FHSA, or TFSA within the meaning of the Tax Act. The Debentures will not be a prohibited investment for a trust governed by an RRSP, RRIF, RESP, RDSP, FHSA, or TFSA provided that the annuitant of the RRSP or RRIF, the subscriber of the RESP or the holder of the RDSP, FHSA, or TFSA, as the case may be, deals at "arm's length" (within the meaning of the Tax Act) with the Corporation and does not have a "significant interest" (within the meaning of the Tax Act) in the Corporation. Prospective purchasers are advised to consult their own advisors in this regard.

LEGAL MATTERS

Certain legal matters in connection with any offering hereunder will be passed on for the Corporation by Norton Rose Fulbright Canada LLP and for the Dealers by Blake, Cassels & Graydon LLP. As of the date hereof, the partners and associates of Norton Rose Fulbright Canada LLP and Blake, Cassels & Graydon LLP, respectively, beneficially own, directly or indirectly, less than one per cent of the securities of the Corporation or any associate or affiliate of the Corporation.

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

The applicable pricing supplement will describe certain principal Canadian federal income tax considerations generally applicable to an investor who is a resident of Canada of the acquisition, ownership and disposition of the Debentures offered thereunder.

AUDITORS, REGISTRAR AND TRANSFER AGENT

The auditor of the Corporation is KPMG LLP, Chartered Professional Accountants ("KPMG LLP"), at their office at Bay Adelaide Centre, 333 Bay Street, Suite 4600, Toronto, Ontario, M5H 2S5. KPMG LLP have been the auditors of the Corporation since April 12, 2011. KPMG LLP has advised that it is independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and applicable legislation or regulation.

Registers for the registration and transfer of the Debentures issued in registered form are kept at the principal offices of the Trustee in the City of Toronto, located at BNY Trust Company of Canada, 1 York Street, 6th Floor, Toronto, Ontario M5J 0B6.

RELIANCE ON EXEMPTIONS FOR WELL-KNOWN SEASONED ISSUERS

The securities regulatory authorities in each of the provinces of Canada each independently adopted a series of substantively harmonized blanket orders, including Ontario Instrument 44-501 – *Exemption from Certain Prospectus Requirements for Well-known Seasoned Issuers (Interim Class Order)*, as extended pursuant to OSC Rule 44-502 - *Extension to Ontario Instrument 44-501 - Certain Prospectus Requirements for Well-Known Seasoned Issuers* (together with the equivalent local blanket orders in each of the other provinces of Canada, collectively, the "WKSI Blanket Orders"). This prospectus has been filed by the Corporation in reliance upon the WKSI Blanket Orders, which permit "well-known seasoned issuers", or "WKSIs", to file a final short form base shelf prospectus as the first public step in an offering, and exempt qualifying issuers from certain disclosure requirements relating to such final short form base shelf prospectus. As of the date hereof, the Corporation has determined that it qualifies as a "well-known seasoned issuer" under the WKSI Blanket Orders.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revision of the price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission, revision of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal advisor.

CERTIFICATE OF THE CORPORATION

Dated: July 27, 2023

This short form prospectus, together with the documents incorporated in this prospectus by reference, will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of all the provinces of Canada.

(Signed) *Anthony Haines*
President and
Chief Executive Officer

(Signed) *Céline Arsenault*
Executive Vice-President and
Chief Financial Officer

On behalf of the Board of Directors

(Signed) *David McFadden*
Director and
Chair of the Board of Directors

(Signed) *Michael Nobrega*
Director

CERTIFICATE OF THE DEALERS

Dated: July 27, 2023

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated in this prospectus by reference will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of all the provinces of Canada.

BMO NESBITT BURNS INC.

By: (Signed) *Andrew Macpherson*
Director

CIBC WORLD MARKETS INC.

By: (Signed) *Brian Pong*
Executive Director

NATIONAL BANK FINANCIAL INC.

By: (Signed) *John Carrique*
Managing Director

RBC DOMINION SECURITIES INC.

By: (Signed) *Robert Brown*
Managing Director

SCOTIA CAPITAL INC.

By: (Signed) *Kristi Pahapill*
Director

TD SECURITIES INC.

By: (Signed) *Mark Laing*
Managing Director

FIFTEENTH SUPPLEMENTAL TRUST INDENTURE

Made as of November 12, 2019

Between

TORONTO HYDRO CORPORATION
as issuer

and

BNY TRUST COMPANY OF CANADA
as trustee

Supplementing the Trust Indenture

made as of May 7, 2003

and

providing for the issue of

2.43% Senior Unsecured Debentures
due 2029 (Series 14)

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FIFTEENTH SUPPLEMENTAL TRUST INDENTURE

THIS FIFTEENTH SUPPLEMENTAL TRUST INDENTURE made as of November 12, 2019,

BETWEEN:

TORONTO HYDRO CORPORATION
a corporation incorporated under the laws of Ontario (the "**Corporation**")

and

BNY TRUST COMPANY OF CANADA
a trust company existing under the laws of Canada (the "**Trustee**")

RECITALS

(A) BNY Trust Company of Canada is the successor trustee of CIBC Mellon Trust Company;

(B) The Corporation has entered into a trust indenture with the Trustee made as of May 7, 2003, as amended, supplemented or restated from time to time (the "**Trust Indenture**") which provides for the issuance of one or more series of unsecured Debentures of the Corporation by way of Supplemental Indentures;

(C) The Corporation entered into a first supplemental trust indenture made as of May 7, 2003 for the purpose of providing for the issue of $225,000,000 aggregate principal amount of Series 1 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 1 Debentures;

(D) The Corporation entered into a second supplemental trust indenture made as of November 14, 2007 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 2 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 2 Debentures;

(E) The Corporation entered into a third supplemental trust indenture made as of November 12, 2009 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 3 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 3 Debentures;

(F) The City Note has been converted, in accordance with its terms, into the Series 4 Debentures and the Series 5 Debentures;

(G) The Corporation entered into a fourth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 4 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 4 Debentures;

(H) The Corporation entered into a fifth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 5 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 5 Debentures;

(I) The Corporation entered into a sixth supplemental trust indenture made as of May 20, 2010 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 6 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 6 Debentures;

(J) The Corporation entered into a seventh supplemental trust indenture made as of September 20, 2011 for the purpose of amending the definition of "GAAP" under the Trust Indenture;

(K) The Corporation entered into an eighth supplemental trust indenture made as of November 18, 2011 for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 7 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 7 Debentures;

(L) The Corporation entered into a ninth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 8 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 8 Debentures;

(M) The Corporation entered into a tenth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 9 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 9 Debentures;

(N) The Corporation entered into an eleventh supplemental trust indenture made as of September 16, 2014 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 10 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 10 Debentures;

(O) The Corporation entered into a twelfth supplemental trust indenture made as of March 16, 2015 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 11 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 11 Debentures;

(P) The Corporation entered into an amended and restated tenth supplemental trust indenture made as of September 2, 2015 for the purpose of making changes and corrections which were required for curing and correcting certain ambiguities and omissions in connection with an issue of $45,000,000 additional aggregate principal amount of the Series 9 Debentures;

(Q) The Corporation entered into a thirteenth supplemental trust indenture made as of June 14, 2016 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 12 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 12 Debentures;

(R) The Corporation entered into a fourteenth supplemental trust indenture made as of November 14, 2017 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 13 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 13 Debentures; and

(S) This Fifteenth Supplemental Trust Indenture is entered into for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 14 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 14 Debentures.

NOW THEREFORE THIS FIFTEENTH SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

Section 1 INTERPRETATION

1.1 To Be Read With Trust Indenture

This Fifteenth Supplemental Trust Indenture is a Supplemental Indenture as that term is used in the Trust Indenture. The Trust Indenture and this Fifteenth Supplemental Trust Indenture shall be read

together and shall have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this Fifteenth Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the interpretation thereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this Fifteenth Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Trust Indenture and used but not defined in this Fifteenth Supplemental Trust Indenture shall have the meanings ascribed to them in the Trust Indenture, as such meanings may be amended or supplemented with respect to Series 14 Debentures by this Fifteenth Supplemental Trust Indenture. In the event of any inconsistency between the meaning given to a term in the Trust Indenture and the meaning given to the same term in this Fifteenth Supplemental Trust Indenture, the meaning given to the term in this Fifteenth Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this Fifteenth Supplemental Trust Indenture and in the Series 14 Debentures, the following terms have the following meanings:

(a) ***Canada Yield*** on any date means the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to September 11, 2029 of the Series 14 Debentures, such yield to maturity being the average of the yields provided by two major Canadian investment dealers specified by the Corporation.

(b) ***Canada Yield Price*** means the amount equal to the net present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Series 14 Debentures that would have been payable September 11, 2029 if redemption had not been made, using a discount rate equal to the sum of the Canada Yield and 24 basis points, calculated at 10:00 a.m. (Toronto, Ontario time) three Business Days prior to the Redemption Date of the Series 14 Debentures.

(c) ***Series 14 Debentures*** means the 2.43% Senior Unsecured Debentures due 2029 (Series 14) referred to in Section 2.1.

(d) ***Series 14 Debentures Debt Account*** means the deposit account established in respect of the Series 14 Debentures pursuant to Section 8.2 of the Trust Indenture that is designated in writing by the Corporation to the Trustee as the "Series 14 Debentures Debt Account".

(e) ***Series 14 Debentures Interest Payment Date*** means June 11 and December 11 in each year that the Series 14 Debentures are outstanding, beginning June 11, 2020.

(f) ***Series 14 Debentures Interest Period*** means the period commencing on and including the later of the date of issue of the Series 14 Debentures and the immediately preceding Series 14 Debentures Interest Payment Date and ending on and including the day immediately preceding the next Series 14 Debentures Interest Payment Date to occur in respect of which interest is payable.

(g) ***Trust Indenture*** means the trust indenture made as of May 7, 2003 between the Corporation and the Trustee, as amended, supplemented or restated from time to time.

Section 2 SERIES 14 DEBENTURES

2.1 Creation and Designation

The Corporation is authorized in accordance with the Trust Indenture to issue under this Fifteenth Supplemental Trust Indenture, and hereby creates and issues, a series of debentures designated "2.43% Senior Unsecured Debentures due 2029 (Series 14)", having the terms set out in this Fifteenth Supplemental Trust Indenture.

2.2 No Limitation on Issue

The aggregate principal amount of Series 14 Debentures which may be issued under this Fifteenth Supplemental Trust Indenture including any supplement hereto is unlimited.

2.3 Date of Issue and Maturity

The Series 14 Debentures shall be dated November 12, 2019 (being the applicable date of issue) and will become due and payable, together with all accrued interest and unpaid interest thereon, on December 11, 2029 (being the applicable Stated Maturity).

2.4 Concerning Interest

(a) The Series 14 Debentures shall be issued in $1,000 principal amount denominations or integral multiples thereof and shall bear interest on the unpaid principal amount thereof at a rate of 2.43% per annum from and including their date of issue, payable semi-annually in arrears, in equal instalments (except in respect of the initial interest payment), on each Series 14 Debentures Interest Payment Date.

(b) Interest shall be payable in respect of each Series 14 Debentures Interest Period (after as well as before maturity, default and judgment, with interest on overdue interest at the same rate) on each Series 14 Debentures Interest Payment Date in accordance with Section 2.8 of the Trust Indenture, commencing on June 11, 2020 with an initial interest payment on June 11, 2020 of $14.08068495 per $1,000 principal amount of Series 14 Debentures.

2.5 Interest Payments

The Corporation shall make payments of interest on the Series 14 Debentures in accordance with the provisions of Section 2.8 of the Trust Indenture.

2.6 Payment of Amounts Due on Maturity

In accordance with Section 8.2 of the Trust Indenture, the Corporation will deposit to the Series 14 Debentures Debt Account all amounts required to be paid to the order of Holders of Series 14 Debentures on maturity, prior to 9:00 a.m. (Toronto, Ontario time), on the Stated Maturity of the Series 14 Debentures. The deposit of such funds will satisfy and discharge the liability of the Corporation for principal of, and any accrued and unpaid interest on, the Series 14 Debentures to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld).

2.7 Redemption and Purchase of Series 14 Debentures

(a) The Series 14 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to September 11, 2029, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to the greater of the Canada Yield Price and par, together in each case with accrued and unpaid interest to (but excluding) the Redemption

Date and in each case otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(b) The Series 14 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after September 11, 2029, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to 100% of the principal amount of the Series 14 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the Redemption Date and otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(c) The Corporation will be entitled at any time when not in default under the Trust Indenture to purchase for cancellation all or any of the Series 14 Debentures in accordance with Section 5.5 of the Trust Indenture.

(d) The Series 14 Debentures will not be subject to repurchase pursuant to any sinking fund provisions.

2.8 Form of Series 14 Debentures

(a) Except as set out in 2.8(b) below, the Series 14 Debentures and the registration panel and the certificate of the Trustee endorsed thereon shall be issuable initially as one Global Debenture to be held by, or on behalf of, CDS as depository for its participants and registered in the name of CDS or its nominee. The Global Debenture shall be substantially in the form set out in Schedule 1 hereto with such appropriate additions, deletions, substitutions and variations as the Directors shall by resolution determine prior to the time of issue thereof and as the Trustee may approve and with such distinguishing letters and numbers as the Trustee may approve, with such approval in each case to be conclusively evidenced by the Trustee's certification of such Global Debenture.

(b) The Trustee understands and acknowledges that the Series 14 Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 14 Debenture originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form set out in Schedule 2 hereto which definitive certificate, and each Series 14 Debenture certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE **"U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT."

If any Series 14 Debentures are being sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S Securities Act, the legend may be removed by providing a declaration to the Trustee to the following effect (or as the Corporation may prescribe from time to time),

> "The undersigned (A) acknowledges that the sale of the _____ Debentures, represented by certificate numbers _____ to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**") and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Toronto Hydro Corporation, (2) the offer of such Debentures was not made to a person in the United States and at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States and (3) neither the seller, nor any affiliate of the seller, nor any person acting on its or their behalf engaged in any directed selling efforts in connection with the offer and sale of such Debentures. Terms used herein have the meanings given to them by Regulation S under the U.S. Securities Act."

If any Series 14 Debentures are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Trustee Counsel (or counsel to the transferor satisfactory to the Trustee) to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 14 Debentures, the Corporation shall notify the Trustee, in writing, concerning which Series 14 Debentures are to be certificated and are to bear the legend described above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 14 Debentures.

2.9 Signatures on Series 14 Debentures

The Series 14 Debentures shall be signed in accordance with the provisions of Section 2.6 of the Trust Indenture.

2.10 Certification

(a) No Series 14 Debenture issued shall be obligatory or shall entitle the Holder of such Series 14 Debenture to the benefits of this Fifteenth Supplemental Trust Indenture until it has been certified by manual signature by or on behalf of the Trustee by execution of the certificate of the Trustee appended thereto substantially in the form set out in Schedule 1 hereto, or in some other form approved by the Trustee, whose approval shall be conclusively evidenced by the Trustee's execution of the certificate. Such certificate on any Series 14 Debenture shall be conclusive evidence that such Series 14 Debenture is duly issued and is a valid and binding obligation of the Corporation and that the Holder of such Series 14 Debenture is entitled to the benefits of the Trust Indenture, as supplemented by this Fifteenth Supplemental Trust Indenture, and such Series 14 Debenture.

(b) The certificate of the Trustee on any Series 14 Debenture shall not be construed as a representation or warranty by the Trustee as to the validity of this Fifteenth Supplemental Trust Indenture or of the Series 14 Debentures (except the due certification thereof and any other warranties implied by law) and the Trustee shall in no respect be liable or answerable for the use made of the Series 14 Debentures or any of them or the proceeds thereof.

2.11 Location of Register

With respect to the Series 14 Debentures, initially the Register referred to in Section 3.1 of the Trust Indenture shall be kept by the Trustee at the Corporate Trust Office and may thereafter be kept by the Trustee in such other place as the Corporation, with the approval of the Trustee, may designate.

2.12 Additional Amounts

The Corporation will not be required to pay an additional amount on the Series 14 Debentures in respect of any tax, assessment or government charge that is required by law to be withheld or deducted by it.

2.13 Trustees, etc.

The Trustee will be the Paying Agent and the Registrar for the Series 14 Debentures.

Section 3 MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this Fifteenth Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this Fifteenth Supplemental Trust Indenture and in accordance with the Trust Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this Fifteenth Supplemental Trust Indenture is in all respects confirmed.

3.3 Counterparts

This Fifteenth Supplemental Trust Indenture may be executed in counterparts, each of which so executed shall be deemed to be original and such counterparts together shall constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this Fifteenth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

TORONTO HYDRO CORPORATION

By: _____

Name: Anthony Haines

Title: President and Chief Executive Officer

By: _____

Name: Aida Cipolla

Title: Executive Vice-President and Chief Financial Officer

[Trustee Signature Page Follows]

IN WITNESS WHEREOF the parties hereto have executed this Fifteenth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

BNY TRUST COMPANY OF CANADA

By: Wanda Camacho

Name: Wanda Camacho

Title: Authorized Signatory

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 14

This Debenture is a Global Debenture within the meaning of the Trust Indenture hereinafter referred to and is registered in the name of a Depository or a nominee thereof. Unless this Certificate is presented by an authorized representative of CDS Clearing and Depository Services Inc. ("CDS") to Toronto Hydro Corporation or its agent for registration of transfer, exchange or payment, and any certificate issued in respect thereof is registered in the name of CDS & CO., or in such other name as is requested by an authorized representative of CDS (and any payment is made to CDS & CO., or to such other entity as is requested by an authorized representative of CDS), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL since the registered holder hereof, CDS & CO., has a property interest in the securities represented by this certificate herein and it is a violation of its rights for another person to hold, transfer or deal with this certificate.

[No. 14-000]

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TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.43% SENIOR UNSECURED DEBENTURES DUE 2029 (SERIES 14)

ISIN CA89119ZAL72
CUSIP 89119ZAL7

Issue Date	November 12, 2019
Stated Maturity	December 11, 2029
Interest Rate Per Annum	2.43%
Interest Payment Dates	June 11 and December 11 in each year
Initial Interest Payment Date	June 11, 2020
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 2.43% Senior Unsecured Debenture due December 11, 2029 (Series 14) (the "**Series 14 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at One York Street, 6th Floor, Toronto, Ontario M5J 0B6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 14 Debenture, at the address of the registered holder hereof appearing on the register of Series 14 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments (except in respect of the initial interest payment) on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing

on the Register. The Corporation will (i) on the day that is each Interest Payment Date, make payment by a wire transfer, or (ii) on the day that is two Business Days before each Interest Payment Date, forward or cause to be forwarded a cheque by same day delivery, to the address of the registered holder hereof appearing on the Register for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 14 Debenture is presented and surrendered to the Trustee. The payment by such wire transfer or forwarding of such cheque (provided such cheque is paid on presentation) will satisfy and discharge the liability for interest upon such Series 14 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid).

This Series 14 Debenture is one of an authorized issue of debentures designated as 2.43% Senior Unsecured Debentures due December 11, 2029 (Series 14) and forming the series of debentures created and issued under a fifteenth supplemental trust indenture made as of November 12, 2019 (the "**Fifteenth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, the fourteenth supplemental trust indenture to the Indenture made as of November 14, 2017 between the Corporation and the Trustee, and the Fifteenth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 14 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 14 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 14 Debenture and to each of which the registered holder of this Series 14 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 14 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 14 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof and, subject to the terms and conditions set forth in the Trust Indenture, are issued as book entry only debentures.

The Series 14 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 14 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to September 11, 2029, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price

(as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 14 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after September 11, 2029, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 14 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 14 Debentures in the open market, by tender or by private contract, at any price. Series 14 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 14 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture relating to the transfer of a Global Debenture (as defined in the Trust Indenture), and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 14 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 14 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 14 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.43% SENIOR UNSECURED DEBENTURES DUE 2029 (SERIES 14)

ISIN CA89119ZAL72
CUSIP 89119ZAL7

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	AMOUNT OF DECREASE	AMOUNT OF INCREASE	AMOUNT OF SERIES 14 DEBENTURES OUTSTANDING FOLLOWING CHANGE	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 14

*THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "**U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT.*

[No. 14-000]

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TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.43% SENIOR UNSECURED DEBENTURES DUE 2029 (SERIES 14)

Issue Date	November 12, 2019
Stated Maturity	December 11, 2029
Interest Rate Per Annum	2.43%
Interest Payment Dates	June 11 and December 11 in each year
Initial Interest Payment Date	June 11, 2020
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 2.43% Senior Unsecured Debenture due December 11, 2029 (Series 14) (the "**Series 14 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at One York Street, 6th Floor, Toronto, Ontario M5J 0B6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 14 Debenture, at the address of the registered holder hereof appearing on the register of Series 14 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments (except in respect of the initial interest payment) on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing

on the Register. The Corporation, on the day that is two Business Days before each Interest Payment Date, will forward or cause to be forwarded by same day delivery to the address of the registered holder hereof appearing on the Register a cheque for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 14 Debenture is presented and surrendered to the Trustee. The forwarding of such cheque will satisfy and discharge the liability for interest upon such Series 14 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid) unless such cheque is not paid on presentation.

This Series 14 Debenture is one of an authorized issue of debentures designated as 2.43% Senior Unsecured Debentures due December 11, 2029 (Series 14) and forming the series of debentures created and issued under a fifteenth supplemental trust indenture made as of November 12, 2019 (the "**Fifteenth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, the fourteenth supplemental trust indenture to the Indenture made as of November 14, 2017 between the Corporation and the Trustee, and the Fifteenth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 14 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 14 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 14 Debenture and to each of which the registered holder of this Series 14 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 14 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 14 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof.

The Series 14 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 14 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to September 11, 2029, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 14 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after September 11, 2029, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 14 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 14 Debentures in the open market, by tender or by private contract, at any price. Series 14 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 14 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture by the registered holder hereof or the holder's legal representative or attorney duly appointed by an instrument in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 14 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 14 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 14 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.43% SENIOR UNSECURED DEBENTURES DUE 2029 (SERIES 14)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

SIXTEENTH SUPPLEMENTAL TRUST INDENTURE

Made as of November 12, 2019

Between

TORONTO HYDRO CORPORATION
as issuer

and

BNY TRUST COMPANY OF CANADA
as trustee

Supplementing the Trust Indenture

made as of May 7, 2003

and

providing for the issue of

2.99% Senior Unsecured Debentures
due 2049 (Series 15)

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SIXTEENTH SUPPLEMENTAL TRUST INDENTURE

THIS SIXTEENTH SUPPLEMENTAL TRUST INDENTURE made as of November 12, 2019,

BETWEEN:

TORONTO HYDRO CORPORATION
a corporation incorporated under the laws of Ontario (the "**Corporation**")

and

BNY TRUST COMPANY OF CANADA
a trust company existing under the laws of Canada (the "**Trustee**")

RECITALS

(A) BNY Trust Company of Canada is the successor trustee of CIBC Mellon Trust Company;

(B) The Corporation has entered into a trust indenture with the Trustee made as of May 7, 2003, as amended, supplemented or restated from time to time (the "**Trust Indenture**") which provides for the issuance of one or more series of unsecured Debentures of the Corporation by way of Supplemental Indentures;

(C) The Corporation entered into a first supplemental trust indenture made as of May 7, 2003 for the purpose of providing for the issue of $225,000,000 aggregate principal amount of Series 1 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 1 Debentures;

(D) The Corporation entered into a second supplemental trust indenture made as of November 14, 2007 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 2 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 2 Debentures;

(E) The Corporation entered into a third supplemental trust indenture made as of November 12, 2009 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 3 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 3 Debentures;

(F) The City Note has been converted, in accordance with its terms, into the Series 4 Debentures and the Series 5 Debentures;

(G) The Corporation entered into a fourth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 4 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 4 Debentures;

(H) The Corporation entered into a fifth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 5 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 5 Debentures;

(I) The Corporation entered into a sixth supplemental trust indenture made as of May 20, 2010 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 6 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 6 Debentures;

(J) The Corporation entered into a seventh supplemental trust indenture made as of September 20, 2011 for the purpose of amending the definition of "GAAP" under the Trust Indenture;

(K) The Corporation entered into an eighth supplemental trust indenture made as of November 18, 2011 for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 7 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 7 Debentures;

(L) The Corporation entered into a ninth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 8 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 8 Debentures;

(M) The Corporation entered into a tenth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 9 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 9 Debentures;

(N) The Corporation entered into an eleventh supplemental trust indenture made as of September 16, 2014 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 10 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 10 Debentures;

(O) The Corporation entered into a twelfth supplemental trust indenture made as of March 16, 2015 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 11 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 11 Debentures;

(P) The Corporation entered into an amended and restated tenth supplemental trust indenture made as of September 2, 2015 for the purpose of making changes and corrections which were required for curing and correcting certain ambiguities and omissions in connection with an issue of $45,000,000 additional aggregate principal amount of the Series 9 Debentures;

(Q) The Corporation entered into a thirteenth supplemental trust indenture made as of June 14, 2016 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 12 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 12 Debentures;

(R) The Corporation entered into a fourteenth supplemental trust indenture made as of November 14, 2017 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 13 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 13 Debentures;

(S) The Corporation entered into a fifteenth supplemental trust indenture made as of November 12, 2019 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 14 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 14 Debentures; and

(T) This Sixteenth Supplemental Trust Indenture is entered into for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 15 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 15 Debentures.

NOW THEREFORE THIS SIXTEENTH SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

Section 1 INTERPRETATION

1.1 To Be Read With Trust Indenture

This Sixteenth Supplemental Trust Indenture is a Supplemental Indenture as that term is used in the Trust Indenture. The Trust Indenture and this Sixteenth Supplemental Trust Indenture shall be read together and shall have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this Sixteenth Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the interpretation thereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this Sixteenth Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Trust Indenture and used but not defined in this Sixteenth Supplemental Trust Indenture shall have the meanings ascribed to them in the Trust Indenture, as such meanings may be amended or supplemented with respect to Series 15 Debentures by this Sixteenth Supplemental Trust Indenture. In the event of any inconsistency between the meaning given to a term in the Trust Indenture and the meaning given to the same term in this Sixteenth Supplemental Trust Indenture, the meaning given to the term in this Sixteenth Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this Sixteenth Supplemental Trust Indenture and in the Series 15 Debentures, the following terms have the following meanings:

(a) ***Canada Yield*** on any date means the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to June 10, 2049 of the Series 15 Debentures, such yield to maturity being the average of the yields provided by two major Canadian investment dealers specified by the Corporation.

(b) ***Canada Yield Price*** means the amount equal to the net present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Series 15 Debentures that would have been payable to June 10, 2049 if redemption had not been made, using a discount rate equal to the sum of the Canada Yield and 34 basis points, calculated at 10:00 a.m. (Toronto, Ontario time) three Business Days prior to the Redemption Date of the Series 15 Debentures.

(c) ***Series 15 Debentures*** means the 2.99% Senior Unsecured Debentures due 2049 (Series 15) referred to in Section 2.1.

(d) ***Series 15 Debentures Debt Account*** means the deposit account established in respect of the Series 15 Debentures pursuant to Section 8.2 of the Trust Indenture that is designated in writing by the Corporation to the Trustee as the "Series 15 Debentures Debt Account".

(e) ***Series 15 Debentures Interest Payment Date*** means June 10 and December 10 in each year that the Series 15 Debentures are outstanding, beginning June 10, 2020.

(f) ***Series 15 Debentures Interest Period*** means the period commencing on and including the later of the date of issue of the Series 15 Debentures and the immediately preceding Series 15 Debentures Interest Payment Date and ending on and including the day

immediately preceding the next Series 15 Debentures Interest Payment Date to occur in respect of which interest is payable.

(g) ***Trust Indenture*** means the trust indenture made as of May 7, 2003 between the Corporation and the Trustee, as amended, supplemented or restated from time to time.

Section 2 SERIES 15 DEBENTURES

2.1 Creation and Designation

The Corporation is authorized in accordance with the Trust Indenture to issue under this Sixteenth Supplemental Trust Indenture, and hereby creates and issues, a series of debentures designated "2.99% Senior Unsecured Debentures due 2049 (Series 15)", having the terms set out in this Sixteenth Supplemental Trust Indenture.

2.2 No Limitation on Issue

The aggregate principal amount of Series 15 Debentures which may be issued under this Sixteenth Supplemental Trust Indenture including any supplement hereto is unlimited.

2.3 Date of Issue and Maturity

The Series 15 Debentures shall be dated November 12, 2019 (being the applicable date of issue) and will become due and payable, together with all accrued interest and unpaid interest thereon, on December 10, 2049 (being the applicable Stated Maturity).

2.4 Concerning Interest

(a) The Series 15 Debentures shall be issued in $1,000 principal amount denominations or integral multiples thereof and shall bear interest on the unpaid principal amount thereof at a rate of 2.99% per annum from and including their date of issue, payable semi-annually in arrears, in equal instalments (except in respect of the initial interest payment), on each Series 15 Debentures Interest Payment Date.

(b) Interest shall be payable in respect of each Series 15 Debentures Interest Period (after as well as before maturity, default and judgment, with interest on overdue interest at the same rate) on each Series 15 Debentures Interest Payment Date in accordance with Section 2.8 of the Trust Indenture, commencing on June 10, 2020 with an initial interest payment on June 10, 2020 of $17.24369865 per $1,000 principal amount of Series 15 Debentures.

2.5 Interest Payments

The Corporation shall make payments of interest on the Series 15 Debentures in accordance with the provisions of Section 2.8 of the Trust Indenture.

2.6 Payment of Amounts Due on Maturity

In accordance with Section 8.2 of the Trust Indenture, the Corporation will deposit to the Series 15 Debentures Debt Account all amounts required to be paid to the order of Holders of Series 15 Debentures on maturity, prior to 9:00 a.m. (Toronto, Ontario time), on the Stated Maturity of the Series 15 Debentures. The deposit of such funds will satisfy and discharge the liability of the Corporation for principal of, and any accrued and unpaid interest on, the Series 15 Debentures to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld).

2.7 Redemption and Purchase of Series 15 Debentures

(a) The Series 15 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to June 10, 2049, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to the greater of the Canada Yield Price and par, together in each case with accrued and unpaid interest to (but excluding) the Redemption Date and in each case otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(b) The Series 15 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after June 10, 2049, on not more than 60 Business Days and not less than 15 Business Days prior notice, at a price equal to 100% of the principal amount of the Series 15 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the Redemption Date and otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(c) The Corporation will be entitled at any time when not in default under the Trust Indenture to purchase for cancellation all or any of the Series 15 Debentures in accordance with Section 5.5 of the Trust Indenture.

(d) The Series 15 Debentures will not be subject to repurchase pursuant to any sinking fund provisions.

2.8 Form of Series 15 Debentures

(a) Except as set out in 2.8(b) below, the Series 15 Debentures and the registration panel and the certificate of the Trustee endorsed thereon shall be issuable initially as one Global Debenture to be held by, or on behalf of, CDS as depository for its participants and registered in the name of CDS or its nominee. The Global Debenture shall be substantially in the form set out in Schedule 1 hereto with such appropriate additions, deletions, substitutions and variations as the Directors shall by resolution determine prior to the time of issue thereof and as the Trustee may approve and with such distinguishing letters and numbers as the Trustee may approve, with such approval in each case to be conclusively evidenced by the Trustee's certification of such Global Debenture.

(b) The Trustee understands and acknowledges that the Series 15 Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 15 Debenture originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form set out in Schedule 2 hereto which definitive certificate, and each Series 15 Debenture certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE **"U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE

OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT."

If any Series 15 Debentures are being sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S Securities Act, the legend may be removed by providing a declaration to the Trustee to the following effect (or as the Corporation may prescribe from time to time),

"The undersigned (A) acknowledges that the sale of the _____ Debentures, represented by certificate numbers _____ to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**") and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Toronto Hydro Corporation, (2) the offer of such Debentures was not made to a person in the United States and at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States and (3) neither the seller, nor any affiliate of the seller, nor any person acting on its or their behalf engaged in any directed selling efforts in connection with the offer and sale of such Debentures. Terms used herein have the meanings given to them by Regulation S under the U.S. Securities Act."

If any Series 15 Debentures are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Trustee Counsel (or counsel to the transferor satisfactory to the Trustee) to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 15 Debentures, the Corporation shall notify the Trustee, in writing, concerning which Series 15 Debentures are to be certificated and are to bear the legend described above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 15 Debentures.

2.9 Signatures on Series 15 Debentures

The Series 15 Debentures shall be signed in accordance with the provisions of Section 2.6 of the Trust Indenture.

2.10 Certification

(a) No Series 15 Debenture issued shall be obligatory or shall entitle the Holder of such Series 15 Debenture to the benefits of this Sixteenth Supplemental Trust Indenture until it has been certified by manual signature by or on behalf of the Trustee by execution of the certificate of the Trustee appended thereto substantially in the form set out in Schedule 1 hereto, or in some other form approved by the Trustee, whose approval shall be conclusively evidenced by the Trustee's execution of the certificate. Such certificate on any Series 15 Debenture shall be conclusive evidence that such Series 15 Debenture is duly issued and is a valid and binding obligation of the Corporation and that the Holder of such Series 15 Debenture is entitled to the benefits of the Trust Indenture, as supplemented by this Sixteenth Supplemental Trust Indenture, and such Series 15 Debenture.

(b) The certificate of the Trustee on any Series 15 Debenture shall not be construed as a representation or warranty by the Trustee as to the validity of this Sixteenth Supplemental Trust Indenture or of the Series 15 Debentures (except the due certification thereof and any other warranties implied by law) and the Trustee shall in no respect be liable or

answerable for the use made of the Series 15 Debentures or any of them or the proceeds thereof.

2.11 Location of Register

With respect to the Series 15 Debentures, initially the Register referred to in Section 3.1 of the Trust Indenture shall be kept by the Trustee at the Corporate Trust Office and may thereafter be kept by the Trustee in such other place as the Corporation, with the approval of the Trustee, may designate.

2.12 Additional Amounts

The Corporation will not be required to pay an additional amount on the Series 15 Debentures in respect of any tax, assessment or government charge that is required by law to be withheld or deducted by it.

2.13 Trustees, etc.

The Trustee will be the Paying Agent and the Registrar for the Series 15 Debentures.

Section 3 MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this Sixteenth Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this Sixteenth Supplemental Trust Indenture and in accordance with the Trust Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this Sixteenth Supplemental Trust Indenture is in all respects confirmed.

3.3 Counterparts

This Sixteenth Supplemental Trust Indenture may be executed in counterparts, each of which so executed shall be deemed to be original and such counterparts together shall constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this Sixteenth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

TORONTO HYDRO CORPORATION

By: _____

Name: Anthony Haines

Title: President and Chief Executive Officer

By: _____

Name: Aida Cipolla

Title: Executive Vice-President and Chief Financial Officer

[Trustee Signature Page Follows]

IN WITNESS WHEREOF the parties hereto have executed this Sixteenth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

BNY TRUST COMPANY OF CANADA

By: 

Name: Wanda Camacho

Title: Authorized Signatory

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 15

This Debenture is a Global Debenture within the meaning of the Trust Indenture hereinafter referred to and is registered in the name of a Depository or a nominee thereof. Unless this Certificate is presented by an authorized representative of CDS Clearing and Depository Services Inc. ("CDS") to Toronto Hydro Corporation or its agent for registration of transfer, exchange or payment, and any certificate issued in respect thereof is registered in the name of CDS & CO., or in such other name as is requested by an authorized representative of CDS (and any payment is made to CDS & CO., or to such other entity as is requested by an authorized representative of CDS), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL since the registered holder hereof, CDS & CO., has a property interest in the securities represented by this certificate herein and it is a violation of its rights for another person to hold, transfer or deal with this certificate.

[No. 15-000]

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TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.99% SENIOR UNSECURED DEBENTURES DUE 2049 (SERIES 15)

ISIN CA89119ZAM55
CUSIP 89119ZAM5

Issue Date	November 12, 2019
Stated Maturity	December 10, 2049
Interest Rate Per Annum	2.99%
Interest Payment Dates	June 10 and December 10 in each year
Initial Interest Payment Date	June 10, 2020
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 2.99% Senior Unsecured Debenture due December 10, 2049 (Series 15) (the "**Series 15 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at One York Street, 6th Floor, Toronto, Ontario M5J 0B6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 15 Debenture, at the address of the registered holder hereof appearing on the register of Series 15 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments (except in respect of the initial interest payment) on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing

on the Register. The Corporation will (i) on the day that is each Interest Payment Date, make payment by a wire transfer, or (ii) on the day that is two Business Days before each Interest Payment Date, forward or cause to be forwarded a cheque by same day delivery, to the address of the registered holder hereof appearing on the Register for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 15 Debenture is presented and surrendered to the Trustee. The payment by such wire transfer or forwarding of such cheque (provided such cheque is paid on presentation) will satisfy and discharge the liability for interest upon such Series 15 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid).

This Series 15 Debenture is one of an authorized issue of debentures designated as 2.99% Senior Unsecured Debentures due December 10, 2049 (Series 15) and forming the series of debentures created and issued under a sixteenth supplemental trust indenture made as of November 12, 2019 (the "**Sixteenth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, the fourteenth supplemental trust indenture to the Indenture made as of November 14, 2017 between the Corporation and the Trustee, the fifteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, and the Sixteenth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 15 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 15 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 15 Debenture and to each of which the registered holder of this Series 15 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 15 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 15 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof and, subject to the terms and conditions set forth in the Trust Indenture, are issued as book entry only debentures.

The Series 15 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 15 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to June 10, 2049, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as

defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 15 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after June 10, 2049, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 15 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 15 Debentures in the open market, by tender or by private contract, at any price. Series 15 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 15 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture relating to the transfer of a Global Debenture (as defined in the Trust Indenture), and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 15 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 15 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 15 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.99% SENIOR UNSECURED DEBENTURES DUE 2049 (SERIES 15)

ISIN CA89119ZAM55
CUSIP 89119ZAM5

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	AMOUNT OF DECREASE	AMOUNT OF INCREASE	AMOUNT OF SERIES 15 DEBENTURES OUTSTANDING FOLLOWING CHANGE	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 15

*THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "**U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT.*

[No. 15-000]

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TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.99% SENIOR UNSECURED DEBENTURES DUE 2049 (SERIES 15)

Issue Date	November 12, 2019
Stated Maturity	December 10, 2049
Interest Rate Per Annum	2.99%
Interest Payment Dates	June 10 and December 10 in each year
Initial Interest Payment Date	June 10, 2020
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 2.99% Senior Unsecured Debenture due December 10, 2049 (Series 15) (the "**Series 15 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at One York Street, 6th Floor, Toronto, Ontario M5J 0B6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 15 Debenture, at the address of the registered holder hereof appearing on the register of Series 15 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments (except in respect of the initial interest payment) on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing

on the Register. The Corporation, on the day that is two Business Days before each Interest Payment Date, will forward or cause to be forwarded by same day delivery to the address of the registered holder hereof appearing on the Register a cheque for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 15 Debenture is presented and surrendered to the Trustee. The forwarding of such cheque will satisfy and discharge the liability for interest upon such Series 15 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid) unless such cheque is not paid on presentation.

This Series 15 Debenture is one of an authorized issue of debentures designated as 2.99% Senior Unsecured Debentures due December 10, 2049 (Series 15) and forming the series of debentures created and issued under a sixteenth supplemental trust indenture made as of November 12, 2019 (the "**Sixteenth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, the fourteenth supplemental trust indenture to the Indenture made as of November 14, 2017 between the Corporation and the Trustee, the fifteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, and the Sixteenth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 15 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 15 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 15 Debenture and to each of which the registered holder of this Series 15 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 15 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 15 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof.

The Series 15 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 15 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to June 10, 2049, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 15 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after June 10, 2049, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 15 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 15 Debentures in the open market, by tender or by private contract, at any price. Series 15 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 15 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture by the registered holder hereof or the holder's legal representative or attorney duly appointed by an instrument in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 15 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 15 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 15 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.99% SENIOR UNSECURED DEBENTURES DUE 2049 (SERIES 15)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

SEVENTEENTH SUPPLEMENTAL TRUST INDENTURE

Made as of October 15, 2020

Between

TORONTO HYDRO CORPORATION
as issuer

and

BNY TRUST COMPANY OF CANADA
as trustee

Supplementing the Trust Indenture

made as of May 7, 2003

and

providing for the issue of

1.50% Senior Unsecured Debentures
due 2030 (Series 16)

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SEVENTEENTH SUPPLEMENTAL TRUST INDENTURE

THIS SEVENTEENTH SUPPLEMENTAL TRUST INDENTURE made as of October 15, 2020,

BETWEEN:

TORONTO HYDRO CORPORATION
a corporation incorporated under the laws of Ontario (the "**Corporation**")

and

BNY TRUST COMPANY OF CANADA
a trust company existing under the laws of Canada (the "**Trustee**")

RECITALS

(A) BNY Trust Company of Canada is the successor trustee of CIBC Mellon Trust Company;

(B) The Corporation has entered into a trust indenture with the Trustee made as of May 7, 2003, as amended, supplemented or restated from time to time (the "**Trust Indenture**") which provides for the issuance of one or more series of unsecured Debentures of the Corporation by way of Supplemental Indentures;

(C) The Corporation entered into a first supplemental trust indenture made as of May 7, 2003 for the purpose of providing for the issue of $225,000,000 aggregate principal amount of Series 1 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 1 Debentures;

(D) The Corporation entered into a second supplemental trust indenture made as of November 14, 2007 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 2 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 2 Debentures;

(E) The Corporation entered into a third supplemental trust indenture made as of November 12, 2009 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 3 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 3 Debentures;

(F) The City Note has been converted, in accordance with its terms, into the Series 4 Debentures and the Series 5 Debentures;

(G) The Corporation entered into a fourth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 4 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 4 Debentures;

(H) The Corporation entered into a fifth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 5 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 5 Debentures;

(I) The Corporation entered into a sixth supplemental trust indenture made as of May 20, 2010 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 6 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 6 Debentures;

(J) The Corporation entered into a seventh supplemental trust indenture made as of September 20, 2011 for the purpose of amending the definition of "GAAP" under the Trust Indenture;

(K) The Corporation entered into an eighth supplemental trust indenture made as of November 18, 2011 for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 7 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 7 Debentures;

(L) The Corporation entered into a ninth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 8 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 8 Debentures;

(M) The Corporation entered into a tenth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 9 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 9 Debentures;

(N) The Corporation entered into an eleventh supplemental trust indenture made as of September 16, 2014 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 10 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 10 Debentures;

(O) The Corporation entered into a twelfth supplemental trust indenture made as of March 16, 2015 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 11 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 11 Debentures;

(P) The Corporation entered into an amended and restated tenth supplemental trust indenture made as of September 2, 2015 for the purpose of making changes and corrections which were required for curing and correcting certain ambiguities and omissions in connection with an issue of $45,000,000 additional aggregate principal amount of the Series 9 Debentures;

(Q) The Corporation entered into a thirteenth supplemental trust indenture made as of June 14, 2016 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 12 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 12 Debentures;

(R) The Corporation entered into a fourteenth supplemental trust indenture made as of November 14, 2017 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 13 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 13 Debentures;

(S) The Corporation entered into a fifteenth supplemental trust indenture made as of November 12, 2019 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 14 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 14 Debentures;

(T) The Corporation entered into a sixteenth supplemental trust indenture made as of November 12, 2019 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 15 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 15 Debentures; and

(U) This Seventeenth Supplemental Trust Indenture is entered into for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 16 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 16 Debentures.

NOW THEREFORE THIS SEVENTEENTH SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

Section 1 INTERPRETATION

1.1 To Be Read With Trust Indenture

This Seventeenth Supplemental Trust Indenture is a Supplemental Indenture as that term is used in the Trust Indenture. The Trust Indenture and this Seventeenth Supplemental Trust Indenture shall be read together and shall have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this Seventeenth Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the interpretation thereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this Seventeenth Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Trust Indenture and used but not defined in this Seventeenth Supplemental Trust Indenture shall have the meanings ascribed to them in the Trust Indenture, as such meanings may be amended or supplemented with respect to Series 16 Debentures by this Seventeenth Supplemental Trust Indenture. In the event of any inconsistency between the meaning given to a term in the Trust Indenture and the meaning given to the same term in this Seventeenth Supplemental Trust Indenture, the meaning given to the term in this Seventeenth Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this Seventeenth Supplemental Trust Indenture and in the Series 16 Debentures, the following terms have the following meanings:

(a) ***Canada Yield*** on any date means the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to July 15, 2030 of the Series 16 Debentures, such yield to maturity being the average of the yields provided by two major Canadian investment dealers specified by the Corporation.

(b) ***Canada Yield Price*** means the amount equal to the net present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Series 16 Debentures that would have been payable to July 15, 2030 if redemption had not been made, using a discount rate equal to the sum of the Canada Yield and 23 basis points, calculated at 10:00 a.m. (Toronto, Ontario time) three Business Days prior to the Redemption Date of the Series 16 Debentures.

(c) ***Series 16 Debentures*** means the 1.50% Senior Unsecured Debentures due 2030 (Series 16) referred to in Section 2.1.

(d) ***Series 16 Debentures Debt Account*** means the deposit account established in respect of the Series 16 Debentures pursuant to Section 8.2 of the Trust Indenture that is designated in writing by the Corporation to the Trustee as the "Series 16 Debentures Debt Account".

(e) ***Series 16 Debentures Interest Payment Date*** means April 15 and October 15 in each year that the Series 16 Debentures are outstanding, beginning April 15, 2021.

(f) ***Series 16 Debentures Interest Period*** means the period commencing on and including the later of the date of issue of the Series 16 Debentures and the immediately preceding Series 16 Debentures Interest Payment Date and ending on and including the day immediately preceding the next Series 16 Debentures Interest Payment Date to occur in respect of which interest is payable.

(g) ***Trust Indenture*** means the trust indenture made as of May 7, 2003 between the Corporation and the Trustee, as amended, supplemented or restated from time to time.

Section 2 SERIES 16 DEBENTURES

2.1 Creation and Designation

The Corporation is authorized in accordance with the Trust Indenture to issue under this Seventeenth Supplemental Trust Indenture, and hereby creates and issues, a series of debentures designated "1.50% Senior Unsecured Debentures due 2030 (Series 16)", having the terms set out in this Seventeenth Supplemental Trust Indenture.

2.2 No Limitation on Issue

The aggregate principal amount of Series 16 Debentures which may be issued under this Seventeenth Supplemental Trust Indenture including any supplement hereto is unlimited.

2.3 Date of Issue and Maturity

The Series 16 Debentures shall be dated October 15, 2020 (being the applicable date of issue) and will become due and payable, together with all accrued interest and unpaid interest thereon, on October 15, 2030 (being the applicable Stated Maturity).

2.4 Concerning Interest

(a) The Series 16 Debentures shall be issued in $1,000 principal amount denominations or integral multiples thereof and shall bear interest on the unpaid principal amount thereof at a rate of 1.50% per annum from and including their date of issue, payable semi-annually in arrears, in equal instalments, on each Series 16 Debentures Interest Payment Date.

(b) Interest shall be payable in respect of each Series 16 Debentures Interest Period (after as well as before maturity, default and judgment, with interest on overdue interest at the same rate) on each Series 16 Debentures Interest Payment Date in accordance with Section 2.8 of the Trust Indenture.

2.5 Interest Payments

The Corporation shall make payments of interest on the Series 16 Debentures in accordance with the provisions of Section 2.8 of the Trust Indenture.

2.6 Payment of Amounts Due on Maturity

In accordance with Section 8.2 of the Trust Indenture, the Corporation will deposit to the Series 16 Debentures Debt Account all amounts required to be paid to the order of Holders of Series 16 Debentures on maturity, prior to 9:00 a.m. (Toronto, Ontario time), on the Stated Maturity of the Series 16 Debentures. The deposit of such funds will satisfy and discharge the liability of the Corporation for principal of, and any accrued and unpaid interest on, the Series 16 Debentures to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld).

2.7 Redemption and Purchase of Series 16 Debentures

(a) The Series 16 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to July 15, 2030, on not more than 60 calendar days and not less than 10 calendar days prior notice, at a price equal to the greater of the Canada Yield Price and par, together in each case with accrued and unpaid interest to (but excluding) the Redemption Date and in each case otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(b) The Series 16 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after July 15, 2030, on not more than 60 calendar days and not less than 10 calendar days prior notice, at a price equal to 100% of the principal amount of the Series 16 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the Redemption Date and otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(c) The Corporation will be entitled at any time when not in default under the Trust Indenture to purchase for cancellation all or any of the Series 16 Debentures in accordance with Section 5.5 of the Trust Indenture.

(d) The Series 16 Debentures will not be subject to repurchase pursuant to any sinking fund provisions.

(e) Notice of redemption of any Series 16 Debentures given to the holders of the Series 16 Debentures may be conditional and, in such case, such notice of redemption shall specify the details and terms of any event (e.g., a financing, asset disposition or other transaction) on which such redemption is conditional.

2.8 Form of Series 16 Debentures

(a) Except as set out in 2.8(b) below, the Series 16 Debentures and the registration panel and the certificate of the Trustee endorsed thereon shall be issuable initially as one Global Debenture to be held by, or on behalf of, CDS as depository for its participants and registered in the name of CDS or its nominee. The Global Debenture shall be substantially in the form set out in Schedule 1 hereto with such appropriate additions, deletions, substitutions and variations as the Directors shall by resolution determine prior to the time of issue thereof and as the Trustee may approve and with such distinguishing letters and numbers as the Trustee may approve, with such approval in each case to be conclusively evidenced by the Trustee's certification of such Global Debenture.

(b) The Trustee understands and acknowledges that the Series 16 Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 16 Debenture originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form set out in Schedule 2 hereto which definitive certificate, and each Series 16 Debenture certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE **"U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE

UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT."

If any Series 16 Debentures are being sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S Securities Act, the legend may be removed by providing a declaration to the Trustee to the following effect (or as the Corporation may prescribe from time to time),

"The undersigned (A) acknowledges that the sale of the _____ Debentures, represented by certificate numbers _____ to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**") and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Toronto Hydro Corporation, (2) the offer of such Debentures was not made to a person in the United States and at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States and (3) neither the seller, nor any affiliate of the seller, nor any person acting on its or their behalf engaged in any directed selling efforts in connection with the offer and sale of such Debentures. Terms used herein have the meanings given to them by Regulation S under the U.S. Securities Act."

If any Series 16 Debentures are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Trustee Counsel (or counsel to the transferor satisfactory to the Trustee) to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 16 Debentures, the Corporation shall notify the Trustee, in writing, concerning which Series 16 Debentures are to be certificated and are to bear the legend described above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 16 Debentures.

2.9 Signatures on Series 16 Debentures

The Series 16 Debentures shall be signed in accordance with the provisions of Section 2.6 of the Trust Indenture.

2.10 Certification

(a) No Series 16 Debenture issued shall be obligatory or shall entitle the Holder of such Series 16 Debenture to the benefits of this Seventeenth Supplemental Trust Indenture until it has been certified by manual, facsimile or electronic signature by or on behalf of the Trustee by execution of the certificate of the Trustee appended thereto substantially in the form set out in Schedule 1 hereto, or in some other form approved by the Trustee, whose approval shall be conclusively evidenced by the Trustee's execution of the certificate. Such certificate on any Series 16 Debenture shall be conclusive evidence that such Series 16 Debenture is duly issued and is a valid and binding obligation of the Corporation and that the Holder of such Series 16 Debenture is entitled to the benefits of the Trust Indenture, as supplemented by this Seventeenth Supplemental Trust Indenture, and such Series 16 Debenture.

(b) The certificate of the Trustee on any Series 16 Debenture shall not be construed as a representation or warranty by the Trustee as to the validity of this Seventeenth Supplemental Trust Indenture or of the Series 16 Debentures (except the due certification thereof and any other warranties implied by law) and the Trustee shall in no respect be liable or answerable for the use made of the Series 16 Debentures or any of them or the proceeds thereof.

2.11 Location of Register

With respect to the Series 16 Debentures, initially the Register referred to in Section 3.1 of the Trust Indenture shall be kept by the Trustee at the Corporate Trust Office and may thereafter be kept by the Trustee in such other place as the Corporation, with the approval of the Trustee, may designate.

2.12 Additional Amounts

The Corporation will not be required to pay an additional amount on the Series 16 Debentures in respect of any tax, assessment or government charge that is required by law to be withheld or deducted by it.

2.13 Trustees, etc.

The Trustee will be the Paying Agent and the Registrar for the Series 16 Debentures.

Section 3 MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this Seventeenth Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this Seventeenth Supplemental Trust Indenture and in accordance with the Trust Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this Seventeenth Supplemental Trust Indenture is in all respects confirmed.

3.3 Counterparts

This Seventeenth Supplemental Trust Indenture may be executed in counterparts, each of which so executed shall be deemed to be original and such counterparts together shall constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this Seventeenth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

TORONTO HYDRO CORPORATION

By: _____

Name: Anthony Haines

Title: President and Chief Executive Officer

By: _____

Name: Aida Cipolla

Title: Executive Vice-President and Chief Financial Officer

[Trustee Signature Page Follows]

IN WITNESS WHEREOF the parties hereto have executed this Seventeenth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

BNY TRUST COMPANY OF CANADA

By: _____

Name: Ismail Bawa

Title: Authorized Signatory

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 16

This Debenture is a Global Debenture within the meaning of the Trust Indenture hereinafter referred to and is registered in the name of a Depository or a nominee thereof. Unless this Certificate is presented by an authorized representative of CDS Clearing and Depository Services Inc. ("CDS") to Toronto Hydro Corporation or its agent for registration of transfer, exchange or payment, and any certificate issued in respect thereof is registered in the name of CDS & CO., or in such other name as is requested by an authorized representative of CDS (and any payment is made to CDS & CO., or to such other entity as is requested by an authorized representative of CDS), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL since the registered holder hereof, CDS & CO., has a property interest in the securities represented by this certificate herein and it is a violation of its rights for another person to hold, transfer or deal with this certificate.

[No. 16-000]

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TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
1.50% SENIOR UNSECURED DEBENTURES DUE 2030 (SERIES 16)

ISIN CA89119ZAN39
CUSIP 89119ZAN3

Issue Date	October 15, 2020
Stated Maturity	October 15, 2030
Interest Rate Per Annum	1.50%
Interest Payment Dates	April 15 and October 15 in each year
Initial Interest Payment Date	April 15, 2021
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 1.50% Senior Unsecured Debenture due October 15, 2030 (Series 16) (the "**Series 16 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at One York Street, 6th Floor, Toronto, Ontario M5J 0B6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 16 Debenture, at the address of the registered holder hereof appearing on the register of Series 16 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments (except in respect of the initial interest payment) on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing

on the Register. The Corporation will (i) on the day that is each Interest Payment Date, make payment by a wire transfer, or (ii) on the day that is two Business Days before each Interest Payment Date, forward or cause to be forwarded a cheque by same day delivery, to the address of the registered holder hereof appearing on the Register for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 16 Debenture is presented and surrendered to the Trustee. The payment by such wire transfer or forwarding of such cheque (provided such cheque is paid on presentation) will satisfy and discharge the liability for interest upon such Series 16 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid).

This Series 16 Debenture is one of an authorized issue of debentures designated as 1.50% Senior Unsecured Debentures due October 15, 2030 (Series 16) and forming the series of debentures created and issued under a seventeenth supplemental trust indenture made as of October 15, 2020 (the "**Seventeenth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, the fourteenth supplemental trust indenture to the Indenture made as of November 14, 2017 between the Corporation and the Trustee, the fifteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the sixteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, and the Seventeenth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 16 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 16 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 16 Debenture and to each of which the registered holder of this Series 16 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 16 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 16 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof and, subject to the terms and conditions set forth in the Trust Indenture, are issued as book entry only debentures.

The Series 16 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 16 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to July 15, 2030, subject to the terms

and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 16 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after July 15, 2030, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 16 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 16 Debentures in the open market, by tender or by private contract, at any price. Series 16 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 16 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture relating to the transfer of a Global Debenture (as defined in the Trust Indenture), and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 16 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 16 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 16 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
1.50% SENIOR UNSECURED DEBENTURES DUE 2030 (SERIES 16)

ISIN CA89119ZAN39
CUSIP 89119ZAN3

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	AMOUNT OF DECREASE	AMOUNT OF INCREASE	AMOUNT OF SERIES 16 DEBENTURES OUTSTANDING FOLLOWING CHANGE	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 16

*THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "**U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT.*

[No. 16-000]

$●

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
1.50% SENIOR UNSECURED DEBENTURES DUE 2030 (SERIES 16)

Issue Date	October 15, 2020
Stated Maturity	October 15, 2030
Interest Rate Per Annum	1.50%
Interest Payment Dates	April 15 and October 15 in each year
Initial Interest Payment Date	April 15, 2021
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 1.50% Senior Unsecured Debenture October 15, 2030 (Series 16) (the "**Series 16 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at One York Street, 6th Floor, Toronto, Ontario M5J 0B6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 16 Debenture, at the address of the registered holder hereof appearing on the register of Series 16 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments (except in respect of the initial interest payment) on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing

on the Register. The Corporation, on the day that is two Business Days before each Interest Payment Date, will forward or cause to be forwarded by same day delivery to the address of the registered holder hereof appearing on the Register a cheque for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 16 Debenture is presented and surrendered to the Trustee. The forwarding of such cheque will satisfy and discharge the liability for interest upon such Series 16 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid) unless such cheque is not paid on presentation.

This Series 16 Debenture is one of an authorized issue of debentures designated as 1.50% Senior Unsecured Debentures due October 15, 2030 (Series 16) and forming the series of debentures created and issued under a seventeenth supplemental trust indenture made as of October 15, 2020 (the "**Seventeenth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, the fourteenth supplemental trust indenture to the Indenture made as of November 14, 2017 between the Corporation and the Trustee, the fifteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the sixteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, and the Seventeenth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 16 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 16 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 16 Debenture and to each of which the registered holder of this Series 16 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 16 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 16 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof.

The Series 16 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 16 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to July 15, 2030, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 16 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after July 15, 2030, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 16 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 16 Debentures in the open market, by tender or by private contract, at any price. Series 16 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 16 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture by the registered holder hereof or the holder's legal representative or attorney duly appointed by an instrument in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 16 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 16 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 16 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
1.50% SENIOR UNSECURED DEBENTURES DUE 2030 (SERIES 16)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

EIGHTEENTH SUPPLEMENTAL TRUST INDENTURE

Made as of October 18, 2021

Between

TORONTO HYDRO CORPORATION
as issuer

and

BNY TRUST COMPANY OF CANADA
as trustee

Supplementing the Trust Indenture

made as of May 7, 2003

and

providing for the issue of

2.47% Senior Unsecured Debentures
due 2031 (Series 17)

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EIGHTEENTH SUPPLEMENTAL TRUST INDENTURE

THIS EIGHTEENTH SUPPLEMENTAL TRUST INDENTURE made as of October 18, 2021,

BETWEEN:

TORONTO HYDRO CORPORATION
a corporation incorporated under the laws of Ontario (the "**Corporation**")

and

BNY TRUST COMPANY OF CANADA
a trust company existing under the laws of Canada (the "**Trustee**")

RECITALS

(A) BNY Trust Company of Canada is the successor trustee of CIBC Mellon Trust Company;

(B) The Corporation has entered into a trust indenture with the Trustee made as of May 7, 2003, as amended, supplemented or restated from time to time (the "**Trust Indenture**") which provides for the issuance of one or more series of unsecured Debentures of the Corporation by way of Supplemental Indentures;

(C) The Corporation entered into a first supplemental trust indenture made as of May 7, 2003 for the purpose of providing for the issue of $225,000,000 aggregate principal amount of Series 1 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 1 Debentures;

(D) The Corporation entered into a second supplemental trust indenture made as of November 14, 2007 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 2 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 2 Debentures;

(E) The Corporation entered into a third supplemental trust indenture made as of November 12, 2009 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 3 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 3 Debentures;

(F) The City Note has been converted, in accordance with its terms, into the Series 4 Debentures and the Series 5 Debentures;

(G) The Corporation entered into a fourth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 4 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 4 Debentures;

(H) The Corporation entered into a fifth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 5 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 5 Debentures;

(I) The Corporation entered into a sixth supplemental trust indenture made as of May 20, 2010 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 6 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 6 Debentures;

(J) The Corporation entered into a seventh supplemental trust indenture made as of September 20, 2011 for the purpose of amending the definition of "GAAP" under the Trust Indenture;

(K) The Corporation entered into an eighth supplemental trust indenture made as of November 18, 2011 for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 7 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 7 Debentures;

(L) The Corporation entered into a ninth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 8 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 8 Debentures;

(M) The Corporation entered into a tenth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 9 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 9 Debentures;

(N) The Corporation entered into an eleventh supplemental trust indenture made as of September 16, 2014 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 10 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 10 Debentures;

(O) The Corporation entered into a twelfth supplemental trust indenture made as of March 16, 2015 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 11 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 11 Debentures;

(P) The Corporation entered into an amended and restated tenth supplemental trust indenture made as of September 2, 2015 for the purpose of making changes and corrections which were required for curing and correcting certain ambiguities and omissions in connection with an issue of $45,000,000 additional aggregate principal amount of the Series 9 Debentures;

(Q) The Corporation entered into a thirteenth supplemental trust indenture made as of June 14, 2016 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 12 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 12 Debentures;

(R) The Corporation entered into a fourteenth supplemental trust indenture made as of November 14, 2017 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 13 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 13 Debentures;

(S) The Corporation entered into a fifteenth supplemental trust indenture made as of November 12, 2019 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 14 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 14 Debentures;

(T) The Corporation entered into a sixteenth supplemental trust indenture made as of November 12, 2019 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 15 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 15 Debentures;

(U) The Corporation entered into a seventeenth supplemental trust indenture made as of October 15, 2020 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 16 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 16 Debentures; and

(V) This Eighteenth Supplemental Trust Indenture is entered into for the purpose of providing for the issue of $150,000,000 aggregate principal amount of Series 17 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 17 Debentures.

NOW THEREFORE THIS EIGHTEENTH SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

Section 1 INTERPRETATION

1.1 To Be Read With Trust Indenture

This Eighteenth Supplemental Trust Indenture is a Supplemental Indenture as that term is used in the Trust Indenture. The Trust Indenture and this Eighteenth Supplemental Trust Indenture shall be read together and shall have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this Eighteenth Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the interpretation thereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this Eighteenth Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Trust Indenture and used but not defined in this Eighteenth Supplemental Trust Indenture shall have the meanings ascribed to them in the Trust Indenture, as such meanings may be amended or supplemented with respect to Series 17 Debentures by this Eighteenth Supplemental Trust Indenture. In the event of any inconsistency between the meaning given to a term in the Trust Indenture and the meaning given to the same term in this Eighteenth Supplemental Trust Indenture, the meaning given to the term in this Eighteenth Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this Eighteenth Supplemental Trust Indenture and in the Series 17 Debentures, the following terms have the following meanings:

(a) ***Canada Yield*** on any date means the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to July 20, 2031 of the Series 17 Debentures, such yield to maturity being the average of the yields provided by two major Canadian investment dealers specified by the Corporation.

(b) ***Canada Yield Price*** means the amount equal to the net present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Series 17 Debentures that would have been payable to July 20, 2031 if redemption had not been made, using a discount rate equal to the sum of the Canada Yield and 22 basis points, calculated at 10:00 a.m. (Toronto, Ontario time) three Business Days prior to the Redemption Date of the Series 17 Debentures.

(c) ***Series 17 Debentures*** means the 2.47% Senior Unsecured Debentures due 2031 (Series 17) referred to in Section 2.1.

(d) ***Series 17 Debentures Debt Account*** means the deposit account established in respect of the Series 17 Debentures pursuant to Section 8.2 of the Trust Indenture that is designated in writing by the Corporation to the Trustee as the "Series 17 Debentures Debt Account".

(e) ***Series 17 Debentures Interest Payment Date*** means April 20 and October 20 in each year that the Series 17 Debentures are outstanding, beginning April 20, 2022.

(f) ***Series 17 Debentures Interest Period*** means the period commencing on and including the later of the date of issue of the Series 17 Debentures and the immediately preceding Series 17 Debentures Interest Payment Date and ending on and including the day immediately preceding the next Series 17 Debentures Interest Payment Date to occur in respect of which interest is payable.

(g) ***Trust Indenture*** means the trust indenture made as of May 7, 2003 between the Corporation and the Trustee, as amended, supplemented or restated from time to time.

Section 2 SERIES 17 DEBENTURES

2.1 Creation and Designation

The Corporation is authorized in accordance with the Trust Indenture to issue under this Eighteenth Supplemental Trust Indenture, and hereby creates and issues, a series of debentures designated "2.47% Senior Unsecured Debentures due 2031 (Series 17)", having the terms set out in this Eighteenth Supplemental Trust Indenture.

2.2 No Limitation on Issue

The aggregate principal amount of Series 17 Debentures which may be issued under this Eighteenth Supplemental Trust Indenture including any supplement hereto is unlimited.

2.3 Date of Issue and Maturity

The Series 17 Debentures shall be dated October 18, 2021 (being the applicable date of issue) and will become due and payable, together with all accrued interest and unpaid interest thereon, on October 20, 2031 (being the applicable Stated Maturity).

2.4 Concerning Interest

(a) The Series 17 Debentures shall be issued in $1,000 principal amount denominations or integral multiples thereof and shall bear interest on the unpaid principal amount thereof at a rate of 2.47% per annum from and including their date of issue, payable semi-annually in arrears, in equal instalments (except in respect of the initial interest payment), on each Series 17 Debentures Interest Payment Date.

(b) Interest shall be payable in respect of each Series 17 Debentures Interest Period (after as well as before maturity, default and judgment, with interest on overdue interest at the same rate) on each Series 17 Debentures Interest Payment Date in accordance with Section 2.8 of the Trust Indenture, commencing on April 20, 2022 with an initial interest payment on April 20, 2022 of $12.48534247 per $1,000 principal amount of Series 17 Debentures.

2.5 Interest Payments

The Corporation shall make payments of interest on the Series 17 Debentures in accordance with the provisions of Section 2.8 of the Trust Indenture.

2.6 Payment of Amounts Due on Maturity

In accordance with Section 8.2 of the Trust Indenture, the Corporation will deposit to the Series 17 Debentures Debt Account all amounts required to be paid to the order of Holders of Series 17 Debentures on maturity, prior to 9:00 a.m. (Toronto, Ontario time), on the Stated Maturity of the Series 17 Debentures. The deposit of such funds will satisfy and discharge the liability of the Corporation for principal of, and any

accrued and unpaid interest on, the Series 17 Debentures to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld).

2.7 Redemption and Purchase of Series 17 Debentures

(a) The Series 17 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to July 20, 2031, on not more than 60 calendar days and not less than 10 calendar days prior notice, at a price equal to the greater of the Canada Yield Price and par, together in each case with accrued and unpaid interest to (but excluding) the Redemption Date and in each case otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(b) The Series 17 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after July 20, 2031, on not more than 60 calendar days and not less than 10 calendar days prior notice, at a price equal to 100% of the principal amount of the Series 17 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the Redemption Date and otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(c) The Corporation will be entitled at any time when not in default under the Trust Indenture to purchase for cancellation all or any of the Series 17 Debentures in accordance with Section 5.5 of the Trust Indenture.

(d) The Series 17 Debentures will not be subject to repurchase pursuant to any sinking fund provisions.

(e) Notice of redemption of any Series 17 Debentures given to the holders of the Series 17 Debentures may be conditional and, in such case, such notice of redemption shall specify the details and terms of any event (e.g., a financing, asset disposition or other transaction) on which such redemption is conditional.

2.8 Form of Series 17 Debentures

(a) Except as set out in 2.8(b) below, the Series 17 Debentures and the registration panel and the certificate of the Trustee endorsed thereon shall be issuable initially as one Global Debenture to be held by, or on behalf of, CDS as depository for its participants and registered in the name of CDS or its nominee. The Global Debenture shall be substantially in the form set out in Schedule 1 hereto with such appropriate additions, deletions, substitutions and variations as the Directors shall by resolution determine prior to the time of issue thereof and as the Trustee may approve and with such distinguishing letters and numbers as the Trustee may approve, with such approval in each case to be conclusively evidenced by the Trustee's certification of such Global Debenture.

(b) The Trustee understands and acknowledges that the Series 17 Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 17 Debenture originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form set out in Schedule 2 hereto which definitive certificate, and each Series 17 Debenture certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE **"U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN

ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT."

If any Series 17 Debentures are being sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S Securities Act, the legend may be removed by providing a declaration to the Trustee to the following effect (or as the Corporation may prescribe from time to time),

"The undersigned (A) acknowledges that the sale of the _____ Debentures, represented by certificate numbers _____ to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**") and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Toronto Hydro Corporation, (2) the offer of such Debentures was not made to a person in the United States and at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States and (3) neither the seller, nor any affiliate of the seller, nor any person acting on its or their behalf engaged in any directed selling efforts in connection with the offer and sale of such Debentures. Terms used herein have the meanings given to them by Regulation S under the U.S. Securities Act."

If any Series 17 Debentures are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Trustee Counsel (or counsel to the transferor satisfactory to the Trustee) to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 17 Debentures, the Corporation shall notify the Trustee, in writing, concerning which Series 17 Debentures are to be certificated and are to bear the legend described above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 17 Debentures.

2.9 Signatures on Series 17 Debentures

The Series 17 Debentures shall be signed in accordance with the provisions of Section 2.6 of the Trust Indenture.

2.10 Certification

(a) No Series 17 Debenture issued shall be obligatory or shall entitle the Holder of such Series 17 Debenture to the benefits of this Eighteenth Supplemental Trust Indenture until it has been certified by manual, facsimile or electronic signature by or on behalf of the Trustee by execution of the certificate of the Trustee appended thereto substantially in the form set out in Schedule 1 hereto, or in some other form approved by the Trustee, whose approval shall be conclusively evidenced by the Trustee's execution of the certificate. Such certificate on any Series 17 Debenture shall be conclusive evidence that such Series 17 Debenture is duly issued and is a valid and binding obligation of the Corporation and that the Holder of such Series 17 Debenture is entitled to the benefits of the Trust Indenture, as supplemented by this Eighteenth Supplemental Trust Indenture, and such Series 17 Debenture.

(b) The certificate of the Trustee on any Series 17 Debenture shall not be construed as a representation or warranty by the Trustee as to the validity of this Eighteenth Supplemental Trust Indenture or of the Series 17 Debentures (except the due certification thereof and any other warranties implied by law) and the Trustee shall in no respect be liable or answerable for the use made of the Series 17 Debentures or any of them or the proceeds thereof.

2.11 Location of Register

With respect to the Series 17 Debentures, initially the Register referred to in Section 3.1 of the Trust Indenture shall be kept by the Trustee at the Corporate Trust Office and may thereafter be kept by the Trustee in such other place as the Corporation, with the approval of the Trustee, may designate.

2.12 Additional Amounts

The Corporation will not be required to pay an additional amount on the Series 17 Debentures in respect of any tax, assessment or government charge that is required by law to be withheld or deducted by it.

2.13 Trustees, etc.

The Trustee will be the Paying Agent and the Registrar for the Series 17 Debentures.

Section 3 MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this Eighteenth Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this Eighteenth Supplemental Trust Indenture and in accordance with the Trust Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this Eighteenth Supplemental Trust Indenture is in all respects confirmed.

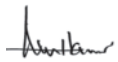
3.3 Counterparts

This Eighteenth Supplemental Trust Indenture may be executed in counterparts, each of which so executed shall be deemed to be original and such counterparts together shall constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this Eighteenth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

TORONTO HYDRO CORPORATION

By: 

Name: Anthony Haines

Title: President and Chief Executive Officer

By: 

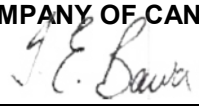
Name: Aida Cipolla

Title: Executive Vice-President and Chief Financial Officer

[Trustee Signature Page Follows]

IN WITNESS WHEREOF the parties hereto have executed this Eighteenth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

BNY TRUST COMPANY OF CANADA

By: 

Name: Ismail Bawa

Title: Authorized Signatory

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 17

This Debenture is a Global Debenture within the meaning of the Trust Indenture hereinafter referred to and is registered in the name of a Depository or a nominee thereof. Unless this Certificate is presented by an authorized representative of CDS Clearing and Depository Services Inc. ("CDS") to Toronto Hydro Corporation or its agent for registration of transfer, exchange or payment, and any certificate issued in respect thereof is registered in the name of CDS & CO., or in such other name as is requested by an authorized representative of CDS (and any payment is made to CDS & CO., or to such other entity as is requested by an authorized representative of CDS), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL since the registered holder hereof, CDS & CO., has a property interest in the securities represented by this certificate herein and it is a violation of its rights for another person to hold, transfer or deal with this certificate.

[No. 17-000]

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TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.47% SENIOR UNSECURED DEBENTURES DUE 2031 (SERIES 17)

ISIN CA89119ZAP86
CUSIP 89119ZAP8

Issue Date	October 18, 2021
Stated Maturity	October 20, 2031
Interest Rate Per Annum	2.47%
Interest Payment Dates	April 20 and October 20 in each year
Initial Interest Payment Date	April 20, 2022
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 2.47% Senior Unsecured Debenture due October 20, 2031 (Series 17) (the "**Series 17 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at One York Street, 6th Floor, Toronto, Ontario M5J 0B6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 17 Debenture, at the address of the registered holder hereof appearing on the register of Series 17 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year (except in respect of the Initial Interest Payment Date), and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation will (i) on the day that is each Interest Payment Date, make payment by a wire transfer, or (ii) on the

day that is two Business Days before each Interest Payment Date, forward or cause to be forwarded a cheque by same day delivery, to the address of the registered holder hereof appearing on the Register for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 17 Debenture is presented and surrendered to the Trustee. The payment by such wire transfer or forwarding of such cheque (provided such cheque is paid on presentation) will satisfy and discharge the liability for interest upon such Series 17 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid).

This Series 17 Debenture is one of an authorized issue of debentures designated as 2.47% Senior Unsecured Debentures due October 20, 2031 (Series 17) and forming the series of debentures created and issued under an eighteenth supplemental trust indenture made as of October 18, 2021 (the "**Eighteenth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, the fourteenth supplemental trust indenture to the Indenture made as of November 14, 2017 between the Corporation and the Trustee, the fifteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the sixteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the seventeenth supplemental trust indenture to the Indenture made as of October 15, 2020 between the Corporation and the Trustee, and the Eighteenth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 17 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 17 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 17 Debenture and to each of which the registered holder of this Series 17 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 17 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 17 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof and, subject to the terms and conditions set forth in the Trust Indenture, are issued as book entry only debentures.

The Series 17 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 17 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to July 20, 2031, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined

in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 17 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after July 20, 2031, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 17 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 17 Debentures in the open market, by tender or by private contract, at any price. Series 17 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 17 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture relating to the transfer of a Global Debenture (as defined in the Trust Indenture), and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 17 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 17 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 17 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.47% SENIOR UNSECURED DEBENTURES DUE 2031 (SERIES 17)

ISIN CA89119ZAP86
CUSIP 89119ZAP8

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	AMOUNT OF DECREASE	AMOUNT OF INCREASE	AMOUNT OF SERIES 17 DEBENTURES OUTSTANDING FOLLOWING CHANGE	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 17

*THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "**U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT.*

[No. 17-000]

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TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.47% SENIOR UNSECURED DEBENTURES DUE 2031 (SERIES 17)

Issue Date	October 18, 2021
Stated Maturity	October 20, 2031
Interest Rate Per Annum	2.47%
Interest Payment Dates	April 20 and October 20 in each year
Initial Interest Payment Date	April 20, 2022
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 2.47% Senior Unsecured Debenture due October 20, 2031 (Series 17) (the "**Series 17 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at One York Street, 6th Floor, Toronto, Ontario M5J 0B6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 17 Debenture, at the address of the registered holder hereof appearing on the register of Series 17 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year (except in respect of the Initial Interest Payment Date), and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The

Corporation, on the day that is two Business Days before each Interest Payment Date, will forward or cause to be forwarded by same day delivery to the address of the registered holder hereof appearing on the Register a cheque for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 17 Debenture is presented and surrendered to the Trustee. The forwarding of such cheque will satisfy and discharge the liability for interest upon such Series 17 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid) unless such cheque is not paid on presentation.

This Series 17 Debenture is one of an authorized issue of debentures designated as 2.47% Senior Unsecured Debentures due October 20, 2031 (Series 17) and forming the series of debentures created and issued under an eighteenth supplemental trust indenture made as of October 18, 2021 (the "**Eighteenth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, the fourteenth supplemental trust indenture to the Indenture made as of November 14, 2017 between the Corporation and the Trustee, the fifteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the sixteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the seventeenth supplemental trust indenture to the Indenture made as of October 15, 2020 between the Corporation and the Trustee and the Eighteenth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 17 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 17 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 17 Debenture and to each of which the registered holder of this Series 17 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 17 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 17 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof.

The Series 17 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 17 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to July 20, 2031, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined

in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 17 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after July 20, 2031, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 17 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 17 Debentures in the open market, by tender or by private contract, at any price. Series 17 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 17 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture by the registered holder hereof or the holder's legal representative or attorney duly appointed by an instrument in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 17 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 17 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 17 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
2.47% SENIOR UNSECURED DEBENTURES DUE 2031 (SERIES 17)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

NINETEENTH SUPPLEMENTAL TRUST INDENTURE

Made as of October 18, 2021

Between

TORONTO HYDRO CORPORATION
as issuer

and

BNY TRUST COMPANY OF CANADA
as trustee

Supplementing the Trust Indenture

made as of May 7, 2003

and

providing for the issue of

3.27% Senior Unsecured Debentures
due 2051 (Series 18)

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NINETEENTH SUPPLEMENTAL TRUST INDENTURE

THIS NINETEENTH SUPPLEMENTAL TRUST INDENTURE made as of October 18, 2021,

BETWEEN:

TORONTO HYDRO CORPORATION
a corporation incorporated under the laws of Ontario (the "**Corporation**")

and

BNY TRUST COMPANY OF CANADA
a trust company existing under the laws of Canada (the "**Trustee**")

RECITALS

(A) BNY Trust Company of Canada is the successor trustee of CIBC Mellon Trust Company;

(B) The Corporation has entered into a trust indenture with the Trustee made as of May 7, 2003, as amended, supplemented or restated from time to time (the "**Trust Indenture**") which provides for the issuance of one or more series of unsecured Debentures of the Corporation by way of Supplemental Indentures;

(C) The Corporation entered into a first supplemental trust indenture made as of May 7, 2003 for the purpose of providing for the issue of $225,000,000 aggregate principal amount of Series 1 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 1 Debentures;

(D) The Corporation entered into a second supplemental trust indenture made as of November 14, 2007 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 2 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 2 Debentures;

(E) The Corporation entered into a third supplemental trust indenture made as of November 12, 2009 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 3 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 3 Debentures;

(F) The City Note has been converted, in accordance with its terms, into the Series 4 Debentures and the Series 5 Debentures;

(G) The Corporation entered into a fourth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 4 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 4 Debentures;

(H) The Corporation entered into a fifth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 5 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 5 Debentures;

(I) The Corporation entered into a sixth supplemental trust indenture made as of May 20, 2010 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 6 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 6 Debentures;

(J) The Corporation entered into a seventh supplemental trust indenture made as of September 20, 2011 for the purpose of amending the definition of "GAAP" under the Trust Indenture;

(K) The Corporation entered into an eighth supplemental trust indenture made as of November 18, 2011 for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 7 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 7 Debentures;

(L) The Corporation entered into a ninth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 8 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 8 Debentures;

(M) The Corporation entered into a tenth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 9 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 9 Debentures;

(N) The Corporation entered into an eleventh supplemental trust indenture made as of September 16, 2014 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 10 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 10 Debentures;

(O) The Corporation entered into a twelfth supplemental trust indenture made as of March 16, 2015 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 11 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 11 Debentures;

(P) The Corporation entered into an amended and restated tenth supplemental trust indenture made as of September 2, 2015 for the purpose of making changes and corrections which were required for curing and correcting certain ambiguities and omissions in connection with an issue of $45,000,000 additional aggregate principal amount of the Series 9 Debentures;

(Q) The Corporation entered into a thirteenth supplemental trust indenture made as of June 14, 2016 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 12 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 12 Debentures;

(R) The Corporation entered into a fourteenth supplemental trust indenture made as of November 14, 2017 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 13 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 13 Debentures;

(S) The Corporation entered into a fifteenth supplemental trust indenture made as of November 12, 2019 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 14 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 14 Debentures;

(T) The Corporation entered into a sixteenth supplemental trust indenture made as of November 12, 2019 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 15 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 15 Debentures;

(U) The Corporation entered into a seventeenth supplemental trust indenture made as of October 15, 2020 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 16 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 16 Debentures;

(V) The Corporation entered into an eighteenth supplemental trust indenture made as of October 18, 2021 for the purpose of providing for the issue of $150,000,000 aggregate principal amount of Series 17 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 17 Debentures; and

(W) This Nineteenth Supplemental Trust Indenture is entered into for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 18 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 18 Debentures.

NOW THEREFORE THIS NINETEENTH SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

Section 1 INTERPRETATION

1.1 To Be Read With Trust Indenture

This Nineteenth Supplemental Trust Indenture is a Supplemental Indenture as that term is used in the Trust Indenture. The Trust Indenture and this Nineteenth Supplemental Trust Indenture shall be read together and shall have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this Nineteenth Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the interpretation thereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this Nineteenth Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Trust Indenture and used but not defined in this Nineteenth Supplemental Trust Indenture shall have the meanings ascribed to them in the Trust Indenture, as such meanings may be amended or supplemented with respect to Series 18 Debentures by this Nineteenth Supplemental Trust Indenture. In the event of any inconsistency between the meaning given to a term in the Trust Indenture and the meaning given to the same term in this Nineteenth Supplemental Trust Indenture, the meaning given to the term in this Nineteenth Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this Nineteenth Supplemental Trust Indenture and in the Series 18 Debentures, the following terms have the following meanings:

(a) ***Canada Yield*** on any date means the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to April 18, 2051 of the Series 18 Debentures, such yield to maturity being the average of the yields provided by two major Canadian investment dealers specified by the Corporation.

(b) ***Canada Yield Price*** means the amount equal to the net present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Series 18 Debentures that would have been payable to April 18, 2051 if redemption had not been made, using a discount rate equal to the sum of the Canada Yield and 30.5 basis points, calculated at 10:00 a.m. (Toronto, Ontario time) three Business Days prior to the Redemption Date of the Series 18 Debentures.

(c) ***Series 18 Debentures*** means the 3.27% Senior Unsecured Debentures due 2051 (Series 18) referred to in Section 2.1.

(d) ***Series 18 Debentures Debt Account*** means the deposit account established in respect of the Series 18 Debentures pursuant to Section 8.2 of the Trust Indenture that is designated in writing by the Corporation to the Trustee as the "Series 18 Debentures Debt Account".

(e) ***Series 18 Debentures Interest Payment Date*** means April 18 and October 18 in each year that the Series 18 Debentures are outstanding, beginning April 18, 2022.

(f) ***Series 18 Debentures Interest Period*** means the period commencing on and including the later of the date of issue of the Series 18 Debentures and the immediately preceding Series 18 Debentures Interest Payment Date and ending on and including the day immediately preceding the next Series 18 Debentures Interest Payment Date to occur in respect of which interest is payable.

(g) ***Trust Indenture*** means the trust indenture made as of May 7, 2003 between the Corporation and the Trustee, as amended, supplemented or restated from time to time.

Section 2 SERIES 18 DEBENTURES

2.1 Creation and Designation

The Corporation is authorized in accordance with the Trust Indenture to issue under this Nineteenth Supplemental Trust Indenture, and hereby creates and issues, a series of debentures designated "3.27% Senior Unsecured Debentures due 2051 (Series 18)", having the terms set out in this Nineteenth Supplemental Trust Indenture.

2.2 No Limitation on Issue

The aggregate principal amount of Series 18 Debentures which may be issued under this Nineteenth Supplemental Trust Indenture including any supplement hereto is unlimited.

2.3 Date of Issue and Maturity

The Series 18 Debentures shall be dated October 18, 2021 (being the applicable date of issue) and will become due and payable, together with all accrued interest and unpaid interest thereon, on October 18, 2051 (being the applicable Stated Maturity).

2.4 Concerning Interest

(a) The Series 18 Debentures shall be issued in $1,000 principal amount denominations or integral multiples thereof and shall bear interest on the unpaid principal amount thereof at a rate of 3.27% per annum from and including their date of issue, payable semi-annually in arrears, in equal instalments, on each Series 18 Debentures Interest Payment Date.

(b) Interest shall be payable in respect of each Series 18 Debentures Interest Period (after as well as before maturity, default and judgment, with interest on overdue interest at the same rate) on each Series 18 Debentures Interest Payment Date in accordance with Section 2.8 of the Trust Indenture.

2.5 Interest Payments

The Corporation shall make payments of interest on the Series 18 Debentures in accordance with the provisions of Section 2.8 of the Trust Indenture.

2.6 Payment of Amounts Due on Maturity

In accordance with Section 8.2 of the Trust Indenture, the Corporation will deposit to the Series 18 Debentures Debt Account all amounts required to be paid to the order of Holders of Series 18 Debentures on maturity, prior to 9:00 a.m. (Toronto, Ontario time), on the Stated Maturity of the Series 18 Debentures. The deposit of such funds will satisfy and discharge the liability of the Corporation for principal of, and any accrued and unpaid interest on, the Series 18 Debentures to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld).

2.7 Redemption and Purchase of Series 18 Debentures

(a) The Series 18 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to April 18, 2051, on not more than 60 calendar days and not less than 10 calendar days prior notice, at a price equal to the greater of the Canada Yield Price and par, together in each case with accrued and unpaid interest to (but excluding) the Redemption Date and in each case otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(b) The Series 18 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after April 18, 2051, on not more than 60 calendar days and not less than 10 calendar days prior notice, at a price equal to 100% of the principal amount of the Series 18 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the Redemption Date and otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(c) The Corporation will be entitled at any time when not in default under the Trust Indenture to purchase for cancellation all or any of the Series 18 Debentures in accordance with Section 5.5 of the Trust Indenture.

(d) The Series 18 Debentures will not be subject to repurchase pursuant to any sinking fund provisions.

(e) Notice of redemption of any Series 18 Debentures given to the holders of the Series 18 Debentures may be conditional and, in such case, such notice of redemption shall specify the details and terms of any event (e.g., a financing, asset disposition or other transaction) on which such redemption is conditional.

2.8 Form of Series 18 Debentures

(a) Except as set out in 2.8(b) below, the Series 18 Debentures and the registration panel and the certificate of the Trustee endorsed thereon shall be issuable initially as one Global Debenture to be held by, or on behalf of, CDS as depository for its participants and registered in the name of CDS or its nominee. The Global Debenture shall be substantially in the form set out in Schedule 1 hereto with such appropriate additions, deletions, substitutions and variations as the Directors shall by resolution determine prior to the time of issue thereof and as the Trustee may approve and with such distinguishing letters and numbers as the Trustee may approve, with such approval in each case to be conclusively evidenced by the Trustee's certification of such Global Debenture.

(b) The Trustee understands and acknowledges that the Series 18 Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 18 Debenture originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form set out in Schedule 2 hereto which definitive certificate, and each Series 18 Debenture certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE **"U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT."

If any Series 18 Debentures are being sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S Securities Act, the legend may be removed by providing a declaration to the Trustee to the following effect (or as the Corporation may prescribe from time to time),

"The undersigned (A) acknowledges that the sale of the _____ Debentures, represented by certificate numbers _____ to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**") and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Toronto Hydro Corporation, (2) the offer of such Debentures was not made to a person in the United States and at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States and (3) neither the seller, nor any affiliate of the seller, nor any person acting on its or their behalf engaged in any directed selling efforts in connection with the offer and sale of such Debentures. Terms used herein have the meanings given to them by Regulation S under the U.S. Securities Act."

If any Series 18 Debentures are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Trustee Counsel (or counsel to the transferor satisfactory to the Trustee) to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 18 Debentures, the Corporation shall notify the Trustee, in writing, concerning which Series 18 Debentures are to be certificated and are to bear the legend described above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 18 Debentures.

2.9 Signatures on Series 18 Debentures

The Series 18 Debentures shall be signed in accordance with the provisions of Section 2.6 of the Trust Indenture.

2.10 Certification

(a) No Series 18 Debenture issued shall be obligatory or shall entitle the Holder of such Series 18 Debenture to the benefits of this Nineteenth Supplemental Trust Indenture until it has been certified by manual, facsimile or electronic signature by or on behalf of the

Trustee by execution of the certificate of the Trustee appended thereto substantially in the form set out in Schedule 1 hereto, or in some other form approved by the Trustee, whose approval shall be conclusively evidenced by the Trustee's execution of the certificate. Such certificate on any Series 18 Debenture shall be conclusive evidence that such Series 18 Debenture is duly issued and is a valid and binding obligation of the Corporation and that the Holder of such Series 18 Debenture is entitled to the benefits of the Trust Indenture, as supplemented by this Nineteenth Supplemental Trust Indenture, and such Series 18 Debenture.

(b) The certificate of the Trustee on any Series 18 Debenture shall not be construed as a representation or warranty by the Trustee as to the validity of this Nineteenth Supplemental Trust Indenture or of the Series 18 Debentures (except the due certification thereof and any other warranties implied by law) and the Trustee shall in no respect be liable or answerable for the use made of the Series 18 Debentures or any of them or the proceeds thereof.

2.11 Location of Register

With respect to the Series 18 Debentures, initially the Register referred to in Section 3.1 of the Trust Indenture shall be kept by the Trustee at the Corporate Trust Office and may thereafter be kept by the Trustee in such other place as the Corporation, with the approval of the Trustee, may designate.

2.12 Additional Amounts

The Corporation will not be required to pay an additional amount on the Series 18 Debentures in respect of any tax, assessment or government charge that is required by law to be withheld or deducted by it.

2.13 Trustees, etc.

The Trustee will be the Paying Agent and the Registrar for the Series 18 Debentures.

Section 3 MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this Nineteenth Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this Nineteenth Supplemental Trust Indenture and in accordance with the Trust Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this Nineteenth Supplemental Trust Indenture is in all respects confirmed.

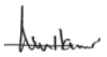
3.3 Counterparts

This Nineteenth Supplemental Trust Indenture may be executed in counterparts, each of which so executed shall be deemed to be original and such counterparts together shall constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this Nineteenth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

TORONTO HYDRO CORPORATION

By: 

Name: Anthony Haines

Title: President and Chief Executive Officer

By: 

Name: Aida Cipolla

Title: Executive Vice-President and Chief Financial Officer

[Trustee Signature Page Follows]

IN WITNESS WHEREOF the parties hereto have executed this Nineteenth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

BNY TRUST COMPANY OF CANADA

By: 

Name: Ismail Bawa

Title: Authorized Signatory

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 18

This Debenture is a Global Debenture within the meaning of the Trust Indenture hereinafter referred to and is registered in the name of a Depository or a nominee thereof. Unless this Certificate is presented by an authorized representative of CDS Clearing and Depository Services Inc. ("CDS") to Toronto Hydro Corporation or its agent for registration of transfer, exchange or payment, and any certificate issued in respect thereof is registered in the name of CDS & CO., or in such other name as is requested by an authorized representative of CDS (and any payment is made to CDS & CO., or to such other entity as is requested by an authorized representative of CDS), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL since the registered holder hereof, CDS & CO., has a property interest in the securities represented by this certificate herein and it is a violation of its rights for another person to hold, transfer or deal with this certificate.

[No. 18-000]

$●

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
3.27% SENIOR UNSECURED DEBENTURES DUE 2051 (SERIES 18)

ISIN CA89119ZAQ69
CUSIP 89119ZAQ6

Issue Date	October 18, 2021
Stated Maturity	October 18, 2051
Interest Rate Per Annum	3.27%
Interest Payment Dates	April 18 and October 18 in each year
Initial Interest Payment Date	April 18, 2022
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 3.27% Senior Unsecured Debenture due October 18, 2051 (Series 18) (the "**Series 18 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at One York Street, 6th Floor, Toronto, Ontario M5J 0B6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 18 Debenture, at the address of the registered holder hereof appearing on the register of Series 18 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation will (i) on the day that is

each Interest Payment Date, make payment by a wire transfer, or (ii) on the day that is two Business Days before each Interest Payment Date, forward or cause to be forwarded a cheque by same day delivery, to the address of the registered holder hereof appearing on the Register for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 18 Debenture is presented and surrendered to the Trustee. The payment by such wire transfer or forwarding of such cheque (provided such cheque is paid on presentation) will satisfy and discharge the liability for interest upon such Series 18 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid).

This Series 18 Debenture is one of an authorized issue of debentures designated as 3.27% Senior Unsecured Debentures due October 18, 2051 (Series 18) and forming the series of debentures created and issued under a nineteenth supplemental trust indenture made as of October 18, 2021 (the "**Nineteenth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, the fourteenth supplemental trust indenture to the Indenture made as of November 14, 2017 between the Corporation and the Trustee, the fifteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the sixteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the seventeenth supplemental trust indenture to the Indenture made as of October 15, 2020 between the Corporation and the Trustee, the eighteenth supplemental trust indenture to the Indenture made as of October 18, 2021 between the Corporation and the Trustee and the Nineteenth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 18 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 18 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 18 Debenture and to each of which the registered holder of this Series 18 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 18 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 18 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof and, subject to the terms and conditions set forth in the Trust Indenture, are issued as book entry only debentures.

The Series 18 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 18 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to April 18, 2051, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 18 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after April 18, 2051, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 18 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 18 Debentures in the open market, by tender or by private contract, at any price. Series 18 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 18 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture relating to the transfer of a Global Debenture (as defined in the Trust Indenture), and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 18 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 18 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 18 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
3.27% SENIOR UNSECURED DEBENTURES DUE 2051 (SERIES 18)

ISIN CA89119ZAQ69
CUSIP 89119ZAQ6

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	AMOUNT OF DECREASE	AMOUNT OF INCREASE	AMOUNT OF SERIES 18 DEBENTURES OUTSTANDING FOLLOWING CHANGE	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 18

*THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "**U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT.*

[No. 18-000]

$●

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
3.27% SENIOR UNSECURED DEBENTURES DUE 2051 (SERIES 18)

Issue Date	October 18, 2021
Stated Maturity	October 18, 2051
Interest Rate Per Annum	3.27%
Interest Payment Dates	April 18 and October 18 in each year
Initial Interest Payment Date	April 18, 2022
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 3.27% Senior Unsecured Debenture due October 18, 2051 (Series 18) (the "**Series 18 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at One York Street, 6th Floor, Toronto, Ontario M5J 0B6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 18 Debenture, at the address of the registered holder hereof appearing on the register of Series 18 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation, on the day that is two

Business Days before each Interest Payment Date, will forward or cause to be forwarded by same day delivery to the address of the registered holder hereof appearing on the Register a cheque for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 18 Debenture is presented and surrendered to the Trustee. The forwarding of such cheque will satisfy and discharge the liability for interest upon such Series 18 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid) unless such cheque is not paid on presentation.

This Series 18 Debenture is one of an authorized issue of debentures designated as 3.27% Senior Unsecured Debentures due October 18, 2051 (Series 18) and forming the series of debentures created and issued under a nineteenth supplemental trust indenture made as of October 18, 2021 (the "**Nineteenth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, the fourteenth supplemental trust indenture to the Indenture made as of November 14, 2017 between the Corporation and the Trustee, the fifteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the sixteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the seventeenth supplemental trust indenture to the Indenture made as of October 15, 2020 between the Corporation and the Trustee, the eighteenth supplemental trust indenture to the Indenture made as of October 18, 2021 between the Corporation and the Trustee and the Nineteenth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 18 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 18 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 18 Debenture and to each of which the registered holder of this Series 18 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 18 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 18 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof.

The Series 18 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 18 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to April 18, 2051, subject to the terms

and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 18 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after April 18, 2051, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 18 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 18 Debentures in the open market, by tender or by private contract, at any price. Series 18 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 18 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture by the registered holder hereof or the holder's legal representative or attorney duly appointed by an instrument in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 18 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 18 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 18 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
3.27% SENIOR UNSECURED DEBENTURES DUE 2051 (SERIES 18)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

TWENTIETH SUPPLEMENTAL TRUST INDENTURE

Made as of October 13, 2022

Between

TORONTO HYDRO CORPORATION
as issuer

and

BNY TRUST COMPANY OF CANADA
as trustee

Supplementing the Trust Indenture

made as of May 7, 2003

and

providing for the issue of

4.95% Senior Unsecured Debentures
due 2052 (Series 19)

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TWENTIETH SUPPLEMENTAL TRUST INDENTURE

THIS TWENTIETH SUPPLEMENTAL TRUST INDENTURE made as of October 13, 2022,

BETWEEN:

TORONTO HYDRO CORPORATION
a corporation incorporated under the laws of Ontario (the "**Corporation**")

and

BNY TRUST COMPANY OF CANADA
a trust company existing under the laws of Canada (the "**Trustee**")

RECITALS

(A) BNY Trust Company of Canada is the successor trustee of CIBC Mellon Trust Company;

(B) The Corporation has entered into a trust indenture with the Trustee made as of May 7, 2003, as amended, supplemented or restated from time to time (the "**Trust Indenture**") which provides for the issuance of one or more series of unsecured Debentures of the Corporation by way of Supplemental Indentures;

(C) The Corporation entered into a first supplemental trust indenture made as of May 7, 2003 for the purpose of providing for the issue of $225,000,000 aggregate principal amount of Series 1 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 1 Debentures;

(D) The Corporation entered into a second supplemental trust indenture made as of November 14, 2007 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 2 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 2 Debentures;

(E) The Corporation entered into a third supplemental trust indenture made as of November 12, 2009 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 3 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 3 Debentures;

(F) The City Note has been converted, in accordance with its terms, into the Series 4 Debentures and the Series 5 Debentures;

(G) The Corporation entered into a fourth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 4 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 4 Debentures;

(H) The Corporation entered into a fifth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 5 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 5 Debentures;

(I) The Corporation entered into a sixth supplemental trust indenture made as of May 20, 2010 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 6 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 6 Debentures;

(J) The Corporation entered into a seventh supplemental trust indenture made as of September 20, 2011 for the purpose of amending the definition of "GAAP" under the Trust Indenture;

(K) The Corporation entered into an eighth supplemental trust indenture made as of November 18, 2011 for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 7 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 7 Debentures;

(L) The Corporation entered into a ninth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 8 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 8 Debentures;

(M) The Corporation entered into a tenth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 9 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 9 Debentures;

(N) The Corporation entered into an eleventh supplemental trust indenture made as of September 16, 2014 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 10 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 10 Debentures;

(O) The Corporation entered into a twelfth supplemental trust indenture made as of March 16, 2015 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 11 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 11 Debentures;

(P) The Corporation entered into an amended and restated tenth supplemental trust indenture made as of September 2, 2015 for the purpose of making changes and corrections which were required for curing and correcting certain ambiguities and omissions in connection with an issue of $45,000,000 additional aggregate principal amount of the Series 9 Debentures;

(Q) The Corporation entered into a thirteenth supplemental trust indenture made as of June 14, 2016 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 12 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 12 Debentures;

(R) The Corporation entered into a fourteenth supplemental trust indenture made as of November 14, 2017 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 13 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 13 Debentures;

(S) The Corporation entered into a fifteenth supplemental trust indenture made as of November 12, 2019 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 14 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 14 Debentures;

(T) The Corporation entered into a sixteenth supplemental trust indenture made as of November 12, 2019 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 15 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 15 Debentures;

(U) The Corporation entered into a seventeenth supplemental trust indenture made as of October 15, 2020 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 16 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 16 Debentures;

(V) The Corporation entered into an eighteenth supplemental trust indenture made as of October 18, 2021 for the purpose of providing for the issue of $150,000,000 aggregate principal amount of Series 17 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 17 Debentures;

(W) The Corporation entered into a nineteenth supplemental trust indenture made as of October 18, 2021 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 18 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 18 Debentures; and

(X) This Twentieth Supplemental Trust Indenture is entered into for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 19 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 19 Debentures.

NOW THEREFORE THIS TWENTIETH SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

Section 1 INTERPRETATION

1.1 To Be Read With Trust Indenture

This Twentieth Supplemental Trust Indenture is a Supplemental Indenture as that term is used in the Trust Indenture. The Trust Indenture and this Twentieth Supplemental Trust Indenture shall be read together and shall have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this Twentieth Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the interpretation thereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this Twentieth Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Trust Indenture and used but not defined in this Twentieth Supplemental Trust Indenture shall have the meanings ascribed to them in the Trust Indenture, as such meanings may be amended or supplemented with respect to Series 19 Debentures by this Twentieth Supplemental Trust Indenture. In the event of any inconsistency between the meaning given to a term in the Trust Indenture and the meaning given to the same term in this Twentieth Supplemental Trust Indenture, the meaning given to the term in this Twentieth Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this Twentieth Supplemental Trust Indenture and in the Series 19 Debentures, the following terms have the following meanings:

(a) ***Canada Yield*** on any date means the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to April 13, 2052 of the Series 19 Debentures, such yield to maturity being the average of the yields provided by two major Canadian investment dealers specified by the Corporation.

(b) ***Canada Yield Price*** means the amount equal to the net present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Series 19 Debentures that would have been payable to April 13, 2052 if redemption had not been made, using a discount rate equal to the sum of the Canada Yield and 41 basis

points, calculated at 10:00 a.m. (Toronto, Ontario time) three Business Days prior to the Redemption Date of the Series 19 Debentures.

(c) ***Series 19 Debentures*** means the 4.95% Senior Unsecured Debentures due 2052 (Series 19) referred to in Section 2.1.

(d) ***Series 19 Debentures Debt Account*** means the deposit account established in respect of the Series 19 Debentures pursuant to Section 8.2 of the Trust Indenture that is designated in writing by the Corporation to the Trustee as the "Series 19 Debentures Debt Account".

(e) ***Series 19 Debentures Interest Payment Date*** means April 13 and October 13 in each year that the Series 19 Debentures are outstanding, beginning April 13, 2023.

(f) ***Series 19 Debentures Interest Period*** means the period commencing on and including the later of the date of issue of the Series 19 Debentures and the immediately preceding Series 19 Debentures Interest Payment Date and ending on and including the day immediately preceding the next Series 19 Debentures Interest Payment Date to occur in respect of which interest is payable.

(g) ***Trust Indenture*** means the trust indenture made as of May 7, 2003 between the Corporation and the Trustee, as amended, supplemented or restated from time to time.

Section 2 SERIES 19 DEBENTURES

2.1 Creation and Designation

The Corporation is authorized in accordance with the Trust Indenture to issue under this Twentieth Supplemental Trust Indenture, and hereby creates and issues, a series of debentures designated "4.95% Senior Unsecured Debentures due 2052 (Series 19)", having the terms set out in this Twentieth Supplemental Trust Indenture.

2.2 No Limitation on Issue

The aggregate principal amount of Series 19 Debentures which may be issued under this Twentieth Supplemental Trust Indenture including any supplement hereto is unlimited.

2.3 Date of Issue and Maturity

The Series 19 Debentures shall be dated October 13, 2022 (being the applicable date of issue) and will become due and payable, together with all accrued interest and unpaid interest thereon, on October 13, 2052 (being the applicable Stated Maturity).

2.4 Concerning Interest

(a) The Series 19 Debentures shall be issued in $1,000 principal amount denominations or integral multiples thereof and shall bear interest on the unpaid principal amount thereof at a rate of 4.95% per annum from and including their date of issue, payable semi-annually in arrears, in equal instalments, on each Series 19 Debentures Interest Payment Date.

(b) Interest shall be payable in respect of each Series 19 Debentures Interest Period (after as well as before maturity, default and judgment, with interest on overdue interest at the same rate) on each Series 19 Debentures Interest Payment Date in accordance with Section 2.8 of the Trust Indenture.

2.5 Interest Payments

The Corporation shall make payments of interest on the Series 19 Debentures in accordance with the provisions of Section 2.8 of the Trust Indenture.

2.6 Payment of Amounts Due on Maturity

In accordance with Section 8.2 of the Trust Indenture, the Corporation will deposit to the Series 19 Debentures Debt Account all amounts required to be paid to the order of Holders of Series 19 Debentures on maturity, prior to 9:00 a.m. (Toronto, Ontario time), on the Stated Maturity of the Series 19 Debentures. The deposit of such funds will satisfy and discharge the liability of the Corporation for principal of, and any accrued and unpaid interest on, the Series 19 Debentures to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld).

2.7 Redemption and Purchase of Series 19 Debentures

(a) The Series 19 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to April 13, 2052, on not more than 60 calendar days and not less than 10 calendar days prior notice, at a price equal to the greater of the Canada Yield Price and par, together in each case with accrued and unpaid interest to (but excluding) the Redemption Date and in each case otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(b) The Series 19 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after April 13, 2052, on not more than 60 calendar days and not less than 10 calendar days prior notice, at a price equal to 100% of the principal amount of the Series 19 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the Redemption Date and otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(c) The Corporation will be entitled at any time when not in default under the Trust Indenture to purchase for cancellation all or any of the Series 19 Debentures in accordance with Section 5.5 of the Trust Indenture.

(d) The Series 19 Debentures will not be subject to repurchase pursuant to any sinking fund provisions.

(e) Notice of redemption of any Series 19 Debentures given to the holders of the Series 19 Debentures may be conditional and, in such case, such notice of redemption shall specify the details and terms of any event (e.g., a financing, asset disposition or other transaction) on which such redemption is conditional.

2.8 Form of Series 19 Debentures

(a) Except as set out in 2.8(b) below, the Series 19 Debentures and the registration panel and the certificate of the Trustee endorsed thereon shall be issuable initially as one Global Debenture to be held by, or on behalf of, CDS as depository for its participants and registered in the name of CDS or its nominee. The Global Debenture shall be substantially in the form set out in Schedule 1 hereto with such appropriate additions, deletions, substitutions and variations as the Directors shall by resolution determine prior to the time of issue thereof and as the Trustee may approve and with such distinguishing letters and numbers as the Trustee may approve, with such approval in each case to be conclusively evidenced by the Trustee's certification of such Global Debenture.

(b) The Trustee understands and acknowledges that the Series 19 Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 19 Debenture originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form

set out in Schedule 2 hereto which definitive certificate, and each Series 19 Debenture certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE **"U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT."

If any Series 19 Debentures are being sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S Securities Act, the legend may be removed by providing a declaration to the Trustee to the following effect (or as the Corporation may prescribe from time to time),

"The undersigned (A) acknowledges that the sale of the _____ Debentures, represented by certificate numbers _____ to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**") and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Toronto Hydro Corporation, (2) the offer of such Debentures was not made to a person in the United States and at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States and (3) neither the seller, nor any affiliate of the seller, nor any person acting on its or their behalf engaged in any directed selling efforts in connection with the offer and sale of such Debentures. Terms used herein have the meanings given to them by Regulation S under the U.S. Securities Act."

If any Series 19 Debentures are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Trustee Counsel (or counsel to the transferor satisfactory to the Trustee) to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 19 Debentures, the Corporation shall notify the Trustee, in writing, concerning which Series 19 Debentures are to be certificated and are to bear the legend described above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 19 Debentures.

2.9 Signatures on Series 19 Debentures

The Series 19 Debentures shall be signed in accordance with the provisions of Section 2.6 of the Trust Indenture.

2.10 Certification

(a) No Series 19 Debenture issued shall be obligatory or shall entitle the Holder of such Series 19 Debenture to the benefits of this Twentieth Supplemental Trust Indenture until it has been certified by manual, facsimile or electronic signature by or on behalf of the Trustee by execution of the certificate of the Trustee appended thereto substantially in the form set out in Schedule 1 hereto, or in some other form approved by the Trustee, whose approval shall be conclusively evidenced by the Trustee's execution of the certificate. Such certificate on any Series 19 Debenture shall be conclusive evidence that such Series 19 Debenture is duly issued and is a valid and binding obligation of the Corporation and that the Holder of such Series 19 Debenture is entitled to the benefits of the Trust Indenture, as supplemented by this Twentieth Supplemental Trust Indenture, and such Series 19 Debenture.

(b) The certificate of the Trustee on any Series 19 Debenture shall not be construed as a representation or warranty by the Trustee as to the validity of this Twentieth Supplemental Trust Indenture or of the Series 19 Debentures (except the due certification thereof and any other warranties implied by law) and the Trustee shall in no respect be liable or answerable for the use made of the Series 19 Debentures or any of them or the proceeds thereof.

2.11 Location of Register

With respect to the Series 19 Debentures, initially the Register referred to in Section 3.1 of the Trust Indenture shall be kept by the Trustee at the Corporate Trust Office and may thereafter be kept by the Trustee in such other place as the Corporation, with the approval of the Trustee, may designate.

2.12 Additional Amounts

The Corporation will not be required to pay an additional amount on the Series 19 Debentures in respect of any tax, assessment or government charge that is required by law to be withheld or deducted by it.

2.13 Trustees, etc.

The Trustee will be the Paying Agent and the Registrar for the Series 19 Debentures.

Section 3 MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this Twentieth Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this Twentieth Supplemental Trust Indenture and in accordance with the Trust Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this Twentieth Supplemental Trust Indenture is in all respects confirmed.

3.3 Counterparts

This Twentieth Supplemental Trust Indenture may be executed in counterparts, each of which so executed shall be deemed to be original and such counterparts together shall constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this Twentieth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

TORONTO HYDRO CORPORATION

By: _____

Name: Anthony Haines

Title: President and Chief Executive Officer

By: _____ Digitally signed by Celine Arsenault DN: cn=Celine Arsenault, email=CArsenault@TorontoHydro.com Date: 2022.10.05 09:52:55 -04'00'

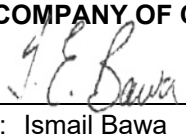
Name: Céline Arsenault

Title: Executive Vice-President and Chief Financial Officer

[Trustee Signature Page Follows]

IN WITNESS WHEREOF the parties hereto have executed this Twentieth Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

BNY TRUST COMPANY OF CANADA

By: 

Name: Ismail Bawa

Title: Authorized Signatory

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 19

This Debenture is a Global Debenture within the meaning of the Trust Indenture hereinafter referred to and is registered in the name of a Depository or a nominee thereof. Unless this Certificate is presented by an authorized representative of CDS Clearing and Depository Services Inc. ("CDS") to Toronto Hydro Corporation or its agent for registration of transfer, exchange or payment, and any certificate issued in respect thereof is registered in the name of CDS & CO., or in such other name as is requested by an authorized representative of CDS (and any payment is made to CDS & CO., or to such other entity as is requested by an authorized representative of CDS), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL since the registered holder hereof, CDS & CO., has a property interest in the securities represented by this certificate herein and it is a violation of its rights for another person to hold, transfer or deal with this certificate.

[No. 19-000]

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TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
4.95% SENIOR UNSECURED DEBENTURES DUE 2052 (SERIES 19)

ISIN CA89119ZAR43
CUSIP 89119ZAR4

Issue Date	October 13, 2022
Stated Maturity	October 13, 2052
Interest Rate Per Annum	4.95%
Interest Payment Dates	April 13 and October 13 in each year
Initial Interest Payment Date	April 13, 2023
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 4.95% Senior Unsecured Debenture due October 13, 2052 (Series 19) (the "**Series 19 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at One York Street, 6th Floor, Toronto, Ontario M5J 0B6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 19 Debenture, at the address of the registered holder hereof appearing on the register of Series 19 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation will (i) on the day that is

each Interest Payment Date, make payment by a wire transfer, or (ii) on the day that is two Business Days before each Interest Payment Date, forward or cause to be forwarded a cheque by same day delivery, to the address of the registered holder hereof appearing on the Register for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 19 Debenture is presented and surrendered to the Trustee. The payment by such wire transfer or forwarding of such cheque (provided such cheque is paid on presentation) will satisfy and discharge the liability for interest upon such Series 19 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid).

This Series 19 Debenture is one of an authorized issue of debentures designated as 4.95% Senior Unsecured Debentures due October 13, 2052 (Series 19) and forming the series of debentures created and issued under a twentieth supplemental trust indenture made as of October 13, 2022 (the "**Twentieth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, the fourteenth supplemental trust indenture to the Indenture made as of November 14, 2017 between the Corporation and the Trustee, the fifteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the sixteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the seventeenth supplemental trust indenture to the Indenture made as of October 15, 2020 between the Corporation and the Trustee, the eighteenth supplemental trust indenture to the Indenture made as of October 18, 2021 between the Corporation and the Trustee, the nineteenth supplemental trust indenture to the Indenture made as of October 18, 2021 between the Corporation and the Trustee, and the Twentieth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 19 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 19 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 19 Debenture and to each of which the registered holder of this Series 19 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 19 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 19 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof and, subject to the terms and conditions set forth in the Trust Indenture, are issued as book entry only debentures.

The Series 19 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding

pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 19 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to April 13, 2052, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 19 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after April 13, 2052, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 19 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 19 Debentures in the open market, by tender or by private contract, at any price. Series 19 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 19 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture relating to the transfer of a Global Debenture (as defined in the Trust Indenture), and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 19 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 19 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 19 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
4.95% SENIOR UNSECURED DEBENTURES DUE 2052 (SERIES 19)

ISIN CA89119ZAR43
CUSIP 89119ZAR4

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	AMOUNT OF DECREASE	AMOUNT OF INCREASE	AMOUNT OF SERIES 19 DEBENTURES OUTSTANDING FOLLOWING CHANGE	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 19

*THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "**U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT.*

[No. 19-000]

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TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
4.95% SENIOR UNSECURED DEBENTURES DUE 2052 (SERIES 19)

Issue Date	October 13, 2022
Stated Maturity	October 13, 2052
Interest Rate Per Annum	4.95%
Interest Payment Dates	April 13 and October 13 in each year
Initial Interest Payment Date	April 13, 2023
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 4.95% Senior Unsecured Debenture due October 13, 2052 (Series 19) (the "**Series 19 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at One York Street, 6th Floor, Toronto, Ontario M5J 0B6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 19 Debenture, at the address of the registered holder hereof appearing on the register of Series 19 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation, on the day that is two

Business Days before each Interest Payment Date, will forward or cause to be forwarded by same day delivery to the address of the registered holder hereof appearing on the Register a cheque for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 19 Debenture is presented and surrendered to the Trustee. The forwarding of such cheque will satisfy and discharge the liability for interest upon such Series 19 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid) unless such cheque is not paid on presentation.

This Series 19 Debenture is one of an authorized issue of debentures designated as 4.95% Senior Unsecured Debentures due October 13, 2052 (Series 19) and forming the series of debentures created and issued under a twentieth supplemental trust indenture made as of October 13, 2022 (the "**Twentieth Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, the fourteenth supplemental trust indenture to the Indenture made as of November 14, 2017 between the Corporation and the Trustee, the fifteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the sixteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the seventeenth supplemental trust indenture to the Indenture made as of October 15, 2020 between the Corporation and the Trustee, the eighteenth supplemental trust indenture to the Indenture made as of October 18, 2021 between the Corporation and the Trustee, the nineteenth supplemental trust indenture to the Indenture made as of October 18, 2021 between the Corporation and the Trustee, and the Twentieth Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 19 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 19 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 19 Debenture and to each of which the registered holder of this Series 19 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 19 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 19 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof.

The Series 19 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 19 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to April 13, 2052, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 19 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after April 13, 2052, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 19 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 19 Debentures in the open market, by tender or by private contract, at any price. Series 19 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 19 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture by the registered holder hereof or the holder's legal representative or attorney duly appointed by an instrument in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 19 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 19 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 19 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
4.95% SENIOR UNSECURED DEBENTURES DUE 2052 (SERIES 19)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

TWENTY-FIRST SUPPLEMENTAL TRUST INDENTURE

Made as of June 14, 2023

Between

TORONTO HYDRO CORPORATION
as issuer

and

BNY TRUST COMPANY OF CANADA
as trustee

Supplementing the Trust Indenture

made as of May 7, 2003

and

providing for the issue of

4.61% Senior Unsecured Debentures
due 2033 (Series 20)

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TWENTY-FIRST SUPPLEMENTAL TRUST INDENTURE

THIS TWENTY-FIRST SUPPLEMENTAL TRUST INDENTURE made as of June 14, 2023,

BETWEEN:

TORONTO HYDRO CORPORATION
a corporation incorporated under the laws of Ontario (the "**Corporation**")

and

BNY TRUST COMPANY OF CANADA
a trust company existing under the laws of Canada (the "**Trustee**")

RECITALS

(A) BNY Trust Company of Canada is the successor trustee of CIBC Mellon Trust Company;

(B) The Corporation has entered into a trust indenture with the Trustee made as of May 7, 2003, as amended, supplemented or restated from time to time (the "**Trust Indenture**") which provides for the issuance of one or more series of unsecured Debentures of the Corporation by way of Supplemental Indentures;

(C) The Corporation entered into a first supplemental trust indenture made as of May 7, 2003 for the purpose of providing for the issue of $225,000,000 aggregate principal amount of Series 1 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 1 Debentures;

(D) The Corporation entered into a second supplemental trust indenture made as of November 14, 2007 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 2 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 2 Debentures;

(E) The Corporation entered into a third supplemental trust indenture made as of November 12, 2009 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 3 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 3 Debentures;

(F) The City Note has been converted, in accordance with its terms, into the Series 4 Debentures and the Series 5 Debentures;

(G) The Corporation entered into a fourth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 4 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 4 Debentures;

(H) The Corporation entered into a fifth supplemental trust indenture made as of April 1, 2010 for the purpose of providing for the issue of $245,057,000 aggregate principal amount of Series 5 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 5 Debentures;

(I) The Corporation entered into a sixth supplemental trust indenture made as of May 20, 2010 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 6 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 6 Debentures;

(J) The Corporation entered into a seventh supplemental trust indenture made as of September 20, 2011 for the purpose of amending the definition of "GAAP" under the Trust Indenture;

(K) The Corporation entered into an eighth supplemental trust indenture made as of November 18, 2011 for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 7 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 7 Debentures;

(L) The Corporation entered into a ninth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 8 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 8 Debentures;

(M) The Corporation entered into a tenth supplemental trust indenture made as of April 9, 2013 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 9 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 9 Debentures;

(N) The Corporation entered into an eleventh supplemental trust indenture made as of September 16, 2014 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 10 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 10 Debentures;

(O) The Corporation entered into a twelfth supplemental trust indenture made as of March 16, 2015 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 11 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 11 Debentures;

(P) The Corporation entered into an amended and restated tenth supplemental trust indenture made as of September 2, 2015 for the purpose of making changes and corrections which were required for curing and correcting certain ambiguities and omissions in connection with an issue of $45,000,000 additional aggregate principal amount of the Series 9 Debentures;

(Q) The Corporation entered into a thirteenth supplemental trust indenture made as of June 14, 2016 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 12 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 12 Debentures;

(R) The Corporation entered into a fourteenth supplemental trust indenture made as of November 14, 2017 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 13 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 13 Debentures;

(S) The Corporation entered into a fifteenth supplemental trust indenture made as of November 12, 2019 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 14 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 14 Debentures;

(T) The Corporation entered into a sixteenth supplemental trust indenture made as of November 12, 2019 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 15 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 15 Debentures;

(U) The Corporation entered into a seventeenth supplemental trust indenture made as of October 15, 2020 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 16 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 16 Debentures;

(V) The Corporation entered into an eighteenth supplemental trust indenture made as of October 18, 2021 for the purpose of providing for the issue of $150,000,000 aggregate principal amount of Series 17 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 17 Debentures;

(W) The Corporation entered into a nineteenth supplemental trust indenture made as of October 18, 2021 for the purpose of providing for the issue of $200,000,000 aggregate principal amount of Series 18 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 18 Debentures;

(X) The Corporation entered into a twentieth supplemental trust indenture made as of October 13, 2022 for the purpose of providing for the issue of $300,000,000 aggregate principal amount of Series 19 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 19 Debentures; and

(Y) This Twenty-First Supplemental Trust Indenture is entered into for the purpose of providing for the issue of $250,000,000 aggregate principal amount of Series 20 Debentures pursuant to the Trust Indenture and establishing the terms, provisions and conditions of the Series 20 Debentures.

NOW THEREFORE THIS TWENTY-FIRST SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

Section 1 INTERPRETATION

1.1 To Be Read With Trust Indenture

This Twenty-First Supplemental Trust Indenture is a Supplemental Indenture as that term is used in the Trust Indenture. The Trust Indenture and this Twenty-First Supplemental Trust Indenture shall be read together and shall have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this Twenty-First Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the interpretation thereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this Twenty-First Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Trust Indenture and used but not defined in this Twenty-First Supplemental Trust Indenture shall have the meanings ascribed to them in the Trust Indenture, as such meanings may be amended or supplemented with respect to Series 20 Debentures by this Twenty-First Supplemental Trust Indenture. In the event of any inconsistency between the meaning given to a term in the Trust Indenture and the meaning given to the same term in this Twenty-First Supplemental Trust Indenture, the meaning given to the term in this Twenty-First Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this Twenty-First Supplemental Trust Indenture and in the Series 20 Debentures, the following terms have the following meanings:

(a) ***Canada Yield*** on any date means the yield to maturity on that date, compounded semi-annually, that a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on that date with a term to maturity approximately equal to the remaining term to March 14, 2033 of the Series 20 Debentures, such yield to maturity being the average of the yields provided by two major Canadian investment dealers specified by the Corporation.

(b) ***Canada Yield Price*** means the amount equal to the net present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Series 20 Debentures that would have been payable to March 14, 2033 if redemption had not been made, using a discount rate equal to the sum of the Canada Yield and 31 basis points, calculated at 10:00 a.m. (Toronto, Ontario time) three Business Days prior to the Redemption Date of the Series 20 Debentures.

(c) ***Series 20 Debentures*** means the 4.61% Senior Unsecured Debentures due 2033 (Series 20) referred to in Section 2.1.

(d) ***Series 20 Debentures Debt Account*** means the deposit account established in respect of the Series 20 Debentures pursuant to Section 8.2 of the Trust Indenture that is designated in writing by the Corporation to the Trustee as the "Series 20 Debentures Debt Account".

(e) ***Series 20 Debentures Interest Payment Date*** means December 14 and June 14 in each year that the Series 20 Debentures are outstanding, beginning December 14, 2023.

(f) ***Series 20 Debentures Interest Period*** means the period commencing on and including the later of the date of issue of the Series 20 Debentures and the immediately preceding Series 20 Debentures Interest Payment Date and ending on and including the day immediately preceding the next Series 20 Debentures Interest Payment Date to occur in respect of which interest is payable.

(g) ***Trust Indenture*** means the trust indenture made as of May 7, 2003 between the Corporation and the Trustee, as amended, supplemented or restated from time to time.

Section 2 SERIES 20 DEBENTURES

2.1 Creation and Designation

The Corporation is authorized in accordance with the Trust Indenture to issue under this Twenty-First Supplemental Trust Indenture, and hereby creates and issues, a series of debentures designated "4.61% Senior Unsecured Debentures due 2033 (Series 20)", having the terms set out in this Twenty-First Supplemental Trust Indenture.

2.2 No Limitation on Issue

The aggregate principal amount of Series 20 Debentures which may be issued under this Twenty-First Supplemental Trust Indenture including any supplement hereto is unlimited.

2.3 Date of Issue and Maturity

The Series 20 Debentures shall be dated June 14, 2023 (being the applicable date of issue) and will become due and payable, together with all accrued interest and unpaid interest thereon, on June 14, 2033 (being the applicable Stated Maturity).

2.4 Concerning Interest

(a) The Series 20 Debentures shall be issued in $1,000 principal amount denominations or integral multiples thereof and shall bear interest on the unpaid principal amount thereof at a rate of 4.61% per annum from and including their date of issue, payable semi-annually in arrears, in equal instalments, on each Series 20 Debentures Interest Payment Date.

(b) Interest shall be payable in respect of each Series 20 Debentures Interest Period (after as well as before maturity, default and judgment, with interest on overdue interest at the

same rate) on each Series 20 Debentures Interest Payment Date in accordance with Section 2.8 of the Trust Indenture.

2.5 Interest Payments

The Corporation shall make payments of interest on the Series 20 Debentures in accordance with the provisions of Section 2.8 of the Trust Indenture.

2.6 Payment of Amounts Due on Maturity

In accordance with Section 8.2 of the Trust Indenture, the Corporation will deposit to the Series 20 Debentures Debt Account all amounts required to be paid to the order of Holders of Series 20 Debentures on maturity, prior to 9:00 a.m. (Toronto, Ontario time), on the Stated Maturity of the Series 20 Debentures. The deposit of such funds will satisfy and discharge the liability of the Corporation for principal of, and any accrued and unpaid interest on, the Series 20 Debentures to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld).

2.7 Redemption and Purchase of Series 20 Debentures

(a) The Series 20 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to March 14, 2033, on not more than 60 calendar days and not less than 10 calendar days prior notice, at a price equal to the greater of the Canada Yield Price and par, together in each case with accrued and unpaid interest to (but excluding) the Redemption Date and in each case otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(b) The Series 20 Debentures may be redeemed, at the Corporation's option when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after March 14, 2033, on not more than 60 calendar days and not less than 10 calendar days prior notice, at a price equal to 100% of the principal amount of the Series 20 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the Redemption Date and otherwise in accordance with Sections 5.1, 5.2, 5.3 and 5.4 of the Trust Indenture.

(c) The Corporation will be entitled at any time when not in default under the Trust Indenture to purchase for cancellation all or any of the Series 20 Debentures in accordance with Section 5.5 of the Trust Indenture.

(d) The Series 20 Debentures will not be subject to repurchase pursuant to any sinking fund provisions.

(e) Notice of redemption of any Series 20 Debentures given to the holders of the Series 20 Debentures may be conditional and, in such case, such notice of redemption shall specify the details and terms of any event (e.g., a financing, asset disposition or other transaction) on which such redemption is conditional.

2.8 Form of Series 20 Debentures

(a) Except as set out in 2.8(b) below, the Series 20 Debentures and the registration panel and the certificate of the Trustee endorsed thereon shall be issuable initially as one Global Debenture to be held by, or on behalf of, CDS as depository for its participants and registered in the name of CDS or its nominee. The Global Debenture shall be substantially in the form set out in Schedule 1 hereto with such appropriate additions, deletions, substitutions and variations as the Directors shall by resolution determine prior to the time of issue thereof and as the Trustee may approve and with such distinguishing

letters and numbers as the Trustee may approve, with such approval in each case to be conclusively evidenced by the Trustee's certification of such Global Debenture.

(b) The Trustee understands and acknowledges that the Series 20 Debentures have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 20 Debenture originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form set out in Schedule 2 hereto which definitive certificate, and each Series 20 Debenture certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE **"U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT."

If any Series 20 Debentures are being sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S Securities Act, the legend may be removed by providing a declaration to the Trustee to the following effect (or as the Corporation may prescribe from time to time),

"The undersigned (A) acknowledges that the sale of the _____ Debentures, represented by certificate numbers _____ to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "**U.S. Securities Act**") and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Toronto Hydro Corporation, (2) the offer of such Debentures was not made to a person in the United States and at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States and (3) neither the seller, nor any affiliate of the seller, nor any person acting on its or their behalf engaged in any directed selling efforts in connection with the offer and sale of such Debentures. Terms used herein have the meanings given to them by Regulation S under the U.S. Securities Act."

If any Series 20 Debentures are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Trustee Counsel (or counsel to the transferor satisfactory to the Trustee) to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 20 Debentures, the Corporation shall notify the Trustee, in writing, concerning which Series 20 Debentures are to be certificated and are to bear the legend described above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 20 Debentures.

2.9 Signatures on Series 20 Debentures

The Series 20 Debentures shall be signed in accordance with the provisions of Section 2.6 of the Trust Indenture.

2.10 Certification

(a) No Series 20 Debenture issued shall be obligatory or shall entitle the Holder of such Series 20 Debenture to the benefits of this Twenty-First Supplemental Trust Indenture until it has been certified by manual, facsimile or electronic signature by or on behalf of the Trustee by execution of the certificate of the Trustee appended thereto substantially in the form set out in Schedule 1 hereto, or in some other form approved by the Trustee, whose approval shall be conclusively evidenced by the Trustee's execution of the certificate. Such certificate on any Series 20 Debenture shall be conclusive evidence that such Series 20 Debenture is duly issued and is a valid and binding obligation of the Corporation and that the Holder of such Series 20 Debenture is entitled to the benefits of the Trust Indenture, as supplemented by this Twenty-First Supplemental Trust Indenture, and such Series 20 Debenture.

(b) The certificate of the Trustee on any Series 20 Debenture shall not be construed as a representation or warranty by the Trustee as to the validity of this Twenty-First Supplemental Trust Indenture or of the Series 20 Debentures (except the due certification thereof and any other warranties implied by law) and the Trustee shall in no respect be liable or answerable for the use made of the Series 20 Debentures or any of them or the proceeds thereof.

2.11 Location of Register

With respect to the Series 20 Debentures, initially the Register referred to in Section 3.1 of the Trust Indenture shall be kept by the Trustee at the Corporate Trust Office and may thereafter be kept by the Trustee in such other place as the Corporation, with the approval of the Trustee, may designate.

2.12 Additional Amounts

The Corporation will not be required to pay an additional amount on the Series 20 Debentures in respect of any tax, assessment or government charge that is required by law to be withheld or deducted by it.

2.13 Trustees, etc.

The Trustee will be the Paying Agent and the Registrar for the Series 20 Debentures.

Section 3 MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this Twenty-First Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this Twenty-First Supplemental Trust Indenture and in accordance with the Trust Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this Twenty-First Supplemental Trust Indenture is in all respects confirmed.

3.3 Counterparts

This Twenty-First Supplemental Trust Indenture may be executed in counterparts, each of which so executed shall be deemed to be original and such counterparts together shall constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this Twenty-First Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

TORONTO HYDRO CORPORATION

By: _____

Name: Anthony Haines

Title: President and Chief Executive Officer

By: _____

Name: Céline Arsenault

Title: Executive Vice-President and Chief Financial Officer

[Trustee Signature Page Follows]

IN WITNESS WHEREOF the parties hereto have executed this Twenty-First Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

BNY TRUST COMPANY OF CANADA

By: _____

Name: Ismail Bawa

Title: Authorized Signatory

Schedule 1 – FORM OF GLOBAL DEBENTURE-SERIES 20

This Debenture is a Global Debenture within the meaning of the Trust Indenture hereinafter referred to and is registered in the name of a Depository or a nominee thereof. Unless this Certificate is presented by an authorized representative of CDS Clearing and Depository Services Inc. ("CDS") to Toronto Hydro Corporation or its agent for registration of transfer, exchange or payment, and any certificate issued in respect thereof is registered in the name of CDS & CO., or in such other name as is requested by an authorized representative of CDS (and any payment is made to CDS & CO., or to such other entity as is requested by an authorized representative of CDS), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL since the registered holder hereof, CDS & CO., has a property interest in the securities represented by this certificate herein and it is a violation of its rights for another person to hold, transfer or deal with this certificate.

[No. 20-000]

$●

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
4.61% SENIOR UNSECURED DEBENTURES DUE 2033 (SERIES 20)

ISIN CA89119ZAS26
CUSIP 89119ZAS2

Issue Date	June 14, 2023
Stated Maturity	June 14, 2033
Interest Rate Per Annum	4.61%
Interest Payment Dates	December 14 and June 14 in each year
Initial Interest Payment Date	December 14, 2023
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 4.61% Senior Unsecured Debenture due June 14, 2033 (Series 20) (the "**Series 20 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at One York Street, 6th Floor, Toronto, Ontario M5J 0B6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 20 Debenture, at the address of the registered holder hereof appearing on the register of Series 20 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation will (i) on the day that is each Interest Payment Date, make payment by a wire transfer, or (ii) on the day that is two Business Days

before each Interest Payment Date, forward or cause to be forwarded a cheque by same day delivery, to the address of the registered holder hereof appearing on the Register for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 20 Debenture is presented and surrendered to the Trustee. The payment by such wire transfer or forwarding of such cheque (provided such cheque is paid on presentation) will satisfy and discharge the liability for interest upon such Series 20 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid).

This Series 20 Debenture is one of an authorized issue of debentures designated as 4.61% Senior Unsecured Debentures due June 14, 2033 (Series 20) and forming the series of debentures created and issued under a twenty-first supplemental trust indenture made as of June 14, 2023 (the "**Twenty-First Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, the fourteenth supplemental trust indenture to the Indenture made as of November 14, 2017 between the Corporation and the Trustee, the fifteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the sixteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the seventeenth supplemental trust indenture to the Indenture made as of October 15, 2020 between the Corporation and the Trustee, the eighteenth supplemental trust indenture to the Indenture made as of October 18, 2021 between the Corporation and the Trustee, the nineteenth supplemental trust indenture to the Indenture made as of October 18, 2021 between the Corporation and the Trustee, the twentieth supplemental trust indenture to the Indenture made as of October 13, 2022 between the Corporation and the Trustee, and the Twenty-First Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 20 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 20 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 20 Debenture and to each of which the registered holder of this Series 20 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 20 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 20 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof and, subject to the terms and conditions set forth in the Trust Indenture, are issued as book entry only debentures.

The Series 20 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 20 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to March 14, 2033, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 20 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after March 14, 2033, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 20 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 20 Debentures in the open market, by tender or by private contract, at any price. Series 20 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 20 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture relating to the transfer of a Global Debenture (as defined in the Trust Indenture), and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 20 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 20 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 20 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
4.61% SENIOR UNSECURED DEBENTURES DUE 2033 (SERIES 20)

ISIN CA89119ZAS26
CUSIP 89119ZAS2

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	AMOUNT OF DECREASE	AMOUNT OF INCREASE	AMOUNT OF SERIES 20 DEBENTURES OUTSTANDING FOLLOWING CHANGE	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE DEBENTURE-SERIES 20

*THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "**U.S. SECURITIES ACT**") OR UNDER ANY STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF THE CORPORATION THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, OR (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH (1) RULE 144A UNDER THE U.S. SECURITIES ACT OR (2) RULE 144 UNDER THE U.S. SECURITIES ACT, IF AVAILABLE, OR (3) IN COMPLIANCE WITH CERTAIN OTHER PROCEDURES SATISFACTORY TO THE CORPORATION. A NEW CERTIFICATE, BEARING NO LEGEND, DELIVERY OF WHICH WILL CONSTITUTE "GOOD DELIVERY", MAY BE OBTAINED FROM BNY TRUST COMPANY OF CANADA UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO BNY TRUST COMPANY OF CANADA AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT.*

[No. 20-000]

$●

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
4.61% SENIOR UNSECURED DEBENTURES DUE 2033 (SERIES 20)

Issue Date	June 14, 2023
Stated Maturity	June 14, 2033
Interest Rate Per Annum	4.61%
Interest Payment Dates	December 14 and June 14 in each year
Initial Interest Payment Date	December 14, 2023
Principal Amount	$●

TORONTO HYDRO CORPORATION (the "**Corporation**") for value received hereby promises to pay to the registered holder hereof on the Stated Maturity, or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), on presentation and surrender of this 4.61% Senior Unsecured Debenture due June 14, 2033 (Series 20) (the "**Series 20 Debenture**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at One York Street, 6th Floor, Toronto, Ontario M5J 0B6, and to pay interest on the Principal Amount at the Interest Rate Per Annum from and including the later of the Issue Date and the last Interest Payment Date on which interest has at that time most recently been paid on this Series 20 Debenture, at the address of the registered holder hereof appearing on the register of Series 20 Debentures maintained by or at the direction of the Trustee (the "**Register**"), in like money semi-annually in arrears, in equal instalments on the Interest Payment Dates in each year, and if the Corporation at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Corporation, on the day that is two

Business Days before each Interest Payment Date, will forward or cause to be forwarded by same day delivery to the address of the registered holder hereof appearing on the Register a cheque for interest due and payable to such holder on such Interest Payment Date, less any taxes required by law to be deducted or withheld, made payable to the order of such holder; provided, however that in case of payment of interest at maturity or redemption or as otherwise provided in the Trust Indenture, the time for payment of interest, less any such taxes, may at the option of the Corporation be determined based on the time that the certificate representing this Series 20 Debenture is presented and surrendered to the Trustee. The forwarding of such cheque will satisfy and discharge the liability for interest upon such Series 20 Debenture to the extent of the sum represented thereby (plus the amount of any taxes deducted or withheld as aforesaid) unless such cheque is not paid on presentation.

This Series 20 Debenture is one of an authorized issue of debentures designated as 4.61% Senior Unsecured Debentures due June 14, 2033 (Series 20) and forming the series of debentures created and issued under a twenty-first supplemental trust indenture made as of June 14, 2023 (the "**Twenty-First Supplemental Trust Indenture**") to a trust indenture (the "**Indenture**") made as of May 7, 2003, between the Corporation and BNY Trust Company of Canada (successor trustee of CIBC Mellon Trust Company) (the "**Trustee**"), as Trustee (the first supplemental trust indenture to the Indenture made as of May 7, 2003 between the Corporation and the Trustee, the second supplemental trust indenture to the Indenture made as of November 14, 2007 between the Corporation and the Trustee, the third supplemental trust indenture to the Indenture made as of November 12, 2009 between the Corporation and the Trustee, the fourth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the fifth supplemental trust indenture to the Indenture made as of April 1, 2010 between the Corporation and the Trustee, the sixth supplemental trust indenture to the Indenture made as of May 20, 2010 between the Corporation and the Trustee, the seventh supplemental trust indenture to the Indenture made as of September 20, 2011 between the Corporation and the Trustee, the eighth supplemental trust indenture to the Indenture made as of November 18, 2011 between the Corporation and the Trustee, the ninth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the tenth supplemental trust indenture to the Indenture made as of April 9, 2013 between the Corporation and the Trustee, the amended and restated tenth supplemental trust indenture to the Indenture made as of September 2, 2015 between the Corporation and the Trustee, the eleventh supplemental trust indenture to the Indenture made as of September 16, 2014 between the Corporation and the Trustee, the twelfth supplemental trust indenture to the Indenture made as of March 16, 2015 between the Corporation and the Trustee, the thirteenth supplemental trust indenture to the Indenture made as of June 14, 2016 between the Corporation and the Trustee, the fourteenth supplemental trust indenture to the Indenture made as of November 14, 2017 between the Corporation and the Trustee, the fifteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the sixteenth supplemental trust indenture to the Indenture made as of November 12, 2019 between the Corporation and the Trustee, the seventeenth supplemental trust indenture to the Indenture made as of October 15, 2020 between the Corporation and the Trustee, the eighteenth supplemental trust indenture to the Indenture made as of October 18, 2021 between the Corporation and the Trustee, the nineteenth supplemental trust indenture to the Indenture made as of October 18, 2021 between the Corporation and the Trustee, the twentieth supplemental trust indenture to the Indenture made as of October 13, 2022 between the Corporation and the Trustee, and the Twenty-First Supplemental Trust Indenture to the Indenture (as amended, supplemented or restated from time to time) are collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 20 Debentures are created and issued or may be created, issued and held and the rights of the registered holders of the Series 20 Debentures, the Corporation and the Trustee, all of which terms and conditions are incorporated by reference in this Series 20 Debenture and to each of which the registered holder of this Series 20 Debenture, by acceptance hereof, agrees.

The aggregate principal amount of Series 20 Debentures that may be created and issued under the Trust Indenture is unlimited. Series 20 Debentures are issuable as fully registered debentures in denominations of $1,000 and integral multiples thereof.

The Series 20 Debentures are direct unsecured obligations of the Corporation and will rank equally with each other and with all other debentures of every other series from time to time issued and outstanding pursuant to the Trust Indenture and, except to the extent prescribed by law, with all other unsecured and unsubordinated Indebtedness of the Corporation.

This Series 20 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, prior to March 14, 2033, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the greater of the Canada Yield Price (as defined in the Trust Indenture) and par, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

This Series 20 Debenture is redeemable, at the option of the Corporation when not in default under the Trust Indenture, in whole at any time or in part from time to time, on or after March 14, 2033, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to 100% of the Principal Amount of the Series 20 Debentures outstanding, together with accrued and unpaid interest to (but excluding) the date fixed for redemption.

At any time when the Corporation is not in default under the Trust Indenture, the Corporation may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 20 Debentures in the open market, by tender or by private contract, at any price. Series 20 Debentures purchased by the Corporation shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Stated Maturity on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of debentures issued by the Corporation pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of debentures issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of debentures issued by the Corporation pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 20 Debenture may be transferred only upon compliance with the conditions prescribed in the Trust Indenture by the registered holder hereof or the holder's legal representative or attorney duly appointed by an instrument in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer shall be duly noted hereon by the Trustee or other registrar.

This Series 20 Debenture shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF TORONTO HYDRO CORPORATION has caused this Series 20 Debenture to be signed by its ● and its ●.

TORONTO HYDRO CORPORATION

By: _____

Name: ●

Title: ●

By: _____

Name: ●

Title: ●

(FORM OF TRUSTEE'S CERTIFICATE)

This Debenture is one of the Series 20 Debentures referred to in the Trust Indenture referred to above.

BNY TRUST COMPANY OF CANADA
Trustee

By: _____
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

TORONTO HYDRO CORPORATION
(Incorporated under the laws of Ontario)
4.61% SENIOR UNSECURED DEBENTURES DUE 2033 (SERIES 20)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

RATING AGENCY REPORTS

In accordance with s. 2.1.8 of the OEB's Filing Requirements,[1] this schedule provides Toronto Hydro-Electric System Limited's rating agency reports, as follows:

- Appendix A: Standard and Poor's, 11 May 2023
- Appendix B: DBRS, 01 May 2023

[1] Ontario Energy Board, Filing Requirements for Electricity Distributor Rate Applications, Chapter 2 (December 15, 2022).

S&P Global Ratings

RatingsDirect®

Research Update:

Toronto Hydro Corp. Outlook Revised To Developing From Positive Due To Heightened Regulatory Lag; Ratings Affirmed

May 11, 2023

Rating Action Overview

- The financial performance of the Ontario local distribution companies (LDC), regulated by the Ontario Energy Board (OEB), has gradually weakened, primarily reflecting regulatory lag. We view this development as negative for credit quality, which could lead to our reassessing Ontario's regulatory framework.
- We therefore affirmed our 'A' issuer credit rating and senior unsecured rating on Toronto Hydro Corp., and we revised the outlook to developing from positive.
- The developing outlook reflects the possibility that we could either affirm, raise, or lower Toronto Hydro Corp. (THC) over the next 12 months. This will depend on THC's financial measures, our view of the Ontario regulatory framework, and if we upgrade the city of Toronto.

PRIMARY CREDIT ANALYST

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Rating Action Rationale

We revised THC's outlook to developing. THC's prior outlook reflected the positive outlook on the city of Toronto because there is a moderate likelihood that the city of Toronto will provide timely and sufficient support in the event of financial distress. The cash injection by the city in 2017, demonstrating its willingness to provide financial support to THC when needed, supports this view. We expect to see ongoing support from the city, as necessary, because the utility provides essential infrastructure services to the population of Toronto.

The developing outlook on THC reflects the possibility that we could reassess our view of the Ontario regulatory framework because of regulatory lag that has weakened financial performance, increased cash flow volatility, and weakened financial predictability.

We have historically assessed the Ontario regulatory framework as one of the most credit-supportive regulatory jurisdictions. Despite the OEB only authorizing its LDCs an average return on equity (ROE) and a significantly below average capital structure, reflecting a 40% equity ratio, we have consistently assessed the Ontario regulatory framework as one of the most

credit-supportive regulatory jurisdictions for LDCs because they have consistently been able to earn at or close to their authorized ROE. However, more recently financial measures have gradually weakened because of rising regulatory lag, which is the timing difference between when costs are incurred and when regulators allow those costs to be fully recovered from ratepayers. During the past two years, transmission costs and wholesale market charges have significantly increased. Although we expect the LDCs to recover these costs from ratepayers, it has taken them as long as 24 months to fully recover these costs, which has eroded financial performance. In general, regulatory jurisdictions that we assess as most credit supportive have a regulatory construct in place that consistently minimizes regulatory lag.

THC's historical financial measures have weakened. THC's financial performance materially weakened in 2022, reflecting high capital spending and regulatory lag. In 2022, funds from operations (FFO) to debt was 10.3%, significantly below our ratings trigger of 13%.

We currently expect THC's financial measures will remain weak in 2023 and 2024, reflecting FFO to debt of 11%-14%. This is driven by high capital expenditures (capex) of about C$800 million per year, refunds to rate payers, and regulatory lag. We currently expect financial measures to improve starting 2025 as the company will enter a new five-year rate period. We expect the company to file a multiyear rate case with the OEB sometime in late 2023.

We assess THC's business risk profile as excellent. We assess the utility's business risk profile as excellent because of the company's lower-risk regulated electric LDC business that serves a large customer base (about 790,000 customers), consisting of mostly residential customers that provide a degree of cash flow stability, and our high assessment of the Ontario regulatory construct. However, should we reassess Ontario's regulatory construct downward, it would likely weaken our relative assessment of THC's business risk profile within its current business risk profile category.

Outlook

The developing outlook reflects the possibility that we could either affirm, raise, or lower the ratings on THC over the next 12 months. This will depend on THC's financial measures, our view of the Ontario regulatory framework, and if we upgrade the city of Toronto. We could affirm our rating on THC and revise the outlook to stable if we revise downward our assessment of Ontario's regulatory construct and THC's FFO to debt is consistently greater than 14%. We could also revise the outlook to stable if we maintain our current assessment of Ontario's regulatory construct and THC's FFO to debt is consistently greater than 11%.

Downside scenario

We could lower the ratings on THC if we revise downward our assessment of Ontario's regulatory construct and THC's FFO to debt is consistently below 14%. We could also lower the rating if we maintain our current assessment of Ontario's regulatory construct and THC's FFO to debt is consistently below 11%.

Upside scenario

We could raise the ratings on THC if we upgrade the city of Toronto, we maintain our current assessment of Ontario's regulatory construct, and THC's FFO to debt is consistently greater than

13%.

Company Description

Toronto Hydro Corp. (THC) is a utility holding company that owns Toronto Hydro-Electric System Ltd., the electricity distribution utility delivering electricity in Toronto.

Our Base-Case Scenario

- Continued rate increases driven by annual rate increases, recovery of energy costs, and anticipated 2025 rate case.
- Recovery of large energy cost variance of 2021 and 2022 in 2023 and 2024.
- We forecast energy sales variance would be between C$50 million to C$70 million in 2023.
- Net refunds of about C$100 million to rate payers through 2024.
- Capex averaging about C$800 million per year through 2025.

Liquidity

As of Dec. 31, 2022, we assess THC's liquidity as adequate, which reflects our expectation that sources will cover uses by 1.1x over the coming 12 months. Additionally, we anticipate its net sources will remain positive even if consolidated EBITDA declines 10%. We believe the predictable regulatory framework for THC provides cash flow stability even in times of economic stress. This supports our use of slightly lower thresholds than for a typical corporate issuer to assess the company's liquidity. In addition, THC has the ability to absorb high-impact, low-probability events, given that it maintains about $1 billion in committed credit facilities that mature beyond 12 months. We also believe the company can significantly lower its robust capital spending during stress, which would reduce the need for refinancing under such conditions. Furthermore, our assessment reflects the company's generally prudent risk management, sound relationships with its banks, and satisfactory standing in the credit markets. Overall, we believe the company could withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations.

Principal liquidity sources

- Committed credit facilities availability of C$1 billion; and
- Cash FFO of about C$550 million.

Principal liquidity uses

- Debt maturities of about C$600 million;
- Assumed maintenance capex of about C$630 million; and
- Dividend payments of about C$100 million.

Ratings Score Snapshot

Issuer credit rating: A/Developing/--

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Strong

Financial risk: Intermediate

- Cash flow/leverage: Intermediate

Anchor: a

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a

- Group credit profile: a
- Entity status within group: Core (no impact)
- Government Related-Entity: Moderate (no impact)

ESG credit indicators: E-2, S-2, G-2

Related Criteria

- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014

- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings List

Ratings Affirmed; Outlook Action

	To	From
Toronto Hydro Corp.		
Issuer Credit Rating	A/Developing/--	A/Positive/--
Issue-Level Ratings Affirmed		
Toronto Hydro Corp.		
Senior Unsecured	A	

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

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Rating Report
Toronto Hydro Corporation

DBRS Morningstar
May 1, 2023

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Senior Unsecured Debentures & MTNs	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On April 28, 2023, DBRS Limited (DBRS Morningstar) confirmed the Issuer Rating and Senior Unsecured Debentures & MTNs rating of Toronto Hydro Corporation (Toronto Hydro or the Company) at "A," and the Commercial Paper (CP) rating at R-1 (low). All trends are Stable. The ratings of Toronto Hydro are based on the Company's stable regulated electricity distribution business, which operates under a reasonable regulatory environment under the Ontario Energy Board (OEB).

There have been no material changes to Toronto Hydro's business risk assessment since the last rating confirmations. The Company continues to operate under the Custom Incentive Rate-setting (IR) framework as approved for 2020–24. DBRS Morningstar notes Toronto Hydro has begun preparation work for its next distribution rates application for the 2025–29 period. DBRS Morningstar will monitor progress on the application for any implications on the Company's credit profile.

Toronto Hydro's financial risk assessment has been supportive of the "A" ratings, with all key credit metrics in line with the current rating category. DBRS Morningstar notes, however, the Company's metrics weakened in 2022 because of the significant capital expenditures (capex) program (gross capex of $675 million for the year) to maintain safety and reliability, support a growing city, enable clean energy, and prepare for and respond to extreme weather. Toronto Hydro's financial ratios may continue to weaken over the next few years as the ongoing capex program will likely require substantial debt financing. DBRS Morningstar expects the Company to be prudent in managing its debt load in order to maintain leverage in line with the regulatory capital structure of 60% debt. However, should the Company's key credit metrics weaken to a level no longer commensurate with the "A" rating category for a sustained period of time (cash flow-to-debt less than 12.5%, debt-to-capital more than 65.0%, and EBIT-interest coverage less than 1.80 times (x)), a negative rating action may occur. Conversely, a positive rating action is considered unlikely at this time given the capex program in place and the current business risk assessment.

Financial Information

	For the year ended December 31				
	2022	**2021**	**2020**	**2019**	**2018**
Cash flow/total debt (%)	14.1	16.3	14.5	17.6	17.9
Total debt in capital structure (%)	60.0	57.8	57.1	55.1	54.1
EBIT gross interest coverage (x)	2.70	2.80	2.64	3.10	3.27

Issuer Description

Toronto Hydro is a holding company with the following subsidiaries: Toronto Hydro-Electric System Limited (THESL), the regulated electricity distributor, and Toronto Hydro Energy Services Inc., which provides street lighting services. The Company's sole shareholder is the City of Toronto (the City; rated AA with a Stable trend by DBRS Morningstar).

Rating Considerations

Strengths

1. Reasonable regulatory environment

Nearly all of Toronto Hydro's earnings are contributed by its low-risk distribution business that operates under a reasonable and supportive regulatory environment. The Company operates under a five-year Custom IR framework that preapproves capex for the term and allows Toronto Hydro to generate relatively stable earnings and cash flow. Toronto Hydro's deemed capital structure (deemed equity of 40%) has remained unchanged for several years.

2. Strong and growing franchise area

Toronto Hydro operates in Toronto, which is one of the largest metropolitan cities in North America and has reasonable growth in population. The Company is one of the largest municipally owned local distribution companies (LDCs) in Canada, providing approximately 18% of the electricity consumed in Ontario, and serves a customer base of approximately 790,000 customers. Toronto Hydro's electricity throughput is predominantly distributed to residential and general service customers who account for approximately 95% of the Company's distribution revenue, reducing its exposure to cyclicality.

3. Reasonable financial profile

Toronto Hydro's credit metrics, including cash flow-to-total debt of 14.1%, total debt-to-capital of 60.0%, and EBIT interest coverage of 2.70x for 2022, have remained reasonable for the "A" ratings.

Challenges

1. Balance sheet pressure as a result of high capex

The Company is executing a substantial capex program of approximately $2.9 billion for the 2020–24 period to replace its aging electricity infrastructure, which is expected to result in consistent free cash flow deficits for the medium term. Historically, Toronto Hydro has depended entirely on debt to fund its cash flow deficits, causing leverage to peak at 62.8% for 2015. Although an equity injection from the City alleviated this pressure in 2017, leverage will likely rise over the next few years after factoring in the higher dividend policy implemented in 2017. While DBRS Morningstar expects the Company's key credit

metrics to remain supportive of the current ratings, should they weaken to a level no longer in line with the "A" rating category, a negative rating action may occur.

2. Limited access to equity market

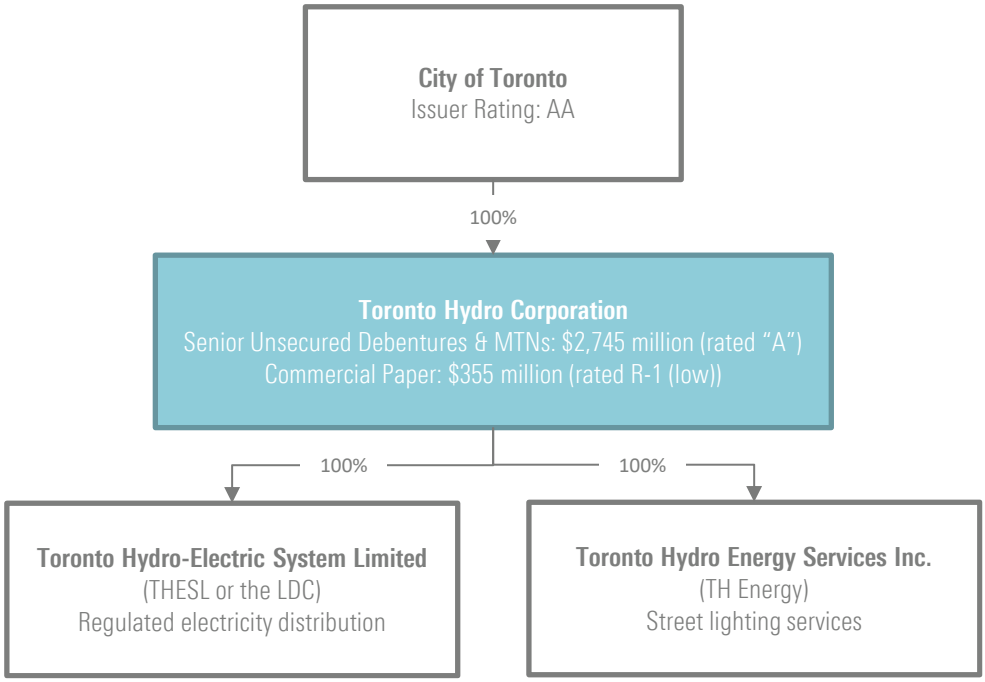
The Company's ownership structure (100% owned by the City) limits its ability to access the equity markets. As a result, cash flow deficits from the large capex program are funded largely through debt.

3. Earnings sensitive to volume

Earnings and cash flow for LDCs are partially dependent on the volume of electricity sold, given that rates typically include a variable charge component. Seasonality, economic cyclicality, and weather variability have a direct impact on the volume of electricity sold and, therefore, on distribution revenue. While volume risk has been largely eliminated for residential customers through a fixed charge, distribution rates for commercial and industrial customers (71% of revenue in 2022) continue to be based on fixed and volumetric components.

Corporate Structure

Simplified Organizational Structure



As at December 31, 2022.
Source: Toronto Hydro.

- Toronto Hydro is a holding company with the following subsidiaries operating in the Toronto area:
  - THESL is one of the largest municipal electricity distribution utilities in Canada (99% of revenue); and

    - Toronto Hydro Energy Services Inc., which has a contractual relationship with the City, owns and operates street lighting services (1% of revenue).
- The Company serves approximately 790,000 customers and distributed 18% of electricity in Ontario for 2022.

Earnings and Outlook

	For the year ended December 31				
(CAD millions where applicable)	**2022**	**2021**	**2020**	**2019**	**2018**
Net revenue	892	846	798	831	820
EBITDA	569	528	493	522	513
EBIT	258	235	219	267	275
Gross interest expense	95	84	83	86	84
Net income before nonrecurring items	164	143	137	153	165
Reported net income	164	141	117	154	167
ROE (%)	8.1	7.3	7.2	8.2	9.2
Achieved regulated ROE (%)	7.44	7.08	5.90	8.44	9.33
Allowed ROE (%)	8.52	8.52	8.52	9.30	9.30
Rate base	4,907	4,675	4,534	4,380	4,123

ROE = return on equity.

2022 Summary

- Earnings for Toronto Hydro improved in 2022 mainly because of higher consumption and electricity distribution rates.
    - DBRS Morningstar notes earnings rebounded following the lower consumption during the past two years because of the Coronavirus Disease (COVID-19) pandemic.
    - The higher earnings were partly offset by higher depreciation from the growing rate base and higher interest expense.

2023 Outlook

- DBRS Morningstar expects Toronto Hydro's earnings to weaken in 2023.
    - The lower earnings will be primarily driven by higher financing costs from funding the significant capex program and higher expenses to operate the growing asset base. Earnings will also be pressured from the regulatory lag in passing through the impact of higher interest rates and inflation on operating expenses.
    - This will be partly offset by an increase in distribution revenue through the annual mechanisms of the Custom IR decision.
    - DBRS Morningstar expects revenues from residential customers should remain steady as distribution rates are decoupled.

Financial Profile

	For the year ended December 31				
(CAD millions where applicable)	**2022**	**2021**	**2020**	**2019**	**2018**
Net income before nonrecurring items	164	143	137	153	165
Depreciation and amortization	311	293	274	256	238
Deferred income taxes and other	(39)	6	(41)	1	(16)
Cash flow from operations	**436**	**442**	**370**	**409**	**387**
Dividends paid	(85)	(70)	(93)	(100)	(94)
Capex	(589)	(492)	(529)	(444)	(388)
Free cash flow (bef. working cap. changes)	**(238)**	**(121)**	**(251)**	**(135)**	**(94)**
Changes in noncash work. cap. items	(6)	(2)	46	(77)	(1)
Changes in regulatory assets and liabilities	(137)	(54)	(19)	62	3
Net free cash flow	**(380)**	**(177)**	**(224)**	**(149)**	**(92)**
Acquisitions and long-term investments	0	0	0	0	0
Proceeds on asset sales	0	3	1	2	117
Net equity change	0	0	0	0	0
Net debt change	384	167	229	161	(47)
Other	(5)	7	(6)	(14)	22
Change in cash	**(0)**	**0**	**0**	**(0)**	**0**
Total debt	3,097	2,715	2,548	2,320	2,161
Total debt in capital structure (%)	60.0	57.8	57.1	55.1	54.1
Cash flow/total debt (%)	14.1	16.3	14.5	17.6	17.9
EBIT gross interest coverage (x)	2.70	2.80	2.64	3.10	3.27
DBRS Morningstar-adjusted dividend payout ratio (%)	51.6	49.2	67.5	65.7	56.8

2022 Summary

- While Toronto Hydro's key credit metrics weakened in 2022, they remained in line with the "A" ratings.
    - The weaker key credit metrics were largely because of the growing debt load to fund the substantial capex program.
- Cash flow from operations was steady with 2021 results.
- Gross capex of $675 million remained elevated as the Company continued to spend on infrastructure renewal projects, customer-initiated plant relocations (such as for public transit expansion projects), new customer connections, and overhead infrastructure.
- Toronto Hydro paid dividends of $85 million in 2022, in line with its distribution policy of 60% of consolidated net income after net movements in regulatory balances.
- The Company funded its net free cash flow deficit through CPs and a $300 million senior unsecured debentures issuance.

2023 Outlook

- DBRS Morningstar expects cash flow from operations to decrease modestly in 2023, in line with the expected lower earnings.
- The Company has planned gross capex of $742 million for the year.

- Dividends are expected to increase because of the higher net income in 2022.
- Combined with the high capex and dividend requirements, Toronto Hydro is expected to continue generating net cash flow deficits in the medium term that will likely be funded by debt.
    - As a result, DBRS Morningstar expects leverage for the Company will increase modestly and be more than the regulatory capital structure of 60% debt.
    - Additionally, DBRS Morningstar expects the cash flow-to-debt and EBIT-to-interest coverage ratios to weaken as well but remain commensurate with the "A" ratings.
    - Should Toronto Hydro's key credit metrics continue to weaken to lower than the "A" rating category, a negative rating action may occur.

Liquidity and Long-Term Debt Maturities

Long-Term Debt

Debentures

(CAD millions - as at December 31, 2022)	Maturity	Outstanding
Series 6 - 5.54%	May 21, 2040	200
Series 8 - 2.91%	Apr. 10, 2023	250
Series 9 - 3.96%	Apr. 9, 2063	245
Series 10 - 4.08%	Sep. 16, 2044	200
Series 11 - 3.55%	Jul. 28, 2045	200
Series 12 - 2.52%	Aug. 25, 2026	200
Series 13 - 3.485%	Feb. 28, 2048	200
Series 14 - 2.43%	Dec. 11, 2029	200
Series 15 - 2.99%	Dec. 10, 2049	200
Series 16 - 1.50%	Oct. 15, 2030	200
Series 17 - 2.47%	Oct. 20, 2031	150
Series 18 - 3.27%	Oct. 18, 2051	200
Series 19 - 4.95%	Oct. 13, 2052	300
Total debentures		**2,745**
Less: Unamortized debt issuance costs		(15)
Less: Unamortized discount/premium		(1)
Less: Current portion of debentures		(250)
Long-term portion of debentures		**2,479**

Long-Term Debt Maturities

(CAD millions - as at December 31, 2022)	2023	2024	2025	2026	2027	2028+	Total
Debentures	250	-	-	200	-	2,295	**2,745**
% of total	9	0	0	7	0	84	**100**

- Debt maturities are reasonably staggered and manageable, and Toronto Hydro continues to have adequate access to debt capital markets.
- In October 2022, the Company issued $300 million of senior unsecured debentures maturing in 2052.

Liquidity

(CAD millions - as at December 31, 2022)	Amount	Drawn/CPs/LOCs	Available	Expiry
Cash and cash equivalents	0	0	**0**	-
Revolving credit facility	800	355	**445**	Sep 17, 2027
Prudential facility	100	58	**42**	Demand
Working capital facility	20	13	**7**	Demand
Total	**920**	**426**	**494**	

- Toronto Hydro's liquidity profile remains adequate to cover near- to medium-term obligations, with approximately $494 million of available facilities.
- In March 2023, Toronto Hydro increased its CP program to $1 billion from $750 million. The program is backstopped by a $1 billion revolving credit facility (previously $800 million) with a maturity date of September 17, 2027.
- Toronto Hydro also has a $100 million Prudential Facility (demand facility) for the purpose of issuing letters of credit (LOCs) mainly to support prudential requirements with the Independent Electricity System Operator (IESO) and a $20 million Working Capital Facility.

Regulation

- THESL is regulated by the OEB under a Custom IR framework. The Company has a good track record of prudently managing its regulatory risk.
    - DBRS Morningstar considers the regulatory regime under the OEB as supportive.
- The five-year Custom IR framework approved by the OEB for THESL is a hybrid between cost of service (COS) and an incentive rate mechanism (IRM).
    - The rate setting for the term is based on THESL's forecasts and OEB's incentive rate analysis using productivity benchmarking.
    - Custom IR is suited to distributors with large, broad, multiyear investment needs over a five-year period or more, and to distributors that require certainty of funding several years in advance.
- On December 19, 2019, the OEB approved THESL's Custom IR application for rates effective January 1, 2020, to December 31, 2024.
    - The application was largely a continuation of the previous Custom IR regime, where rates will increase annually by a capital factor (based on the approved capex program), an inflation factor (as updated annually by the OEB), less the productivity and stretch factors, and a growth factor (based on changes in load and customer count).
    - The OEB approved a deemed capital structure of 60% debt (56% long-term and 4% short-term), 40% equity, and an allowed return on equity (ROE) of 8.52%.
    - Total approved capex of approximately $2.9 billion for the 2020–24 period.
    - THESL must file annual mechanistic IRM applications to finalize the rates approved on an interim basis as part of the application. The OEB has approved those annual rates consistent with the Company's applications and in accordance with the approved 2020–24 Custom IR framework.

    - THESL is required to share earnings in excess of 100 basis points (bps) over the allowed ROE equally between the Company and its customers.
    - A regulatory review may be initiated by THESL or the OEB (off-ramp), should actual ROE vary from the allowed ROE by 300 bps (either positive or negative).
- In December 2021, the OEB approved THESL's application for base rate increase of 1.49% effective January 1, 2022.
- In December 2022, the OEB approved THESL's application for base rate increase of 3.7% effective January 1, 2023.
- Preparatory work is under way for Toronto Hydro's next Custom IR application for rates effective January 1, 2025, to December 31, 2029.

Assessment of Regulatory Framework

Criteria	Score	Analysis
1. Deemed Equity	Excellent Good **Satisfactory** Below Average Poor	The OEB allows THESL to have a deemed equity of 40%, which is consistent with other electricity distribution companies in Ontario.
2. Allowed ROE	Excellent Good **Satisfactory** Below Average Poor	THESL has an allowed ROE of 8.52% for 2020–24, which is in line with the other distribution companies in Ontario. Any difference in ROE between the Company and other distribution companies is mainly because of the timing of the regulatory filings and the interest environment prevalent at that time.
3. Energy Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	There is no power price risk for Toronto Hydro, as it is not responsible for purchasing power from generation facilities or the wholesale market. Power costs are passed on to ratepayers at rates set by the OEB, and the Company collects the payments from its customers on a monthly basis.
4. Capital and Operating Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	Under Custom IR, the capex program for THESL is pre-approved for a five-year period by the OEB and recovered through distribution rates. Additionally, beginning in 2020, all residential customers are charged a fully fixed monthly fee for distribution services, significantly reducing volume risk.
5. COS versus IRM	Excellent Good **Satisfactory** Below Average Poor	THESL operates under Custom IR, which is a hybrid of COS and IRM. The Custom IR is for a five-year term from 2020–24. The productivity factor has been set at 0% and the stretch factor for operating expenses has been set at 0.6% for the current Custom IR term.
6. Political Interference	Excellent Good Satisfactory **Below Average** Poor	The Government of Ontario plays a significant role in the electricity sector in Ontario, given that most of the utilities are government owned (Toronto Hydro is owned by the City). Furthermore, stakeholders, such as the IESO, are also government owned. As a result, the government has direct and indirect influence on Ontario's electricity industry.
7. Stranded Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	LDCs in Ontario have a limited history of stranded costs. Most prudently incurred or budgeted capex are approved by the OEB.
8. Rate Freeze	Excellent **Good** Satisfactory Below Average Poor	From 2002–05, as a result of rising rates during Ontario's utility deregulation phase, a provincewide distribution rate freeze was imposed. There have been no subsequent provincewide rate freezes.

Environmental, Social, and Governance (ESG) Credit Risk Considerations

Environmental

There were no Environmental factors that had a relevant or significant effect on the credit analysis. For more details about which Environmental factors could have an effect on the credit analysis, please refer to the following checklist. DBRS Morningstar notes regulated utilities may be exposed to severe weather events. DBRS Morningstar expects any costs associated with these events to be recovered through rates.

Social

There were no Social factors that had a relevant or significant effect on the credit analysis. For more details about which Social factors could have an effect on the credit, please refer to the following checklist.

Governance

There were no Governance factors that had a relevant or significant effect on the credit analysis. For more details about which Governance factors could have an effect on the credit analysis, please refer to the following checklist.

A description of how DBRS Morningstar considers ESG factors within the DBRS Morningstar analytical framework can be found in *DBRS Morningstar Criteria: Approach to Environmental, Social, and Governance Risk Factors in Credit Ratings* at https://www.dbrsmorningstar.com/research/396929.

ESG Factor		ESG Credit Consideration Applicable to the Credit Analysis: Y/N		Extent of the Effect on the ESG Factor on the Credit Analysis: Relevant (R) or Significant (S)*
Environmental		Overall:	N	N
	Emissions,Effluents, and Waste	Do we consider the costs or risks result, or could result in changes to an issuer's financial, operational, and/or reputational standing?	N	N
	Carbon and GHG Costs	Does the issuer face increased regulatory pressure relating to the carbon impact of its or its clients' operations resulting in additional costs?	N	N
	Resource and Energy Management	Does the scarcity of sourcing key resources hinder the production or operations of the issuer, resulting in lower productivity and therefore revenues?	N	N
	Land Impact and Biodiversity	Is there a financial risk to the issuer for failing to effectively manage land conversion, rehabilitation, land impact, or biodiversity activities?	N	N
	Climate and Weather Risks	Will climate change and adverse weather events potentially disrupt issuer or client operations, causing a negative financial impact?	N	N
Social		Overall:	N	N
	Social Impact of Products and Services	Do we consider that the social impact of the issuer's products and services could pose a financial or regulatory risk to the issuer?	N	N
	Human Capital and Human Rights	Is the issuer exposed to staffing risks, such as the scarcity of skilled labour, uncompetitive wages, or frequent labour relations conflicts that could result in a material financial or operational impact?	N	N
		Do violations of rights create a potential liability that can negatively affect the issue's financial wellbeing or reputation?	N	N
		Human Capital and Human Rights:	N	N
	Product Governance	Does failure in delivering quality products and services cause damage to customers and expose the issuer to financial and legal liability?	N	N
	Data Privacy and Security	Has misuse or negligence in maintaining private client or stakeholder data resulted, or could result, in financial penalties or client attrition to the issuer?	N	N
	Occupational Health and Safety	Would the failure to address workplace hazards have a negative financial impact on the issuer?	N	N
	Community Relations	Does engagement, or lack of engagement, with local communities pose a financial or reputational risk to the issuer?	N	N
	Access to Basic Services	Does a failure to provide or protect with respect to essential products or services have the potential to result in any significant negative financial impact on the issuer?	N	N
Governance		Overall:	N	N
	Bribery, Corruption, and Political Risks	Do alleged or actual illicit payments pose a financial or reputational risk to the issuer?	N	N
		Are there any political risks that could impact the issuer's financial position or its reputation?	N	N
		Bribery, Corruption, and Political Risks:	N	N
	Business Ethics	Do general professional ethics pose a financial or reputational risk to the issuer?	N	N
	Corporate / Transaction Governance	Does the issuer's corporate structure limit appropriate board and audit independence?	N	N
		Have there been significant governance failures that could negatively affect the issuer's financial wellbeing or reputation?	N	N
		Corporate / Transaction Governance:	N	N
	Institutional Strength, Governance, and Transparency (Governments Only)s	Compared with other governments, do institutional arrangements provide a higher or lesser degree of accountability, transparency, and effectiveness?	N	N
		Are regulatory and oversight bodies insufficiently protected from inappropriate political influence?	N	N
		Are government officials insufficiently exposed to public scrutiny or held to insufficiently high ethical standards of conduct?	N	N
		Institutional Strength, Governance, and Transparency (Governments Only)s:	N	N
		Consolidated ESG Criteria Output:	N	N

Balance Sheet

(CAD millions)	Dec. 31	Dec. 31	Dec. 31		Dec. 31	Dec. 31	Dec. 31
Assets	**2022**	**2021**	**2020**	**Liabilities and Equity**	**2022**	**2021**	**2020**
Cash and equivalents	0	0	0	Short-term debt	368	284	166
Accounts receivable	246	247	241	Accounts payable	463	425	406
Inventories	8	10	10	Current portion long-term debt	250	0	300
Unbilled revenue	255	212	229	Customer advanced deposits	55	62	45
Prepaid expenses and other	16	21	29	Other current liabilities	47	37	34
Total Current Assets	**526**	**490**	**508**	**Total Current Liabilities**	**1,183**	**808**	**951**
Net fixed assets	5,757	5,377	5,039	Long-term debt	2,479	2,431	2,082
Future income tax assets	87	64	48	Deferred income taxes	85	64	47
Goodwill and intangibles	387	358	343	Regulatory liabilities	150	151	183
Regulatory assets	176	118	123	Other long-term liabilities	989	977	893
Investments and others	14	7	8	Shareholders' equity	2,062	1,983	1,912
Total Assets	**6,947**	**6,414**	**6,069**	**Total Liabilities and Equity**	**6,947**	**6,414**	**6,069**

Ratios

	For the year ended December 31				
Balance Sheet, Liquidity, and Capital Ratios	**2022**	**2021**	**2020**	**2019**	**2018**
Current ratio	0.44	0.61	0.53	0.79	0.53
Total debt in capital structure (%)	60.0	57.8	57.1	55.1	54.1
Cash flow/total debt (%)	14.1	16.3	14.5	17.6	17.9
(Cash flow-dividends)/Capex (x)	0.60	0.75	0.53	0.70	0.76
DBRS Morningstar-adjusted dividend payout ratio (%)	51.6	49.2	67.5	65.7	56.8
Coverage Ratios (x)					
EBIT gross interest coverage	2.70	2.80	2.64	3.10	3.27
EBITDA gross interest coverage	5.97	6.28	5.96	6.07	6.11
Fixed-charges coverage	2.70	2.80	2.64	3.10	3.27
Profitability Ratios					
EBITDA margin (%)	63.8	62.4	61.8	62.8	62.5
EBIT margin (%)	28.9	27.8	27.4	32.1	33.5
Profit margin (%)	18.4	16.9	17.2	18.4	20.2
ROE (%)	8.1	7.3	7.2	8.2	9.2
Return on capital (%)	5.2	5.1	5.0	6.5	6.9

Rating History

	Current	2022	2021	2020	2019	2018
Issuer Rating	A	A	A	A	A	A
Senior Unsecured Debentures & MTNs	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Commercial Paper Limit

- $1 billion.

Previous Actions

- "DBRS Morningstar Notes Toronto Hydro Corporation's Commercial Paper Limit Increase," March 24, 2023.
- "DBRS Morningstar Assigns Rating of “A” with Stable Trend to Toronto Hydro Corporation’s 4.95% $300 Million Senior Unsecured Debentures," October 13, 2022.
- "DBRS Morningstar Confirms Ratings of Toronto Hydro Corporation With Stable Trends," April 29, 2022.

Previous Report

- Toronto Hydro Corporation: Rating Report, May 5, 2022.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrsmorningstar.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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We rate more than 4,000 issuers and nearly 60,000 securities worldwide, providing independent credit ratings for financial institutions, corporate and sovereign entities, and structured finance products and instruments. Market innovators choose to work with us because of our agility, transparency, and tech-forward approach.

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EXISTING ACCOUNTING ORDERS AND DEPARTURES FROM USoA

Toronto Hydro confirms that it has, to the best of its knowledge, materially complied with the Uniform System of Accounts ("USoA") as set out in the OEB's Accounting Procedures Handbook ("APH"), and with the following utility-specific accounting orders:

- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record the variance between actual and approved cumulative 2015 – 2019 and 2020 – 2024 capital in-service additions related revenue requirement included in rates;[1]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record any excess expansion deposits to the variance account;[2]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record the variance between actual and approved revenue requirement related to third party initiated relocation and expansion projects;[3]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to track the variance in actual gains on sale of utility property from the $1.0 million amount included in base rates as part of 2020 Revenue Offsets;[4]
- Impact for USGAAP Deferral Account, effective January 1, 2012, to record the financial impacts resulting from the transition to and implementation of USGAAP;[5]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record the costs and revenues associated with wireless pole attachments;[6]

[1] EB-2014-0116, Decision and Rate Order (March 1, 2016).
[2] EB-2018-0165, Decision and Rate Order (February 20, 2020).
[3] EB-2014-0116, Decision and Rate Order (March 1, 2016).
[4] EB-2018-0165, Decision and Rate Order (February 20, 2020).
[5] EB-2012-0079, Decision and Order (June 7, 2012).
[6] EB-2013-0234, Decision and Accounting Order (June 5, 2014).

- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record any revenue impact associated with the difference between the OEB-approved charge in effect in any given period and the charge embedded in their underlying rate structure for pole attachments;[7]
- Renewable Generation Connection Funding Adder Deferral Account, to track the difference between the revenue requirement associated with Renewable Enabling Improvements that is funded through Provincial Rate Protection and collected through payments from the IESO and revenue requirement based on actual REI investments;[8]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record the variance between actual and forecasted gains net of tax with the gross up for the PILs tax savings related to the sale of 5800 Yonge and 28 Underwriters properties;[9]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record the difference between the forecasted other post-employment benefit costs calculated using the accounting accrual method versus actual cash payments made;[10]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record any earnings outside of Toronto Hydro's approved annual return on equity exceeding a +/- 100 basis-point dead band;[11]
- Sub-Accounts to Account 1508 – Other Regulatory Assets, to record the revenue requirement impact of a reduction to rate base associated with payments from Carillion to Toronto Hydro resulting from the ongoing insolvency litigation;[12] and

[7] Accounting Guidance for Wireline Pole Attachment Charges (December 16, 2021).
[8] EB-2014-0116, Decision and Order (December 29, 2015).
[9] EB-2014-0116, Decision and Rate Order (March 1, 2016).
[10] Ibid.
[11] EB-2018-0165, Decision and Rate Order (February 20, 2020).
[12] Ibid.

- Sub-Accounts to Account 1508 – Other Regulatory Assets, to track the difference in revenue requirement impacts of the existing and updated depreciation rates as a result of Toronto Hydro's comprehensive depreciation study on its assets over 2023 and 2024.[13]

[13] EB-2022-0065, Decision and Order (December 8, 2022).

Toronto Hydro-Electric System Limited
EB-2023-0195
Exhibit 1C
Tab 3
Schedule 9
ORIGINAL
(10 pages)

TORONTO HYDRO® Corporation

The Power of Action

2022 Annual Report



®A registered trademark of Toronto Hydro Corporation used under licence.

The Power of Action



MESSAGE FROM THE CHAIR OF THE BOARD, AND PRESIDENT AND CHIEF EXECUTIVE OFFICER

We're pleased to present Toronto Hydro's 2022 Annual Report: *The Power of Action*. This year's theme highlights our commitment to purposeful, strategic action, which in 2022 resulted in another successful year safely and reliably powering Canada's largest city. Through the power of action, we successfully navigated external challenges including the COVID-19 pandemic, global supply chain issues and climate change in order to deliver results for our customers and shareholder.

In 2022, we delivered the largest capital investment program in our company's history to renew and modernize our grid. We achieved this while maintaining our portion of the electricity bill below 2019 levels and delivering dividends that can help fund City services. We also maintained our unwavering commitment to employee health and safety throughout the year, achieving our best safety performance on record.

While we continue to be a utility that serves our customers and keeps the lights on, the way we do it is evolving. As we enter a future that will see continued city growth, increased electrification, more frequent extreme weather due to climate change, and changes in grid technology, we recognize that there are difficult challenges ahead, but we're committed to being part of the solution. We also know we can't do it alone, which is why we're committed to pursuing strategic partnerships to harness the power of collective action.

As we enter a future that will see continued city growth, increased electrification, more frequent extreme weather due to climate change, and changes in grid technology, we recognize that there are difficult challenges ahead, but we're committed to being part of the solution.

In 2022, we were proud to receive unanimous approval from Toronto City Council to begin implementing our Climate Action Plan, which we developed to support the City of Toronto's Net Zero 2040 Strategy. Our plan includes investing in the local grid to make increased electrification a possibility for all Torontonians and a new climate advisory services offering that will help mobilize climate action by making it easier, faster and more affordable for Toronto residents and businesses to adopt clean-energy technologies.

We also worked to further our role as a green city builder. Last year, we continued to work with the City of Toronto, City agencies and local start-up companies to support electrified transportation in the city, including by installing more on-street electric vehicle (EV) charging stations across Toronto and piloting an EV smart charging program for customers. We also continued to collaborate on climate change adaptation with the City and its agencies to help reduce the impacts of climate change on the residents of Toronto.

As we continue to invest in the upkeep of our grid, we're simultaneously modernizing and innovating to address system needs. In 2022, we developed a 10-year grid modernization roadmap to help enhance the value we provide to customers and prepare the grid for a decarbonized and electrified energy system. We also partnered to launch an innovative non-wires alternatives pilot project. With support from the Independent Electricity System Operator and the Ontario Energy Board, we're exploring how demand-side resources can be used to help defer or avoid costly distribution system and bulk system infrastructure upgrades, to the benefit of ratepayers.

To help ensure we're able to meet our customers' needs and expectations now and into the future, in 2022, we also began work on our next five-year investment plan for 2025 to 2029. We asked customers from across the city about their needs and priorities for electricity distribution service, and we used their feedback to guide the development of our plan.

On behalf of Toronto Hydro, we thank all of our employees for their hard work and commitment throughout the year. Together with our customers, partners and stakeholders, we look forward to powering transformative action across our city for years to come.

David McFadden
Chair



Anthony Haines
President and
Chief Executive Officer

The Power of Action



COMPANY OVERVIEW

Toronto Hydro Corporation is a holding company which wholly owns two subsidiaries:

- **Toronto Hydro-Electric System Limited** distributes electricity; and
- **Toronto Hydro Energy Services Inc.** provides streetlighting and expressway lighting services in the city of Toronto

To learn more about our company, including our leadership, governance and sustainability performance, visit **torontohydro.com/about-us**.

Did you know that Toronto Hydro serves both smaller and larger customers, including:

707,178
Residential Service customers (includes houses, apartments and condominiums)

82,820
General Service customers with monthly peak demand of less than 5,000 kW* (includes schools, restaurants and most shopping malls)

42
Large Users with monthly peak demand of 5,000 kW or greater[1] (includes hospitals, universities and large manufacturers)

[1] Averaged over a 12-month period.

Our customers are serviced from:

37
terminal stations

17,060*
primary switches

61,300*
distribution transformers

139
in-service municipal substations

15,393*
circuit kilometres of overhead wires

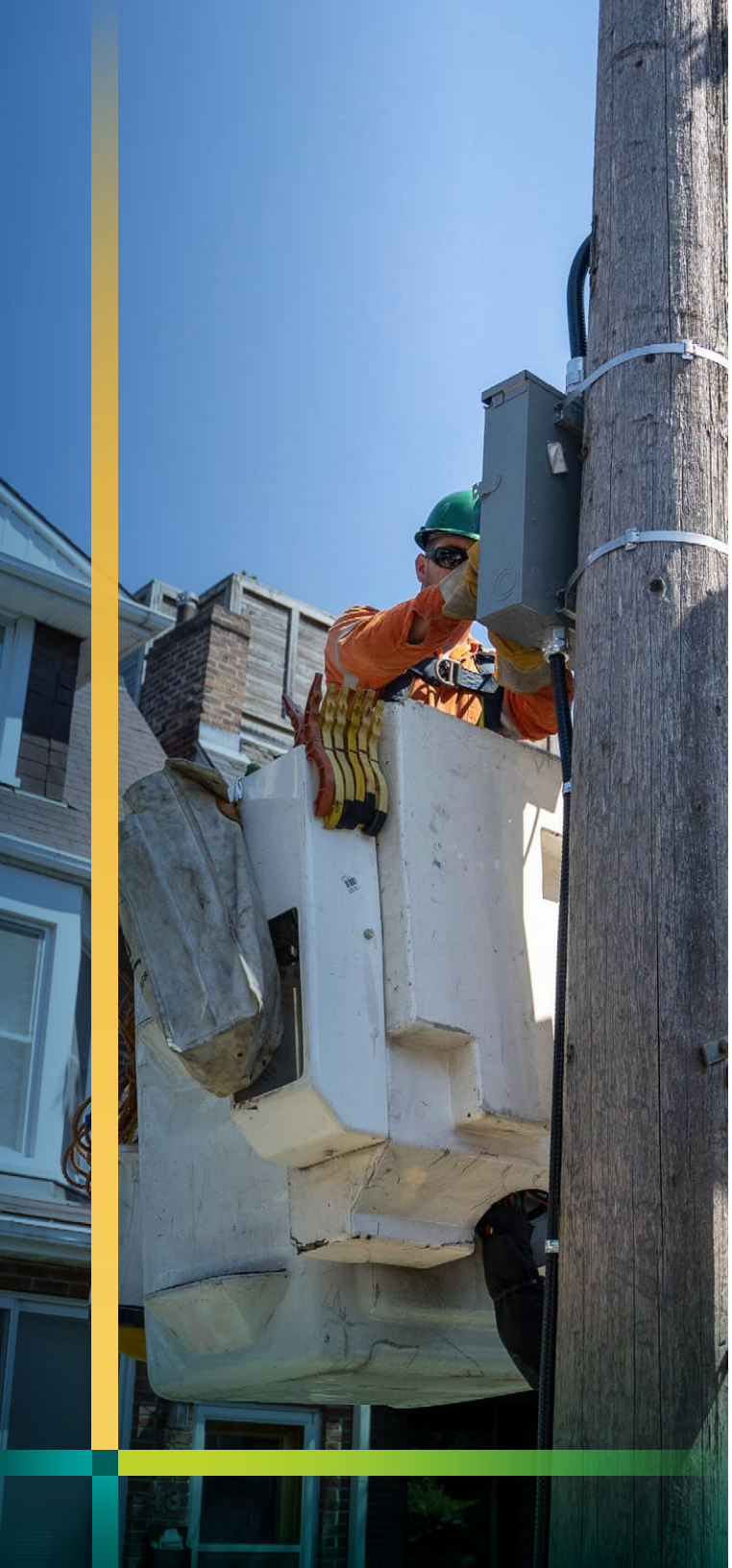
13,765*
circuit kilometres of underground wires

183,620*
poles

4
operation centres

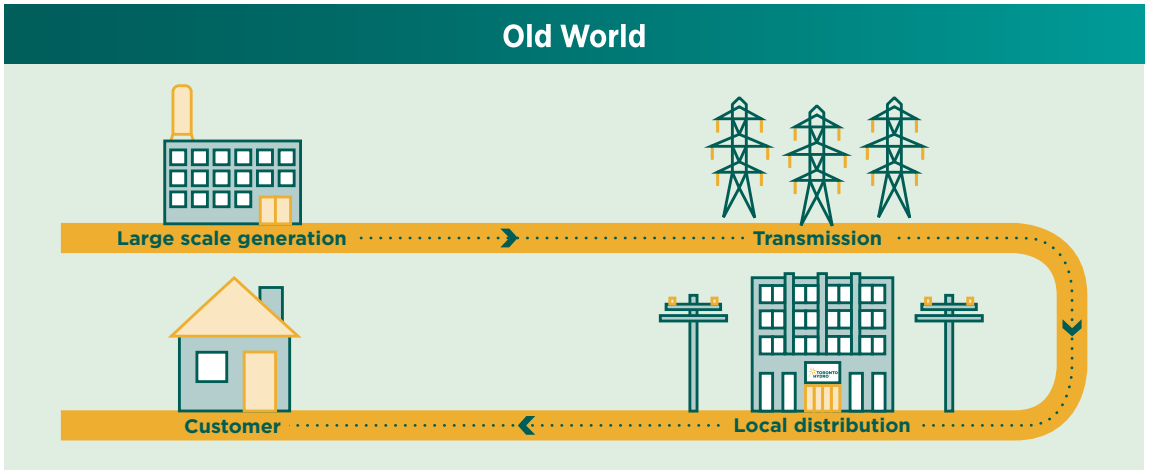
1
control centre

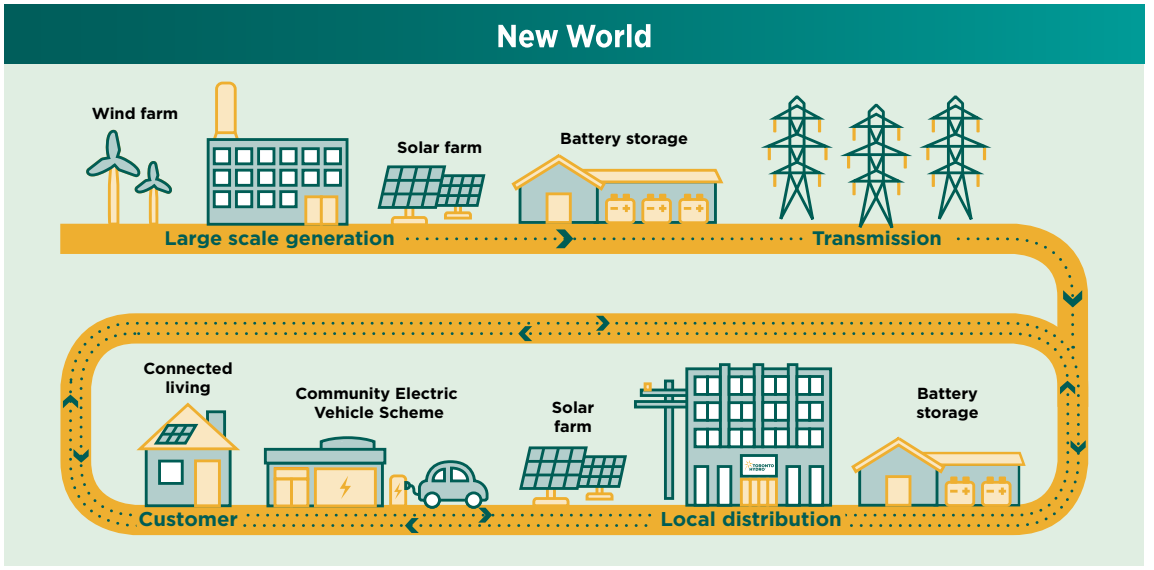
*Figures are approximate.



THE CHANGING WORLD OF ELECTRICITY

For over 100 years, Toronto Hydro has owned and maintained a physical grid of poles and wires that delivers one-way power flow across the city: from the grid to customers. While we'll continue to fulfill our fundamental role of serving our customers and keeping the lights on, our role as the owner and operator of the local grid is also evolving, as it's now possible for electricity to flow both from the grid to customers and from customers back to the grid.





Adapted from UK Power Networks' "Changing world of electricity" (FutureSmart Consultation Report, 2019).

Our next five-year investment plan — for 2025 to 2029 — is focused in part on keeping pace with changes to the electricity system and evolving customer needs. To learn more, visit **torontohydro.com/investmentplan**.

Our Climate Action Plan

As a clean energy leader in the city and nationally, Toronto Hydro is committed to bold, practical and equitable climate action. To help do our part in building a greener city, we developed a Climate Action Plan that supports the City of Toronto's Net Zero 2040 vision. Together with our customers, local cleantech companies, governments and stakeholders, we're committed to:



1. **Delivering nationally significant emissions reductions.**



2. **Stimulating and facilitating the local cleantech economy.**



3. **Advancing social equity in Toronto.**

Our climate action focus areas

Expanded electricity distribution

To support customers through their energy transition — one in which they start to use electricity for more of their day-to-day energy needs — Toronto Hydro must first expand its existing, provincially regulated electricity distribution business to build a grid that's capable of supporting a net-zero future.

This is about building the backbone of the electricity grid to help ensure that electrification is an option for everyone in the city. This significant investment in the grid will enable increased electrification of major sectors, such as transportation and buildings, which is an essential step for getting Toronto to net zero.

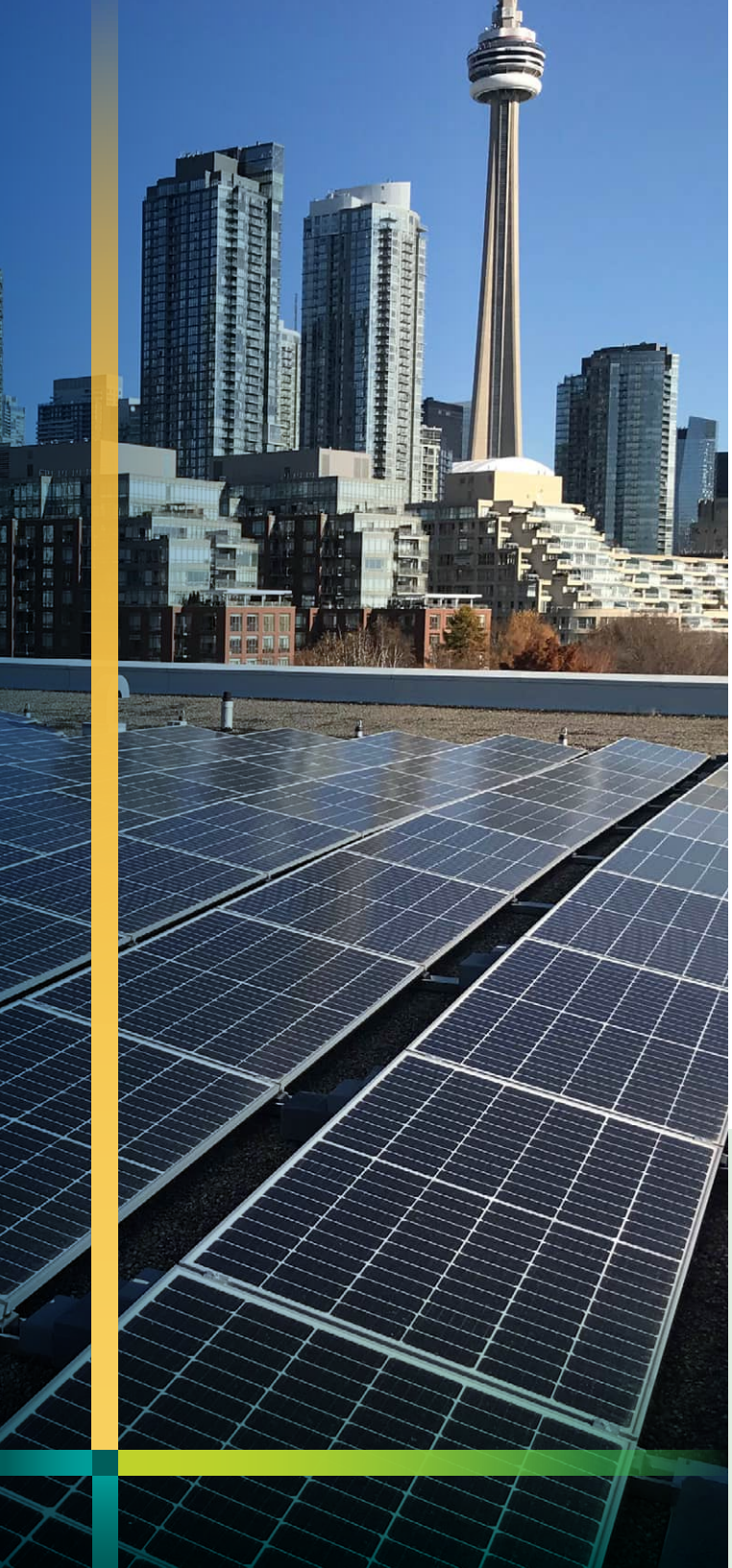
Climate advisory services

The second part of our Climate Action Plan is building a new climate advisory services offering through which Toronto Hydro will work directly with customers — free of charge — to help them find personalized, sustainable energy solutions tailored to their needs.

Through this new service, Toronto Hydro will act as a trusted partner with customers, local cleantech companies, governments and other stakeholders to help make it easier, faster and more affordable for Toronto residents and businesses to adopt clean-energy technologies.

TECHNOLOGY	PROGRAM SIZE		IMPACT 2040
	2023–2040	UNITS	
Building electrification	60,000+	Air source heat pumps + electric hot water heaters	15% of all buildings
Electric vehicles	50,000	Chargers	Serving 1 million+ EVs
Renewables + energy storage	300	Megawatts (MW) of local generation	300,000 projects

To learn more about our Climate Action Plan, visit **torontohydro.com/climateaction**.



BUILDING A GREENER CITY THROUGH CLIMATE ACTION

2022 highlights

- Received a formal mandate from Toronto City Council to begin implementing our Climate Action Plan, including the establishment of a new climate advisory services offering that will help reduce greenhouse gas (GHG) emissions in the city by mobilizing increased climate action by Toronto residents and businesses
- Continued our commitment to achieving net-zero emissions in our own operations by 2040, including by establishing and exceeding internal targets for two new environmental performance metrics: Building Emissions Reduction and Fleet Electrification
- Certified to stringent, internationally recognized standards for environmental (ISO 14001:2015) and occupational safety (ISO 45001:2018) management systems by independent third-party auditors for the tenth consecutive year
- Ranked in the top 10 on Corporate Knights' list of the Best 50 Corporate Citizens in Canada and first overall among electricity transmission and distribution companies
- Continued to partner with Elocity (a start-up company associated with Toronto Metropolitan University's Centre for Urban Energy) on an EV charging pilot project offering smart charging monitoring and controls for participating customers, as well as a voluntary demand response program capable of helping reduce aggregate load on the grid
- Continued to support renewable generation in Toronto by connecting customers' renewable energy projects and through direct project investments in renewable generation and energy storage projects across the city
- Continued to invest in and learn from innovative battery energy storage projects, including our Bulwer Battery Energy Storage System in downtown Toronto, three energy management and energy storage projects at TTC facilities and the Eglinton Crosstown LRT battery energy storage system
- Continued to improve the system's resiliency to extreme weather events and collaborate on climate change adaptation with the City and its agencies to help reduce the impacts of climate change on the residents of Toronto

Additional highlights



Named a **5-Star Energy and Resource Company** by Canadian Occupational Safety for our strong Environmental, Social and Governance (ESG) program, measurable environmental and social impact, and consistent health and safety policy



Reduced our GHG emissions by **40%** over the last five years (i.e. since 2018)



Enabled the planting of **5,000** trees through our tree planting eBills promotional program with Tree Canada



DRIVING STRONG UTILITY PERFORMANCE AND PRODUCTIVITY

2022 highlights

- Completed the third year of our five-year investment plan for 2020–2024 by investing $722.7 million primarily in our grid to maintain safety and reliability, support a growing city, enable clean energy, and prepare for and respond to extreme weather
- Paid dividends totalling $84.6 million to our sole shareholder, the City of Toronto, which can be used to fund essential City services for the benefit of Toronto residents
- Connected new services to the grid on time more than 99% of the time
- Met our target for estimated times of restoration for power outages 94% of the time
- Developed a refreshed grid modernization roadmap to prepare the grid for a decarbonized and electrified energy system, and to help enable the transition towards a more integrated, intelligent and self-healing grid
- Launched a non-wires alternatives pilot project in partnership with Power Advisory LLC and Toronto Metropolitan University's Centre for Urban Energy to explore how demand-side resources can be used to help defer or avoid costly distribution system and bulk system infrastructure upgrades
- Continued to support Metrolinx's regional transit expansion and priority transit programs (including *Building Transit Faster Act* projects, the GO Expansion program and light rail transit lines)
- Continued to enhance our Disaster Preparedness Management program to help improve our disaster and emergency response outcomes
- Completed tree pruning on more than 70,000 trees that were adjacent to distribution lines in order to help protect the system against damage from inclement weather
- Responded safely and effectively to two extreme weather events throughout the year and provided mutual aid to Hydro Ottawa to help restore power following a major windstorm in May

Additional highlights



Completed nearly **300** planned capital projects as part of our grid investment initiatives and more than **6,000** reactive projects that supported our distribution system health



Achieved a **99%** response rate to nearly **20,000** service requests for streetlight outages



Achieved a Total Recordable Injury Frequency (TRIF) rate of **0.47**, our best record to date (and nearly **80%** better than the Electricity Canada composite average)[1]

[1] TRIF, which is sometimes termed "total recordable injury rate" or simply "total recordable rate," is the ratio of injuries of a certain severity (termed "recordable injuries") to hours worked. Toronto Hydro's 2022 result was compared to the latest available composite average for Electricity Canada member utilities (2021).

SUPPORTING OUR COMMUNITY

People are at the heart of what we do, and Toronto Hydro is proud to support a number of initiatives in our community.

2022 highlights

- Raised approximately $134,000 for the United Way Greater Toronto through our annual employee campaign
- Built on the success of our previous fundraising efforts for Sunnybrook's Ross Tilley Burn Centre by raising approximately $730,000 for the Canadian Ukrainian Immigrant Aid Society to help vulnerable families settle into our community
- Continued sponsoring several community groups and events to support local organizations, including: Tree Canada, Cavalcade of Lights, CycleTO, Kids' World of Energy, Plug'n Drive and the Centre for Urban Energy at Toronto Metropolitan University



EMPOWERING OUR CUSTOMERS TO SERVE THEM BETTER

2022 highlights

- Launched a new Toronto Hydro mobile app to provide customers with convenient access to outage and construction maps, online account info, and other tools and services
- Continued to offer improved online engagement options for customers, including online chat tools for convenient, real-time customer support for outages and account-related inquiries
- Initiated the rollout of next-gen smart meters to help mitigate risks of end-of-life meters, improve operational performance and reliability, and create a modernized system to meet evolving customer expectations
- Launched a new Frequently Asked Questions web page with answers to our top customer questions, all in one place and organized into categories
- Continued to offer email and text (SMS) outage notifications, allowing customers to sign up to receive key outage updates, such as crew status and estimated restoration times
- Updated the electricity usage tracker in our customer self-serve portal to help customers better manage their electricity usage and costs
- Continued to support pricing optionality for customers on Time-of-Use and Tiered pricing, offering customers the option to choose the electricity price plan that works best for them
- Worked directly with customers to provide more flexible payment options and additional support through various financial assistance programs, including the Ontario Electricity Support Program, the Low-income Energy Assistance Program and the Energy Affordability Program
- Continued to drive increased customer and public safety awareness through education campaigns about electrical safety, fraud prevention and emergency preparedness

Additional highlights



Issued accurate bills more than **99%** of the time[1] and resolved customer inquiries on first contact **92%** of the time

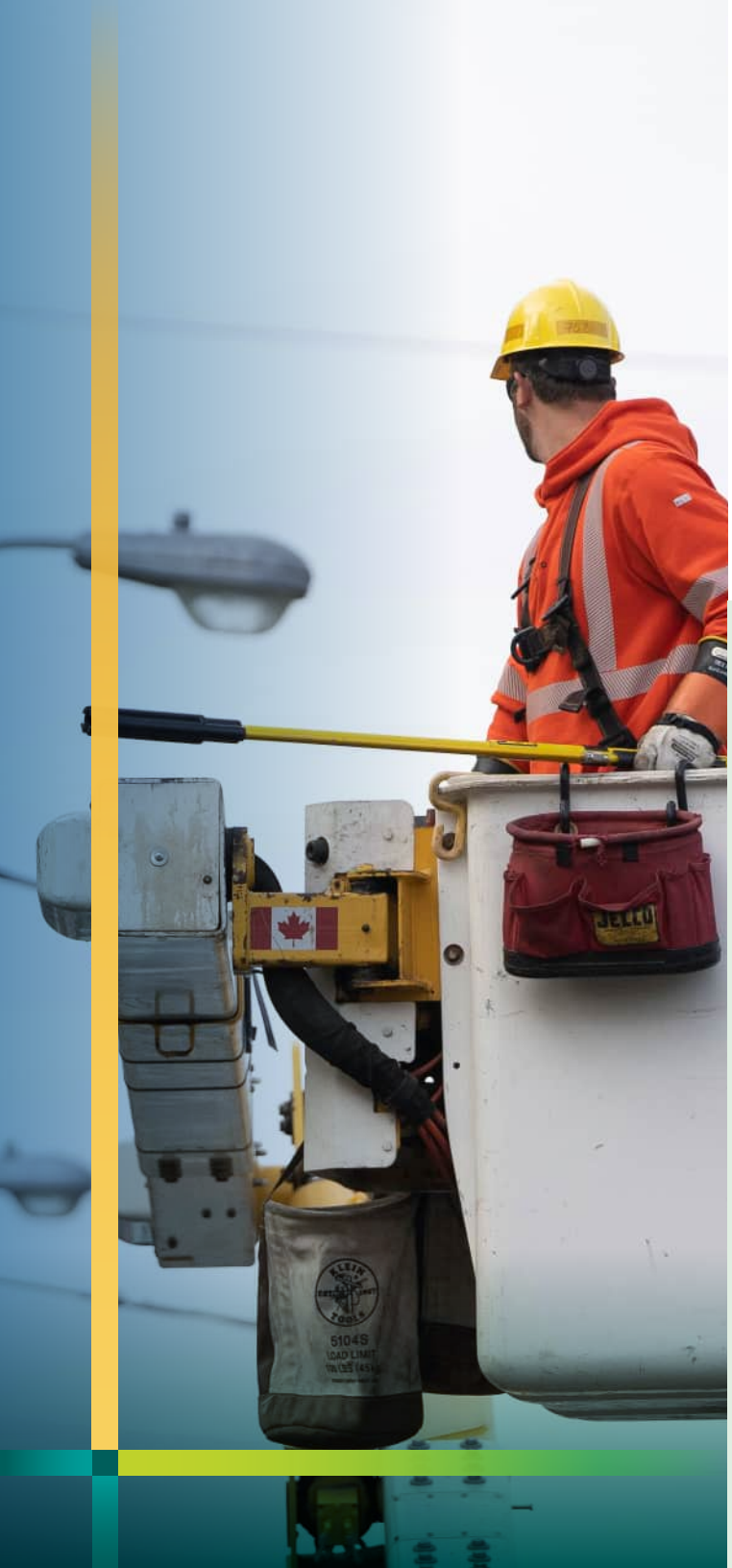


Enrolled an additional **30,000** customers for paperless billing — a convenient, sustainable and cost-effective way for customers to receive their bills



Collected feedback from approximately **3,600** customers across the city to support the development of our draft 2025–2029 investment plan

[1] The remaining 1% represents both billing estimates (which are used in rare cases where we aren't able to obtain accurate meter readings) and billing adjustment corrections due to billing errors.



FINANCIAL PERFORMANCE

2022 highlights

- Throughout 2022, the Corporation continued with critical work in its grid investment plan to maintain safety and reliability, support a growing city, enable clean energy, and prepare for and respond to extreme weather
- Net income after net movements in regulatory balances for the year ended December 31, 2022, was $163.9 million, compared to $141.0 million for the comparable period in 2021
- Capital expenditures were primarily related to the renewal of the electricity infrastructure of Toronto Hydro-Electric System Limited and were $722.7 million for the year ended December 31, 2022, compared to $647.4 million for the comparable period in 2021

Selected annual consolidated financial information (in millions of Canadian dollars)[1]

YEAR ENDED DECEMBER 31	2022 $	2021 $
Total revenues	3,601.7	3,567.1
Net income after net movements in regulatory balances	163.9	141.0
AS AT DECEMBER 31		
Total assets and regulatory balances	6,947.0	6,413.8
Total debentures and other non-current financial liabilities[2]	2,750.7	2,458.2
Total equity	2,062.0	1,982.7
Dividends	84.6	70.3

[1] Derived from Toronto Hydro's consolidated financial statements based on extracts of selected information only and do not represent the full set of consolidated financial statements.

[2] Total debentures include current and long-term debentures. Other non-current financial liabilities include primarily non-current obligations under finance lease and non-current customer deposits. Under International Financial Reporting Standards, deposits that are due or will be due on demand within one year from the end of the reporting period have been reclassified to other current financial liabilities.



FINANCIAL PERFORMANCE

Consolidated statements of income — year ended December 31 (in millions of Canadian dollars)

REVENUES	2022 $	2021 $	CHANGE $
Energy sales	2,737.8	2,702.4	35.4
Distribution revenue	754.2	759.1	(4.9)
Other	109.7	105.6	4.1
	3,601.7	**3,567.1**	**34.6**
EXPENSES			
Energy purchases	2,846.7	2,775.2	71.5
Operating expenses	322.5	323.0	(0.5)
Depreciation and amortization	311.4	292.7	18.7
	3,480.6	**3,390.9**	**89.7**
Finance costs	(87.6)	(79.1)	(8.5)
Gain on disposals of property, plant and equipment	—	2.7	(2.7)
Income before income taxes	**33.5**	**99.8**	**(66.3)**
Income tax expense	(8.5)	(21.8)	13.3
Net income	25.0	78.0	(53.0)
Net movements in regulatory balances	136.5	54.1	82.4
Net movements in regulatory balances arising from deferred taxes	2.4	8.9	(6.5)
Net income after net movements in regulatory balances	**163.9**	**141.0**	**22.9**

Additional information with respect to the Corporation (including its 2022 Annual Information Form and 2022 Fourth Quarter Financial Report) is available on **torontohydro.com**.

RATE BASE OVERVIEW

This schedule provides an overview of Toronto Hydro's rate base in accordance with section 2.2.1 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022) (the "Filing Requirements").

Continuity statements for Toronto Hydro's fixed assets, including interest during construction and overhead costs, are filed at Exhibit 2A, Tab 1, Schedule 2. Toronto Hydro confirms that:

- the continuity statements provide year-end balances and include interest during construction, and all overheads;
- the opening and closing balances of gross assets and accumulated depreciation that are used to calculate the fixed asset component of rate base correspond to the respective balances in the fixed asset continuity statements; and
- the continuity statements reconcile to calculated depreciation expenses (Exhibit 2A, Tab 2, Schedule 1) and are presented by asset account.

1. RATE BASE

Rate base consists of Net Book Value of PP&E (i.e. Gross Book Value minus accumulated depreciation) less Construction Work In-Progress (CWIP). Rate Base also includes a working capital allowance ("WCA") based on the cost of power and controllable expenses such as operations and maintenance, billing, collections and administration expenses.

Tables 1 and 2 below summarize Toronto Hydro's rate base values for 2020-2024 and 2025-2029 respectively, including opening and closing PP&E net book values ("NBV").

Table 1: 2020-2024 Rate Base Summary ($ Millions)

	OEB Approved	Actuals			Bridge	
	2020	2020	2021	2022	2023	2024
Opening PP&E NBV	4,229.4	4,233.2	4,419.2	4,628.1	4,893.9	5,244.3
In-Service Additions	527.4	447.9	485.2	554.4	607.9	606.3
Depreciation	(265.4)	(262.0)	(276.2)	(288.7)	(257.4)	(271.8)
Closing PP&E NBV	4,491.3	4,419.2	4,628.1	4,893.9	5,244.3	5,578.8
Monthly Avg PP&E NBV	**4,298.6**	**4,284.3**	**4,457.7**	**4,686.3**	**4,954.3**	**5,348.5**
Working Capital Allowance	216.2	249.8	217.2	220.7	221.1	230.3
Rate Base	**4,514.8**	**4,534.1**	**4,674.9**	**4,907.0**	**5,175.3**	**5,578.8**

Table 2: 2025-2029 Rate Base Summary ($ Millions)

	Forecast				
	2025	2026	2027	2028	2029
Opening PP&E NBV	5,578.8	5,934.5	6,325.6	6,794.1	7,219.0
In-Service Additions	642.1	691.7	789.8	769.2	859.5
Depreciation	(286.3)	(300.6)	(321.4)	(344.3)	(356.5)
Closing PP&E NBV	5,934.5	6,325.6	6,794.1	7,219.0	7,722.0
Monthly Avg PP&E NBV	**5,668.6**	**6,041.6**	**6,460.1**	**6,911.7**	**7,335.2**
Working Capital Allowance	231.5	237.1	242.5	250.8	255.6
Rate Base	**5,900.0**	**6,278.7**	**6,702.6**	**7,162.5**	**7,590.8**

As further explained below, rate base variances are primarily driven by changes in PP&E NBV due to in-service additions derived from the capital programs in Exhibit 2B. Depreciation and Working Capital Allowance variances are discussed in Exhibit 2A, Tab 2, Schedule 1, and Exhibit 2A, Tab 3, Schedule 1, respectively.

Actual rate base in 2020 was approximately $19.2 million higher than the rate base approved by the OEB in the last rebasing application (EB-2018-0165) because of a higher than forecasted WCA ($33.5 million), offset by lower than forecasted in-service additions ($14.3 million), resulting primarily from lower expenditures in System Renewal programs.

2. IN-SERVICE ADDITIONS (ISA)

Toronto Hydro's actual ISAs are calculated in accordance with its Capitalization policy set out in Exhibit 2A, Tab 4, Schedule 1. The methodology used to forecast ISAs by asset class is consistent with the last rebasing application (EB-2018-0165).[1]

Table 3 below compares the total in-service additions included in base rates per the 2020-2024 Draft Rate Order (DRO) in EB-2018-0165, and the 2020-2024 actual and forecasted in-service additions based on the actual and forecasted expenditure levels in Exhibit 2B. In accordance with the OEB's direction in EB-2018-0165, this information is provided at the investment category level.[2] Appendix A to this schedule provides an annual breakdown of Table 3.

Table 3: 2020-2024 In-Service Additions Variances ($ Millions)

	2020-2024 DRO	2020-2024 Actual/Bridge	Var. ($)	Var. (%)
System Access	469.1	621.7	152.7	32.5%
System Renewal	1,535.8	1,407.7	(128.1)	-8.3%
System Service	259.8	270.5	10.8	4.1%
General Plant	403.7	396.6	(7.1)	-1.8%
Other	5.1	5.2	0.1	1.1%
Net In-Service Additions	**2,673.4**	**2,701.7**	**28.3**	**1.1%**

Total in-service additions for 2020-2024 are expected to be approximately $28.3 million or 1 percent higher than the in-service additions per the DRO. The key variances are as follows:

[1] In the response to Undertaking JTC3.1 in the utility's last rebasing application, Toronto Hydro noted that the methodology to forecast ISA is subject to certain limitations which may undermine the veracity of these forecasts. For example, historical conversion ratios of capital expenditures to in-service additions to the program are based on aggregate values for distribution capital, and may not be entirely aligned with program level assumptions.
[2] EB-2018-0165, Decision and Order (December 19, 2019) at page 195.

System Access related in-service additions are forecasted to be $152.7 million greater than the amounts included in base rates per the DRO primarily due to increased expenditures in demand-driven programs such as Customer Connections (Exhibit 2B, Section E5.1) and Load Demand (Exhibit 2B, Section E5.3). Toronto Hydro had to make additional investments in these programs in order to fulfil its core obligations to connect new and expanded services to the grid, including a higher than anticipated volume of system access requests for large projects (>5 MVA demand) over this period. For more details about System Access variances please refer to Exhibit 2B, Section E4.1.1.

System Service related in-service additions are forecasted to be $10.8 million greater than the amounts included in base rates per the DRO primarily due to higher expenditures in the Stations Expansion program (Exhibit 2B, Section E7.4) related to Hydro One contribution for the Horner TS expansion project. For more details about System Service variances please refer to Exhibit 2B, Section E4.1.3.

System Renewal related expenditures are forecasted to be $128.1 million lower than the amounts included in base rates per the DRO primarily due to lower expenditures in the Underground System Renewal programs (Exhibit 2B, Section E6.2 and E6.3) and Overhead System Renewal program (Exhibit 2B, Section E6.5). Toronto Hydro decided to defer expenditures in these programs in an effort to manage capital funding pressures driven by the capital stretch factor and by higher than forecasted expenditures in System Access and Service as noted above. For more details about System Renewal variances please refer to Exhibit 2B, Section E4.1.2.

General Plant related in-service additions are forecasted to be $7.1 million lower than the amounts included in base rates per the DRO primarily due to lower expenditures in the

IT/OT Systems program (Exhibit 2B, Section E8.4) related to the decision to defer the Enterprise Resource Planning (ERP) upgrade based on new information that the vendor (SAP) will continue to support the current system until 2027 with extended support available until 2030. For more details about General Plant variances please refer to Exhibit 2B, Section E4.1.4.

3. PROPERTY, PLANT AND EQUIPMENT (PP&E)

Tables 4 and 5 below present a summary of Toronto Hydro's Gross and Net PP&E, before and after accumulated depreciation, for the current 2020-2024 rate period and future 2025-2029 rate period. Toronto Hydro confirms that the PP&E net book values (NBV) reported under the Reporting and Record-keeping Requirements (RRR) are aligned with the amounts utilized for rate base purposes.[3]

Table 4: 2020-2024 Gross and Net PP&E – Years Ending December 31 ($ Millions)

	Actual			Bridge	
	2020	2021	2022	2023	2024
Land and Buildings	185.4	190.5	205.3	222.1	229.9
Other Distribution Assets	505.7	560.4	674.0	722.8	815.8
General Plant	248.1	262.5	270.0	311.6	327.9
TS Primary Above 50	40.2	40.2	37.9	75.7	82.1
Distribution System	250.9	273.6	298.6	314.5	332.9
Poles, Wires	3,475.0	3,820.4	4,185.9	4,605.8	5,017.8
Contributions and Grants	(334.7)	(459.5)	(586.0)	(745.3)	(898.8)
Line Transformers	716.0	796.4	867.2	942.2	1,027.2
Services and Meters	379.9	398.3	418.4	439.9	476.5
Equipment	166.5	184.3	204.8	239.7	262.1

[3] In past applications, the OEB approved planned investments in certain assets that meet the OEB's definition for high voltage assets. This includes qualifying assets at the Copeland TS and contributions paid to HONI for work conducted on the transmission system. Toronto Hydro also proposes investments in high voltage assets in its 2025-2029 application. Once incurred, actual costs of such assets are separately reported annually as part of RRR (section 2.1.5.2).

	Actual			Bridge	
	2020	**2021**	**2022**	**2023**	**2024**
IT Assets	94.6	110.0	121.1	138.3	154.6
Gross Assets	**5,727.5**	**6,177.1**	**6,697.2**	**7,267.3**	**7,827.9**
Accumulated Depreciation	(1,308.4)	(1,548.9)	(1,803.4)	(2,023.0)	(2,249.2)
Closing PP&E NBV	**4,419.2**	**4,628.1**	**4,893.9**	**5,244.3**	**5,578.8**

Note: Variances due to rounding may exist

Table 5: 2025-2029 Gross and Net PP&E – Years Ending December 31 ($ Millions)

	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
Land and Buildings	237.7	249.1	268.4	279.9	302.3
Other Distribution Assets	877.7	940.3	1,036.6	1,102.5	1,210.3
General Plant	338.7	358.0	382.8	413.1	459.1
TS Primary Above 50	81.3	80.5	79.8	79.0	78.3
Distribution System	368.4	407.9	455.3	492.3	523.9
Poles, Wires	5,423.6	5,896.6	6,385.9	6,919.3	7,488.3
Contributions and Grants	(1,008.6)	(1,155.5)	(1,294.0)	(1,448.4)	(1,617.8)
Line Transformers	1,110.7	1,193.1	1,277.7	1,367.4	1,461.2
Services and Meters	526.6	584.8	647.6	699.0	733.9
Equipment	286.7	307.3	325.1	345.1	370.6
IT Assets	176.1	195.8	226.7	254.7	295.1
Gross Assets	**8,418.8**	**9,057.7**	**9,791.8**	**10,503.9**	**11,305.1**
Accumulated Depreciation	(2,484.3)	(2,732.1)	(2,997.8)	(3,284.9)	(3,583.2)
Closing PP&E NBV	**5,934.5**	**6,325.6**	**6,794.1**	**7,219.0**	**7,722.0**

Note: Variances due to rounding may exist

/C

3.1 2020 versus 2021 Actual

Table 6 below presents the 2020 versus 2021 actual PP&E NBV values by asset class.

Table 6: 2020 Historical versus 2021 Historical PP&E NBV ($ Millions)[4]

Asset Class	2020 Actual	2021 Actual	Variance ($)	Variance (%)
Land and Buildings	185.4	190.5	5.2	3%
Other Distribution Assets	505.7	560.4	54.7	11%
General Plant	248.1	262.5	14.5	6%
TS Primary Above 50	40.2	40.2	-	0%
Distribution System	250.9	273.6	22.7	9%
Poles, Wires	3,475.0	3,820.4	345.4	10%
Contributions and Grants	(334.7)	(459.5)	(124.8)	37%
Line Transformers	716.0	796.4	80.3	11%
Services and Meters	379.9	398.3	18.5	5%
Equipment	166.5	184.3	17.8	11%
IT Assets	94.6	110.0	15.3	16%
Gross Assets	**5,727.5**	**6,177.1**	**449.5**	**8%**
Accumulated Depreciation	(1,308.4)	(1,548.9)	(240.6)	18%
Closing PP&E NBV	**4,419.2**	**4,628.1**	**209.0**	**5%**

From 2020 to 2021, PP&E by asset class variances were as follows:

- **Land and Buildings Assets** increased by $5.2 million or 3 percent primarily due to in-service additions related to (1) Facilities Management and Security ($2.7 million) as detailed in Exhibit 2B, Section E8.2 and (2) Stations Renewal ($2.5 million) as detailed in Exhibit 2B, Section E6.6.
- **Other Distribution Assets** increased by $54.7 million or 11 percent, primarily due to (1) IT software additions ($24.4 million) as detailed in Exhibit 2B, Section E8.4 and (2) capital contributions paid to Hydro One ($18.2 million) as detailed in Exhibit 2B, Section E7.4.

[4] Further breakdown of the categories and amounts presented in Tables 3 to 7 is provided in fixed asset continuity schedules provided in Exhibit 2A, Tab 1, Schedule 2, Appendix 2-BA.

- **General Plant Assets** increased by $14.5 million or 6 percent primarily due to the in-service amounts related to Facilities Management and Security ($11.2 million) as detailed in Exhibit 2B, Section E8.2.
- **Distribution System Assets** increased by $22.7 million or 9 percent, primarily due to the completion of Stations Renewal projects ($20.9 million) as outlined Exhibit 2B, Section E6.6.
- **Poles and Wires Assets** increased by $345.4 million or 10 percent as a result of in-service additions from investments in the following programs: Customer Connections (Exhibit 2B, Section E5.1), Externally Initiated Plant Relocations & Expansions (Exhibit 2B, Section E5.2), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and the Overhead System Renewal Program (Exhibit 2B, Section E6.5). Of these programs, the largest increases were in the Customer Connections ($107.5 million) and Externally Initiated Plant Relocations & Expansions programs ($64 million) due to external factors.
- **Contributions and Grants** increased by $124.8 million or 37 percent due to customer and third-party contributions related to the Customer Connections and EIPRE programs. These contributions resulted in a reduction to NBV.
- **Line Transformers** increased by $80.3 million or 11 percent primarily from in-service additions related to Reactive and Corrective Capital program ($25.2 million) as outlined in Exhibit 2B, Section E6.7 and the Customer Connections program ($16.8 million) as outlined in Exhibit 2B, Section E5.1.
- **Services and Meter assets** increased by $18.5 million or 5 percent primarily due to the Customer Connections (Exhibit 2B, Section E5.1) and the Metering (Exhibit 2B, Section E5.4) programs.

- **Equipment Assets** increased by $17.8 million or 11 percent primarily due to investment in the Network Condition Monitoring & Control (Exhibit 2B, Section E7.3) and the Fleet and Equipment Services (Exhibit 2B, Section E8.3) programs.
- **IT assets** increased by $15.3 million or 16 percent primarily due to investment in hardware equipment within the IT/OT program (Exhibit 2B, Section E8.4).

3.2 2021 Historical versus 2022 Historical PP&E NBV

Table 7 below presents the 2020 versus 2021 actual PP&E NBV values by asset class.

Table 7: 2021 Historical versus 2022 Historical PP&E NBV ($ Millions)

	2021 Actual	2022 Actual	Variance ($)	Variance (%)
Land and Buildings	190.5	205.3	14.8	8%
Other Distribution Assets	560.4	674.0	113.6	20%
General Plant	262.5	270.0	7.5	3%
TS Primary Above 50	40.2	37.9	(2.3)	(6%)
Distribution System	273.6	298.6	25.0	9%
Poles, Wires	3,820.4	4,185.9	365.5	10%
Contributions and Grants	(459.5)	(586.0)	(126.4)	28%
Line Transformers	796.4	867.2	70.8	9%
Services and Meters	398.3	418.4	20.1	5%
Equipment	184.3	204.8	20.5	11%
IT Assets	110.0	121.1	11.1	10%
Gross Assets	**6,177.1**	**6,697.2**	**520.2**	**8%**
Accumulated Depreciation	(1,548.9)	(1,803.4)	(254.4)	16%
Closing PP&E NBV	**4,628.1**	**4,893.9**	**265.8**	**6%**

From 2021 to 2022, PP&E by asset class variances were as follows:

- **Land and Buildings Assets** increased by $14.8 million or 8 percent primarily due to investments in the Facilities Management and Security program (Exhibit 2B, Section E8.2).
- **Other Distribution Assets** increased by $113.6 million or 20 percent primarily due to capital contributions paid to Hydro One related to the expansion of Horner TS (Exhibit 2B, Section E7.4) and IT software additions (Exhibit 2B, Section E8.4).
- **General Plant Assets** increased by $7.5 million or 3 percent primarily due to the in-service amounts in the Facilities Management and Security program (Exhibit 2B, Section E8.2).
- **Distribution System Assets** increased by $25 million or 9 percent primarily due to in-service additions related to Copeland TS Phase 2 project within the Stations Expansion program (Exhibit 2B, Section E7.4).
- **Poles and Wires** increased by $365.5 million, or 10 percent, as a result of in-service additions from investments in the following programs: Customer Connections (Exhibit 2B, Section E5.1), Externally Initiated Plant Relocations & Expansion (Exhibit 2B, Section E5.2), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Load Demand (Exhibit 2B, Section E5.3), Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and the Overhead System Renewal Program (Exhibit 2B, Section E6.5). Of these programs, the largest increases were in the Customer Connections program ($99.2 million) and Externally Initiated Plant Relocations & Expansion ($80.8 million) due to external demand.
- **Contributions and grants** increased by $126.4 million or 28 percent due to customer and third-party contributions related to the Customer Connections and Externally Initiated Plant Relocations & Expansions programs. The contributions resulted in a reduction to NBV.

- **Line transformers** increased by $70.8 million or 9 percent primarily from in-service additions related to Reactive and Corrective Capital (Exhibit 2B, Section E6.7), Network System Renewal (Exhibit 2B, E6.4), Customer Connections (Exhibit 2B, Section E5.1) and Overhead System Renewal (Exhibit 2B, Section E6.5) programs.
- **Services and meter assets** increased by $20.1 million or 5 percent primarily due to the Customer Connections (Exhibit 2B, Section E5.1) and Metering (Exhibit 2B, Section E5.4) programs.
- **Equipment assets** increased by $20.5 million or 11 percent primarily due to investment in the Network Condition Monitoring & Control (Exhibit 2B, Section E7.3) and the Fleet and Equipment Services (Exhibit 2B, Section E8.3) programs.
- **IT assets** increased by $11.1 million or 10 percent primarily due to investment in hardware equipment within the IT/OT Systems program (Exhibit 2B, Section E8.4).

3.3 2022 Historical versus 2023 Bridge PP&E NBV

Table 8 below presents the 2022 actual versus 2023 bridge PP&E NBV values by asset class.

Table 8: 2022 Historical versus 2023 Bridge PP&E NBV ($ Millions)

	2022 Actual	2023 Bridge	Variance ($)	Variance (%)
Land and Buildings	205.3	222.1	16.8	8%
Other Distribution Assets	674.0	722.8	48.8	7%
General Plant	270.0	311.6	41.7	15%
TS Primary Above 50	37.9	75.7	37.8	100%
Distribution System	298.6	314.5	15.8	5%
Poles, Wires	4,185.9	4,605.8	419.8	10%
Contributions and Grants	(586.0)	(745.3)	(159.4)	27%
Line Transformers	867.2	942.2	75.0	9%
Services and Meters	418.4	439.9	21.4	5%

	2022 Actual	2023 Bridge	Variance ($)	Variance (%)
Equipment	204.8	239.7	34.9	17%
IT Assets	121.1	138.3	17.3	14%
Gross Assets	**6,697.2**	**7,267.3**	**570.1**	**9%**
Accumulated Depreciation	(1,803.4)	(2,023.0)	(219.6)	12%
Closing PP&E NBV	**4,893.9**	**5,244.3**	**350.5**	**7%**

From 2022 to 2023, PP&E by asset class variances are forecasted as follows:

- **Land and Buildings Assets** are forecasted to increase by $16.8 million or 8 percent primarily due to in-service amounts related to Copeland TS Phase 2 within the Stations Expansion program (Exhibit 2B, Section E7.4) and Facilities Management and Security (Exhibit 2B, Section E8.2)
- **Other Distribution Assets** are forecasted to increase by $48.8 million or 7 percent primarily due to IT software additions (Exhibit 2B, Section E8.4).
- **General Plant Assets** are forecasted to increase by $41.7 million or 15 percent primarily due to the in-service amounts related to Control Operations Reinforcement program (Exhibit 2B, Section E4.1.4) and the Facilities Management and Security program (Exhibit 2B, Section E8.2).
- **TS Primary Above 50** assets are forecasted to increase by $37.8 million or 100 percent due to the in-service amounts related to Copeland TS Phase 2 project in the Stations Expansion program (Exhibit 2B, Section E7.4).
- **Distribution System assets** are forecasted to increase by $15.8 million or 5 percent, primarily due to in-service additions related to Stations Renewal projects (Exhibit 2B, Section E6.6).
- **Poles and Wires Assets** are forecasted to increase by $419.8 million, or 10 percent, as a result of in-service additions from investments in the following programs: Customer Connections (Exhibit 2B, Section E5.1), Externally Initiated

Plant Relocations & Expansion (Exhibit 2B, Section E5.2), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and the Overhead System Renewal Program (Exhibit 2B, Section E6.5). Of these programs, the largest increases were from the Customer Connections ($137.4 million) and the Externally Initiated Plant Relocations & Expansion ($80.9 million) programs, followed by increases in planned renewal work as part the Underground System Renewal – Horseshoe program ($68.1 million) and other renewal work programs noted above.

- **Contributions and Grants** are forecasted to increase by $159.4 million or 27 percent due to customer and third-party contributions related to the Customer Connections and Externally Initiated Plant Relocations & Expansion programs. The contributions resulted in a reduction to NBV.
- **Line Transformers** are forecasted to increase by $75.0 million or 9 percent primarily due to Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and the Customer Connections (Exhibit 2B, Section E5.1) programs.
- **Services and Meter Assets** are forecasted to increase by $21.4 million or 5 percent primarily due to the Customer Connections (Exhibit 2B, Section E5.1) and the Metering (Exhibit 2B, Section E5.4) programs.
- **Equipment Assets** are forecasted to increase by $34.9 million or 17 percent, primarily due to investment in the Fleet and Equipment Services (Exhibit 2B, Section E8.3) and the Network Condition Monitoring & Control (Exhibit 2B, Section E7.3) programs.
- **IT assets** are forecasted to increase by $17.3 million or 14 percent primarily due to investment in hardware within the IT/OT program (Exhibit 2B, Section E8.4).

3.4 2023 Bridge versus 2024 Bridge PP&E NBV

Table 9 below presents the 2023 bridge versus 2024 bridge PP&E NBV values by asset class.

Table 9: 2023 Bridge versus 2024 Bridge PP&E NBV ($ Millions)

	2023 Bridge	2024 Bridge	Variance ($)	Variance (%)
Land and Buildings	222.1	229.9	7.8	3%
Other Distribution Assets	722.8	815.8	93.0	13%
General Plant	311.6	327.9	16.2	5%
TS Primary Above 50	75.7	82.1	6.4	8%
Distribution System	314.5	332.9	18.4	6%
Poles, Wires	4,605.8	5,017.8	412.1	9%
Contributions and Grants	(745.3)	(898.8)	(153.4)	21%
Line Transformers	942.2	1,027.2	85.0	9%
Services and Meters	439.9	476.5	36.6	8%
Equipment	239.7	262.1	22.4	9%
IT Assets	138.3	154.6	16.2	12%
Gross Assets	**7,267.3**	**7,827.9**	**560.6**	**8%**
Accumulated Depreciation	(2,023.0)	(2,249.2)	(226.2)	11%
Closing PP&E NBV	**5,244.3**	**5,578.8**	**334.4**	**6%**

From 2023 to 2024, PP&E by asset class variances are forecasted as follows:

- **Land and Buildings Assets** are forecasted to increase by $7.8 million or 3 percent primarily due to in-service amounts related to Facilities Management and Security (Exhibit 2B, Section E8.2).
- **Other Distribution Assets** are forecasted to increase by $93 million or 13 percent, primarily due to IT software additions (Exhibit 2B, Section E8.4), including the Customer Information System upgrade project ($64.7 million).

- **General Plant Assets** are forecasted to increase by $16.2 million or 5 percent primarily due to the in-service amounts related to the Facilities Management and Security program (Exhibit 2B, Section E8.2).
- **TS Primary Above 50** assets are forecasted to increase by $6.4 million or 8 percent due to the in-service amounts related to Copeland TS Phase 2 project in the Stations Expansion program (Exhibit 2B, Section E7.4).
- **Distribution System assets** are forecasted to increase by $18.4 million or 6 percent, primarily due to in-service additions related to Stations Renewal projects (Exhibit 2B, Section E6.6).
- **Poles and Wires Assets** are forecasted to increase $412.1 million or 9 percent as a result of in-service additions from investments in the following programs: Customer Connections (Exhibit 2B, Section E5.1), Externally Initiated Plant Relocations & Expansion (Exhibit 2B, Section E5.2), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and the Overhead System Renewal Program (Exhibit 2B, Section E6.5). Of these programs, the largest increases are forecasted in the Customer Connections ($125.6 million) and Externally Initiated Plant Relocations & Expansion ($78.5 million) programs, followed by increases in planned renewal work as part the Underground System Renewal – Horseshoe program ($69.9 million) and other renewal work programs noted above.
- **Contributions and Grants** are forecasted to increase by $153.4 million or 21 percent due to customer and third-party contributions related to the Customer Connections and Externally Initiated Plant Relocations & Expansion programs. The contributions resulted in a reduction to NBV.
- **Line Transformers** are forecasted to increase by $85.0 million or 9 percent primarily from in-service additions related to the Reactive and Corrective Capital

(Exhibit 2B, Section E6.7), Overhead System Renewal (Exhibit 2B, Section E5.1), Customer Connections (Exhibit 2B, Section E5.1) and Underground System Renewal- Horseshoe (Exhibit 2B, Section E6.2) programs.

- **Services and Meter Assets** are forecasted to increase by $36.6 million or 8 percent primarily due to the Metering program (Exhibit 2B, Section E5.4).
- **Equipment Assets** are forecasted to increase by $22.4 million or 9 percent, primarily due to investment in the Network Condition Monitoring & Control (Exhibit 2B, Section E7.3) and the Fleet and Equipment Services (Exhibit 2B, Section E8.3) programs.
- **IT assets** are forecasted to increase by $16.2 million or 12 percent, primarily due to investment in hardware within the IT/OT program (Exhibit 2B, Section E8.4).

3.5 2024 Bridge versus 2025 Forecast Year PP&E NBV

Table 10 below presents the 2024 bridge versus 2025 forecast PP&E NBV values by asset class.

Table 10: 2024 Bridge versus 2025 Forecast PP&E NBV ($ Millions)

	2024 Bridge	2025 Forecast	Variance ($)	Variance (%)
Land and Buildings	229.9	237.7	7.8	3.4%
Other Distribution Assets	815.8	877.7	61.9	7.6%
General Plant	327.9	338.7	10.8	3.3%
TS Primary Above 50	82.1	81.3	(0.8)	-0.9%
Distribution System	332.9	368.4	35.6	10.7%
Poles, Wires	5,017.8	5,423.6	405.8	8.1%
Contributions and Grants	(898.8)	(1,008.6)	(109.9)	12.2%
Line Transformers	1,027.2	1,110.7	83.5	8.1%
Services and Meters	476.5	526.6	50.1	10.5%
Equipment	262.1	286.7	24.6	9.4%

/C

	2024 Bridge	2025 Forecast	Variance ($)	Variance (%)
IT Assets	154.6	176.1	21.5	13.9%
Gross Assets	**7,827.9**	**8,418.8**	**590.9**	**7.5%**
Accumulated Depreciation	(2,249.2)	(2,484.3)	(235.2)	10.5%
Closing PP&E NBV	**5,578.8**	**5,934.5**	**355.7**	**6.4%**

/C

From 2024 to 2025, PP&E by asset class variances are forecasted as follows:

- **Land and Buildings Assets** are forecasted to increase by $7.8 million or 3.4 percent from in-service additions related to Facilities Management and Security (Exhibit 2B, Section E8.2) and Stations Renewal (Exhibit 2B, Section E6.6).
- **Other Distribution Assets** are forecasted to increase by $61.9 million or 7.6 percent primarily due to IT software additions (Exhibit 2B, Section E8.4), and capital contributions paid to Hydro One (Exhibit 2B, Section E7.4).
- **General Plant Assets** are forecasted to increase by $10.8 million or 3.3 percent primarily due to the in-service amounts related to the Facilities Management and Security program (Exhibit 2B, Section E8.2).
- **Distribution System assets** are forecasted to increase by $35.6 million or 10.7 percent, primarily due to in-service additions related to Stations Renewal projects (Exhibit 2B, Section E6.6).
- **Poles and Wires Assets** are forecasted to increase by $405.8 million or 8.1 percent as a result of in-service additions from investments in the following programs: Customer Connections (Exhibit 2B, Section E5.1), Externally Initiated Plant Relocations & Expansion (Exhibit 2B, Section E5.2), Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and the Overhead System Renewal Program (Exhibit 2B, Section E6.5). Of these programs, the largest increases are forecasted in the Customer Connections ($128.8 million) and Externally Initiated Plant Relocations & /C

Expansion ($73.4 million) programs, followed by increases planned renewal work as part the Underground System Renewal – Horseshoe program ($48.5 million) and other renewal work programs noted above.

- **Contributions and Grants** are forecasted to increase by $109.9 million or 12.2 percent due to customer and third-party contributions related to the Customer Connections and Externally Initiated Plant Relocations & Expansion programs. The contributions resulted in a reduction to NBV.
- **Line Transformers** are forecasted to increase by $83.5 million or 8.1 percent primarily from in-service additions related to Reactive and Corrective Capital (Exhibit 2B, Section E6.7) and Customer Connections ($16.8 million, Exhibit 2B, Section E5.1) programs.
- **Services and Meter Assets** are forecasted to increase by $50.1 million or 10.5 percent primarily due to the Metering program (Exhibit 2B, Section E5.4).
- **Equipment Assets** are forecasted to increase by $24.6 million or 9.4 percent, primarily due to investment in the Network Condition Monitoring & Control (Exhibit 2B, Section E7.3) and the Fleet and Equipment Services (Exhibit 2B, Section E8.3) programs. /C
- **IT assets** are forecasted increase by $21.5 million or 13.9 percent primarily due to investment in computer hardware within the IT/OT program (Exhibit 2B, Section E8.4).

3.6 2025 versus 2029 Forecast Year PP&E NBV

Table 11 below presents the 2025 forecast versus 2029 forecast PP&E NBV values by asset class.

Table 11: 2025 Forecast versus 2029 Forecast ($ Millions)

	2025 Forecast	2029 Forecast	Variance ($)	Variance (%)
Land and Buildings	237.7	302.3	64.7	27.2%
Other Distribution Assets	877.7	1,210.3	332.6	37.9%
General Plant	338.7	459.1	120.4	35.5%
TS Primary Above 50	81.3	78.3	(3.0)	-3.7%
Distribution System	368.4	523.9	155.5	42.2%
Poles, Wires	5,423.6	7,488.3	2,064.6	38.1%
Contributions and Grants	(1,008.6)	(1,617.8)	(609.1)	60.4%
Line Transformers	1,110.7	1,461.2	350.5	31.6%
Services and Meters	526.6	733.9	207.3	39.4%
Equipment	286.7	370.6	83.8	29.2%
IT Assets	176.1	295.1	119.0	67.6%
Gross Assets	**8,418.8**	**11,305.1**	**2,886.3**	**34.3%**
Accumulated Depreciation	(2,484.3)	(3,583.2)	(1,098.8)	44.2%
Closing PP&E NBV	**5,934.5**	**7,722.0**	**1,787.5**	**30.1%**

/C

From 2025 to 2029, PP&E by asset class variances are forecasted as follows:

- **Land and Buildings Assets** are forecasted to increase by $64.7 million or 27.2 percent, primarily from in-service additions related to Facilities Management and Security ($33 million) per Exhibit 2B, Section E8.2, the Stations Renewal work ($16.7 million) per Exhibit 2B, Section E6., and 6 the Downsview TS project ($15 million) per Exhibit 2B, Section E7.4.
- **Other Distribution Assets** are forecasted to increase by $332.6 million or 37.9 percent primarily due to the in-service amounts related to IT software additions ($155.3 million) per Exhibit 2B, Section E8.4, capital contributions paid to Hydro One ($84.4 million) per Exhibit 2B, Section E7.4, and Stations Renewal ($37.2 million) per Exhibit 2B, Section E6.6. /C /C /C

- **General Plant Assets** are forecasted to increase $120.4 million or 35.5 percent primarily due to the in-service amounts for Facilities Management and Security program ($80.4 million) per Exhibit 2B, Section E8.2, and the Enterprise Data Centre project ($37.5 million) per Exhibit 2B, Section E8.1.
- **TS Primary Above 50** are forecasted to decrease by $3 million or 3.7 percent due to depreciation expenses being higher than in-service additions.
- **Distribution System Assets** are forecasted to increase by $155.5 million or 42.2 percent primarily due to Stations Renewal projects ($95.8 million) per Exhibit 2B, Section E6.6 and work in the Metering program ($49.8 million) per Exhibit 2B, Section E5.4. /C
- **Poles and Wires Assets** are forecasted to increase by $2,064.6 million or 38.1 percent primarily due to: /C
    - Demand-related investments in the Customer Connections program ($593.2 million) per Exhibit 2B, Section E5.1, and the Externally Initiated Plant Relocations and Expansion program ($281.6 million) per Exhibit 2B, Section E5.2;
    - Planned renewal work in the Underground System Renewal – Horseshoe ($305.2 million) per Exhibit 2B, Section E6.2 and Overhead System Renewal ($147.3 million) per Exhibit 2B, Section E6.5.
- **Contributions and Grants** are forecasted to increase by $609.1 million or 60.4 percent due to customer and third-party contributions related to the Customer Connections and Externally Initiated Plant Relocations & Expansion programs. The contributions resulted in a reduction to NBV.
- **Line Transformers** are forecasted to increase by $350.5 million or 31.6 percent primarily from in-service additions related to Reactive and Corrective Capital program ($88.8 million) per Exhibit 2B, Section E6.7, the Customer Connections /C

program ($77.2 million) per Exhibit 2B, Section E5.1, the Overhead System Renewal program ($61.8 million) per Exhibit 2B, Section E6.5, and the Network System Renewal program ($49.7 million) per Exhibit 2B, Section E6.4.

- **Services and Meter Assets** are forecasted to increase by $207.3 million or 39.4 percent primarily due to the implementation of the Advanced Metering Infrastructure (AMI2.0) project per Exhibit 2B, Section E5.4.
- **Equipment Assets** are forecasted to increase by $83.8 million or 29.2 percent, primarily due to investment in the Network Condition Monitoring & Control (Exhibit 2B, Section E7.3) and the Fleet and Equipment Services (Exhibit 2B, Section E8.3) programs. /C
- **IT Assets** are forecasted to increase by $119.0 million or 67.6 percent primarily due to investment in hardware equipment ($85.3 million) per the IT/OT program in Exhibit 2B, Section E8.4, and the Enterprise Data Centre project ($32.7 million) per Exhibit 2B, Section E8.1.

DEPRECIATION AND AMORTIZATION

This schedule provides information about Toronto Hydro's depreciation and amortization rates and expenses. Toronto Hydro converted to International Financial Reporting Standards ("IFRS") effective January 1, 2015. This application represents Toronto Hydro's third rebasing application under Modified IFRS ("MIFRS").

1. FILING REQUIREMENTS

In accordance with s. 2.2.4 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022), this schedule provides the following information:

- Details regarding depreciation, amortization and depletion by asset group for the current (2020-2024) and future (2025-2029) rate periods;
- A description of Toronto Hydro's depreciation and amortization practices and a summary of the changes implemented since the utility's last rebasing application;
- An explanation of Toronto Hydro's variance from the "half-year rule" regarding the calculation of depreciation expense;
- An explanation to reconcile methodological differences between Toronto Hydro's depreciation expense and OEB Appendix 2-C; and
- Information about the utility's decommissioning provision and any associated depreciation or accretion expenses in relation to the decommissioning provision.

2. DEPRECIATION EXPENSE DETAILS

Appendix A to this schedule provides a summary of depreciation expense by Uniform System of Accounts for the current (2020-2024) and future (2025-2029) rate periods. These amounts include derecognition as described in Exhibit 2A, Tab 2, Schedule 2.

3. DEPRECIATION AND AMORTIZATION

In accordance with the OEB's Accounting Procedures Handbook for Electricity Distributors (the "APH"), Toronto Hydro depreciates and amortizes its assets on a straight-line basis over the estimated useful lives of the assets. Tables 1 and 2 below provide Toronto Hydro's annual depreciation and amortization rates by asset category for the current (2020-2024) and future (2025-2029) rate periods.

Table 1: Property, Plant, and Equipment Depreciation Rates (%)[1]

Asset Category	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge	2025-29 Forecast
Distribution Lines	1.7 - 5.0	1.7 - 5.0	1.7 - 5.0	1.5 - 5	1.5 - 5	1.5 - 5
Transformers	3.3 - 5.0	3.3 - 5.0	3.3 - 5.0	2.9 - 3.3	2.9 - 3.3	2.9 - 3.3
Meters	2.5 - 6.7	2.5 - 6.7	2.5 - 6.7	2.5 - 6.7	2.5 - 6.7	2.5 - 6.7
Stations	2.5 - 10.0	2.5 - 10.0	2.0 - 10.0	2.0 - 10.0	2.0 - 10.0	2.0 - 10.0
Buildings	1.3 - 5.0	1.3 - 5.0	1.3 - 5.0	1.5 - 10.0	1.5 - 10.0	1.5 - 10.0
Other Capital Assets	4.0 - 25.0	4.0 - 25.0	4.0 - 25.0	4.0 - 25.0	4.0 - 25.0	4.0 - 25.0
Right-of-use assets	1.0 - 11.1	1.0 - 11.1	1.0 - 11.1	1.0 - 11.1	1.0 - 11.1	1.0 - 11.1

Table 2: Intangible Assets Amortization Rates (%)

Asset Category	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge	2025-29 Forecast
Computer Software	10.0 - 25.0	10.0 - 25.0	10.0 - 25.0	10.0 - 25.0	10.0 - 25.0	10.0 - 25.0
Contributions	4.0	4.0	4.0	4.0	4.0	4.0

[1] Toronto Hydro added new asset classes and made minor presentation changes to the grouping of asset categories related to depreciation. Specifically: (1) the Streetlighting and Signal Systems and Storage Battery Equipment assets were rolled into the Other Capital asset category; and (2) assets under the Building category were re-categorized to better align with actual use.

3.1 Depreciation Study

In accordance with the OEB's decision in the 2020-2024 Rate Application (EB-2018-0165), Toronto Hydro retained Concentric Advisors, ULC ("Concentric") to complete a Depreciation study, which is filed as Appendix D to this schedule (the "Study"). The Study resulted in changes to depreciation rates effective January 1, 2023.

As summarized in Appendix D at Tables 1 – 3, the financial average service lives of six asset classes were shortened by the Study, and the financial average service lives of 73 asset were lengthened by Study, resulting in a significant overall reduction in depreciation expenses. Concentric concludes at section 1, page 1 of the report in Appendix D, that the lengthening of average service lives is consistent with trends observed throughout the North American electric industry, due to many factors including the increased focus of utilities in maintaining and extending the life of infrastructure.

At Toronto Hydro's request, in the 2023 Decision and Rate Order (EB-2022-0065) issued on December 8, 2022, the OEB approved a new variance account ("Useful Life Changes") "*to separately track the difference in revenue requirement impacts between the existing and updated depreciation rates over the 2023 and 2024 period, in a new sub-account of its existing capital-related revenue requirement variance account (CRRRVA)*." The total revenue requirement impact of the change in depreciation rates using Toronto Hydro's proposed approach is $136.5 million as of the end of 2024. For further details about the calculation of the balance, including a comparison of Toronto Hydro's proposed approach and the methodology proposed by OEB Staff, please refer to Exhibit 9, Tab 1, Schedule 1.

Appendix 2-BB contains the updated useful lives. Assets that fall outside the Kinectrics Report useful life ranges are supported by the Study.

3.2 Variance from Half-Year Rule

Toronto Hydro calculates depreciation based on the month that an asset comes into service, rather than on the basis of the half-year rule, which assumes that all asset additions are put into service in the middle of the fiscal year. Similarly, Toronto Hydro calculates depreciation associated with assets that are retired, transferred or become fully depreciated within a given year based on the month of transaction. This practice is consistent with past rate applications reviewed by the OEB.

4. DECOMMISSIONING PROVISION

Toronto Hydro recognizes liabilities for the future removal and handling costs for contamination in distribution equipment and for the future environmental remediation of certain properties (collectively known as "decommissioning provisions") in accordance with Article 410 of the OEB Accounting Procedures Handbook for Electricity Distributors (the "APH").

A decommissioning provision is recognized at the time that the obligation arises. Initially, Toronto Hydro measures the liability at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the utility depreciates the capitalized amount over the useful life of the related asset and the liability is adjusted quarterly for the discount applied upon initial recognition of the liability ("accretion expense") and for changes in the underlying assumptions.

Tables 3 and 4 below sets out Toronto Hydro's decommissioning costs and the related depreciation expense for the current (2020-2024) and future (2025-2029) rate periods. Tables 5 and 6 below shows the corresponding decommissioning liability and related

accretion expense over the same periods. The methodology to forecast decommissioning provisions is consistent with the last rebasing application.[2]

Table 3: Actual and Bridge Decommissioning Costs & Related Depreciation Expense ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge
Decommissioning Costs	0.7	0.5	0.2	0.2	0.1
Related Depreciation Expense	0.1	0.1	0.0	0.0	0.0

Table 4: Forecast Decommissioning Costs & Related Depreciation Expense ($ Millions)

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Decommissioning Costs	0.1	0.0	(0.0)	(0.0)	(0.1)
Related Depreciation Expense	0.0	0.1	0.0	0.0	0.0

Table 5: Actual and Bridge Decommissioning Liability & Related Accretion Expense ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge
Decommissioning Liability	1.4	1.1	0.8	0.6	0.5
Related Accretion Expense	-	-	-	-	-

Table 6: Forecast Decommissioning Liability & Related Accretion Expense ($ Millions)

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Decommissioning Liability	0.5	0.5	0.5	0.5	0.4
Related Accretion Expense	-	-	-	-	-

[2] EB-2018-0165 at Exhibit 4B, Tab 1, Schedule 1.

5. DEPRECIATION AND AMORTIZATION EXPENSE

Tables 7 and 8 below summarize the depreciation and amortization expense reflected in the Revenue Requirement presented in Exhibit 6, Tab 1, Schedule 1 and in OEB Appendix 2-BA at Exhibit 2A, Tab 1, Schedule 2.

Table 7: Depreciation and Amortization Expense[3] 2020 to 2024 ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge
Depreciation and Amortization Expense[4]	237.8	250.7	262.0	229.0	237.2

Table 8: Depreciation and Amortization Expense[5] 2025 to 2029 ($ Millions)

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Depreciation and Amortization Expense[6]	247.4	260.1	278.5	300.1	311.2

/C

Depreciation and amortization expense results from detailed calculations by asset class which are determined through the utility's enterprise financial system for historical amounts, and financial models for the bridge and forecast years. This method incorporates the depreciation and amortization rates presented in Tables 1 and 2 above, and considers the actual and forecasted timing of asset additions and removals from service.

The year-over-year increases in depreciation and amortization expense summarized above are primarily due to Toronto Hydro's in-service asset additions summarized in Exhibit 2A,

[3] Includes depreciation of the decommissioning costs and excludes derecognition. See Exhibit 2A, Tab 2, Schedule 2 for information about asset derecognition.
[4] See Exhibit 2A, Tab 2, Schedule 1, Appendix A for additional information.
[5] Includes depreciation of the decommissioning costs and excludes derecognition. See Exhibit 2A, Tab 2, Schedule 2 for information about asset derecognition.
[6] See Exhibit 2A, Tab 2, Schedule 1, Appendix A for additional information.

Tab 1, Schedule 1, with the exception of 2022 versus 2023 where there is a decrease as a result of implementing the revised rates resulting from the Study.

5.1 OEB Appendix 2-C

OEB's Appendix 2-C is filed as Appendix B to this schedule. The utility notes that the depreciation and amortization values in Appendix 2-C are based on broad assumptions. As a result, differences in depreciation and amortization values calculated by the financial system and using the formulas in Appendix 2-C are expected. For example, Appendix 2-C assumes depreciation in the first year, for all assets placed into service, begins at mid-year while Toronto Hydro depreciates assets from the month they are capitalized. In addition, applying broad depreciation assumptions to assets within an account that contains assets with varying remaining useful lives depending on when they were put in-service, also creates differences in depreciation and amortization in Appendix 2-C.

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES
APPLICABLE TO ASSETS IN SERVICE

July 2023

Prepared for Toronto Hydro

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July 31, 2023

Toronto Hydro-Electric System Limited
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Attention:
Elias Lyberogiannis, EVP Planning and Chief Engineering and Modernization Officer;
Celine Arsenault, EVP and Chief Financial Officer; *and*
Sheikh Nahyaan, EVP, Customer Care and Chief Information Officer

Dear Elias, Celine and Sheikh,

Pursuant to your request, we conducted a review and assessment of the regulated life estimates related to the Toronto Hydro assets as of December 31, 2022. Our report presents a description of the methods used in the estimation of depreciation, the statistical analysis of service life and the summary of annual depreciation expense.

We gratefully acknowledge the assistance of Toronto Hydro personnel in the completion of the review.

Should you have any questions or concerns, please do not hesitate to contact me directly at 587.997.6489

Yours truly,

Concentric Advisors, ULC

Larry E. Kennedy
Senior Vice President

Amanda Nori
Senior Project Manager

LEK/ta
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SECTION 1

1 STUDY HIGHLIGHTS

Pursuant to Toronto Hydro-Electric System's ("Toronto Hydro" or the "Company") request, Concentric Advisors, ULC ("Concentric") conducted a depreciation study related to the electric distribution and general plant accounts, as of December 31, 2022.

The purpose of this study was to determine the average service lives, whole life annual accrual percentages, and remaining life accrual amount related to the return of original cost for ratemaking objectives based on assets in-service at December 31, 2023 and December 31, 2024.

The depreciation study sought determination if the current average service life estimates are providing an appropriate return of investment over the useful life of the assets, and provides recommendation for accounts where it is considered that the current average service life estimates require adjustment.

The consideration of the above included preparation of detailed historic retirement patterns, in depth discussion with internal Toronto Hydro subject matter experts and management staff, and a review of Canadian peer electric distribution utilities.

Based on the above review, Concentric recommends the average service lives set forth herein applied specifically to assets in service, as of December 31, 2023, and December 31, 2024 as summarized in Tables 1 and 2 in Section 4 of this report by account detail. Supporting data and calculations are provided as well.

This study recommends the shortening of the financial average service life in six accounts, and the lengthening of the financial average service lives in 73 accounts. This lengthening of average service lives is consistent with trends throughout the North American electric industry and is due to many factors including the increased focus of utilities industry wide in maintaining and extending the life of infrastructure. The specific reasons for the average service life changes for each of the large accounts are discussed in Section 3.4.

Finally, this study results in an annual depreciation expense accrual related to the recovery of original cost is forecast to be $222.1 million, when applied to depreciable distribution and common assets study balances, as of January 1, 2023, of $4.907 billion. Annual depreciation expense accrual related to the recovery of original cost is forecast to be $205 million, when applied to depreciable distribution and common assets study balances, as of January 1, 2024, of $4.685 billion. The study results are summarized at an annual level as follows:

SUMMARY OF NET BOOK VALUE AND ACCRUAL AMOUNTS

Depreciation Study Date	Net Book Value	Annual Accrual
January 1, 2023	$4,907,165,802	$222,093,476
January 1, 2024	$4,685,072,326	$205,049,475

1.1 BASIS OF STUDY

1.1.1 Scope

Concentric has been retained by Toronto Hydro to develop reasonable and appropriate average service life estimates for use in the estimated depreciation calculations for the purpose of determining the annual regulated revenue requirement and for use in financial accounting statements. The review included the analysis based on distribution and common assets in service as of December 31, 2022 and resulting impacts of the results of this study were applied specifically to distribution and common assets in service as of January 1, 2023 and January 1, 2024. This report sets forth the findings of our independent review. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates.

The results of this study will be implemented on an individual asset level within the Toronto Hydro accounting system on a remaining life basis. This is a continuation of the accounting practice of Toronto Hydro. Concentric notes that original cost amounts within the Toronto Hydro accounting system have been reset to the then existing net book value during International Financial Reporting Standards ("IFRS") based implementations. Within this implementation, the net book value of the asset amounts were not changed, however the original cost was reset to the then existing net book value and the accumulated depreciation balances were reset to zero. As such, the continued use of the remaining life calculations applied to each specific asset is reasonable and continues to be the appropriate method of depreciation expense calculation.

The Straight-Line method, Average Life Group ("ALG") procedure, applied on a remaining life basis as used within the Toronto Hydro accounting system is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. The calculations as applied within the Toronto Hydro systems are on an individual asset basis.

As part of this study, Concentric Advisors reviewed the operating considerations and typical asset configurations throughout the Toronto Hydro distribution system, through the completion of detailed operational staff discussions. Site tours of Toronto Hydro's system were completed in March of 2023 including visits to the Toronto Hydro office on Commissioners Street, the Control Room, the Windsor Station assets and the Strachan Substation.

SECTION 2

2 PLAN OF STUDY

This study is presented in the following order:

Section 1:	Study Highlights, presents a brief summary of the depreciation study and results
Section 2:	Contains statements with respect to the plan and the Basis of the Study
Section 3:	Development of the Required Average Service Life Estimates, presents descriptions of the methods used and factors considered in the service life study
Section 4:	Results of Study, presents summaries by depreciable group of annual depreciation in Tables 1, 2 and 3
Section 5:	Presents the results of the Retirement Rate Statistics
Section 6:	Estimation of Survivor Curves, is an overview of Iowa curves and the Retirement Rate Analysis

2.1 Depreciation

A full and comprehensive depreciation study includes the following components:

1. supported recommendations regarding Average Service Life estimates for each account; and
2. a document explaining the procedures followed and justifying the results in a format suitable for submission to senior management and regulatory authorities.

A diagram of the nine primary processes followed by Concentric in the development of the depreciation study is provided below. Each of the steps is undertaken by Concentric using proprietary software.



2.2 Information Provided by Toronto Hydro

Toronto Hydro has provided Concentric with required information, as of December 31, 2022, for all accounts being studied. This information has been compiled from the distribution and common assets accounting records and includes the following:

- current balances by vintage year for each account (aged balances). The balances provide the amount of investment sorted by installation year currently in operation. This file is only inclusive of current distribution and common assets in service and does not include any retirement information; and
- retirement transactions for all accounts. The transactions include information regarding the transaction year of the retirement, the installation year of the asset being retired, and the original cost of the asset being retired.

2.3 Procedures Performed

The above data was reviewed and reconciled to Company control schedules to ensure accuracy and reasonableness. These checks include that the surviving investment by account equals (or can be reconciled to) the Company's gross distribution and common assets in service and accumulated depreciation ledger balances. In addition, Concentric performed the following procedures to form the basis of the results of this study:

- confirm accounting policies being followed in accordance with International Financial Reporting Standards principles;
- conduct interviews with Toronto Hydro personnel to obtain understanding of company operations;
- completed an actuarial analysis for all depreciable accounts; and
- comparison against industry peers that operate facilities similar to Toronto Hydro's regulated assets.

SECTION 3

3 DEVELOPMENT OF DEPRECIATION RATES

3.1 Depreciation

Depreciation, as applied to depreciable assets, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of assets in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and, in the case of electric companies, the exhaustion of natural resources.[1]

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a time period by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the time over which the fixed capital cost is allocated to the cost of service, is equal to the time over which an item renders service – that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line method of depreciation.

When considering the action of the elements, the average service life calculations have considered large catastrophic events that have occurred and impacted the life estimates of utilities across North America. The average service life of utilities has been influenced by events including:

- forest fires;
- earthquakes;
- tornadoes;
- ice storms;
- wind-storms;
- large scale flooding;
- fires;
- lightning;
- intentional actions of third parties;
- hoar frost; and
- other forces of nature.

Toronto Hydro continues to determine depreciation using the Straight-Line method for all distribution and common assets comprising regulated assets, based on the Average Life Group Procedure – Remaining Life Technique. The Average Life Group Procedure is the most commonly used depreciation procedure for North American utilities, whereby one average service life estimate is applied to all assets and vintages within the asset class. The Remaining Life Technique calculates depreciation on the basis of recovering the net book value of the investment over the remaining life

[1] Federal Energy Regulatory Commission -Part 201- Uniform System of Accounts Prescribed for Electric Companies Subject to the Provisions of the Electric Act Definitions

of an asset, or group of assets, with no provision for separate accumulated depreciation true-up. As such, a common life estimate is applied to each of the assets. Concentric finds the application of the Straight-Line method and the Average Life Group Procedure – Remaining Life Technique results in a reasonable recovery of Toronto Hydro's capital investment over time and recommends their continued application.

3.2 Estimation of Average Service Life

3.2.1 Average Service Life

The use of an average service life or a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. The Iowa curves *"…were sorted into three groups according to whether the mode was to the left, approximately coincident with, or to the right of the average-life ordinate. The curves in each of these three groups were then sub-classified in accordance with the height of the mode, taking also into consideration the distance of the mode to the left or right of the average life."* [2] The Iowa curves are described as L-type (i.e. left-moded), R-type (i.e. right-moded), and S-type (i.e. symmetrical). Further development resulted in the introduction of O-type (i.e. origin-moded curves) where the greatest frequency of retirement occurs at the origin, or immediately after age zero. Individual type curves are further depicted with numerical subscripts which represent the relative heights of the modes of the frequency curves within each family.

The program that is used by Concentric for statistical smooth curve fitting utilizes an internal "goodness-of-fit" criterion known as the Residual Measure. This Residual Measure is based on a least squares solution of the differences between the stub curve (or original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve.

The criterion of goodness-of-fit is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The residual measure, or standard error of estimate, shown in the output format is the square root of this mean square. As such, the lower the Residual Measure the better the statistical fit between the analyzed Iowa curve and the observed data points. Concentric follows the widely used practice of fitting Iowa curves up to one percent of the maximum exposures. This standard practice is utilized to minimize the influence of typically small retirements applied to similarly small exposures which may unduly affect the Iowa curve fitting process. However, Concentric will recognize the observed data points beyond the one percent of maximum exposures if it is determined that the additional data is a valid consideration for life recommendation.

[2] Robley Winfrey, Statistical Analyses of Industrial Property Retirements, Bulletin 125 revised (Engineering Research Institute, Iowa State University, 1935) 65

A discussion of the general concept of survivor curves and retirement rate method is presented in Section 6.

Concentric notes that original cost amounts within the Toronto Hydro accounting system have been reset to the then existing net book value during International Financial Reporting Standards ("IFRS") based implementation in 2014. Within these implementations, the net book value of the asset amounts were not changed, however the original cost was reset to the then existing net book value and the accumulated depreciation balances were reset to zero. As such, the retirement rate analysis only considered retirement transactions that occurred after 2014 in order to avoid comparing dollars of retirement before the IFRS adjustment to the exposures calculated after the adjustments. Consequently, Concentric placed limited weighting on the results of the retirement rate analysis.

The service life used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life estimates from Concentric's studies of other electric utilities. The use of survivor curves, to reflect the expected dispersion of retirement, provides a consistent method of estimating depreciation for assets. Iowa type survivor curves were used to depict the estimated survivor curves for the distribution and common assets accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the distribution and common assets accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data and the probable future. Probable future expectations included management and operational staff interviews. The combination of the historical experience and the probable future expectations yielded estimated survivor curves from which the average service lives were derived.

The resultant depreciation rates are summarized in the applicable table of this study (Section 4). The depreciation rates should be reviewed periodically to reflect the changes that result from distribution and common assets and reserve account activity.

3.2.2 Operations Discussions

Discussions with operations representatives undertaken as part of this study provided Concentric with an understanding of the type of assets in service for the electric system. These discussions provide Concentric with the necessary background to make an assessment of the physical installations of the Toronto Hydro distribution and common assets, and to understand the type of distribution and common assets in service and the operating conditions of the facilities.

Operational interviews were undertaken to understand the historic operating conditions that have led to retirement of distribution and common assets in the past and to understand the current condition of the assets which may impact future retirement plans. Operational interviews covered the following topics:

- Operating history of assets in service;

- Replacement history of major asset components and review of any significant retirement programs;
- General operating experience of the major asset components;
- Review of any life restricting operational issues;
- Review of instances where advancements in technology may cause changes to average service life indications; and
- Discussions of the manner in which Toronto Hydro's assets may differ from peer assets.

3.2.3 Peer Analysis

In order to provide a comparison for each account grouping, Concentric selected a peer group of companies to use in the development of average service lives. The companies selected for comparison were all companies for which Concentric has recently completed depreciation studies relating to Canadian electric generation, transmission, and/or distribution plants. As such, Concentric was able to make a meaningful comparison giving consideration to factors such as, capitalization and retirement policies, maintenance practices, and general operational practices. The companies selected for comparison were:

- BC Hydro;
- ENMAX;
- Newfoundland and Labrador Hydro Corporation (NALCOR);
- Northwest Territories Power Corporation;
- Manitoba Hydro;
- Hydro One; and
- New Brunswick Power.

In addition to the above, Concentric reviewed the 2010 Kinetrics Study used for the determination of depreciation parameters throughout the province of Ontario. The above studies provided Concentric Advisors with a comparable base of average service life estimates to use in the development of the service life estimates for Toronto Hydro's asset classes through Concentric's professional judgement.

3.2.4 Professional Judgement

The use of professional judgment in the development of average service life estimates is a practice that is appropriate and has been used for many years in North American regulatory jurisdictions. When available, the use of statistical analysis of the historic retirement transactions combined with the use of professional judgment, which includes review of accounting procedures and practices, use of operational staff interviews, review of prior studies, and review of the approved life estimates of peer companies, provides the most complete method of service life analysis.

3.3 Account Reorganization

Concentric reviewed the account structure currently being used by Toronto Hydro to find accounts where duplication may exist. This was done to ensure efficiency within the accounting practices and reduce regulatory burden.

FACILITIES ACCOUNTS

2023 Net Book Value	Previously Approved Life	Concentric Recommended Life
$341,859,631	Varies	Varies

The assets in these accounts relate to facilities owned by Toronto Hydro. These accounts contain a variety of asset types with differing average lives. Through the completion of the depreciation study, Concentric was made aware that the currently utilized account structure for facilities was leading to non-homogeneous assets being grouped together. Concentric recommends Toronto Hydro examine the facilities accounts and create a set of accounts that better aligns with the actual use of facilities assets. In discussion with Toronto Hydro operations and management, Concentric recommends the following account structure be created:

Account Name	Assets Included	Proposed Asset Life
Buildings - Exterior	Landscape Parking Roadway Fencing Signage Exterior Electrical Exterior Lighting	15
Interior Finishings	Carpets Interior Walls Lighting Cubicles Interior Security Systems Window Coverings Electronic Equipment	10
Buildings – Auxiliary	Roofs HVAC Systems Elevators Washroom Facilities Wiring Fire Fighting Systems Exterior Security Systems	20

Account Name	Assets Included	Proposed Asset Life
Buildings – Other – 5 Years	Facilities Technology Assets	5
Buildings – Other – 10 Years	Interior Cameras Kitchen Facilities	10
Buildings – Other – 30 Years	Windows Major Building Structural Components Exterior Cladding	30
Buildings – Other – 65 Years	Building shell Structure Foundations	65

3.4 Average Service Life Assessments

Concentric has reviewed the average service life estimates for Toronto Hydro's asset categories, based on December 31, 2022 asset values.

The following discussion, dealing with a number of accounts which comprise the majority of the investment analyzed, presents an overview of the factors considered by Concentric in the determination of the average service life estimates. The survivor curve estimates for the remainder of the accounts not discussed in the following sections were based on similar considerations.

ACCOUNT 2011 – TRANSFORMER STATION EQUIPMENT – POWER TRANSFORMERS

2023 Net Book Value	Investment %	Previously Approved Accounting Life	Concentric Recommended Life
$18,143,761	0.37%	32	45-R3

The assets in this account relate to transformers located within power transforming stations. There are stations throughout the Toronto Hydro system, where power is generally reduced from 27.6 kV. The transformers located within these stations are replaced based on age and asset health condition assessments. There are no transformers containing PCBs.

The net book value in Transformer Station Equipment – Power Transformers is approximately $18.1 million, representing 0.37 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1995 through 2022 were analyzed by the retirement rate method. There were $2.2 million in retirements recorded in 2022. The Iowa 45-R3 provides a residual measure of 0.1908 as depicted on page 5-41. A review of peer Canadian electric distribution utilities indicates a range of 30 to 55 years. The 2010 Kinetrics report suggested a range of 30 – 60 years. The accounting life for this account has historically been 32 years and the engineering SMEs have historically used a life of 44 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 45 years is reasonable. Based on the above, Concentric recommends the Iowa 45-R3 to represent the future expectations for the investment in this account.

ACCOUNT 2111 – SUBSTATION EQUIPMENT – OUTDOOR BREAKER

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$22,307,820	0.46%	30	45-R3

The assets in this account relate to a combination of oil circuit breakers, air blast breakers, air magnetic breakers, and vacuum breakers located at municipal stations throughout the Toronto Hydro service area. There is an ongoing retirement program related to the oil circuit breakers which is expected to be completed in the next three years, and another program related to the air blast breakers which is expected to be completed by 2030. When assets are retired, it is Toronto Hydro standard to replace the breakers with vacuum breakers.

The net book value in Substation Equipment – Outdoor Breakers is approximately $22.3 million, representing 0.46 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1985 through 2022 were analyzed by the retirement rate method. Retirements of $506 thousand were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-69. The Iowa 45-R3 provides a residual measure of 0.3521. A review of peer Canadian electric distribution utilities indicates a range of 42 to 45 years. The 2010 Kinetrics report suggested a range of 35 – 65 years. The accounting life for this account has historically been 30 years and the engineering SMEs have historically used an average life of 45 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 45 years is reasonable. Based on the above, Concentric recommends the Iowa 45-R3 to represent the future expectations for the investment in this account.

ACCOUNT 2113 – SUBSTATION EQUIPMENT – INDOOR BREAKER

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$12,192,523	0.25%	30	45-R3

The assets in this account relate to a combination of oil circuit breakers, air blast breakers, air magnetic breakers, and vacuum breakers located at municipal stations throughout the Toronto Hydro service area. There is an ongoing retirement program related to the oil circuit breakers which is expected to be completed in the next three year, and another program related to the air blast breakers which is expected to be completed by 2030. When assets are retired, it is Toronto Hydro standard to replace the breakers with vacuum breakers.

The net book value in Substation Equipment – Indoor Breakers is approximately $12.2 million, representing 0.25 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1985 through 2022 were analyzed by the retirement rate method. Retirements of $1.4 million were recorded for the period 2018 through 2022, resulting in actual observed data points as depicted on page 5-72. The Iowa 45-R3 provides a residual measure of 0.5799. A review of peer Canadian electric distribution utilities indicates a range of 42 to 45 years. The 2010 Kinetrics report suggested a range of 35 – 65 years. The

accounting life for this account has historically been 30 years and the engineering SMEs have historically used an average life of 43 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 45 years is reasonable. Based on the above, Concentric recommends the Iowa 45-R3 to represent the future expectations for the investment in this account.

ACCOUNT 2117 – SUBSTATION EQUIPMENT – SWITCHGEAR AIR

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$64,195,591	1.32%	40	50-R3

The assets in this account relate to the air switches located at municipal stations throughout the Toronto Hydro area.

The net book value in Substation Equipment – Switchgear Air is approximately $64.2 million, representing 1.32 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1986 through 2022 were analyzed by the retirement rate method. Retirements of $150 thousand were recorded for the period 2018 through 2021, resulting in actual observed data points as depicted on page 5-77. The Iowa 50-R3 provides a residual measure of 0.6431. A review of peer Canadian electric distribution utilities indicates a range of 38 to 45 years. The 2010 Kinetrics report suggested a range of 30 – 60 years. The accounting life for this account has historically been 40 years and the engineering SMEs have historically used a life of 50 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 50 years is reasonable. Based on the above, Concentric recommends the Iowa 50-R3 to represent the future expectations for the investment in this account.

ACCOUNT 2119 – SUBSTATION EQUIPMENT – SWITCHGEAR GIS

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$38,824,443	0.80%	40	50-R3

The assets in this account relate to the GIS switches located at municipal stations throughout the Toronto Hydro area.

The net book value in Substation Equipment – Switchgear GIS is approximately $38.8 million, representing 0.80 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1986 through 2022 were analyzed by the retirement rate method. There were no retirements recorded through 2022. A review of peer Canadian electric distribution utilities indicates a range of 38 to 45 years. The 2010 Kinetrics report suggested a range of 30 – 60 years. The accounting life for this account has historically been 40 years and the engineering SMEs have historically used a life of 50 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 50 years is reasonable. Based on the above, Concentric recommends the Iowa 50-R3 to represent the future expectations for the investment in this account.

ACCOUNT 2123 – SUBSTATION EQUIPMENT – POWER TRANSFORMERS

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$25,646,294	0.53%	32	45-R3

The assets in this account relate to transformers located within power transforming stations. There are municipal stations throughout the Toronto Hydro system, where power is generally reduced from 27.6 kV. The transformers located within these stations are replaced based on age and asset health condition assessments. There are no transformers containing PCBs.

The net book value in Substation Equipment – Power Transformers is approximately $25.6 million, representing 0.53 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1983 through 2022 were analyzed by the retirement rate method. Retirements of $230 thousand were recorded for the period 2017 through 2022, resulting in actual observed data points as depicted on page 5-83. The Iowa 45-R3 provides a residual measure of 0.3757. A review of peer Canadian electric distribution utilities indicates a range of 30 to 55 years. The 2010 Kinetrics report suggested a range of 30 – 55 years. The accounting life for this account has historically been 32 years and the engineering SMEs have historically used a life of 44 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 45 years is reasonable. Based on the above, Concentric recommends the Iowa 45-R3 to represent the future expectations for the investment in this account.

ACCOUNT 3011 – O/H – POLES CONCRETE LEGACY

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$41,885,813	0.86%	50	55-R2

The assets in this account relate to concrete poles located throughout the Toronto Hydro service area. Concrete poles are often used for both distribution and street lighting purposes. Concrete poles tend to be less expensive while being able to support the added weight required for streetlighting.

The net book value in O/H – Poles Concrete Legacy is approximately $41.9 million, representing 0.86 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1979 through 2022 were analyzed by the retirement rate method. Retirements of $4.2 million were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-90. The Iowa 55-R2 provides a residual measure of 0.1471. A review of peer Canadian electric distribution utilities indicates a range of 25 to 55 years. The 2010 Kinetrics report suggested a range of 50 – 80 years. The accounting life for this account has historically been 50 years and the engineering SMEs have historically used a life of 55 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 55 years is reasonable. Based on the above, Concentric recommends the Iowa 55-R2 to represent the future expectations for the investment in this account.

ACCOUNT 3013 – O/H – POLES WOOD

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$327,139,939	6.71%	40	45-R0.5

The assets in this account relate to wood poles located throughout the Toronto Hydro service area. The majority of the overhead system utilizes wooden poles. Toronto Hydro currently installs primarily red cedar and has a 10-year inspection program. Common forces of retirement include change in voltage requirements, relocations, third party strikes, and tree contact. Poles are recycled upon retirement, and do not have any scrap value.

The net book value in O/H – Poles Wood is approximately $327.1 million, representing 6.71 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1987 through 2022 were analyzed by the retirement rate method. Retirements of $29.7 million were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-93. The Iowa 45-R0.5 provides a residual measure of 0.2523. A review of peer Canadian electric distribution utilities indicates a range of 43 to 65 years, although it is noted that many peer accounts include towers, crossarms, and other assets with differing life characteristics. The 2010 Kinetrics report suggested a range of 35 – 75 years. The accounting life for this account has historically been 40 years and the engineering SMEs have historically used a life of 45 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 45 years is reasonable. Based on the above, Concentric recommends the Iowa 45-R0.5 to represent the future expectations for the investment in this account.

ACCOUNT 3051 – O/H - CONDUCTORS

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$121,868,987	2.50%	50	60-R2

The assets in this account relate to overhead conductor, operating at 4 kV, 13.8 kV, or 27.6 kV. There is currently an ongoing replacement program targeting the 4 kV conductor and replacing it with 13.8 kV or 27.6 kV. Historically, most overhead conductor has been 4 kV, however this has stopped in recent years. Common forces of retirement include upgrades to the feeders, an increase in the required voltage, capacity requirements of the surrounding area, and age of the cable.

The net book value in O/H – Conductors is approximately $121.9 million, representing 2.50 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1987 through 2022 were analyzed by the retirement rate method. Retirements of $7.2 million were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-96. The Iowa 60-R2 provides a residual measure of 0.725. A review of peer Canadian electric distribution utilities indicates a range of 50 to 75 years. The 2010 Kinetrics report suggested a range of 50 – 60 years. The accounting life for this account has historically been 50 years and the engineering SMEs have historically used a life of 64 years for

planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 60 years is reasonable. Based on the above, Concentric recommends the Iowa 60-R2 to represent the future expectations for the investment in this account.

ACCOUNT 3053 – O/H – SECONDARY CONDUCTORS

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$213,675,792	4.38%	50	60-R3

The assets in this account relate to overhead conductor, operating at 4 kV, 13.8 kV, or 27.6 kV. There is currently an ongoing replacement program targeting the 4 kV conductor and replacing it with 13.8 kV or 27.6 kV. Historically, most overhead conductor has been 4 kV, however this has stopped in recent years. Common forces of retirement include upgrades to the feeders, an increase in the required voltage, capacity requirements of the surrounding area, and age of the cable.

The net book value in O/H – Secondary Conductors is approximately $213.7 million, representing 4.38 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1987 through 2022 were analyzed by the retirement rate method. Retirements of $10.6 million were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-99. The Iowa 60-R3 provides a residual measure of 1.34. A review of peer Canadian electric distribution utilities indicates a range of 40 to 60 years. The 2010 Kinetrics report suggested a range of 50 – 75 years. The accounting life for this account has historically been 50 years and the engineering SMEs have historically used a physical life of 64 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 60 years is reasonable. Based on the above, Concentric recommends the Iowa 60-R3 to represent the future expectations for the investment in this account.

ACCOUNT 3057 – O/H - SWITCHES

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$120,324,226	2.47%	30	30-R2

The assets in this account relate to switches located on the overhead distribution system. These assets are used primarily for capacity restoration and are replaced with SCADA compatible switches whenever needed. It is expected that the move to SCADA compatible switches may have a life shortening impact. Switches are generally retired due to failure, deteriorated condition, or as a result of the associated pole being replaced.

The net book value in O/H – Switches is approximately $120.3 million, representing 2.47 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1986 through 2022 were analyzed by the retirement rate method. Retirements of $7.9 million were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-102. The Iowa 30-R2 provides a residual measure of 0.398. A review of peer Canadian electric distribution utilities indicates a range of 48 - 60 years. The 2010 Kinetrics report suggested a range of 30 - 55 years. The accounting life for this account has

historically been 30 years and the engineering SMEs have historically used a life of 40 years for planning purposes, however it is expected that the life may shorten in the future due to introduction of SCADA compatible switches and the impact of technological change. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 30 years is reasonable. Based on the above, Concentric recommends the Iowa 30-R2 to represent the future expectations for the investment in this account.

ACCOUNT 3061 – O/H – SMD-20 SWITCHES

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$26,999,035	0.55%	45	25-R3

The assets in this account relate to fuses and switches located on the overhead distribution system. These assets are used primarily for capacity restoration and are replaced with SCADA compatible switches whenever needed. It is expected that the move to SCADA compatible switches may have a life shortening impact. Switches are generally retired due to failure or as a result of the associated pole being replaced.

The net book value in O/H – Switches is approximately $26.9 million, representing 0.55 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 2013 through 2022 were analyzed by the retirement rate method. Retirements of $1.8 million were recorded for the period 2015 through 2022, resulting in actual observed data points as depicted on page 5-105. The Iowa 25-R3 provides a residual measure of 0.1568. A review of peer Canadian electric distribution utilities indicates a range of 7 – 48 years. The accounting and engineering lives for SMD-Switches account have historically been 45 years for planning purposes, however the SMD-20 switches are likely to have a shorter life. Further, the impact of SCADA compatible switches and the impact of technological change will likely have a life shortening impact on these assets. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 25 years is reasonable. Based on the above, Concentric recommends the Iowa 25-R3 to represent the future expectations for the investment in this account.

ACCOUNT 3411 – O/H – POLES STL CONVENTIONAL LEGACY

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$35,241,602	0.72%	40	55-R3

The assets in this account relate to steel poles located throughout the Toronto Hydro service area. The majority of the overhead system utilizes wooden poles. Common forces of retirement include change in voltage requirements, relocations, third party strikes, and tree contact. Poles are recycled upon retirement, and do not have any scrap value.

The net book value in O/H – Poles Stl Conventional Legacy is approximately $35.2 million, representing 0.72 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 2015 through 2022 were analyzed by the retirement rate method. Retirements of $1.9 million were recorded for the period 2019

through 2022, resulting in actual observed data points as depicted on page 5-107. The Iowa 55-R3 provides a residual measure of 0.0657. A review of peer Canadian electric distribution utilities indicates a range of 43 to 55 years, although it is noted that many peer accounts include towers, crossarms, and other assets with differing life characteristics. The 2010 Kinetrics report suggested a range of 60 – 80 years. The accounting and engineering life for this account has historically been 40 years and the engineering SMEs have historically used a life of 55 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 55 years is reasonable. Based on the above, Concentric recommends the Iowa 55-R3 to represent the future expectations for the investment in this account.

ACCOUNT 3511 – U/G CONDUIT – DUCT BANK

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$932,089,696	19.12%	30	50-R3

The assets in this account relate to duct banks containing underground cable.

The net book value in U/G Conduit – Duct Bank is approximately $932.1 million, representing 19.12 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1985 through 2022 were analyzed by the retirement rate method. Retirements of $2.2 million were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-113. The Iowa 50-R3 provides a residual measure of 0.2821. A review of peer Canadian electric distribution utilities indicates a range of 30 to 76 years. The 2010 Kinetrics report suggested a range of 30 – 85 years. The accounting life for this account has historically been 30 years and the engineering SMEs have historically used a life of 55 years for planning purposes but agree the use of 50 years is reasonable. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 50 years is reasonable. Based on the above, Concentric recommends the Iowa 50-R3 to represent the future expectations for the investment in this account.

ACCOUNT 3513 – U/G CONDUIT - VAULT

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$117,304,905	2.41%	40	60-R2.5

The assets in this account relate to vaults containing underground cable.

The net book value in U/G Conduit – Vaults is approximately $117.3 million, representing 2.41 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1979 through 2022 were analyzed by the retirement rate method. Retirements of $1.9 million were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-116. The Iowa 60-R3 provides a residual measure of 0.3151. A review of peer Canadian electric distribution utilities indicates a range of 30 to 75 years. The 2010 Kinetrics report suggested a range of 40 – 80 years. The accounting life for this account has historically been 40 years and the engineering SMEs have historically used a life of 60 years for

planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 60 years is reasonable. Based on the above, Concentric recommends the Iowa 60-R2.5 to represent the future expectations for the investment in this account.

ACCOUNT 3515 – U/G CONDUIT – VAULT ROOF

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$15,221,592	0.31%	20	25-R3

The assets in this account relate to the roof of the vaults containing underground cable. These roofs have ventilation and are often made out of slats.

The net book value in U/G Conduit – Vault Roof is approximately $15.2 million, representing 0.31 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1988 through 2022 were analyzed by the retirement rate method. There were no retirements recorded through 2022, resulting in actual observed data points as depicted on page 5-119. The Iowa 25-R3 provides a residual measure of 2.3287 for this account. A review of peer Canadian electric distribution utilities indicates a range of 30 to 75 years, although it is noted that the peer utilities include both vaults and roofs in a single account. The 2010 Kinetrics report suggested a range of 20 – 45 years. The accounting life for this account has historically been 20 years and the engineering SMEs have historically used a life of 25 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 25 years is reasonable. Based on the above, Concentric recommends the Iowa 25-R3 to represent the future expectations for the investment in this account.

ACCOUNT 3517 – U/G CONDUIT – CABLE CHAMBER

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$227,729,942	4.67%	50	65-R4

The assets in this account relate to the cable chambers containing underground cable. These chambers are smaller than similar vaults.

The net book value in U/G Conduit – Cable Chamber is approximately $227.7 million, representing 4.67 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1979 through 2022 were analyzed by the retirement rate method. Retirements in the amount of $1.2 million were recorded for the period 2015 through 2022, resulting in actual observed data points as depicted on page 5-122. The Iowa 65-R4 provides a residual measure of 0.112. A review of peer Canadian electric distribution utilities indicates a range of 30 to 76 years, although it is noted that the peer utilities include both chambers and roofs in a single account. The 2010 Kinetrics report suggested a range of 50 - 80 years. The accounting life for this account has historically been 50 years and the engineering SMEs have historically used a life of 65 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 65 years is reasonable. Based on the

above, Concentric recommends the Iowa 65-R4 to represent the future expectations for the investment in this account.

ACCOUNT 3611 – U/G – PRIMARY CABLE DUCT (xLPE)

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$730,454,448	14.98%	40	50-R3

The assets in this account relate to primary cable located in ducts throughout the Toronto Hydro service area. This cable operates at 4 kV, 13.8 kV, or 27.6 kV. There is currently an ongoing replacement program targeting the 4 kV conductor and replace it with 13 kV or 27.6 kV. Common forces of retirement include upgrades to the feeders, an increase in the required voltage, capacity requirements of the surrounding area, and age of the cable.

The net book value in U/G – Primary Cable Duct (xLPE) is approximately $730.5 million, representing 14.98 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1980 through 2022 were analyzed by the retirement rate method. Retirements of $24.2 million were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-134. The Iowa 50-R3 provides a residual measure of 1.4426. A review of peer Canadian electric distribution utilities indicates a range of 30 to 60 years. The 2010 Kinetrics report suggested a range of 35 – 55 years. The accounting life for this account has historically been 40 years and the engineering SMEs have historically used a life of 50 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 50 years is reasonable. Based on the above, Concentric recommends the Iowa 50-R3 to represent the future expectations for the investment in this account.

ACCOUNT 3613 – U/G – PRIMARY CABLE BURIED (xLPE)

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$415,904	0.01%	20	20-R2

The assets in this account relate to primary buried cable located throughout the Toronto Hydro service area. This cable operates at 4 kV, 13.8 kV, or 27.6 kV. There is currently an ongoing replacement program removing the direct buried cable. Common forces of retirement include upgrades to the feeders, an increase in the required voltage, capacity requirements of the surrounding area, and age of the cable.

The net book value in U/G – Primary Cable Buried is approximately $415 thousand, representing 0.01 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 2010 through 2022 were analyzed by the retirement rate method. Retirements of $750 thousand were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-137. The Iowa 20-R2 provides a residual measure of 0.3517. A review of peer Canadian electric distribution utilities indicates a range of 30 to 60 years, however it is noted that many peers include all primary cable in the same account which may result in assets with differing life characteristics being included in the peer analysis. The

accounting life for this account has historically been 20 years and the engineering SMEs have historically used a life of 23 years for planning purposes. Based on discussions with Toronto Hydro operational and management staff, Concentric recommends no change to the currently approved life of 20 years. Concentric recommends the Iowa 20-R2 to represent the future expectations for the investment in this account.

ACCOUNT 3615 – U/G – PRIMARY PILC CABLE

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$138,186,314	2.83%	60	65-R3

The assets in this account relate to primary Paper Insulated Lead Covered (PILC) cable located in ducts throughout the Toronto Hydro service area. This cable operates at 4 kV, 13.8 kV, or 27.6 kV. There is currently an ongoing replacement program targeting the 4 kV conductor and replace it with 27.6 kV. Common forces of retirement include upgrades to the feeders, an increase in the required voltage, capacity requirements of the surrounding area, and age of the cable. There is an ongoing replacement program targeting the assets in this account.

The net book value in U/G – Primary PILC Cable is approximately $138.2 million, representing 2.83 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1980 through 2022 were analyzed by the retirement rate method. Retirements of $28.1 million were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-139. The Iowa 65-R3 provides a residual measure of 1.7716. A review of peer Canadian electric distribution utilities indicates a range of 30 to 60 years, however it is noted that many peers include all primary cable in the same account which may result in assets with differing life characteristics being included in the peer analysis. The 2010 Kinetrics report suggested a range of 60 – 75 years. The accounting life for this account has historically been 60 years and the engineering SMEs have historically used a life of 75 years for planning purposes, however it is expected that the lead covering will result in increased retirements in the future. Given the shorter life indications from the historical data and the peer review, Concentric recommends a moderated life increase at this time. While a life of up to 75 years may be appropriate, Concentric recommends the Iowa 65-R3 to represent the future expectations for the investment in this account.

ACCOUNT 3617 – U/G – SECONDARY CABLE IN DUCT

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$184,600,888	3.79%	40	60-R3

The assets in this account relate to secondary cable contained in ducts throughout the Toronto Hydro service area. Secondary cable is primarily used to connect vaults together or as part of a network.

The net book value in U/G – Secondary Cable in Duct is approximately $184.6 million, representing 3.79 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1980 through 2022 were analyzed by the retirement rate method. Retirements of $1.2 million were recorded for the period 2014 through

2022, resulting in actual observed data points as depicted on page 5-142. The Iowa 60-R3 provides a residual measure of 0.9088. A review of peer Canadian electric distribution utilities indicates a range of 30 to 70 years, however it is noted that many peers include all secondary and service cable in the same account which may result in assets with differing life characteristics being included in the peer analysis. Consequently, most peer utilities include cable not in a duct with the secondary and service cable. As such, Toronto Hydro should be on the longer end of the peer review, necessitating an increase from the currently approved average service life estimate. The 2010 Kinetrics report suggested a range of 35 – 60 years. The accounting life for this account has historically been 40 years and the engineering SMEs have historically used a life of 50 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 60 years is reasonable. Based on the above, Concentric recommends the Iowa 60-R3 to represent the future expectations for the investment in this account.

ACCOUNT 3625 – U/G – SWITCH INSTALLATION

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$95,556,759	1.96%	20	40-R3

The assets in this account relate to switches located on the underground distribution system. These assets are used primarily for capacity restoration and are replaced with SCADA compatible switches whenever needed. It is expected that the move to SCADA compatible switches may have a life shortening impact, however this has not yet been seen for the assets in this account overall.

The net book value in U/G – Switch Installation is approximately $95.6 million, representing 1.96 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1995 through 2022 were analyzed by the retirement rate method. Retirements of $28.8 million were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-152. The Iowa 40-R3 provides a residual measure of 1.6076. A review of peer Canadian electric distribution utilities indicates a range of 38 to 60 years. The accounting life for this account has historically been 20 years and the engineering SMEs have historically used an average life of 40 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 40 years is reasonable. Based on the above, Concentric recommends the Iowa 40-R3 to represent the future expectations for the investment in this account.

ACCOUNT 4011 – DIST TRANSF – GENERAL OVERHEAD

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$176,708,602	3.62%	30	35-R3

The assets in this account relate to transformers located throughout the Toronto Hydro system. Transformers are reused where possible, which may have a life lengthening impact compared to some peers. However, there has also been an ongoing retirement program related to transformers containing PCBs. This program is planned to be completed by 2025 with 3,076 overhead transformers remaining at the time of this report.

The net book value in Dist Transformers – General Overhead in Duct is approximately $176.7 million, representing 3.62 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1983 through 2022 were analyzed by the retirement rate method. Retirements of $16.6 million were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-157. The Iowa 35-R3 provides a residual measure of 0.9579. A review of peer Canadian electric distribution utilities indicates a range of 30 to 50 years. The 2010 Kinetrics report suggested a range of 20 – 50 years. The accounting life for this account has historically been 30 years and the engineering SMEs have historically used a life of 35 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 35 years is reasonable. Based on the above, Concentric recommends the Iowa 35-R3 to represent the future expectations for the investment in this account.

ACCOUNT 4013 – DIST TRANSF – UNDERGROUND

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$347,436,084	7.13%	30	30-R2

The assets in this account relate to underground transformers located throughout the Toronto Hydro system. Transformers are reused where possible, which may have a life lengthening impact compared to some peers. However, there has also been an ongoing retirement program related to transformers containing PCBs. This program is planned to be completed by 2025 with 2,278 underground transformers remaining at the time of this report. It is expected that underground transformers may have a life that is shorter than overhead transformers due to the increased forces of retirement related to snow, salt, and third-party strikes.

The net book value in Dist Transformers – Underground is approximately $347.4 million, representing 7.13 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1984 through 2022 were analyzed by the retirement rate method. Retirements of $53.2 million were recorded for the period 2014 through 2021, resulting in actual observed data points as depicted on page 5-160. The Iowa 30-R2 provides a residual measure of 0.5834. A review of peer Canadian electric distribution utilities indicates a range of 33 to 50 years. The 2010 Kinetrics report suggested a range of 25 – 45 years. The

accounting life for this account has historically been 30 years and the engineering SMEs have historically used an average life of 35 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 30 years is reasonable. Based on the above, Concentric recommends the Iowa 30-R2 to represent the future expectations for the investment in this account.

ACCOUNT 4015 – DIST TRANSF – U/G NETWORK W/ PROTECTOR

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$139,780,173	2.87%	20	35-R3

The assets in this account relate to underground transformers with protection devices located throughout the Toronto Hydro system. Transformers are reused where possible, which may have a life lengthening impact compared to some peers. However, there has also been an ongoing retirement program related to transformers containing PCBs. This program is planned to be completed by 2025 with 66 network transformers remaining at the time of this report. It is expected that underground transformers may have a life that is shorter than overhead transformers due to the increased forces of retirement related to snow, salt, and third-party strikes.

The net book value in Dist Transformers – Underground Network with Protection is approximately $139.8 million, representing 2.787 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1995 through 2022 were analyzed by the retirement rate method. Retirements of $7.9 million were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-163. The Iowa 35-R3 provides a residual measure of 1.1614. A review of peer Canadian electric distribution utilities indicates a range of 40 to 55 years. The 2010 Kinetrics report suggested a range of 20 – 50 years. The accounting life for this account has historically been 20 years and the engineering SMEs have historically used a life of 35 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 35 years is reasonable. Based on the above, Concentric recommends the Iowa 35-R3 to represent the future expectations for the investment in this account.

ACCOUNT 4111 – O/H SERVICES

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$62,443,839	1.28%	50	60-R2

The assets in this account relate to overhead services located throughout the Toronto Hydro system.

The net book value in Overhead Services is approximately $62.4 million, representing 1.28 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1988 through 2022 were analyzed by the retirement rate method. Retirements of $4.8 million were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-166. The Iowa 60-R2 provides a residual measure of 1.0568. A review of peer Canadian electric distribution utilities indicates a range of 35 to 55 years,

however it is noted that many peers include all secondary and service cable in the same account which may result in assets with differing life characteristics being included in the peer analysis. The 2010 Kinetrics report suggested a range of 50 – 75 years, although it is noted that all overhead cable is included in the same account. The accounting life for this account has historically been 50 years and the engineering SMEs have historically used a life of 64 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 60 years is reasonable. Based on the above, Concentric recommends the Iowa 60-R2 to represent the future expectations for the investment in this account.

ACCOUNT 4113 – U/G SERVICES IN DUCT

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$48,413,205	0.99%	40	50-R3

The assets in this account relate to underground services contained in ducts located throughout the Toronto Hydro system.

The net book value in Underground Services in Duct is approximately $48.4 million, representing 0.99 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 2000 through 2022 were analyzed by the retirement rate method. Retirements of $922 thousand were recorded for the period 2014 through 2022, resulting in actual observed data points as depicted on page 5-169. The Iowa 50-R3 provides a residual measure of 0.0741. A review of peer Canadian electric distribution utilities indicates a range of 30 to 55 years, however it is noted that many peers include all secondary and service cable in the same account which may result in assets with differing life characteristics being included in the peer analysis. The 2010 Kinetrics report suggested a range of 35 – 60 years, although it is noted that both underground services and underground secondary cable are included in the same grouping. The accounting and engineering lives for this account have historically been 40 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 50 years is reasonable. Based on the above, Concentric recommends the Iowa 50-R3 to represent the future expectations for the investment in this account.

ACCOUNT 4611 – DIST METERS – SMART METERS RESIDENTIAL

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$29,336,561	0.60%	15	15-R3

The assets in this account relate to Advanced Meter Infrastructure ("AMI") meters installed in residential locations throughout the Toronto Hydro service area. These meters began to be installed between 2006 and 2008 resulting in the earliest meters reaching the end of their useful lives. Toronto Hydro is undertaking a transition to a second generation AMI meter, which will require the retirement of the first generation meters and collecting devices. The new meters will have better functionality and better align with energy transition considerations. The transition to new meters is

expected to begin in 2023. Currently the largest force of retirement for AMI meters is reaching the physical end of life, generally between 15 and 18 years.

The net book value in Dist Meters – Smart Meters Residential is approximately $29.3 million, representing 0.60 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 2000 through 2022 were analyzed by the retirement rate method. Retirements of $8.3 million were recorded for the period 2015 through 2022, resulting in actual observed data points as depicted on page 5-177. The Iowa 15-R3 provides a residual measure of 0.759. A review of peer Canadian electric distribution utilities indicates a range of 15 to 25 years. The 2010 Kinetrics report suggested a range of 5 – 15 years, although it is noted that the technology currently being installed may vary from that available at the time of 2010 study. The accounting and engineering lives for this account have historically been 15 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 15 years is reasonable. Based on the above, Concentric recommends the Iowa 15-R3 to represent the future expectations for the investment in this account.

ACCOUNT 4613 – DIST METERS – SMART METERS GS

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$37,999,872	0.78%	15	15-R3

The assets in this account relate to Advanced Meter Infrastructure ("AMI") meters installed in general service throughout the Toronto Hydro service area. These meters began to be installed between 2006 and 2008 resulting in the earliest meters reaching the end of their useful lives. Toronto Hydro is undertaking a transition to a second-generation AMI meter, which will require the retirement of the first-generation meters and collecting devices. The new meters will have better functionality and better align with energy transition considerations. The transition to new meters is expected to begin in 2023. Currently the largest force of retirement for AMI meters is reaching the physical end of life, generally between 15 and 18 years.

The net book value in Dist Meters – Smart Meters GS is approximately $38 million, representing 0.78 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 2006 through 2022 were analyzed by the retirement rate method. Retirements of $6.7 million were recorded for the period 2015 through 2022, resulting in actual observed data points as depicted on page 5-179. The Iowa 15-R3 provides a residual measure of 0.4643. A review of peer Canadian electric distribution utilities indicates a range of 15 to 20 years. The 2010 Kinetrics report suggested a range of 5 – 15 years, although it is noted that the technology currently being installed may vary from that available at the time of 2010 study. The accounting and engineering lives for this account have historically been 15 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 15 years is reasonable. Based on the above, Concentric recommends the Iowa 15-R3 to represent the future expectations for the investment in this account.

ACCOUNT 6251 – ROLLING STOCK – VEHICLES > 3 TONS

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$11,047,300	0.23%	8	12-L3

The assets in this account relate to heavy duty vehicles, including material handlers, dump trucks, cable trucks, crane trucks, line trucks, and single bucket trucks.

The investment in Rolling Stock – Vehicles Greater than Three Tons is approximately $11 million, representing 0.23 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 1962 through 2022 were analyzed by the retirement rate method. Retirements of $18.2 million were recorded for the period 2010 through 2022, resulting in actual observed data points as depicted on page 5-187. The Iowa 12-L3 provides a residual measure of 0.9683. A review of peer Canadian electric distribution utilities indicates a range of 8 to 19 years. The 2010 Kinetrics report suggested a range of 5 – 15 years, although it is noted that this range includes all trucks, and therefore likely has some influence of shorter-lived light weight vehicles. The accounting and engineering lives for this account have historically been 8 years for planning purposes. An independent third-party life cycle analysis of the Toronto Hydro fleet concluded that many of the assets within this account have a useful life of 10 to 14 years. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 12 years is reasonable. Based on the above, Concentric recommends the Iowa 12-L3 to represent the future expectations for the investment in this account.

ACCOUNT 6455 – SYSTEM SUPERVISORY – SCADA RTU

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$50,753,353	1.04%	15	20-R3

The net book value in System Supervisory – SCADA RTU is approximately $50.8 million, representing 1.04 percent of the total depreciable distribution and common assets studied. The retirements, additions and other plant transactions for the period 2001 through 2022 were analyzed by the retirement rate method. Retirements of $71 thousand were recorded for the period 2018 through 2022, resulting in actual observed data points as depicted on page 5-201. The Iowa 20-R3 provides a residual measure of 0.7343. The 2010 Kinetrics report suggested a range of 15 - 30 years. The accounting life for this account has historically been 15 years and the engineering SMEs have historically used a life of 20 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 20 years is reasonable. Based on the above, Concentric recommends the Iowa 20-R3 to represent the future expectations for the investment in this account.

ACCOUNT 8011– SOFTWARE ENTERPRISE

2023 Net Book Value	Investment %	Previously Approved Life	Concentric Recommended Life
$89,644,033	1.84%	10	10-SQ

The net book value in Software Enterprise is approximately $89.6 million, representing 1.84 percent of the total depreciable distribution and common assets studied. As this account uses amortization accounting, an actuarial analysis was not completed. The 2010 Kinetrics report suggested a range of 2 – 5 years, although this range includes smaller software packages than those included in the Toronto Hydro account. A review of peer Canadian electric distribution utilities indicates a range of 6 to 11 years The accounting and engineering lives for this account have historically been 10 years for planning purposes. Discussions with Toronto Hydro operational and management staff indicated that a life of approximately 10 years is reasonable, however there may be software packages that require a shorter life due to agreements with vendors. In these circumstances, it is reasonable to amortize the software package over the life of the agreement. Based on the above, Concentric recommends the 10-SQ to represent the future expectations for the investment in this account.

SECTION 4

4 RESULTS OF STUDY

4.1 Qualification of Results

The average service life estimates are the principal results of the study and are shown in Tables 1, 2, and 3. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual parameters. An assumption that depreciation parameters can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service.

Toronto Hydro

TABLE 1 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS
RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2023
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class	Description	Current Accounting Life	Recommended Life*	Recommended Curve	2023 Opening Net Book Value	2023 Depreciation Expense
1101	Buildings Adm Existing Structures	N/A**	50	R0.5	$ 4,721,165	$ 1,038,867
1103	Buildings Adm Substructure	N/A**	75	R3	$ 5,666,278	$ 131,919
1105	Buildings Adm Shell Site	N/A**	25	R3	$ 10,495,004	$ 603,903
1107	Buildings Adm Interior	N/A**	25	R3	$ 14,618,335	$ 1,615,731
1113	Buildings Service Centres Substructure	N/A**	75	R3	$ 29,358,069	$ 906,000
1115	Buildings Service Centres Shell Site	N/A**	25	R3	$ 49,382,907	$ 2,597,298
1117	Buildings Service Centres Interior	N/A**	25	R3	$ 70,874,437	$ 6,432,581
1131	Buildings Substation Structure	N/A**	50	R0.5	$ 8,752,288	$ 2,975,458
1133	Buildings Substation Substructure	N/A**	75	R3	$ 97,645,063	$ 1,666,312
1134	Building Substation Substructure - CC	N/A**	75	R3	-$ 302,801	-$ 4,813
1135	Buildings Substation Shell Site	N/A**	25	R3	$ 15,622,063	$ 973,175
1136	Building Substation Interior-Capital Contribution	N/A**	25	R3	-$ 497,343	-$ 30,476
1137	Buildings Substation Interior	N/A**	25	R3	$ 29,726,095	$ 3,853,439
1138	Buildings Substation Shell Site - CC	N/A**	25	R3	-$ 84,571	-$ 3,029
1150	Buildings Substation ARO	N/A**	0	R3	$ -	$ -
1171	Leasehold Improvements - Admin	5	5	R3	$ 26,598	$ 7,254
1173	Leasehold Improvements - Service Centres	5	5	R3	$ 112,763	$ 38,661
2011	Transformer Station Equip - Power Transformer	32	45	R3	$ 18,143,761	$ 482,998
2013	Transformer Station Equip - Steel Struct Bus Work	35	50	R3	$ 64,524	$ 2,933
2015	Transformer Station Equip - Disconnect Switch	30	45	R3	$ 15,637	$ 920
2017	Transformer Station Equip - Station Service	32	45	R3	$ 4,362,804	$ 109,587
2019	Transformer Station Equip - High Voltage Switchgea	50	50	R3	$ 8,030,306	$ 179,783
2101	Substation Equipment - Steel Structures Bus Work	35	50	R3	$ 406,123	$ 10,517
2103	Substation Equipment - Disconnect Switch	30	40	R3	$ 1,706,215	$ 63,499
2104	Substation Equipment - Disconnect Switch CC	30	40	R3	-$ 29,262	-$ 755
2105	Substation Equipment - MS Station Service	32	50	R3	$ 21,045	$ 756
2107	Substation Equipment - DC Stn Service Batteries	10	10	R3	$ 4,177,786	$ 782,760
2109	Substation Equipment - DC Stn Service Chargers	20	20	R3	$ 4,719,809	$ 360,941
2111	Substation Equipment - Outdoor Breaker	30	45	R3	$ 22,307,820	$ 632,604
2112	Substation Equip Outdr Brk - Capital Contribution	30	45	R3	-$ 425,739	-$ 9,301
2113	Substation Equipment - Indoor Breaker	30	45	R3	$ 12,192,523	$ 401,134
2114	Substation Equip Indr Brk - Capital Contribution	30	45	R3	-$ 1,374,681	-$ 35,362
2115	Substation Equipment - Station Relays	10	15	R3	$ 12,614,711	$ 1,036,480
2116	Substation Equip Stn Relays - Capital Contribution	10	15	R3	-$ 444,330	-$ 39,375

Toronto Hydro

TABLE 1 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS
RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2023
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class	Description	Current Accounting Life	Recommended Life*	Recommended Curve	2023 Opening Net Book Value	2023 Depreciation Expense
2117	Substation Equipment - Switchgear Air	40	50	R3	$ 64,195,591	$ 1,459,205
2119	Substation Equipment - Switchgear GIS	40	50	R3	$ 38,824,443	$ 878,406
2123	Substation Equipment - Power Transformers	32	45	R3	$ 25,646,294	$ 870,569
2125	Substation Equipment - Grounding System	25	35	R3	$ 1,119,191	$ 37,918
2127	Substation Equipment - Grounding Transformer	30	45	R3	$ 276,699	$ 8,239
3011	O/H - Poles Concrete Legacy	50	55	R2	$ 41,885,813	$ 1,147,458
3012	O/H - Poles Concrete - Capital Contribution Legacy	50	55	R2	-$ 2,557,947	-$ 53,566
3013	O/H - Poles Wood	40	45	R0.5	$ 327,139,939	$ 9,432,465
3014	O/H - Poles Wood - Capital Contribution	40	45	R0.5	-$ 20,669,099	-$ 582,158
3051	O/H - Conductors	50	60	R2	$ 121,868,987	$ 2,501,284
3052	O/H - Conductors - Capital Contribution	50	60	R2	-$ 11,224,729	-$ 273,906
3053	O/H - Secondary conductors	50	60	R3	$ 213,675,792	$ 4,325,645
3054	O/H - Secondary conductors - Capital Contribution	50	60	R3	-$ 10,771,869	-$ 252,055
3057	O/H - Switches	30	30	R2	$ 120,324,226	$ 5,273,241
3058	O/H - Switches - Capital Contribution	30	30	R2	-$ 13,060,089	-$ 469,816
3061	O/H - SMD-20 Switches	45	25	R3	$ 26,999,035	$ 1,351,690
3062	O/H - SMD-20 Switches - Capital Contribution	45	25	R3	-$ 3,204,757	-$ 161,610
3411	O/H - Poles STL Conventional Legacy	40	55	R3	$ 35,241,602	$ 836,396
3427	O/H - Poles Handwell	40	20	R3	$ 959,608	$ 66,423
3451	O/H - Street Lighting Cable	40	50	R3	$ 5,870,985	$ 126,873
3511	U/G Conduit - Duct Bank	30	50	R3	$ 932,089,696	$ 21,955,650
3512	U/G Conduit - Duct Bank - Capital Contribution	30	50	R3	-$ 119,365,161	-$ 2,536,715
3513	U/G Conduit - Vault	40	60	R2.5	$ 117,304,905	$ 2,646,204
3514	U/G Conduit - Vault - Capital Contribution	40	60	R2.5	-$ 2,054,698	-$ 37,081
3515	U/G Conduit - Vault Roof	20	25	R3	$ 15,221,592	$ 1,375,892
3516	U/G Conduit - Vault Roof - Capital Contribution	20	25	R3	-$ 188,063	-$ 8,424
3517	U/G Conduit - Cable Chamber	50	65	R4	$ 227,729,942	$ 4,066,711
3518	U/G Conduit - Cable Chamber - Capital Contribution	50	65	R4	-$ 56,639,142	-$ 909,997
3521	U/G Conduit - Cable Chamber Roof	20	25	R3	$ 8,400,884	$ 791,473
3522	U/G Conduit - CC Roof - Capital Contribution	20	25	R3	-$ 263,330	-$ 11,739
3523	U/G Conduit - Civil Street Lighting	50	50	R3	$ 2,570,066	$ 101,048
3524	Cable Chamber Lid - Capital Contribution	25	25	R3	-$ 17,331	-$ 700
3525	Cable Chamber Lid	25	25	R3	$ 8,062,316	$ 341,694
3609	UG Dist Lines – High Voltage Cable	40	50	R3	$ 2,436,069	$ 53,054

Toronto Hydro

TABLE 1 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS
RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2023
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class	Description	Current Accounting Life	Recommended Life*	Recommended Curve	2023 Opening Net Book Value	2023 Depreciation Expense
3610	U/G - Dist Lines & Feeders - Capital Contribution	25	50	R3	$ 12,439	-$ 9
3611	U/G - Primary Cable Duct (xLPE)	40	50	R3	$ 730,454,448	$ 17,889,157
3612	U/G - Primary Cable Duct - Capital Contribution	40	50	R3	-$ 163,047,021	-$ 4,168,789
3613	U/G - Primary Cable Buried (xLPE)	20	20	R2	$ 415,904	$ 57,943
3614	U/G - Primary Cable Buried - Capital Contribution	20	20	R2	-$ 31,895	-$ 2,640
3615	U/G - Primary PILC Cable	60	65	R3	$ 138,186,314	$ 2,937,930
3616	U/G - Primary PILC Cable - Capital Contribution	60	65	R3	-$ 9,766,861	-$ 294,601
3617	U/G - Secondary Cable in Duct	40	60	R3	$ 184,600,888	$ 3,569,628
3618	U/G - Secondary Cable in Duct-Capital Contribution	40	60	R3	-$ 21,191,140	-$ 472,921
3619	U/G - Secondary Cable Direct Buried	20	23	R3	$ 4,004	$ 377
3620	U/G - Secondary Cable DB - Capital Contribution	20	23	R3	$ -	$ -
3621	U/G - Handwells	20	20	R3	$ 20,435,699	$ 1,798,052
3622	U/G - Handwells - Capital Contribution	20	20	R3	-$ 47,485	-$ 3,744
3623	U/G - ATS Switches	30	40	R3	$ 47,844	$ 2,184
3624	U/G - ATS Switches - Capital Contribution	30	40	R3	-$ 52,474	-$ 1,340
3625	U/G - Switch Installation	20	40	R3	$ 95,556,759	$ 2,697,518
3628	U/G - Padmount Switchgear - Capital Contribution	20	40	R3	-$ 11,366,435	-$ 304,141
3630	U/G - Cable ARO	60	60	R3	-$ 163,685	-$ 4,111
3711	Network Automation Vaultt Communication	10	10	R3	$ 25,281,826	$ 3,078,598
3712	Network Automation Vault Communication-CC	10	10	R3	-$ 87,143	-$ 10,560
4011	Dist Transf - General Overhead	30	35	R3	$ 176,708,602	$ 6,322,070
4012	Dist Transf - Overhead - Capital Contribution	30	35	R3	-$ 12,856,108	-$ 493,600
4013	Dist Transf - Underground	30	30	R2	$ 347,436,084	$ 16,831,719
4014	Dist Transf - Underground - Capital Contribution	30	30	R2	-$ 30,792,308	-$ 1,242,762
4015	Dist Transf - U/G Network w/ Protector	20	35	R3	$ 139,780,173	$ 4,673,873
4016	Dist Transf - U/G NW w/ Protector-Capital Contrib	20	35	R3	-$ 3,815,320	-$ 120,280
4111	O/H Services	50	60	R2	$ 62,443,839	$ 1,353,008
4112	O/H Services - Capital Contribution	50	60	R2	-$ 902,702	-$ 38,141
4113	U/G Services in Duct	40	50	R3	$ 48,413,205	$ 1,172,296
4114	U/G Services in Duct - Capital Contribution	40	50	R3	-$ 5,121,939	-$ 125,707
4115	U/G Services Secondary Cable Direct Buried	20	23	R3	-$ 12,856	-$ 1,085
4510	Dist Meters - Capital Contribution	25	15	R3	-$ 45,212	-$ 6,545
4511	Dist Meters - Demand/Energy Meters	25	15	R3	$ 29,290,543	$ 5,740,935
4512	Demand Energy Meter - Capital Contribution	25	15	R3	-$ 5,875,700	-$ 581,685

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TABLE 1 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS
RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2023
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class	Description	Current Accounting Life	Recommended Life*	Recommended Curve	2023 Opening Net Book Value	2023 Depreciation Expense
4513	Dist Meters - Meters Transformers	40	40	R3	$ 18,261,036	$ 709,665
4514	Meter Transformers - Capital Contribution	40	40	R3	-$ 5,330,277	-$ 191,001
4515	Dist Meters - Suite Meters	15	15	R3	$ 33,884,070	$ 3,813,996
4611	Dist Meters - Smart Meters Residential	15	15	R3	$ 29,336,561	$ 4,778,630
4613	Dist Meters - Smart Meters GS	15	15	R3	$ 37,999,872	$ 4,638,900
4711	Grid Point Meters	25	25	R3	$ 31,082,531	$ 1,667,067
5011	Street Lighting Luminaires	0	0	R3	$ -	$ -
5013	Street Lighting Luminaire Brackets	0	0	R3	$ -	$ -
5031	Street Lighting Distribution Assembly	20	25	R3	$ 73,103	$ 3,374
6011	General Office Furnishings & Equipment	N/A**	15	SQ	$ 5,882,642	$ 753,287
6111	Computer Hardware - Client/Network	4	4	SQ	$ 19,403,201	$ 8,141,481
6113	Computer Hardware - Printers/storage	5	5	SQ	$ 5,079,739	$ 1,886,098
6115	Computer Hardware - P series Servers	6	6	SQ	$ 2,869,483	$ 1,255,283
6117	Computer Hardware - Data centre Cabling/racks	10	10	SQ	$ 612,934	$ 167,164
6131	Computer Hardware - Scada	5	5	SQ	$ 4,943,458	$ 1,466,235
6231	Rolling Stock - Vehicles < 3 Tons	5	9	L3	$ 5,531,365	$ 691,279
6251	Rolling Stock - Vehicles > 3 Tons	8	12	L3	$ 11,047,300	$ 1,220,365
6271	Rolling Stock - Service Equipment	8	20	R4	$ 1,013,743	$ 56,450
6281	Rolling Stock - Electric Vehicles	4	7	L1	$ 155,120	$ 29,547
6282	Rolling Stock - Electric Vehicle Charge Stations	10	10	R3	$ 58,537	$ 9,894
6290	Energy Storage Inverter - Capital Contribution	20	20	R3	-$ 499,418	-$ 27,875
6291	Energy Storage Inverter	20	20	R3	$ 2,886,548	$ 164,014
6292	Energy Storage System Battery	10	10	R3	$ 989,325	$ 124,967
6293	Energy Storage System Battery-Contributed Capital	10	10	R3	-$ 220,634	-$ 27,869
6311	Stores Equipment	10	15	SQ	$ 9,267	$ 621
6331	Tools and Equipment - Tools and Misc Equipment	10	10	SQ	$ 15,551,994	$ 2,678,177
6333	Tool Crib	10	10	SQ	$ -	$ -
6335	Linehose	6	6	SQ	$ -	$ -
6351	Testing Equipment - Instruments	10	15	SQ	$ -	$ -
6371	Communication Equipment - Wireless	5	5	SQ	$ 440,634	$ 331,521
6391	Communication Equipment - Network Mgment Equipmnt	5	5	SQ	$ -	$ -
6411	Communication Equipment - Telephony	5	5	SQ	$ 8,992,907	$ 2,167,366
6431	Miscellaneous Equipment	10	10	SQ	$ 1,237	$ 391
6451	System Supervisory Equipment	15	20	R3	$ 1,980,435	$ 167,672

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TABLE 1 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS
RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2023
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class	Description	Current Accounting Life	Recommended Life*	Recommended Curve	2023 Opening Net Book Value	2023 Depreciation Expense
6452	System Supervisory Eq - Capital Contribution	15	20	R3	-$ 12,919,419	-$ 690,906
6453	System Supervisory - Scadamate Switches	30	30	R3	$ 1,642,471	$ 113,620
6455	System Supervisory - Scada RTU	15	20	R3	$ 50,753,353	$ 3,092,349
6511	Fibre Optic Network - Control Cable	10	20	R3	$ 10,545,925	$ 585,279
6512	Fibre Optic Network - Capital Contribution	20	20	R3	-$ 99,826	-$ 5,012
6531	Fibre Optic Network - Customer Term Equipment	10	10	R3	$ 9,053,010	$ 619,139
6533	Fibre Optic Network - SubstationTerm Equipment	10	10	R3	$ 69,425	$ 10,752
6534	Fibre Optic Network-Substation Term Equipment - CC	10	10	R3	-$ 41,269	-$ 5,213
7111	Load Management Controls - Customer Location	10	10	R3	$ -	$ -
8011	Software Enterprise	10	10	SQ	$ 89,644,033	$ 23,823,284
8031	Software Client	4	4	SQ	$ 1,855,754	$ 1,028,989
8051	Software General	5	5	SQ	$ 13,728,909	$ 4,176,249
8071	Contribution to HONI Station	25	25	0	$ 225,255,660	$ 11,081,625
8511	Capital Allocations	25	25	0	$ 23,769	$ 23,769
	TOTAL PLANT STUDIED				**$ 4,875,873,651**	**$ 221,915,421**
	**** Applied to grouped assets only***					
	PLANT NOT STUDIED					
1011	Land - Administration	N/A	N/A	N/A	$ 8,008,235	$ -
1013	Land - Service Centres	N/A	N/A	N/A	$ 9,347,822	$ -
1031	Land - Substations	N/A	N/A	N/A	$ 1,441,142	$ -
1051	Land - Transformer Stations	N/A	N/A	N/A	$ 5,557,807	$ -
1071	Land - Finance Lease	99	99	0	$ 6,386,284	$ 89,423
1511	ROU - Property Leases	5	5	0	$ 189,944	$ 38,633
4031	Dist Transf - ARO	25	25	0	$ 360,917	$ 49,999
	TOTAL PLANT NOT STUDIED				**$ 31,292,151**	**$ 178,055**
	TOTAL PLANT				**$ 4,907,165,802**	**$ 222,093,476**
	***** Please refer to Table 3 for details on the facilities assets***					

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TABLE 2 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS
RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2024
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class	Description	Current Accounting Life	Recommended Life*	Recommended Curve	2024 Opening Net Book Value	2024 Depreciation Expense
1101	Buildings Adm Existing Structures	N/A**	50	R0.5	$ 3,682,299	$ 1,038,867
1103	Buildings Adm Substructure	N/A**	75	R3	$ 5,534,359	$ 131,919
1105	Buildings Adm Shell Site	N/A**	25	R3	$ 9,891,101	$ 603,903
1107	Buildings Adm Interior	N/A**	25	R3	$ 13,002,604	$ 1,341,128
1113	Buildings Service Centres Substructure	N/A**	75	R3	$ 28,452,069	$ 906,000
1115	Buildings Service Centres Shell Site	N/A**	25	R3	$ 46,785,608	$ 2,532,372
1117	Buildings Service Centres Interior	N/A**	25	R3	$ 64,441,857	$ 6,381,169
1131	Buildings Substation Structure	N/A**	50	R0.5	$ 5,776,830	$ 987,411
1133	Buildings Substation Substructure	N/A**	75	R3	$ 95,978,751	$ 1,666,312
1134	Building Substation Substructure - CC	N/A**	75	R3	-$ 297,989	-$ 4,813
1135	Buildings Substation Shell Site	N/A**	25	R3	$ 14,648,888	$ 973,175
1136	Building Substation Interior-Capital Contribution	N/A**	25	R3	-$ 466,867	-$ 30,476
1137	Buildings Substation Interior	N/A**	25	R3	$ 25,872,656	$ 2,543,628
1138	Buildings Substation Shell Site - CC	N/A**	25	R3	-$ 81,541	-$ 3,029
1150	Buildings Substation ARO	N/A**	0	R3	$ -	$ -
1171	Leasehold Improvements - Admin	5	5	R3	$ 19,344	$ 7,254
1173	Leasehold Improvements - Service Centres	5	5	R3	$ 74,101	$ 38,661
2011	Transformer Station Equip - Power Transformer	32	45	R3	$ 17,660,763	$ 482,998
2013	Transformer Station Equip - Steel Struct Bus Work	35	50	R3	$ 61,591	$ 2,933
2015	Transformer Station Equip - Disconnect Switch	30	45	R3	$ 14,717	$ 920
2017	Transformer Station Equip - Station Service	32	45	R3	$ 4,253,217	$ 109,587
2019	Transformer Station Equip - High Voltage Switchgea	50	50	R3	$ 7,850,523	$ 179,783
2101	Substation Equipment - Steel Structures Bus Work	35	50	R3	$ 395,606	$ 10,517
2103	Substation Equipment - Disconnect Switch	30	40	R3	$ 1,642,716	$ 63,499
2104	Substation Equipment - Disconnect Switch CC	30	40	R3	-$ 28,507	-$ 755
2105	Substation Equipment - MS Station Service	32	50	R3	$ 20,289	$ 756
2107	Substation Equipment - DC Stn Service Batteries	10	10	R3	$ 3,395,026	$ 703,509
2109	Substation Equipment - DC Stn Service Chargers	20	20	R3	$ 4,358,868	$ 351,029
2111	Substation Equipment - Outdoor Breaker	30	45	R3	$ 21,675,217	$ 632,604
2112	Substation Equip Outdr Brk - Capital Contribution	30	45	R3	-$ 416,438	-$ 9,301
2113	Substation Equipment - Indoor Breaker	30	45	R3	$ 11,791,389	$ 401,134
2114	Substation Equip Indr Brk - Capital Contribution	30	45	R3	-$ 1,339,318	-$ 35,362
2115	Substation Equipment - Station Relays	10	15	R3	$ 11,578,231	$ 1,036,480
2116	Substation Equip Stn Relays - Capital Contribution	10	15	R3	-$ 404,955	-$ 39,375

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TABLE 2 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2024 DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class	Description	Current Accounting Life	Recommended Life*	Recommended Curve	2024 Opening Net Book Value	2024 Depreciation Expense
2117	Substation Equipment - Switchgear Air	40	50	R3	$ 62,736,386	$ 1,459,205
2119	Substation Equipment - Switchgear GIS	40	50	R3	$ 37,946,036	$ 878,406
2123	Substation Equipment - Power Transformers	32	45	R3	$ 24,775,724	$ 870,569
2125	Substation Equipment - Grounding System	25	35	R3	$ 1,081,273	$ 37,918
2127	Substation Equipment - Grounding Transformer	30	45	R3	$ 268,459	$ 8,239
3011	O/H - Poles Concrete Legacy	50	55	R2	$ 40,738,355	$ 1,144,148
3012	O/H - Poles Concrete - Capital Contribution Legacy	50	55	R2	-$ 2,504,380	-$ 50,493
3013	O/H - Poles Wood	40	45	R0.5	$ 317,707,475	$ 9,347,689
3014	O/H - Poles Wood - Capital Contribution	40	45	R0.5	-$ 20,086,940	-$ 516,295
3051	O/H - Conductors	50	60	R2	$ 119,367,703	$ 2,422,181
3052	O/H - Conductors - Capital Contribution	50	60	R2	-$ 10,950,823	-$ 214,305
3053	O/H - Secondary conductors	50	60	R3	$ 209,350,147	$ 4,234,473
3054	O/H - Secondary conductors - Capital Contribution	50	60	R3	-$ 10,519,814	-$ 197,534
3057	O/H - Switches	30	30	R2	$ 115,050,985	$ 5,248,558
3058	O/H - Switches - Capital Contribution	30	30	R2	-$ 12,590,273	-$ 466,255
3061	O/H - SMD-20 Switches	45	25	R3	$ 25,647,345	$ 1,338,181
3062	O/H - SMD-20 Switches - Capital Contribution	45	25	R3	-$ 3,043,147	-$ 150,603
3411	O/H - Poles STL Conventional Legacy	40	55	R3	$ 34,405,206	$ 836,396
3427	O/H - Poles Handwell	40	20	R3	$ 893,185	$ 66,423
3451	O/H - Street Lighting Cable	40	50	R3	$ 5,744,111	$ 126,873
3511	U/G Conduit - Duct Bank	30	50	R3	$ 910,134,046	$ 21,951,946
3512	U/G Conduit - Duct Bank - Capital Contribution	30	50	R3	-$ 116,828,446	-$ 2,533,647
3513	U/G Conduit - Vault	40	60	R2.5	$ 114,658,701	$ 2,646,204
3514	U/G Conduit - Vault - Capital Contribution	40	60	R2.5	-$ 2,017,617	-$ 37,081
3515	U/G Conduit - Vault Roof	20	25	R3	$ 13,845,700	$ 1,228,842
3516	U/G Conduit - Vault Roof - Capital Contribution	20	25	R3	-$ 179,639	-$ 8,424
3517	U/G Conduit - Cable Chamber	50	65	R4	$ 223,663,231	$ 4,066,711
3518	U/G Conduit - Cable Chamber - Capital Contribution	50	65	R4	-$ 55,729,145	-$ 909,997
3521	U/G Conduit - Cable Chamber Roof	20	25	R3	$ 7,609,410	$ 702,578
3522	U/G Conduit - CC Roof - Capital Contribution	20	25	R3	-$ 251,592	-$ 11,739
3523	U/G Conduit - Civil Street Lighting	50	50	R3	$ 2,469,018	$ 101,048
3524	Cable Chamber Lid - Capital Contribution	25	25	R3	-$ 16,631	-$ 700
3525	Cable Chamber Lid	25	25	R3	$ 7,720,622	$ 341,694
3609	UG Dist Lines – High Voltage Cable	40	50	R3	$ 2,383,015	$ 53,054

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TABLE 2 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS
RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2024
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class	Description	Current Accounting Life	Recommended Life*	Recommended Curve	2024 Opening Net Book Value	2024 Depreciation Expense
3610	U/G - Dist Lines & Feeders - Capital Contribution	25	50	R3	$ 12,448	-$ 9
3611	U/G - Primary Cable Duct (xLPE)	40	50	R3	$ 712,565,291	$ 16,978,028
3612	U/G - Primary Cable Duct - Capital Contribution	40	50	R3	-$ 158,878,232	-$ 3,624,104
3613	U/G - Primary Cable Buried (xLPE)	20	20	R2	$ 357,961	$ 57,943
3614	U/G - Primary Cable Buried - Capital Contribution	20	20	R2	-$ 29,255	-$ 2,640
3615	U/G - Primary PILC Cable	60	65	R3	$ 135,248,384	$ 2,808,502
3616	U/G - Primary PILC Cable - Capital Contribution	60	65	R3	-$ 9,472,260	-$ 215,356
3617	U/G - Secondary Cable in Duct	40	60	R3	$ 181,031,261	$ 3,421,609
3618	U/G - Secondary Cable in Duct-Capital Contribution	40	60	R3	-$ 20,718,218	-$ 383,584
3619	U/G - Secondary Cable Direct Buried	20	23	R3	$ 3,627	$ 377
3620	U/G - Secondary Cable DB - Capital Contribution	20	23	R3	$ -	$ -
3621	U/G - Handwells	20	20	R3	$ 18,637,647	$ 1,798,052
3622	U/G - Handwells - Capital Contribution	20	20	R3	-$ 43,742	-$ 3,744
3623	U/G - ATS Switches	30	40	R3	$ 45,660	$ 2,184
3624	U/G - ATS Switches - Capital Contribution	30	40	R3	-$ 51,134	-$ 1,340
3625	U/G - Switch Installation	20	40	R3	$ 92,859,240	$ 2,697,518
3628	U/G - Padmount Switchgear - Capital Contribution	20	40	R3	-$ 11,062,294	-$ 304,141
3630	U/G - Cable ARO	60	60	R3	-$ 159,574	-$ 4,111
3711	Network Automation Vaultt Communication	10	10	R3	$ 22,203,228	$ 3,078,598
3712	Network Automation Vault Communication-CC	10	10	R3	-$ 76,583	-$ 10,560
4011	Dist Transf - General Overhead	30	35	R3	$ 170,386,532	$ 6,229,564
4012	Dist Transf - Overhead - Capital Contribution	30	35	R3	-$ 12,362,508	-$ 408,250
4013	Dist Transf - Underground	30	30	R2	$ 330,604,365	$ 16,466,334
4014	Dist Transf - Underground - Capital Contribution	30	30	R2	-$ 29,549,546	-$ 1,189,006
4015	Dist Transf - U/G Network w/ Protector	20	35	R3	$ 135,106,300	$ 4,673,873
4016	Dist Transf - U/G NW w/ Protector-Capital Contrib	20	35	R3	-$ 3,695,040	-$ 120,280
4111	O/H Services	50	60	R2	$ 61,090,830	$ 1,313,409
4112	O/H Services - Capital Contribution	50	60	R2	-$ 864,561	-$ 17,776
4113	U/G Services in Duct	40	50	R3	$ 47,240,909	$ 1,149,471
4114	U/G Services in Duct - Capital Contribution	40	50	R3	-$ 4,996,232	-$ 112,552
4115	U/G Services Secondary Cable Direct Buried	20	23	R3	-$ 11,771	-$ 1,085
4510	Dist Meters - Capital Contribution	25	15	R3	-$ 38,668	-$ 6,545
4511	Dist Meters - Demand/Energy Meters	25	15	R3	$ 23,549,607	$ 3,002,612
4512	Demand Energy Meter - Capital Contribution	25	15	R3	-$ 5,294,015	-$ 564,359

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TABLE 2 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2024 DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class	Description	Current Accounting Life	Recommended Life*	Recommended Curve	2024 Opening Net Book Value	2024 Depreciation Expense
4513	Dist Meters - Meters Transformers	40	40	R3	$ 17,551,371	$ 602,541
4514	Meter Transformers - Capital Contribution	40	40	R3	-$ 5,139,277	-$ 157,473
4515	Dist Meters - Suite Meters	15	15	R3	$ 30,070,074	$ 3,813,996
4611	Dist Meters - Smart Meters Residential	15	15	R3	$ 24,557,931	$ 3,685,450
4613	Dist Meters - Smart Meters GS	15	15	R3	$ 33,360,973	$ 4,383,871
4711	Grid Point Meters	25	25	R3	$ 29,415,464	$ 1,667,067
5011	Street Lighting Luminaires	0	0	R3	$ -	$ -
5013	Street Lighting Luminaire Brackets	0	0	R3	$ -	$ -
5031	Street Lighting Distribution Assembly	20	25	R3	$ 69,729	$ 3,374
6011	General Office Furnishings & Equipment	N/A**	15	SQ	$ 5,129,354	$ 597,150
6111	Computer Hardware - Client/Network	4	4	SQ	$ 11,261,720	$ 6,148,212
6113	Computer Hardware - Printers/storage	5	5	SQ	$ 3,193,641	$ 1,461,537
6115	Computer Hardware - P series Servers	6	6	SQ	$ 1,614,200	$ 901,517
6117	Computer Hardware - Data centre Cabling/racks	10	10	SQ	$ 445,770	$ 167,164
6131	Computer Hardware - Scada	5	5	SQ	$ 3,477,222	$ 1,425,526
6231	Rolling Stock - Vehicles < 3 Tons	5	9	L3	$ 4,840,086	$ 691,279
6251	Rolling Stock - Vehicles > 3 Tons	8	12	L3	$ 9,826,935	$ 1,220,365
6271	Rolling Stock - Service Equipment	8	20	R4	$ 957,293	$ 56,450
6281	Rolling Stock - Electric Vehicles	4	7	L1	$ 125,573	$ 29,547
6282	Rolling Stock - Electric Vehicle Charge Stations	10	10	R3	$ 48,643	$ 9,894
6290	Energy Storage Inverter - Capital Contribution	20	20	R3	-$ 471,544	-$ 27,875
6291	Energy Storage Inverter	20	20	R3	$ 2,722,533	$ 164,014
6292	Energy Storage System Battery	10	10	R3	$ 864,358	$ 124,967
6293	Energy Storage System Battery-Contributed Capital	10	10	R3	-$ 192,764	-$ 27,869
6311	Stores Equipment	10	15	SQ	$ 8,646	$ 621
6331	Tools and Equipment - Tools and Misc Equipment	10	10	SQ	$ 12,873,817	$ 2,475,304
6333	Tool Crib	10	10	SQ	$ -	$ -
6335	Linehose	6	6	SQ	$ -	$ -
6351	Testing Equipment - Instruments	10	15	SQ	$ -	$ -
6371	Communication Equipment - Wireless	5	5	SQ	$ 109,113	$ 109,113
6391	Communication Equipment - Network Mgment Equipmnt	5	5	SQ	$ -	$ -
6411	Communication Equipment - Telephony	5	5	SQ	$ 6,825,541	$ 1,532,059
6431	Miscellaneous Equipment	10	10	SQ	$ 847	$ 391
6451	System Supervisory Equipment	15	20	R3	$ 1,812,763	$ 167,672

Toronto Hydro

TABLE 2 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2024 DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Asset Class	Description	Current Accounting Life	Recommended Life*	Recommended Curve	2024 Opening Net Book Value	2024 Depreciation Expense
6452	System Supervisory Eq - Capital Contribution	15	20	R3	-$ 12,228,513	-$ 690,906
6453	System Supervisory - Scadamate Switches	30	30	R3	$ 1,528,851	$ 113,620
6455	System Supervisory - Scada RTU	15	20	R3	$ 47,661,004	$ 3,092,349
6511	Fibre Optic Network - Control Cable	10	20	R3	$ 9,960,647	$ 585,279
6512	Fibre Optic Network - Capital Contribution	20	20	R3	-$ 94,814	-$ 5,012
6531	Fibre Optic Network - Customer Term Equipment	10	10	R3	$ 8,433,871	$ 619,139
6533	Fibre Optic Network - SubstationTerm Equipment	10	10	R3	$ 58,673	$ 10,752
6534	Fibre Optic Network-Substation Term Equipment - CC	10	10	R3	-$ 36,056	-$ 5,213
7111	Load Management Controls - Customer Location	10	10	R3	$ -	$ -
8011	Software Enterprise	10	10	SQ	$ 65,820,749	$ 21,272,967
8031	Software Client	4	4	SQ	$ 826,765	$ 476,399
8051	Software General	5	5	SQ	$ 9,552,660	$ 3,367,231
8071	Contribution to HONI Station	25	25	0	$ 214,174,035	$ 11,081,625
8511	Capital Allocations	25	25	0	$ -	$ -
	TOTAL PLANT STUDIED				**$ 4,653,958,230**	**$ 204,871,428**
	**** Applied to grouped assets only***					
	PLANT NOT STUDIED					
1011	Land - Administration	N/A	N/A	N/A	$ 8,008,235	$ -
1013	Land - Service Centres	N/A	N/A	N/A	$ 9,347,822	$ -
1031	Land - Substations	N/A	N/A	N/A	$ 1,441,142	$ -
1051	Land - Transformer Stations	N/A	N/A	N/A	$ 5,557,807	$ -
1071	Land - Finance Lease	99	99	0	$ 6,296,861	$ 89,423
1511	ROU - Property Leases	5	5	0	$ 151,311	$ 38,633
4031	Dist Transf - ARO	25	25	0	$ 310,918	$ 49,991
	TOTAL PLANT NOT STUDIED				**$ 31,114,097**	**$ 178,046**
	TOTAL PLANT				**$ 4,685,072,326**	**$ 205,049,475**
	***** Please refer to Table 3 for details on the facilities assets***					

Toronto Hydro

TABLE 3 - ORIGINAL COST, AND ANNUAL DEPRECIATION ACCRUALS
RELATED TO FACILITIES IN UTILITY PLANT AS OF DECEMBER 31, 2023 & DECEMBER 31, 2024
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Description	Recommended Life	Recommended Curve	2023 Opening Net Book Value	2023 Depreciation Expense	2024 Opening Net Book Value	2024 Depreciation Expense
5 - Infrastructure Technology	5	R0.5	$ 327,555	$ 275,724	$ 51,831	$ 25,726
10 - Interior Finishings	10	R3	$ 4,946,574	$ 1,247,784	$ 3,698,790	$ 1,057,029
10 - Building Other (short lived)	10	R3	$ 12,200,209	$ 3,173,906	$ 9,026,304	$ 1,757,770
15 - Landscape/parking/roadways	15	R3	$ 22,436,583	$ 2,363,171	$ 20,073,412	$ 2,363,171
15 - General Office Furnishings & Equipment	15	R3	$ 5,643,136	$ 571,105	$ 5,072,030	$ 571,105
20 - Auxiliary (HVAC, roof, wiring, fire, security)	20	R0.5	$ 104,405,327	$ 7,455,021	$ 96,950,306	$ 7,455,021
30 - Building Other (medium lived)	30	R3	$ 69,403,508	$ 6,322,102	$ 63,081,406	$ 4,334,055
65 - Building Other (long lived)	65	R3	$ 122,496,739	$ 2,100,838	$ 120,395,901	$ 2,100,838
TOTAL FACILITIES PLANT STUDIED			**$ 341,859,631**	**$ 23,509,652**	**$ 318,349,979**	**$ 19,664,716**

SECTION 5

5 RETIREMENT RATE ANALYSIS

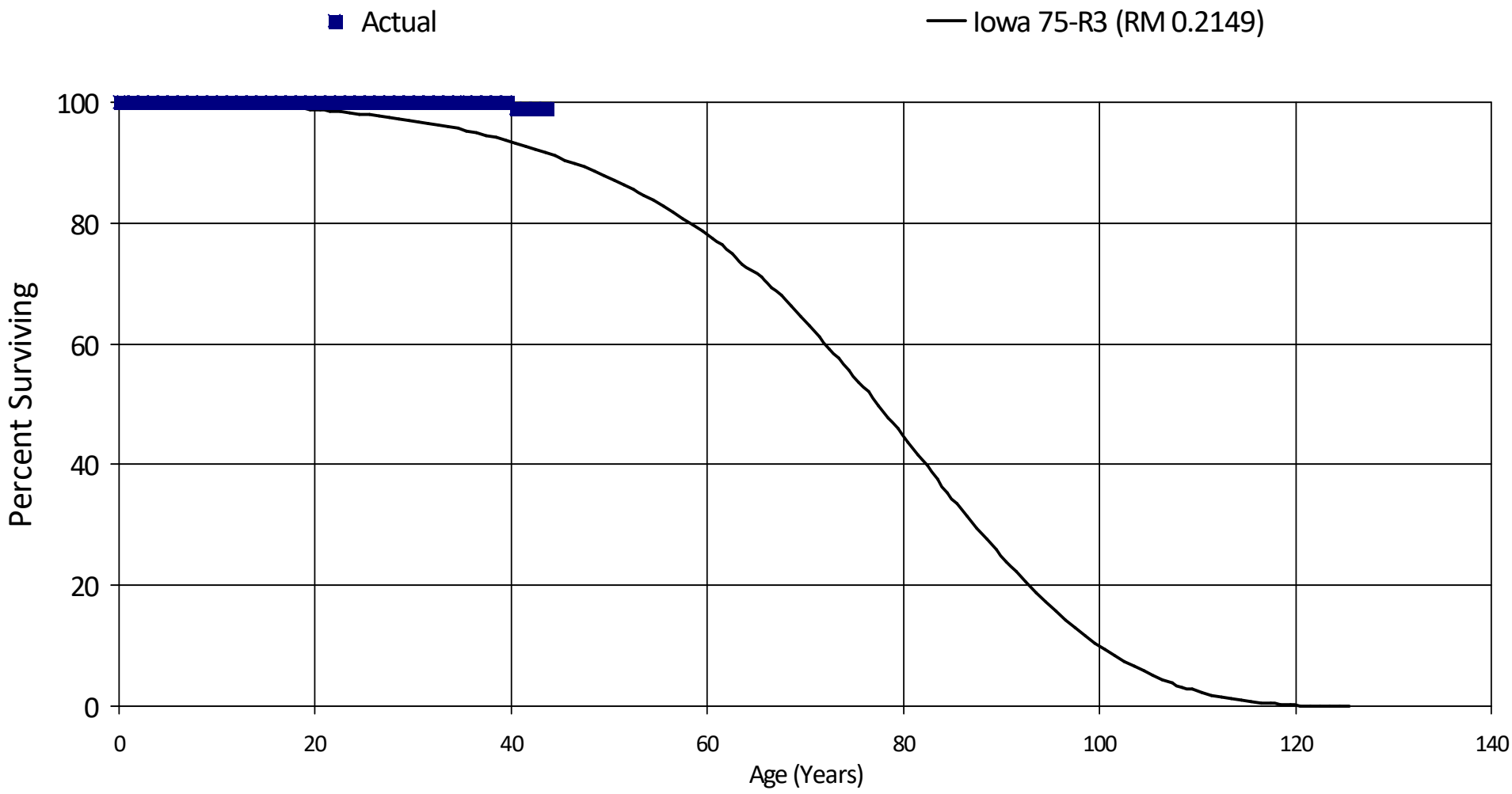
PLEASE SEE SECTION 3 FOR A DETAILED DISCUSSION OF THE SELECTION OF AVERAGE SERVICE LIFE ESTIMATES AND IOWA CURVE DISPERSION

Toronto Hydro

Account 1011 - Land - Administration

Placement Band - 1958 - 2022 Experience Band - 2019 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1011 - Land - Administration

Placement Band - 1958 - 2022 Experience Band - 2019 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	8,013,435	0	0.00000	1.00000	100.00
0.5	8,013,435	0	0.00000	1.00000	100.00
1.5	8,013,435	0	0.00000	1.00000	100.00
2.5	8,013,435	0	0.00000	1.00000	100.00
3.5	8,013,435	0	0.00000	1.00000	100.00
4.5	8,013,435	0	0.00000	1.00000	100.00
5.5	8,013,435	0	0.00000	1.00000	100.00
6.5	8,013,435	0	0.00000	1.00000	100.00
7.5	8,013,435	0	0.00000	1.00000	100.00
8.5	8,013,435	0	0.00000	1.00000	100.00
9.5	8,013,435	0	0.00000	1.00000	100.00
10.5	8,013,435	0	0.00000	1.00000	100.00
11.5	752,223	0	0.00000	1.00000	100.00
12.5	752,223	0	0.00000	1.00000	100.00
13.5	752,223	0	0.00000	1.00000	100.00
14.5	752,223	0	0.00000	1.00000	100.00
15.5	752,223	0	0.00000	1.00000	100.00
16.5	752,223	0	0.00000	1.00000	100.00
17.5	752,223	0	0.00000	1.00000	100.00
18.5	752,223	0	0.00000	1.00000	100.00
19.5	752,223	0	0.00000	1.00000	100.00
20.5	752,223	0	0.00000	1.00000	100.00
21.5	752,223	0	0.00000	1.00000	100.00
22.5	752,223	0	0.00000	1.00000	100.00
23.5	752,223	0	0.00000	1.00000	100.00
24.5	752,223	0	0.00000	1.00000	100.00
25.5	646,398	0	0.00000	1.00000	100.00
26.5	646,398	0	0.00000	1.00000	100.00

Toronto Hydro

Account 1011 - Land - Administration

Placement Band - 1958 - 2022 Experience Band - 2019 - 2022

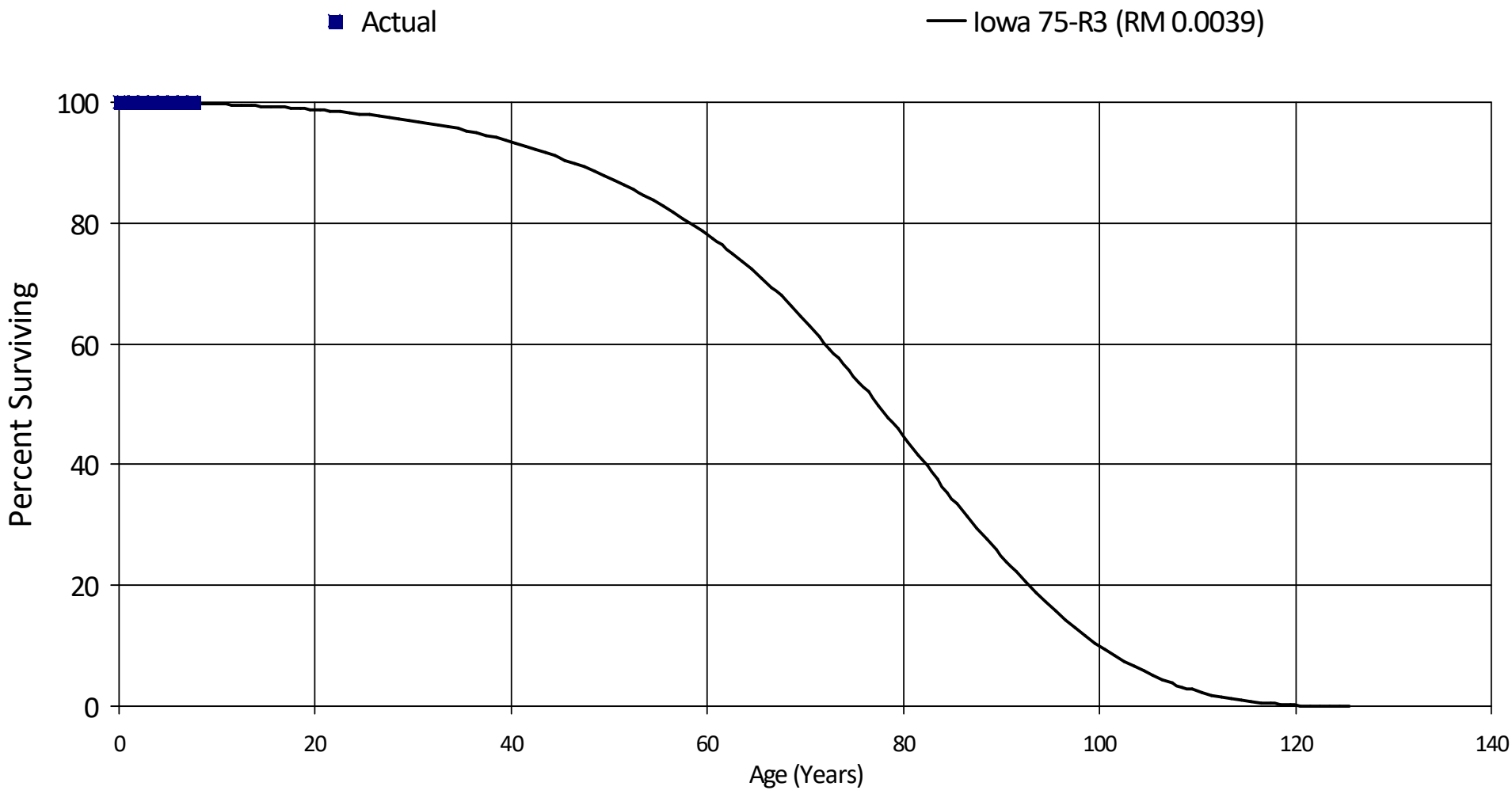
27.5	646,398	0	0.00000	1.00000	100.00
28.5	646,398	0	0.00000	1.00000	100.00
29.5	646,398	0	0.00000	1.00000	100.00
30.5	639,463	0	0.00000	1.00000	100.00
31.5	639,463	0	0.00000	1.00000	100.00
32.5	563,009	0	0.00000	1.00000	100.00
33.5	563,009	0	0.00000	1.00000	100.00
34.5	563,009	0	0.00000	1.00000	100.00
35.5	563,009	0	0.00000	1.00000	100.00
36.5	563,009	0	0.00000	1.00000	100.00
37.5	563,009	0	0.00000	1.00000	100.00
38.5	563,009	0	0.00000	1.00000	100.00
39.5	563,009	5,200	0.00924	0.99076	100.00
40.5	557,809	0	0.00000	1.00000	99.08
41.5	557,809	0	0.00000	1.00000	99.08
42.5	285,769	0	0.00000	1.00000	99.08
43.5	0	0	0.00000	0.00000	99.08
	Totals:	5,200			

Toronto Hydro

Account 1013 - Land - Service Centres

Placement Band - 2014 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1013 - Land - Service Centres

Placement Band - 2014 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

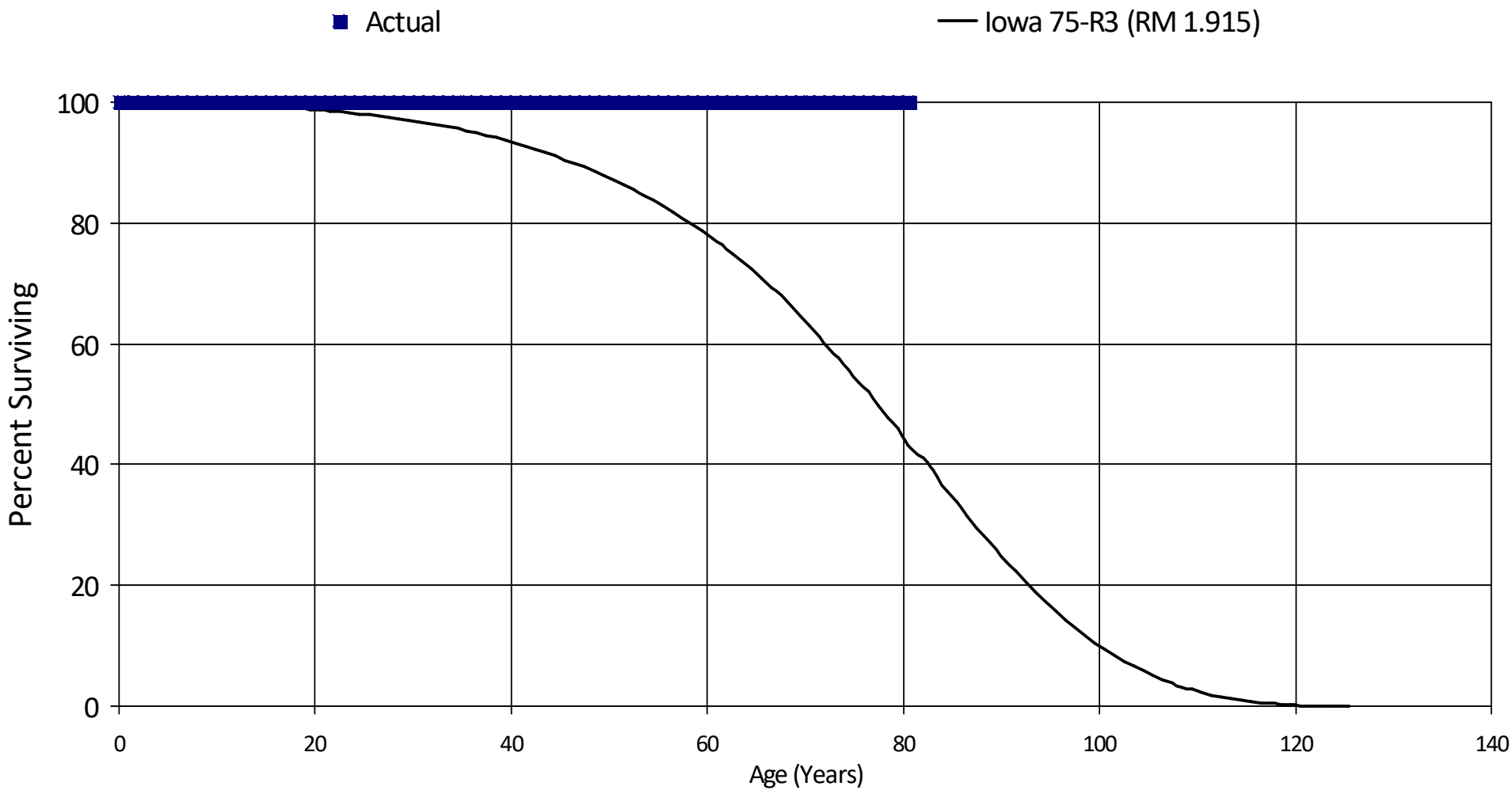
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	9,347,822	0	0.00000	1.00000	100.00
0.5	9,347,822	0	0.00000	1.00000	100.00
1.5	8,814,391	0	0.00000	1.00000	100.00
2.5	8,814,391	0	0.00000	1.00000	100.00
3.5	8,814,391	0	0.00000	1.00000	100.00
4.5	8,814,391	0	0.00000	1.00000	100.00
5.5	8,814,391	0	0.00000	1.00000	100.00
6.5	8,814,391	0	0.00000	1.00000	100.00
7.5	8,814,391	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 1031 - Land - Substations

Placement Band - 1941 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1031 - Land - Substations

Placement Band - 1941 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,441,142	0	0.00000	1.00000	100.00
0.5	1,441,142	0	0.00000	1.00000	100.00
1.5	1,441,142	0	0.00000	1.00000	100.00
2.5	1,441,142	0	0.00000	1.00000	100.00
3.5	1,441,142	0	0.00000	1.00000	100.00
4.5	1,441,142	0	0.00000	1.00000	100.00
5.5	1,441,142	0	0.00000	1.00000	100.00
6.5	1,441,142	0	0.00000	1.00000	100.00
7.5	1,441,142	0	0.00000	1.00000	100.00
8.5	1,441,142	0	0.00000	1.00000	100.00
9.5	1,441,142	0	0.00000	1.00000	100.00
10.5	1,441,142	0	0.00000	1.00000	100.00
11.5	1,441,142	0	0.00000	1.00000	100.00
12.5	1,441,142	0	0.00000	1.00000	100.00
13.5	1,441,142	0	0.00000	1.00000	100.00
14.5	1,441,142	0	0.00000	1.00000	100.00
15.5	1,441,142	0	0.00000	1.00000	100.00
16.5	1,441,142	0	0.00000	1.00000	100.00
17.5	1,441,142	0	0.00000	1.00000	100.00
18.5	1,441,142	0	0.00000	1.00000	100.00
19.5	1,441,142	0	0.00000	1.00000	100.00
20.5	1,441,142	0	0.00000	1.00000	100.00
21.5	1,441,142	0	0.00000	1.00000	100.00
22.5	1,441,142	0	0.00000	1.00000	100.00
23.5	1,441,142	0	0.00000	1.00000	100.00
24.5	1,441,142	0	0.00000	1.00000	100.00
25.5	1,441,142	0	0.00000	1.00000	100.00
26.5	1,441,142	0	0.00000	1.00000	100.00

Toronto Hydro

Account 1031 - Land - Substations

Placement Band - 1941 - 2022 Experience Band - 2022 - 2022

27.5	1,441,142	0	0.00000	1.00000	100.00
28.5	1,441,142	0	0.00000	1.00000	100.00
29.5	1,441,142	0	0.00000	1.00000	100.00
30.5	1,441,142	0	0.00000	1.00000	100.00
31.5	1,441,142	0	0.00000	1.00000	100.00
32.5	1,441,142	0	0.00000	1.00000	100.00
33.5	1,441,142	0	0.00000	1.00000	100.00
34.5	1,441,142	0	0.00000	1.00000	100.00
35.5	1,441,142	0	0.00000	1.00000	100.00
36.5	1,441,142	0	0.00000	1.00000	100.00
37.5	1,441,142	0	0.00000	1.00000	100.00
38.5	1,441,142	0	0.00000	1.00000	100.00
39.5	1,441,142	0	0.00000	1.00000	100.00
40.5	1,441,142	0	0.00000	1.00000	100.00
41.5	1,441,142	0	0.00000	1.00000	100.00
42.5	1,107,258	0	0.00000	1.00000	100.00
43.5	565,852	0	0.00000	1.00000	100.00
44.5	565,852	0	0.00000	1.00000	100.00
45.5	565,852	0	0.00000	1.00000	100.00
46.5	565,852	0	0.00000	1.00000	100.00
47.5	502,379	0	0.00000	1.00000	100.00
48.5	502,379	0	0.00000	1.00000	100.00
49.5	502,379	0	0.00000	1.00000	100.00
50.5	488,348	0	0.00000	1.00000	100.00
51.5	488,348	0	0.00000	1.00000	100.00
52.5	486,111	0	0.00000	1.00000	100.00
53.5	459,258	0	0.00000	1.00000	100.00
54.5	432,780	0	0.00000	1.00000	100.00
55.5	398,451	0	0.00000	1.00000	100.00
56.5	388,724	0	0.00000	1.00000	100.00
57.5	367,951	0	0.00000	1.00000	100.00

Toronto Hydro

Account 1031 - Land - Substations

Placement Band - 1941 - 2022 Experience Band - 2022 - 2022

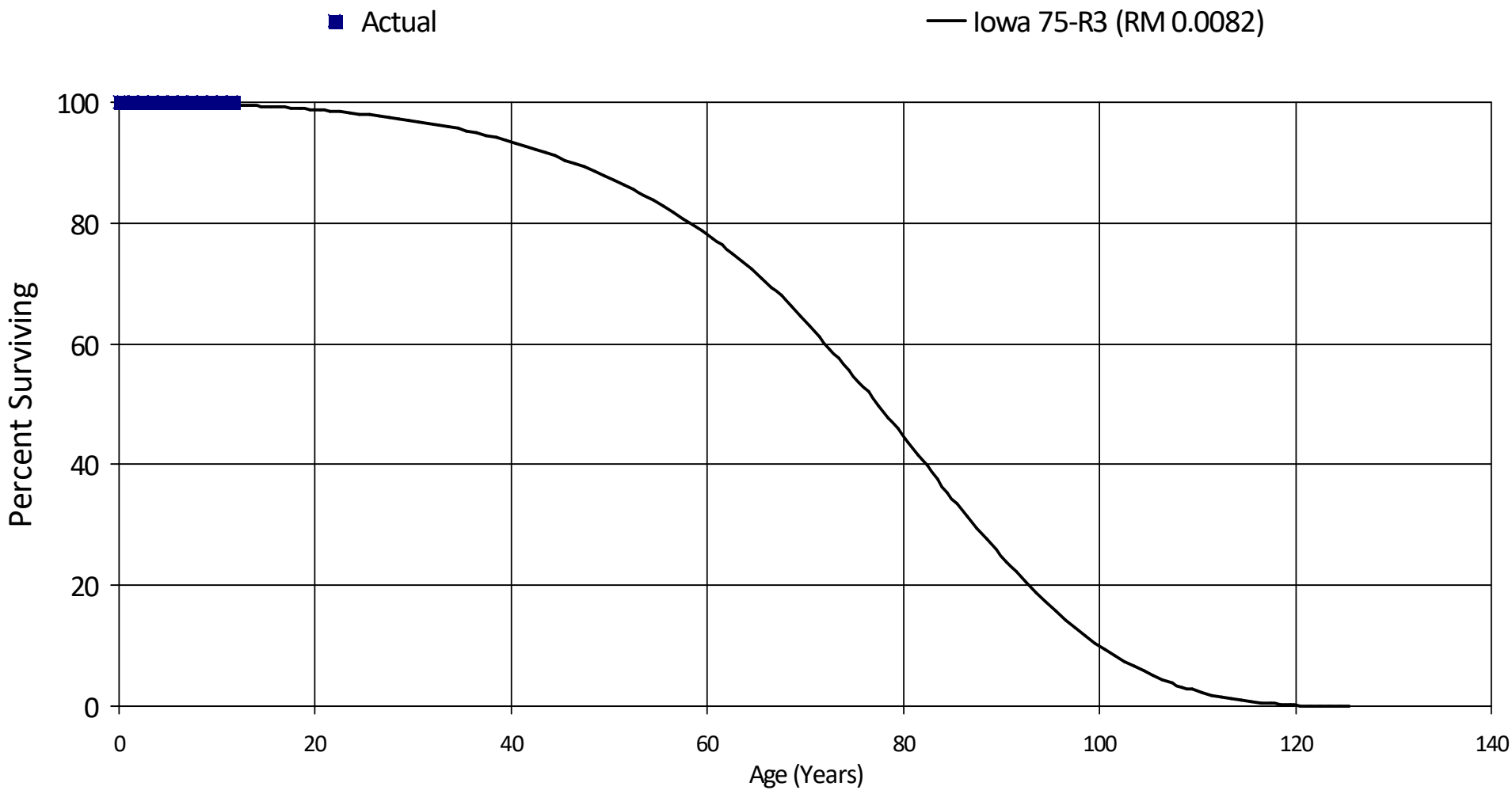
58.5	347,639	0	0.00000	1.00000	100.00
59.5	97,980	0	0.00000	1.00000	100.00
60.5	93,168	0	0.00000	1.00000	100.00
61.5	69,992	0	0.00000	1.00000	100.00
62.5	66,310	0	0.00000	1.00000	100.00
63.5	66,310	0	0.00000	1.00000	100.00
64.5	52,606	0	0.00000	1.00000	100.00
65.5	43,597	0	0.00000	1.00000	100.00
66.5	30,561	0	0.00000	1.00000	100.00
67.5	23,341	0	0.00000	1.00000	100.00
68.5	18,061	0	0.00000	1.00000	100.00
69.5	9,343	0	0.00000	1.00000	100.00
70.5	5,050	0	0.00000	1.00000	100.00
71.5	4,100	0	0.00000	1.00000	100.00
72.5	1,004	0	0.00000	1.00000	100.00
73.5	1,004	0	0.00000	1.00000	100.00
74.5	1,004	0	0.00000	1.00000	100.00
75.5	1,004	0	0.00000	1.00000	100.00
76.5	1,004	0	0.00000	1.00000	100.00
77.5	1,004	0	0.00000	1.00000	100.00
78.5	1,004	0	0.00000	1.00000	100.00
79.5	1,004	0	0.00000	1.00000	100.00
80.5	1,004	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 1051 - Land - Transformer Stations

Placement Band - 2010 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1051 - Land - Transformer Stations

Placement Band - 2010 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

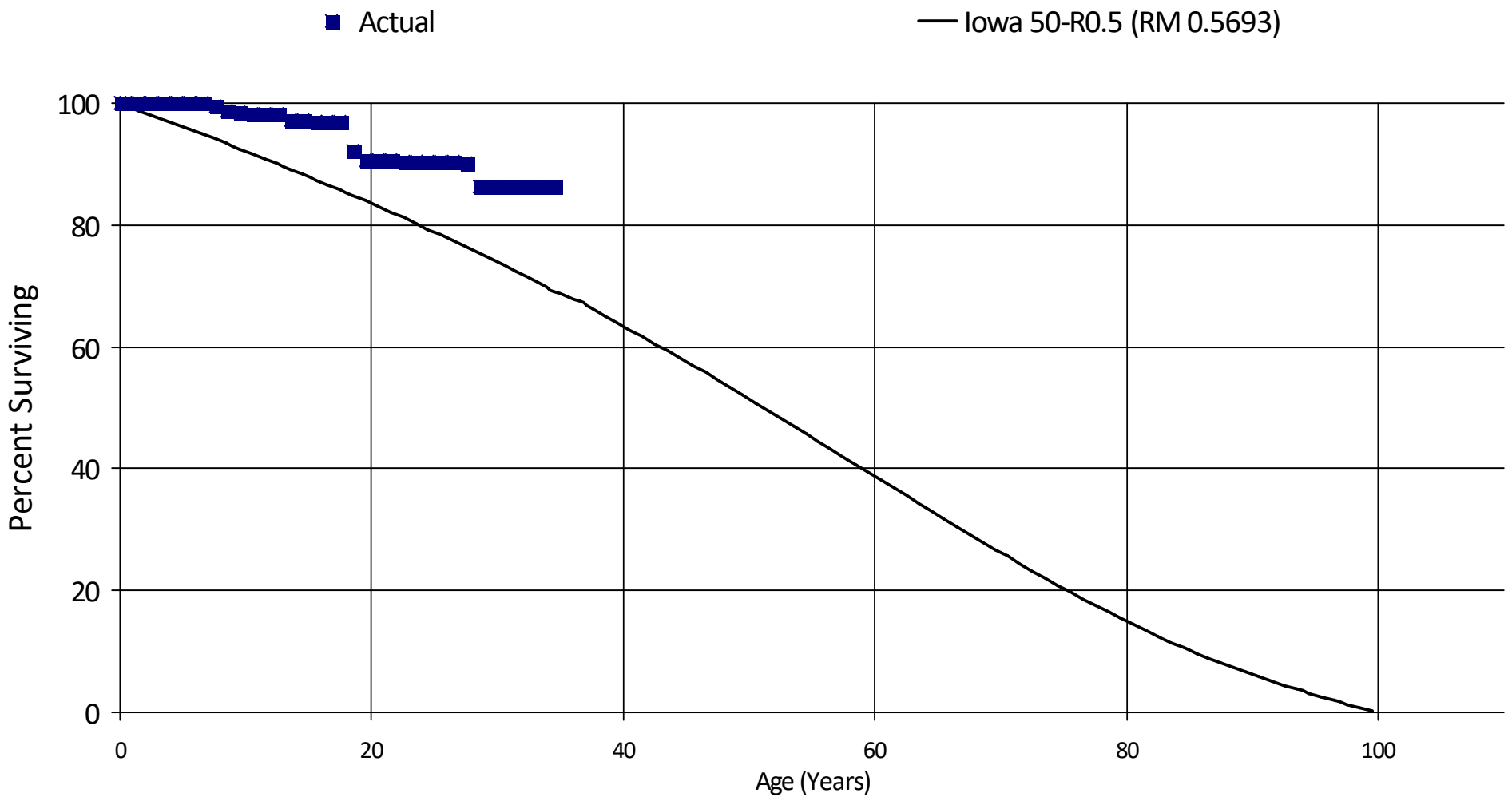
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	5,557,807	0	0.00000	1.00000	100.00
0.5	5,557,807	0	0.00000	1.00000	100.00
1.5	5,557,807	0	0.00000	1.00000	100.00
2.5	5,557,807	0	0.00000	1.00000	100.00
3.5	5,557,807	0	0.00000	1.00000	100.00
4.5	5,557,807	0	0.00000	1.00000	100.00
5.5	5,557,807	0	0.00000	1.00000	100.00
6.5	5,557,807	0	0.00000	1.00000	100.00
7.5	5,557,807	0	0.00000	1.00000	100.00
8.5	5,557,807	0	0.00000	1.00000	100.00
9.5	5,557,807	0	0.00000	1.00000	100.00
10.5	5,557,807	0	0.00000	1.00000	100.00
11.5	5,557,807	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 1101 - Buildings Adm Existing Structures

Placement Band - 1987 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1101 - Buildings Adm Existing Structures

Placement Band - 1987 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	35,148,519	0	0.00000	1.00000	100.00
0.5	35,148,519	0	0.00000	1.00000	100.00
1.5	35,148,519	0	0.00000	1.00000	100.00
2.5	35,148,519	0	0.00000	1.00000	100.00
3.5	35,148,519	0	0.00000	1.00000	100.00
4.5	35,148,519	0	0.00000	1.00000	100.00
5.5	35,148,519	0	0.00000	1.00000	100.00
6.5	35,148,519	180,275	0.00513	0.99487	100.00
7.5	34,968,244	303,381	0.00868	0.99132	99.49
8.5	34,664,863	90,731	0.00262	0.99738	98.63
9.5	34,574,132	19,282	0.00056	0.99944	98.37
10.5	34,554,849	1,945	0.00006	0.99994	98.31
11.5	34,552,904	0	0.00000	1.00000	98.30
12.5	34,552,093	404,182	0.01170	0.98830	98.30
13.5	33,594,096	16,712	0.00050	0.99950	97.15
14.5	32,923,737	25,669	0.00078	0.99922	97.10
15.5	32,647,225	0	0.00000	1.00000	97.02
16.5	32,423,798	39,385	0.00121	0.99879	97.02
17.5	32,042,613	1,573,561	0.04911	0.95089	96.90
18.5	30,136,148	503,850	0.01672	0.98328	92.14
19.5	29,632,298	2,814	0.00009	0.99991	90.60
20.5	29,617,811	23,687	0.00080	0.99920	90.59
21.5	29,263,244	15,762	0.00054	0.99946	90.52
22.5	28,213,574	6,266	0.00022	0.99978	90.47
23.5	27,832,454	55,131	0.00198	0.99802	90.45
24.5	26,427,050	9	0.00000	1.00000	90.27
25.5	24,924,459	1,797	0.00007	0.99993	90.27
26.5	3,751,713	6,711	0.00179	0.99821	90.26

Toronto Hydro

Account 1101 - Buildings Adm Existing Structures

Placement Band - 1987 - 2022 Experience Band - 2014 - 2022

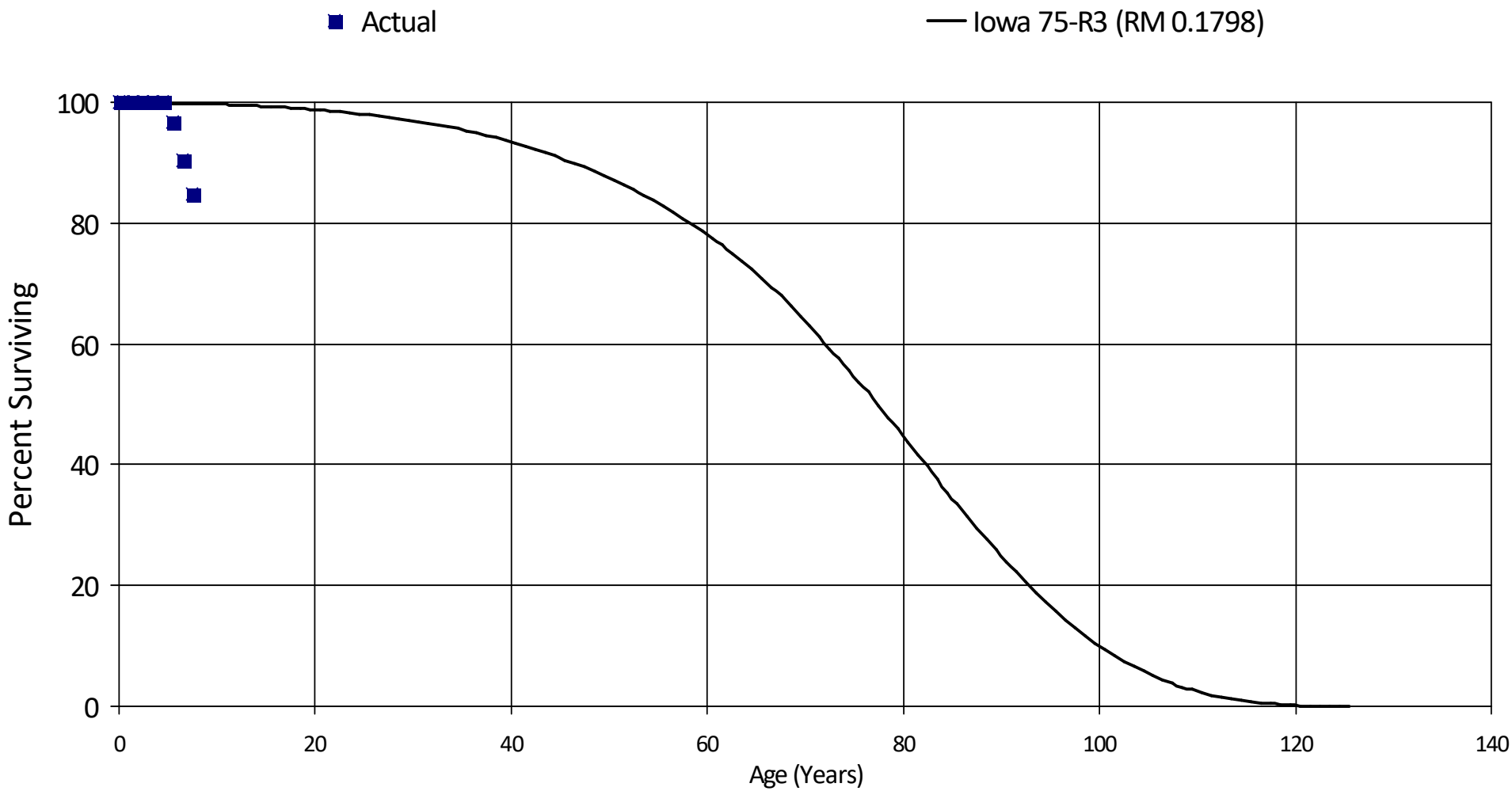
27.5	2,323,639	95,347	0.04103	0.95897	90.10
28.5	1,414,018	192	0.00014	0.99986	86.40
29.5	685,093	14	0.00002	0.99998	86.39
30.5	597,600	70	0.00012	0.99988	86.39
31.5	248,646	0	0.00000	1.00000	86.38
32.5	195,193	0	0.00000	1.00000	86.38
33.5	181,160	0	0.00000	1.00000	86.38
34.5	6,558	0	0.00000	1.00000	86.38
	Totals:	3,366,773			

Toronto Hydro

Account 1103 - Buildings Adm Substructure

Placement Band - 2010 - 2022 Experience Band - 2017 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1103 - Buildings Adm Substructure

Placement Band - 2010 - 2022 Experience Band - 2017 - 2022

RETIREMENT RATE ANALYSIS

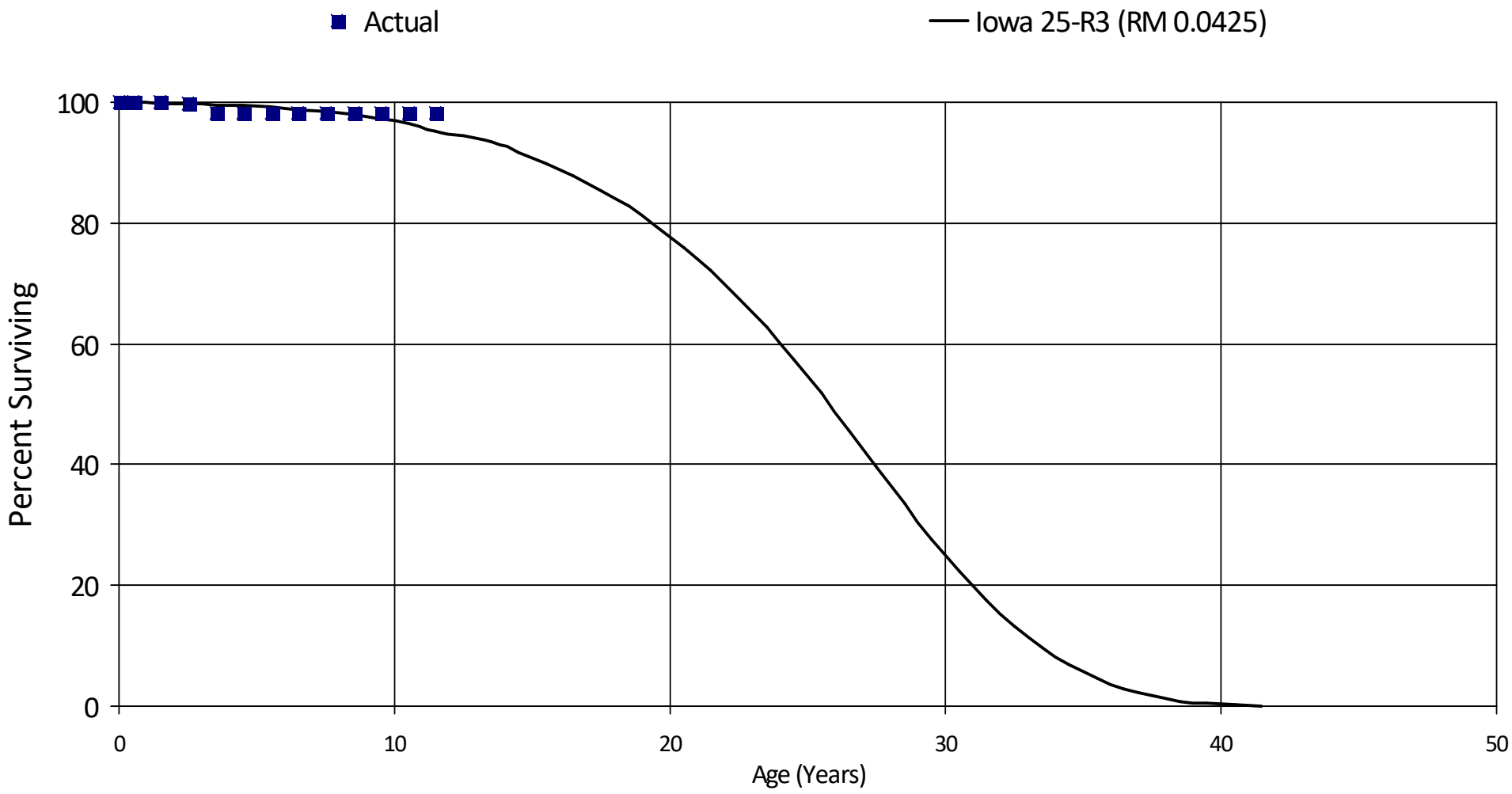
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	8,754,399	0	0.00000	1.00000	100.00
0.5	8,754,399	0	0.00000	1.00000	100.00
1.5	5,241,163	0	0.00000	1.00000	100.00
2.5	4,637,267	0	0.00000	1.00000	100.00
3.5	4,637,267	0	0.00000	1.00000	100.00
4.5	4,565,344	152,260	0.03335	0.96665	100.00
5.5	4,413,084	287,953	0.06525	0.93475	96.66
6.5	4,125,131	252,298	0.06116	0.93884	90.35
7.5	2,148,689	2,148,689	1.00000		84.82
	Totals:	2,841,200			

Toronto Hydro

Account 1105 - Buildings Adm Shell Site

Placement Band - 2010 - 2022 Experience Band - 2015 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1105 - Buildings Adm Shell Site

Placement Band - 2010 - 2022 Experience Band - 2015 - 2022

RETIREMENT RATE ANALYSIS

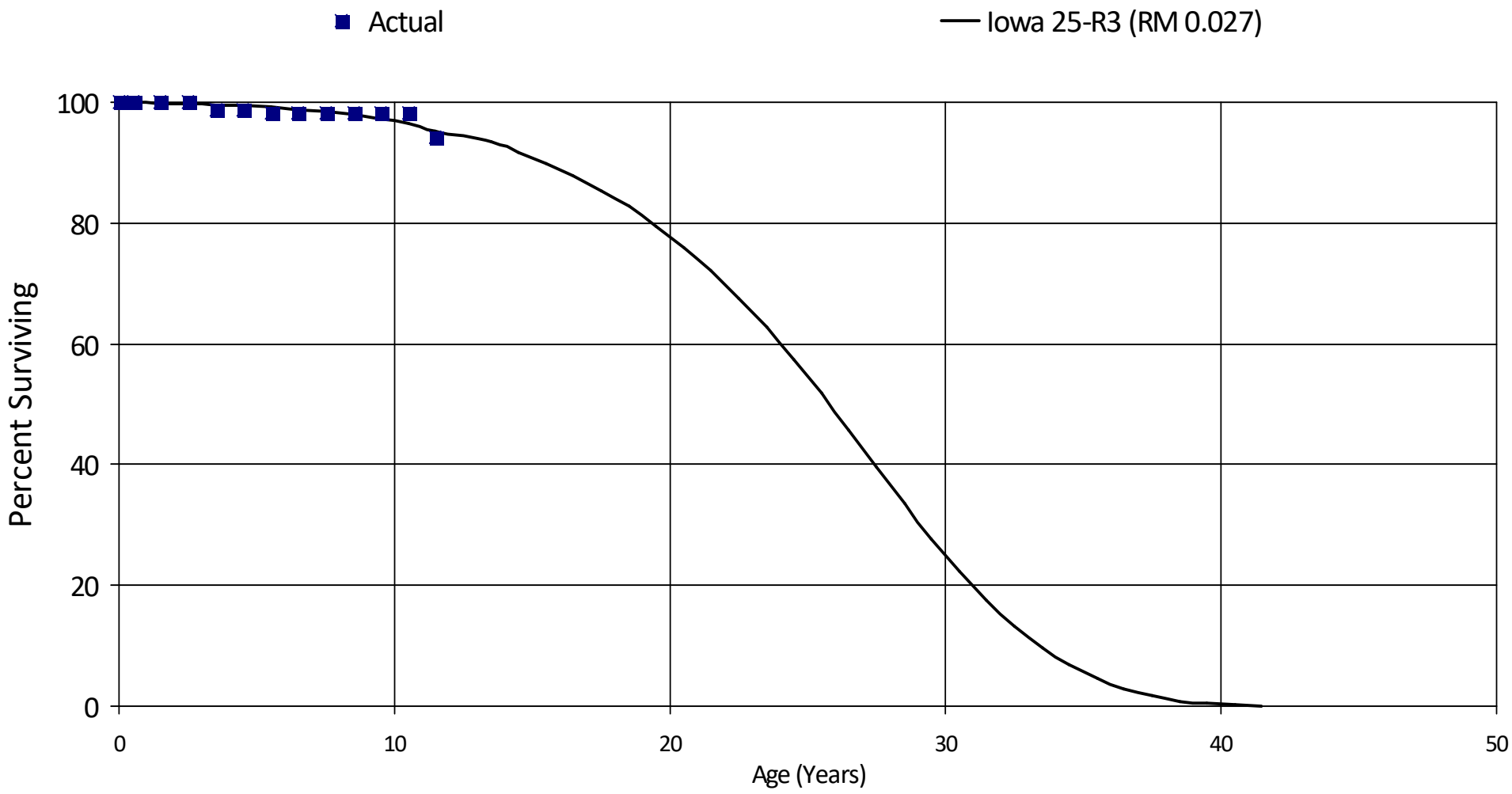
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	13,577,212	0	0.00000	1.00000	100.00
0.5	13,182,906	0	0.00000	1.00000	100.00
1.5	11,005,347	24,861	0.00226	0.99774	100.00
2.5	10,193,437	149,548	0.01467	0.98533	99.77
3.5	10,023,846	0	0.00000	1.00000	98.31
4.5	9,958,305	14,356	0.00144	0.99856	98.31
5.5	9,934,492	0	0.00000	1.00000	98.17
6.5	7,111,934	0	0.00000	1.00000	98.17
7.5	5,598,587	-20	0.00000	1.00000	98.17
8.5	4,607,500	0	0.00000	1.00000	98.17
9.5	1,128,307	0	0.00000	1.00000	98.17
10.5	961,911	0	0.00000	1.00000	98.17
11.5	942,992	0	0.00000	1.00000	98.17
	Totals:	188,745			

Toronto Hydro

Account 1107 - Buildings Adm Interior

Placement Band - 2010 - 2022 Experience Band - 2017 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1107 - Buildings Adm Interior

Placement Band - 2010 - 2022 Experience Band - 2017 - 2022

RETIREMENT RATE ANALYSIS

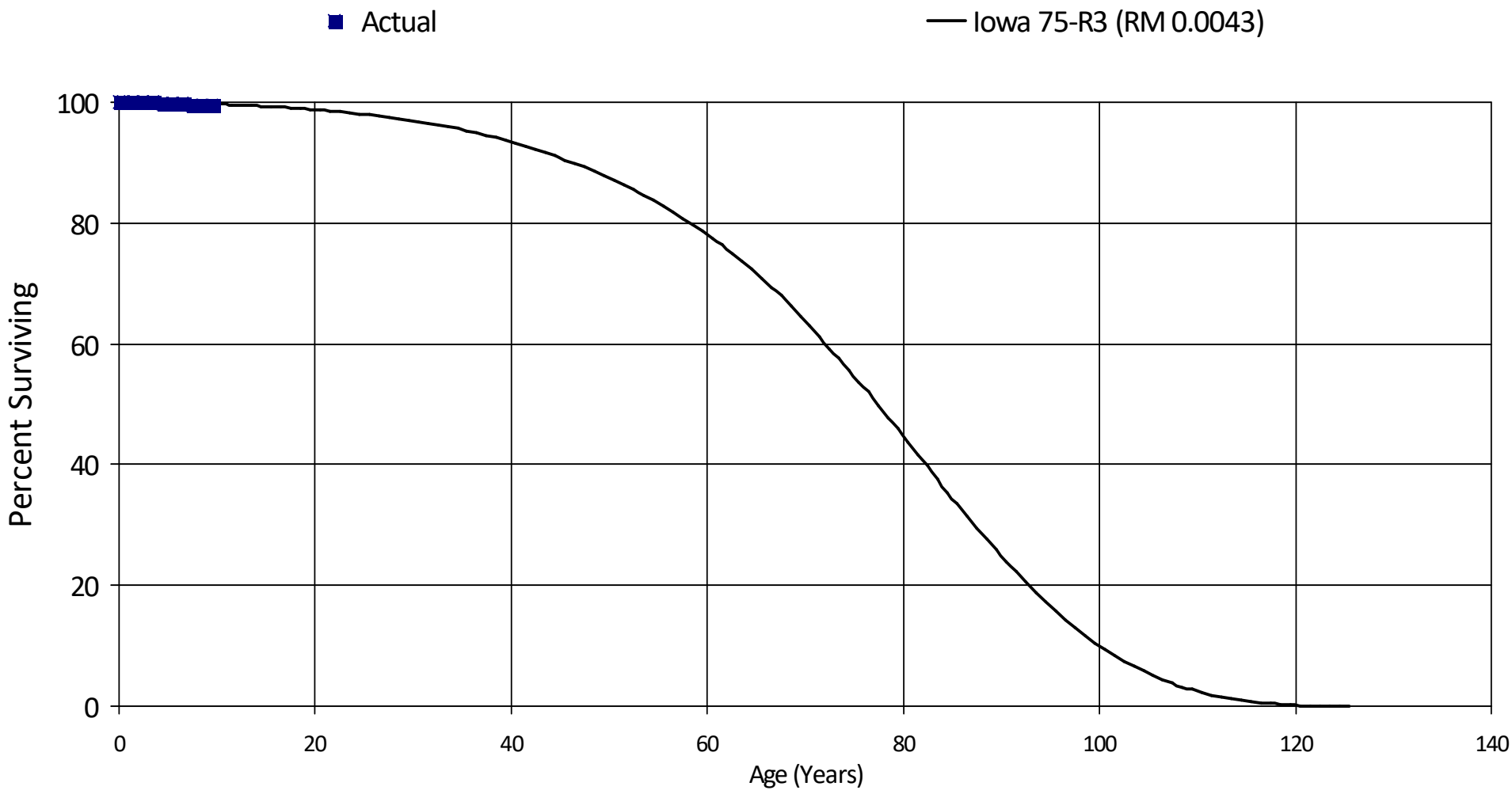
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	19,281,720	0	0.00000	1.00000	100.00
0.5	16,407,205	0	0.00000	1.00000	100.00
1.5	11,623,242	0	0.00000	1.00000	100.00
2.5	9,619,198	115,608	0.01202	0.98798	100.00
3.5	9,487,190	0	0.00000	1.00000	98.80
4.5	9,314,695	62,983	0.00676	0.99324	98.80
5.5	8,750,769	2,040	0.00023	0.99977	98.13
6.5	6,051,995	0	0.00000	1.00000	98.11
7.5	2,222,847	-207	-0.00009	1.00009	98.11
8.5	2,168,319	0	0.00000	1.00000	98.12
9.5	2,053,312	0	0.00000	1.00000	98.12
10.5	1,577,167	64,488	0.04089	0.95911	98.12
11.5	508,480	0	0.00000	1.00000	94.11
	Totals:	244,912			

Toronto Hydro

Account 1113 - Buildings Service Centres Substructure

Placement Band - 2010 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1113 - Buildings Service Centres Substructure

Placement Band - 2010 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

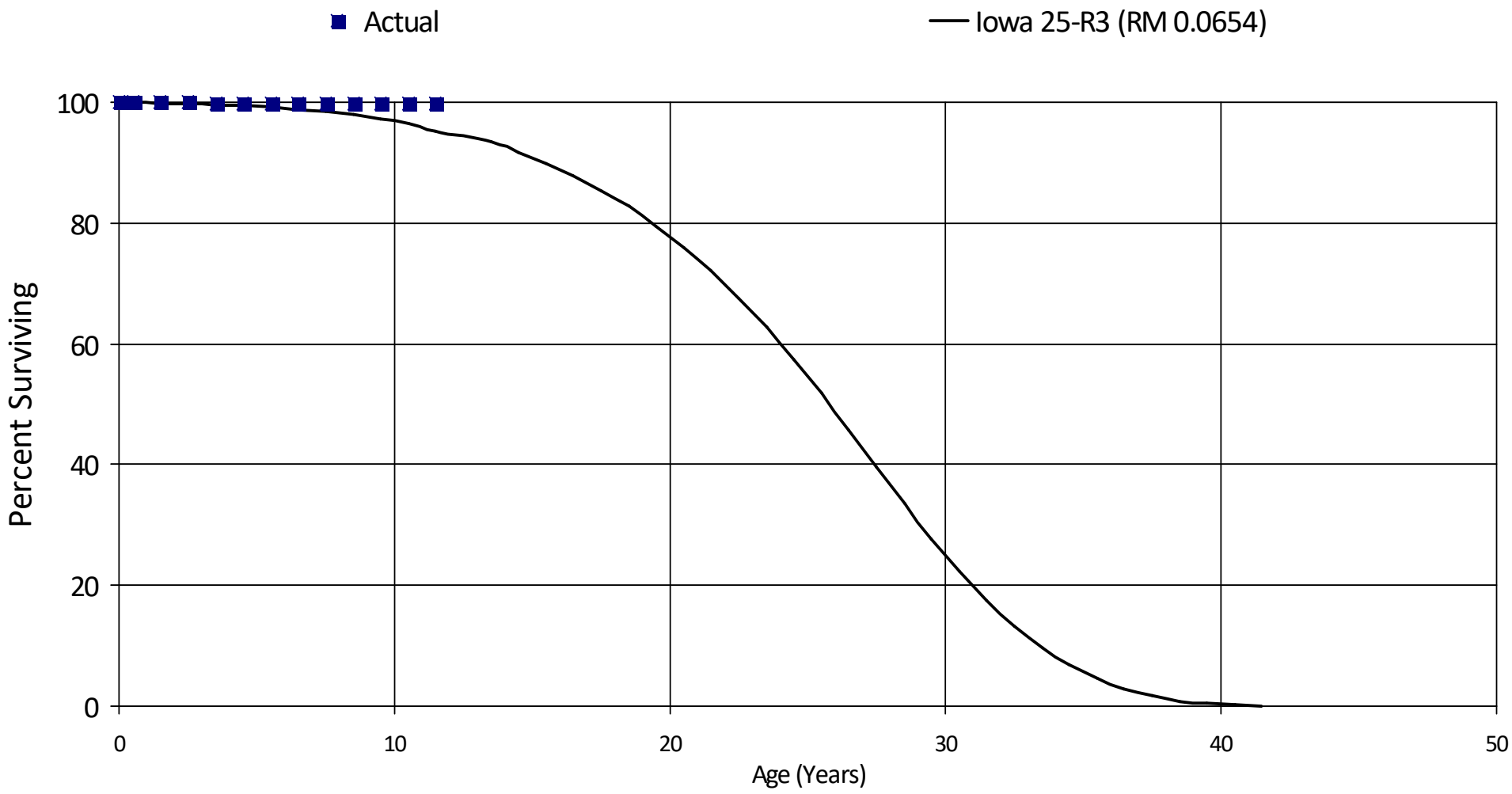
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	32,432,533	0	0.00000	1.00000	100.00
0.5	30,827,396	0	0.00000	1.00000	100.00
1.5	30,731,367	0	0.00000	1.00000	100.00
2.5	30,731,367	6,568	0.00021	0.99979	100.00
3.5	30,478,188	54,181	0.00178	0.99822	99.98
4.5	30,211,134	0	0.00000	1.00000	99.80
5.5	20,128,940	0	0.00000	1.00000	99.80
6.5	1,792,170	5,605	0.00313	0.99687	99.80
7.5	290,873	0	0.00000	1.00000	99.49
8.5	3,278	0	0.00000	1.00000	99.49
9.5	0	0	0.00000	0.00000	99.49
	Totals:	66,354			

Toronto Hydro

Account 1115 - Buildings Service Centres Shell Site

Placement Band - 2010 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1115 - Buildings Service Centres Shell Site

Placement Band - 2010 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

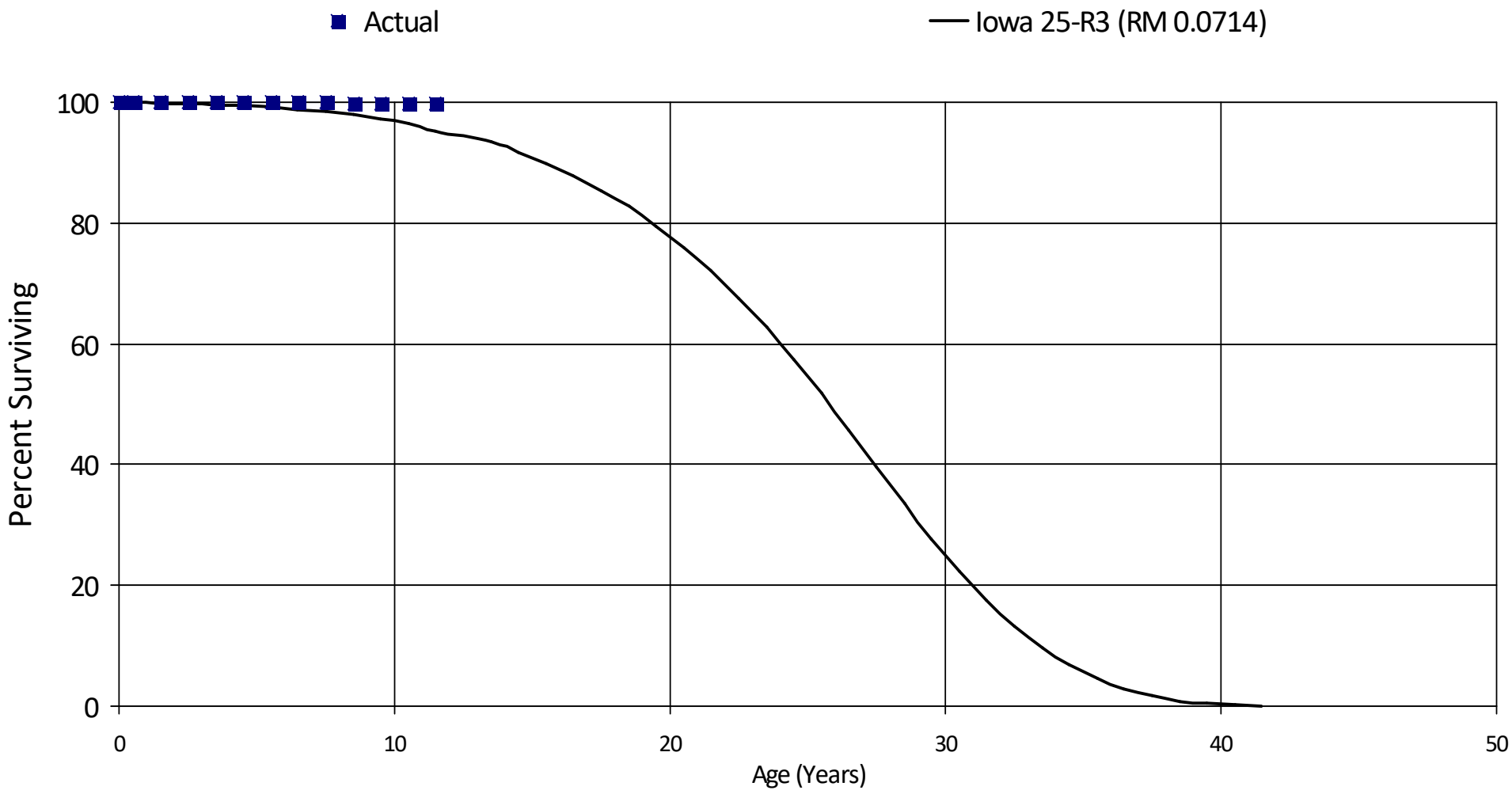
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	62,517,003	0	0.00000	1.00000	100.00
0.5	61,227,501	0	0.00000	1.00000	100.00
1.5	60,956,221	0	0.00000	1.00000	100.00
2.5	59,517,929	222,993	0.00375	0.99625	100.00
3.5	58,411,592	0	0.00000	1.00000	99.62
4.5	58,278,780	0	0.00000	1.00000	99.62
5.5	36,283,363	0	0.00000	1.00000	99.62
6.5	18,386,618	0	0.00000	1.00000	99.62
7.5	12,748,984	0	0.00000	1.00000	99.62
8.5	3,567,877	0	0.00000	1.00000	99.62
9.5	1,823,090	0	0.00000	1.00000	99.62
10.5	484,970	0	0.00000	1.00000	99.62
11.5	177,780	0	0.00000	1.00000	99.62
	Totals:	222,993			

Toronto Hydro

Account 1117 - Buildings Service Centres Interior

Placement Band - 2010 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1117 - Buildings Service Centres Interior

Placement Band - 2010 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

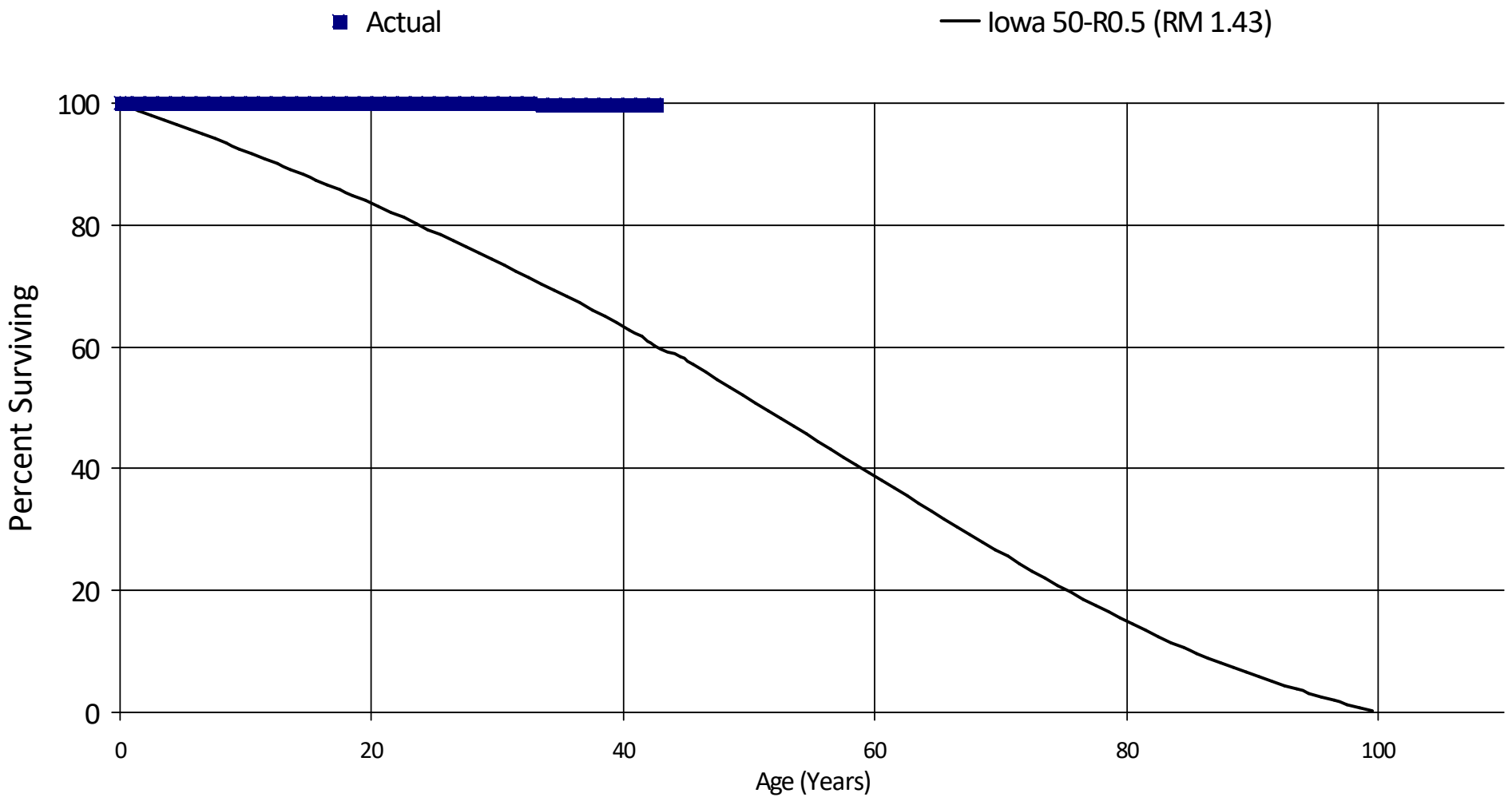
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	104,209,461	0	0.00000	1.00000	100.00
0.5	102,988,500	0	0.00000	1.00000	100.00
1.5	99,314,990	75,965	0.00076	0.99924	100.00
2.5	98,155,298	12,933	0.00013	0.99987	99.92
3.5	96,303,208	10,124	0.00011	0.99989	99.91
4.5	94,123,285	3,857	0.00004	0.99996	99.90
5.5	62,882,936	0	0.00000	1.00000	99.90
6.5	46,441,296	0	0.00000	1.00000	99.90
7.5	17,307,103	5,953	0.00034	0.99966	99.90
8.5	5,304,252	0	0.00000	1.00000	99.87
9.5	2,967,596	0	0.00000	1.00000	99.87
10.5	2,272,618	0	0.00000	1.00000	99.87
11.5	85,685	0	0.00000	1.00000	99.87
	Totals:	108,832			

Toronto Hydro

Account 1131 - Buildings Substation Structure

Placement Band - 1979 - 2022 Experience Band - 2016 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1131 - Buildings Substation Structure

Placement Band - 1979 - 2022 Experience Band - 2016 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	18,947,027	0	0.00000	1.00000	100.00
0.5	18,947,027	0	0.00000	1.00000	100.00
1.5	18,947,027	0	0.00000	1.00000	100.00
2.5	18,947,027	0	0.00000	1.00000	100.00
3.5	18,947,027	0	0.00000	1.00000	100.00
4.5	18,947,027	0	0.00000	1.00000	100.00
5.5	18,947,027	0	0.00000	1.00000	100.00
6.5	18,947,027	0	0.00000	1.00000	100.00
7.5	18,947,027	2,280	0.00012	0.99988	100.00
8.5	18,944,747	0	0.00000	1.00000	99.99
9.5	18,944,747	0	0.00000	1.00000	99.99
10.5	18,944,747	12,033	0.00064	0.99936	99.99
11.5	18,932,714	0	0.00000	1.00000	99.93
12.5	18,892,937	76	0.00000	1.00000	99.93
13.5	18,892,861	0	0.00000	1.00000	99.93
14.5	17,393,429	150	0.00001	0.99999	99.93
15.5	16,473,759	0	0.00000	1.00000	99.93
16.5	15,317,094	0	0.00000	1.00000	99.93
17.5	14,140,687	0	0.00000	1.00000	99.93
18.5	13,780,251	0	0.00000	1.00000	99.93
19.5	13,746,855	0	0.00000	1.00000	99.93
20.5	13,534,314	0	0.00000	1.00000	99.93
21.5	12,942,270	0	0.00000	1.00000	99.93
22.5	12,168,621	0	0.00000	1.00000	99.93
23.5	10,563,473	0	0.00000	1.00000	99.93
24.5	9,972,806	0	0.00000	1.00000	99.93
25.5	8,447,470	0	0.00000	1.00000	99.93
26.5	7,645,103	2,568	0.00034	0.99966	99.93

Toronto Hydro

Account 1131 - Buildings Substation Structure

Placement Band - 1979 - 2022 Experience Band - 2016 - 2022

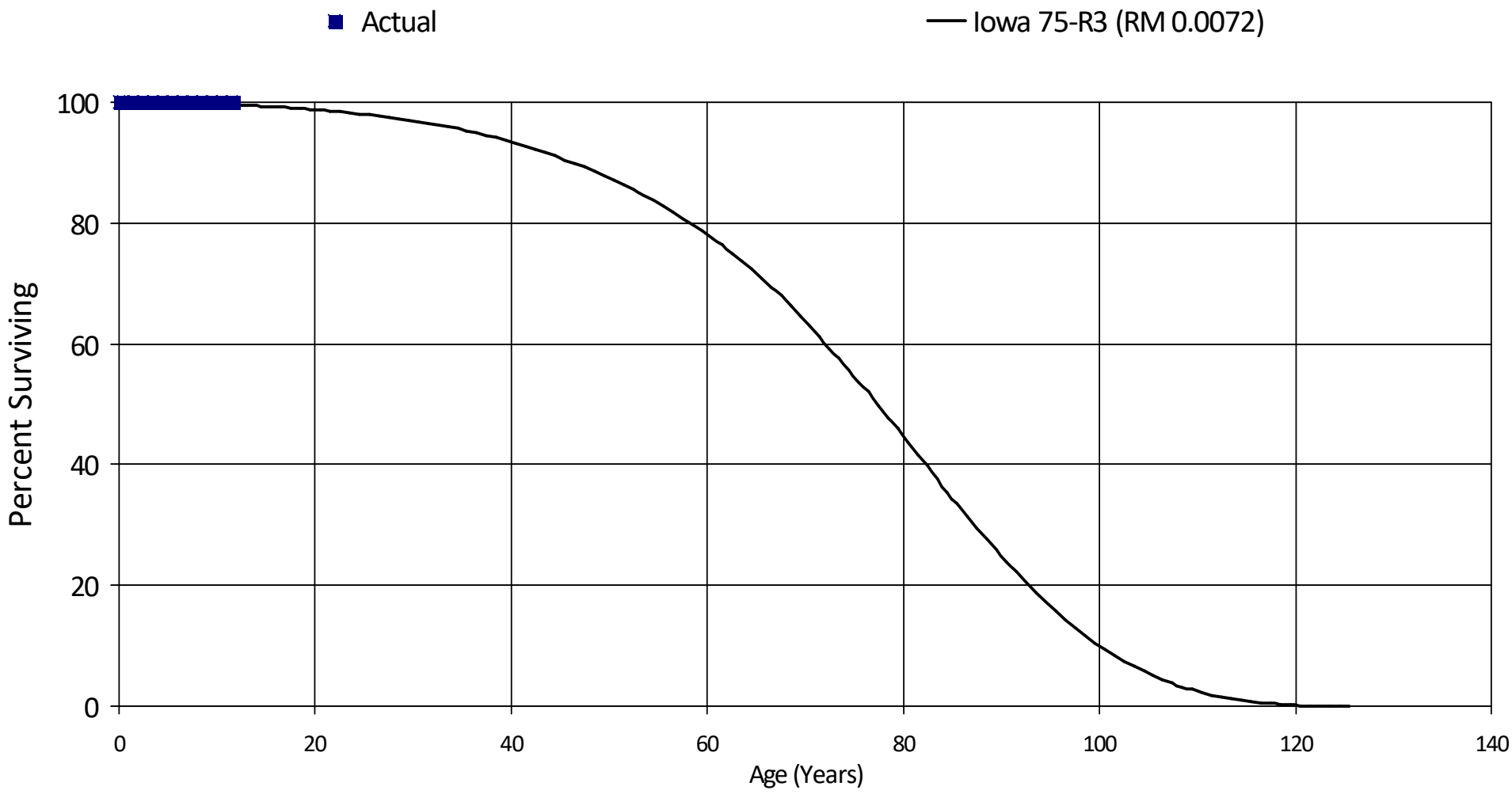
27.5	7,271,939	0	0.00000	1.00000	99.90
28.5	6,833,434	0	0.00000	1.00000	99.90
29.5	5,835,993	0	0.00000	1.00000	99.90
30.5	3,067,155	0	0.00000	1.00000	99.90
31.5	2,845,641	0	0.00000	1.00000	99.90
32.5	2,570,869	1,947	0.00076	0.99924	99.90
33.5	1,289,264	0	0.00000	1.00000	99.82
34.5	895,268	0	0.00000	1.00000	99.82
35.5	720,756	0	0.00000	1.00000	99.82
36.5	647,577	0	0.00000	1.00000	99.82
37.5	436,794	0	0.00000	1.00000	99.82
38.5	348,451	0	0.00000	1.00000	99.82
39.5	277,234	0	0.00000	1.00000	99.82
40.5	256,556	0	0.00000	1.00000	99.82
41.5	244,314	0	0.00000	1.00000	99.82
42.5	21,298	0	0.00000	1.00000	99.82
	Totals:	19,054			

Toronto Hydro

Account 1133 - Buildings Substation Substructure

Placement Band - 2010 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1133 - Buildings Substation Substructure

Placement Band - 2010 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

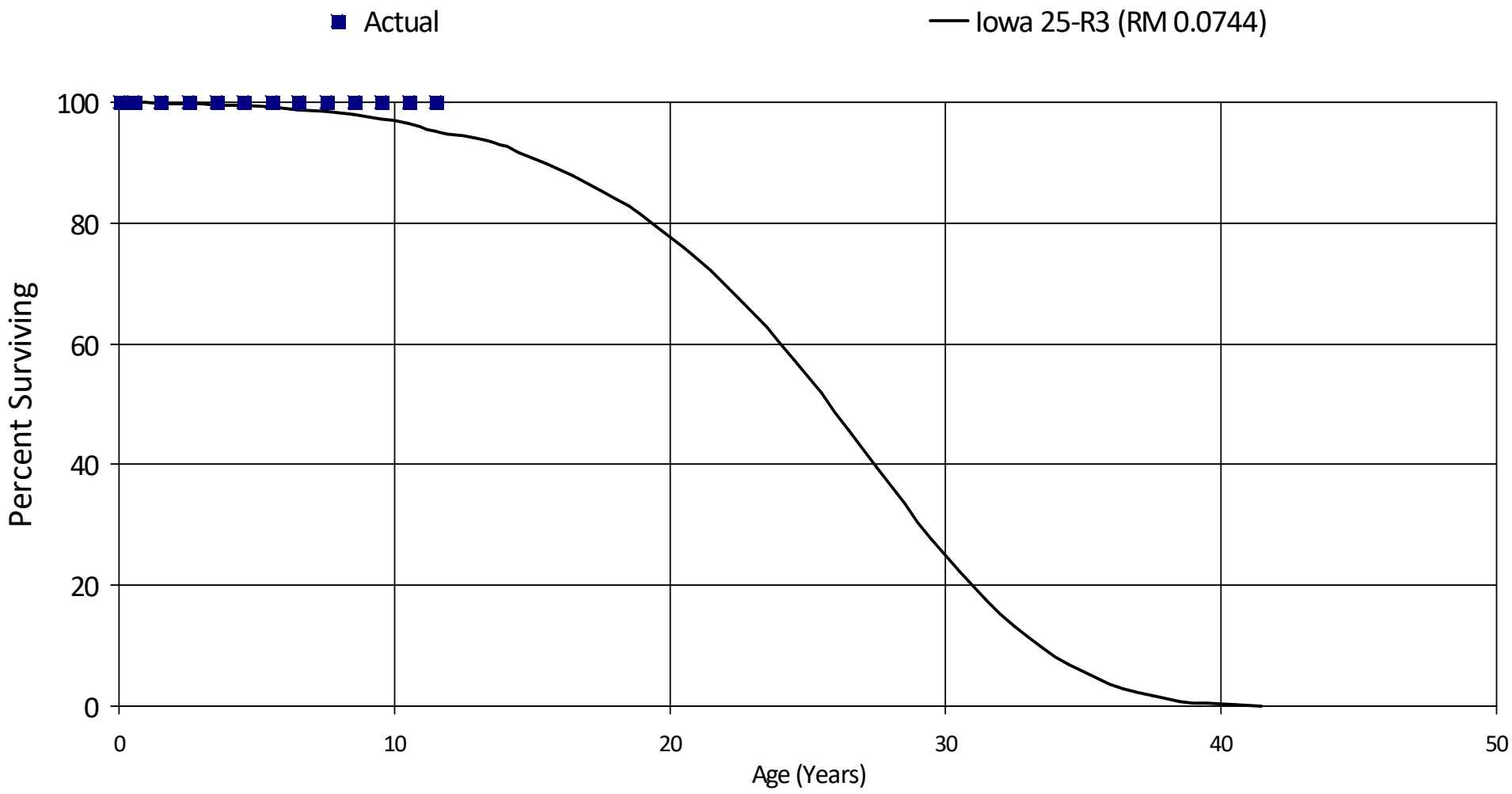
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	106,054,854	0	0.00000	1.00000	100.00
0.5	102,472,543	0	0.00000	1.00000	100.00
1.5	100,911,254	0	0.00000	1.00000	100.00
2.5	99,039,389	1,815	0.00002	0.99998	100.00
3.5	98,924,016	20,597	0.00021	0.99979	100.00
4.5	86,636,655	14,888	0.00017	0.99983	99.98
5.5	79,672,864	0	0.00000	1.00000	99.96
6.5	19,079,130	0	0.00000	1.00000	99.96
7.5	106,242	0	0.00000	1.00000	99.96
8.5	106,242	0	0.00000	1.00000	99.96
9.5	106,242	0	0.00000	1.00000	99.96
10.5	64,143	0	0.00000	1.00000	99.96
11.5	0	0	0.00000	0.00000	99.96
	Totals:	37,300			

Toronto Hydro

Account 1135 - Buildings Substation Shell Site

Placement Band - 2010 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1135 - Buildings Substation Shell Site

Placement Band - 2010 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

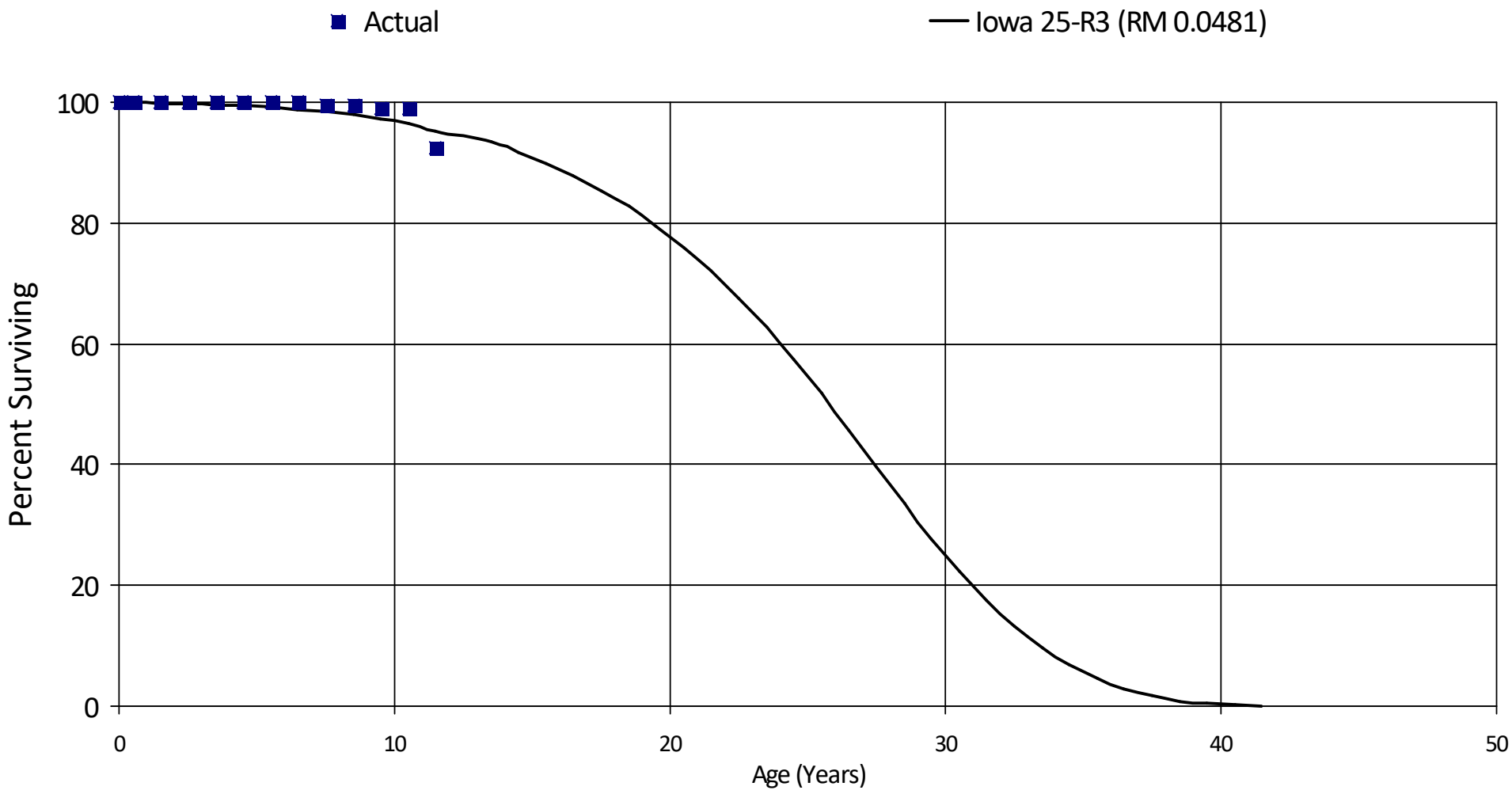
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	18,152,858	0	0.00000	1.00000	100.00
0.5	15,278,762	0	0.00000	1.00000	100.00
1.5	14,273,686	0	0.00000	1.00000	100.00
2.5	13,374,502	0	0.00000	1.00000	100.00
3.5	5,096,656	0	0.00000	1.00000	100.00
4.5	4,744,650	0	0.00000	1.00000	100.00
5.5	4,726,845	0	0.00000	1.00000	100.00
6.5	3,767,535	0	0.00000	1.00000	100.00
7.5	2,974,579	0	0.00000	1.00000	100.00
8.5	2,460,776	0	0.00000	1.00000	100.00
9.5	2,164,886	0	0.00000	1.00000	100.00
10.5	2,119,047	0	0.00000	1.00000	100.00
11.5	884,472	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 1137 - Buildings Substation Interior

Placement Band - 2010 - 2022 Experience Band - 2016 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1137 - Buildings Substation Interior

Placement Band - 2010 - 2022 Experience Band - 2016 - 2022

RETIREMENT RATE ANALYSIS

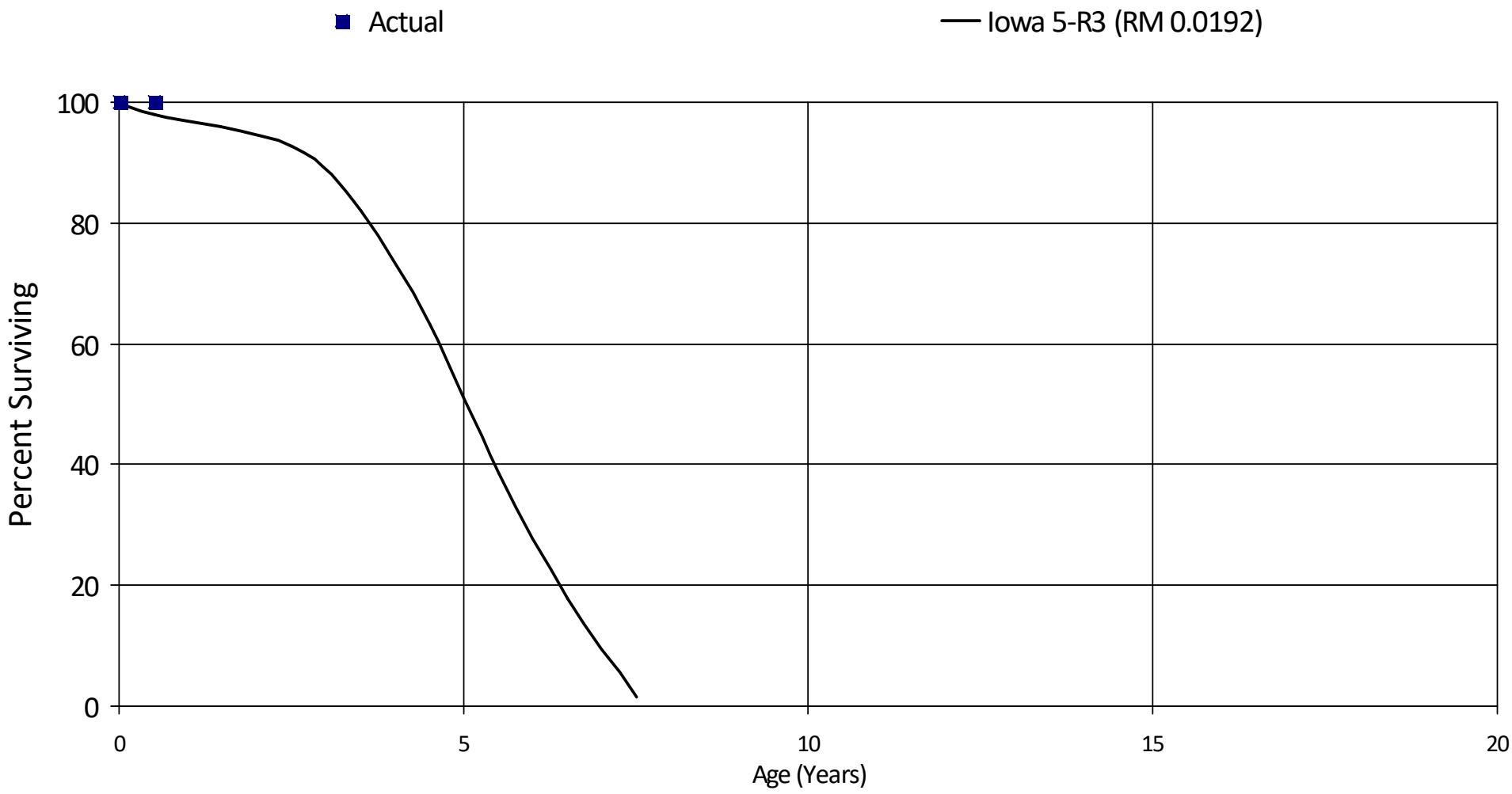
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	37,980,338	0	0.00000	1.00000	100.00
0.5	29,661,142	0	0.00000	1.00000	100.00
1.5	26,984,194	0	0.00000	1.00000	100.00
2.5	22,051,881	0	0.00000	1.00000	100.00
3.5	18,387,901	0	0.00000	1.00000	100.00
4.5	17,757,174	6,236	0.00035	0.99965	100.00
5.5	12,108,758	0	0.00000	1.00000	99.96
6.5	9,329,548	50,275	0.00539	0.99461	99.96
7.5	6,612,049	0	0.00000	1.00000	99.42
8.5	4,666,078	23,825	0.00511	0.99489	99.42
9.5	2,270,589	0	0.00000	1.00000	98.91
10.5	802,684	53,944	0.06720	0.93280	98.91
11.5	292,838	0	0.00000	1.00000	92.26
	Totals:	134,280			

Toronto Hydro

Account 1171 - Leasehold Improvements - Admin

Placement Band - 2021 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1171 - Leasehold Improvements - Admin

Placement Band - 2021 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

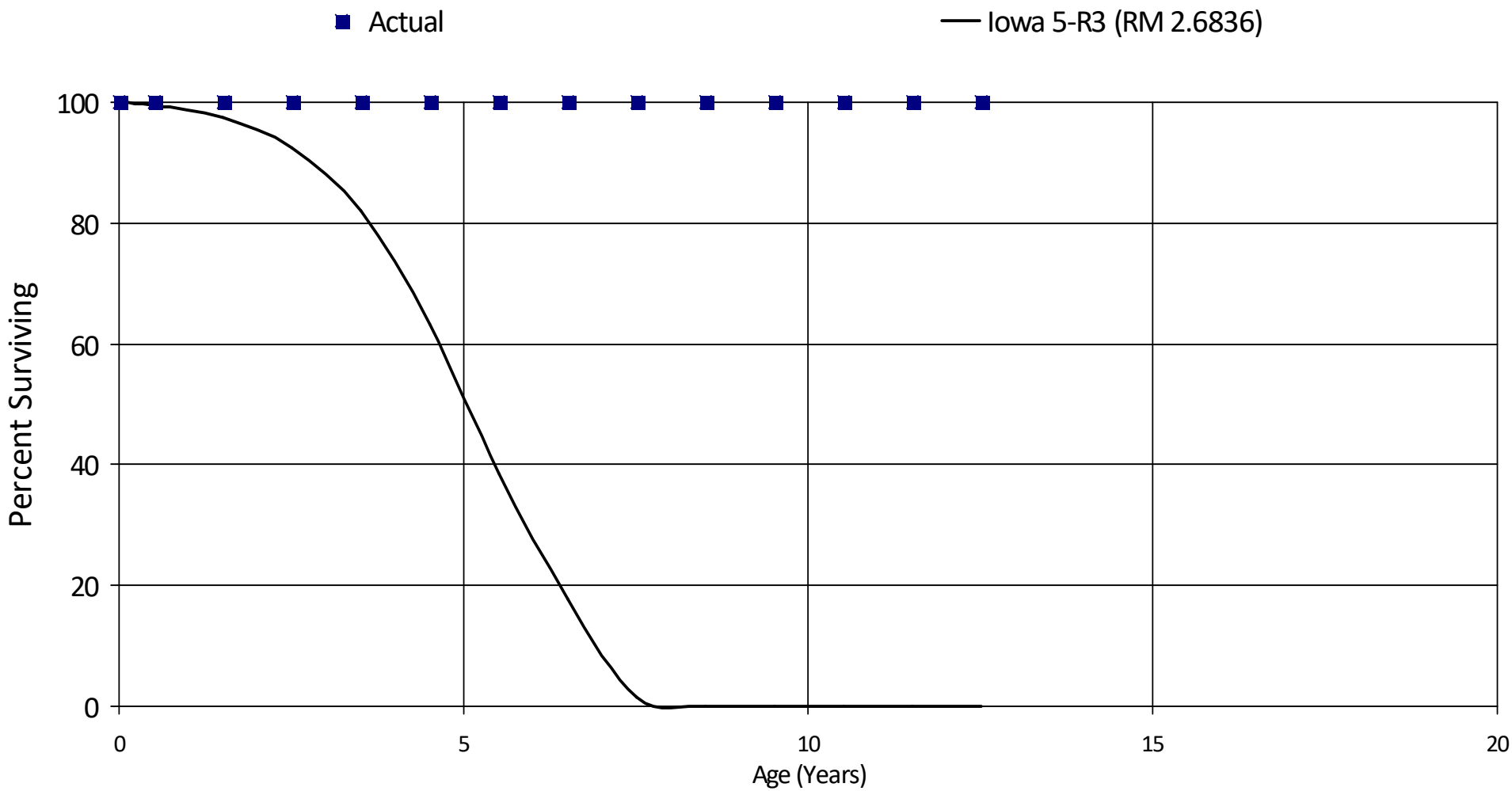
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	36,269	0	0.00000	1.00000	100.00
0.5	36,269	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 1173 - Leasehold Improvements - Service Centres

Placement Band - 2009 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 1173 - Leasehold Improvements - Service Centres

Placement Band - 2009 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

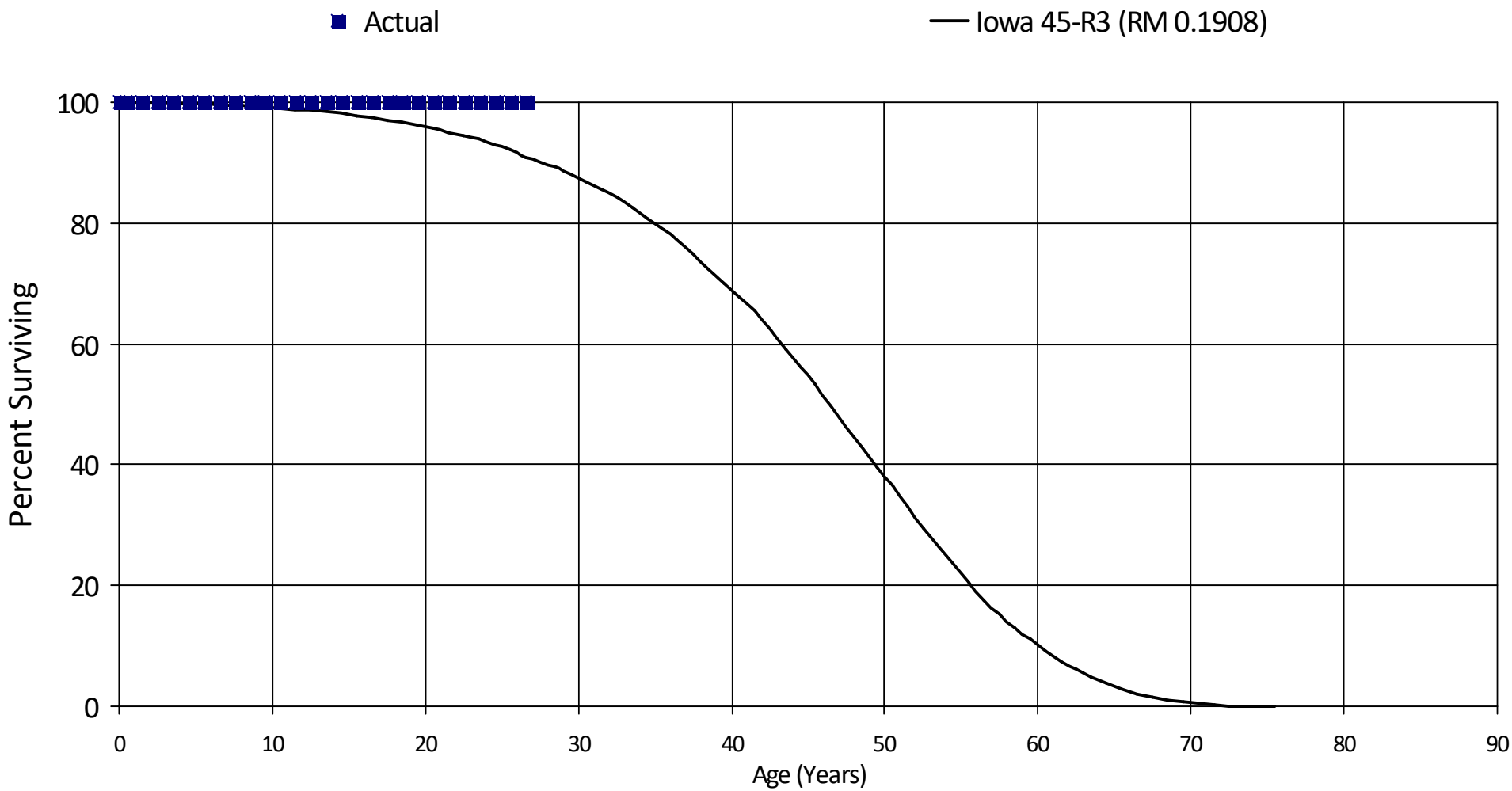
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	947,147	0	0.00000	1.00000	100.00
0.5	947,147	0	0.00000	1.00000	100.00
1.5	947,147	0	0.00000	1.00000	100.00
2.5	753,840	0	0.00000	1.00000	100.00
3.5	753,840	0	0.00000	1.00000	100.00
4.5	753,840	0	0.00000	1.00000	100.00
5.5	753,840	0	0.00000	1.00000	100.00
6.5	753,840	0	0.00000	1.00000	100.00
7.5	753,840	0	0.00000	1.00000	100.00
8.5	701,434	0	0.00000	1.00000	100.00
9.5	698,312	0	0.00000	1.00000	100.00
10.5	268,978	0	0.00000	1.00000	100.00
11.5	132,441	0	0.00000	1.00000	100.00
12.5	7,035	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 2011 - Transformer Station Equip - Power Transformer

Placement Band - 1995 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2011 - Transformer Station Equip - Power Transformer

Placement Band - 1995 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	25,497,963	0	0.00000	1.00000	100.00
0.5	25,497,963	0	0.00000	1.00000	100.00
1.5	25,497,963	0	0.00000	1.00000	100.00
2.5	25,497,963	0	0.00000	1.00000	100.00
3.5	25,497,963	0	0.00000	1.00000	100.00
4.5	25,497,963	0	0.00000	1.00000	100.00
5.5	5,662,636	0	0.00000	1.00000	100.00
6.5	5,507,942	0	0.00000	1.00000	100.00
7.5	5,507,942	0	0.00000	1.00000	100.00
8.5	5,507,942	0	0.00000	1.00000	100.00
9.5	5,507,942	0	0.00000	1.00000	100.00
10.5	5,058,583	0	0.00000	1.00000	100.00
11.5	4,499,118	0	0.00000	1.00000	100.00
12.5	4,499,118	0	0.00000	1.00000	100.00
13.5	4,499,118	0	0.00000	1.00000	100.00
14.5	4,499,118	0	0.00000	1.00000	100.00
15.5	4,499,118	0	0.00000	1.00000	100.00
16.5	4,499,118	0	0.00000	1.00000	100.00
17.5	4,499,118	0	0.00000	1.00000	100.00
18.5	4,499,118	0	0.00000	1.00000	100.00
19.5	4,499,118	0	0.00000	1.00000	100.00
20.5	4,499,118	0	0.00000	1.00000	100.00
21.5	4,499,118	0	0.00000	1.00000	100.00
22.5	4,499,118	0	0.00000	1.00000	100.00
23.5	4,499,118	0	0.00000	1.00000	100.00
24.5	4,499,118	0	0.00000	1.00000	100.00
25.5	4,499,118	0	0.00000	1.00000	100.00
26.5	4,499,118	2,249,559	0.50000	0.50000	100.00

Toronto Hydro

Account 2011 - Transformer Station Equip - Power Transformer

Placement Band - 1995 - 2022 Experience Band - 2022 - 2022

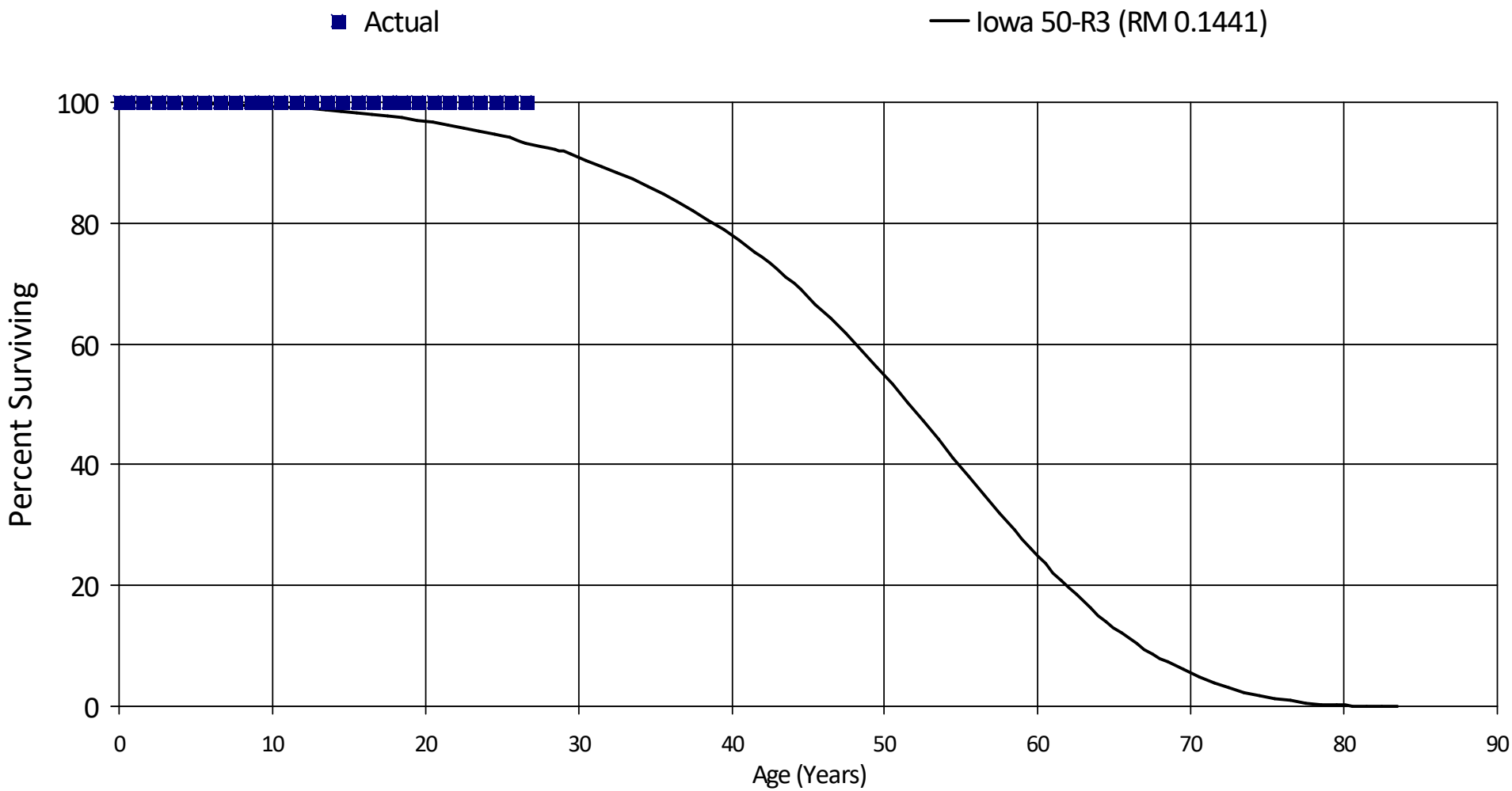
Totals:	2,249,559

Toronto Hydro

Account 2013 - Transformer Station Equip - Steel Struct Bus Work

Placement Band - 1995 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2013 - Transformer Station Equip - Steel Struct Bus Work

Placement Band - 1995 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	147,482	0	0.00000	1.00000	100.00
0.5	147,482	0	0.00000	1.00000	100.00
1.5	147,482	0	0.00000	1.00000	100.00
2.5	147,482	0	0.00000	1.00000	100.00
3.5	147,482	0	0.00000	1.00000	100.00
4.5	147,482	0	0.00000	1.00000	100.00
5.5	147,482	0	0.00000	1.00000	100.00
6.5	147,482	0	0.00000	1.00000	100.00
7.5	147,482	0	0.00000	1.00000	100.00
8.5	147,482	0	0.00000	1.00000	100.00
9.5	147,482	0	0.00000	1.00000	100.00
10.5	147,482	0	0.00000	1.00000	100.00
11.5	147,482	0	0.00000	1.00000	100.00
12.5	147,482	0	0.00000	1.00000	100.00
13.5	147,482	0	0.00000	1.00000	100.00
14.5	147,482	0	0.00000	1.00000	100.00
15.5	147,482	0	0.00000	1.00000	100.00
16.5	147,482	0	0.00000	1.00000	100.00
17.5	147,482	0	0.00000	1.00000	100.00
18.5	147,482	0	0.00000	1.00000	100.00
19.5	147,482	0	0.00000	1.00000	100.00
20.5	147,482	0	0.00000	1.00000	100.00
21.5	147,482	0	0.00000	1.00000	100.00
22.5	147,482	0	0.00000	1.00000	100.00
23.5	147,482	0	0.00000	1.00000	100.00
24.5	147,482	0	0.00000	1.00000	100.00
25.5	147,482	0	0.00000	1.00000	100.00
26.5	147,482	0	0.00000	1.00000	100.00

Toronto Hydro

Account 2013 - Transformer Station Equip - Steel Struct Bus Work

Placement Band - 1995 - 2022 Experience Band - 2022 - 2022

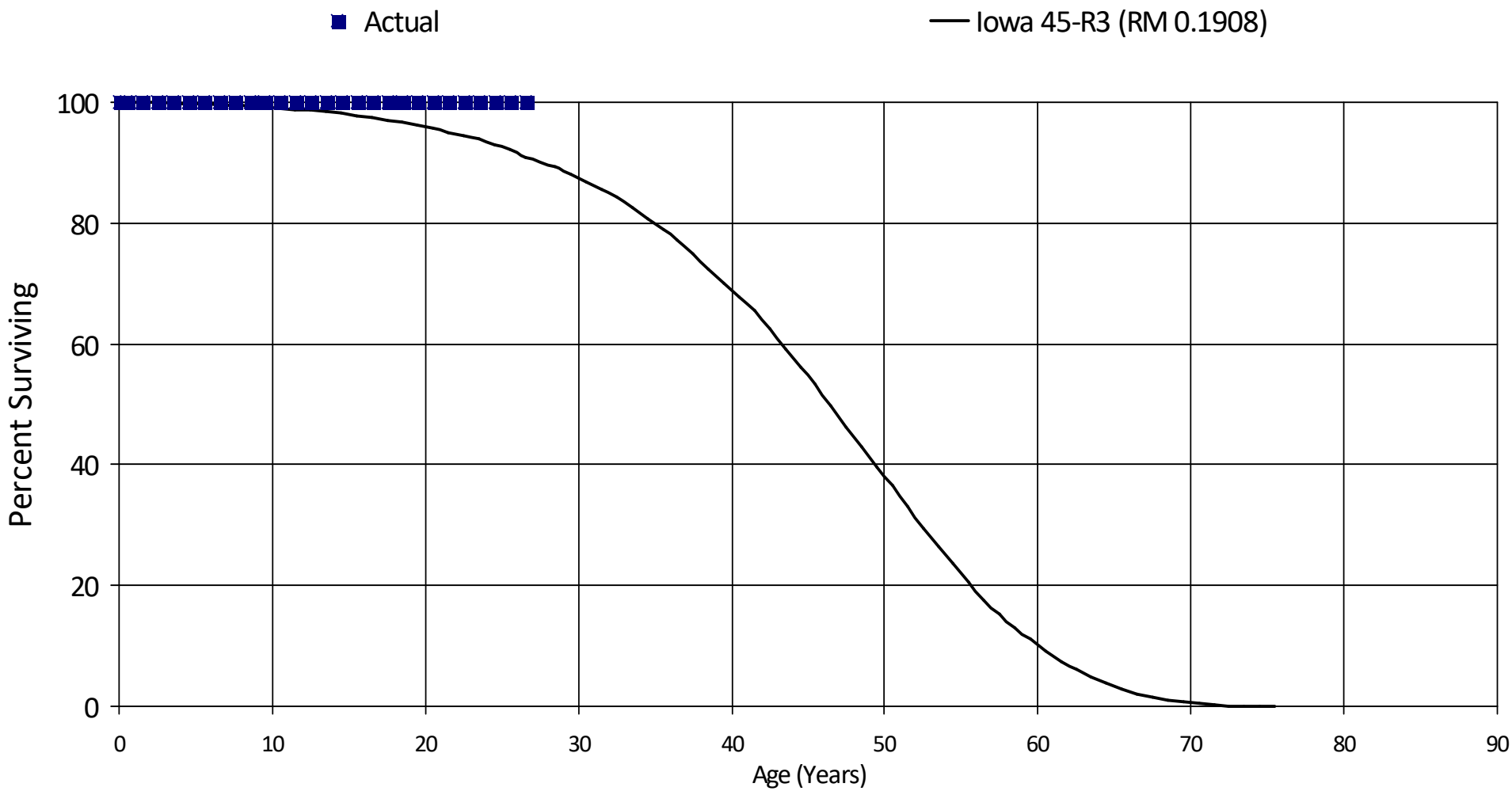
Totals:	0

Toronto Hydro

Account 2015 - Transformer Station Equip - Disconnect Switch

Placement Band - 1995 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2015 - Transformer Station Equip - Disconnect Switch

Placement Band - 1995 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	86,004	0	0.00000	1.00000	100.00
0.5	86,004	0	0.00000	1.00000	100.00
1.5	86,004	0	0.00000	1.00000	100.00
2.5	86,004	0	0.00000	1.00000	100.00
3.5	86,004	0	0.00000	1.00000	100.00
4.5	86,004	0	0.00000	1.00000	100.00
5.5	86,004	0	0.00000	1.00000	100.00
6.5	86,004	0	0.00000	1.00000	100.00
7.5	86,004	0	0.00000	1.00000	100.00
8.5	86,004	0	0.00000	1.00000	100.00
9.5	86,004	0	0.00000	1.00000	100.00
10.5	86,004	0	0.00000	1.00000	100.00
11.5	86,004	0	0.00000	1.00000	100.00
12.5	86,004	0	0.00000	1.00000	100.00
13.5	86,004	0	0.00000	1.00000	100.00
14.5	86,004	0	0.00000	1.00000	100.00
15.5	86,004	0	0.00000	1.00000	100.00
16.5	86,004	0	0.00000	1.00000	100.00
17.5	86,004	0	0.00000	1.00000	100.00
18.5	86,004	0	0.00000	1.00000	100.00
19.5	86,004	0	0.00000	1.00000	100.00
20.5	86,004	0	0.00000	1.00000	100.00
21.5	86,004	0	0.00000	1.00000	100.00
22.5	86,004	0	0.00000	1.00000	100.00
23.5	86,004	0	0.00000	1.00000	100.00
24.5	86,004	0	0.00000	1.00000	100.00
25.5	86,004	0	0.00000	1.00000	100.00
26.5	86,004	0	0.00000	1.00000	100.00

Toronto Hydro

Account 2015 - Transformer Station Equip - Disconnect Switch

Placement Band - 1995 - 2022 Experience Band - 2022 - 2022

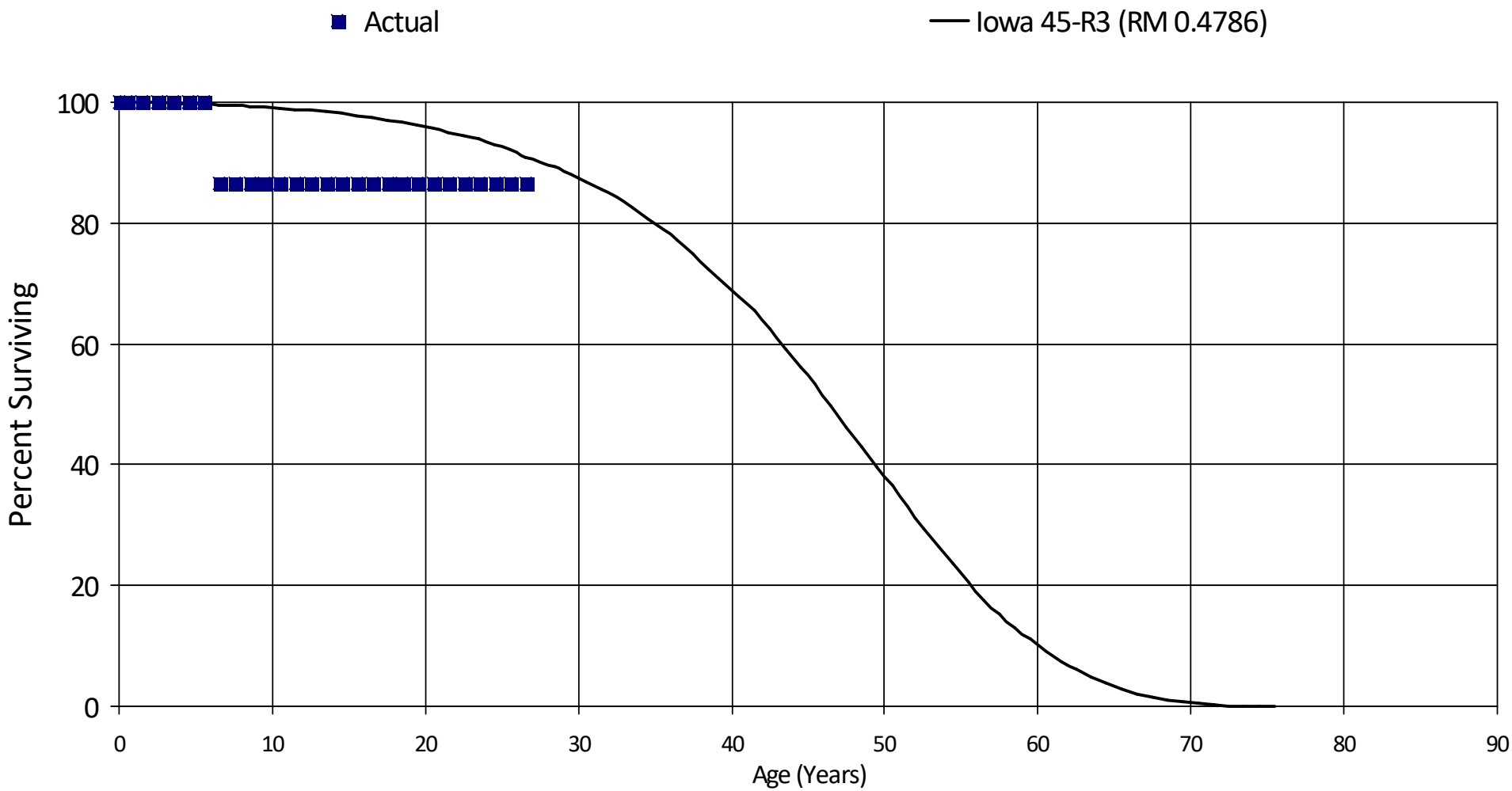
Totals:	0

Toronto Hydro

Account 2017 - Transformer Station Equip - Station Service

Placement Band - 1995 - 2022 Experience Band - 2017 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2017 - Transformer Station Equip - Station Service

Placement Band - 1995 - 2022 Experience Band - 2017 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	5,229,173	0	0.00000	1.00000	100.00
0.5	5,229,173	0	0.00000	1.00000	100.00
1.5	5,229,173	0	0.00000	1.00000	100.00
2.5	5,229,173	0	0.00000	1.00000	100.00
3.5	5,229,173	0	0.00000	1.00000	100.00
4.5	4,913,205	0	0.00000	1.00000	100.00
5.5	98,551	13,224	0.13418	0.86582	100.00
6.5	85,327	0	0.00000	1.00000	86.58
7.5	85,327	0	0.00000	1.00000	86.58
8.5	85,327	0	0.00000	1.00000	86.58
9.5	85,327	0	0.00000	1.00000	86.58
10.5	85,327	0	0.00000	1.00000	86.58
11.5	85,378	0	0.00000	1.00000	86.58
12.5	85,378	0	0.00000	1.00000	86.58
13.5	85,378	0	0.00000	1.00000	86.58
14.5	85,378	0	0.00000	1.00000	86.58
15.5	85,378	0	0.00000	1.00000	86.58
16.5	85,378	0	0.00000	1.00000	86.58
17.5	85,378	0	0.00000	1.00000	86.58
18.5	85,378	0	0.00000	1.00000	86.58
19.5	85,378	0	0.00000	1.00000	86.58
20.5	85,378	0	0.00000	1.00000	86.58
21.5	85,378	0	0.00000	1.00000	86.58
22.5	85,378	0	0.00000	1.00000	86.58
23.5	85,378	0	0.00000	1.00000	86.58
24.5	85,378	0	0.00000	1.00000	86.58
25.5	85,378	0	0.00000	1.00000	86.58
26.5	85,378	42,689	0.50000	0.50000	86.58

Toronto Hydro

Account 2017 - Transformer Station Equip - Station Service

Placement Band - 1995 - 2022 Experience Band - 2017 - 2022

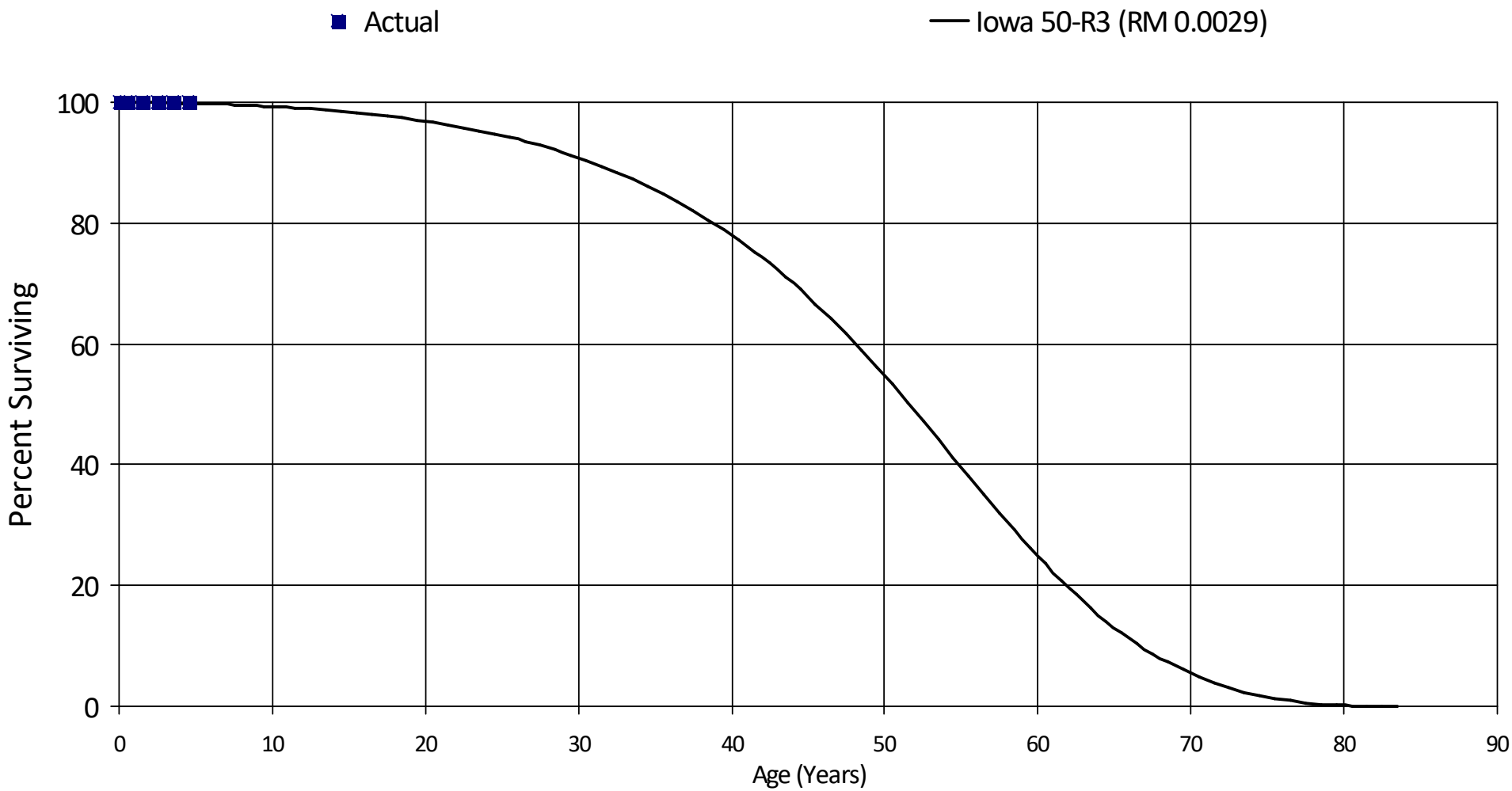
Totals:	55,913

Toronto Hydro

Account 2019 - Transformer Station Equip - High Voltage Switchgea

Placement Band - 2017 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2019 - Transformer Station Equip - High Voltage Switchgea

Placement Band - 2017 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

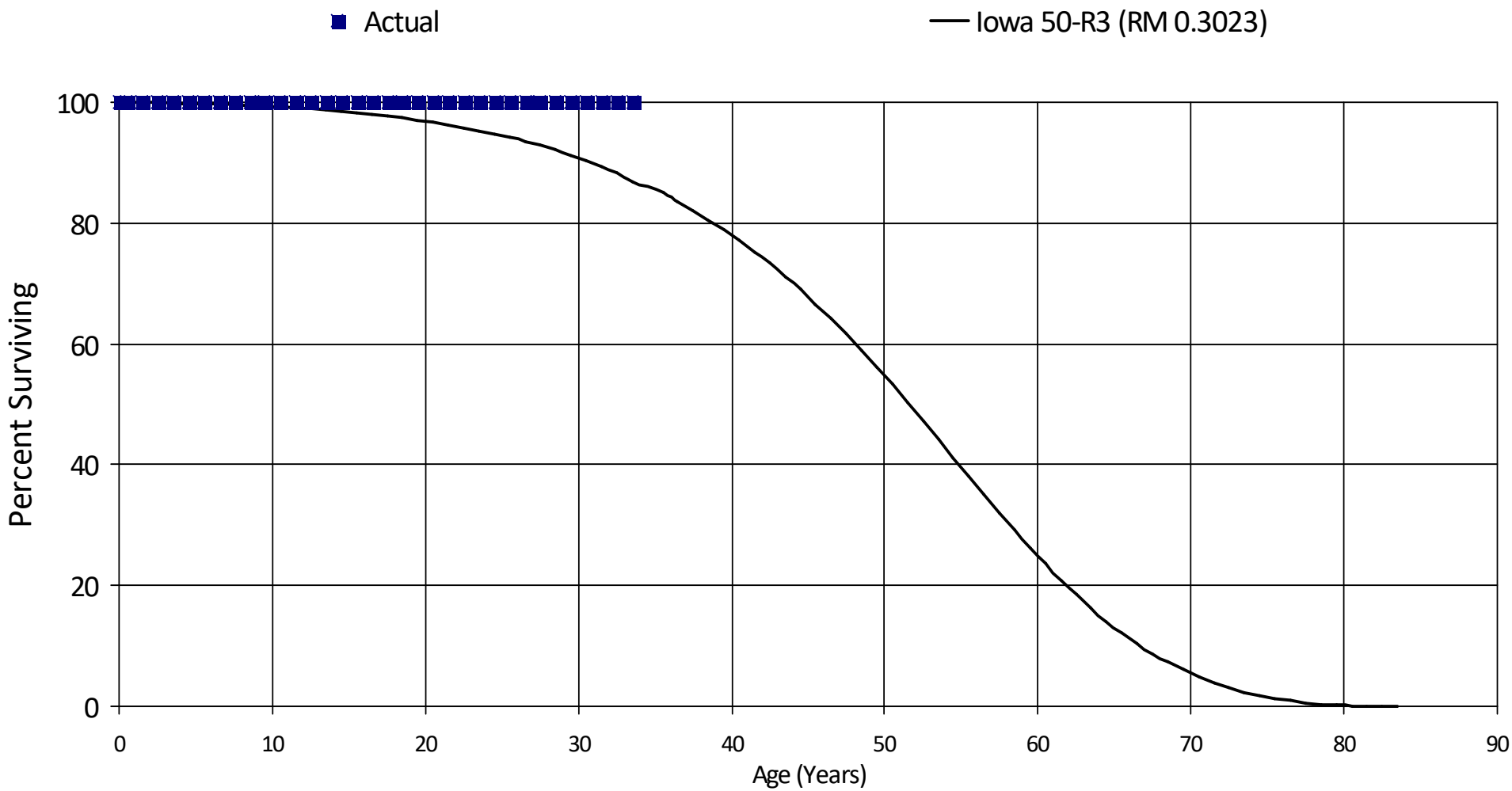
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	9,014,221	0	0.00000	1.00000	100.00
0.5	9,014,221	0	0.00000	1.00000	100.00
1.5	9,014,221	0	0.00000	1.00000	100.00
2.5	9,014,221	0	0.00000	1.00000	100.00
3.5	9,014,221	0	0.00000	1.00000	100.00
4.5	9,014,221	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 2101 - Substation Equipment - Steel Structures Bus Work

Placement Band - 1988 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2101 - Substation Equipment - Steel Structures Bus Work

Placement Band - 1988 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	561,976	0	0.00000	1.00000	100.00
0.5	561,976	0	0.00000	1.00000	100.00
1.5	561,976	0	0.00000	1.00000	100.00
2.5	561,976	0	0.00000	1.00000	100.00
3.5	561,976	0	0.00000	1.00000	100.00
4.5	561,976	0	0.00000	1.00000	100.00
5.5	561,976	0	0.00000	1.00000	100.00
6.5	561,976	0	0.00000	1.00000	100.00
7.5	561,976	0	0.00000	1.00000	100.00
8.5	561,976	0	0.00000	1.00000	100.00
9.5	382,462	0	0.00000	1.00000	100.00
10.5	382,462	0	0.00000	1.00000	100.00
11.5	382,462	0	0.00000	1.00000	100.00
12.5	876	0	0.00000	1.00000	100.00
13.5	876	0	0.00000	1.00000	100.00
14.5	876	0	0.00000	1.00000	100.00
15.5	876	0	0.00000	1.00000	100.00
16.5	876	0	0.00000	1.00000	100.00
17.5	876	0	0.00000	1.00000	100.00
18.5	876	0	0.00000	1.00000	100.00
19.5	876	0	0.00000	1.00000	100.00
20.5	876	0	0.00000	1.00000	100.00
21.5	876	0	0.00000	1.00000	100.00
22.5	876	0	0.00000	1.00000	100.00
23.5	876	0	0.00000	1.00000	100.00
24.5	876	0	0.00000	1.00000	100.00
25.5	876	0	0.00000	1.00000	100.00
26.5	876	0	0.00000	1.00000	100.00

Toronto Hydro

Account 2101 - Substation Equipment - Steel Structures Bus Work

Placement Band - 1988 - 2022 Experience Band - 2022 - 2022

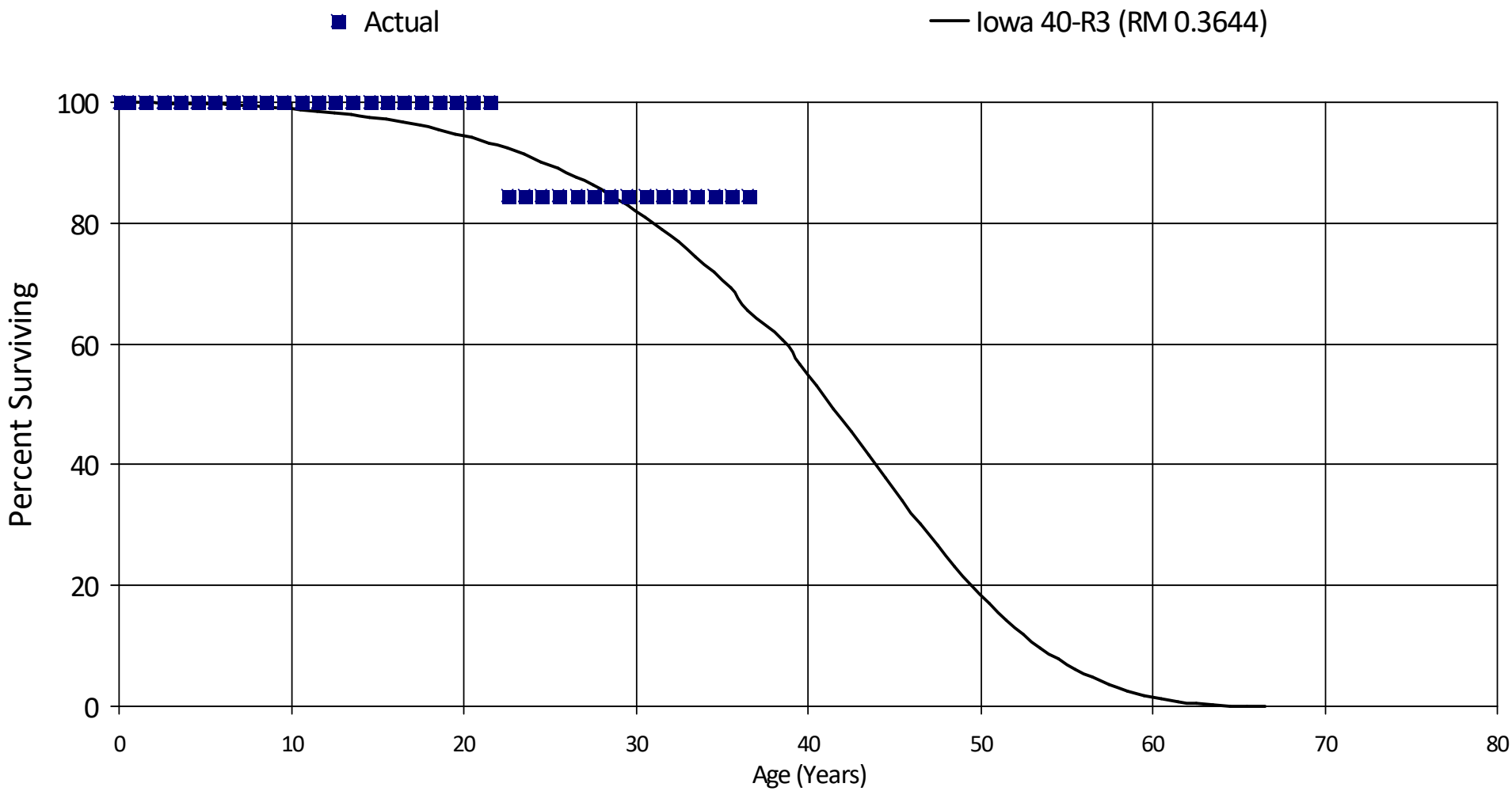
27.5	876	0	0.00000	1.00000	100.00
28.5	876	0	0.00000	1.00000	100.00
29.5	876	0	0.00000	1.00000	100.00
30.5	876	0	0.00000	1.00000	100.00
31.5	876	0	0.00000	1.00000	100.00
32.5	876	0	0.00000	1.00000	100.00
33.5	876	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 2103 - Substation Equipment - Disconnect Switch

Placement Band - 1985 - 2022 Experience Band - 2018 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2103 - Substation Equipment - Disconnect Switch

Placement Band - 1985 - 2022 Experience Band - 2018 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	3,043,938	0	0.00000	1.00000	100.00
0.5	3,043,938	0	0.00000	1.00000	100.00
1.5	2,974,324	0	0.00000	1.00000	100.00
2.5	2,974,324	0	0.00000	1.00000	100.00
3.5	2,974,324	0	0.00000	1.00000	100.00
4.5	2,620,054	0	0.00000	1.00000	100.00
5.5	2,620,054	0	0.00000	1.00000	100.00
6.5	2,620,054	0	0.00000	1.00000	100.00
7.5	2,452,692	0	0.00000	1.00000	100.00
8.5	2,452,692	0	0.00000	1.00000	100.00
9.5	2,376,979	0	0.00000	1.00000	100.00
10.5	1,913,196	0	0.00000	1.00000	100.00
11.5	1,913,196	0	0.00000	1.00000	100.00
12.5	1,913,196	0	0.00000	1.00000	100.00
13.5	1,913,196	0	0.00000	1.00000	100.00
14.5	939,325	0	0.00000	1.00000	100.00
15.5	726,794	0	0.00000	1.00000	100.00
16.5	726,794	0	0.00000	1.00000	100.00
17.5	726,794	0	0.00000	1.00000	100.00
18.5	726,794	0	0.00000	1.00000	100.00
19.5	726,794	0	0.00000	1.00000	100.00
20.5	726,794	0	0.00000	1.00000	100.00
21.5	726,794	111,933	0.15401	0.84599	100.00
22.5	567,961	0	0.00000	1.00000	84.60
23.5	542,002	0	0.00000	1.00000	84.60
24.5	485,691	0	0.00000	1.00000	84.60
25.5	402,207	0	0.00000	1.00000	84.60
26.5	402,207	0	0.00000	1.00000	84.60

Toronto Hydro

Account 2103 - Substation Equipment - Disconnect Switch

Placement Band - 1985 - 2022 Experience Band - 2018 - 2022

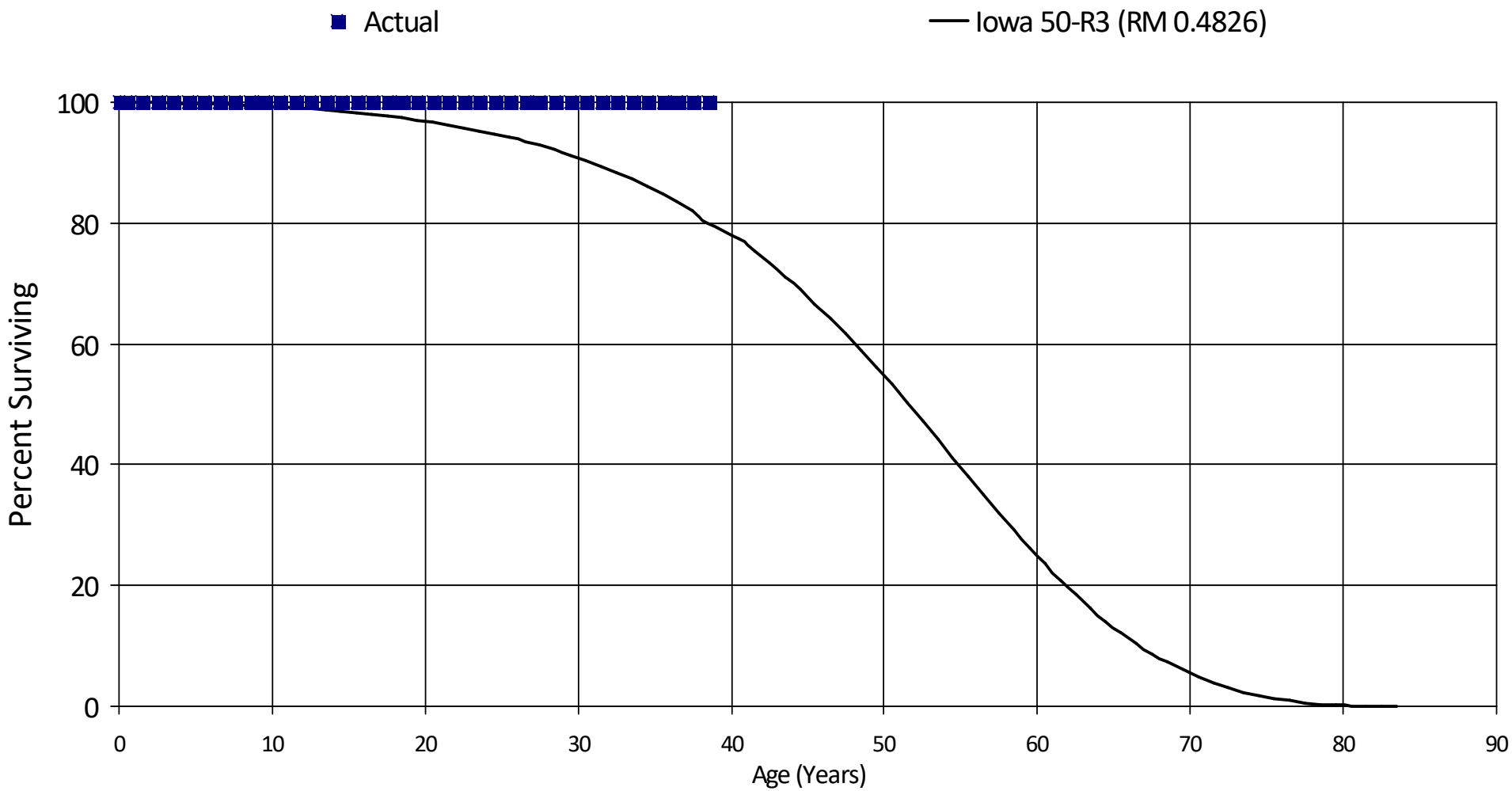
27.5	292,848	0	0.00000	1.00000	84.60
28.5	233,714	0	0.00000	1.00000	84.60
29.5	185,339	0	0.00000	1.00000	84.60
30.5	99,471	0	0.00000	1.00000	84.60
31.5	78,306	0	0.00000	1.00000	84.60
32.5	38,118	0	0.00000	1.00000	84.60
33.5	26,510	0	0.00000	1.00000	84.60
34.5	11,087	0	0.00000	1.00000	84.60
35.5	6,080	0	0.00000	1.00000	84.60
36.5	1,837	0	0.00000	1.00000	84.60
	Totals:	111,933			

Toronto Hydro

Account 2105 - Substation Equipment - MS Station Service

Placement Band - 1983 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2105 - Substation Equipment - MS Station Service

Placement Band - 1983 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	73,004	0	0.00000	1.00000	100.00
0.5	73,004	0	0.00000	1.00000	100.00
1.5	69,487	0	0.00000	1.00000	100.00
2.5	69,487	0	0.00000	1.00000	100.00
3.5	69,487	0	0.00000	1.00000	100.00
4.5	69,487	0	0.00000	1.00000	100.00
5.5	69,487	0	0.00000	1.00000	100.00
6.5	69,487	0	0.00000	1.00000	100.00
7.5	69,487	0	0.00000	1.00000	100.00
8.5	69,487	0	0.00000	1.00000	100.00
9.5	69,487	0	0.00000	1.00000	100.00
10.5	69,487	0	0.00000	1.00000	100.00
11.5	60,449	0	0.00000	1.00000	100.00
12.5	60,449	0	0.00000	1.00000	100.00
13.5	60,449	0	0.00000	1.00000	100.00
14.5	60,449	0	0.00000	1.00000	100.00
15.5	60,449	0	0.00000	1.00000	100.00
16.5	60,449	0	0.00000	1.00000	100.00
17.5	60,449	0	0.00000	1.00000	100.00
18.5	60,449	0	0.00000	1.00000	100.00
19.5	60,449	0	0.00000	1.00000	100.00
20.5	60,449	0	0.00000	1.00000	100.00
21.5	60,449	0	0.00000	1.00000	100.00
22.5	60,449	0	0.00000	1.00000	100.00
23.5	60,449	0	0.00000	1.00000	100.00
24.5	60,449	0	0.00000	1.00000	100.00
25.5	60,449	0	0.00000	1.00000	100.00
26.5	48,460	0	0.00000	1.00000	100.00

Toronto Hydro

Account 2105 - Substation Equipment - MS Station Service

Placement Band - 1983 - 2022 Experience Band - 2022 - 2022

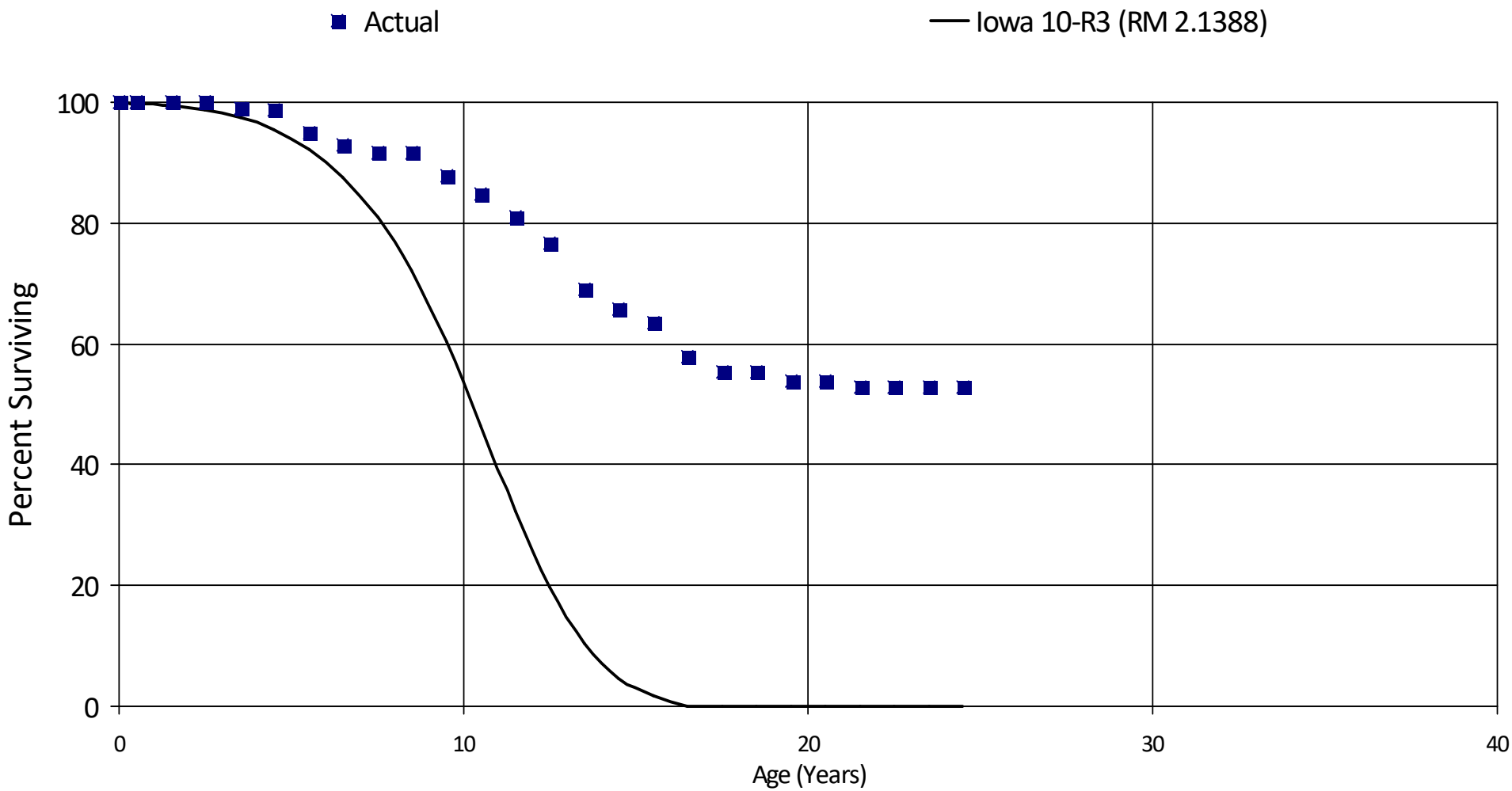
27.5	36,693	0	0.00000	1.00000	100.00
28.5	30,294	0	0.00000	1.00000	100.00
29.5	25,021	0	0.00000	1.00000	100.00
30.5	15,572	0	0.00000	1.00000	100.00
31.5	13,212	0	0.00000	1.00000	100.00
32.5	8,651	0	0.00000	1.00000	100.00
33.5	6,191	0	0.00000	1.00000	100.00
34.5	2,787	0	0.00000	1.00000	100.00
35.5	2,136	0	0.00000	1.00000	100.00
36.5	1,505	0	0.00000	1.00000	100.00
37.5	1,123	0	0.00000	1.00000	100.00
38.5	253	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 2107 - Substation Equipment - DC Stn Service Batteries

Placement Band - 1997 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2107 - Substation Equipment - DC Stn Service Batteries

Placement Band - 1997 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

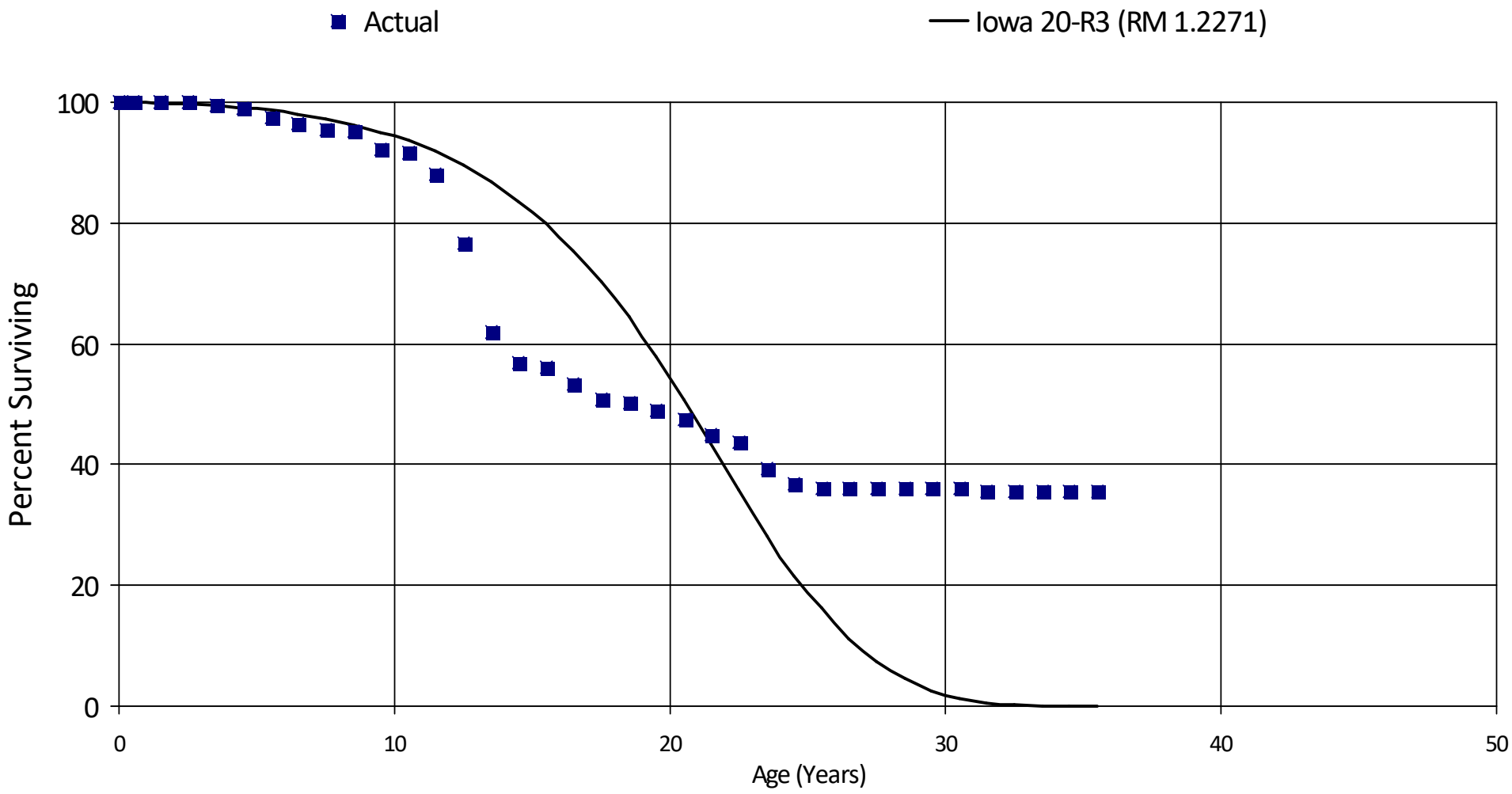
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	12,835,998	0	0.00000	1.00000	100.00
0.5	12,145,918	0	0.00000	1.00000	100.00
1.5	11,726,413	0	0.00000	1.00000	100.00
2.5	10,966,397	106,344	0.00970	0.99030	100.00
3.5	10,419,477	27,452	0.00263	0.99737	99.03
4.5	9,632,762	371,269	0.03854	0.96146	98.77
5.5	7,837,167	172,752	0.02204	0.97796	94.96
6.5	7,452,539	94,992	0.01275	0.98725	92.87
7.5	7,167,680	14,238	0.00199	0.99801	91.69
8.5	6,752,215	281,441	0.04168	0.95832	91.51
9.5	6,151,820	199,862	0.03249	0.96751	87.70
10.5	5,763,562	270,299	0.04690	0.95310	84.85
11.5	5,128,141	266,120	0.05189	0.94811	80.87
12.5	4,826,555	484,485	0.10038	0.89962	76.67
13.5	3,858,577	177,033	0.04588	0.95412	68.97
14.5	2,022,402	74,709	0.03694	0.96306	65.81
15.5	1,674,379	144,627	0.08638	0.91362	63.38
16.5	1,529,753	70,354	0.04599	0.95401	57.91
17.5	1,272,472	0	0.00000	1.00000	55.25
18.5	859,418	21,570	0.02510	0.97490	55.25
19.5	784,834	0	0.00000	1.00000	53.86
20.5	609,895	11,852	0.01943	0.98057	53.86
21.5	318,836	0	0.00000	1.00000	52.81
22.5	256,543	0	0.00000	1.00000	52.81
23.5	183,049	0	0.00000	1.00000	52.81
24.5	35,555	0	0.00000	1.00000	52.81
	Totals:	2,789,399			

Toronto Hydro

Account 2109 - Substation Equipment - DC Stn Service Chargers

Placement Band - 1986 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2109 - Substation Equipment - DC Stn Service Chargers

Placement Band - 1986 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	11,054,591	0	0.00000	1.00000	100.00
0.5	10,700,649	0	0.00000	1.00000	100.00
1.5	10,304,653	0	0.00000	1.00000	100.00
2.5	9,346,518	59,217	0.00634	0.99366	100.00
3.5	8,863,005	24,811	0.00280	0.99720	99.37
4.5	8,264,975	132,442	0.01602	0.98398	99.09
5.5	7,436,517	75,992	0.01022	0.98978	97.50
6.5	7,283,645	82,784	0.01137	0.98863	96.50
7.5	6,985,938	22,814	0.00327	0.99673	95.40
8.5	6,862,201	210,038	0.03061	0.96939	95.09
9.5	6,536,147	45,673	0.00699	0.99301	92.18
10.5	6,381,138	240,302	0.03766	0.96234	91.54
11.5	6,081,254	793,666	0.13051	0.86949	88.09
12.5	5,262,875	1,007,885	0.19151	0.80849	76.59
13.5	4,254,990	349,831	0.08222	0.91778	61.92
14.5	2,549,722	38,453	0.01508	0.98492	56.83
15.5	2,511,269	125,077	0.04981	0.95019	55.97
16.5	2,386,192	111,247	0.04662	0.95338	53.18
17.5	2,176,336	20,242	0.00930	0.99070	50.70
18.5	1,832,976	45,923	0.02505	0.97495	50.23
19.5	1,787,053	57,174	0.03199	0.96801	48.97
20.5	1,603,055	85,761	0.05350	0.94650	47.40
21.5	1,263,127	36,661	0.02902	0.97098	44.86
22.5	1,226,466	118,110	0.09630	0.90370	43.56
23.5	1,029,243	66,048	0.06417	0.93583	39.37
24.5	816,098	20,271	0.02484	0.97516	36.84
25.5	702,537	0	0.00000	1.00000	35.92
26.5	514,916	0	0.00000	1.00000	35.92

Toronto Hydro

Account 2109 - Substation Equipment - DC Stn Service Chargers

Placement Band - 1986 - 2022 Experience Band - 2014 - 2022

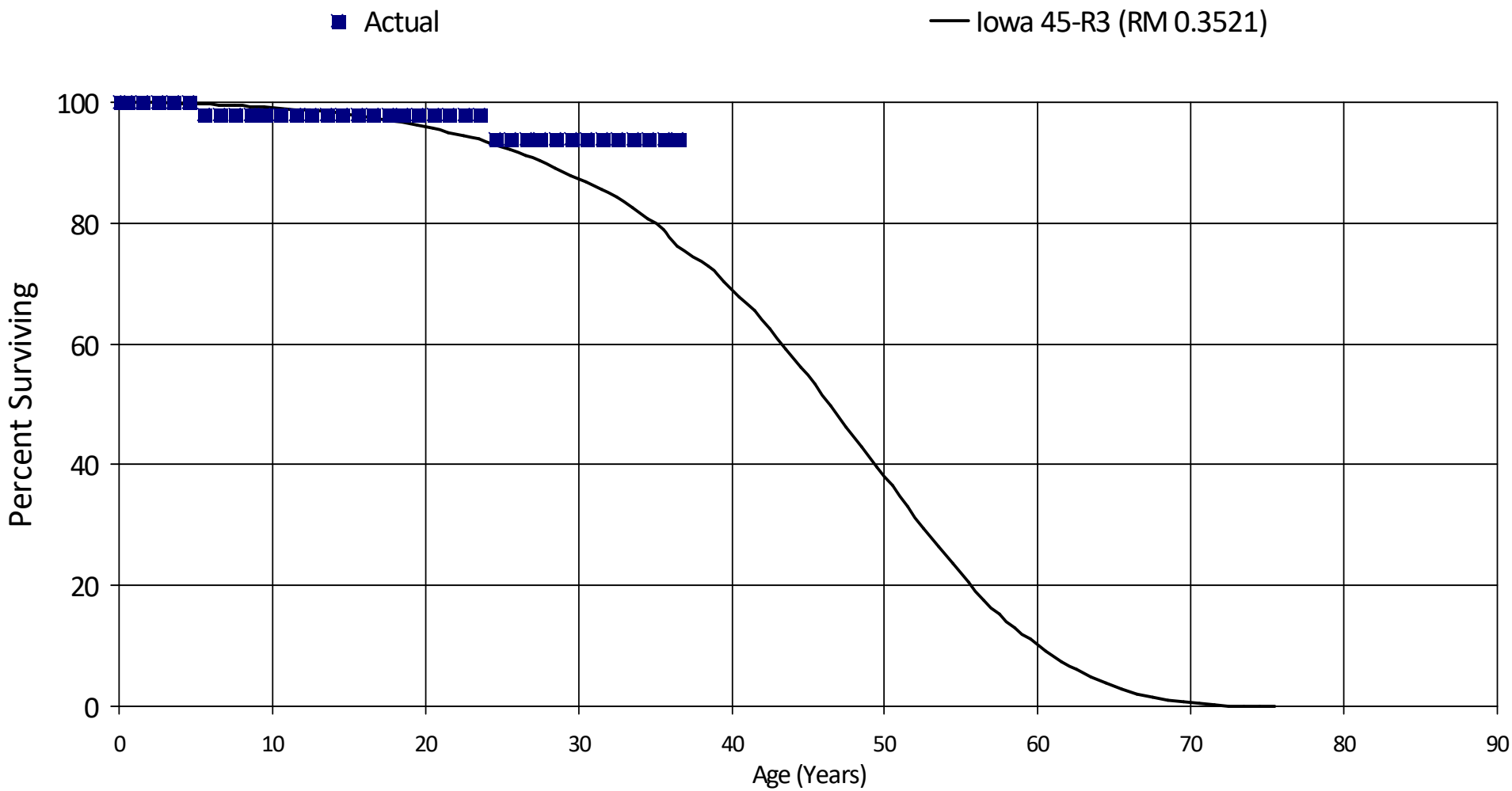
27.5	441,593	0	0.00000	1.00000	35.92
28.5	342,472	0	0.00000	1.00000	35.92
29.5	322,201	0	0.00000	1.00000	35.92
30.5	178,270	2,098	0.01177	0.98823	35.92
31.5	140,695	0	0.00000	1.00000	35.50
32.5	95,786	0	0.00000	1.00000	35.50
33.5	60,410	0	0.00000	1.00000	35.50
34.5	13,408	0	0.00000	1.00000	35.50
35.5	7,114	0	0.00000	1.00000	35.50
	Totals:	3,772,520			

Toronto Hydro

Account 2111 - Substation Equipment - Outdoor Breaker

Placement Band - 1985 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2111 - Substation Equipment - Outdoor Breaker

Placement Band - 1985 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	32,382,008	0	0.00000	1.00000	100.00
0.5	30,476,046	0	0.00000	1.00000	100.00
1.5	29,725,485	0	0.00000	1.00000	100.00
2.5	26,884,896	0	0.00000	1.00000	100.00
3.5	23,072,226	0	0.00000	1.00000	100.00
4.5	19,506,596	384,628	0.01972	0.98028	100.00
5.5	18,368,893	0	0.00000	1.00000	98.03
6.5	17,312,172	0	0.00000	1.00000	98.03
7.5	16,600,995	0	0.00000	1.00000	98.03
8.5	16,434,730	0	0.00000	1.00000	98.03
9.5	15,513,311	0	0.00000	1.00000	98.03
10.5	14,421,686	0	0.00000	1.00000	98.03
11.5	14,409,672	0	0.00000	1.00000	98.03
12.5	14,254,316	0	0.00000	1.00000	98.03
13.5	12,715,804	0	0.00000	1.00000	98.03
14.5	8,711,080	0	0.00000	1.00000	98.03
15.5	7,833,965	0	0.00000	1.00000	98.03
16.5	6,899,824	0	0.00000	1.00000	98.03
17.5	6,220,021	0	0.00000	1.00000	98.03
18.5	4,982,480	0	0.00000	1.00000	98.03
19.5	4,749,902	0	0.00000	1.00000	98.03
20.5	4,203,451	0	0.00000	1.00000	98.03
21.5	3,529,520	0	0.00000	1.00000	98.03
22.5	3,177,593	0	0.00000	1.00000	98.03
23.5	2,982,808	121,602	0.04077	0.95923	98.03
24.5	2,438,672	0	0.00000	1.00000	94.03
25.5	2,215,735	0	0.00000	1.00000	94.03
26.5	1,753,786	0	0.00000	1.00000	94.03

Toronto Hydro

Account 2111 - Substation Equipment - Outdoor Breaker

Placement Band - 1985 - 2022 Experience Band - 2014 - 2022

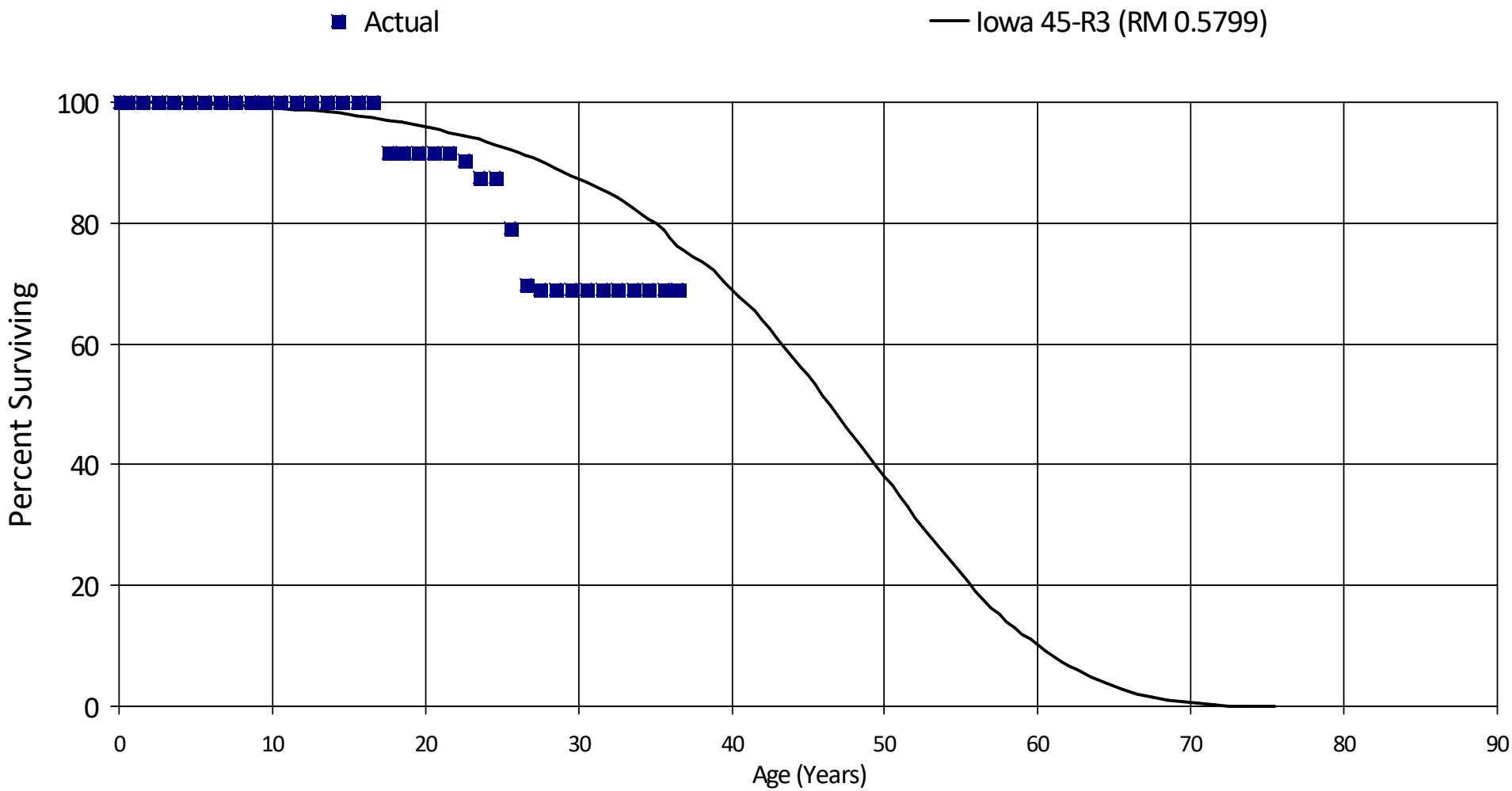
27.5	1,302,459	0	0.00000	1.00000	94.03
28.5	1,058,411	0	0.00000	1.00000	94.03
29.5	858,768	0	0.00000	1.00000	94.03
30.5	504,390	0	0.00000	1.00000	94.03
31.5	417,041	0	0.00000	1.00000	94.03
32.5	251,184	0	0.00000	1.00000	94.03
33.5	164,082	0	0.00000	1.00000	94.03
34.5	48,356	0	0.00000	1.00000	94.03
35.5	27,694	0	0.00000	1.00000	94.03
36.5	10,179	0	0.00000	1.00000	94.03
	Totals:	506,230			

Toronto Hydro

Account 2113 - Substation Equipment - Indoor Breaker

Placement Band - 1985 - 2022 Experience Band - 2018 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2113 - Substation Equipment - Indoor Breaker

Placement Band - 1985 - 2022 Experience Band - 2018 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	22,315,084	0	0.00000	1.00000	100.00
0.5	22,315,084	0	0.00000	1.00000	100.00
1.5	22,294,843	0	0.00000	1.00000	100.00
2.5	22,294,843	0	0.00000	1.00000	100.00
3.5	22,109,860	0	0.00000	1.00000	100.00
4.5	20,630,724	0	0.00000	1.00000	100.00
5.5	19,980,218	0	0.00000	1.00000	100.00
6.5	19,610,976	0	0.00000	1.00000	100.00
7.5	19,211,927	0	0.00000	1.00000	100.00
8.5	18,899,485	0	0.00000	1.00000	100.00
9.5	18,898,664	0	0.00000	1.00000	100.00
10.5	18,898,664	0	0.00000	1.00000	100.00
11.5	16,620,231	0	0.00000	1.00000	100.00
12.5	16,620,231	0	0.00000	1.00000	100.00
13.5	14,096,423	0	0.00000	1.00000	100.00
14.5	9,649,137	0	0.00000	1.00000	100.00
15.5	8,677,570	0	0.00000	1.00000	100.00
16.5	7,642,835	632,901	0.08281	0.91719	100.00
17.5	6,256,926	0	0.00000	1.00000	91.72
18.5	5,519,021	0	0.00000	1.00000	91.72
19.5	5,261,397	0	0.00000	1.00000	91.72
20.5	4,656,102	0	0.00000	1.00000	91.72
21.5	3,909,598	60,199	0.01540	0.98460	91.72
22.5	3,459,575	101,534	0.02935	0.97065	90.31
23.5	3,243,814	0	0.00000	1.00000	87.66
24.5	2,775,779	269,393	0.09705	0.90295	87.66
25.5	2,394,139	285,250	0.11915	0.88085	79.15
26.5	1,687,494	19,627	0.01163	0.98837	69.72

Toronto Hydro

Account 2113 - Substation Equipment - Indoor Breaker

Placement Band - 1985 - 2022 Experience Band - 2018 - 2022

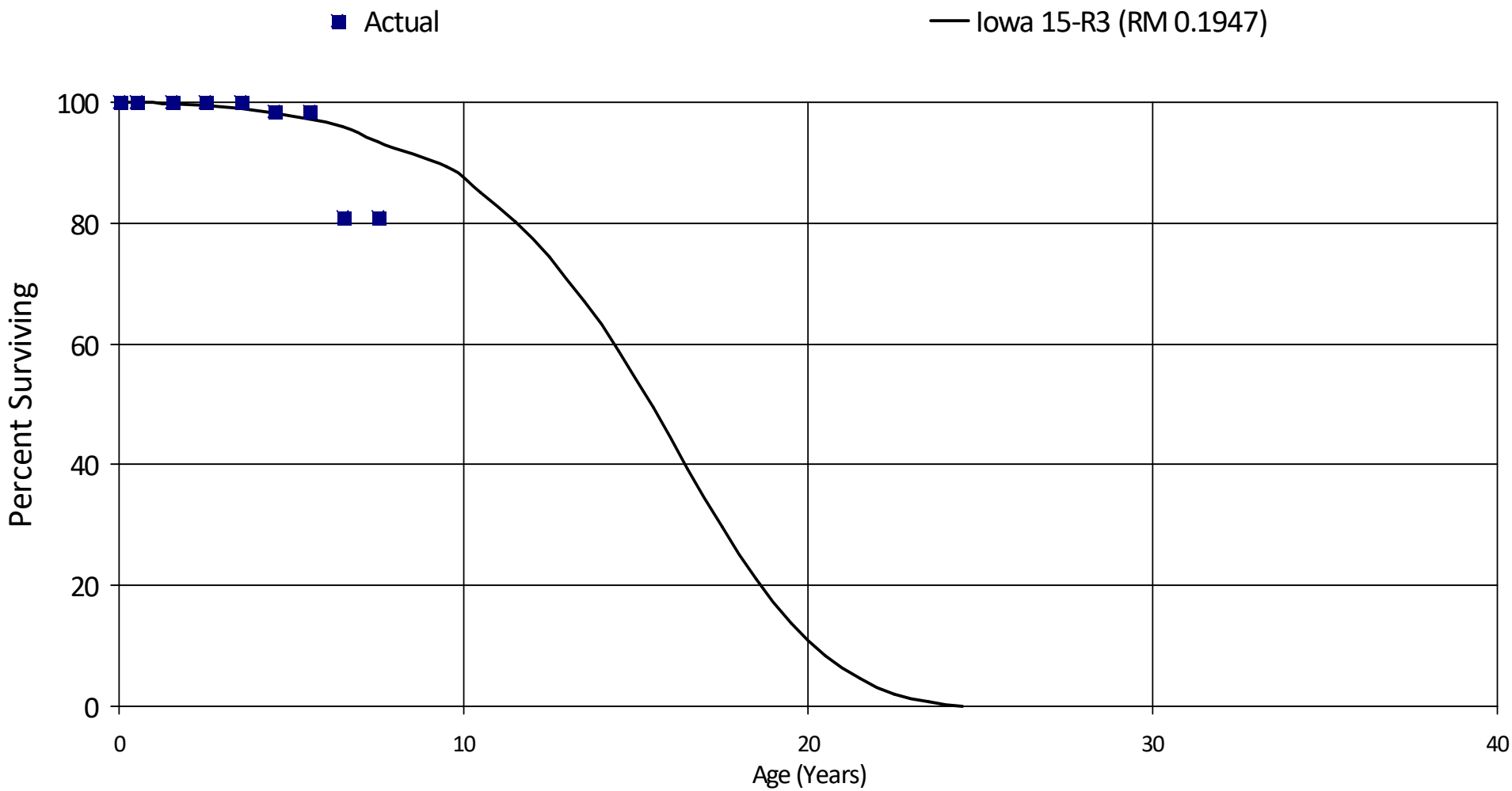
27.5	1,167,938	0	0.00000	1.00000	68.91
28.5	897,610	0	0.00000	1.00000	68.91
29.5	676,468	0	0.00000	1.00000	68.91
30.5	558,706	0	0.00000	1.00000	68.91
31.5	461,950	0	0.00000	1.00000	68.91
32.5	278,233	0	0.00000	1.00000	68.91
33.5	181,752	0	0.00000	1.00000	68.91
34.5	53,564	0	0.00000	1.00000	68.91
35.5	30,676	0	0.00000	1.00000	68.91
36.5	11,275	0	0.00000	1.00000	68.91
	Totals:	1,368,904			

Toronto Hydro

Account 2115 - Substation Equipment - Station Relays

Placement Band - 2014 - 2022 Experience Band - 2018 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2115 - Substation Equipment - Station Relays

Placement Band - 2014 - 2022 Experience Band - 2018 - 2022

RETIREMENT RATE ANALYSIS

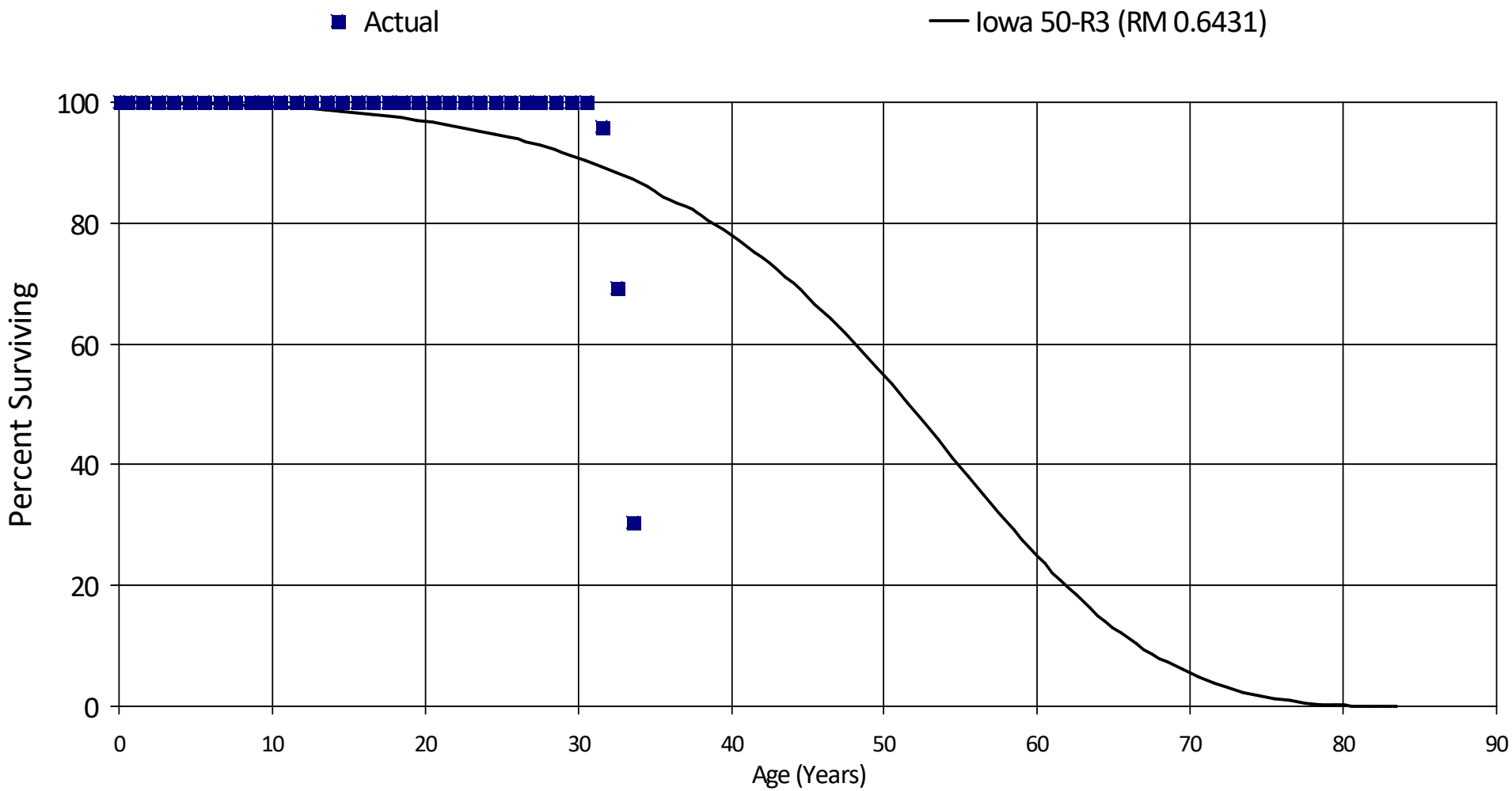
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	19,270,070	0	0.00000	1.00000	100.00
0.5	15,029,736	0	0.00000	1.00000	100.00
1.5	13,147,475	0	0.00000	1.00000	100.00
2.5	12,040,533	0	0.00000	1.00000	100.00
3.5	10,026,036	140,061	0.01397	0.98603	100.00
4.5	3,638,699	0	0.00000	1.00000	98.60
5.5	2,180,541	388,877	0.17834	0.82166	98.60
6.5	1,409,861	0	0.00000	1.00000	81.02
7.5	1,409,861	0	0.00000	1.00000	81.02
	Totals:	528,938			

Toronto Hydro

Account 2117 - Substation Equipment - Switchgear Air

Placement Band - 1986 - 2022 Experience Band - 2018 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2117 - Substation Equipment - Switchgear Air

Placement Band - 1986 - 2022 Experience Band - 2018 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	73,809,262	0	0.00000	1.00000	100.00
0.5	70,981,358	0	0.00000	1.00000	100.00
1.5	51,683,158	0	0.00000	1.00000	100.00
2.5	49,444,421	0	0.00000	1.00000	100.00
3.5	49,444,421	0	0.00000	1.00000	100.00
4.5	35,331,572	0	0.00000	1.00000	100.00
5.5	24,087,682	0	0.00000	1.00000	100.00
6.5	21,243,014	0	0.00000	1.00000	100.00
7.5	19,840,672	0	0.00000	1.00000	100.00
8.5	16,419,022	0	0.00000	1.00000	100.00
9.5	16,413,060	0	0.00000	1.00000	100.00
10.5	16,413,060	0	0.00000	1.00000	100.00
11.5	5,005,258	0	0.00000	1.00000	100.00
12.5	5,005,258	0	0.00000	1.00000	100.00
13.5	5,005,258	0	0.00000	1.00000	100.00
14.5	2,307,062	0	0.00000	1.00000	100.00
15.5	2,307,062	0	0.00000	1.00000	100.00
16.5	2,307,062	0	0.00000	1.00000	100.00
17.5	2,307,062	0	0.00000	1.00000	100.00
18.5	1,814,429	0	0.00000	1.00000	100.00
19.5	1,814,429	0	0.00000	1.00000	100.00
20.5	1,595,172	0	0.00000	1.00000	100.00
21.5	1,595,172	0	0.00000	1.00000	100.00
22.5	1,452,506	0	0.00000	1.00000	100.00
23.5	1,373,040	0	0.00000	1.00000	100.00
24.5	1,199,385	0	0.00000	1.00000	100.00
25.5	1,056,552	0	0.00000	1.00000	100.00
26.5	863,067	0	0.00000	1.00000	100.00

Toronto Hydro

Account 2117 - Substation Equipment - Switchgear Air

Placement Band - 1986 - 2022 Experience Band - 2018 - 2022

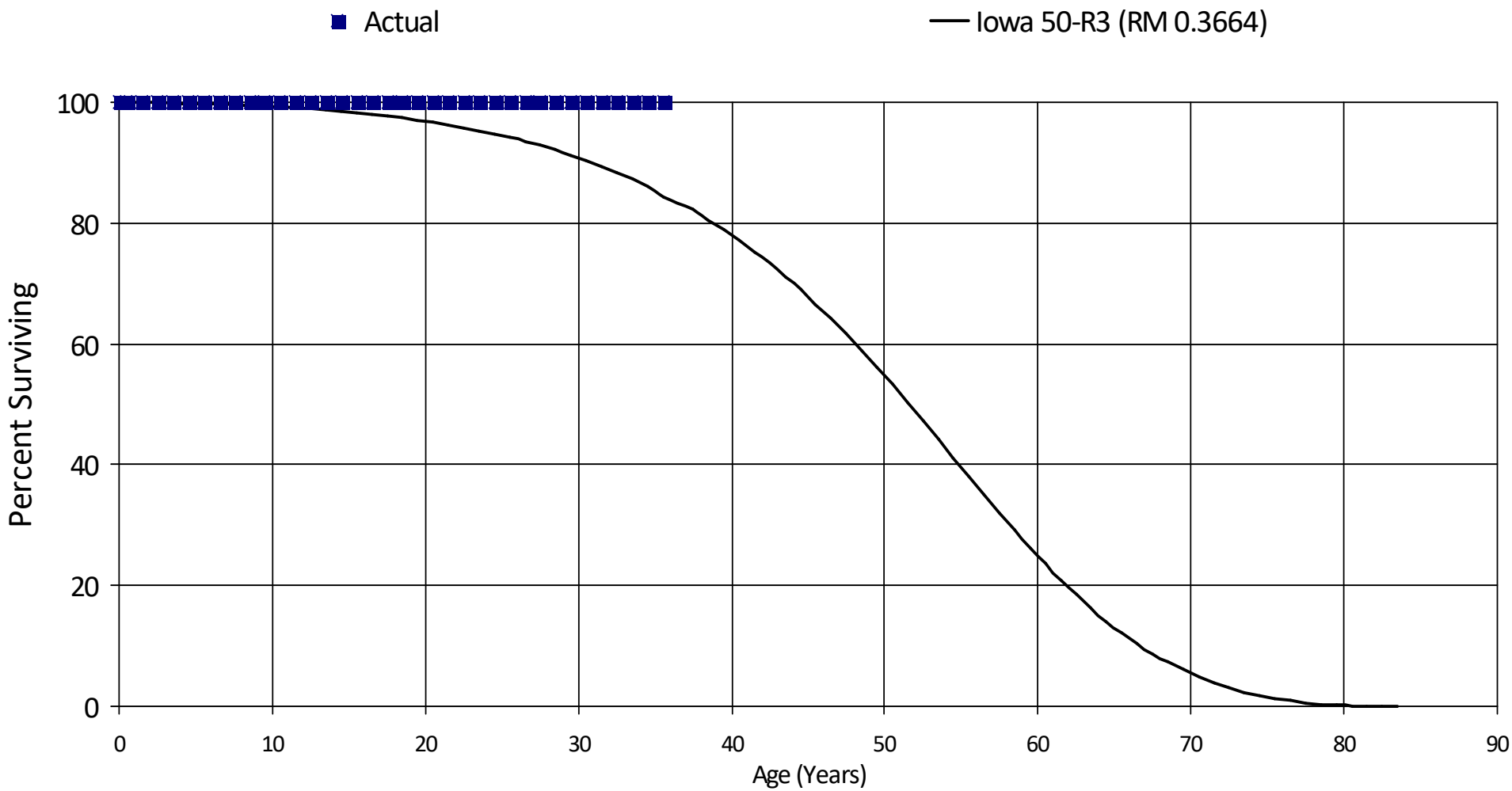
27.5	671,689	0	0.00000	1.00000	100.00
28.5	566,642	0	0.00000	1.00000	100.00
29.5	479,107	0	0.00000	1.00000	100.00
30.5	320,076	12,785	0.03994	0.96006	100.00
31.5	266,904	74,195	0.27798	0.72202	96.01
32.5	112,937	63,505	0.56230	0.43770	69.32
33.5	0	0	0.00000	0.00000	30.34
	Totals:	150,485			

Toronto Hydro

Account 2119 - Substation Equipment - Switchgear GIS

Placement Band - 1986 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2119 - Substation Equipment - Switchgear GIS

Placement Band - 1986 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	43,464,897	0	0.00000	1.00000	100.00
0.5	28,497,166	0	0.00000	1.00000	100.00
1.5	28,497,166	0	0.00000	1.00000	100.00
2.5	16,915,785	0	0.00000	1.00000	100.00
3.5	16,915,785	0	0.00000	1.00000	100.00
4.5	16,915,785	0	0.00000	1.00000	100.00
5.5	6,527,928	0	0.00000	1.00000	100.00
6.5	6,527,928	0	0.00000	1.00000	100.00
7.5	6,527,928	0	0.00000	1.00000	100.00
8.5	6,527,928	0	0.00000	1.00000	100.00
9.5	6,527,928	0	0.00000	1.00000	100.00
10.5	6,527,928	0	0.00000	1.00000	100.00
11.5	6,528,679	0	0.00000	1.00000	100.00
12.5	6,528,679	0	0.00000	1.00000	100.00
13.5	6,528,679	0	0.00000	1.00000	100.00
14.5	3,734,988	0	0.00000	1.00000	100.00
15.5	3,734,988	0	0.00000	1.00000	100.00
16.5	3,734,988	0	0.00000	1.00000	100.00
17.5	3,734,988	0	0.00000	1.00000	100.00
18.5	2,913,933	0	0.00000	1.00000	100.00
19.5	2,913,933	0	0.00000	1.00000	100.00
20.5	2,548,505	0	0.00000	1.00000	100.00
21.5	2,548,505	0	0.00000	1.00000	100.00
22.5	2,310,728	0	0.00000	1.00000	100.00
23.5	2,178,285	0	0.00000	1.00000	100.00
24.5	1,888,859	0	0.00000	1.00000	100.00
25.5	1,650,804	0	0.00000	1.00000	100.00
26.5	1,328,330	0	0.00000	1.00000	100.00

Toronto Hydro

Account 2119 - Substation Equipment - Switchgear GIS

Placement Band - 1986 - 2022 Experience Band - 2022 - 2022

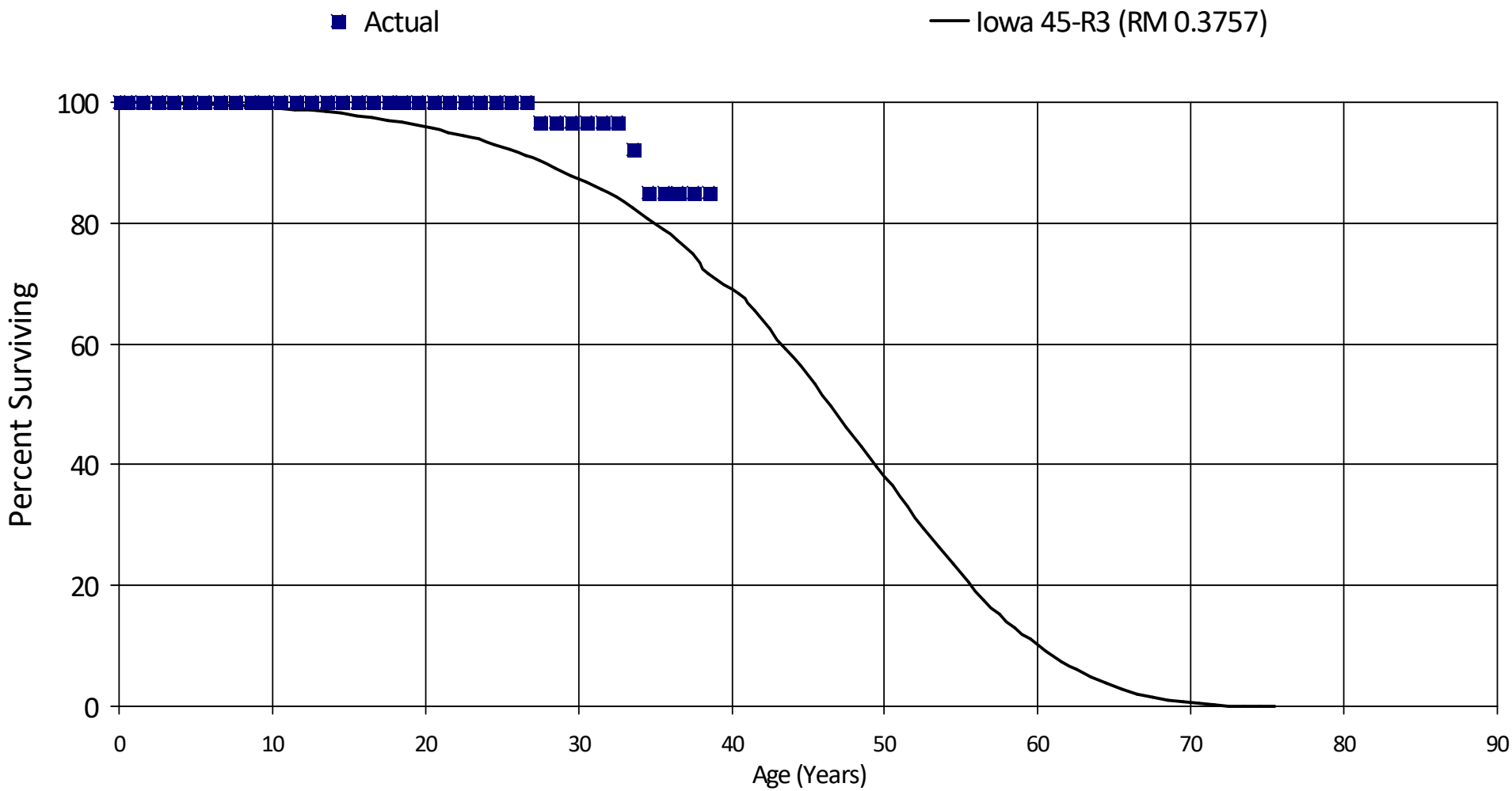
27.5	1,009,366	0	0.00000	1.00000	100.00
28.5	834,289	0	0.00000	1.00000	100.00
29.5	688,396	0	0.00000	1.00000	100.00
30.5	423,345	0	0.00000	1.00000	100.00
31.5	356,033	0	0.00000	1.00000	100.00
32.5	223,081	0	0.00000	1.00000	100.00
33.5	149,379	0	0.00000	1.00000	100.00
34.5	43,538	0	0.00000	1.00000	100.00
35.5	22,230	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 2123 - Substation Equipment - Power Transformers

Placement Band - 1983 - 2022 Experience Band - 2017 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2123 - Substation Equipment - Power Transformers

Placement Band - 1983 - 2022 Experience Band - 2017 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	43,277,836	0	0.00000	1.00000	100.00
0.5	43,277,836	0	0.00000	1.00000	100.00
1.5	43,277,836	0	0.00000	1.00000	100.00
2.5	43,277,836	0	0.00000	1.00000	100.00
3.5	43,277,836	0	0.00000	1.00000	100.00
4.5	42,358,615	0	0.00000	1.00000	100.00
5.5	41,101,553	0	0.00000	1.00000	100.00
6.5	41,101,553	0	0.00000	1.00000	100.00
7.5	39,006,244	0	0.00000	1.00000	100.00
8.5	36,679,905	0	0.00000	1.00000	100.00
9.5	36,117,587	0	0.00000	1.00000	100.00
10.5	32,226,980	0	0.00000	1.00000	100.00
11.5	31,860,696	0	0.00000	1.00000	100.00
12.5	31,860,696	0	0.00000	1.00000	100.00
13.5	27,294,422	0	0.00000	1.00000	100.00
14.5	16,757,829	0	0.00000	1.00000	100.00
15.5	14,493,006	0	0.00000	1.00000	100.00
16.5	12,551,354	0	0.00000	1.00000	100.00
17.5	11,137,024	0	0.00000	1.00000	100.00
18.5	11,137,024	0	0.00000	1.00000	100.00
19.5	10,652,138	0	0.00000	1.00000	100.00
20.5	10,652,138	0	0.00000	1.00000	100.00
21.5	8,900,365	0	0.00000	1.00000	100.00
22.5	8,207,159	0	0.00000	1.00000	100.00
23.5	7,798,322	0	0.00000	1.00000	100.00
24.5	6,909,238	0	0.00000	1.00000	100.00
25.5	6,005,206	0	0.00000	1.00000	100.00
26.5	4,788,647	154,294	0.03222	0.96778	100.00

Toronto Hydro

Account 2123 - Substation Equipment - Power Transformers

Placement Band - 1983 - 2022 Experience Band - 2017 - 2022

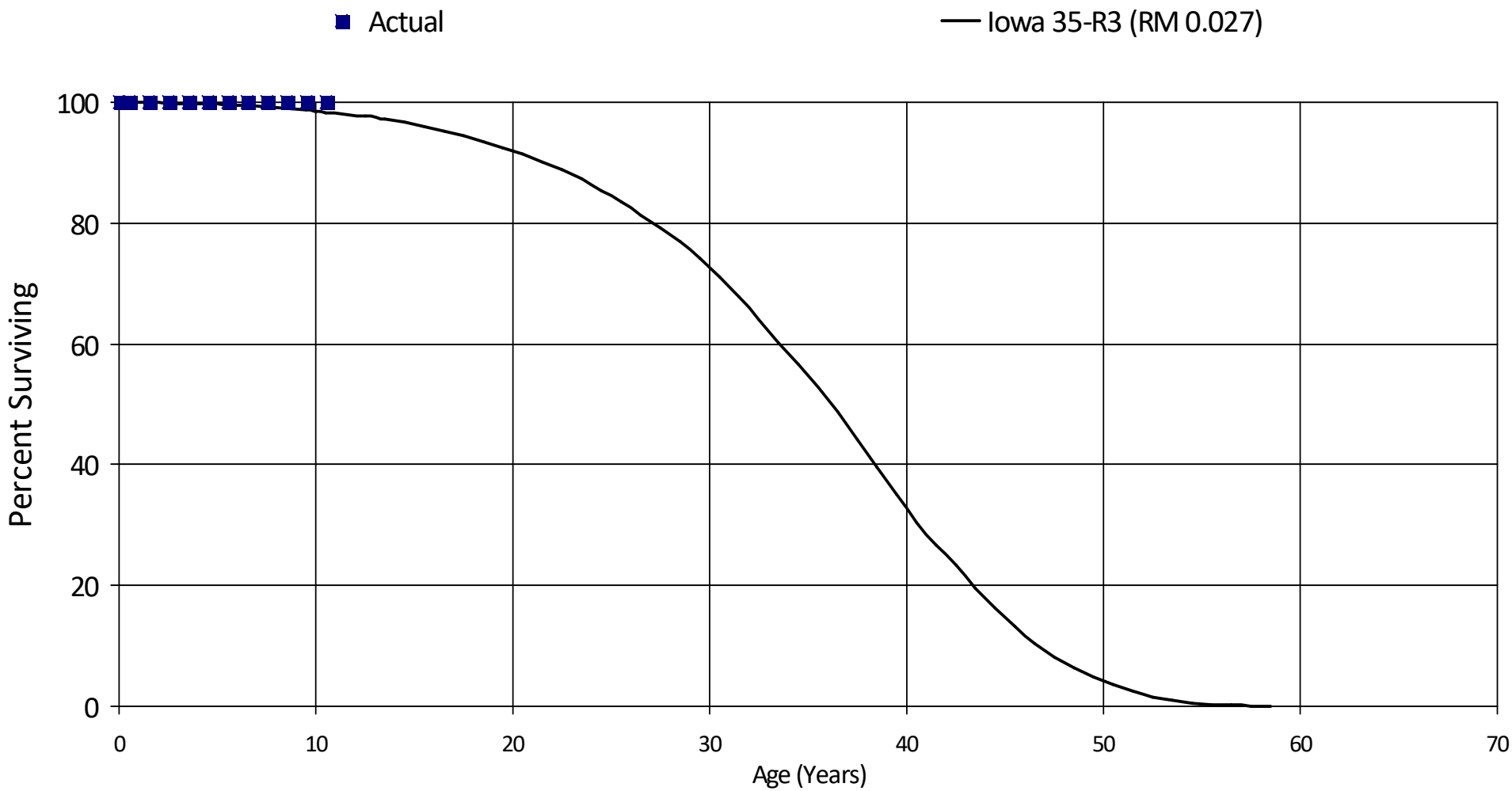
27.5	3,440,365	0	0.00000	1.00000	96.78
28.5	2,791,044	0	0.00000	1.00000	96.78
29.5	2,255,977	0	0.00000	1.00000	96.78
30.5	1,297,072	0	0.00000	1.00000	96.78
31.5	1,057,644	0	0.00000	1.00000	96.78
32.5	749,055	35,508	0.04740	0.95260	96.78
33.5	512,805	40,447	0.07887	0.92113	92.19
34.5	194,533	0	0.00000	1.00000	84.92
35.5	128,457	0	0.00000	1.00000	84.92
36.5	64,447	0	0.00000	1.00000	84.92
37.5	25,665	0	0.00000	1.00000	84.92
38.5	25,665	0	0.00000	1.00000	84.92
	Totals:	230,249			

Toronto Hydro

Account 2125 - Substation Equipment - Grounding System

Placement Band - 2011 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2125 - Substation Equipment - Grounding System

Placement Band - 2011 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

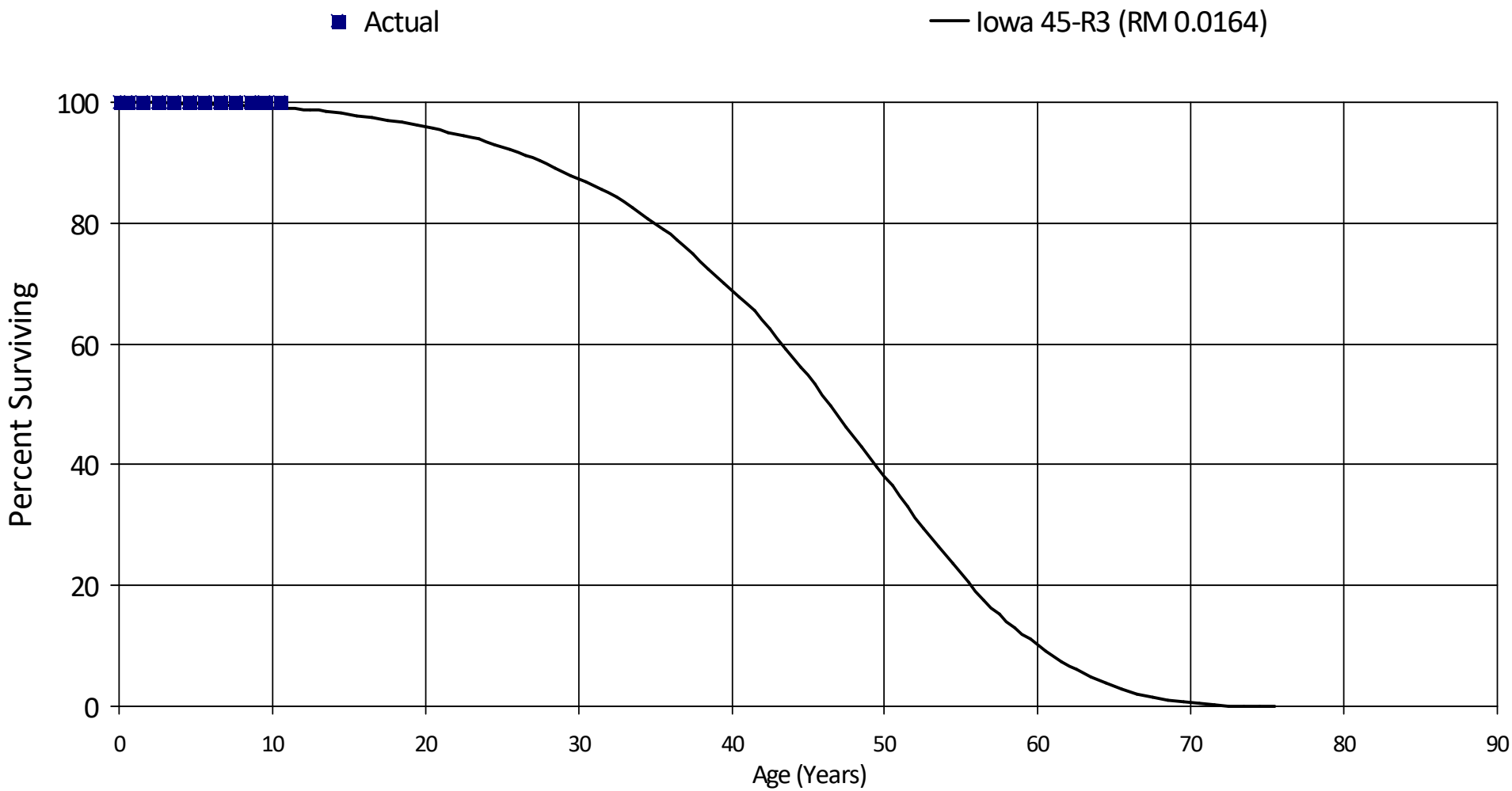
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,426,374	0	0.00000	1.00000	100.00
0.5	1,426,374	0	0.00000	1.00000	100.00
1.5	1,426,374	0	0.00000	1.00000	100.00
2.5	1,426,374	0	0.00000	1.00000	100.00
3.5	1,426,374	0	0.00000	1.00000	100.00
4.5	1,426,374	0	0.00000	1.00000	100.00
5.5	96,745	0	0.00000	1.00000	100.00
6.5	96,745	0	0.00000	1.00000	100.00
7.5	96,745	0	0.00000	1.00000	100.00
8.5	96,745	0	0.00000	1.00000	100.00
9.5	96,695	0	0.00000	1.00000	100.00
10.5	96,695	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 2127 - Substation Equipment - Grounding Transformer

Placement Band - 2011 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 2127 - Substation Equipment - Grounding Transformer

Placement Band - 2011 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

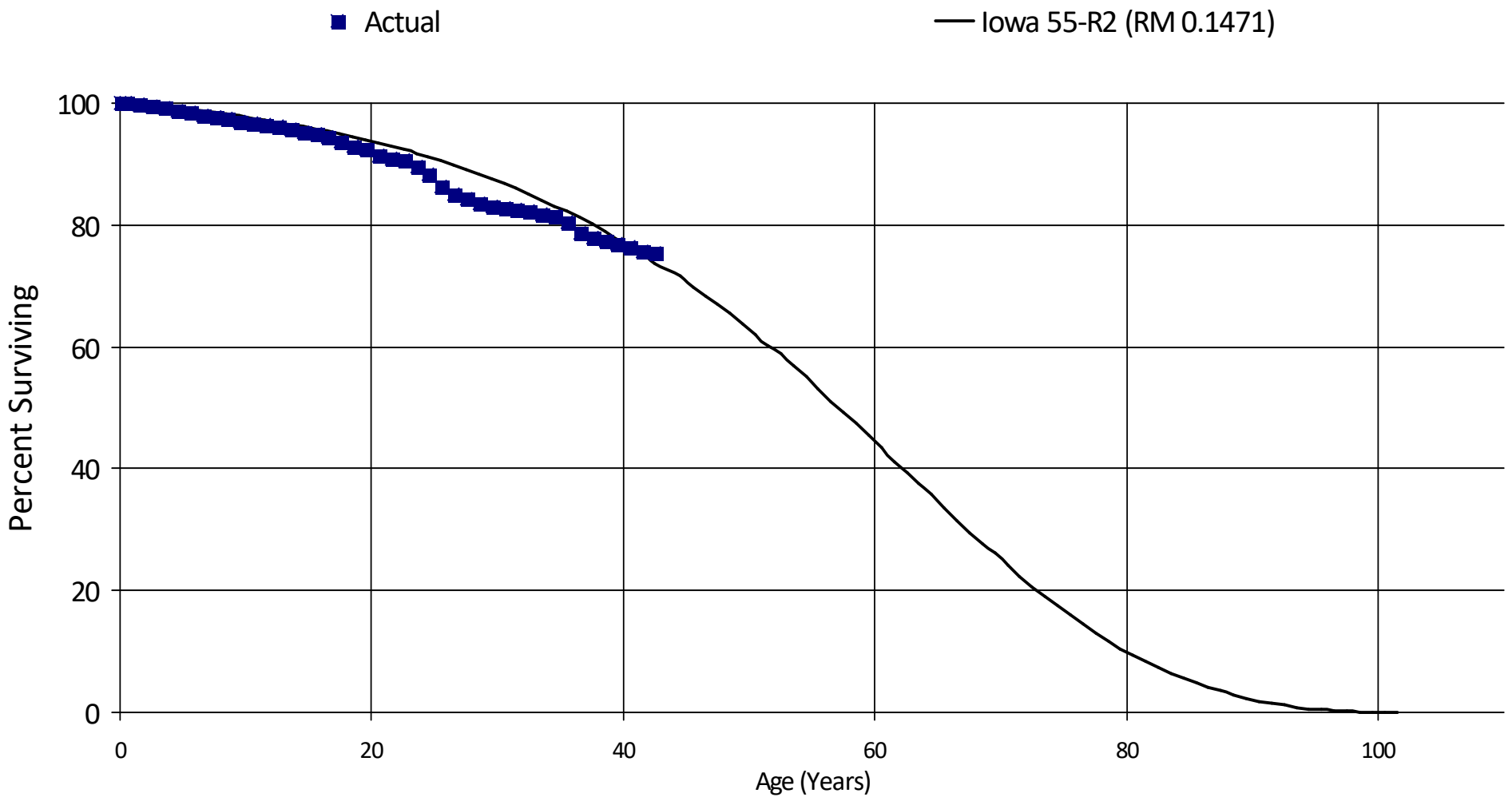
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	410,715	0	0.00000	1.00000	100.00
0.5	410,715	0	0.00000	1.00000	100.00
1.5	410,715	0	0.00000	1.00000	100.00
2.5	410,715	0	0.00000	1.00000	100.00
3.5	410,715	0	0.00000	1.00000	100.00
4.5	410,715	0	0.00000	1.00000	100.00
5.5	410,715	0	0.00000	1.00000	100.00
6.5	410,715	0	0.00000	1.00000	100.00
7.5	410,715	0	0.00000	1.00000	100.00
8.5	410,715	0	0.00000	1.00000	100.00
9.5	410,481	0	0.00000	1.00000	100.00
10.5	410,481	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 3011 - O/H - Poles Concrete legacy

Placement Band - 1979 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3011 - O/H - Poles Concrete legacy

Placement Band - 1979 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	57,269,274	27,419	0.00048	0.99952	100.00
0.5	56,240,506	90,930	0.00162	0.99838	99.95
1.5	54,507,545	179,799	0.00330	0.99670	99.79
2.5	53,464,453	173,984	0.00325	0.99675	99.46
3.5	51,442,071	186,481	0.00363	0.99637	99.14
4.5	50,857,488	211,875	0.00417	0.99583	98.78
5.5	49,713,240	151,961	0.00306	0.99694	98.37
6.5	48,736,250	125,723	0.00258	0.99742	98.07
7.5	47,309,863	174,066	0.00368	0.99632	97.82
8.5	46,162,438	251,645	0.00545	0.99455	97.46
9.5	43,995,344	120,619	0.00274	0.99726	96.93
10.5	43,368,615	144,952	0.00334	0.99666	96.66
11.5	41,913,701	109,123	0.00260	0.99740	96.34
12.5	40,639,803	133,809	0.00329	0.99671	96.09
13.5	38,351,999	236,797	0.00617	0.99383	95.77
14.5	35,120,720	129,871	0.00370	0.99630	95.18
15.5	31,764,995	152,972	0.00482	0.99518	94.83
16.5	30,170,760	236,839	0.00785	0.99215	94.37
17.5	28,961,178	261,341	0.00902	0.99098	93.63
18.5	26,765,894	142,895	0.00534	0.99466	92.79
19.5	22,035,550	220,429	0.01000	0.99000	92.29
20.5	21,199,499	103,465	0.00488	0.99512	91.37
21.5	17,600,780	77,469	0.00440	0.99560	90.92
22.5	12,070,067	112,094	0.00929	0.99071	90.52
23.5	7,254,275	112,435	0.01550	0.98450	89.68
24.5	6,058,654	133,756	0.02208	0.97792	88.29
25.5	4,546,204	69,830	0.01536	0.98464	86.34
26.5	3,898,661	36,554	0.00938	0.99062	85.01

Toronto Hydro

Account 3011 - O/H - Poles Concrete legacy

Placement Band - 1979 - 2022 Experience Band - 2014 - 2022

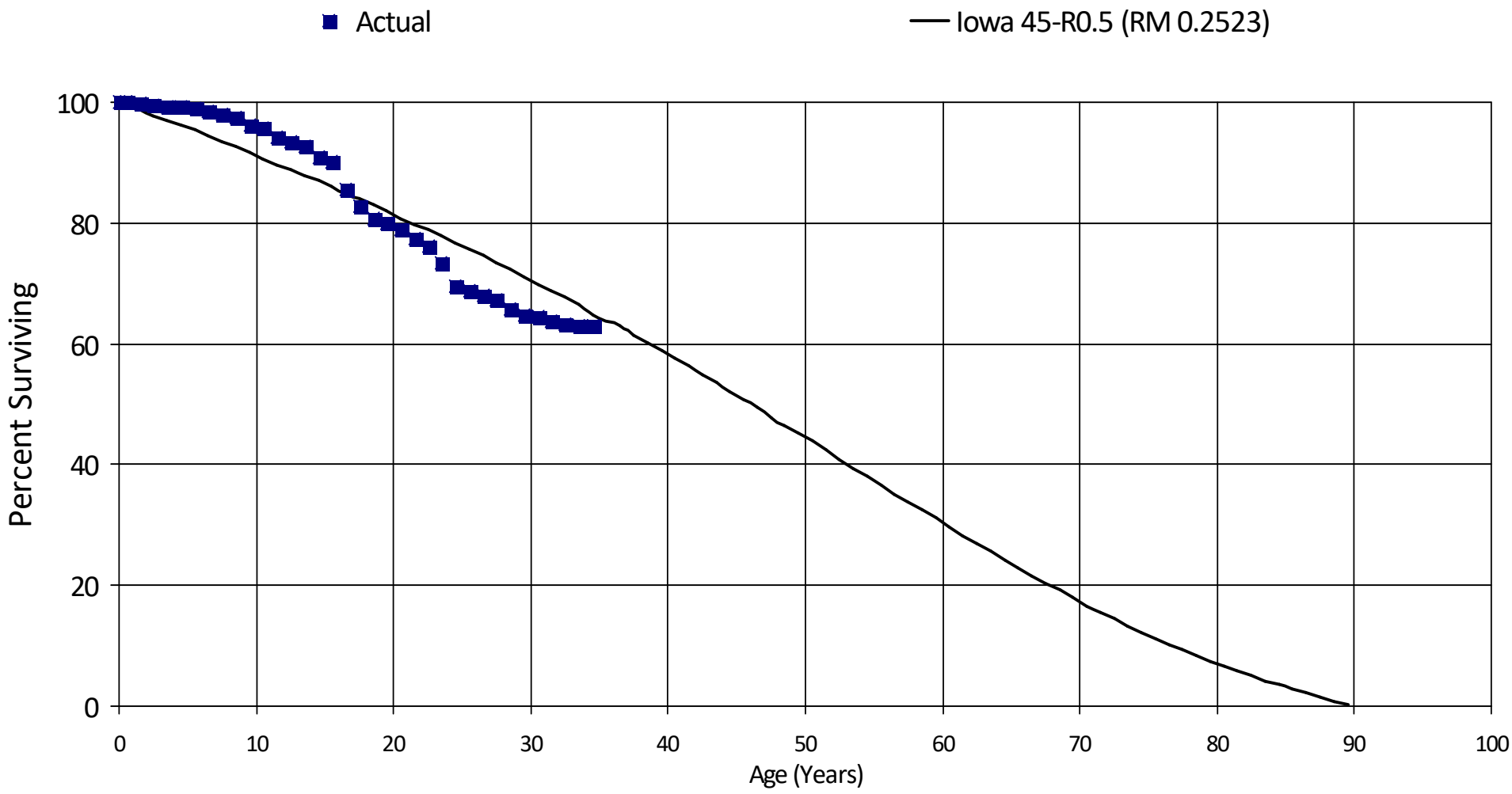
27.5	3,011,278	25,382	0.00843	0.99157	84.21
28.5	2,383,148	16,630	0.00698	0.99302	83.50
29.5	1,679,999	3,017	0.00180	0.99820	82.92
30.5	1,210,834	4,312	0.00356	0.99644	82.77
31.5	898,982	3,886	0.00432	0.99568	82.48
32.5	671,181	2,739	0.00408	0.99592	82.12
33.5	501,658	2,595	0.00517	0.99483	81.78
34.5	466,391	4,707	0.01009	0.98991	81.36
35.5	441,647	10,870	0.02461	0.97539	80.54
36.5	430,777	4,032	0.00936	0.99064	78.56
37.5	426,746	2,629	0.00616	0.99384	77.82
38.5	424,116	2,444	0.00576	0.99424	77.34
39.5	421,672	2,366	0.00561	0.99439	76.89
40.5	419,306	4,640	0.01107	0.98893	76.46
41.5	414,666	1,594	0.00384	0.99616	75.61
42.5	413,073	356	0.00086	0.99914	75.32
	Totals:	4,201,332			

Toronto Hydro

Account 3013 - O/H - Poles Wood

Placement Band - 1987 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3013 - O/H - Poles Wood

Placement Band - 1987 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	429,193,473	308,943	0.00072	0.99928	100.00
0.5	401,952,850	555,937	0.00138	0.99862	99.93
1.5	371,741,385	963,551	0.00259	0.99741	99.79
2.5	341,080,556	811,331	0.00238	0.99762	99.53
3.5	313,920,420	430,496	0.00137	0.99863	99.29
4.5	294,889,531	535,951	0.00182	0.99818	99.15
5.5	271,319,860	1,531,761	0.00565	0.99435	98.97
6.5	240,134,099	1,239,132	0.00516	0.99484	98.41
7.5	202,368,642	767,467	0.00379	0.99621	97.90
8.5	174,679,907	2,192,692	0.01255	0.98745	97.53
9.5	145,911,350	1,021,823	0.00700	0.99300	96.31
10.5	137,318,954	2,087,308	0.01520	0.98480	95.64
11.5	113,278,556	1,001,401	0.00884	0.99116	94.19
12.5	99,847,816	767,019	0.00768	0.99232	93.36
13.5	92,613,198	1,894,981	0.02046	0.97954	92.64
14.5	84,356,224	693,054	0.00822	0.99178	90.74
15.5	76,373,613	3,835,154	0.05022	0.94978	89.99
16.5	70,919,818	2,220,231	0.03131	0.96869	85.47
17.5	66,047,093	1,658,453	0.02511	0.97489	82.79
18.5	61,042,705	607,352	0.00995	0.99005	80.71
19.5	48,711,897	535,110	0.01099	0.98901	79.91
20.5	48,121,433	986,992	0.02051	0.97949	79.03
21.5	38,274,731	676,858	0.01768	0.98232	77.41
22.5	25,627,342	905,957	0.03535	0.96465	76.04
23.5	15,617,489	809,882	0.05186	0.94814	73.35
24.5	12,611,334	128,601	0.01020	0.98980	69.55
25.5	9,936,672	135,346	0.01362	0.98638	68.84
26.5	9,573,995	86,461	0.00903	0.99097	67.90

Toronto Hydro

Account 3013 - O/H - Poles Wood

Placement Band - 1987 - 2022 Experience Band - 2014 - 2022

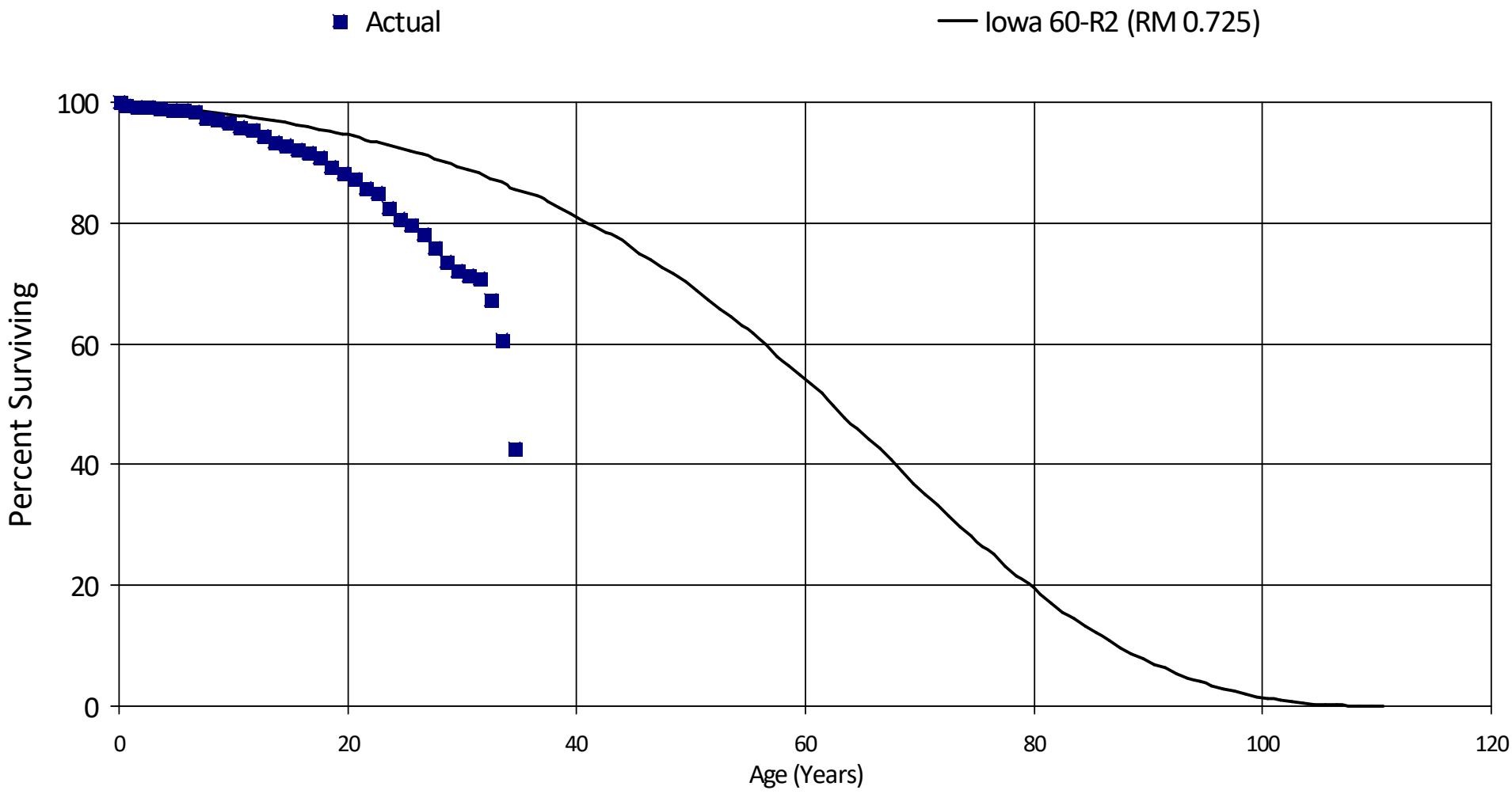
27.5	7,222,548	176,439	0.02443	0.97557	67.29
28.5	5,426,296	69,300	0.01277	0.98723	65.65
29.5	3,582,927	16,037	0.00448	0.99552	64.81
30.5	2,238,886	28,936	0.01292	0.98708	64.52
31.5	1,047,043	7,829	0.00748	0.99252	63.69
32.5	447,864	2,081	0.00465	0.99535	63.21
33.5	12	0	0.00000	1.00000	62.92
34.5	12	0	0.00000	1.00000	62.92
	Totals:	29,689,866			

Toronto Hydro

Account 3051 - O/H - Conductors

Placement Band - 1987 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3051 - O/H - Conductors

Placement Band - 1987 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	148,837,427	667,147	0.00448	0.99552	100.00
0.5	136,324,407	284,088	0.00208	0.99792	99.55
1.5	125,238,304	110,382	0.00088	0.99912	99.34
2.5	117,562,636	256,308	0.00218	0.99782	99.25
3.5	110,816,122	196,693	0.00177	0.99823	99.03
4.5	102,677,671	138,060	0.00134	0.99866	98.85
5.5	91,526,976	148,497	0.00162	0.99838	98.72
6.5	77,159,979	810,732	0.01051	0.98949	98.56
7.5	62,699,387	237,077	0.00378	0.99622	97.52
8.5	51,434,211	267,688	0.00520	0.99480	97.15
9.5	42,363,940	268,116	0.00633	0.99367	96.64
10.5	40,024,372	296,998	0.00742	0.99258	96.03
11.5	32,458,668	308,974	0.00952	0.99048	95.32
12.5	29,176,332	282,276	0.00967	0.99033	94.41
13.5	26,579,259	202,234	0.00761	0.99239	93.50
14.5	23,876,066	181,870	0.00762	0.99238	92.79
15.5	21,528,910	118,147	0.00549	0.99451	92.08
16.5	19,599,301	129,697	0.00662	0.99338	91.57
17.5	18,277,951	311,288	0.01703	0.98297	90.96
18.5	16,675,916	188,235	0.01129	0.98871	89.41
19.5	10,785,183	127,329	0.01181	0.98819	88.40
20.5	10,705,251	182,894	0.01708	0.98292	87.36
21.5	10,343,888	104,582	0.01011	0.98989	85.87
22.5	10,239,306	298,712	0.02917	0.97083	85.00
23.5	9,940,594	221,636	0.02230	0.97770	82.52
24.5	8,437,279	107,365	0.01273	0.98727	80.68
25.5	7,527,186	143,785	0.01910	0.98090	79.65
26.5	6,407,854	177,178	0.02765	0.97235	78.13

Toronto Hydro

Account 3051 - O/H - Conductors

Placement Band - 1987 - 2022 Experience Band - 2014 - 2022

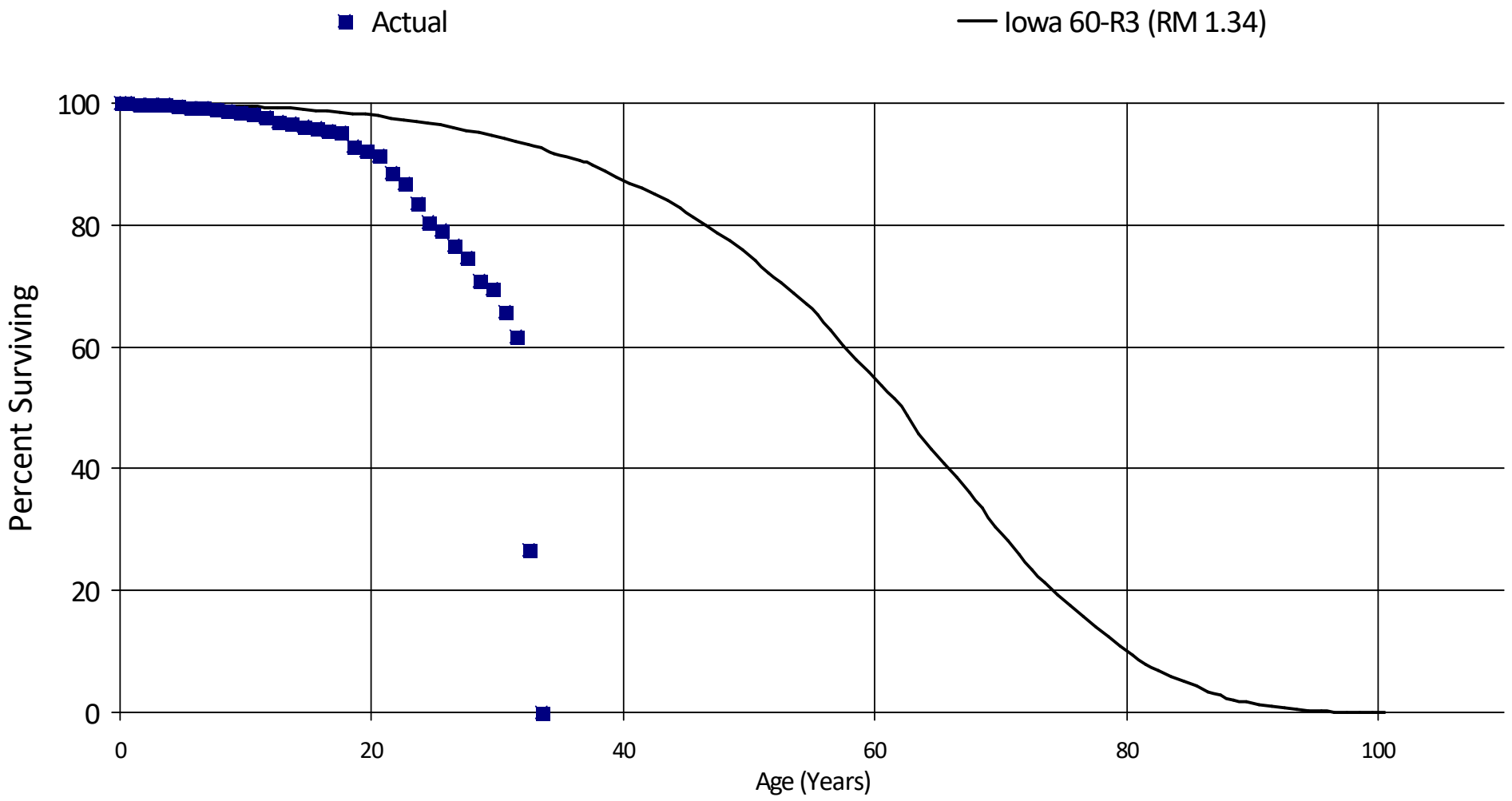
27.5	5,414,350	163,426	0.03018	0.96982	75.97
28.5	4,748,255	111,017	0.02338	0.97662	73.68
29.5	1,981,220	19,251	0.00972	0.99028	71.96
30.5	1,219,449	9,823	0.00806	0.99194	71.26
31.5	708,045	35,544	0.05020	0.94980	70.69
32.5	326,278	30,898	0.09470	0.90530	67.14
33.5	125,310	37,399	0.29845	0.70155	60.78
34.5	0	0	0.00000	0.00000	42.64
	Totals:	7,175,346			

Toronto Hydro

Account 3053 - O/H - Secondary conductors

Placement Band - 1987 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3053 - O/H - Secondary conductors

Placement Band - 1987 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	259,943,478	130,868	0.00050	0.99950	100.00
0.5	243,707,788	187,923	0.00077	0.99923	99.95
1.5	226,498,659	209,116	0.00092	0.99908	99.87
2.5	213,175,690	184,648	0.00087	0.99913	99.78
3.5	199,777,824	485,628	0.00243	0.99757	99.69
4.5	178,775,985	242,062	0.00135	0.99865	99.45
5.5	157,892,264	175,595	0.00111	0.99889	99.32
6.5	141,375,872	297,085	0.00210	0.99790	99.21
7.5	120,677,254	293,637	0.00243	0.99757	99.00
8.5	101,655,809	280,339	0.00276	0.99724	98.76
9.5	86,491,898	224,923	0.00260	0.99740	98.49
10.5	82,445,257	368,730	0.00447	0.99553	98.23
11.5	67,418,275	496,961	0.00737	0.99263	97.79
12.5	54,105,886	195,306	0.00361	0.99639	97.07
13.5	48,519,833	316,207	0.00652	0.99348	96.72
14.5	43,530,810	123,042	0.00283	0.99717	96.09
15.5	39,491,209	133,656	0.00338	0.99662	95.82
16.5	36,208,515	162,601	0.00449	0.99551	95.50
17.5	33,497,756	741,339	0.02213	0.97787	95.07
18.5	29,952,681	234,047	0.00781	0.99219	92.97
19.5	19,564,506	196,540	0.01005	0.98995	92.24
20.5	19,450,911	565,052	0.02905	0.97095	91.31
21.5	18,897,536	379,334	0.02007	0.97993	88.66
22.5	18,518,202	728,767	0.03935	0.96065	86.88
23.5	17,789,435	626,952	0.03524	0.96476	83.46
24.5	15,079,380	267,136	0.01772	0.98228	80.52
25.5	13,462,597	424,882	0.03156	0.96844	79.09
26.5	11,465,013	297,353	0.02594	0.97406	76.59

Toronto Hydro

Account 3053 - O/H - Secondary conductors

Placement Band - 1987 - 2022 Experience Band - 2014 - 2022

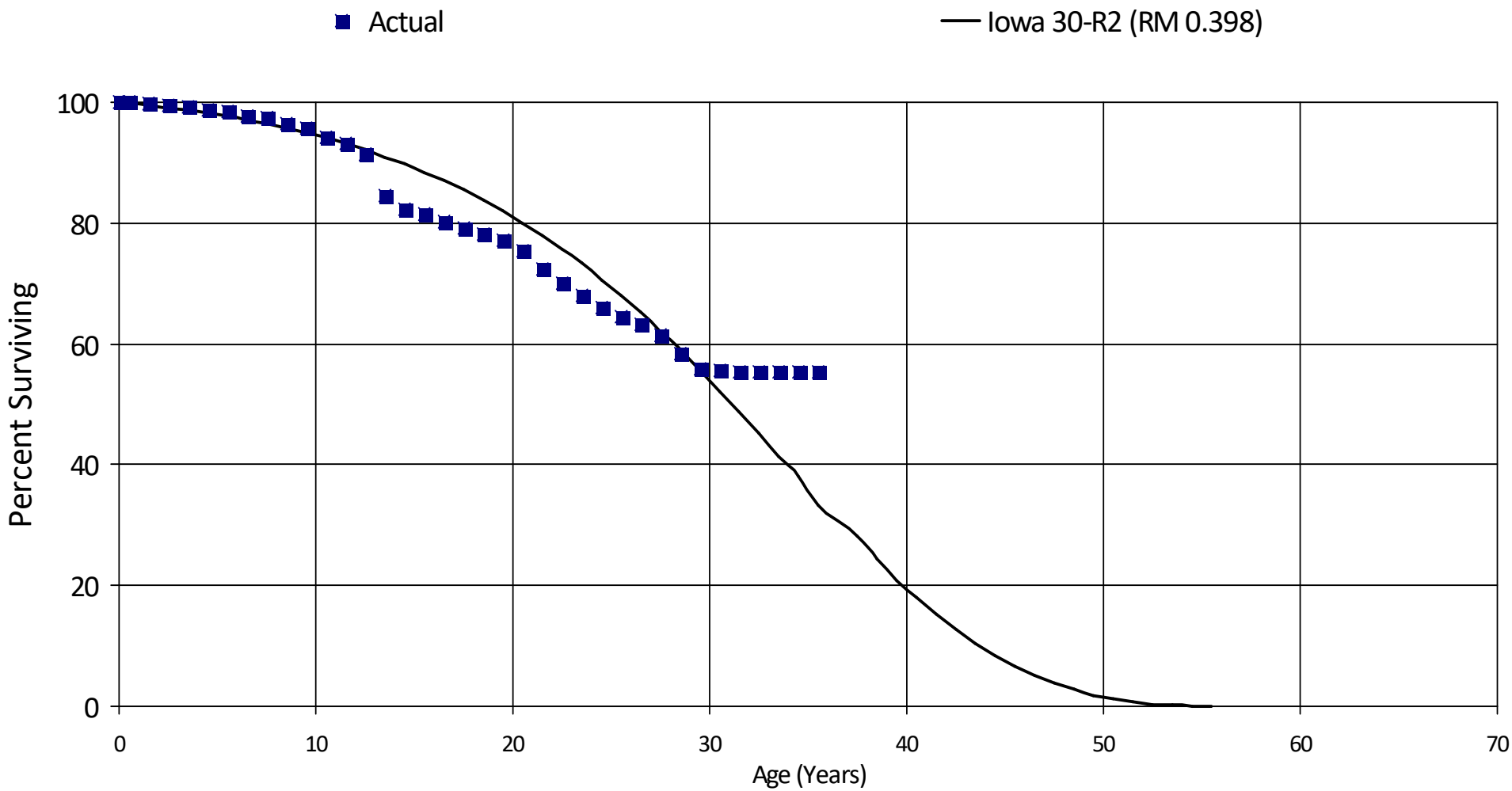
27.5	9,807,346	487,822	0.04974	0.95026	74.60
28.5	8,532,173	169,416	0.01986	0.98014	70.89
29.5	3,429,201	186,796	0.05447	0.94553	69.48
30.5	2,098,240	128,509	0.06125	0.93875	65.70
31.5	1,209,582	686,463	0.56752	0.43248	61.68
32.5	1,345	1,345	1.00004	-0.00004	26.68
33.5	0	0	0.00000	0.00000	0.00
	Totals:	10,630,080			

Toronto Hydro

Account 3057 - O/H - Switches

Placement Band - 1986 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3057 - O/H - Switches

Placement Band - 1986 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	160,726,808	88,986	0.00055	0.99945	100.00
0.5	144,884,017	224,454	0.00155	0.99845	99.94
1.5	129,749,692	387,519	0.00299	0.99701	99.79
2.5	118,590,248	419,255	0.00354	0.99646	99.49
3.5	109,681,181	377,178	0.00344	0.99656	99.14
4.5	99,278,027	399,363	0.00402	0.99598	98.80
5.5	90,354,891	637,526	0.00706	0.99294	98.40
6.5	76,534,059	276,613	0.00361	0.99639	97.71
7.5	65,395,883	647,533	0.00990	0.99010	97.36
8.5	55,201,692	428,589	0.00776	0.99224	96.40
9.5	38,741,528	653,442	0.01687	0.98313	95.65
10.5	32,230,278	327,928	0.01017	0.98983	94.04
11.5	22,702,952	427,534	0.01883	0.98117	93.08
12.5	11,605,004	857,104	0.07386	0.92614	91.33
13.5	9,189,355	250,321	0.02724	0.97276	84.58
14.5	8,016,850	67,996	0.00848	0.99152	82.28
15.5	7,252,139	123,684	0.01705	0.98295	81.58
16.5	6,534,213	83,639	0.01280	0.98720	80.19
17.5	6,128,695	82,673	0.01349	0.98651	79.16
18.5	5,784,190	75,523	0.01306	0.98694	78.09
19.5	4,291,297	97,976	0.02283	0.97717	77.07
20.5	4,211,095	163,949	0.03893	0.96107	75.31
21.5	4,199,067	130,233	0.03101	0.96899	72.38
22.5	4,068,834	125,902	0.03094	0.96906	70.14
23.5	3,942,932	112,157	0.02845	0.97155	67.97
24.5	3,354,603	80,201	0.02391	0.97609	66.04
25.5	2,928,334	56,504	0.01930	0.98070	64.46
26.5	2,525,034	71,146	0.02818	0.97182	63.22

Toronto Hydro

Account 3057 - O/H - Switches

Placement Band - 1986 - 2022 Experience Band - 2014 - 2022

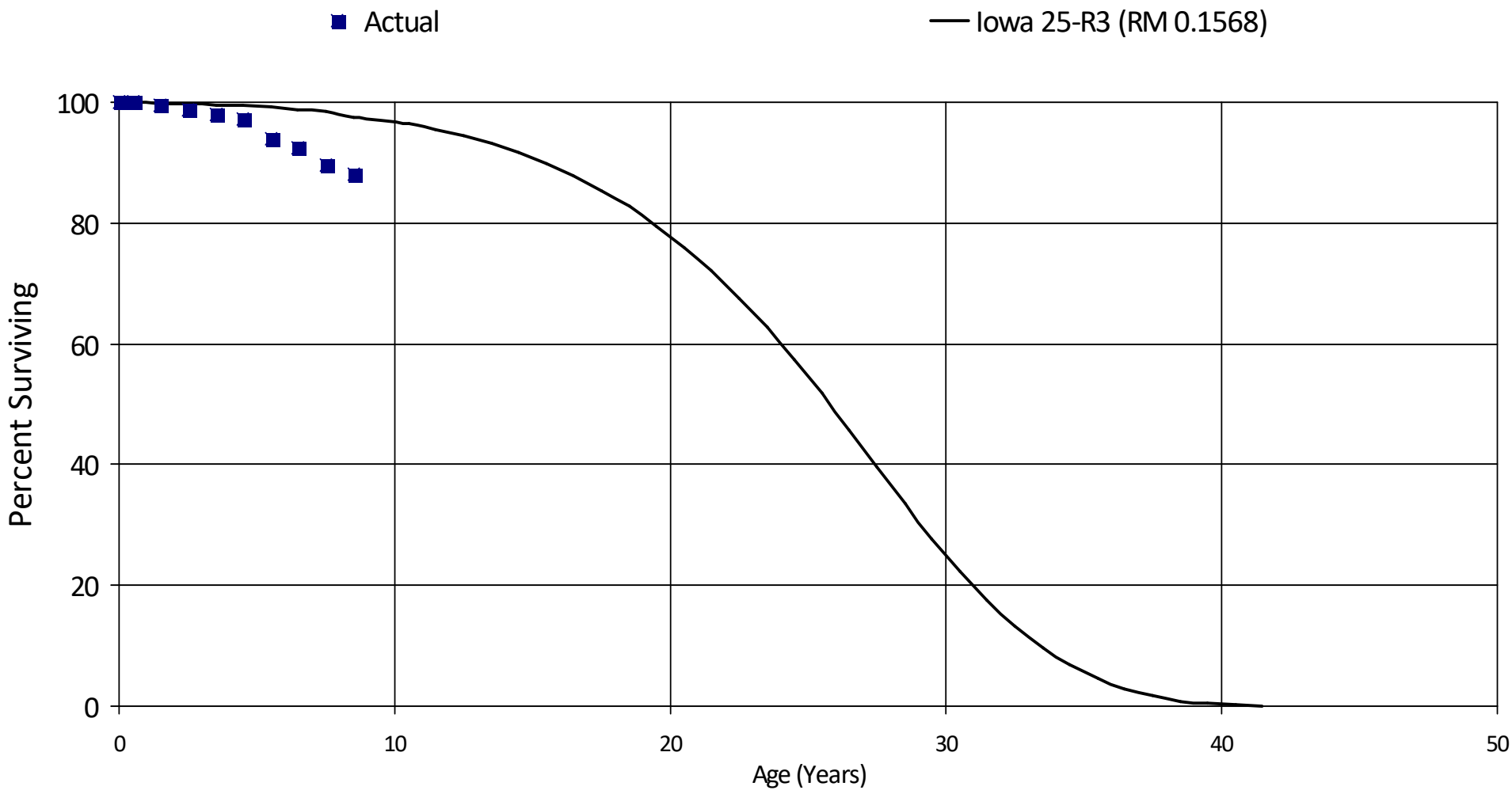
27.5	2,141,621	107,916	0.05039	0.94961	61.44
28.5	1,826,468	81,768	0.04477	0.95523	58.34
29.5	725,767	3,136	0.00432	0.99568	55.73
30.5	444,222	395	0.00089	0.99911	55.49
31.5	289,144	0	0.00000	1.00000	55.44
32.5	101,543	0	0.00000	1.00000	55.44
33.5	46,471	0	0.00000	1.00000	55.44
34.5	654	0	0.00000	1.00000	55.44
35.5	0	0	0.00000	0.00000	55.44
	Totals:	7,868,143			

Toronto Hydro

Account 3061 - O/H - SMD-20 Switches

Placement Band - 2013 - 2022 Experience Band - 2015 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3061 - O/H - SMD-20 Switches

Placement Band - 2013 - 2022 Experience Band - 2015 - 2022

RETIREMENT RATE ANALYSIS

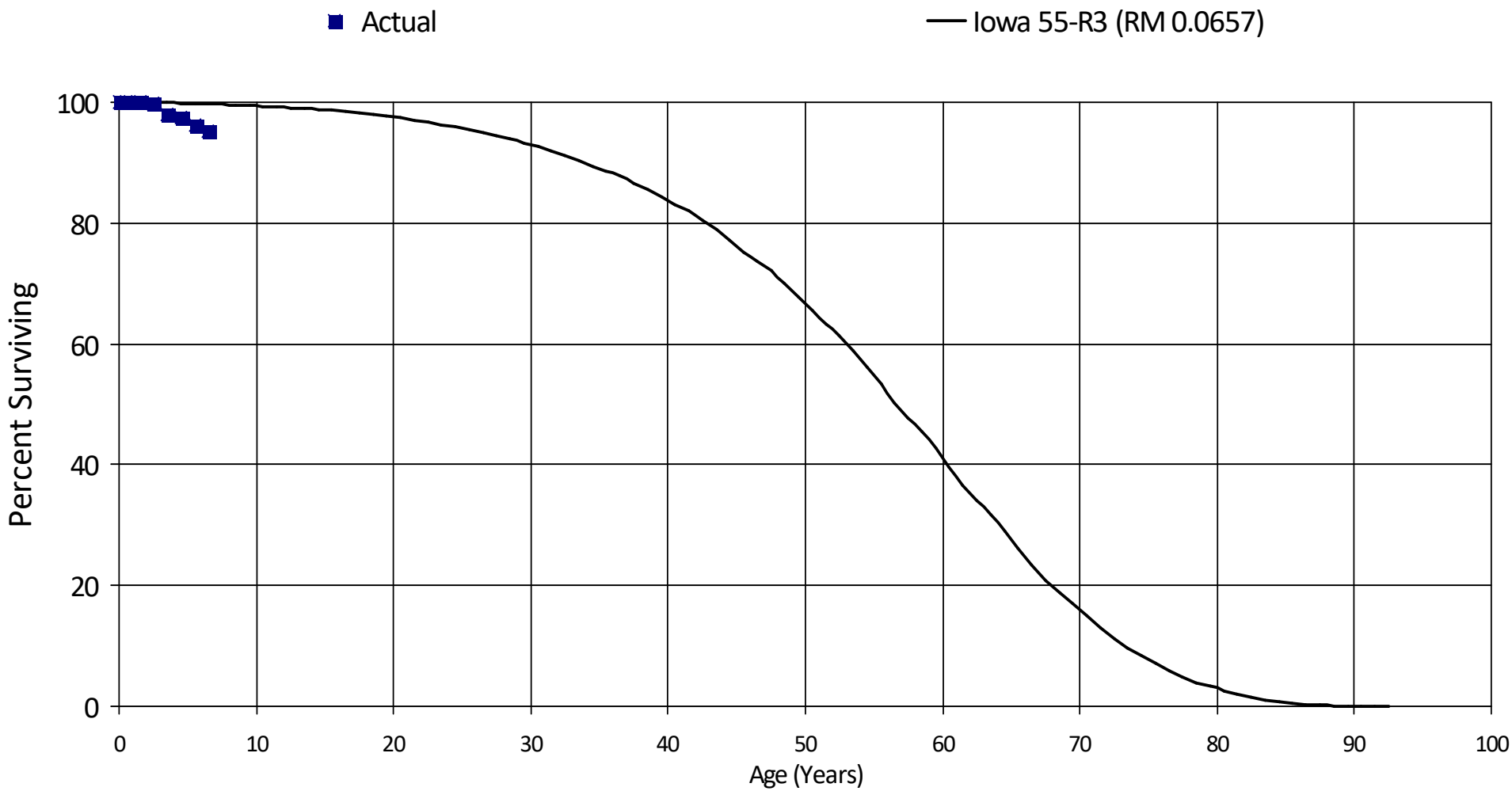
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	31,854,761	3,549	0.00011	0.99989	100.00
0.5	27,781,760	122,258	0.00440	0.99560	99.99
1.5	23,144,539	199,424	0.00862	0.99138	99.55
2.5	21,117,749	137,880	0.00653	0.99347	98.69
3.5	17,756,994	165,965	0.00935	0.99065	98.05
4.5	15,444,640	503,439	0.03260	0.96740	97.13
5.5	12,937,087	231,401	0.01789	0.98211	93.96
6.5	8,658,619	258,647	0.02987	0.97013	92.28
7.5	5,143,029	81,146	0.01578	0.98422	89.52
8.5	2,261,264	63,366	0.02802	0.97198	88.11
	Totals:	1,767,075			

Toronto Hydro

Account 3411 - O/H - Poles STL Conventional Legacy

Placement Band - 2015 - 2022 Experience Band - 2019 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3411 - O/H - Poles STL Conventional Legacy

Placement Band - 2015 - 2022 Experience Band - 2019 - 2022

RETIREMENT RATE ANALYSIS

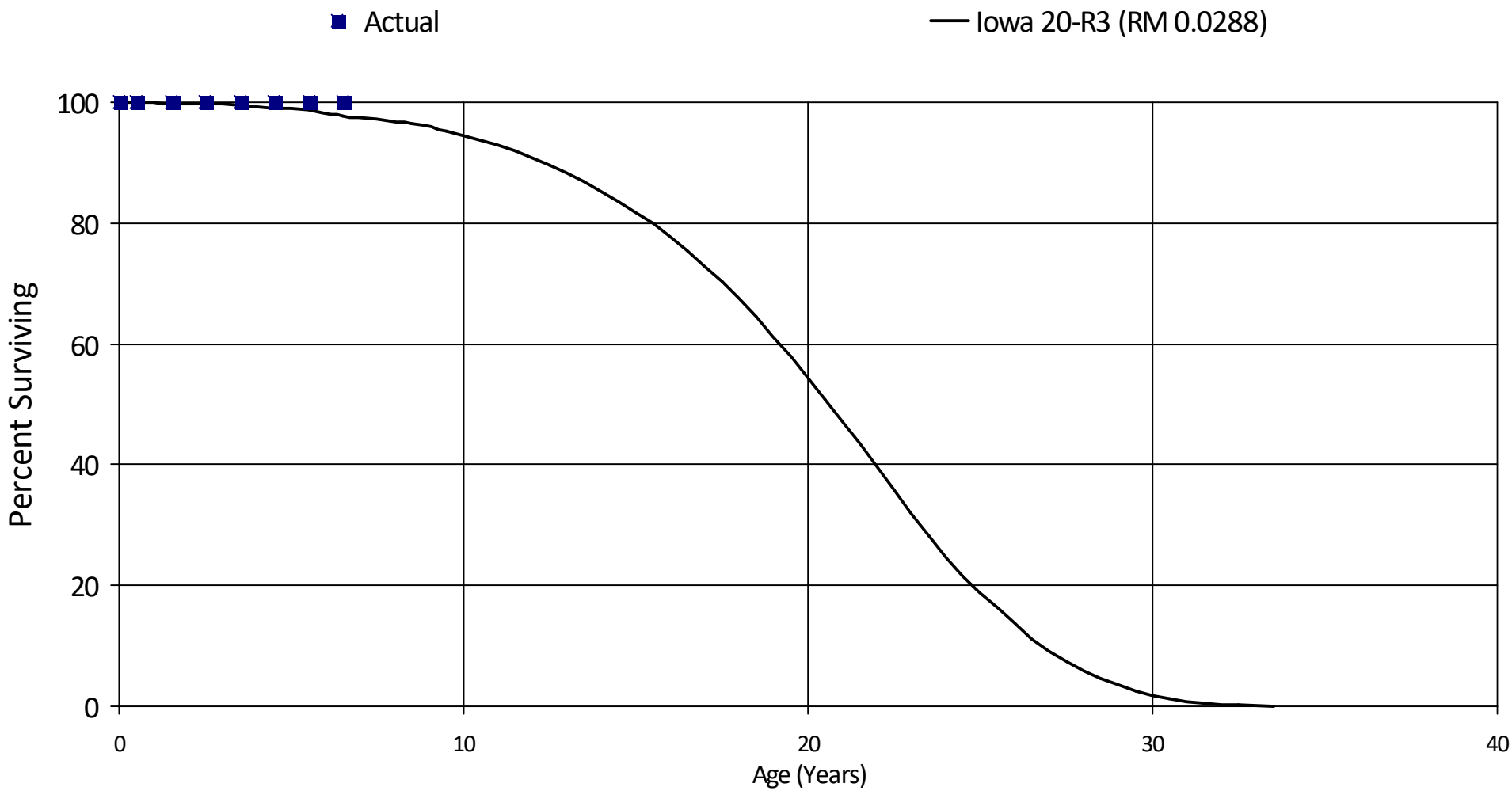
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	48,217,660	10,165	0.00021	0.99979	100.00
0.5	47,166,595	42,330	0.00090	0.99910	99.98
1.5	45,671,543	49,733	0.00109	0.99891	99.89
2.5	43,616,946	767,053	0.01759	0.98241	99.78
3.5	37,625,279	253,066	0.00673	0.99327	98.02
4.5	35,912,715	470,065	0.01309	0.98691	97.36
5.5	33,465,155	308,382	0.00922	0.99078	96.09
6.5	274,038	27,392	0.09996	0.90004	95.20
	Totals:	1,928,186			

Toronto Hydro

Account 3427 - O/H - Poles Handwell

Placement Band - 2015 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3427 - O/H - Poles Handwell

Placement Band - 2015 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

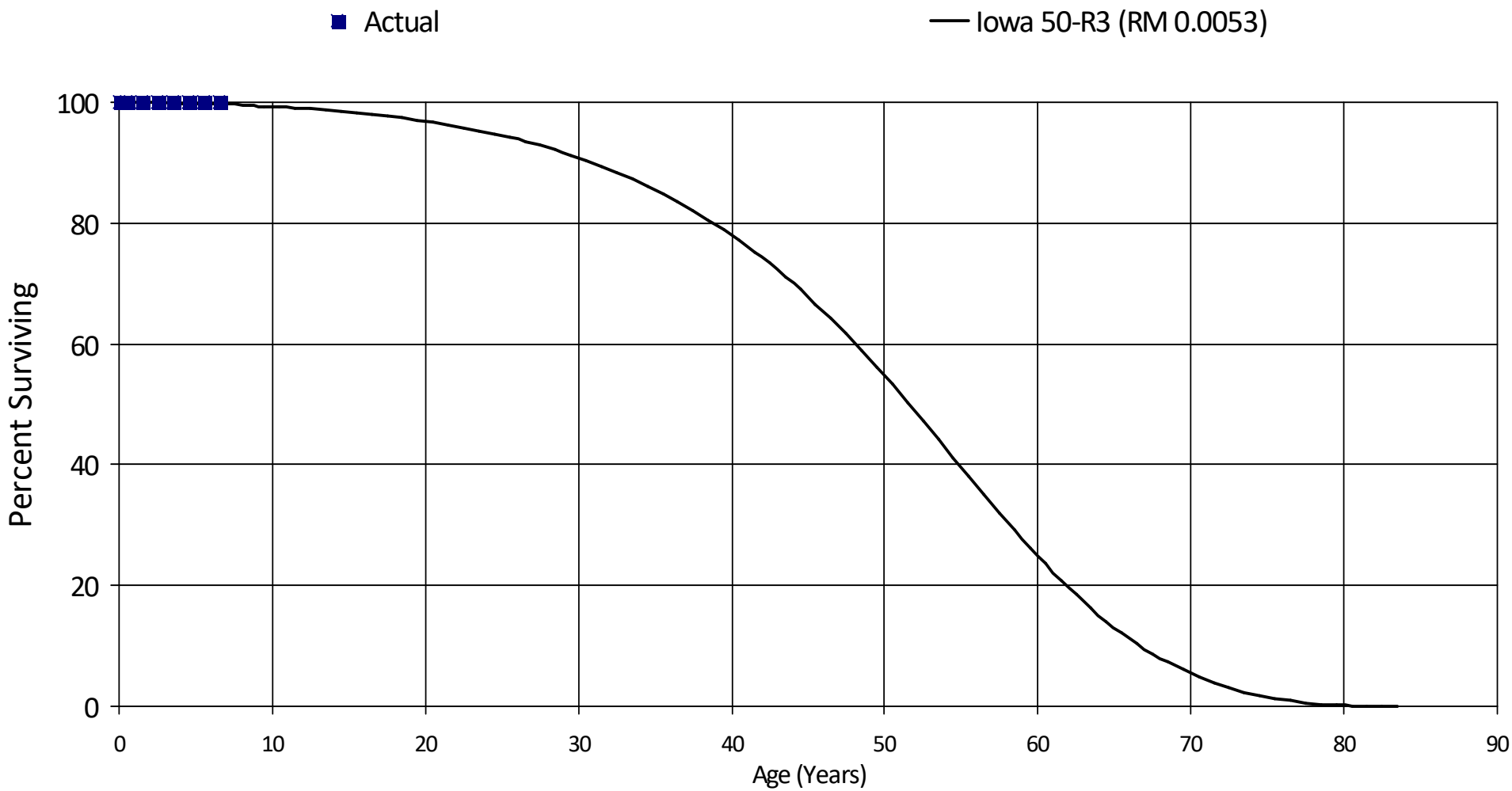
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,105,991	0	0.00000	1.00000	100.00
0.5	1,094,364	0	0.00000	1.00000	100.00
1.5	1,001,623	0	0.00000	1.00000	100.00
2.5	881,653	0	0.00000	1.00000	100.00
3.5	608,996	0	0.00000	1.00000	100.00
4.5	594,955	0	0.00000	1.00000	100.00
5.5	430,965	0	0.00000	1.00000	100.00
6.5	109,801	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 3451 - O/H - Street Lighting Cable

Placement Band - 2015 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3451 - O/H - Street Lighting Cable

Placement Band - 2015 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

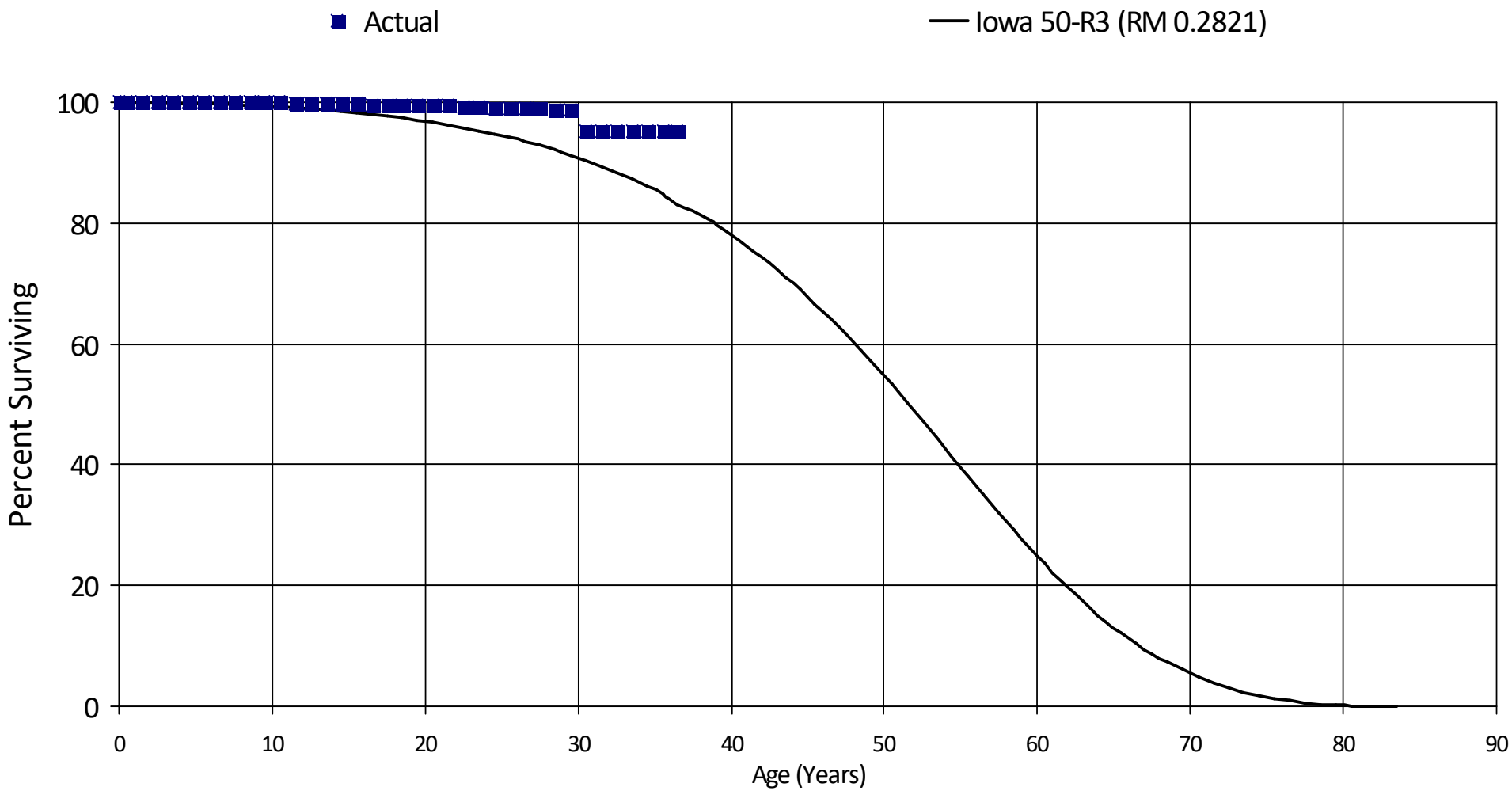
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,459,708	0	0.00000	1.00000	100.00
0.5	5,582,879	0	0.00000	1.00000	100.00
1.5	4,596,010	0	0.00000	1.00000	100.00
2.5	3,592,201	0	0.00000	1.00000	100.00
3.5	2,070,371	0	0.00000	1.00000	100.00
4.5	2,009,577	0	0.00000	1.00000	100.00
5.5	1,395,863	0	0.00000	1.00000	100.00
6.5	325,050	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 3511 - U/G Conduit - Duct Bank

Placement Band - 1985 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3511 - U/G Conduit - Duct Bank

Placement Band - 1985 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,239,135,524	14,798	0.00001	0.99999	100.00
0.5	1,139,278,411	20,634	0.00002	0.99998	100.00
1.5	1,050,648,787	101,192	0.00010	0.99990	100.00
2.5	965,945,387	150,618	0.00016	0.99984	99.99
3.5	878,080,052	20,882	0.00002	0.99998	99.97
4.5	809,342,350	40,492	0.00005	0.99995	99.97
5.5	747,146,191	24,781	0.00003	0.99997	99.97
6.5	674,930,343	250,084	0.00037	0.99963	99.97
7.5	591,025,779	90,607	0.00015	0.99985	99.93
8.5	470,517,430	65,528	0.00014	0.99986	99.92
9.5	395,549,401	65,107	0.00016	0.99984	99.91
10.5	356,589,450	77,079	0.00022	0.99978	99.89
11.5	252,201,503	92,136	0.00037	0.99963	99.87
12.5	191,261,705	71,023	0.00037	0.99963	99.83
13.5	163,954,030	59,459	0.00036	0.99964	99.79
14.5	134,399,478	166,496	0.00124	0.99876	99.75
15.5	120,780,008	31,166	0.00026	0.99974	99.63
16.5	109,965,054	41,467	0.00038	0.99962	99.60
17.5	107,593,669	8,259	0.00008	0.99992	99.56
18.5	96,922,874	55,114	0.00057	0.99943	99.55
19.5	79,959,586	21,759	0.00027	0.99973	99.49
20.5	84,963,759	49,167	0.00058	0.99942	99.46
21.5	79,476,690	91,939	0.00116	0.99884	99.40
22.5	64,289,468	52,753	0.00082	0.99918	99.28
23.5	49,958,159	44,923	0.00090	0.99910	99.20
24.5	41,956,653	16,777	0.00040	0.99960	99.11
25.5	34,957,250	19,132	0.00055	0.99945	99.07
26.5	30,673,703	23,432	0.00076	0.99924	99.02

Toronto Hydro

Account 3511 - U/G Conduit - Duct Bank

Placement Band - 1985 - 2022 Experience Band - 2014 - 2022

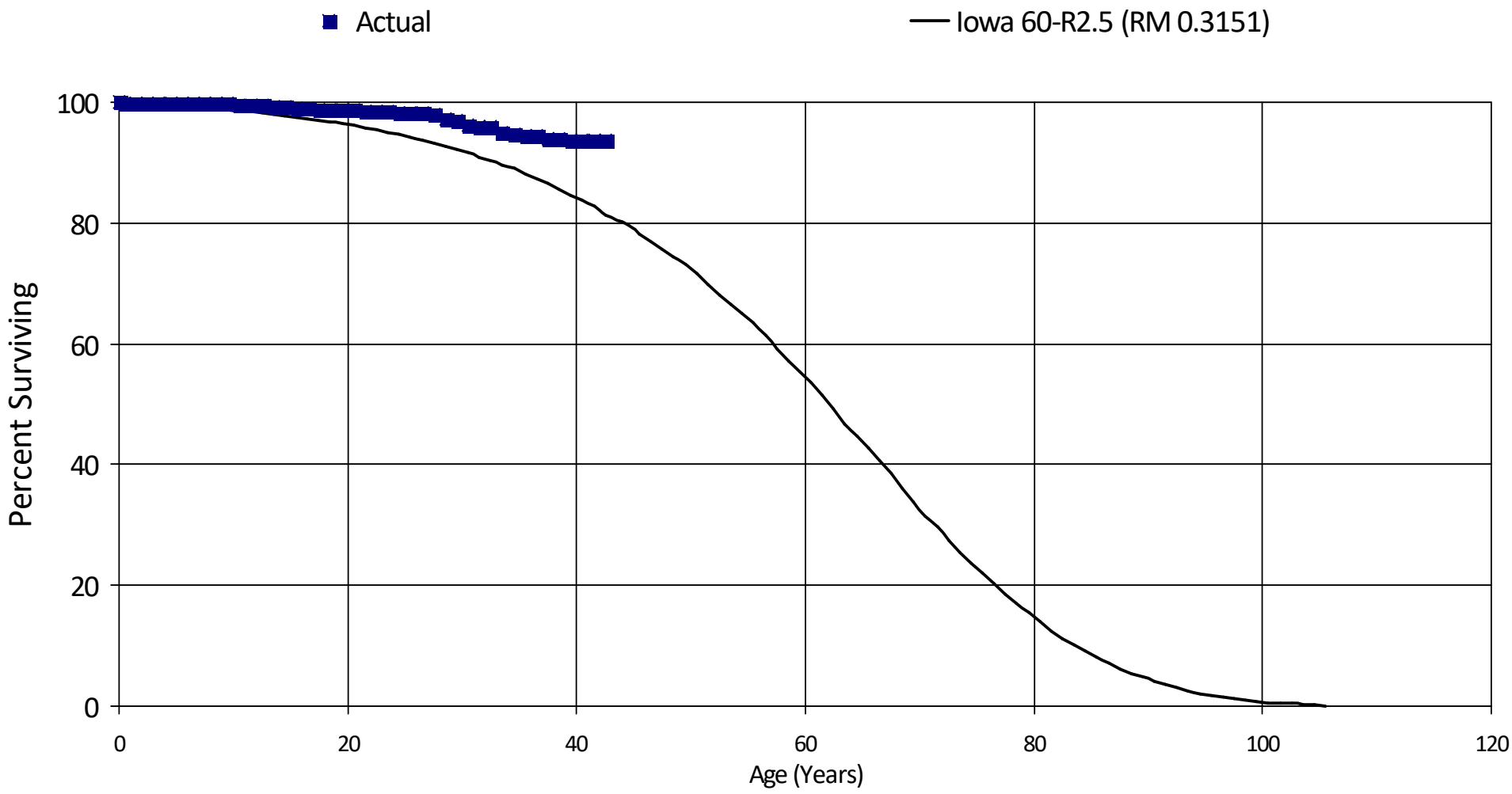
27.5	23,924,956	21,728	0.00091	0.99909	98.94
28.5	17,308,419	5,185	0.00030	0.99970	98.85
29.5	11,653,223	425,744	0.03653	0.96347	98.82
30.5	4,965,113	0	0.00000	1.00000	95.21
31.5	2,716,868	43	0.00002	0.99998	95.21
32.5	1,259,994	0	0.00000	1.00000	95.21
33.5	668,813	0	0.00000	1.00000	95.21
34.5	668,813	0	0.00000	1.00000	95.21
35.5	489,933	0	0.00000	1.00000	95.21
36.5	481,500	0	0.00000	1.00000	95.21
	Totals:	2,219,504			

Toronto Hydro

Account 3513 - U/G Conduit - Vault

Placement Band - 1979 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3513 - U/G Conduit - Vault

Placement Band - 1979 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	163,311,823	218,328	0.00134	0.99866	100.00
0.5	153,274,499	0	0.00000	1.00000	99.87
1.5	146,660,977	48,448	0.00033	0.99967	99.87
2.5	138,066,828	832	0.00001	0.99999	99.84
3.5	132,972,728	0	0.00000	1.00000	99.84
4.5	130,695,978	32,748	0.00025	0.99975	99.84
5.5	127,307,335	179,647	0.00141	0.99859	99.82
6.5	123,318,926	0	0.00000	1.00000	99.68
7.5	120,668,406	0	0.00000	1.00000	99.68
8.5	117,232,812	3,858	0.00003	0.99997	99.68
9.5	112,622,158	176,026	0.00156	0.99844	99.68
10.5	112,008,594	40,186	0.00036	0.99964	99.52
11.5	109,577,502	0	0.00000	1.00000	99.48
12.5	107,530,859	212,492	0.00198	0.99802	99.48
13.5	96,005,227	17,621	0.00018	0.99982	99.28
14.5	80,195,717	262,491	0.00327	0.99673	99.26
15.5	72,794,802	50,960	0.00070	0.99930	98.94
16.5	66,927,416	49,332	0.00074	0.99926	98.87
17.5	65,475,847	65,116	0.00099	0.99901	98.80
18.5	59,538,496	0	0.00000	1.00000	98.70
19.5	50,169,504	35,568	0.00071	0.99929	98.70
20.5	52,779,371	57,770	0.00109	0.99891	98.63
21.5	49,625,948	19,184	0.00039	0.99961	98.52
22.5	41,064,902	0	0.00000	1.00000	98.48
23.5	32,973,268	60,365	0.00183	0.99817	98.48
24.5	28,570,258	18,948	0.00066	0.99934	98.30
25.5	24,503,229	0	0.00000	1.00000	98.24
26.5	22,090,288	49,807	0.00225	0.99775	98.24

Toronto Hydro

Account 3513 - U/G Conduit - Vault

Placement Band - 1979 - 2022 Experience Band - 2014 - 2022

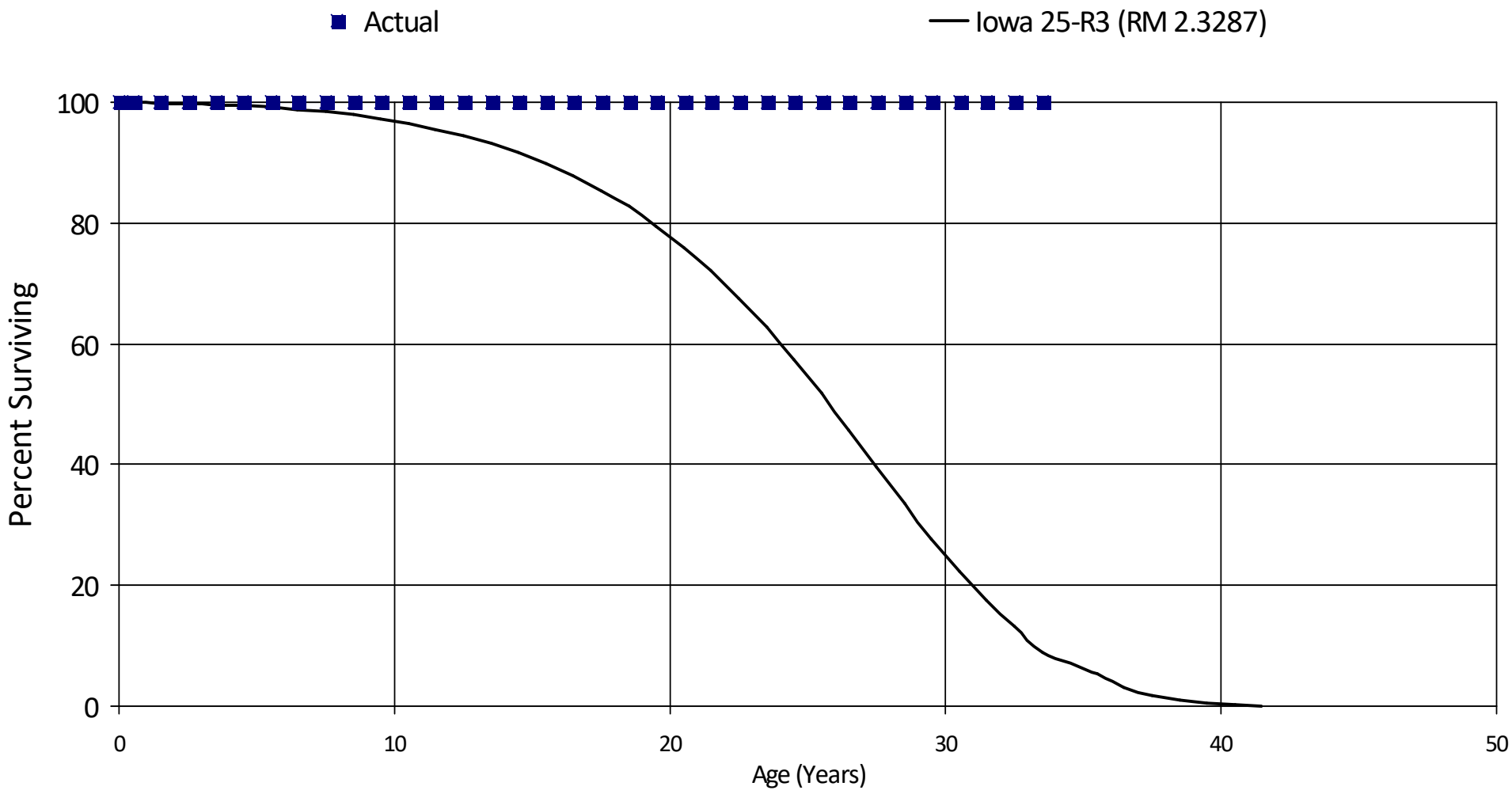
27.5	18,086,521	169,951	0.00940	0.99060	98.02
28.5	13,955,805	26,836	0.00192	0.99808	97.10
29.5	10,691,551	77,705	0.00727	0.99273	96.91
30.5	6,726,261	14,821	0.00220	0.99780	96.21
31.5	5,291,845	7,756	0.00147	0.99853	96.00
32.5	4,317,951	43,452	0.01006	0.98994	95.86
33.5	3,862,814	9,416	0.00244	0.99756	94.90
34.5	3,536,266	7,583	0.00214	0.99786	94.67
35.5	3,463,216	5,255	0.00152	0.99848	94.47
36.5	3,452,143	11,214	0.00325	0.99675	94.33
37.5	2,690,526	0	0.00000	1.00000	94.02
38.5	2,156,485	7,736	0.00359	0.99641	94.02
39.5	1,609,643	0	0.00000	1.00000	93.68
40.5	995,657	0	0.00000	1.00000	93.68
41.5	649,280	0	0.00000	1.00000	93.68
42.5	445,454	0	0.00000	1.00000	93.68
	Totals:	1,981,452			

Toronto Hydro

Account 3515 - U/G Conduit - Vault Roof

Placement Band - 1988 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3515 - U/G Conduit - Vault Roof

Placement Band - 1988 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	30,249,381	0	0.00000	1.00000	100.00
0.5	28,934,783	0	0.00000	1.00000	100.00
1.5	27,447,707	0	0.00000	1.00000	100.00
2.5	25,445,416	0	0.00000	1.00000	100.00
3.5	23,865,890	0	0.00000	1.00000	100.00
4.5	22,614,616	0	0.00000	1.00000	100.00
5.5	20,806,017	0	0.00000	1.00000	100.00
6.5	20,180,147	0	0.00000	1.00000	100.00
7.5	19,631,209	0	0.00000	1.00000	100.00
8.5	18,988,360	0	0.00000	1.00000	100.00
9.5	18,508,330	0	0.00000	1.00000	100.00
10.5	18,358,534	0	0.00000	1.00000	100.00
11.5	18,303,797	0	0.00000	1.00000	100.00
12.5	18,303,797	0	0.00000	1.00000	100.00
13.5	16,083,175	0	0.00000	1.00000	100.00
14.5	12,977,138	0	0.00000	1.00000	100.00
15.5	11,593,083	0	0.00000	1.00000	100.00
16.5	10,470,585	0	0.00000	1.00000	100.00
17.5	10,218,244	0	0.00000	1.00000	100.00
18.5	9,090,638	0	0.00000	1.00000	100.00
19.5	7,328,283	0	0.00000	1.00000	100.00
20.5	7,925,804	0	0.00000	1.00000	100.00
21.5	7,408,823	0	0.00000	1.00000	100.00
22.5	5,828,660	0	0.00000	1.00000	100.00
23.5	4,358,163	0	0.00000	1.00000	100.00
24.5	3,551,381	0	0.00000	1.00000	100.00
25.5	2,848,000	0	0.00000	1.00000	100.00
26.5	2,428,652	0	0.00000	1.00000	100.00

Toronto Hydro

Account 3515 - U/G Conduit - Vault Roof

Placement Band - 1988 - 2022 Experience Band - 2022 - 2022

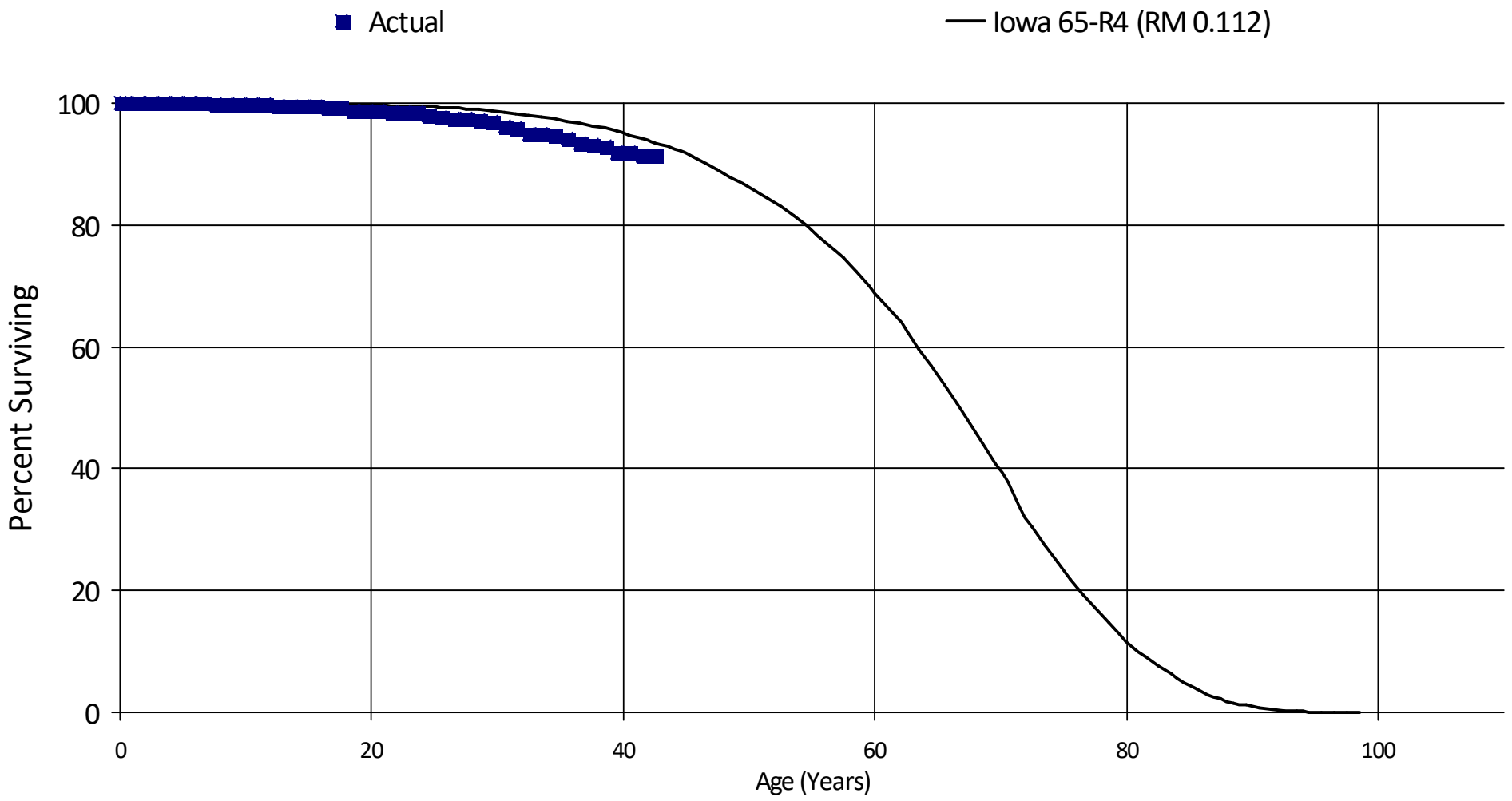
27.5	1,788,863	0	0.00000	1.00000	100.00
28.5	1,189,905	0	0.00000	1.00000	100.00
29.5	709,514	0	0.00000	1.00000	100.00
30.5	230,552	0	0.00000	1.00000	100.00
31.5	87,466	0	0.00000	1.00000	100.00
32.5	1,111	0	0.00000	1.00000	100.00
33.5	1,111	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 3517 - U/G Conduit - Cable Chamber

Placement Band - 1979 - 2022 Experience Band - 2015 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3517 - U/G Conduit - Cable Chamber

Placement Band - 1979 - 2022 Experience Band - 2015 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	262,037,175	0	0.00000	1.00000	100.00
0.5	238,114,410	68,358	0.00029	0.99971	100.00
1.5	209,645,052	7,994	0.00004	0.99996	99.97
2.5	180,824,375	15,788	0.00009	0.99991	99.97
3.5	156,223,447	0	0.00000	1.00000	99.96
4.5	146,144,517	0	0.00000	1.00000	99.96
5.5	138,901,121	0	0.00000	1.00000	99.96
6.5	125,011,876	241,354	0.00193	0.99807	99.96
7.5	116,287,197	41,828	0.00036	0.99964	99.77
8.5	86,211,446	26,264	0.00030	0.99970	99.73
9.5	75,646,489	6,396	0.00008	0.99992	99.70
10.5	68,872,754	24,648	0.00036	0.99964	99.69
11.5	63,316,469	66,022	0.00104	0.99896	99.65
12.5	56,471,294	53,819	0.00095	0.99905	99.55
13.5	50,532,277	24,137	0.00048	0.99952	99.46
14.5	42,339,963	0	0.00000	1.00000	99.41
15.5	38,524,764	58,099	0.00151	0.99849	99.41
16.5	35,402,050	4,663	0.00013	0.99987	99.26
17.5	34,643,864	192,057	0.00554	0.99446	99.25
18.5	31,366,966	0	0.00000	1.00000	98.70
19.5	26,622,826	7,963	0.00030	0.99970	98.70
20.5	27,834,209	45,923	0.00165	0.99835	98.67
21.5	26,089,999	22,001	0.00084	0.99916	98.51
22.5	21,665,799	3,520	0.00016	0.99984	98.43
23.5	17,487,227	70,990	0.00406	0.99594	98.41
24.5	15,112,535	25,649	0.00170	0.99830	98.01
25.5	12,996,964	41,814	0.00322	0.99678	97.84
26.5	11,554,014	8,555	0.00074	0.99926	97.52

Toronto Hydro

Account 3517 - U/G Conduit - Cable Chamber

Placement Band - 1979 - 2022 Experience Band - 2015 - 2022

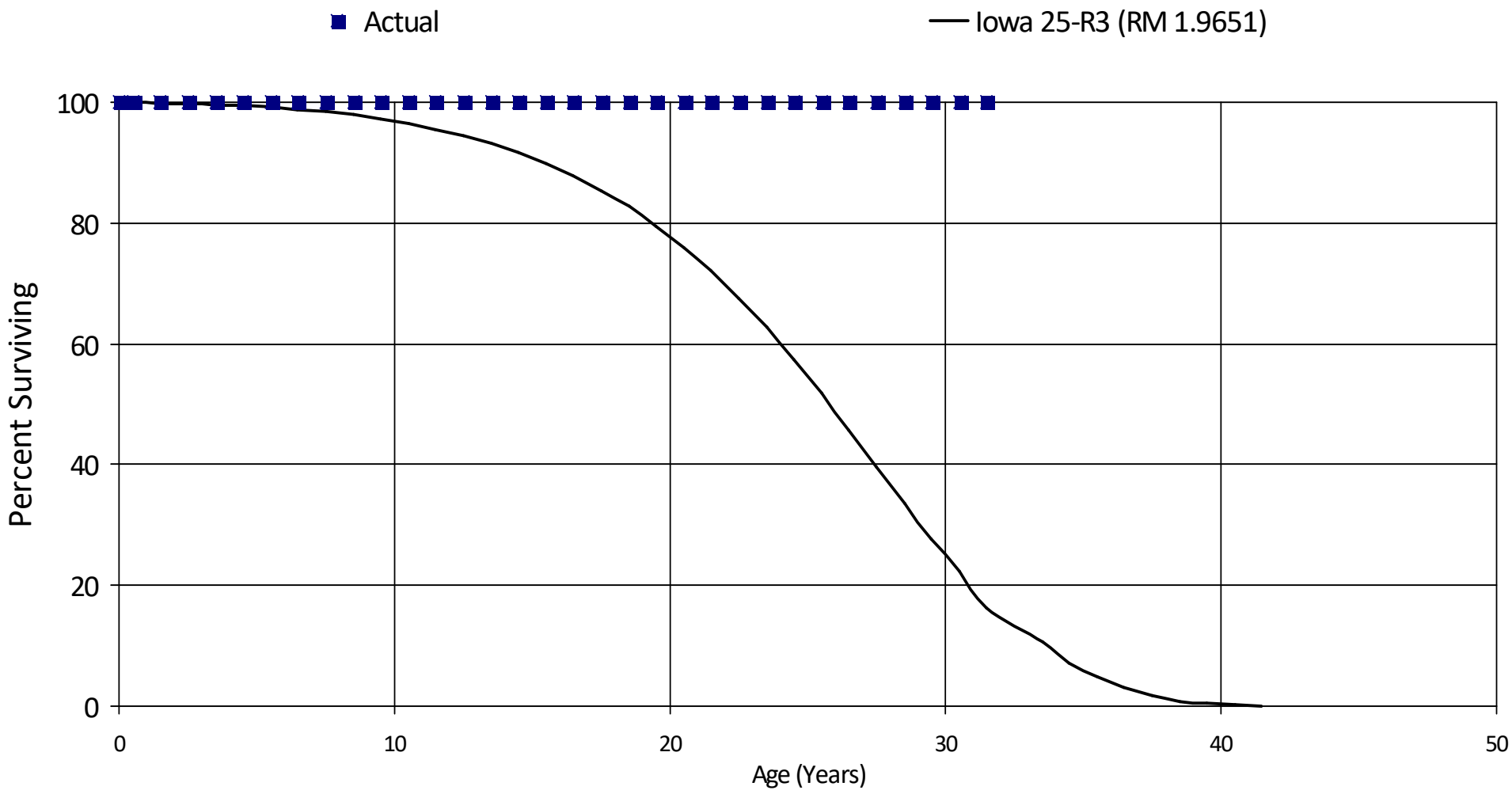
27.5	9,516,802	16,514	0.00174	0.99826	97.45
28.5	7,430,791	22,184	0.00299	0.99701	97.28
29.5	5,608,853	43,901	0.00783	0.99217	96.99
30.5	3,567,058	6,286	0.00176	0.99824	96.23
31.5	2,819,800	31,815	0.01128	0.98872	96.06
32.5	2,273,336	0	0.00000	1.00000	94.98
33.5	2,059,361	4,109	0.00200	0.99800	94.98
34.5	1,883,958	10,090	0.00536	0.99464	94.79
35.5	1,827,561	15,376	0.00841	0.99159	94.28
36.5	1,812,185	4,351	0.00240	0.99760	93.49
37.5	1,375,542	6,185	0.00450	0.99550	93.27
38.5	1,343,277	12,535	0.00933	0.99067	92.85
39.5	1,030,559	2,492	0.00242	0.99758	91.98
40.5	631,427	3,328	0.00527	0.99473	91.76
41.5	421,566	0	0.00000	1.00000	91.28
42.5	291,421	0	0.00000	1.00000	91.28
	Totals:	1,237,008			

Toronto Hydro

Account 3521 - U/G Conduit - Cable Chamber Roof

Placement Band - 1990 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3521 - U/G Conduit - Cable Chamber Roof

Placement Band - 1990 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	16,866,333	0	0.00000	1.00000	100.00
0.5	15,287,039	0	0.00000	1.00000	100.00
1.5	13,753,442	0	0.00000	1.00000	100.00
2.5	12,597,197	0	0.00000	1.00000	100.00
3.5	12,318,043	0	0.00000	1.00000	100.00
4.5	12,225,916	0	0.00000	1.00000	100.00
5.5	12,090,932	0	0.00000	1.00000	100.00
6.5	11,946,926	0	0.00000	1.00000	100.00
7.5	11,867,597	0	0.00000	1.00000	100.00
8.5	11,651,703	0	0.00000	1.00000	100.00
9.5	11,622,514	0	0.00000	1.00000	100.00
10.5	11,620,550	0	0.00000	1.00000	100.00
11.5	11,390,062	0	0.00000	1.00000	100.00
12.5	11,390,062	0	0.00000	1.00000	100.00
13.5	10,015,362	0	0.00000	1.00000	100.00
14.5	8,084,156	0	0.00000	1.00000	100.00
15.5	7,182,378	0	0.00000	1.00000	100.00
16.5	6,447,781	0	0.00000	1.00000	100.00
17.5	6,274,434	0	0.00000	1.00000	100.00
18.5	5,572,519	0	0.00000	1.00000	100.00
19.5	4,463,060	0	0.00000	1.00000	100.00
20.5	4,745,446	0	0.00000	1.00000	100.00
21.5	4,462,669	0	0.00000	1.00000	100.00
22.5	3,507,417	0	0.00000	1.00000	100.00
23.5	2,618,462	0	0.00000	1.00000	100.00
24.5	2,130,740	0	0.00000	1.00000	100.00
25.5	1,705,527	0	0.00000	1.00000	100.00
26.5	1,452,020	0	0.00000	1.00000	100.00

Toronto Hydro

Account 3521 - U/G Conduit - Cable Chamber Roof

Placement Band - 1990 - 2022 Experience Band - 2022 - 2022

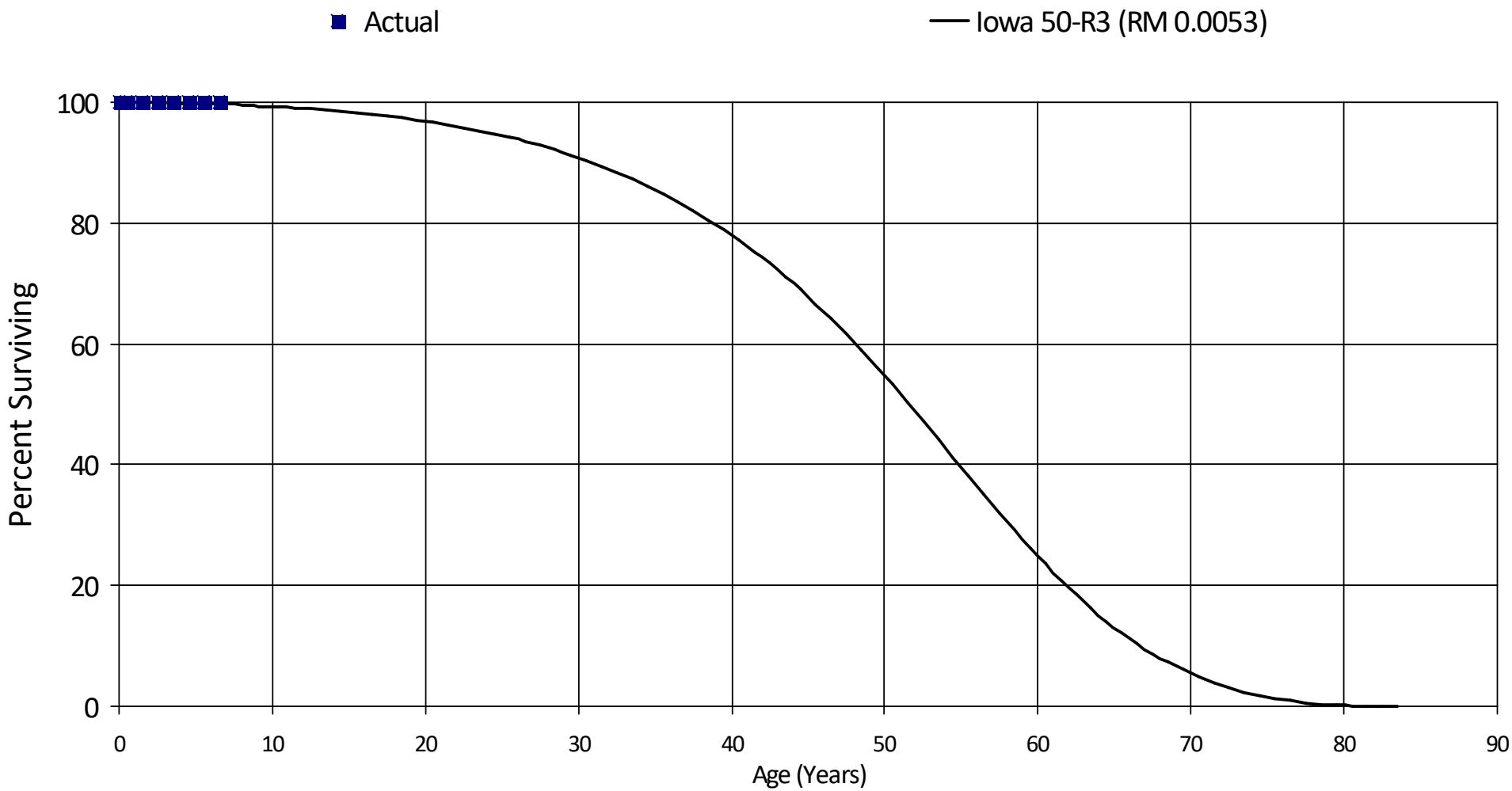
27.5	1,065,250	0	0.00000	1.00000	100.00
28.5	703,164	0	0.00000	1.00000	100.00
29.5	412,755	0	0.00000	1.00000	100.00
30.5	123,209	0	0.00000	1.00000	100.00
31.5	36,710	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 3523 - U/G Conduit - Civil Street Lighting

Placement Band - 2015 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3523 - U/G Conduit - Civil Street Lighting

Placement Band - 2015 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	3,410,633	0	0.00000	1.00000	100.00
0.5	3,410,633	0	0.00000	1.00000	100.00
1.5	3,410,633	0	0.00000	1.00000	100.00
2.5	3,236,492	0	0.00000	1.00000	100.00
3.5	3,146,127	0	0.00000	1.00000	100.00
4.5	3,108,230	0	0.00000	1.00000	100.00
5.5	3,107,790	0	0.00000	1.00000	100.00
6.5	35,815	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 3525 - Cable Chamber Lid

Placement Band - 2019 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3525 - Cable Chamber Lid

Placement Band - 2019 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

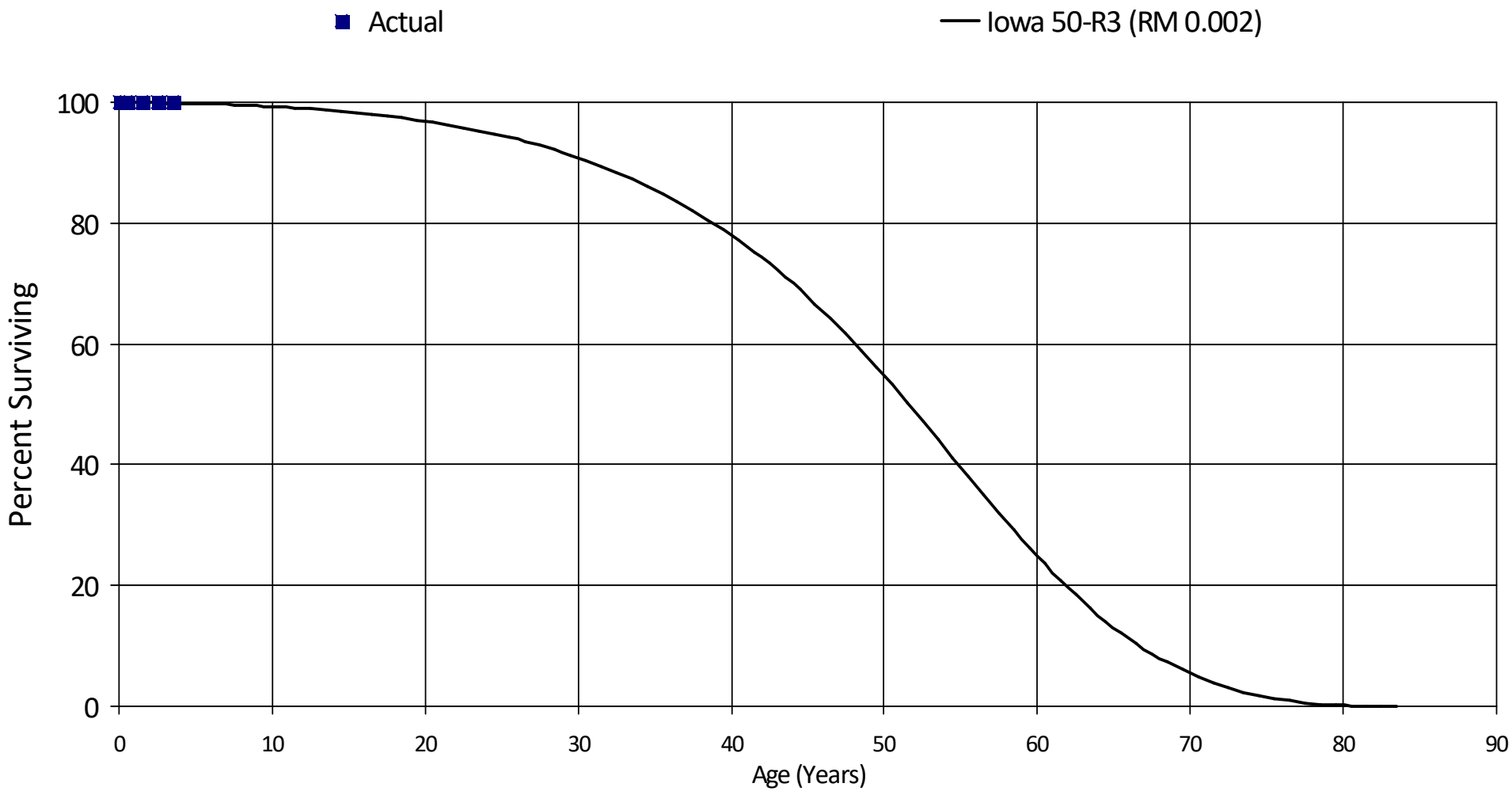
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	8,546,889	0	0.00000	1.00000	100.00
0.5	4,673,103	0	0.00000	1.00000	100.00
1.5	2,120,909	0	0.00000	1.00000	100.00
2.5	2,117,049	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 3609 - U/G Conductors

Placement Band - 2018 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3609 - U/G Conductors

Placement Band - 2018 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

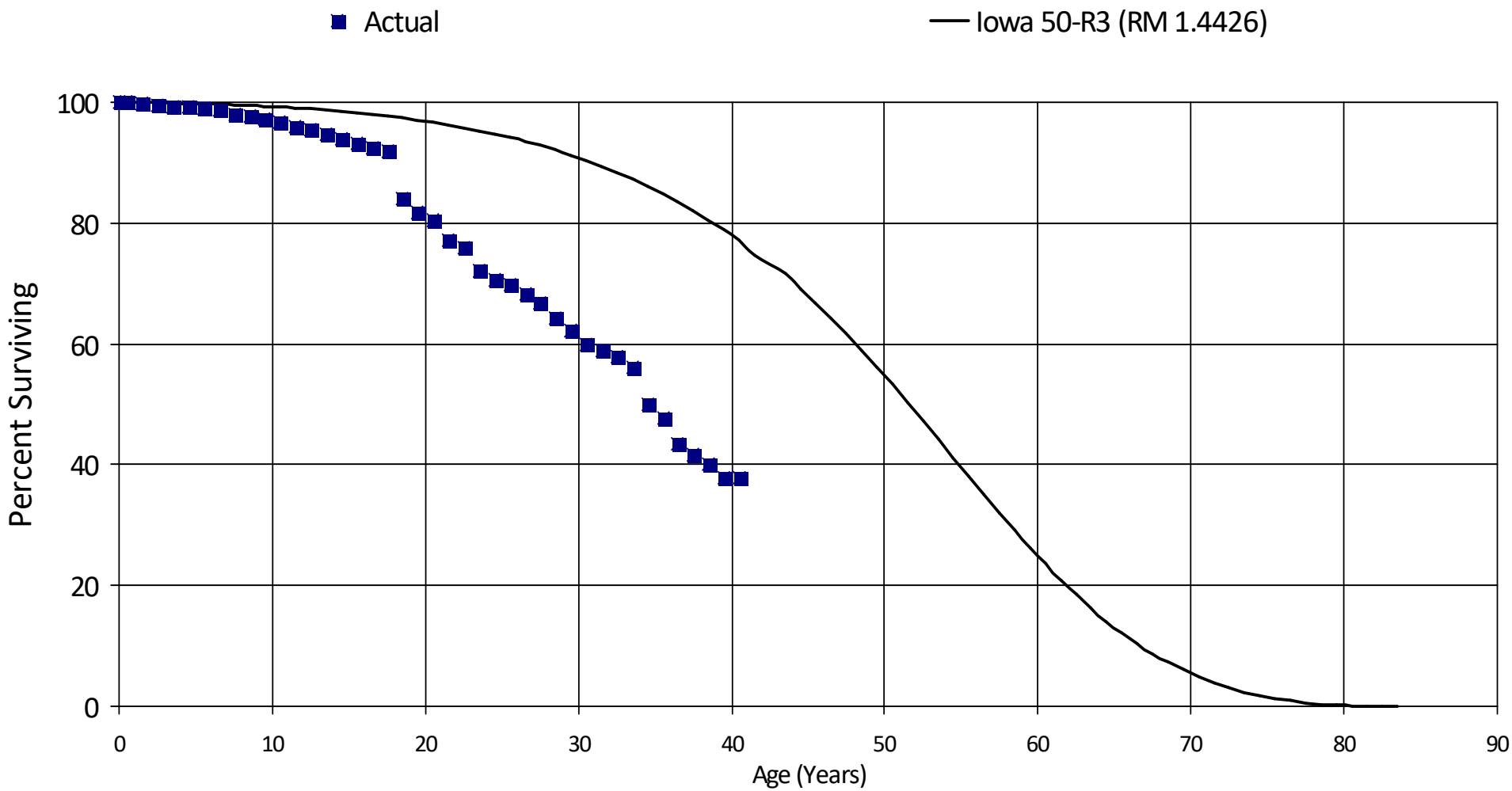
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,712,861	0	0.00000	1.00000	100.00
0.5	2,712,861	0	0.00000	1.00000	100.00
1.5	2,712,861	0	0.00000	1.00000	100.00
2.5	2,712,861	0	0.00000	1.00000	100.00
3.5	2,712,861	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 3611 - U/G - Primary Cable Duct (xLPE)

Placement Band - 1980 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3611 - U/G - Primary Cable Duct (xLPE)

Placement Band - 1980 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	869,657,724	304,832	0.00035	0.99965	100.00
0.5	746,347,364	1,521,693	0.00204	0.99796	99.96
1.5	638,499,584	1,084,730	0.00170	0.99830	99.76
2.5	539,353,091	1,383,354	0.00256	0.99744	99.59
3.5	470,653,581	899,200	0.00191	0.99809	99.34
4.5	402,785,885	1,016,028	0.00252	0.99748	99.15
5.5	346,109,037	865,150	0.00250	0.99750	98.90
6.5	291,243,565	2,127,697	0.00731	0.99269	98.65
7.5	241,692,313	577,918	0.00239	0.99761	97.93
8.5	197,222,031	1,071,110	0.00543	0.99457	97.70
9.5	151,408,644	841,885	0.00556	0.99444	97.17
10.5	132,297,935	852,128	0.00644	0.99356	96.63
11.5	105,982,079	586,635	0.00554	0.99446	96.01
12.5	88,141,106	854,417	0.00969	0.99031	95.48
13.5	77,840,978	581,371	0.00747	0.99253	94.55
14.5	65,479,709	451,082	0.00689	0.99311	93.84
15.5	54,872,686	448,633	0.00818	0.99182	93.19
16.5	46,080,140	235,675	0.00511	0.99489	92.43
17.5	40,573,525	3,527,641	0.08694	0.91306	91.96
18.5	30,098,065	802,024	0.02665	0.97335	83.96
19.5	17,380,908	286,831	0.01650	0.98350	81.72
20.5	17,505,225	709,564	0.04053	0.95947	80.37
21.5	17,967,427	258,516	0.01439	0.98561	77.11
22.5	16,631,734	851,809	0.05122	0.94878	76.00
23.5	15,779,926	332,395	0.02106	0.97894	72.11
24.5	13,929,548	169,183	0.01215	0.98785	70.59
25.5	11,825,080	242,276	0.02049	0.97951	69.73
26.5	9,329,410	223,612	0.02397	0.97603	68.30

Toronto Hydro

Account 3611 - U/G - Primary Cable Duct (xLPE)

Placement Band - 1980 - 2022 Experience Band - 2014 - 2022

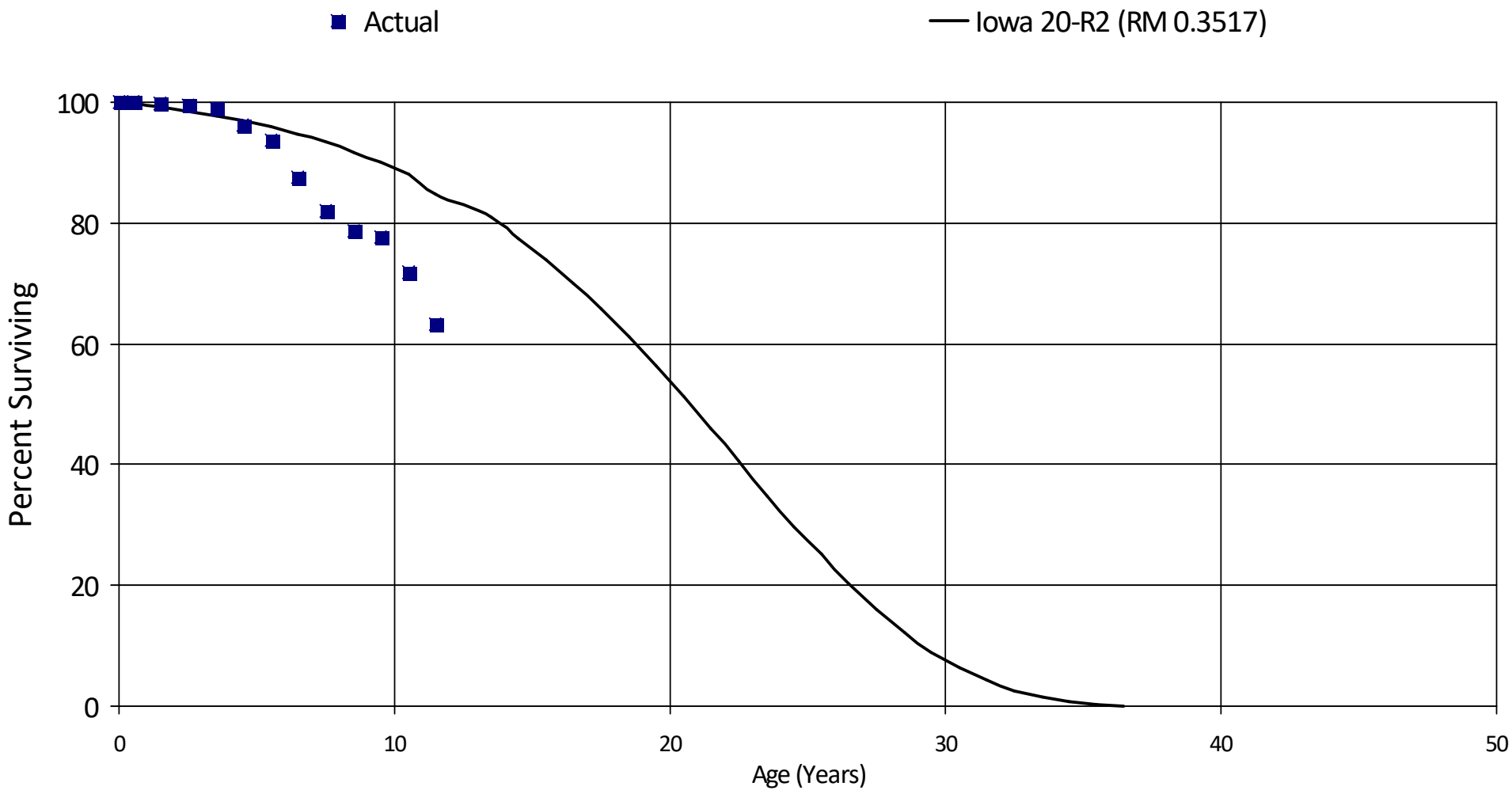
27.5	7,122,525	262,949	0.03692	0.96308	66.66
28.5	5,756,577	191,443	0.03326	0.96674	64.20
29.5	4,474,880	161,692	0.03613	0.96387	62.06
30.5	3,057,385	46,740	0.01529	0.98471	59.82
31.5	2,662,800	42,234	0.01586	0.98414	58.91
32.5	1,421,919	48,440	0.03407	0.96593	57.98
33.5	1,194,406	128,640	0.10770	0.89230	56.00
34.5	1,016,563	47,477	0.04670	0.95330	49.97
35.5	969,086	85,550	0.08828	0.91172	47.64
36.5	883,536	39,275	0.04445	0.95555	43.43
37.5	571,020	17,618	0.03085	0.96915	41.50
38.5	307,126	19,014	0.06191	0.93809	40.22
39.5	76,272	0	0.00000	1.00000	37.73
40.5	30,168	30,168	1.00000		37.73
	Totals:	24,228,629			

Toronto Hydro

Account 3613 - U/G - Primary Cable Buried (xLPE)

Placement Band - 2010 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3613 - U/G - Primary Cable Buried (xLPE)

Placement Band - 2010 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

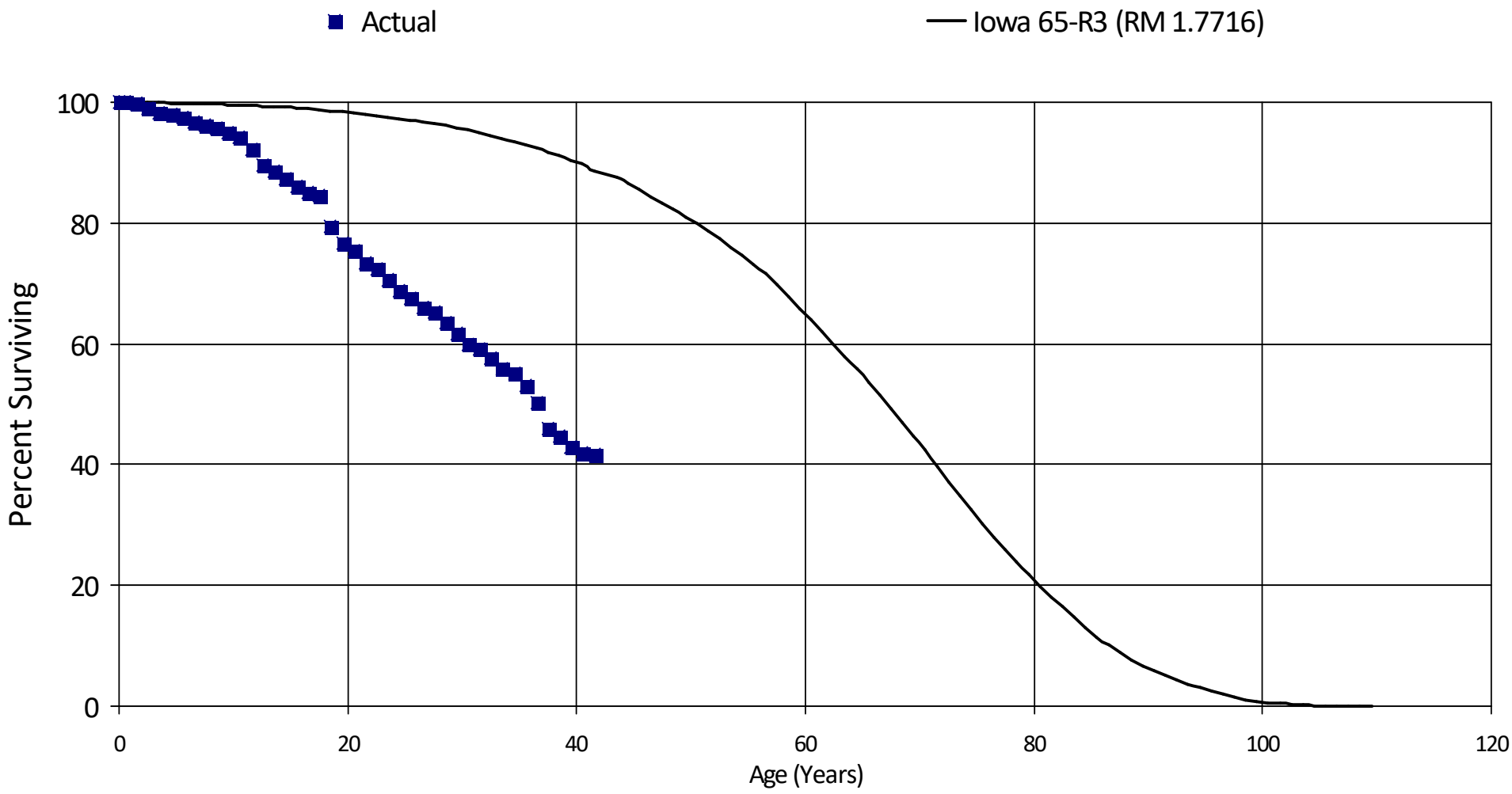
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,687,488	0	0.00000	1.00000	100.00
0.5	1,687,488	5,655	0.00335	0.99665	100.00
1.5	1,681,833	4,325	0.00257	0.99743	99.66
2.5	1,677,508	6,292	0.00375	0.99625	99.40
3.5	1,671,216	49,400	0.02956	0.97044	99.03
4.5	1,621,817	40,526	0.02499	0.97501	96.10
5.5	1,581,291	104,684	0.06620	0.93380	93.70
6.5	1,476,607	92,647	0.06274	0.93726	87.50
7.5	1,383,960	56,711	0.04098	0.95902	82.01
8.5	1,327,249	17,364	0.01308	0.98692	78.65
9.5	1,306,123	96,822	0.07413	0.92587	77.62
10.5	1,209,301	143,945	0.11903	0.88097	71.87
11.5	1,065,356	131,722	0.12364	0.87636	63.32
	Totals:	750,093			

Toronto Hydro

Account 3615 - U/G - Primary PILC Cable

Placement Band - 1980 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3615 - U/G - Primary PILC Cable

Placement Band - 1980 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	192,079,560	69,493	0.00036	0.99964	100.00
0.5	188,065,032	206,202	0.00110	0.99890	99.96
1.5	181,511,659	1,596,455	0.00880	0.99120	99.85
2.5	172,061,294	1,358,763	0.00790	0.99210	98.97
3.5	162,638,941	516,444	0.00318	0.99682	98.19
4.5	159,738,604	588,085	0.00368	0.99632	97.88
5.5	154,790,505	1,481,497	0.00957	0.99043	97.52
6.5	147,703,182	751,060	0.00508	0.99492	96.59
7.5	141,910,175	667,810	0.00471	0.99529	96.10
8.5	130,986,321	976,092	0.00745	0.99255	95.65
9.5	122,506,767	1,165,279	0.00951	0.99049	94.94
10.5	118,717,488	2,275,685	0.01917	0.98083	94.04
11.5	111,617,863	3,344,999	0.02997	0.97003	92.24
12.5	103,678,023	1,020,129	0.00984	0.99016	89.48
13.5	91,314,080	1,328,989	0.01455	0.98545	88.60
14.5	78,367,172	1,249,475	0.01594	0.98406	87.31
15.5	66,194,508	660,211	0.00997	0.99003	85.92
16.5	55,481,244	385,950	0.00696	0.99304	85.06
17.5	48,835,355	2,843,994	0.05824	0.94176	84.47
18.5	38,348,552	1,345,268	0.03508	0.96492	79.55
19.5	23,752,236	417,828	0.01759	0.98241	76.76
20.5	23,829,896	688,214	0.02888	0.97112	75.41
21.5	22,495,775	240,920	0.01071	0.98929	73.23
22.5	20,768,130	517,467	0.02492	0.97508	72.45
23.5	20,250,663	519,965	0.02568	0.97432	70.64
24.5	17,171,143	306,785	0.01787	0.98213	68.83
25.5	14,547,469	334,385	0.02299	0.97701	67.60
26.5	11,470,013	146,987	0.01281	0.98719	66.05

Toronto Hydro

Account 3615 - U/G - Primary PILC Cable

Placement Band - 1980 - 2022 Experience Band - 2014 - 2022

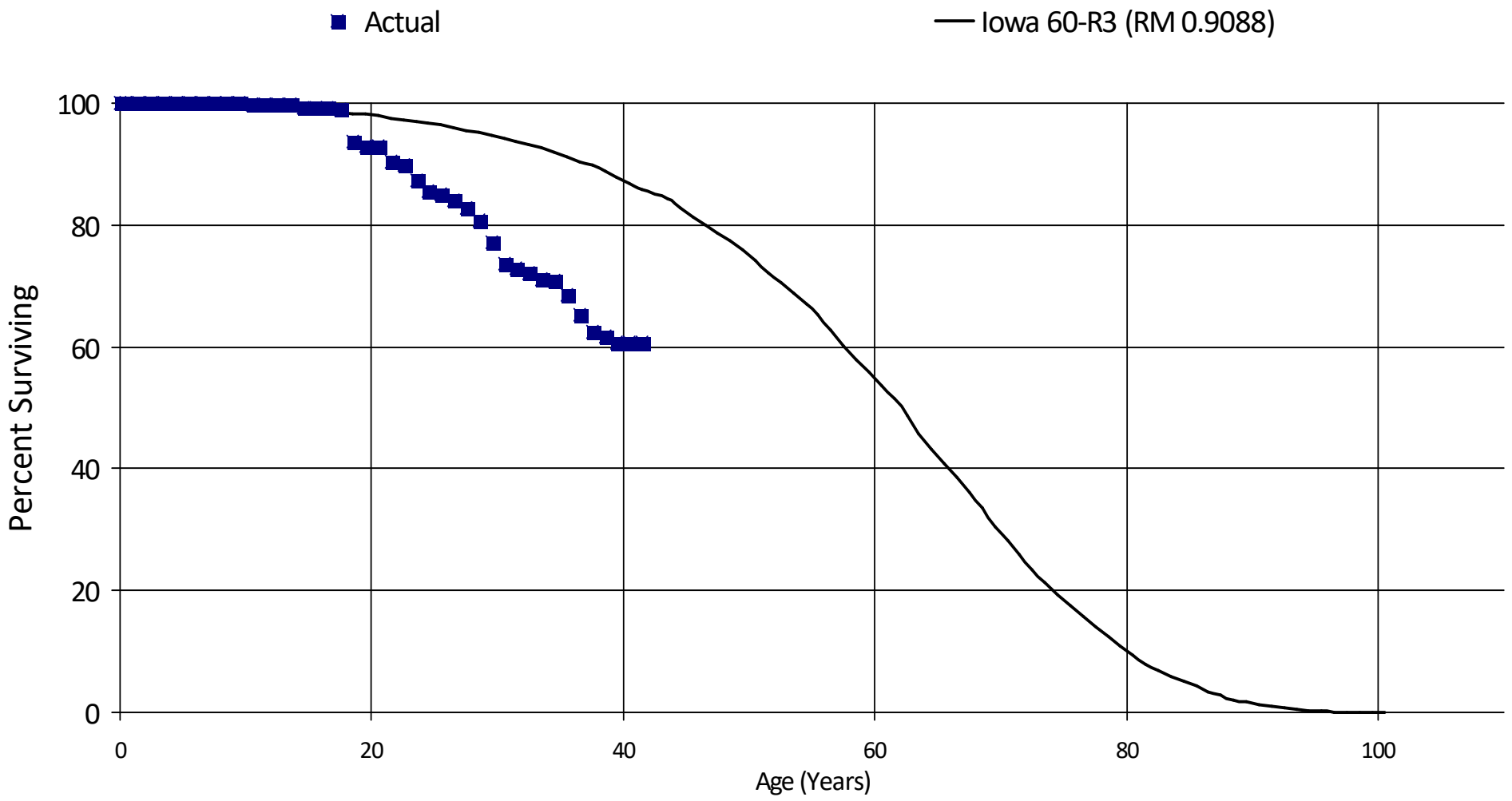
27.5	8,891,584	224,067	0.02520	0.97480	65.20
28.5	7,169,300	210,064	0.02930	0.97070	63.56
29.5	5,820,326	178,436	0.03066	0.96934	61.70
30.5	4,015,977	37,731	0.00940	0.99060	59.81
31.5	3,289,607	91,674	0.02787	0.97213	59.25
32.5	1,778,162	54,575	0.03069	0.96931	57.60
33.5	1,438,521	19,595	0.01362	0.98638	55.83
34.5	1,418,926	55,265	0.03895	0.96105	55.07
35.5	1,363,661	70,103	0.05141	0.94859	52.93
36.5	1,293,558	106,937	0.08267	0.91733	50.21
37.5	956,703	27,627	0.02888	0.97112	46.06
38.5	639,677	24,466	0.03825	0.96175	44.73
39.5	319,559	7,633	0.02389	0.97611	43.02
40.5	155,210	1,666	0.01073	0.98927	41.99
41.5	27,297	582	0.02132	0.97868	41.54
	Totals:	28,114,852			

Toronto Hydro

Account 3617 - U/G - Secondary Cable in Duct

Placement Band - 1980 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3617 - U/G - Secondary Cable in Duct

Placement Band - 1980 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	215,156,577	6,612	0.00003	0.99997	100.00
0.5	186,704,150	14,502	0.00008	0.99992	100.00
1.5	164,699,369	10,464	0.00006	0.99994	99.99
2.5	144,279,733	26,640	0.00018	0.99982	99.98
3.5	121,586,056	1,869	0.00002	0.99998	99.96
4.5	108,516,734	8,305	0.00008	0.99992	99.96
5.5	93,622,362	11,821	0.00013	0.99987	99.95
6.5	80,248,402	2,362	0.00003	0.99997	99.94
7.5	66,559,537	13,511	0.00020	0.99980	99.94
8.5	52,664,832	18,347	0.00035	0.99965	99.92
9.5	34,780,149	12,059	0.00035	0.99965	99.89
10.5	30,453,565	30,163	0.00099	0.99901	99.86
11.5	21,094,469	9,071	0.00043	0.99957	99.76
12.5	13,008,932	12,176	0.00094	0.99906	99.72
13.5	11,734,415	38,367	0.00327	0.99673	99.63
14.5	9,839,304	7,502	0.00076	0.99924	99.30
15.5	8,511,935	2,270	0.00027	0.99973	99.22
16.5	7,390,067	7,755	0.00105	0.99895	99.19
17.5	6,765,376	378,498	0.05595	0.94405	99.09
18.5	5,555,812	33,007	0.00594	0.99406	93.55
19.5	3,903,094	3,716	0.00095	0.99905	92.99
20.5	3,941,547	106,721	0.02708	0.97292	92.90
21.5	3,930,632	21,140	0.00538	0.99462	90.38
22.5	3,753,347	105,499	0.02811	0.97189	89.89
23.5	3,647,848	76,340	0.02093	0.97907	87.36
24.5	3,156,277	15,158	0.00480	0.99520	85.53
25.5	2,690,276	36,645	0.01362	0.98638	85.12
26.5	2,094,858	32,522	0.01552	0.98448	83.96

Toronto Hydro

Account 3617 - U/G - Secondary Cable in Duct

Placement Band - 1980 - 2022 Experience Band - 2014 - 2022

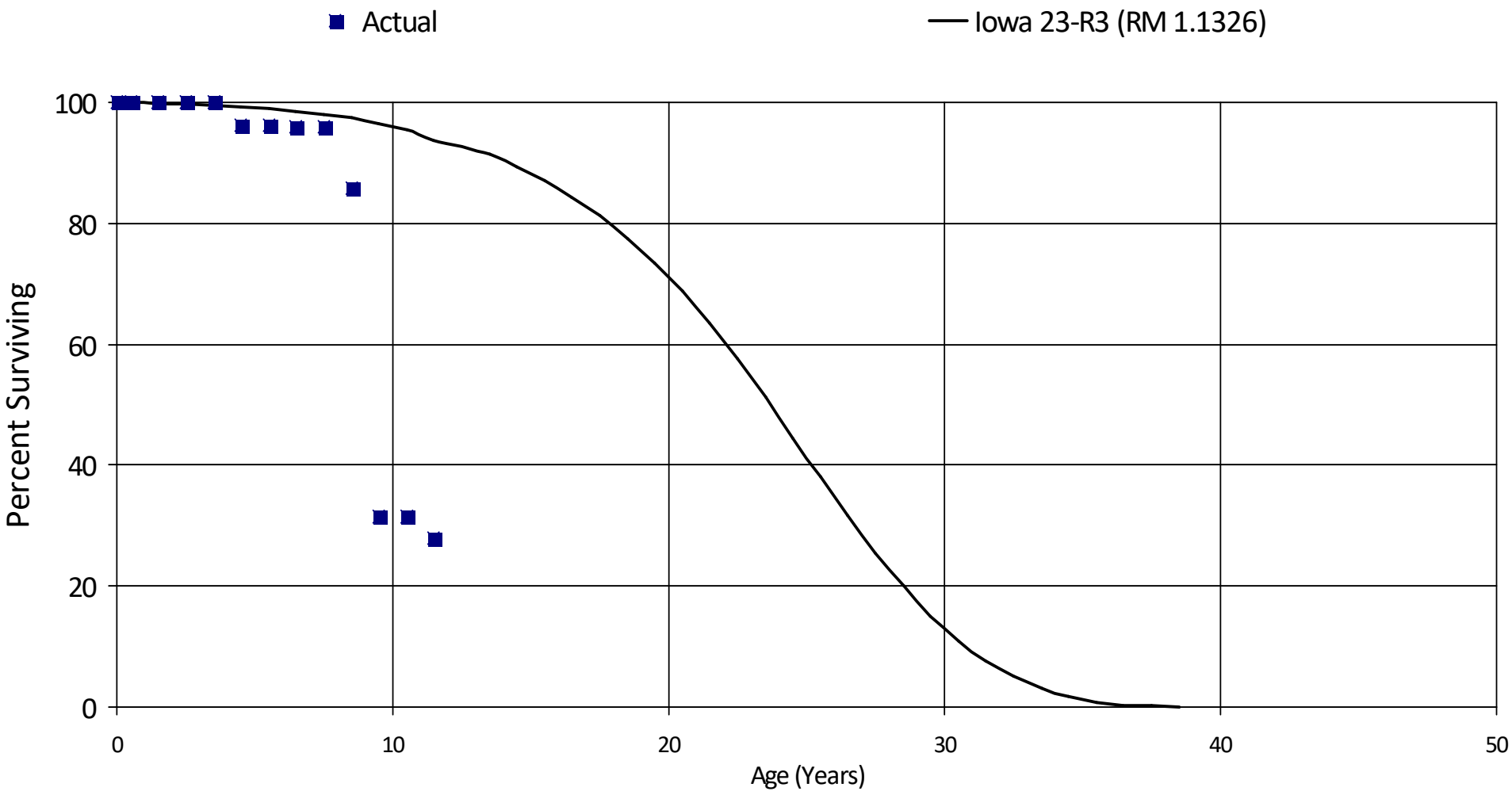
27.5	1,563,526	35,055	0.02242	0.97758	82.66
28.5	1,261,013	55,100	0.04370	0.95630	80.81
29.5	973,032	45,723	0.04699	0.95301	77.28
30.5	655,245	7,760	0.01184	0.98816	73.65
31.5	536,368	4,646	0.00866	0.99134	72.78
32.5	280,138	4,171	0.01489	0.98511	72.15
33.5	218,391	1,155	0.00529	0.99471	71.08
34.5	197,963	5,985	0.03023	0.96977	70.70
35.5	191,979	9,317	0.04853	0.95147	68.56
36.5	182,662	7,811	0.04276	0.95724	65.23
37.5	125,958	1,352	0.01073	0.98927	62.44
38.5	73,998	1,472	0.01989	0.98011	61.77
39.5	19,965	0	0.00000	1.00000	60.54
40.5	8,089	0	0.00000	1.00000	60.54
41.5	1,681	0	0.00000	1.00000	60.54
	Totals:	1,222,589			

Toronto Hydro

Account 3619 - U/G - Secondary Cable Direct Buried

Placement Band - 2010 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3619 - U/G - Secondary Cable Direct Buried

Placement Band - 2010 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

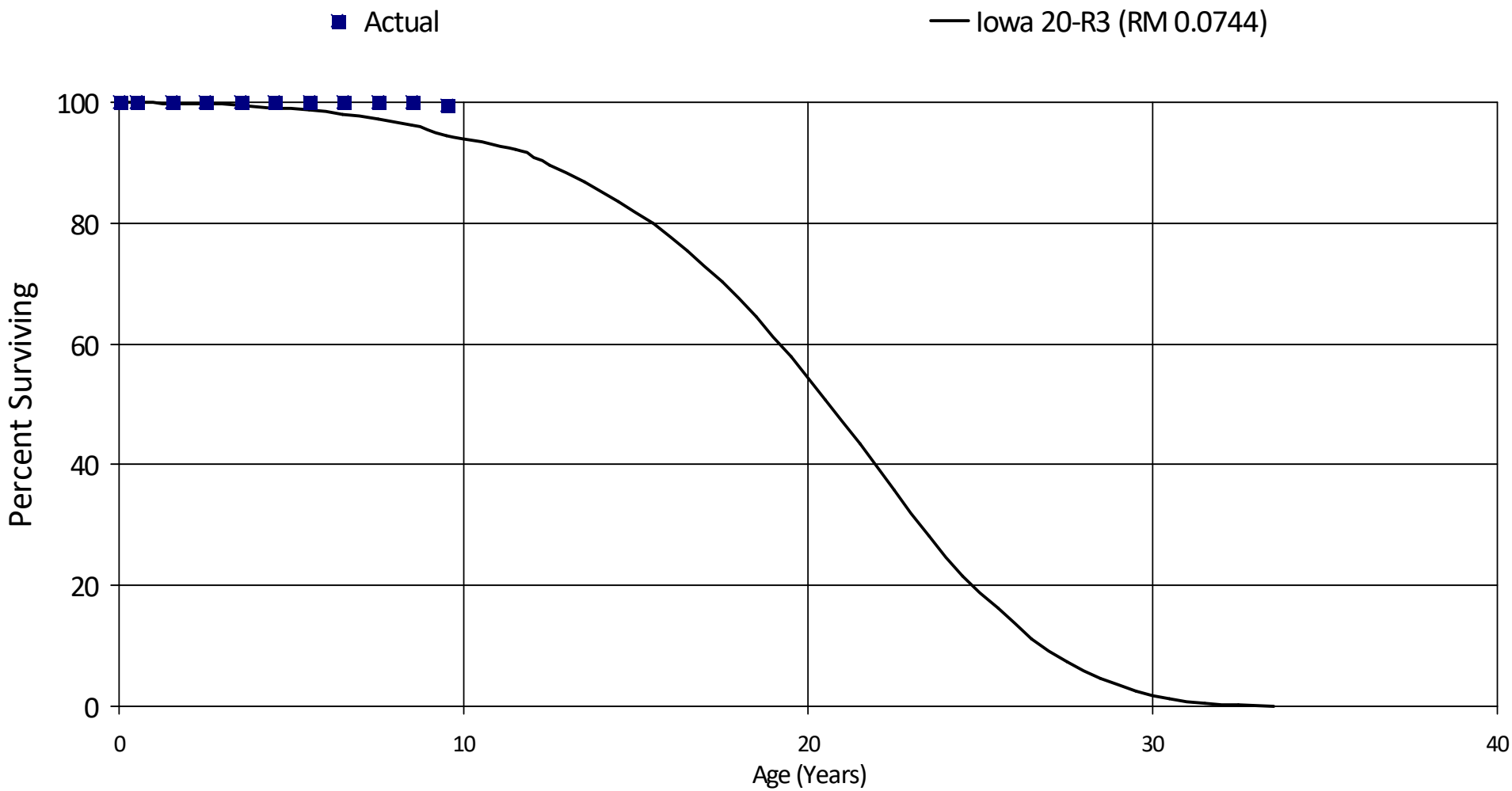
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	345,480	0	0.00000	1.00000	100.00
0.5	345,480	0	0.00000	1.00000	100.00
1.5	345,480	0	0.00000	1.00000	100.00
2.5	345,480	0	0.00000	1.00000	100.00
3.5	345,480	13,063	0.03781	0.96219	100.00
4.5	332,417	0	0.00000	1.00000	96.22
5.5	332,417	586	0.00176	0.99824	96.22
6.5	331,831	710	0.00214	0.99786	96.05
7.5	331,121	34,401	0.10389	0.89611	95.84
8.5	296,719	187,630	0.63235	0.36765	85.88
9.5	108,295	334	0.00308	0.99692	31.57
10.5	107,961	12,418	0.11502	0.88498	31.47
11.5	95,493	87,590	0.91724	0.08276	27.85
	Totals:	336,732			

Toronto Hydro

Account 3621 - U/G - Handwells

Placement Band - 2012 - 2022 Experience Band - 2021 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3621 - U/G - Handwells

Placement Band - 2012 - 2022 Experience Band - 2021 - 2022

RETIREMENT RATE ANALYSIS

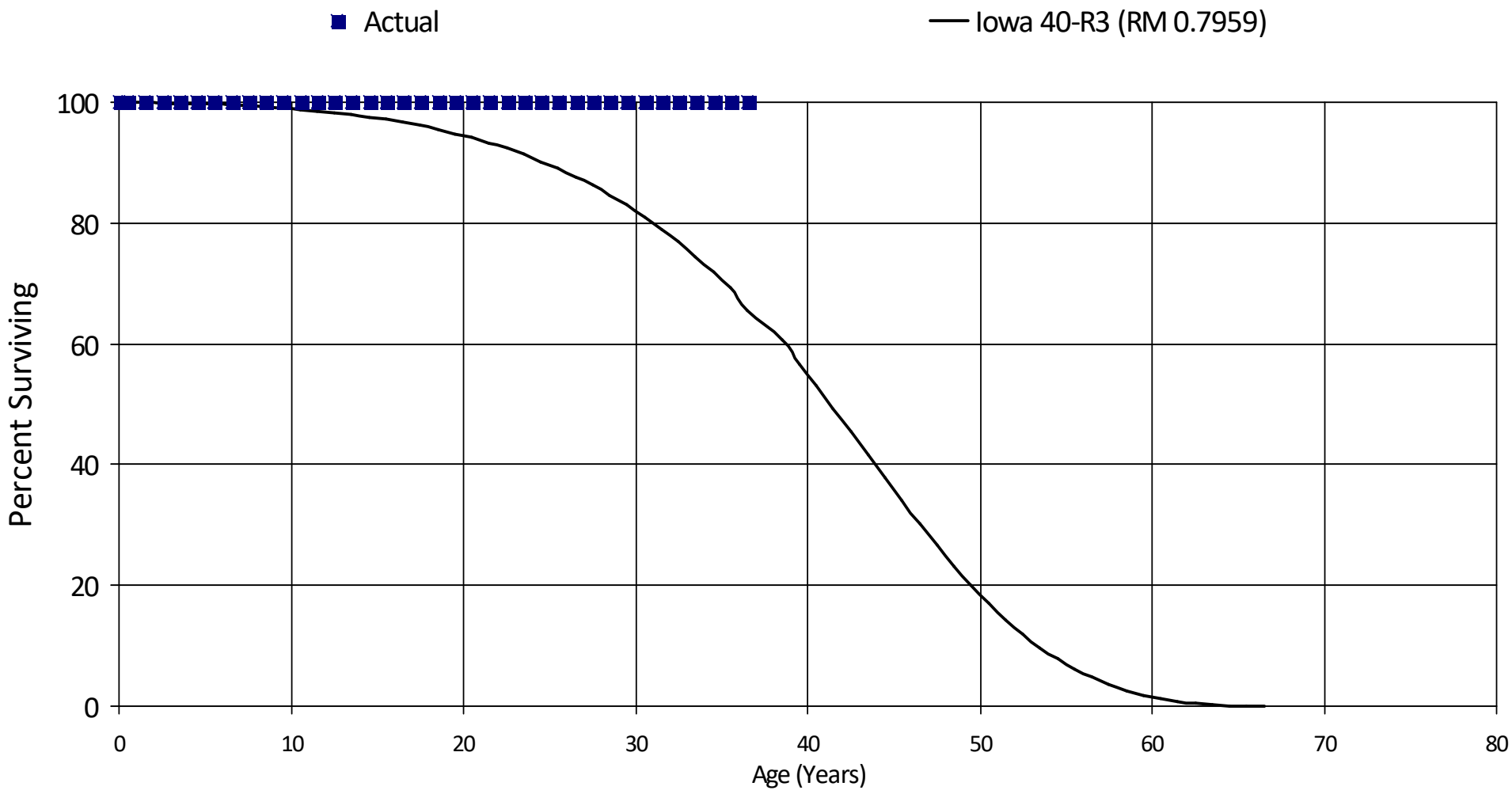
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	35,552,700	0	0.00000	1.00000	100.00
0.5	35,552,700	0	0.00000	1.00000	100.00
1.5	35,552,700	0	0.00000	1.00000	100.00
2.5	35,552,700	0	0.00000	1.00000	100.00
3.5	35,549,708	0	0.00000	1.00000	100.00
4.5	35,484,063	0	0.00000	1.00000	100.00
5.5	35,475,075	0	0.00000	1.00000	100.00
6.5	34,303,968	0	0.00000	1.00000	100.00
7.5	27,301,370	0	0.00000	1.00000	100.00
8.5	15,814,693	61,201	0.00387	0.99613	100.00
9.5	3,429,225	0	0.00000	1.00000	99.61
	Totals:	61,201			

Toronto Hydro

Account 3623 - U/G - ATS Switches

Placement Band - 1985 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3623 - U/G - ATS Switches

Placement Band - 1985 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	286,381	0	0.00000	1.00000	100.00
0.5	286,381	0	0.00000	1.00000	100.00
1.5	286,381	0	0.00000	1.00000	100.00
2.5	286,381	0	0.00000	1.00000	100.00
3.5	286,381	0	0.00000	1.00000	100.00
4.5	286,381	0	0.00000	1.00000	100.00
5.5	286,381	0	0.00000	1.00000	100.00
6.5	286,381	0	0.00000	1.00000	100.00
7.5	286,381	0	0.00000	1.00000	100.00
8.5	286,381	0	0.00000	1.00000	100.00
9.5	286,381	0	0.00000	1.00000	100.00
10.5	286,381	0	0.00000	1.00000	100.00
11.5	287,117	0	0.00000	1.00000	100.00
12.5	287,117	0	0.00000	1.00000	100.00
13.5	275,460	0	0.00000	1.00000	100.00
14.5	261,891	0	0.00000	1.00000	100.00
15.5	249,874	0	0.00000	1.00000	100.00
16.5	239,820	0	0.00000	1.00000	100.00
17.5	234,170	0	0.00000	1.00000	100.00
18.5	226,647	0	0.00000	1.00000	100.00
19.5	212,493	0	0.00000	1.00000	100.00
20.5	212,915	0	0.00000	1.00000	100.00
21.5	210,821	0	0.00000	1.00000	100.00
22.5	209,306	0	0.00000	1.00000	100.00
23.5	209,306	0	0.00000	1.00000	100.00
24.5	206,698	0	0.00000	1.00000	100.00
25.5	204,333	0	0.00000	1.00000	100.00
26.5	201,460	0	0.00000	1.00000	100.00

Toronto Hydro

Account 3623 - U/G - ATS Switches

Placement Band - 1985 - 2022 Experience Band - 2022 - 2022

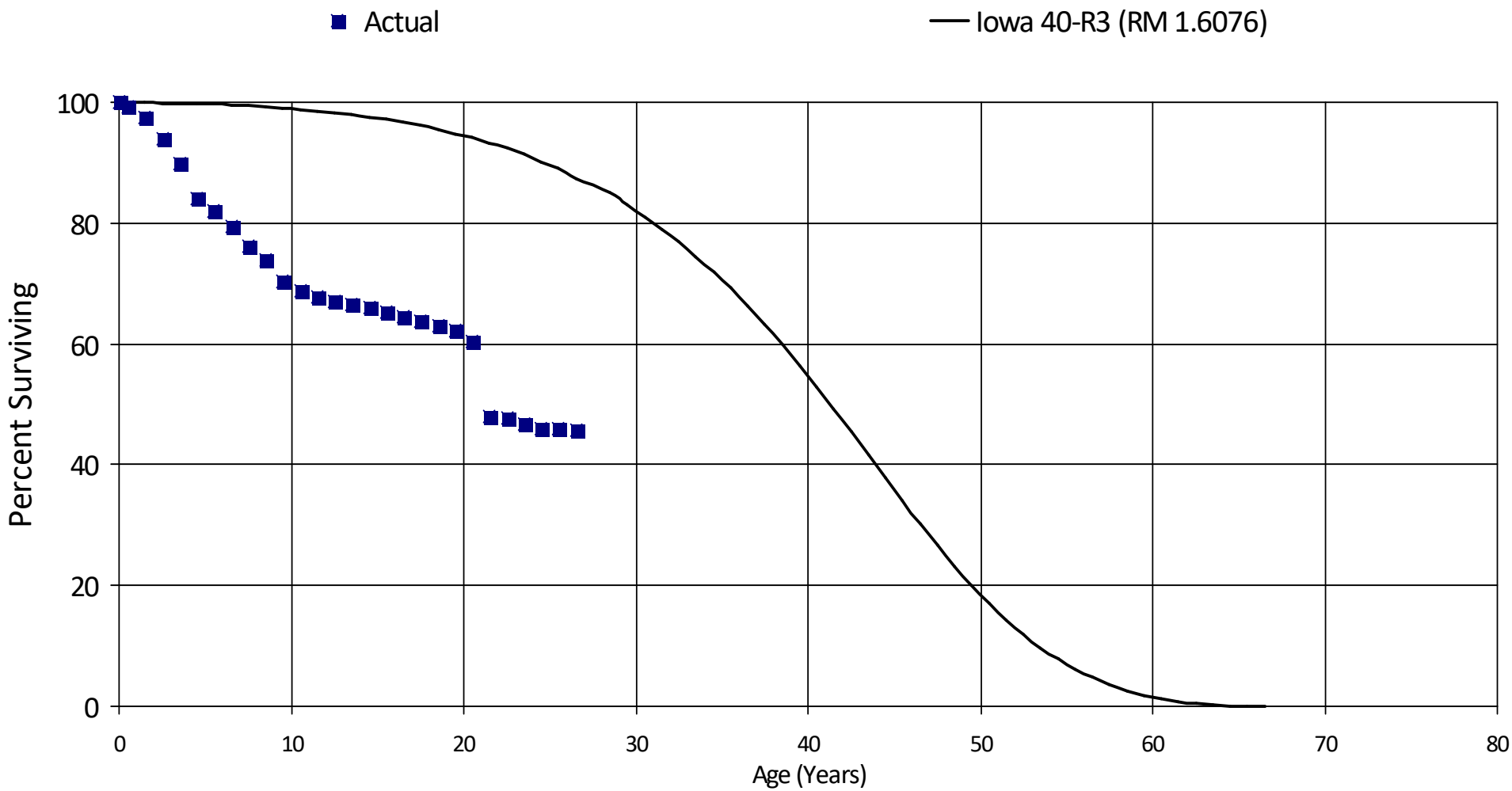
27.5	199,345	0	0.00000	1.00000	100.00
28.5	198,031	0	0.00000	1.00000	100.00
29.5	196,861	0	0.00000	1.00000	100.00
30.5	195,464	0	0.00000	1.00000	100.00
31.5	194,869	0	0.00000	1.00000	100.00
32.5	193,870	0	0.00000	1.00000	100.00
33.5	279	0	0.00000	1.00000	100.00
34.5	188	0	0.00000	1.00000	100.00
35.5	138	0	0.00000	1.00000	100.00
36.5	114	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 3625 - U/G - Switch Installation

Placement Band - 1995 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3625 - U/G - Switch Installation

Placement Band - 1995 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	160,952,342	1,170,209	0.00727	0.99273	100.00
0.5	143,872,851	2,799,874	0.01946	0.98054	99.27
1.5	127,579,219	4,502,876	0.03529	0.96471	97.34
2.5	104,768,109	4,566,383	0.04359	0.95641	93.90
3.5	86,412,507	5,681,792	0.06575	0.93425	89.81
4.5	70,144,167	1,608,006	0.02292	0.97708	83.90
5.5	59,562,804	1,820,516	0.03056	0.96944	81.98
6.5	49,291,976	2,050,521	0.04160	0.95840	79.47
7.5	39,103,205	1,129,379	0.02888	0.97112	76.16
8.5	30,062,382	1,433,669	0.04769	0.95231	73.96
9.5	23,266,648	560,544	0.02409	0.97591	70.43
10.5	21,964,579	304,864	0.01388	0.98612	68.73
11.5	18,150,207	201,918	0.01112	0.98888	67.78
12.5	15,312,281	122,995	0.00803	0.99197	67.03
13.5	12,681,960	109,934	0.00867	0.99133	66.49
14.5	10,126,624	86,241	0.00852	0.99148	65.91
15.5	8,070,782	108,279	0.01342	0.98658	65.35
16.5	6,369,401	85,357	0.01340	0.98660	64.47
17.5	5,402,361	58,156	0.01076	0.98924	63.61
18.5	4,038,190	46,673	0.01156	0.98844	62.93
19.5	1,465,414	42,224	0.02881	0.97119	62.20
20.5	1,528,191	315,527	0.20647	0.79353	60.41
21.5	1,117,826	7,248	0.00648	0.99352	47.94
22.5	852,740	18,236	0.02139	0.97861	47.63
23.5	834,504	10,106	0.01211	0.98789	46.61
24.5	513,793	2,188	0.00426	0.99574	46.05
25.5	511,605	3,282	0.00642	0.99358	45.85
26.5	153,260	0	0.00000	1.00000	45.56

Toronto Hydro

Account 3625 - U/G - Switch Installation

Placement Band - 1995 - 2022 Experience Band - 2014 - 2022

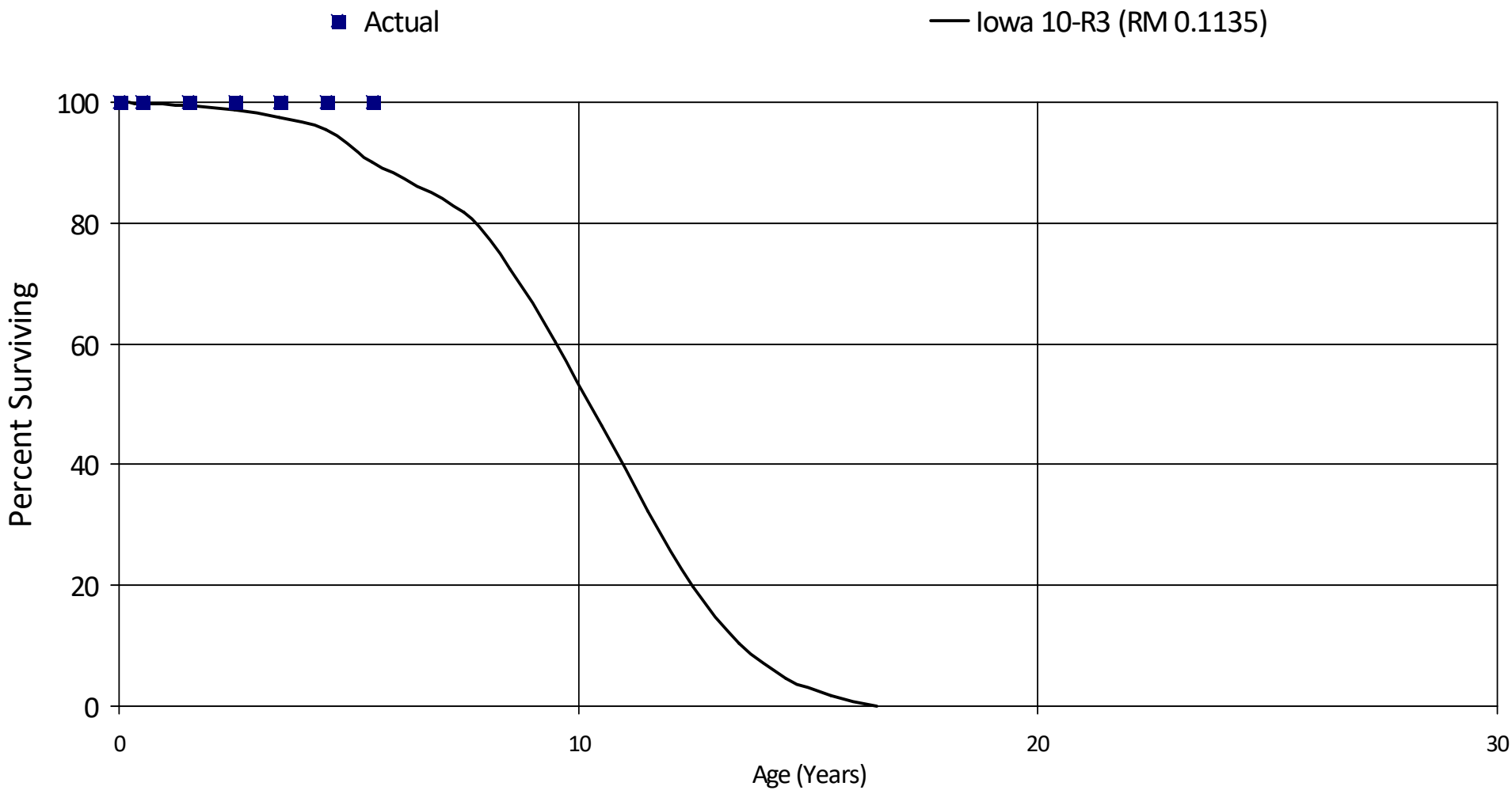
Totals:	28,846,997

Toronto Hydro

Account 3711 - Network Automation Vault Communication

Placement Band - 2016 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 3711 - Network Automation Vault Communication

Placement Band - 2016 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

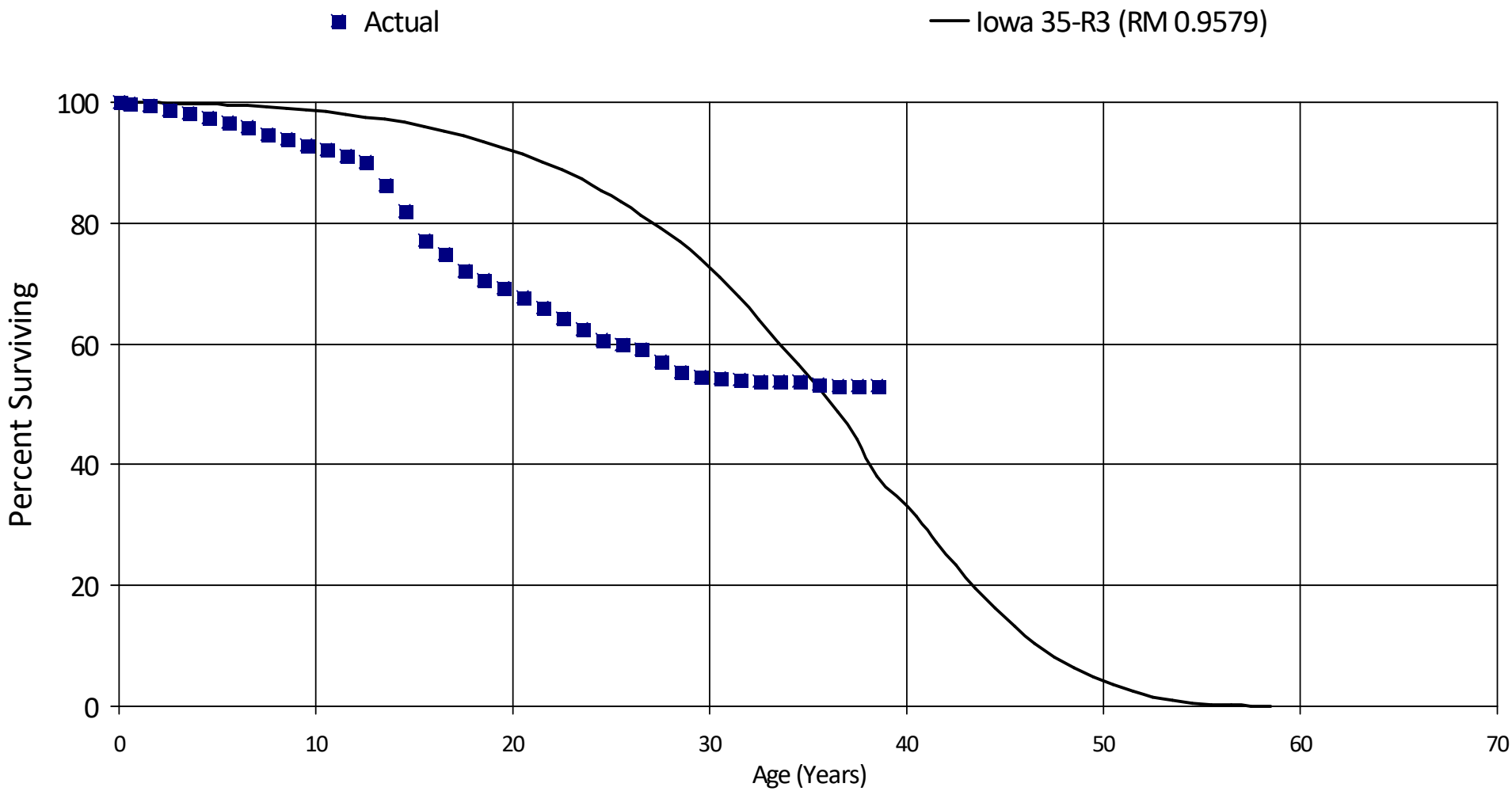
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	31,012,254	0	0.00000	1.00000	100.00
0.5	24,346,409	0	0.00000	1.00000	100.00
1.5	13,124,326	0	0.00000	1.00000	100.00
2.5	4,935,882	0	0.00000	1.00000	100.00
3.5	2,144,776	0	0.00000	1.00000	100.00
4.5	2,055,667	0	0.00000	1.00000	100.00
5.5	368,634	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 4011 - Dist Transf - General Overhead

Placement Band - 1983 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 4011 - Dist Transf - General Overhead

Placement Band - 1983 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	238,863,845	621,791	0.00260	0.99740	100.00
0.5	216,831,970	769,699	0.00355	0.99645	99.74
1.5	185,866,093	1,342,761	0.00722	0.99278	99.39
2.5	165,714,548	872,749	0.00527	0.99473	98.67
3.5	148,231,360	1,117,506	0.00754	0.99246	98.15
4.5	137,195,438	1,022,337	0.00745	0.99255	97.41
5.5	124,634,680	1,090,063	0.00875	0.99125	96.68
6.5	108,422,820	1,250,330	0.01153	0.98847	95.83
7.5	87,646,912	784,356	0.00895	0.99105	94.73
8.5	71,912,050	715,585	0.00995	0.99005	93.88
9.5	55,917,531	564,273	0.01009	0.98991	92.95
10.5	50,245,681	541,537	0.01078	0.98922	92.01
11.5	32,290,725	325,793	0.01009	0.98991	91.02
12.5	23,641,431	977,320	0.04134	0.95866	90.10
13.5	20,575,846	1,050,327	0.05105	0.94895	86.38
14.5	17,899,752	1,030,316	0.05756	0.94244	81.97
15.5	15,295,169	452,079	0.02956	0.97044	77.25
16.5	12,977,274	504,281	0.03886	0.96114	74.97
17.5	10,592,485	218,915	0.02067	0.97933	72.06
18.5	8,226,460	161,101	0.01958	0.98042	70.57
19.5	6,412,985	122,629	0.01912	0.98088	69.19
20.5	7,336,828	199,358	0.02717	0.97283	67.87
21.5	7,715,653	213,637	0.02769	0.97231	66.03
22.5	6,452,490	174,348	0.02702	0.97298	64.20
23.5	5,501,557	152,600	0.02774	0.97226	62.47
24.5	5,206,104	82,275	0.01580	0.98420	60.74
25.5	3,919,951	44,638	0.01139	0.98861	59.78
26.5	3,175,414	106,910	0.03367	0.96633	59.10

Toronto Hydro

Account 4011 - Dist Transf - General Overhead

Placement Band - 1983 - 2022 Experience Band - 2014 - 2022

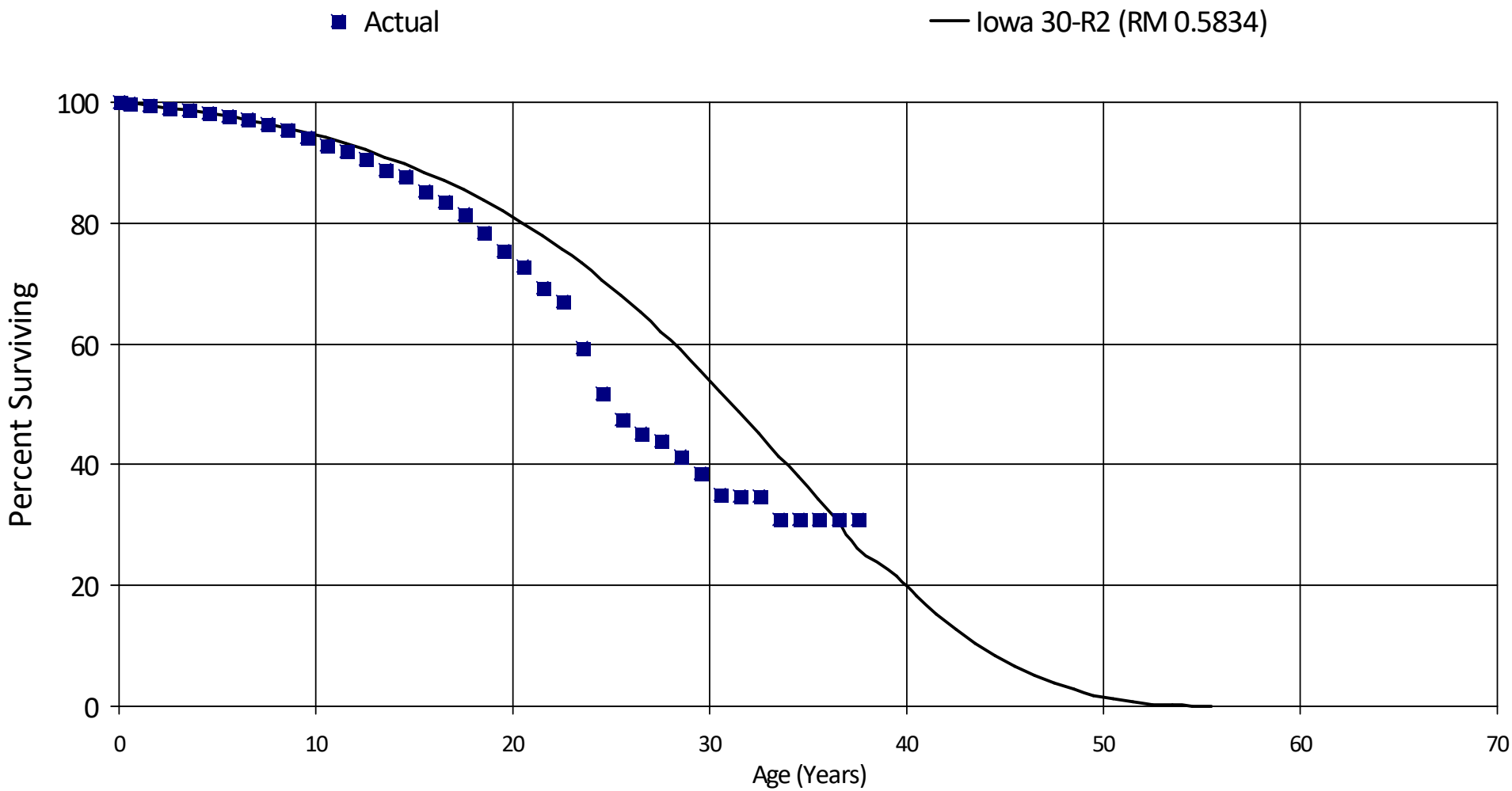
27.5	2,426,340	73,749	0.03040	0.96960	57.11
28.5	1,866,017	27,543	0.01476	0.98524	55.37
29.5	1,489,532	7,906	0.00531	0.99469	54.55
30.5	1,028,239	3,519	0.00342	0.99658	54.26
31.5	645,814	2,485	0.00385	0.99615	54.07
32.5	335,068	206	0.00061	0.99939	53.86
33.5	151,562	204	0.00135	0.99865	53.83
34.5	59,530	379	0.00637	0.99363	53.76
35.5	35,487	206	0.00580	0.99420	53.42
36.5	33,422	116	0.00347	0.99653	53.11
37.5	11	0	0.00000	1.00000	52.93
38.5	0	0	0.00000	0.00000	52.93
	Totals:	16,625,827			

Toronto Hydro

Account 4013 - Dist Transf - Underground

Placement Band - 1984 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 4013 - Dist Transf - Underground

Placement Band - 1984 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	506,093,611	668,210	0.00132	0.99868	100.00
0.5	473,036,142	1,289,696	0.00273	0.99727	99.87
1.5	428,722,495	2,106,059	0.00491	0.99509	99.60
2.5	383,028,672	1,375,858	0.00359	0.99641	99.11
3.5	338,397,348	1,546,892	0.00457	0.99543	98.75
4.5	302,884,611	1,463,846	0.00483	0.99517	98.30
5.5	264,990,364	1,534,428	0.00579	0.99421	97.83
6.5	235,562,664	2,227,904	0.00946	0.99054	97.26
7.5	211,815,853	1,955,414	0.00923	0.99077	96.34
8.5	190,388,609	2,790,979	0.01466	0.98534	95.45
9.5	170,306,051	2,224,755	0.01306	0.98694	94.05
10.5	162,159,373	1,849,101	0.01140	0.98860	92.82
11.5	146,846,500	1,860,754	0.01267	0.98733	91.76
12.5	129,105,642	2,429,856	0.01882	0.98118	90.60
13.5	113,485,456	1,437,054	0.01266	0.98734	88.89
14.5	98,401,943	2,751,263	0.02796	0.97204	87.76
15.5	87,091,828	1,961,251	0.02252	0.97748	85.31
16.5	75,636,195	1,818,274	0.02404	0.97596	83.39
17.5	63,924,768	2,344,464	0.03668	0.96332	81.39
18.5	50,543,501	1,940,435	0.03839	0.96161	78.40
19.5	37,154,478	1,262,071	0.03397	0.96603	75.39
20.5	41,498,506	1,954,628	0.04710	0.95290	72.83
21.5	37,327,452	1,237,946	0.03316	0.96684	69.40
22.5	29,981,993	3,434,139	0.11454	0.88546	67.10
23.5	23,346,288	3,028,095	0.12970	0.87030	59.41
24.5	20,318,193	1,663,833	0.08189	0.91811	51.70
25.5	18,291,704	841,322	0.04599	0.95401	47.47
26.5	14,231,215	398,386	0.02799	0.97201	45.29

Toronto Hydro

Account 4013 - Dist Transf - Underground

Placement Band - 1984 - 2022 Experience Band - 2014 - 2022

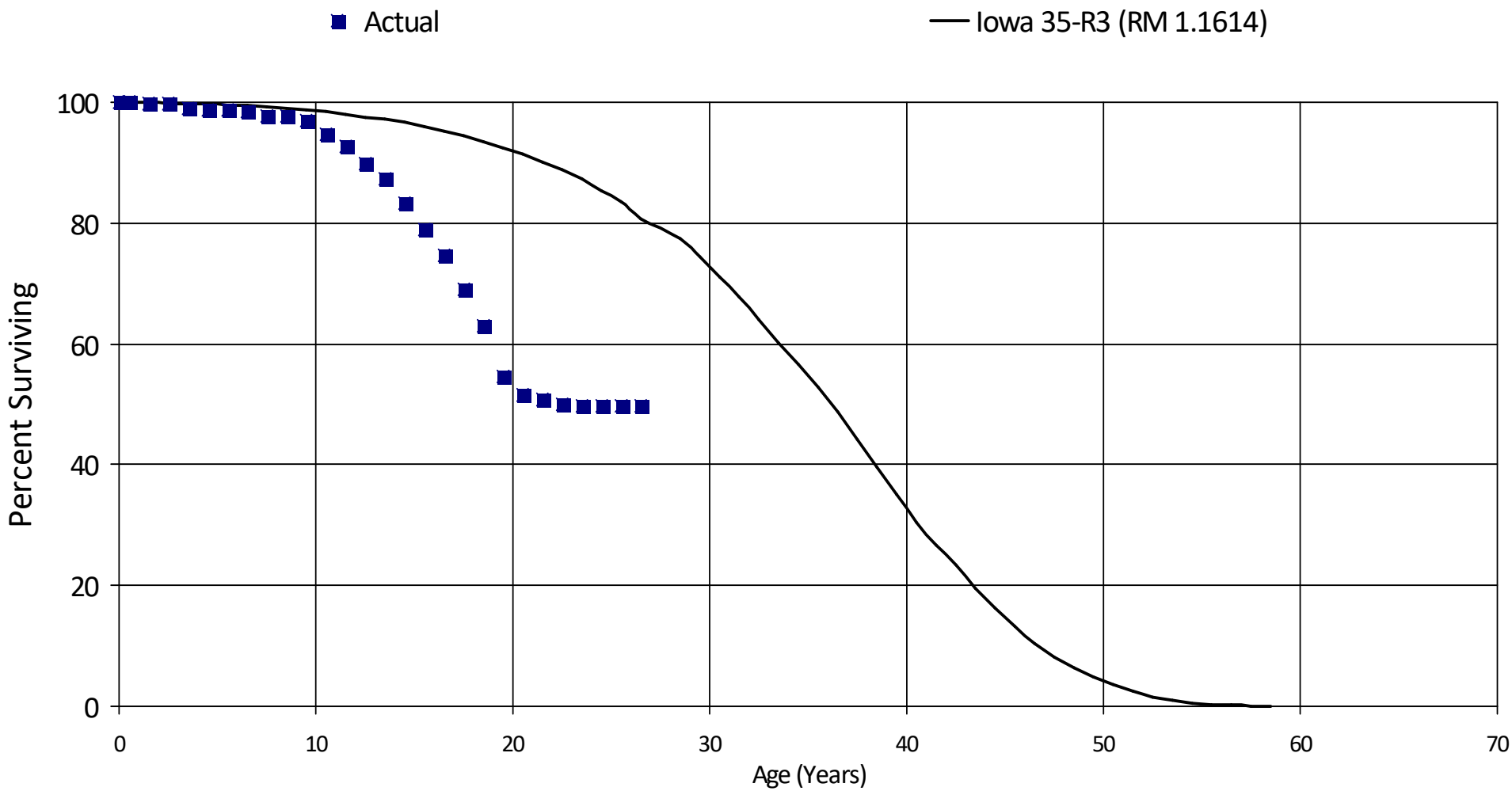
27.5	10,495,127	618,452	0.05893	0.94107	44.02
28.5	6,872,144	488,358	0.07106	0.92894	41.43
29.5	6,383,786	558,224	0.08744	0.91256	38.49
30.5	4,327,374	41,947	0.00969	0.99031	35.12
31.5	2,889,743	3,584	0.00124	0.99876	34.78
32.5	1,280,703	137,197	0.10713	0.89287	34.74
33.5	201,720	6	0.00003	0.99997	31.02
34.5	201,713	0	0.00000	1.00000	31.02
35.5	46,830	0	0.00000	1.00000	31.02
36.5	46,654	0	0.00000	1.00000	31.02
37.5	-442	-443	1.00215	-0.00215	31.02
	Totals:	53,244,238			

Toronto Hydro

Account 4015 - Dist Transf - U/G Network w/ Protector

Placement Band - 1995 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 4015 - Dist Transf - U/G Network w/ Protector

Placement Band - 1995 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	201,320,569	116,159	0.00058	0.99942	100.00
0.5	176,818,471	147,907	0.00084	0.99916	99.94
1.5	162,190,445	96,370	0.00059	0.99941	99.86
2.5	141,003,145	1,243,037	0.00882	0.99118	99.80
3.5	122,158,051	277,357	0.00227	0.99773	98.92
4.5	104,652,086	30,735	0.00029	0.99971	98.70
5.5	88,431,606	83,371	0.00094	0.99906	98.67
6.5	72,851,951	557,294	0.00765	0.99235	98.58
7.5	62,482,095	132,040	0.00211	0.99789	97.83
8.5	49,420,744	355,419	0.00719	0.99281	97.62
9.5	34,321,048	779,502	0.02271	0.97729	96.92
10.5	28,673,441	619,017	0.02159	0.97841	94.72
11.5	22,192,240	682,629	0.03076	0.96924	92.67
12.5	12,262,036	333,999	0.02724	0.97276	89.82
13.5	10,521,262	502,424	0.04775	0.95225	87.37
14.5	8,285,322	428,183	0.05168	0.94832	83.20
15.5	6,450,001	342,469	0.05310	0.94690	78.90
16.5	4,982,416	385,706	0.07741	0.92259	74.71
17.5	3,744,075	320,962	0.08573	0.91427	68.93
18.5	1,975,625	267,290	0.13529	0.86471	63.02
19.5	1,817,442	102,092	0.05617	0.94383	54.49
20.5	2,537,578	29,244	0.01152	0.98848	51.43
21.5	2,316,060	37,693	0.01627	0.98373	50.84
22.5	1,708,933	5,686	0.00333	0.99667	50.01
23.5	1,246,700	0	0.00000	1.00000	49.84
24.5	1,067,201	0	0.00000	1.00000	49.84
25.5	446,302	0	0.00000	1.00000	49.84
26.5	164,902	0	0.00000	1.00000	49.84

Toronto Hydro

Account 4015 - Dist Transf - U/G Network w/ Protector

Placement Band - 1995 - 2022 Experience Band - 2014 - 2022

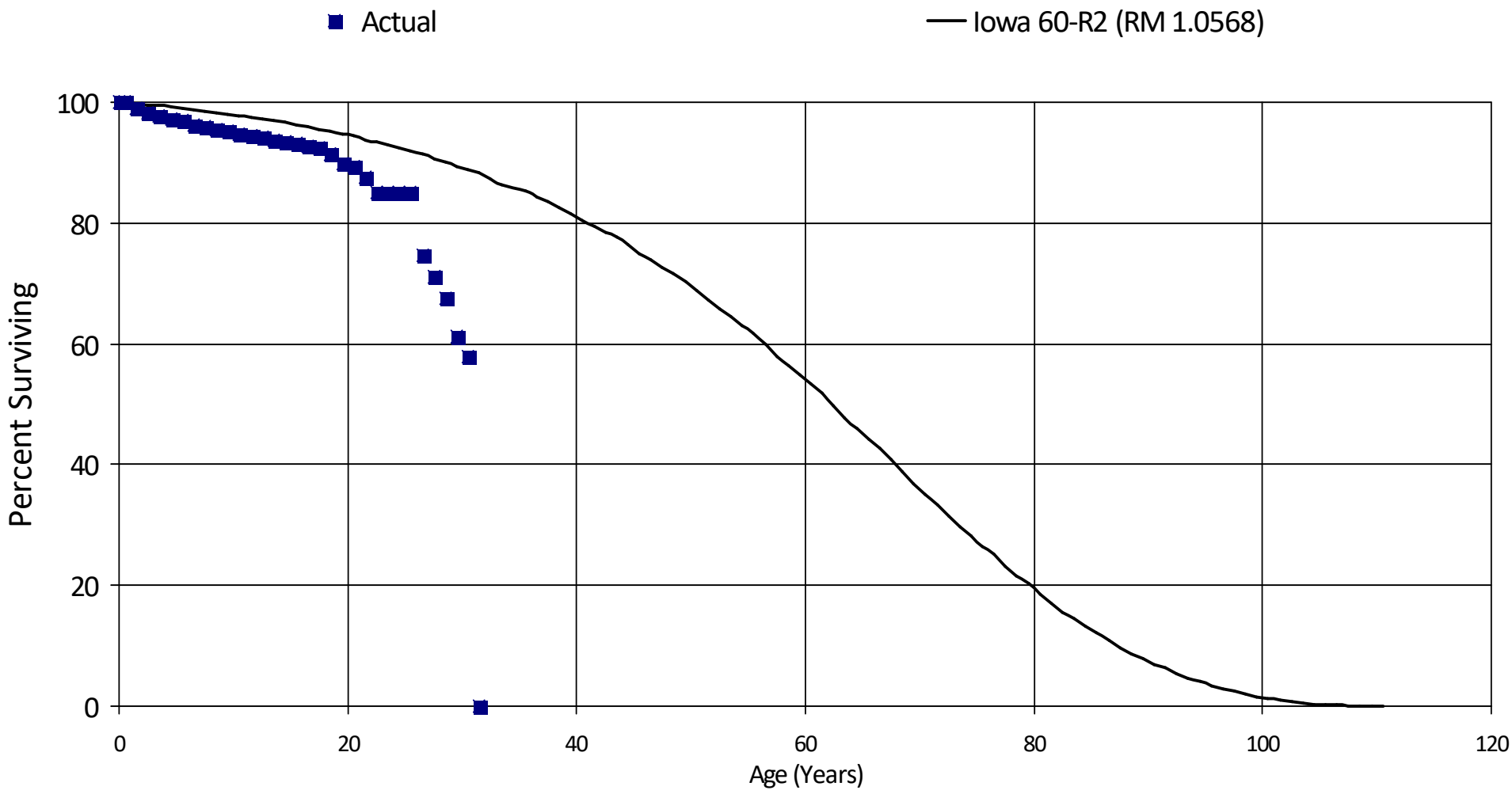
Totals:	7,876,585

Toronto Hydro

Account 4111 - O/H Services

Placement Band - 1988 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 4111 - O/H Services

Placement Band - 1988 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	80,938,525	84,867	0.00105	0.99895	100.00
0.5	80,258,791	765,535	0.00954	0.99046	99.90
1.5	77,966,070	594,040	0.00762	0.99238	98.95
2.5	77,016,106	412,086	0.00535	0.99465	98.20
3.5	76,557,914	315,602	0.00412	0.99588	97.67
4.5	75,266,810	311,701	0.00414	0.99586	97.27
5.5	71,862,870	474,940	0.00661	0.99339	96.87
6.5	62,721,076	213,250	0.00340	0.99660	96.23
7.5	55,693,952	257,608	0.00463	0.99537	95.90
8.5	49,329,087	186,167	0.00377	0.99623	95.46
9.5	45,877,111	170,291	0.00371	0.99629	95.10
10.5	42,011,567	165,667	0.00394	0.99606	94.75
11.5	39,371,244	142,316	0.00361	0.99639	94.38
12.5	37,908,612	103,278	0.00272	0.99728	94.04
13.5	28,894,432	123,591	0.00428	0.99572	93.78
14.5	23,605,066	63,119	0.00267	0.99733	93.38
15.5	17,418,579	106,731	0.00613	0.99387	93.13
16.5	14,539,444	41,521	0.00286	0.99714	92.56
17.5	11,506,393	108,612	0.00944	0.99056	92.30
18.5	5,359,075	98,149	0.01831	0.98169	91.43
19.5	1,814,308	10,998	0.00606	0.99394	89.76
20.5	1,803,310	36,001	0.01996	0.98004	89.22
21.5	1,076,488	31,179	0.02896	0.97104	87.44
22.5	656	0	0.00000	1.00000	84.91
23.5	656	0	0.00000	1.00000	84.91
24.5	656	0	0.00000	1.00000	84.91
25.5	656	79	0.12038	0.87962	84.91
26.5	578	28	0.04847	0.95153	74.69

Toronto Hydro

Account 4111 - O/H Services

Placement Band - 1988 - 2022 Experience Band - 2014 - 2022

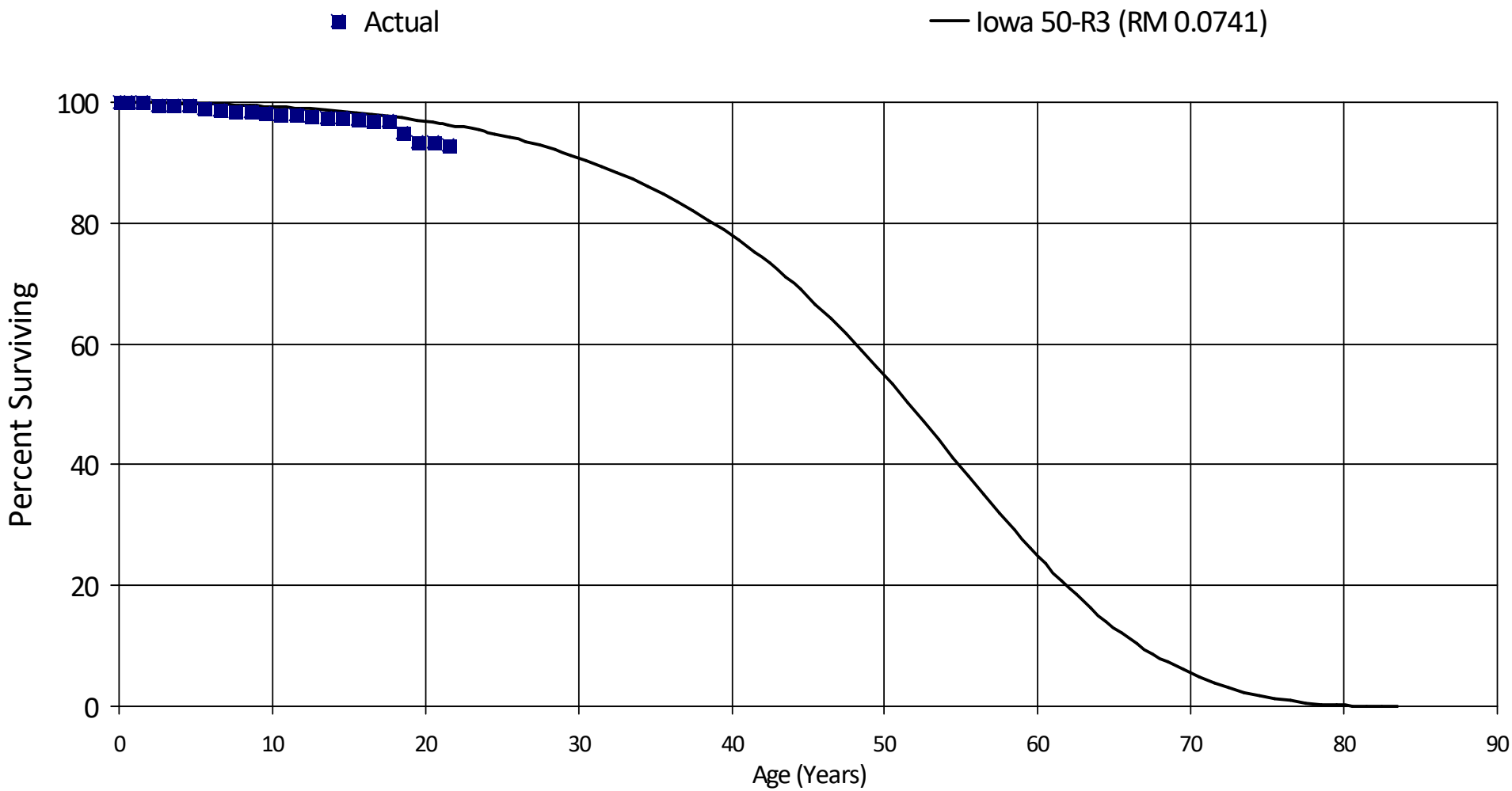
27.5	549	28	0.05096	0.94904	71.07
28.5	521	48	0.09205	0.90795	67.45
29.5	473	27	0.05705	0.94295	61.24
30.5	446	446	0.99957	0.00043	57.75
31.5	0	0	0.00000	0.00000	0.02
	Totals:	4,817,905			

Toronto Hydro

Account 4113 - U/G Services in Duct

Placement Band - 2000 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 4113 - U/G Services in Duct

Placement Band - 2000 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	59,212,921	6,466	0.00011	0.99989	100.00
0.5	55,928,009	23,888	0.00043	0.99957	99.99
1.5	52,195,677	198,826	0.00381	0.99619	99.95
2.5	50,398,632	37,735	0.00075	0.99925	99.57
3.5	50,305,988	21,700	0.00043	0.99957	99.50
4.5	48,295,447	183,182	0.00379	0.99621	99.46
5.5	39,100,568	171,083	0.00438	0.99562	99.08
6.5	30,458,573	38,190	0.00125	0.99875	98.65
7.5	18,835,006	27,980	0.00149	0.99851	98.53
8.5	14,062,547	27,392	0.00195	0.99805	98.38
9.5	11,640,996	25,872	0.00222	0.99778	98.19
10.5	11,185,191	2,110	0.00019	0.99981	97.97
11.5	10,834,904	39,311	0.00363	0.99637	97.95
12.5	9,369,573	2,874	0.00031	0.99969	97.59
13.5	7,162,826	9,278	0.00130	0.99870	97.56
14.5	5,846,968	10,552	0.00180	0.99820	97.43
15.5	4,301,469	13,274	0.00309	0.99691	97.25
16.5	3,581,219	1,548	0.00043	0.99957	96.95
17.5	2,847,705	56,917	0.01999	0.98001	96.91
18.5	1,309,095	20,245	0.01546	0.98454	94.97
19.5	424,956	603	0.00142	0.99858	93.50
20.5	424,353	1,931	0.00455	0.99545	93.37
21.5	257,087	1,789	0.00696	0.99304	92.95
	Totals:	922,746			

Toronto Hydro

Account 4115 - U/G Services Secondary Cable Direct Buried

Placement Band - 2010 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 4115 - U/G Services Secondary Cable Direct Buried

Placement Band - 2010 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

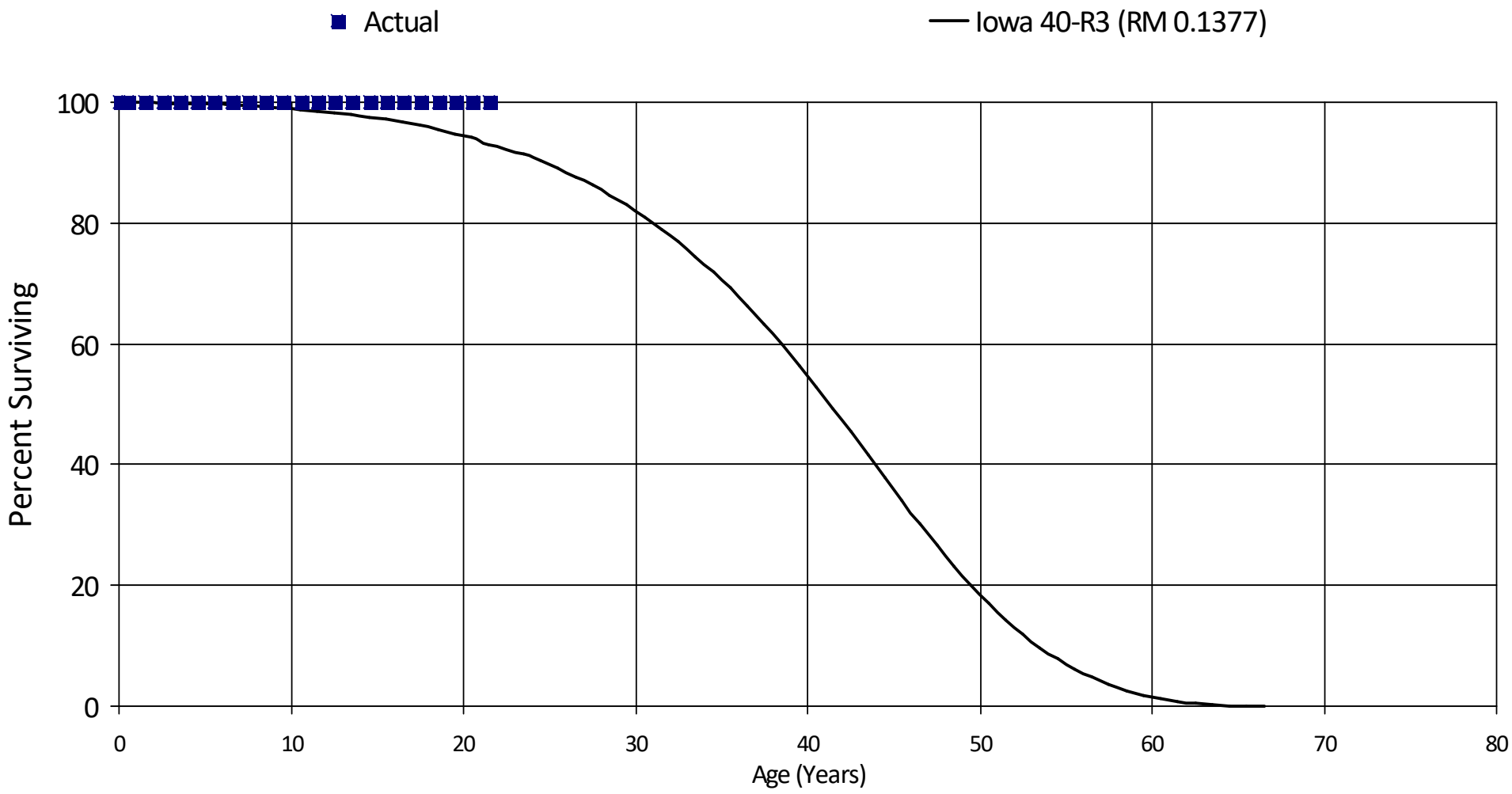
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	544,324	0	0.00000	1.00000	100.00
0.5	544,324	0	0.00000	1.00000	100.00
1.5	544,324	0	0.00000	1.00000	100.00
2.5	544,324	0	0.00000	1.00000	100.00
3.5	544,324	287,495	0.52817	0.47183	100.00
4.5	256,829	1,923	0.00749	0.99251	47.18
5.5	254,905	6,457	0.02533	0.97467	46.83
6.5	248,449	274,354	1.10427	-0.10427	45.64
7.5	-25,905	0	0.00000	1.00000	-4.76
8.5	-25,905	0	0.00000	1.00000	-4.76
9.5	-27,243	0	0.00000	1.00000	-4.76
10.5	-27,243	0	0.00000	1.00000	-4.76
11.5	2,483	0	0.00000	1.00000	-4.76
	Totals:	570,229			

Toronto Hydro

Account 4513 - Dist Meters - Meter Transformers

Placement Band - 2000 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 4513 - Dist Meters - Meter Transformers

Placement Band - 2000 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

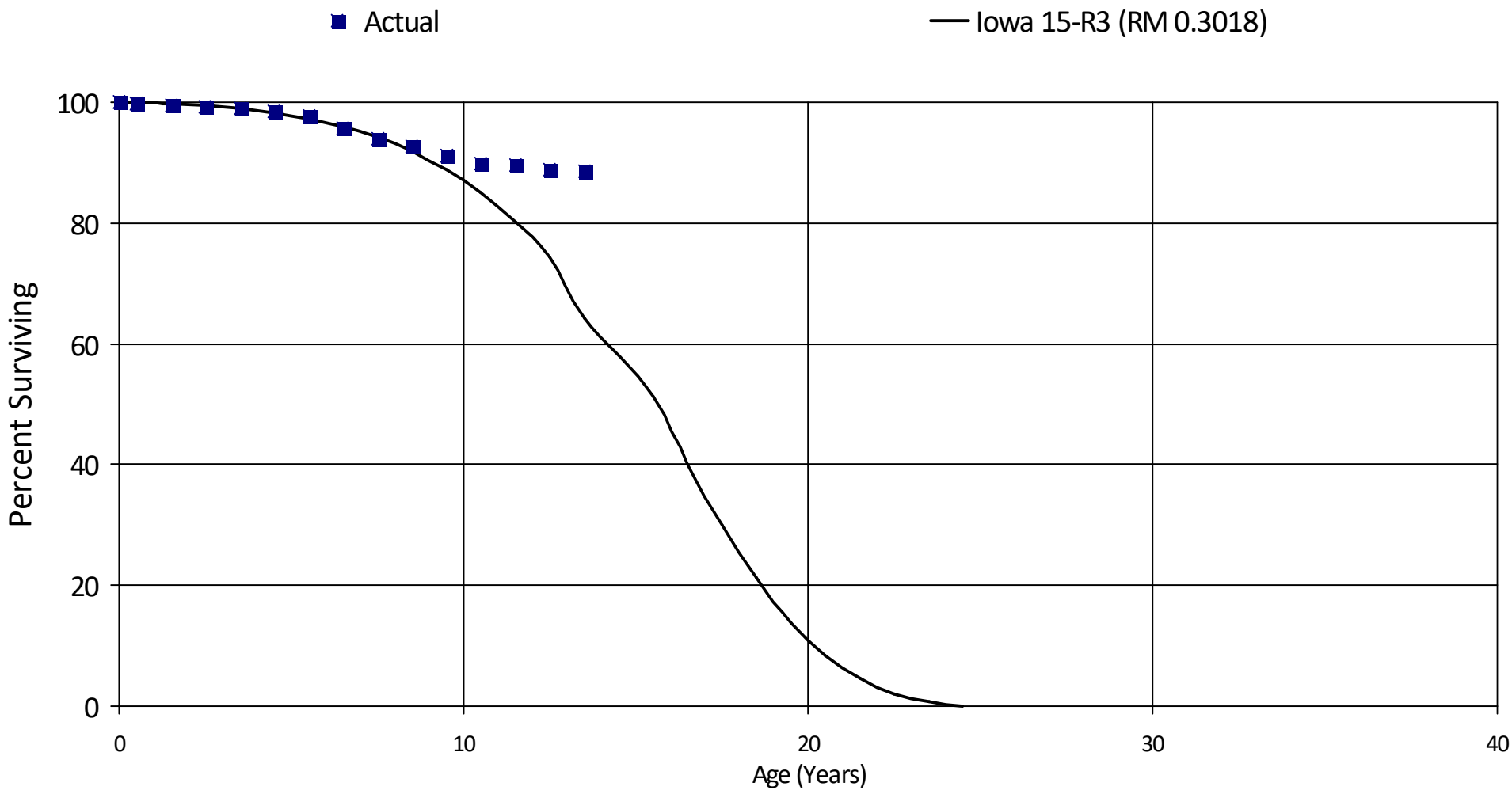
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	22,033,158	0	0.00000	1.00000	100.00
0.5	19,848,268	0	0.00000	1.00000	100.00
1.5	17,683,508	0	0.00000	1.00000	100.00
2.5	15,307,321	0	0.00000	1.00000	100.00
3.5	13,251,207	0	0.00000	1.00000	100.00
4.5	11,627,568	0	0.00000	1.00000	100.00
5.5	10,723,504	0	0.00000	1.00000	100.00
6.5	9,376,443	0	0.00000	1.00000	100.00
7.5	8,341,693	0	0.00000	1.00000	100.00
8.5	7,576,882	0	0.00000	1.00000	100.00
9.5	7,051,163	0	0.00000	1.00000	100.00
10.5	6,579,695	0	0.00000	1.00000	100.00
11.5	5,195,399	0	0.00000	1.00000	100.00
12.5	3,427,169	0	0.00000	1.00000	100.00
13.5	3,415,022	0	0.00000	1.00000	100.00
14.5	3,264,541	0	0.00000	1.00000	100.00
15.5	2,068,438	0	0.00000	1.00000	100.00
16.5	1,113,964	0	0.00000	1.00000	100.00
17.5	626,258	0	0.00000	1.00000	100.00
18.5	351,514	0	0.00000	1.00000	100.00
19.5	69,478	0	0.00000	1.00000	100.00
20.5	69,478	0	0.00000	1.00000	100.00
21.5	60,669	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 4515 - Dist Meters - Suite Meters

Placement Band - 2008 - 2022 Experience Band - 2015 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 4515 - Dist Meters - Suite Meters

Placement Band - 2008 - 2022 Experience Band - 2015 - 2022

RETIREMENT RATE ANALYSIS

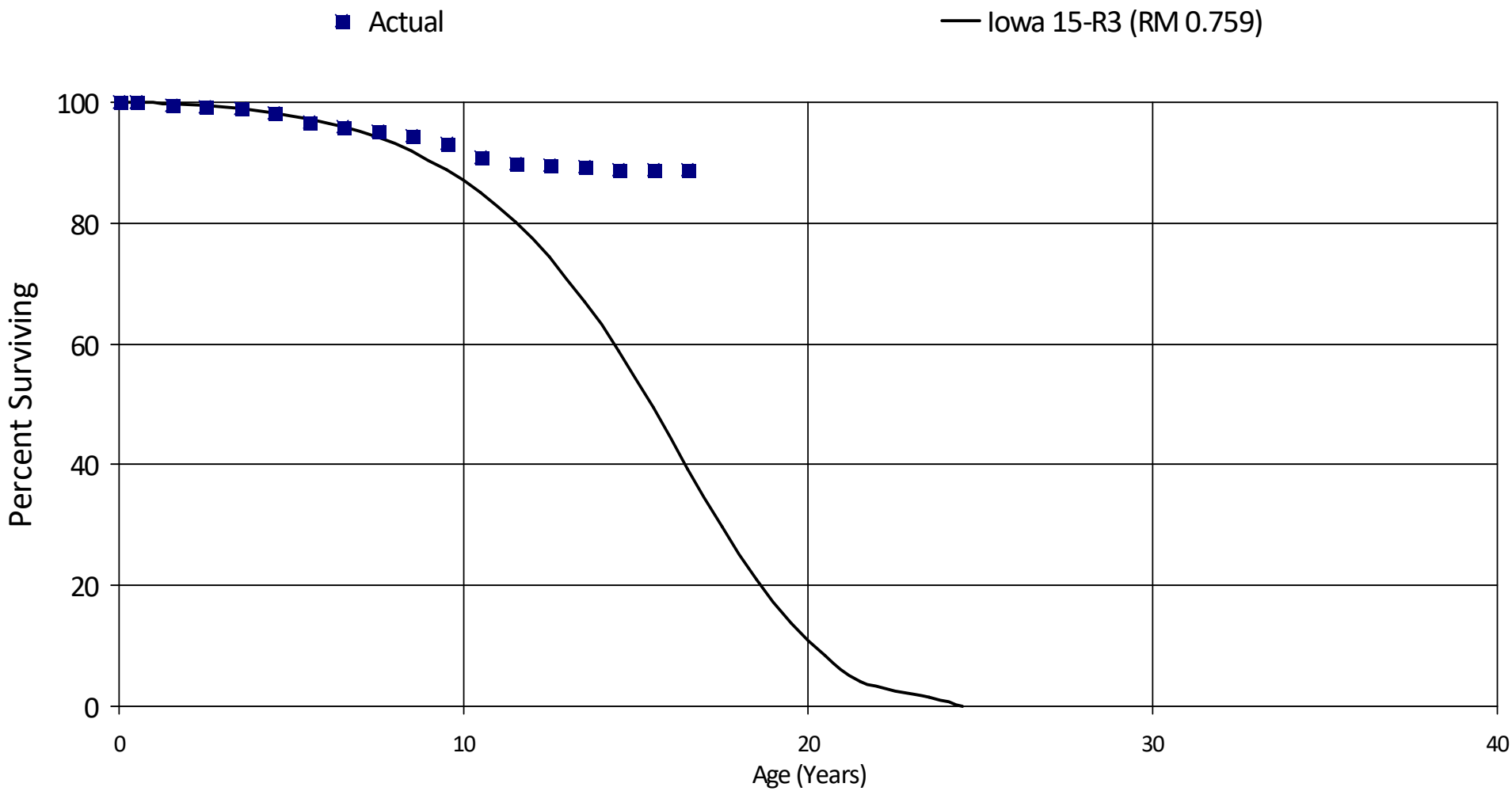
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	62,133,925	95,578	0.00154	0.99846	100.00
0.5	59,300,828	161,476	0.00272	0.99728	99.85
1.5	57,973,414	218,601	0.00377	0.99623	99.58
2.5	53,416,762	159,639	0.00299	0.99701	99.20
3.5	52,118,778	191,885	0.00368	0.99632	98.90
4.5	46,202,281	396,824	0.00859	0.99141	98.54
5.5	42,216,616	890,395	0.02109	0.97891	97.69
6.5	37,295,005	654,846	0.01756	0.98244	95.63
7.5	31,004,744	447,707	0.01444	0.98556	93.95
8.5	16,710,112	252,242	0.01510	0.98490	92.59
9.5	11,925,126	186,820	0.01567	0.98433	91.19
10.5	10,277,017	31,313	0.00305	0.99695	89.76
11.5	8,671,292	75,259	0.00868	0.99132	89.49
12.5	944,629	1,431	0.00151	0.99849	88.71
13.5	193,220	1,871	0.00968	0.99032	88.58
	Totals:	3,765,887			

Toronto Hydro

Account 4611 - Dist Meters - Smart Meters Residential

Placement Band - 2000 - 2022 Experience Band - 2015 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 4611 - Dist Meters - Smart Meters Residential

Placement Band - 2000 - 2022 Experience Band - 2015 - 2022

RETIREMENT RATE ANALYSIS

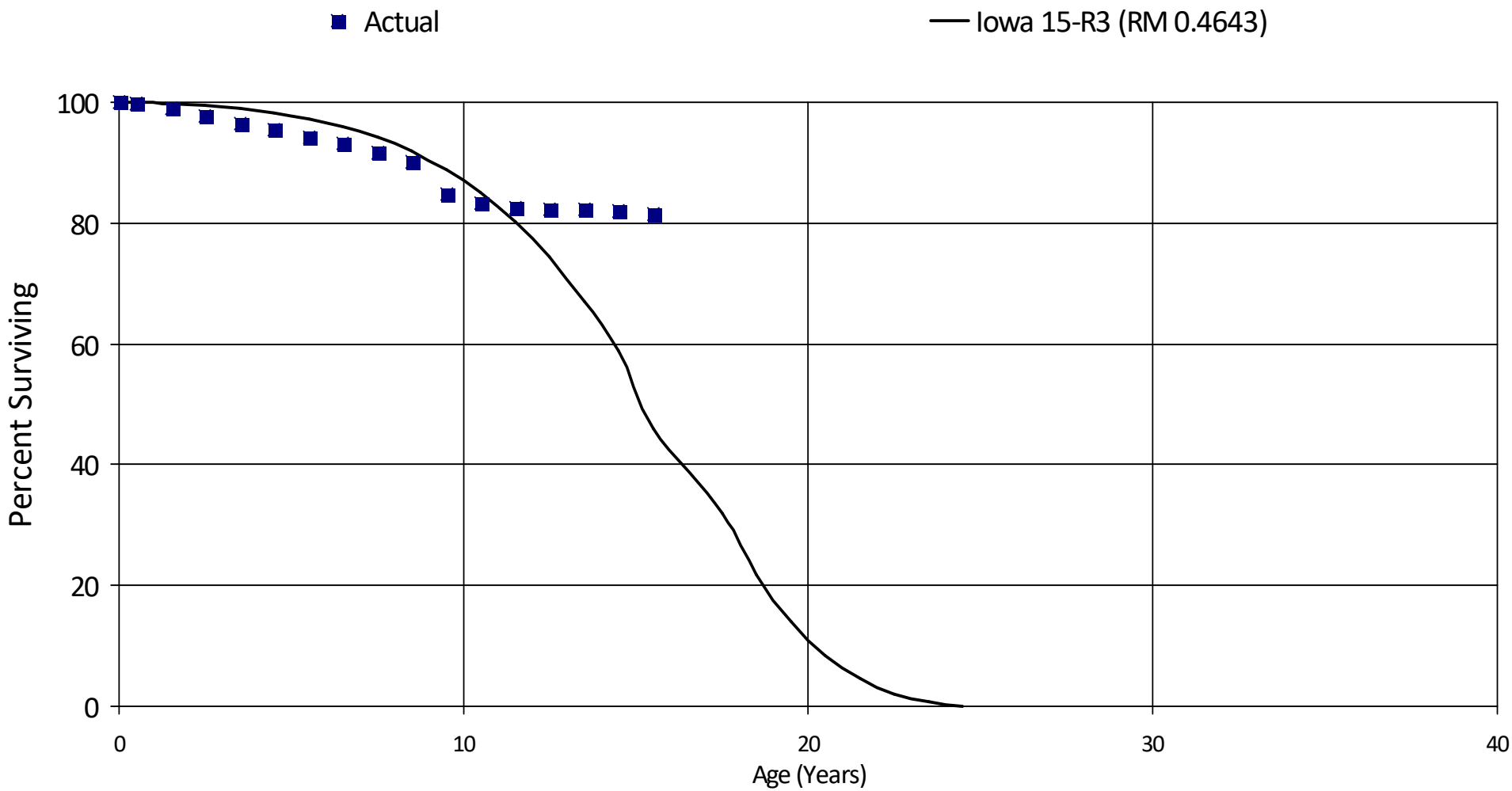
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	104,684,581	51,630	0.00049	0.99951	100.00
0.5	102,429,995	422,345	0.00412	0.99588	99.95
1.5	99,335,275	325,145	0.00327	0.99673	99.54
2.5	94,737,811	231,288	0.00244	0.99756	99.21
3.5	92,023,035	726,889	0.00790	0.99210	98.97
4.5	85,028,769	1,393,584	0.01639	0.98361	98.19
5.5	77,247,373	524,838	0.00679	0.99321	96.58
6.5	71,871,574	576,302	0.00802	0.99198	95.92
7.5	70,116,395	602,192	0.00859	0.99141	95.15
8.5	67,477,032	801,772	0.01188	0.98812	94.33
9.5	61,205,070	1,526,129	0.02493	0.97507	93.21
10.5	56,884,704	575,493	0.01012	0.98988	90.89
11.5	54,087,820	255,579	0.00473	0.99527	89.97
12.5	48,769,342	105,194	0.00216	0.99784	89.54
13.5	40,850,371	207,834	0.00509	0.99491	89.35
14.5	28,028,388	34,287	0.00122	0.99878	88.90
15.5	14,435,955	0	0.00000	1.00000	88.79
16.5	0	0	0.00000	0.00000	88.79
	Totals:	8,360,501			

Toronto Hydro

Account 4613 - Dist Meters - Smart Meters GS

Placement Band - 2006 - 2022 Experience Band - 2015 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 4613 - Dist Meters - Smart Meters GS

Placement Band - 2006 - 2022 Experience Band - 2015 - 2022

RETIREMENT RATE ANALYSIS

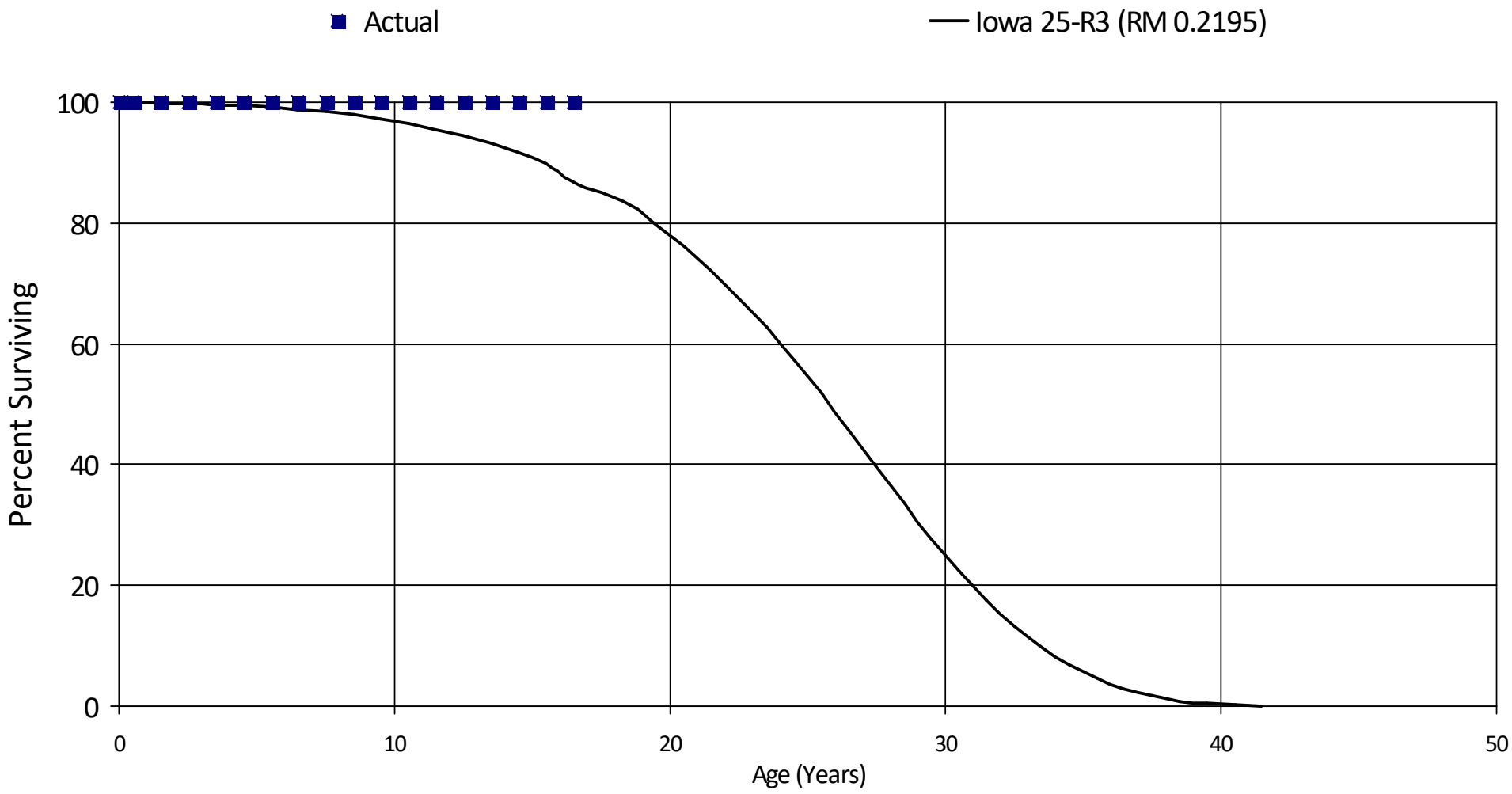
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	74,150,593	238,912	0.00322	0.99678	100.00
0.5	67,876,319	445,133	0.00656	0.99344	99.68
1.5	62,897,548	912,086	0.01450	0.98550	99.03
2.5	56,868,947	644,893	0.01134	0.98866	97.59
3.5	50,839,895	611,579	0.01203	0.98797	96.48
4.5	41,205,692	523,343	0.01270	0.98730	95.32
5.5	31,207,661	339,502	0.01088	0.98912	94.11
6.5	30,860,891	455,094	0.01475	0.98525	93.09
7.5	25,602,798	433,743	0.01694	0.98306	91.72
8.5	23,667,563	1,406,734	0.05944	0.94056	90.17
9.5	21,496,698	374,770	0.01743	0.98257	84.81
10.5	20,761,605	207,003	0.00997	0.99003	83.33
11.5	16,180,335	37,369	0.00231	0.99769	82.50
12.5	9,092,391	18,218	0.00200	0.99800	82.31
13.5	4,580,962	15,479	0.00338	0.99662	82.15
14.5	1,415,891	4,830	0.00341	0.99659	81.87
15.5	208,229	0	0.00000	1.00000	81.59
	Totals:	6,668,688			

Toronto Hydro

Account 4711 - Grid Point Meters

Placement Band - 2005 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 4711 - Grid Point Meters

Placement Band - 2005 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	41,762,307	0	0.00000	1.00000	100.00
0.5	40,300,309	0	0.00000	1.00000	100.00
1.5	37,285,955	0	0.00000	1.00000	100.00
2.5	35,784,657	0	0.00000	1.00000	100.00
3.5	29,322,003	0	0.00000	1.00000	100.00
4.5	26,804,998	0	0.00000	1.00000	100.00
5.5	26,168,967	0	0.00000	1.00000	100.00
6.5	24,900,754	0	0.00000	1.00000	100.00
7.5	23,071,720	0	0.00000	1.00000	100.00
8.5	13,093,201	0	0.00000	1.00000	100.00
9.5	7,957,805	0	0.00000	1.00000	100.00
10.5	7,621,156	0	0.00000	1.00000	100.00
11.5	5,371,929	0	0.00000	1.00000	100.00
12.5	4,739,482	0	0.00000	1.00000	100.00
13.5	1,452,622	0	0.00000	1.00000	100.00
14.5	873,748	0	0.00000	1.00000	100.00
15.5	364,495	0	0.00000	1.00000	100.00
16.5	46,482	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 5031 - Street Lighting Distribution Assembly

Placement Band - 2019 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 5031 - Street Lighting Distribution Assembly

Placement Band - 2019 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

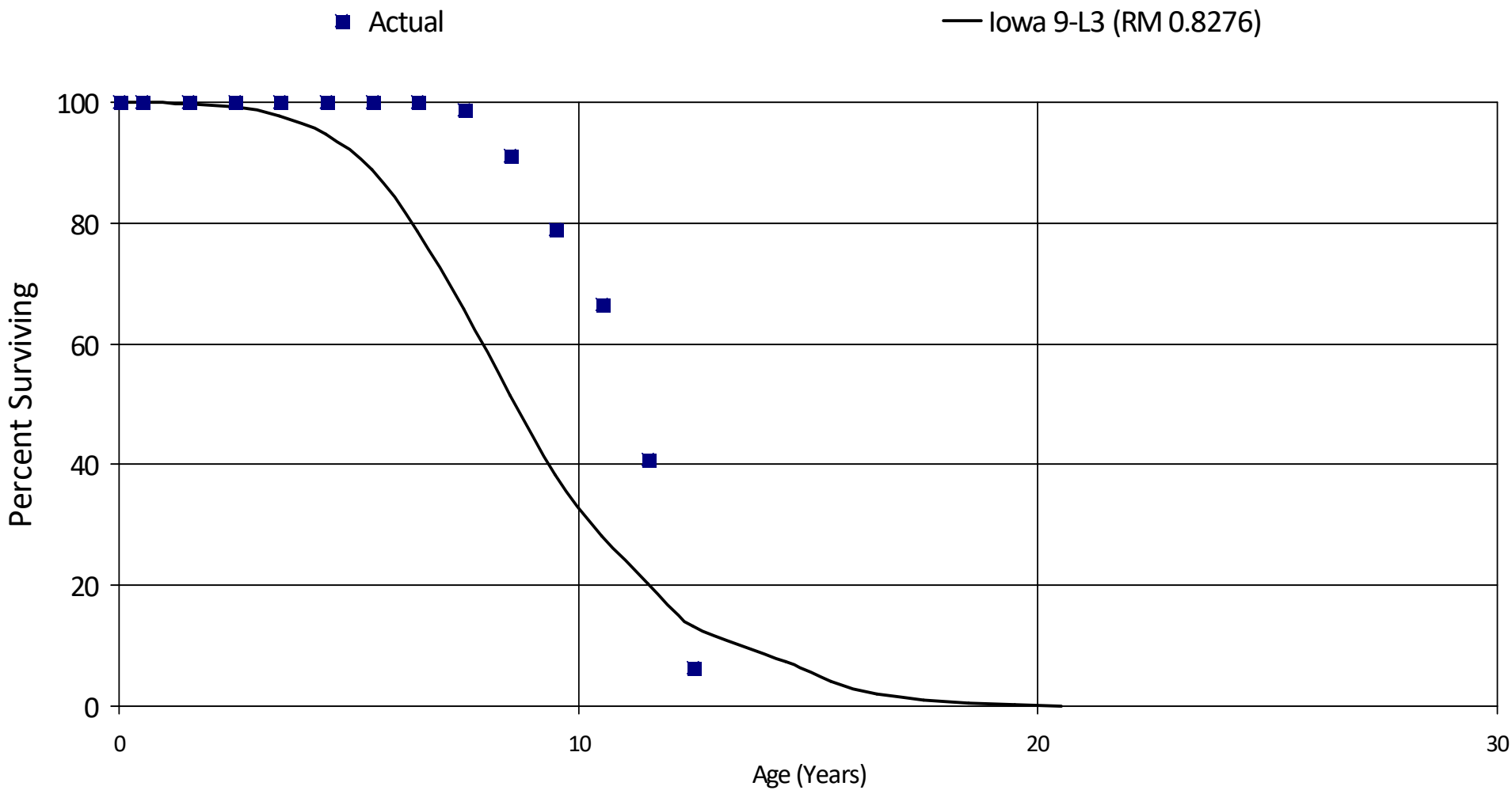
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	87,699	0	0.00000	1.00000	100.00
0.5	87,699	0	0.00000	1.00000	100.00
1.5	87,699	0	0.00000	1.00000	100.00
2.5	87,475	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 6231 - Rolling Stock - Vehicles < 3 Tons

Placement Band - 2009 - 2022 Experience Band - 2018 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 6231 - Rolling Stock - Vehicles < 3 Tons

Placement Band - 2009 - 2022 Experience Band - 2018 - 2022

RETIREMENT RATE ANALYSIS

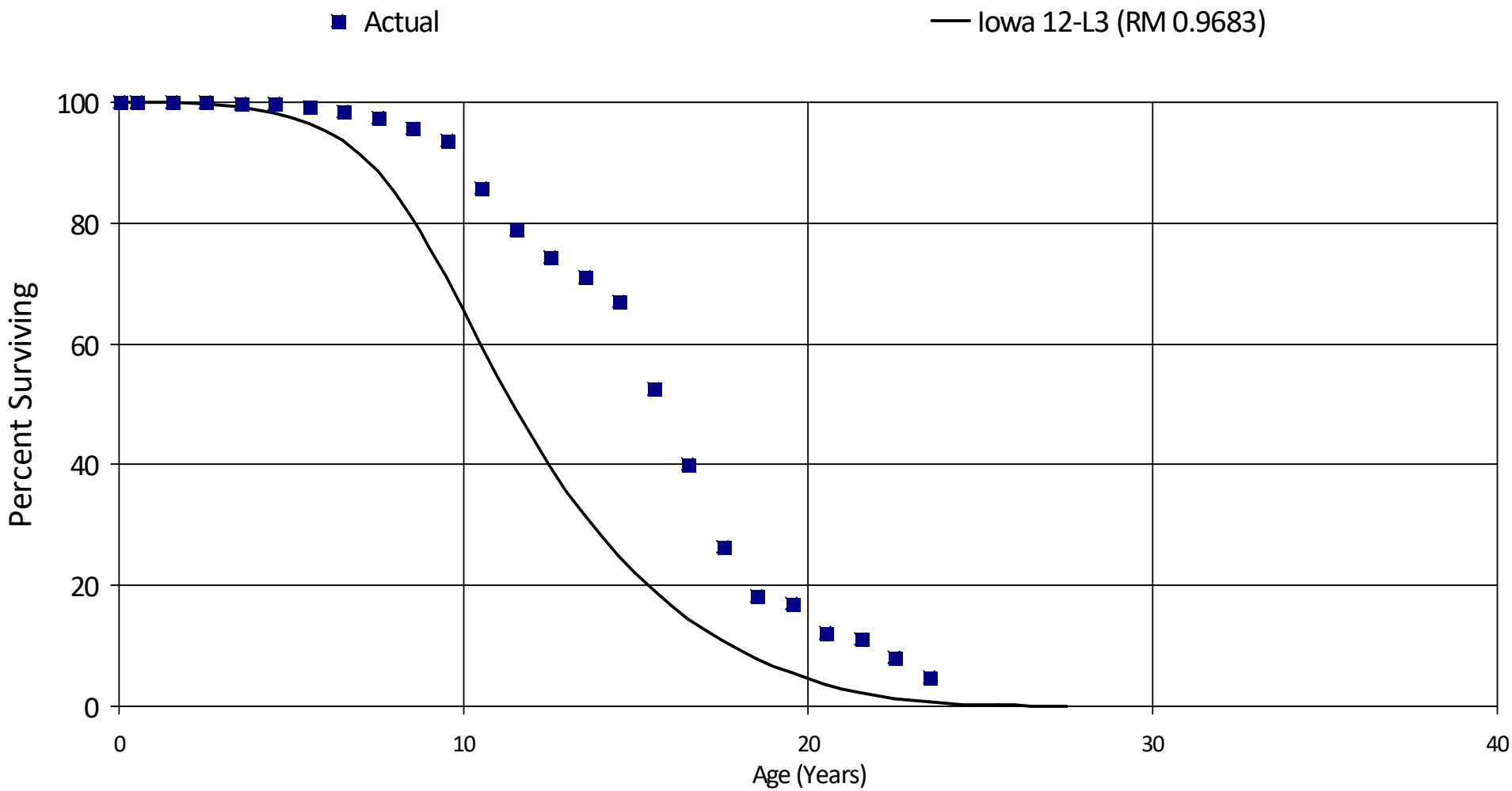
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	13,467,904	0	0.00000	1.00000	100.00
0.5	9,419,396	0	0.00000	1.00000	100.00
1.5	8,633,655	0	0.00000	1.00000	100.00
2.5	7,454,736	0	0.00000	1.00000	100.00
3.5	6,474,823	0	0.00000	1.00000	100.00
4.5	5,774,978	0	0.00000	1.00000	100.00
5.5	5,231,568	0	0.00000	1.00000	100.00
6.5	3,958,086	52,264	0.01320	0.98680	100.00
7.5	3,520,419	270,361	0.07680	0.92320	98.68
8.5	3,250,058	435,799	0.13409	0.86591	91.10
9.5	2,814,259	437,926	0.15561	0.84439	78.88
10.5	2,307,660	893,181	0.38705	0.61295	66.61
11.5	277,808	234,516	0.84417	0.15583	40.83
12.5	4,493	0	0.00000	1.00000	6.36
	Totals:	2,324,047			

Toronto Hydro

Account 6251 - Rolling Stock - Vehicles > 3 Tons

Placement Band - 1962 - 2022 Experience Band - 2010 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 6251 - Rolling Stock - Vehicles > 3 Tons

Placement Band - 1962 - 2022 Experience Band - 2010 - 2022

RETIREMENT RATE ANALYSIS

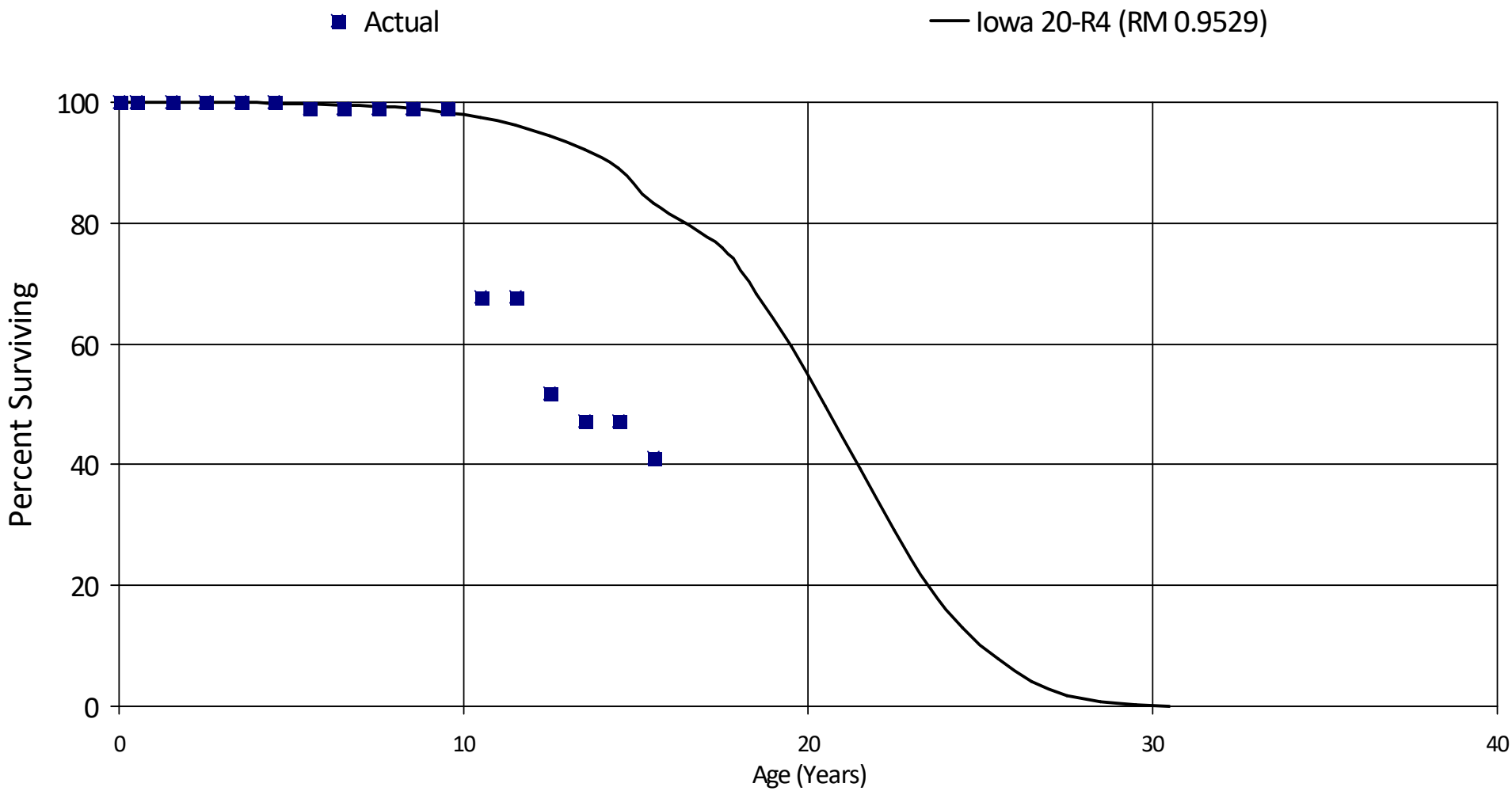
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	54,212,165	0	0.00000	1.00000	100.00
0.5	52,022,085	19,077	0.00037	0.99963	100.00
1.5	48,944,986	0	0.00000	1.00000	99.96
2.5	46,036,159	142,694	0.00310	0.99690	99.96
3.5	43,126,844	0	0.00000	1.00000	99.65
4.5	41,250,583	157,514	0.00382	0.99618	99.65
5.5	37,587,758	284,645	0.00757	0.99243	99.27
6.5	35,609,966	344,420	0.00967	0.99033	98.52
7.5	33,183,495	612,941	0.01847	0.98153	97.57
8.5	30,407,654	704,631	0.02317	0.97683	95.77
9.5	29,521,770	2,457,258	0.08324	0.91676	93.55
10.5	26,143,147	2,077,943	0.07948	0.92052	85.76
11.5	20,339,107	1,208,399	0.05941	0.94059	78.94
12.5	14,860,468	637,371	0.04289	0.95711	74.25
13.5	11,203,275	633,923	0.05658	0.94342	71.07
14.5	9,482,092	2,053,076	0.21652	0.78348	67.05
15.5	7,286,377	1,739,330	0.23871	0.76129	52.53
16.5	5,534,141	1,874,264	0.33867	0.66133	39.99
17.5	3,659,877	1,119,906	0.30600	0.69400	26.45
18.5	2,539,971	202,368	0.07967	0.92033	18.36
19.5	2,337,604	657,288	0.28118	0.71882	16.90
20.5	1,680,316	123,222	0.07333	0.92667	12.15
21.5	1,557,094	429,915	0.27610	0.72390	11.26
22.5	1,127,179	468,092	0.41528	0.58472	8.15
23.5	659,087	239,595	0.36353	0.63647	4.77
	Totals:	18,187,872			

Toronto Hydro

Account 6271 - Rolling Stock - Service Equipment

Placement Band - 2006 - 2022 Experience Band - 2019 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 6271 - Rolling Stock - Service Equipment

Placement Band - 2006 - 2022 Experience Band - 2019 - 2022

RETIREMENT RATE ANALYSIS

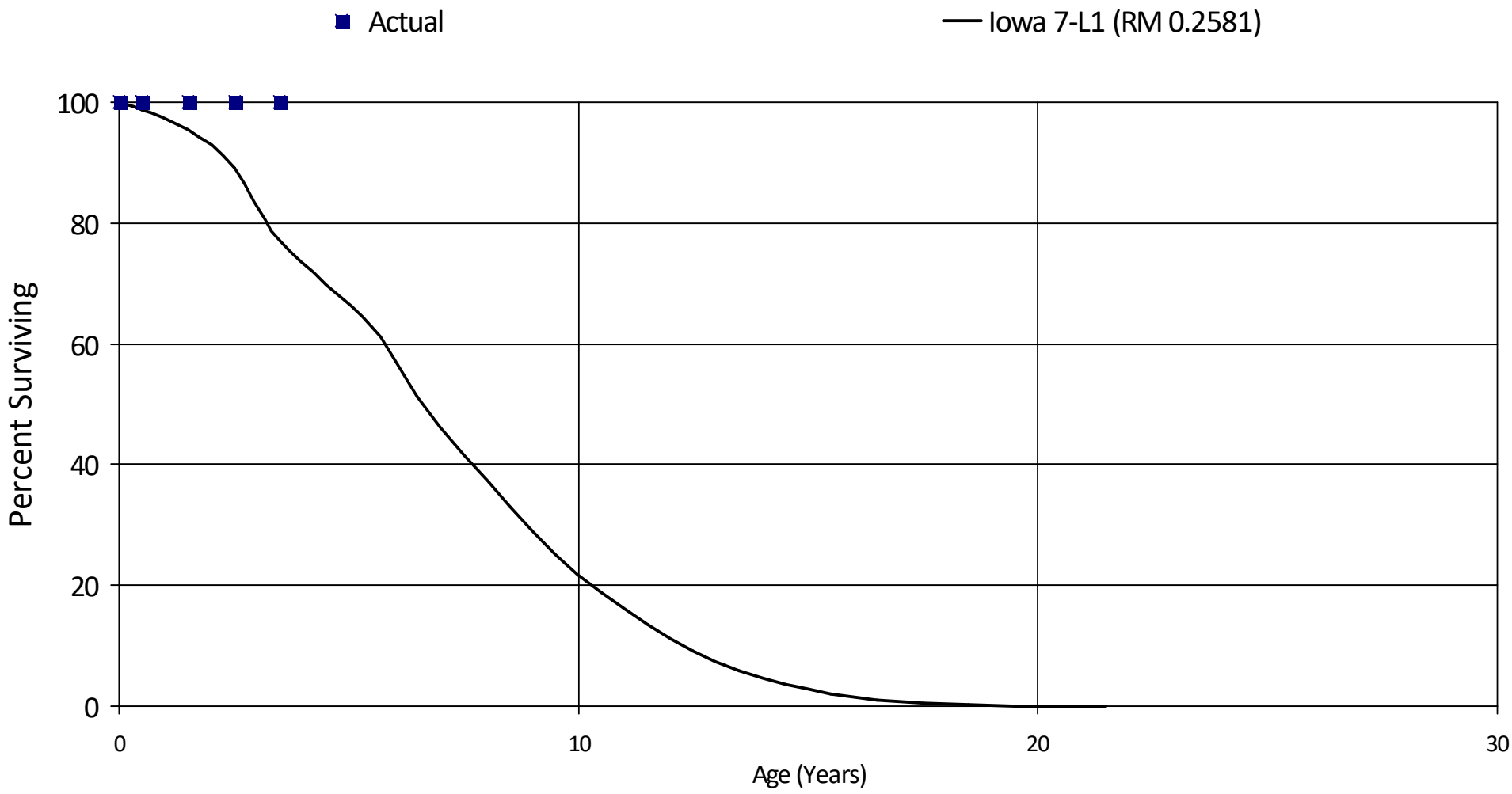
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,277,985	0	0.00000	1.00000	100.00
0.5	1,642,754	0	0.00000	1.00000	100.00
1.5	1,620,484	0	0.00000	1.00000	100.00
2.5	1,620,484	0	0.00000	1.00000	100.00
3.5	1,393,228	0	0.00000	1.00000	100.00
4.5	945,892	8,800	0.00930	0.99070	100.00
5.5	749,754	0	0.00000	1.00000	99.07
6.5	732,154	0	0.00000	1.00000	99.07
7.5	732,154	0	0.00000	1.00000	99.07
8.5	711,407	0	0.00000	1.00000	99.07
9.5	573,851	180,658	0.31482	0.68518	99.07
10.5	305,712	0	0.00000	1.00000	67.88
11.5	242,835	57,807	0.23805	0.76195	67.88
12.5	63,061	5,616	0.08906	0.91094	51.72
13.5	57,445	0	0.00000	1.00000	47.11
14.5	24,890	3,186	0.12800	0.87200	47.11
15.5	7,323	0	0.00000	1.00000	41.08
	Totals:	256,067			

Toronto Hydro

Account 6281 - Electric Vehicles

Placement Band - 2018 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 6281 - Electric Vehicles

Placement Band - 2018 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

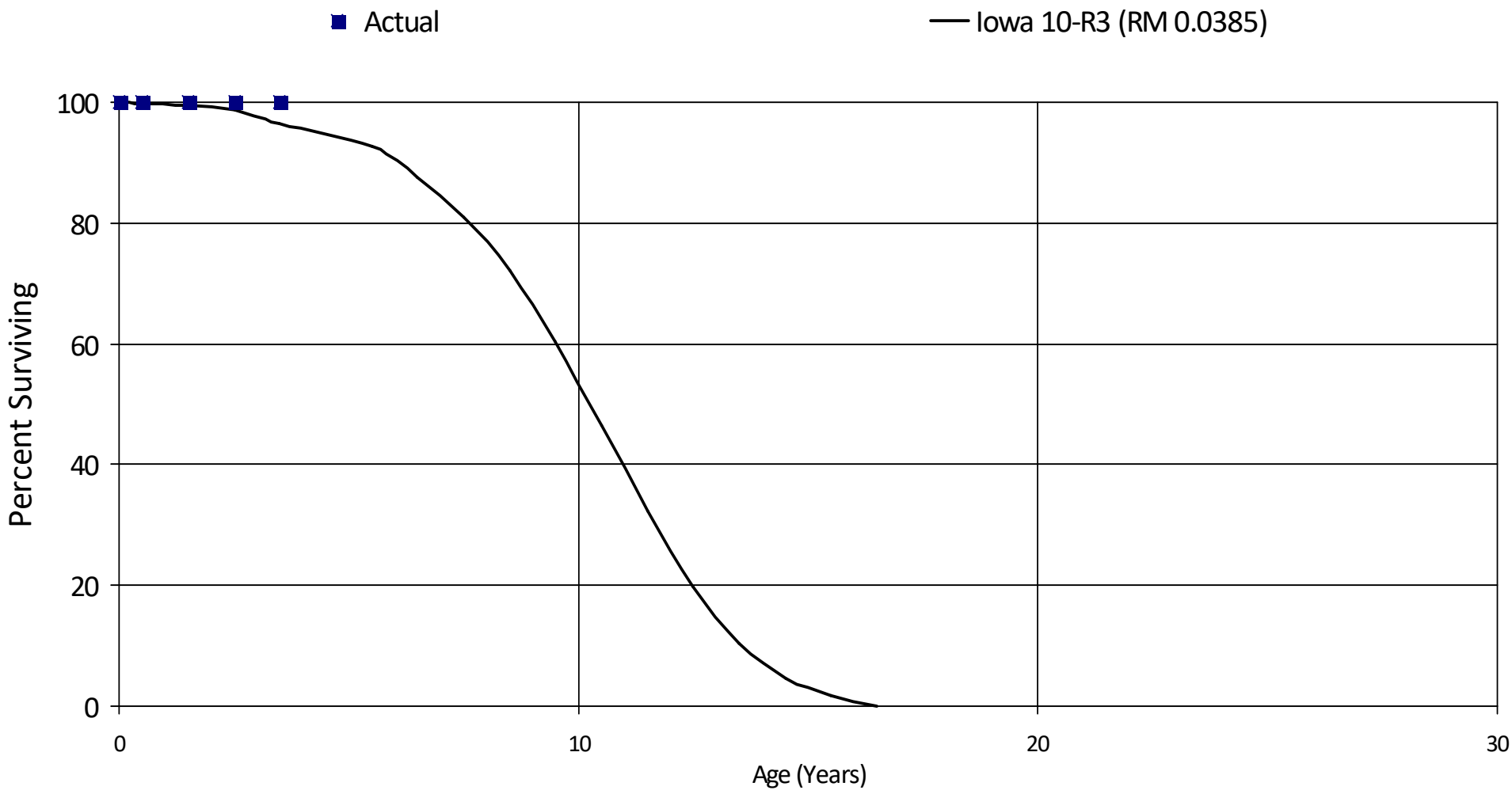
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	606,502	0	0.00000	1.00000	100.00
0.5	606,502	0	0.00000	1.00000	100.00
1.5	330,734	0	0.00000	1.00000	100.00
2.5	330,734	0	0.00000	1.00000	100.00
3.5	330,734	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 6282 - Electric Vehicle Charging Station

Placement Band - 2018 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 6282 - Electric Vehicle Charging Station

Placement Band - 2018 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

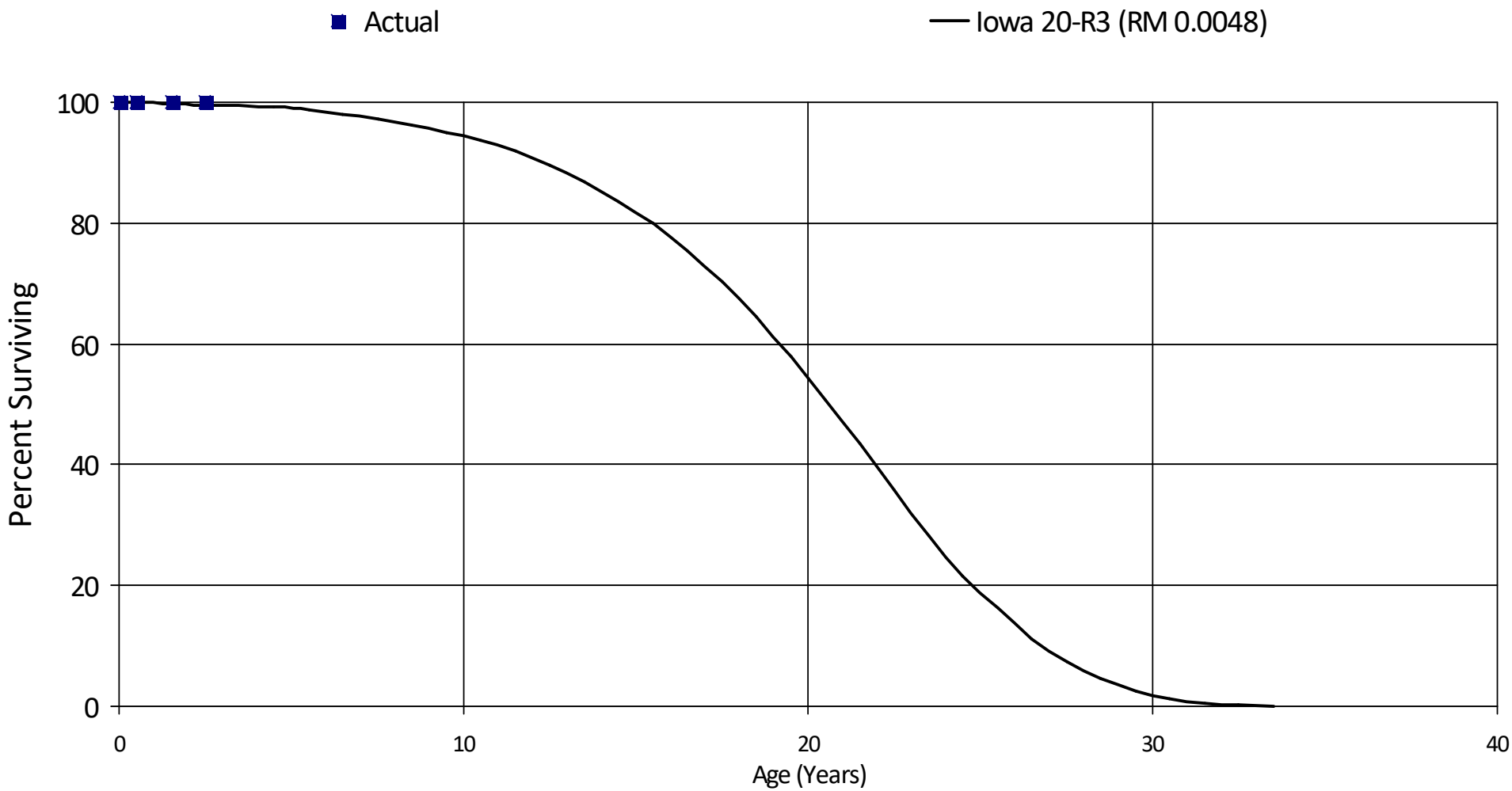
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	98,915	0	0.00000	1.00000	100.00
0.5	98,915	0	0.00000	1.00000	100.00
1.5	98,915	0	0.00000	1.00000	100.00
2.5	98,915	0	0.00000	1.00000	100.00
3.5	98,915	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 6291 - Energy Storage Inverter

Placement Band - 2019 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 6291 - Energy Storage Inverter

Placement Band - 2019 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

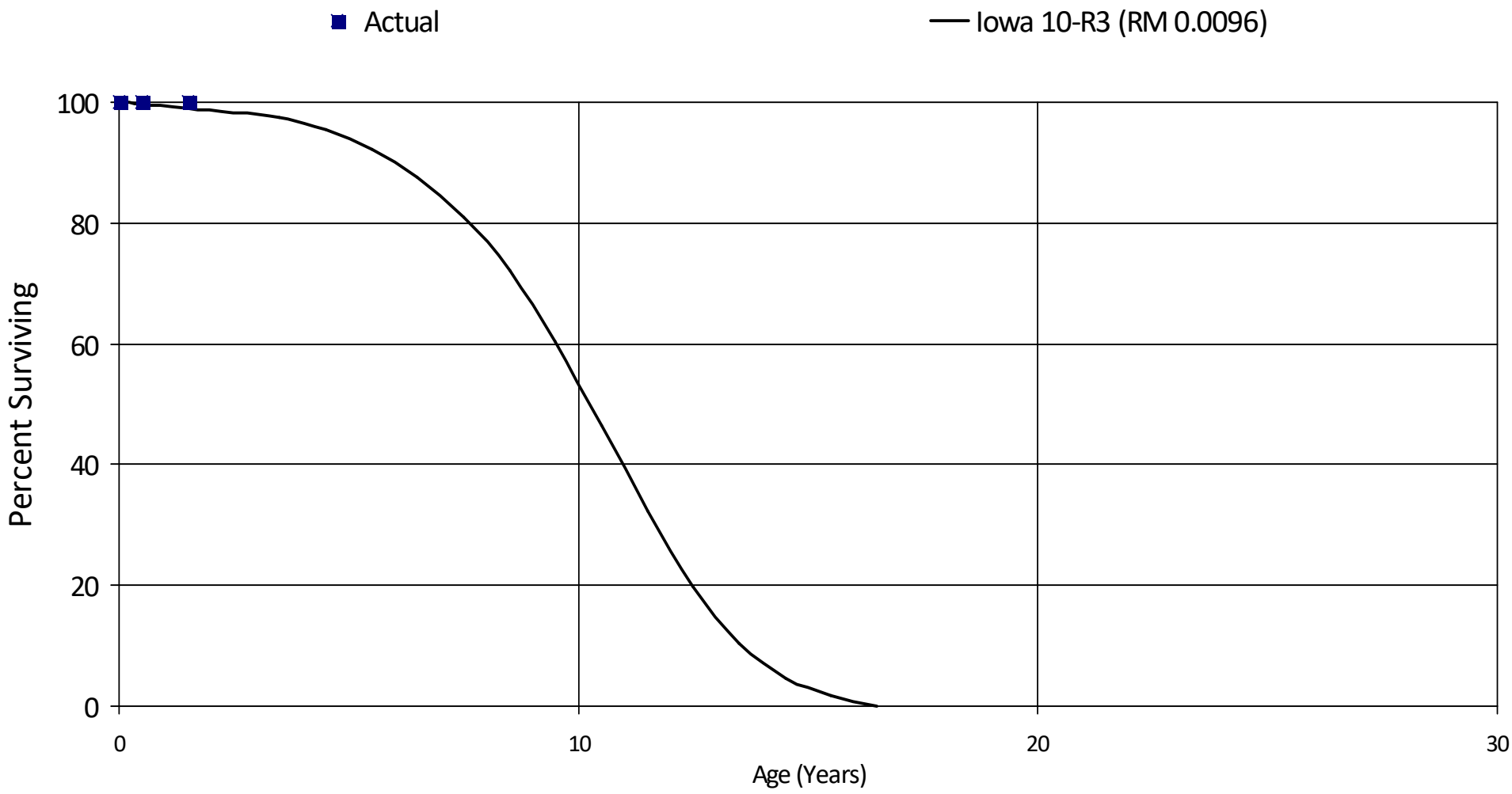
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	3,280,131	0	0.00000	1.00000	100.00
0.5	3,280,131	0	0.00000	1.00000	100.00
1.5	3,280,131	0	0.00000	1.00000	100.00
2.5	780,668	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 6292 - Energy Storage System Battery

Placement Band - 2020 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 6292 - Energy Storage System Battery

Placement Band - 2020 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

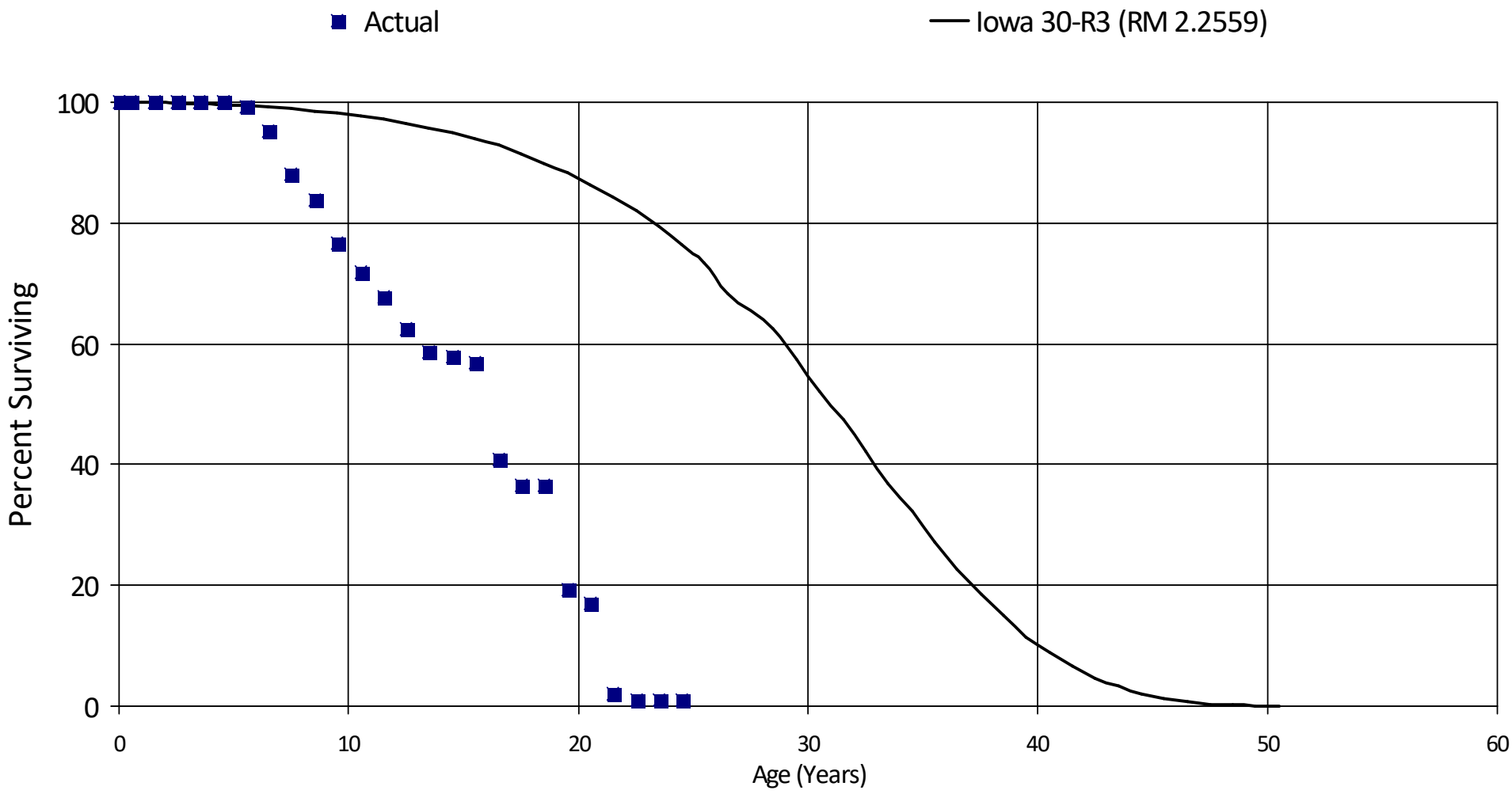
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,249,507	0	0.00000	1.00000	100.00
0.5	1,249,507	0	0.00000	1.00000	100.00
1.5	1,249,507	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 6453 - System Supervisory - Scadamate Switches

Placement Band - 1995 - 2022 Experience Band - 2014 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 6453 - System Supervisory - Scadamate Switches

Placement Band - 1995 - 2022 Experience Band - 2014 - 2022

RETIREMENT RATE ANALYSIS

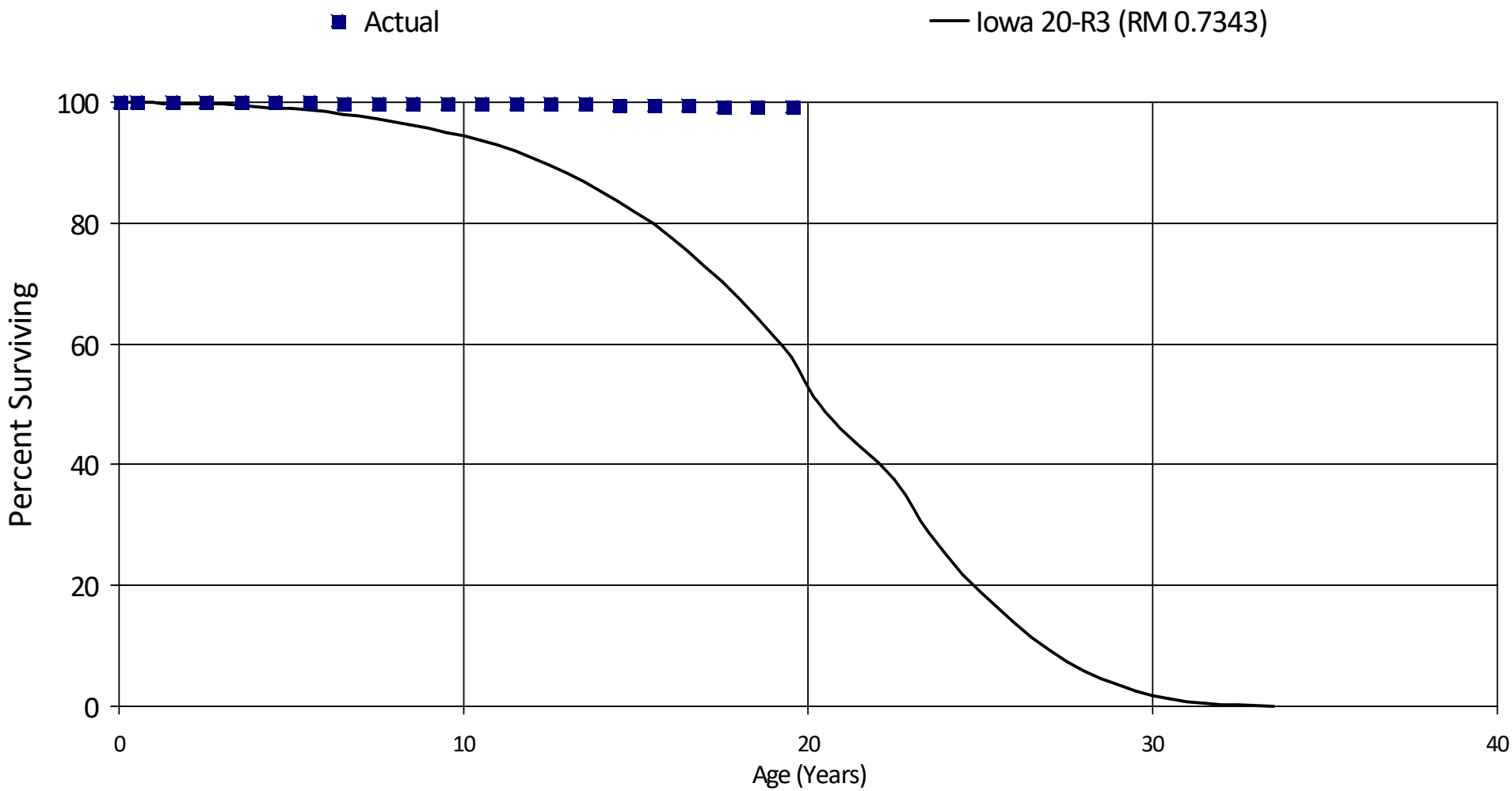
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	5,819,017	0	0.00000	1.00000	100.00
0.5	5,819,017	0	0.00000	1.00000	100.00
1.5	5,819,017	0	0.00000	1.00000	100.00
2.5	5,819,017	0	0.00000	1.00000	100.00
3.5	5,819,017	0	0.00000	1.00000	100.00
4.5	5,819,017	46,299	0.00796	0.99204	100.00
5.5	5,772,718	228,803	0.03964	0.96036	99.20
6.5	5,543,915	414,654	0.07479	0.92521	95.27
7.5	5,129,261	258,906	0.05048	0.94952	88.14
8.5	4,870,355	414,130	0.08503	0.91497	83.69
9.5	4,456,202	278,212	0.06243	0.93757	76.57
10.5	4,177,990	239,855	0.05741	0.94259	71.79
11.5	3,938,381	306,268	0.07776	0.92224	67.67
12.5	3,632,112	216,000	0.05947	0.94053	62.41
13.5	3,416,112	43,619	0.01277	0.98723	58.70
14.5	1,691,596	30,179	0.01784	0.98216	57.95
15.5	782,647	220,678	0.28196	0.71804	56.92
16.5	561,969	60,358	0.10740	0.89260	40.87
17.5	451,423	0	0.00000	1.00000	36.48
18.5	412,529	194,748	0.47208	0.52792	36.48
19.5	213,213	24,435	0.11460	0.88540	19.26
20.5	188,777	165,488	0.87663	0.12337	17.05
21.5	21,191	11,336	0.53495	0.46505	2.10
22.5	7,683	0	0.00000	1.00000	0.98
23.5	7,683	0	0.00000	1.00000	0.98
24.5	0	0	0.00000	0.00000	0.98
	Totals:	3,153,968			

Toronto Hydro

Account 6455 - System Supervisory - Scada RTU

Placement Band - 2001 - 2022 Experience Band - 2018 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 6455 - System Supervisory - Scada RTU

Placement Band - 2001 - 2022 Experience Band - 2018 - 2022

RETIREMENT RATE ANALYSIS

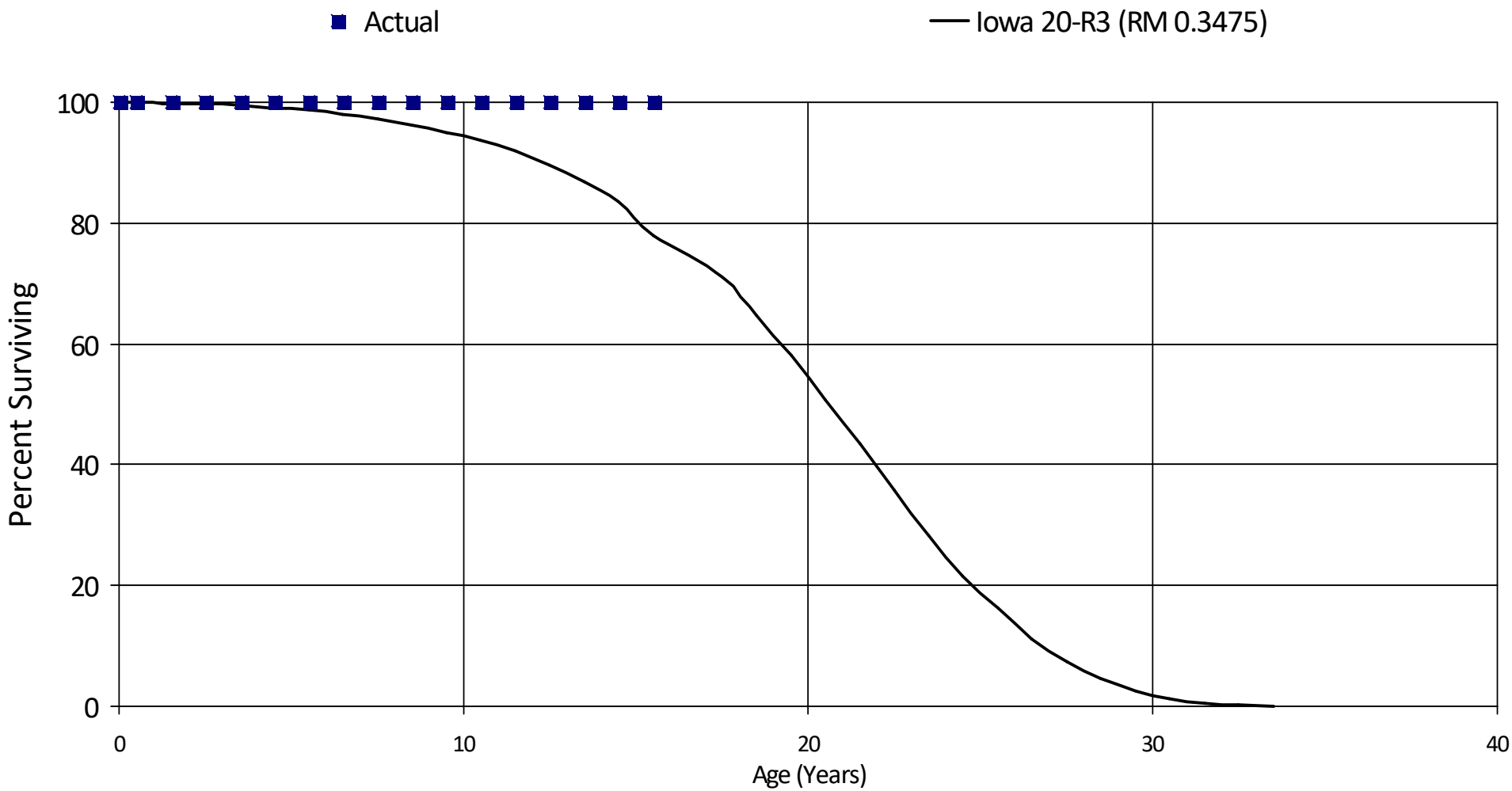
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	73,077,764	0	0.00000	1.00000	100.00
0.5	61,236,476	0	0.00000	1.00000	100.00
1.5	50,124,112	0	0.00000	1.00000	100.00
2.5	38,932,296	0	0.00000	1.00000	100.00
3.5	33,062,237	0	0.00000	1.00000	100.00
4.5	26,671,931	31,684	0.00119	0.99881	100.00
5.5	20,567,438	22,346	0.00109	0.99891	99.88
6.5	17,477,916	0	0.00000	1.00000	99.77
7.5	14,271,709	0	0.00000	1.00000	99.77
8.5	10,931,984	0	0.00000	1.00000	99.77
9.5	7,444,029	0	0.00000	1.00000	99.77
10.5	7,166,070	0	0.00000	1.00000	99.77
11.5	6,733,380	0	0.00000	1.00000	99.77
12.5	5,443,842	0	0.00000	1.00000	99.77
13.5	4,716,885	15,676	0.00332	0.99668	99.77
14.5	2,453,369	0	0.00000	1.00000	99.44
15.5	1,314,840	0	0.00000	1.00000	99.44
16.5	640,775	1,192	0.00186	0.99814	99.44
17.5	371,212	0	0.00000	1.00000	99.26
18.5	3,651	0	0.00000	1.00000	99.26
19.5	0	0	0.00000	0.00000	99.26
	Totals:	70,898			

Toronto Hydro

Account 6511 - Fibre Optic Network - Control Cable

Placement Band - 2006 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 6511 - Fibre Optic Network - Control Cable

Placement Band - 2006 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

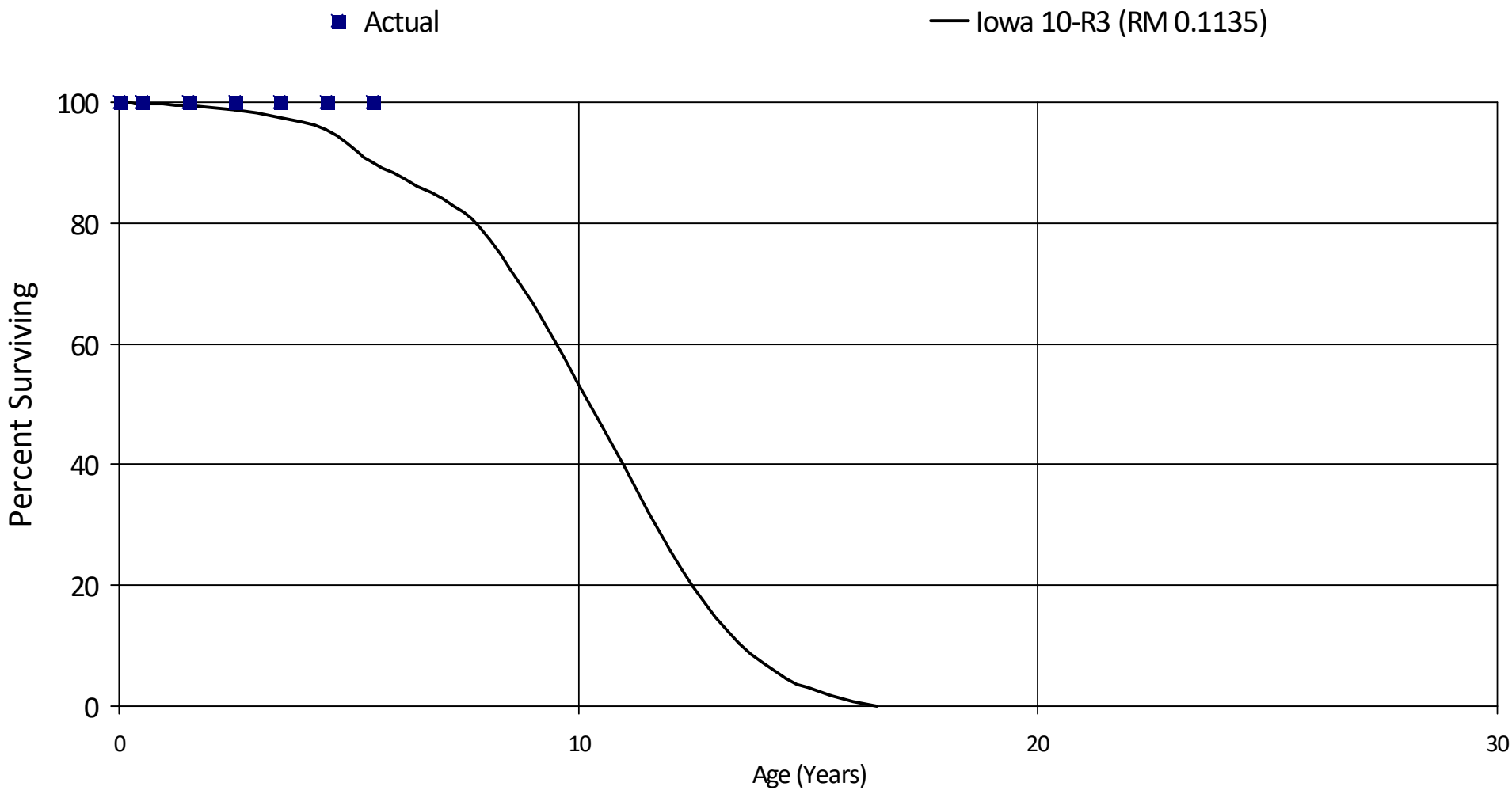
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	13,756,542	0	0.00000	1.00000	100.00
0.5	10,080,436	0	0.00000	1.00000	100.00
1.5	8,049,283	0	0.00000	1.00000	100.00
2.5	5,037,761	0	0.00000	1.00000	100.00
3.5	2,098,426	0	0.00000	1.00000	100.00
4.5	590,432	0	0.00000	1.00000	100.00
5.5	574,344	0	0.00000	1.00000	100.00
6.5	574,344	0	0.00000	1.00000	100.00
7.5	574,344	0	0.00000	1.00000	100.00
8.5	297,951	0	0.00000	1.00000	100.00
9.5	63,597	0	0.00000	1.00000	100.00
10.5	63,597	0	0.00000	1.00000	100.00
11.5	63,597	0	0.00000	1.00000	100.00
12.5	63,597	0	0.00000	1.00000	100.00
13.5	63,597	0	0.00000	1.00000	100.00
14.5	61,137	0	0.00000	1.00000	100.00
15.5	61,137	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 6531 - Fibre Optic Network - Customer Term Equipment

Placement Band - 2016 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 6531 - Fibre Optic Network - Customer Term Equipment

Placement Band - 2016 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

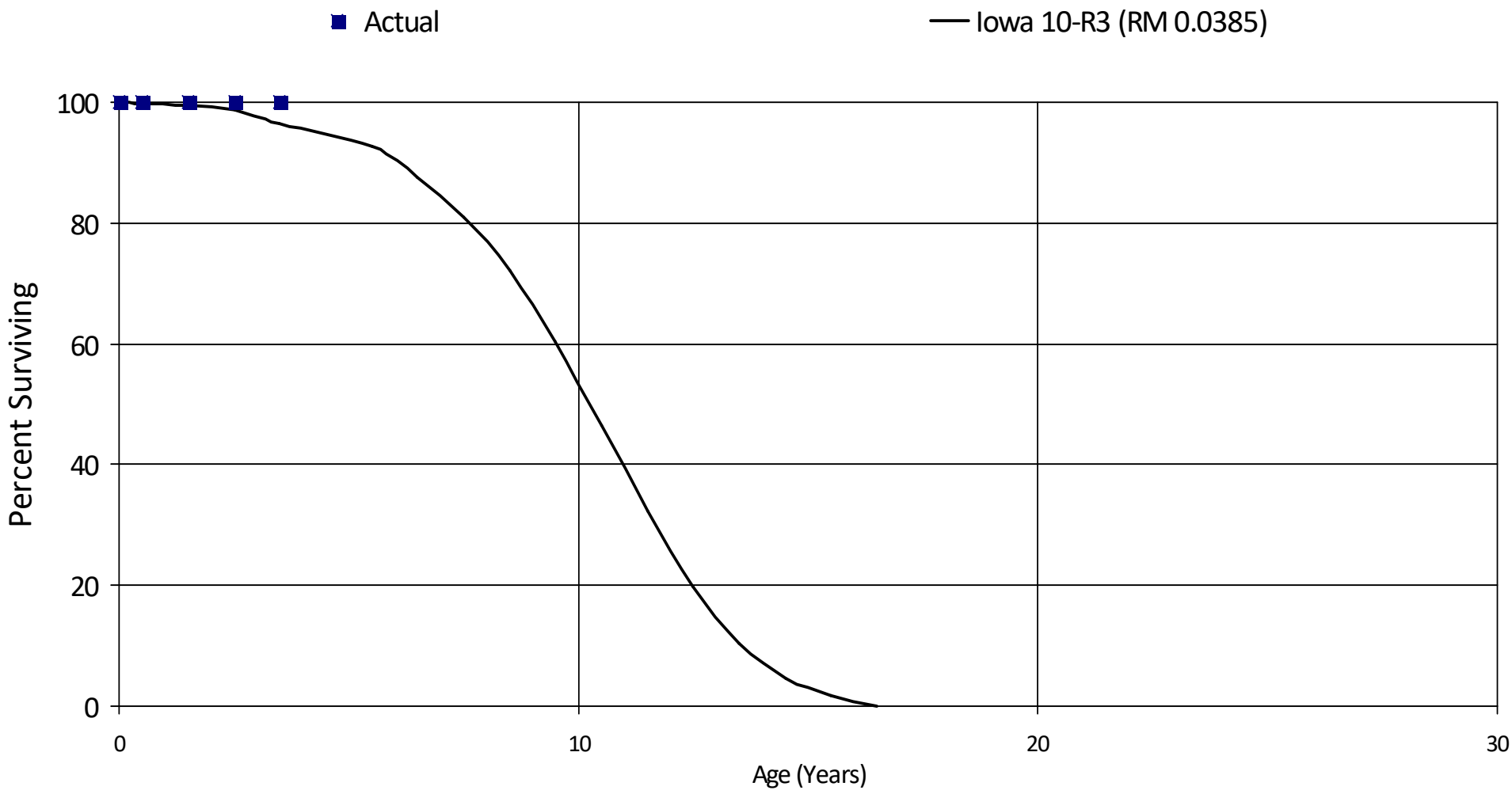
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	12,465,517	0	0.00000	1.00000	100.00
0.5	12,465,517	0	0.00000	1.00000	100.00
1.5	12,465,517	0	0.00000	1.00000	100.00
2.5	12,465,517	0	0.00000	1.00000	100.00
3.5	12,465,517	0	0.00000	1.00000	100.00
4.5	11,594,462	0	0.00000	1.00000	100.00
5.5	4,942,012	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 6533 - Fibre Optic Network - SubstationTerm Equipment

Placement Band - 2018 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 6533 - Fibre Optic Network - SubstationTerm Equipment

Placement Band - 2018 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

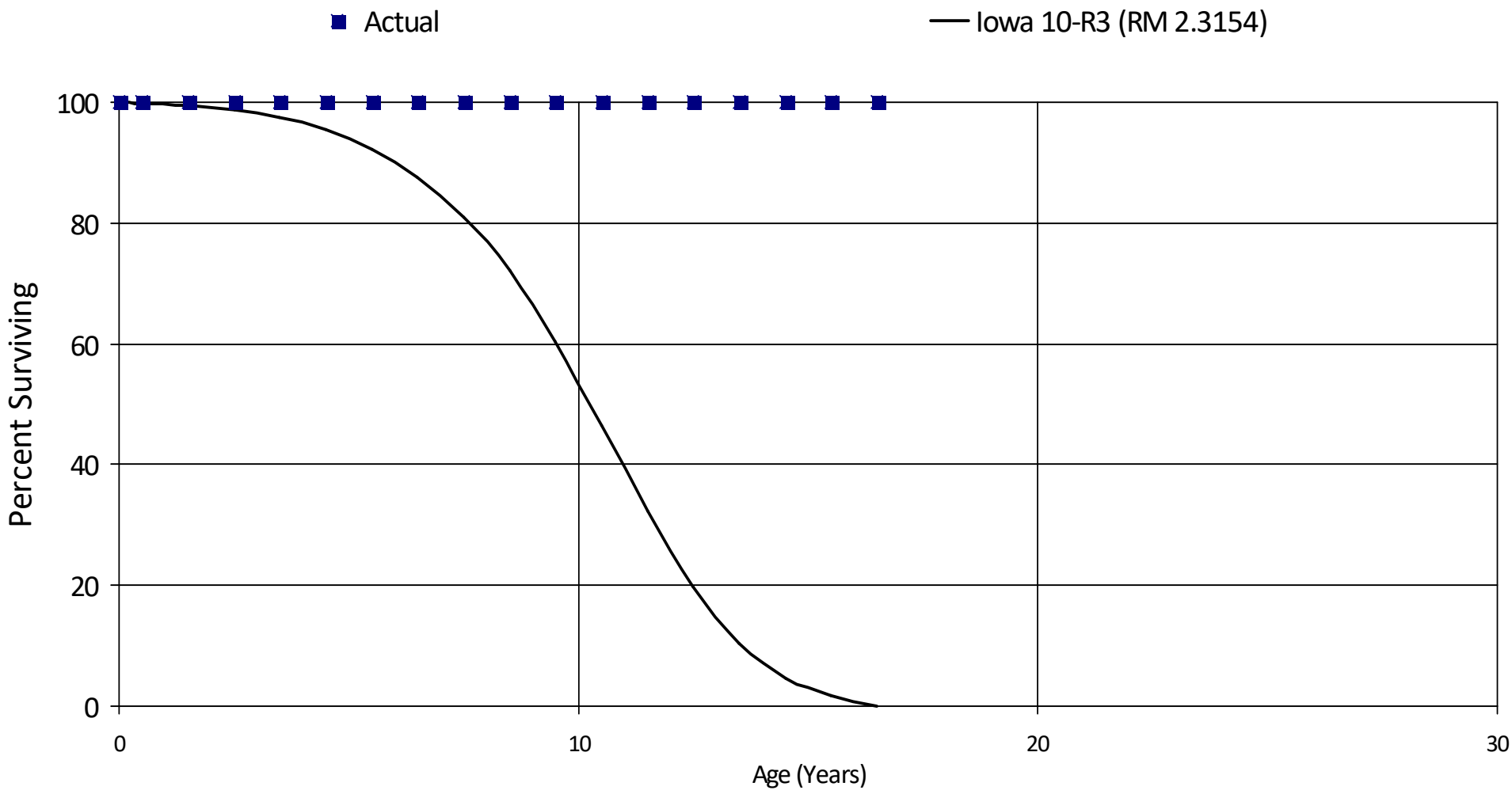
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	107,517	0	0.00000	1.00000	100.00
0.5	107,517	0	0.00000	1.00000	100.00
1.5	107,517	0	0.00000	1.00000	100.00
2.5	55,388	0	0.00000	1.00000	100.00
3.5	55,388	0	0.00000	1.00000	100.00
	Totals:	0			

Toronto Hydro

Account 7111 - Load Management Controls - Customer Location

Placement Band - 2005 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Toronto Hydro

Account 7111 - Load Management Controls - Customer Location

Placement Band - 2005 - 2022 Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	3,022,834	0	0.00000	1.00000	100.00
0.5	3,022,834	0	0.00000	1.00000	100.00
1.5	3,022,834	0	0.00000	1.00000	100.00
2.5	3,022,834	0	0.00000	1.00000	100.00
3.5	3,022,834	0	0.00000	1.00000	100.00
4.5	3,022,834	0	0.00000	1.00000	100.00
5.5	3,022,834	0	0.00000	1.00000	100.00
6.5	3,022,834	0	0.00000	1.00000	100.00
7.5	3,022,834	0	0.00000	1.00000	100.00
8.5	3,022,834	0	0.00000	1.00000	100.00
9.5	3,022,834	0	0.00000	1.00000	100.00
10.5	3,022,834	0	0.00000	1.00000	100.00
11.5	3,022,834	0	0.00000	1.00000	100.00
12.5	3,022,834	0	0.00000	1.00000	100.00
13.5	3,022,834	0	0.00000	1.00000	100.00
14.5	3,022,834	0	0.00000	1.00000	100.00
15.5	2,013,119	0	0.00000	1.00000	100.00
16.5	87,491	0	0.00000	1.00000	100.00
	Totals:	0			

SECTION 6

6 ESTIMATION OF SURVIVOR CURVES

6.1 Average Service Life

All assets have a service life, which is defined as "the period of time from its installation until it is retired from service"[3]. All account groups of property are made up of various assets with differing service lives and investment values. To calculate a depreciation rate, one must first calculate an average life for all assets in a single account. This can be done by ascertaining the age at retirement for every asset in an account and plotting it as a percentage of the units surviving at each age interval (a "Survivor Curve"). From the average life for each account, remaining lives can then be found which are then used to calculate the annual depreciation accruals and ultimately depreciation rate. A discussion of the general concept of survivor curves is presented and the Iowa type survivor curves are reviewed.

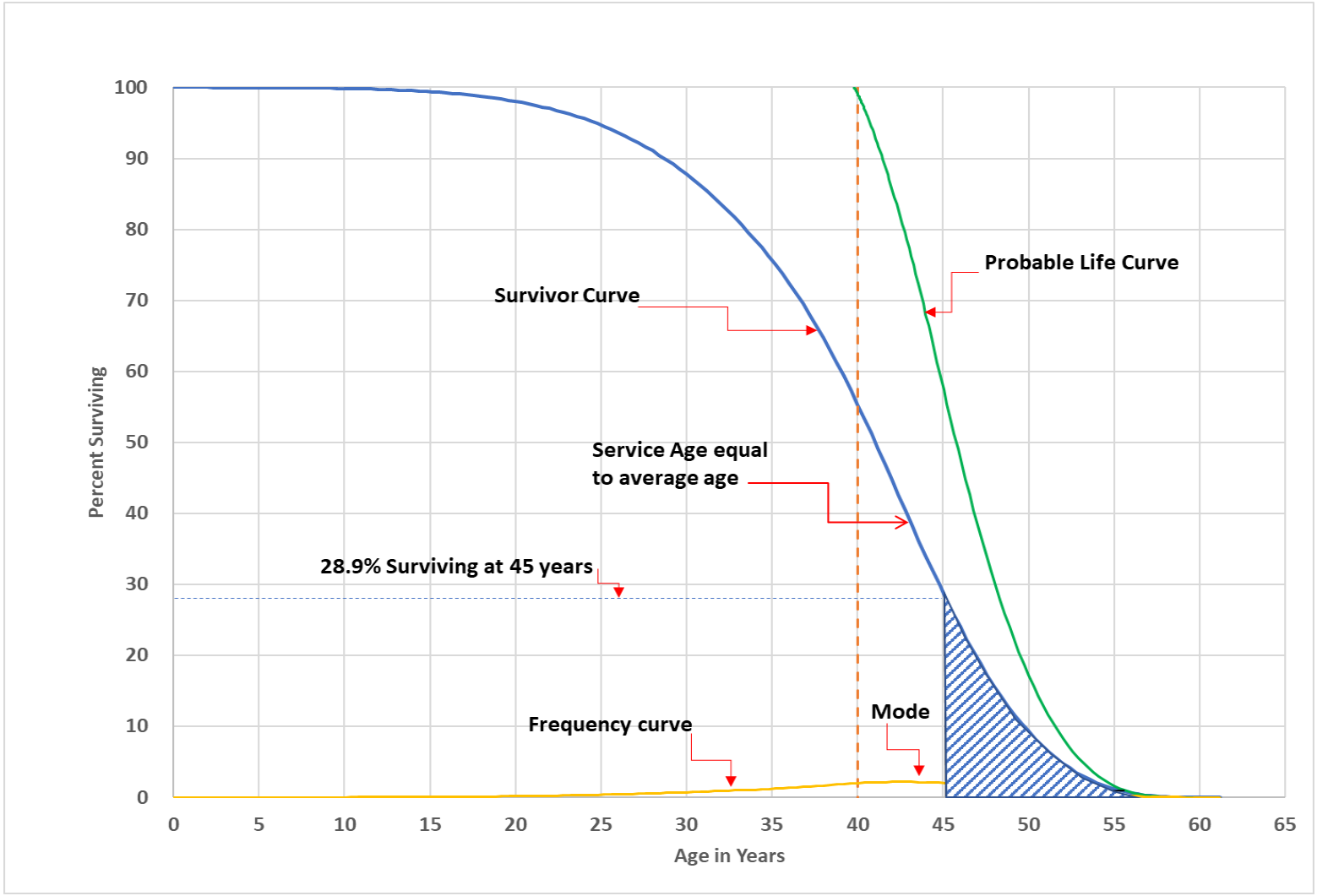
6.2 Survivor Curves

A survivor curve is defined as "a graph of the percent of units remaining in service expressed as a function of age".[4] To calculate the average life of the group, the remaining life expectancy, the probable life and the frequency curve, one must first create a survivor curve. Figure 1 shows a typical 40-R4 smoothed survivor curve as well as the accompanying derived curves. The type 40-R4 refers to the Iowa type curve, whose designation will be explained in further detail in the next section

To calculate the average service life, one must calculate the area under the survivor curve and divide by the percent surviving at age zero. The remaining life is equal to the area under the survivor curve and to the right of the current age, divided by the percent surviving at the current age. In Figure 1, for example, the hatched area to the right of age 45 divided by 28.9 percent surviving balance represents the remaining life for an asset that has reached that age. The probable life is "the total life expectancy of the property surviving at any age and is equal to the remaining life plus the current age."[5] If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve is calculated by taking the difference between the percent surviving on successive years on the survivor curve[6]. Alternatively, frequency can be empirically determined by finding the amount of retirements at any given age. Plotting retirement frequency from the youngest to oldest ages and then taking the cumulative frequencies will generate percent surviving versus age.

[3] Wolf, Frank K. and W. Chester Fitch, Depreciation Systems (Iowa State University Press, 1994), 21.
[4] *Ibid*, 23.
[5] *Ibid*, 29.
[6] *Ibid*, 23-24.

FIGURE 1: TYPICAL SURVIVOR CURVE (40-R4) AND DERIVED CURVES



6.3 Iowa Type Curves

In 19The 1, Robley Winfrey and Edwin Kurtz of the Engineering Research Institute at Iowa State University published Bulletin 103, which laid the groundwork for what would eventually be known as the Iowa Curves. "The 13 type curves can be used as valuable aids in forecasting the probable future service lives of individual items and of groups of items of different kinds of physical equipment".[7] The 13 curves described in Bulletin 103 eventually became a series of 22 generalized survivor curves which are used throughout the regulated utility industry. These 22 curves were described in Bulletin 125, published in 1967 by Harold A. Cowles, which became known as the Iowa curves.

The Iowa curves are organized with three variables: the average life of the plant; the location of the mode; and the variation of the life. All Iowa curves have both a letter and a number to represent the shape and height of the mode. The L curves, or left-moded curves, are used when the mode of the curve should be to the left of the average life. There are six L curves are presented in Figure 2. The R curves, or right-moded, are used when the mode of the curve should be to the right of the average life. There are five R curves, which are presented in Figure 3. The S curves, or symmetrically-moded, are used when the mode is equal to the average life. There are seven S curves, which are presented in Figure 4. The O curves, or origin curves, are used when the mode occurs at age 0. There are four O curves, which are presented in Figure 5. There are some occasions where it is appropriate to use a half curve. In these cases, the curve is assumed to be exactly half way between the two curves.

In addition to Bulletin 125, Iowa curves have also been presented in subsequent Experiment Station bulletins and in the text Engineering Valuation and Depreciation[8]. In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[9] presenting his development of the fourth family consisting of the four O-type survivor curves.

[7] *Ibid*, 21

[8] Marston, Anson, Robley Winfrey and Jean C. Hempstead, Engineering Valuation and Depreciation (The Iowa State University Press, 1953)

[9] Couch, Frank V. B., Jr., Classification of Type O Retirement Characteristics of Industrial Property Unpublished M.S. Thesis (Engineering Valuation, Library, Iowa State College, Ames, Iowa, 1957)

FIGURE 2: LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

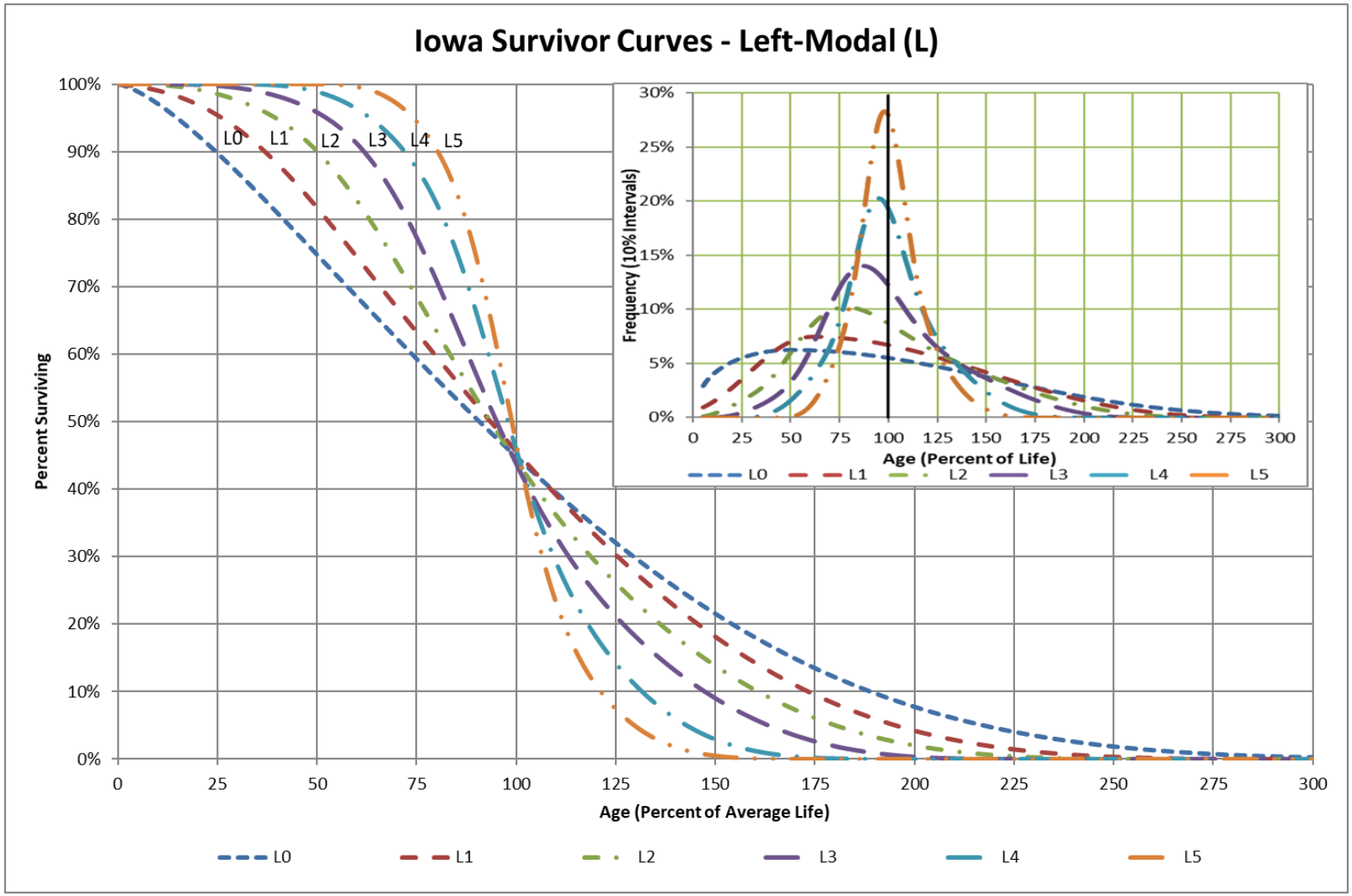


FIGURE 3: RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

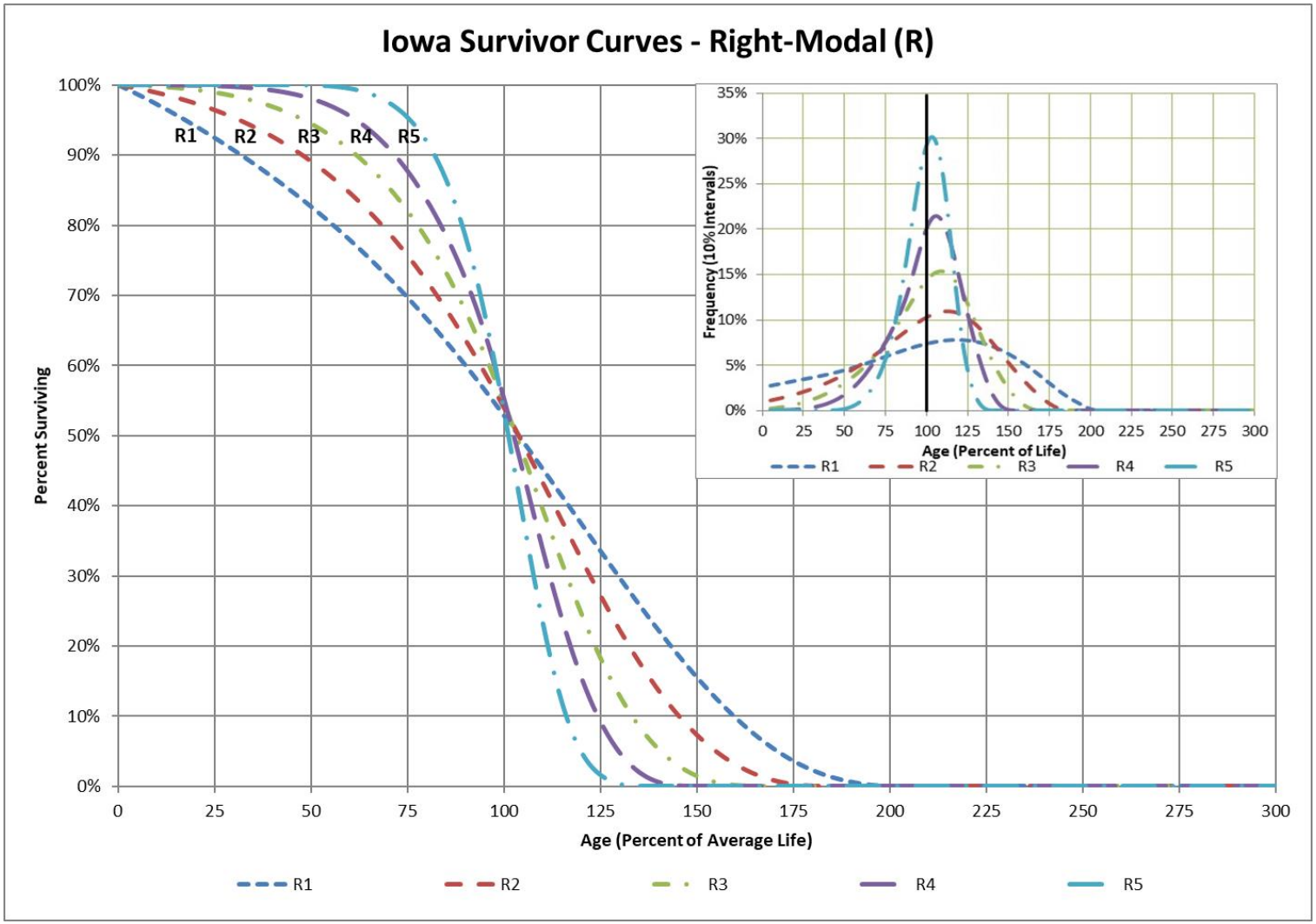


FIGURE 4: SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

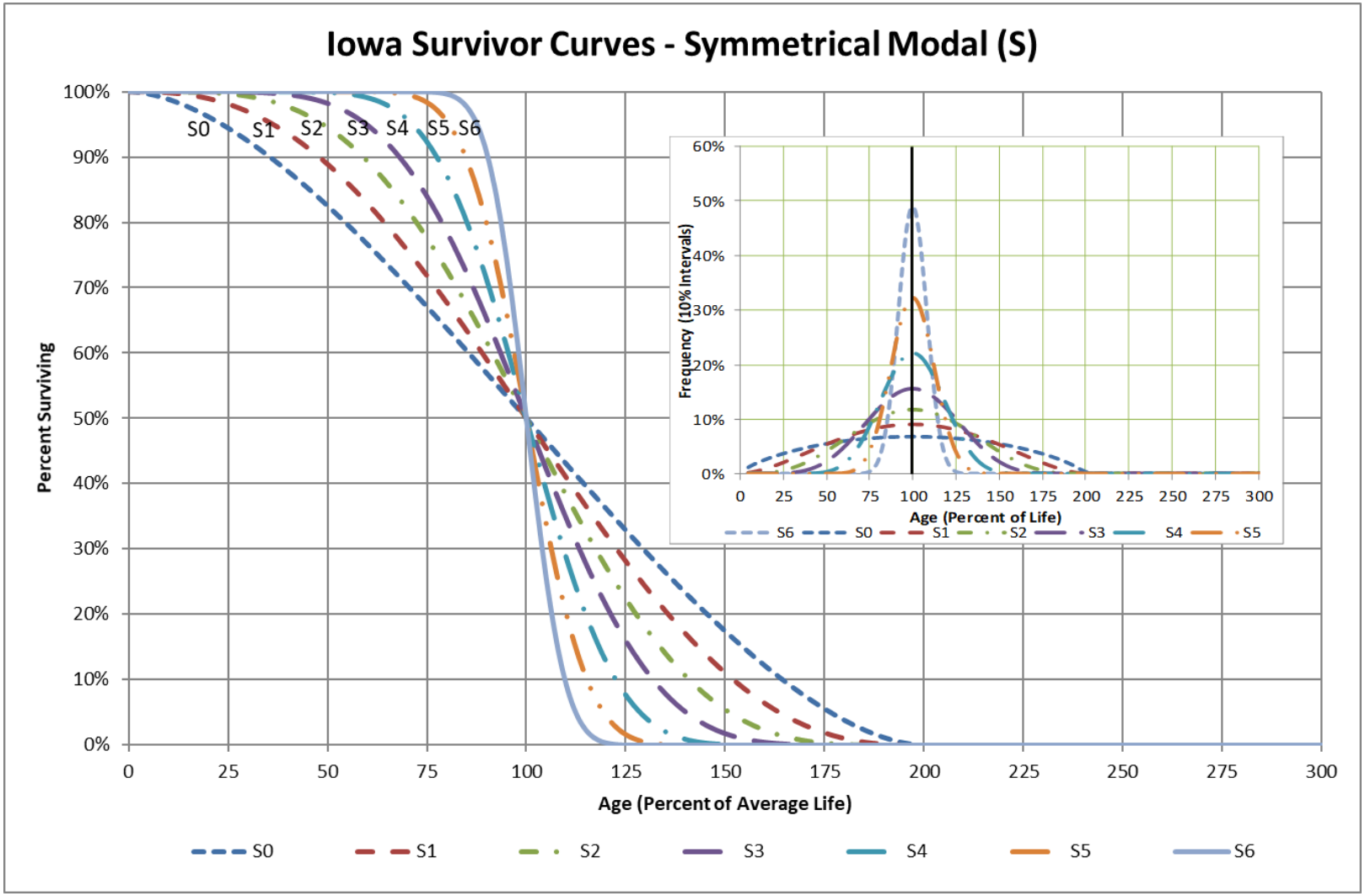
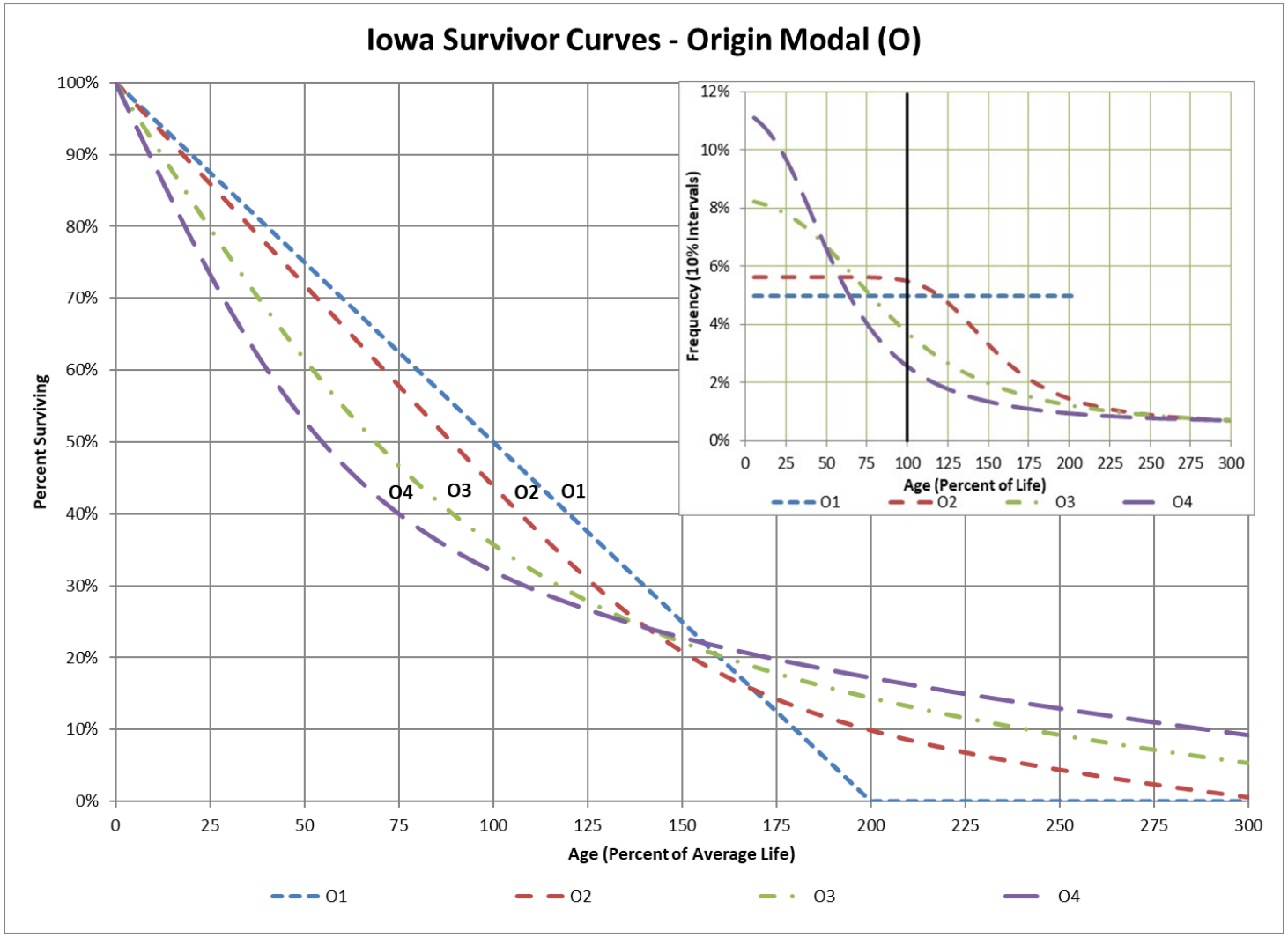


FIGURE 5: ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES



6.4 Retirement Rate Method of Analysis

The retirement rate method is a widely accepted actuarial method used to create survivor curves[10]. This method is also referred to as an original life table. These survivor curves can then be used to determine the average service life of a plant account. The retirement rate method is thoroughly explained in several publications, including Statistical Analyses of Industrial Property Retirements,[11] Engineering Valuation and Depreciation[12] and Depreciation Systems[13].

The retirement rate method is a subgroup of the placement and the experience band methods, as described in "Depreciation Systems". The placement band method creates a survivor curve which describes the life characteristics of assets placed into service during a selected timeframe. The experience band method creates a survivor curve which describes the life characteristics of assets removed from service during a selected time frame. The retirement rate method creates both placement and experience bands to give the most complete or representative data. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

6.5 Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2008-2017 during which there were placements during the years 2003-2017. In order to illustrate the summation of the aged data by age interval, the data was compiled in the manner presented in Schedules 1 and 2. In Schedule 1 (page 9-10), the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the asset invested in 2003 were retired in 2008. The $10,000 retirement occurred during the age interval between 4 ½ and 5 ½ years (2008 - 2003) on the basis that approximately one-half of the amount of property was installed prior to and after July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2008

[10] The Alberta Utilities Commission in particular has approved the use of the retirement rate method for many decades.
[11] Anson, Winfrey & Hempstead, supra note 7
[12] Anson, Winfrey & Hempstead, supra note 7
[13] Wolf & Fitch, supra note 2

retirements of 2003 installations and ending with the 2017 retirements of the 2012 installations. Thus, the total amount of $143,000 for age interval 4½-5½ equals the sum of:

$10 + $12 + $13 + $11 + $13 + $13 + $15 + $17 + $19 + $20= $143 k

Other transactions which affect the group are recorded in a similar manner in Schedule 2 (page 9-11). The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements but are used in developing the exposures at the beginning of each age interval.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017 Placement Band 2003-2017

Retirements (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total Durring Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2003	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2004	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2005	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2006	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2007	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2008	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2009		5	11	12	13	14	15	16	18	20	113	7½-8½
2010			6	12	13	15	16	17	19	19	124	6½-7½
2011				6	13	15	16	17	19	19	131	5½-6½
2012					7	14	16	17	19	20	143	4½-5½
2013						8	18	20	22	23	146	3½-4½
2014							9	20	22	25	150	2½-3½
2015								11	23	25	151	1½-2½
2016									11	24	153	½-1½
2017										13	80	0-½
Total	**53**	**68**	**86**	**106**	**128**	**157**	**196**	**231**	**273**	**308**	**1,606**	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017 Placement Band 2003-2017

Acquisitions, Transfers and Sales (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2004	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2005	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2006	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2007	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2008	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2009		-	-	-	-	-	-	-	-	-	-	7½-8½
2010			-	-	-	-	-	-	-	-	-	6½-7½
2011				-	-	-	-	(12)[b]	-	-	-	5½-6½
2012					-	-	-	-	22[a]	-	-	4½-5½
2013						-	-	(19)[b]	-	-	10	3½-4½
2014							-	-	-	-	-	2½-3½
2015								-	-	(102)[c]	(121)	1½-2½
2016									-	-	-	½-1½
2017												0-½
Total	**-**	**-**	**-**	**-**	**-**	**-**	**60**	**(30)**	**22**	**(102)**	**(50)**	

[a] *Transfer Affecting Exposures at Beginning of Year*
[b] *Transfer Affecting Exposures at End of Year*
[c] *Sale with Continued Use*
Parentheses denote Credit amount.

6.6 Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 (page 9-13). The surviving plant at the beginning of each year from 2007 through 2016 is recorded by year in the portion of the table titled "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2013 are calculated in the following manner:

Exposures at age 0	=	amount of addition	=	$750,000
Exposures at age ½	=	$750,000 - $ 8,000	=	$742,000
Exposures at age 1½	=	$742,000 - $18,000	=	$724,000
Exposures at age 2½	=	$724,000 - $20,000 - $19,000	=	$685,000
Exposures at age 3½	=	$685,000 - $22,000	=	$663,000

For the entire experience band 2008-2018, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

$255 + $268 + $ 284 + $311 + $334 + $374 + $405 + $448 + $501 $ $609 = $3,789k

SCHEDULE 3 – PLANT EXPOSED TO RETIREMENT AT THE BEGINNING OF EACH YEAR, 2008 -2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008 - 2017 Placement Band 2003-2017

Exposures (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
2003	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2004	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2005	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2006	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2007	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2008	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2009		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2010			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2011				580[a]	574	561	546	530	501	482	3,057	5½-6½
2012					660[a]	653	639	623	628	609	3,789	4½-5½
2013						750[a]	742	724	685	663	4,332	3½-4½
2014							850[a]	841	821	799	4,955	2½-3½
2015								960[a]	949	923	5,719	1½-2½
2016									1,080[a]	1,069	6,579	½-1½
2017										1,220[a]	7,490	0-½
Total	**1,975**	**2,382**	**2,724**	**3,318**	**3,872**	**4,494**	**5,247**	**5,987**	**6,852**	**7,796**	**44,780**	

[a] *Additions during the year.*

	1555	1922	2214	2738	3212	3744	4397	5027	5772	6576	44780
	420	460	510	580	660	750	850	960	1080	1220	0
	1975	2382	2724	3318	3872	4494	5247	5987	6852	7796	44780

6.7 Original Life Tables

The original life table, illustrated in Schedule 4 (page 9-15) is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100 percent at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15		
Exposures at age 4½	=	$3,789,000		
Retirements from age 4½ to 5½	=	$143,000		
Retirement Ratio	=	$143,000 ÷ $3,789,000	=	0.0377
Survivor Ratio	=	1.000 - 0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

SCHEDULE 4: ORIGINAL LIFE TABLE - CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2008-2017					Placement Band 2003-2017
Age at Beginning of Interval	**Exposures at Beginning of Age Interval**	**Retirements During Age Interval**	**Retirement Ratio**	**Survivor Ratio**	**% Surviving at Beginning of Age Interval**
0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.6
12.5	323	44	0.1362	0.8638	48.9
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	**44,780**	**1,606**			

- Exposure and Retirement Amounts are in Thousands of Dollars
- Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
- Column 3 from Schedule 1, Column 12, Retirements for Each Year.
- Column 4 = Column 3 divided by Column 2.
- Column 5 = 1.0000 minus Column 4.
- Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

6.8 Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100 percent to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percentages surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

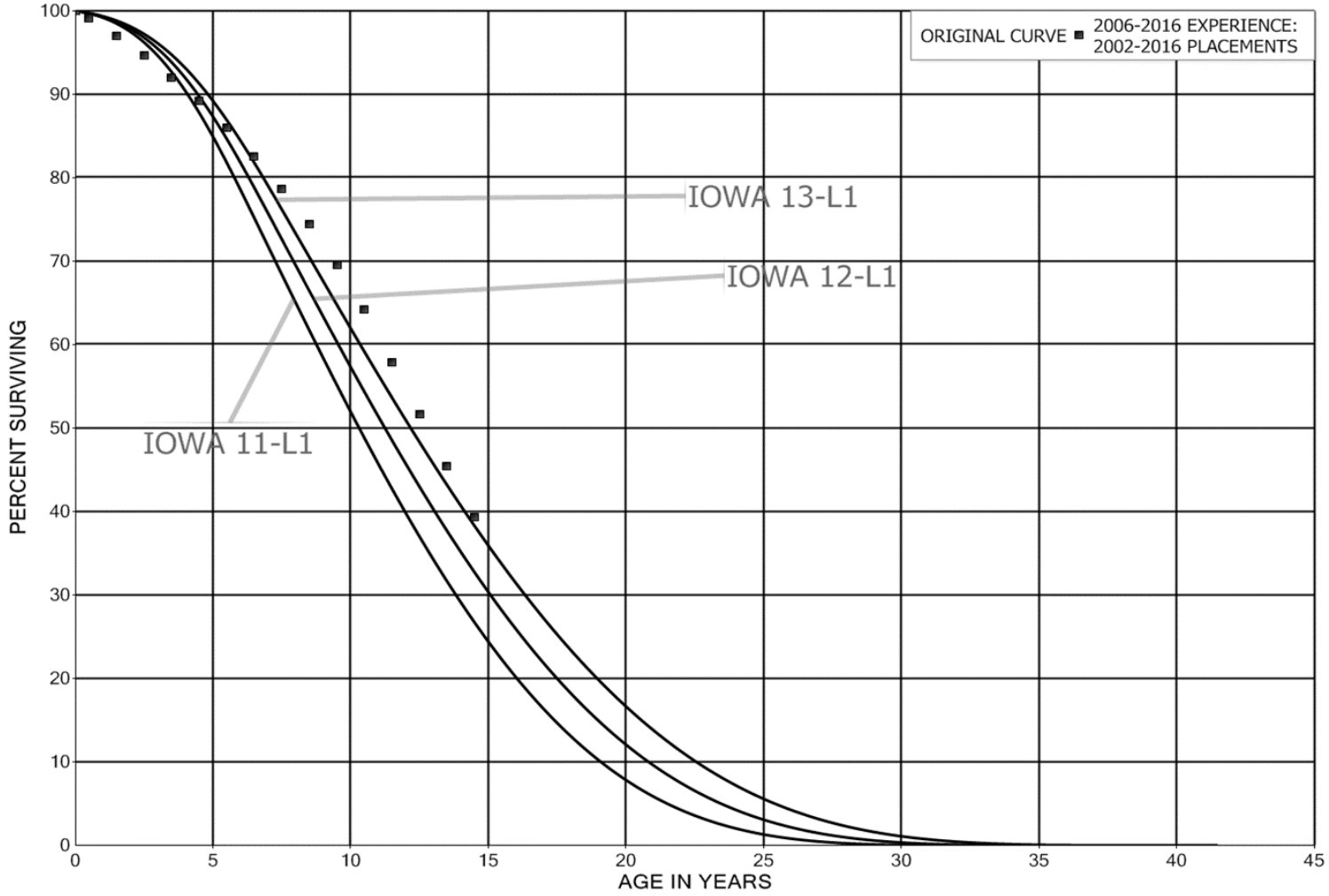


FIGURE 7: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A SO IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

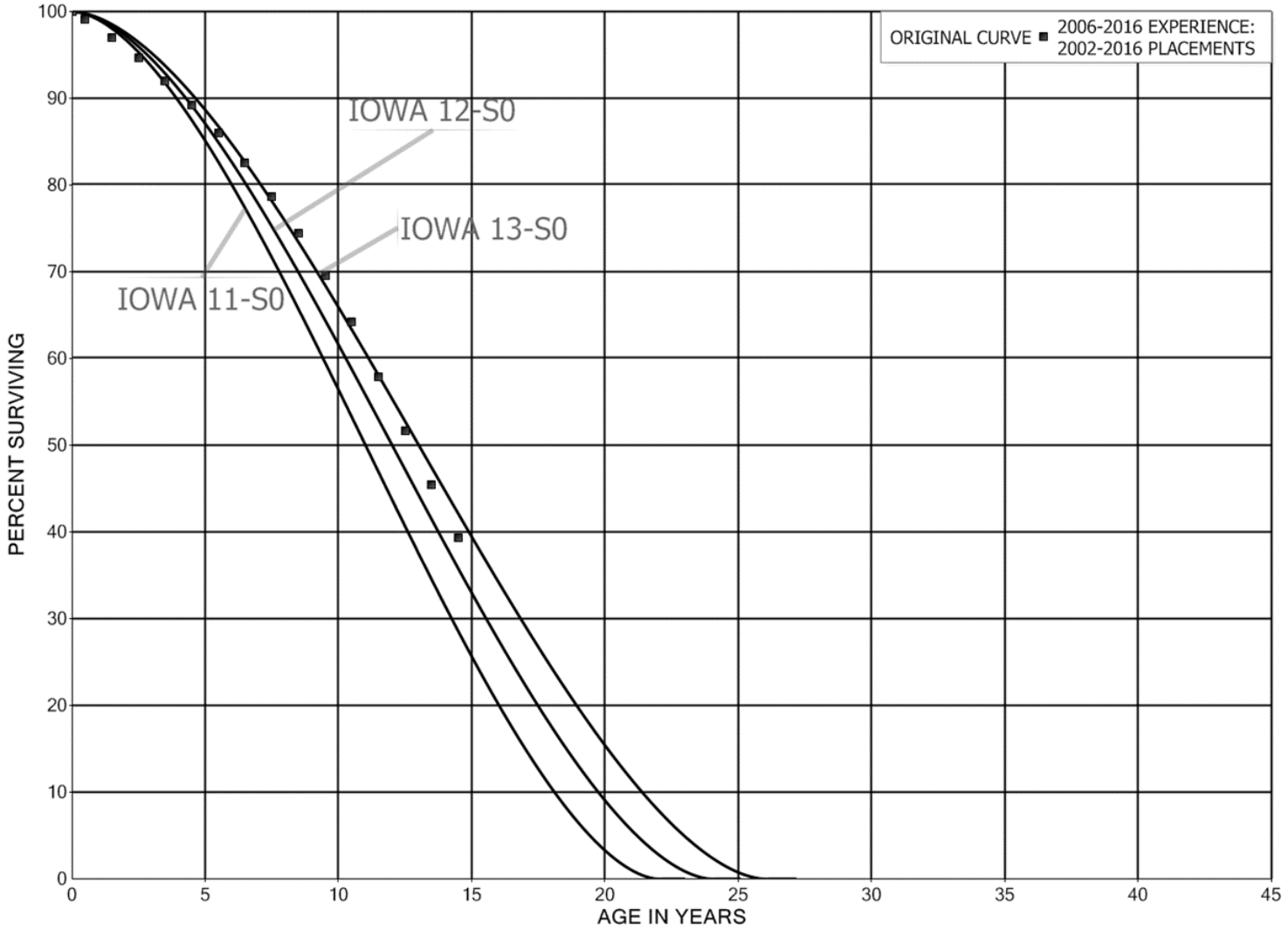


FIGURE 8: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A R1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

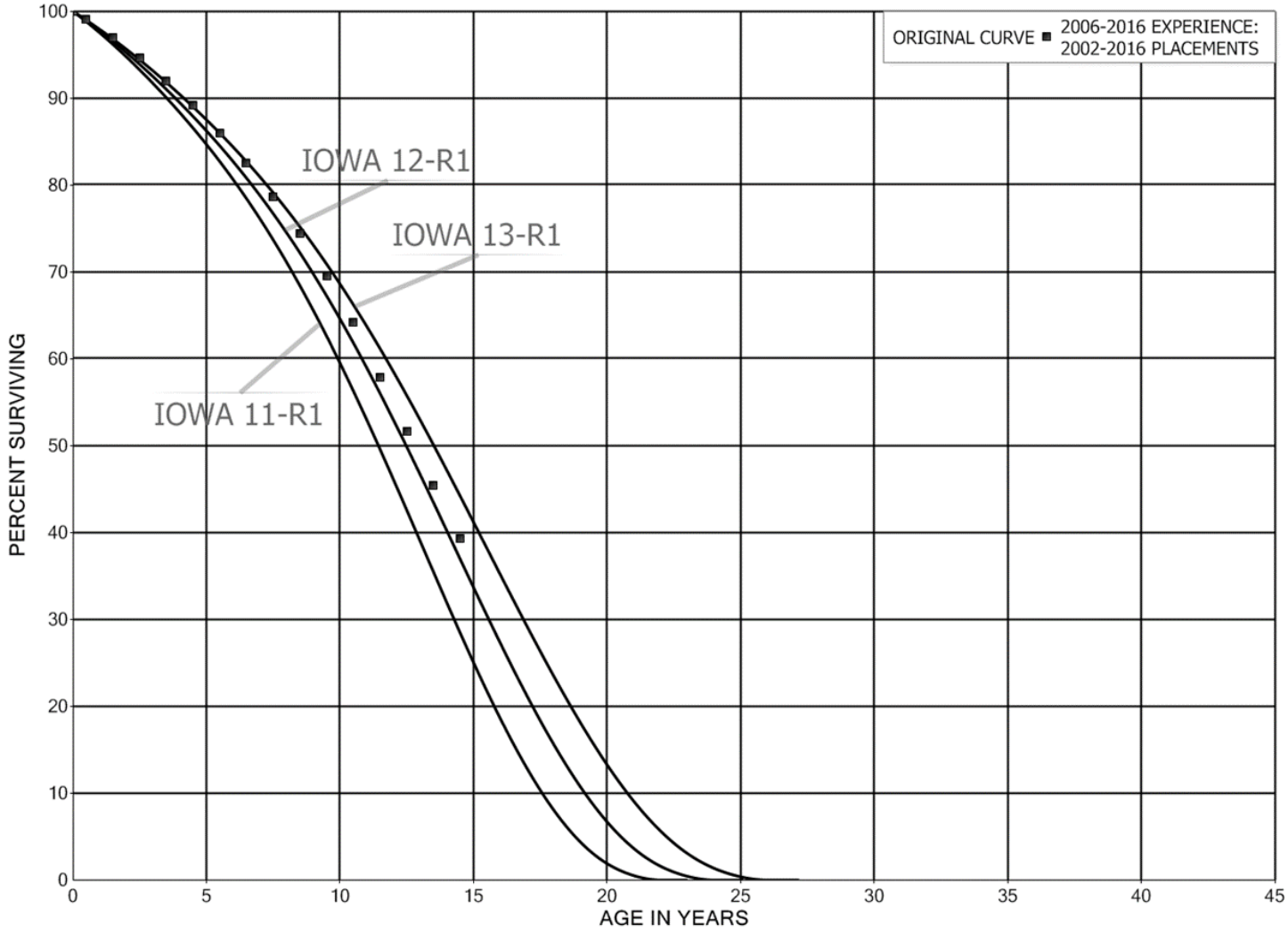
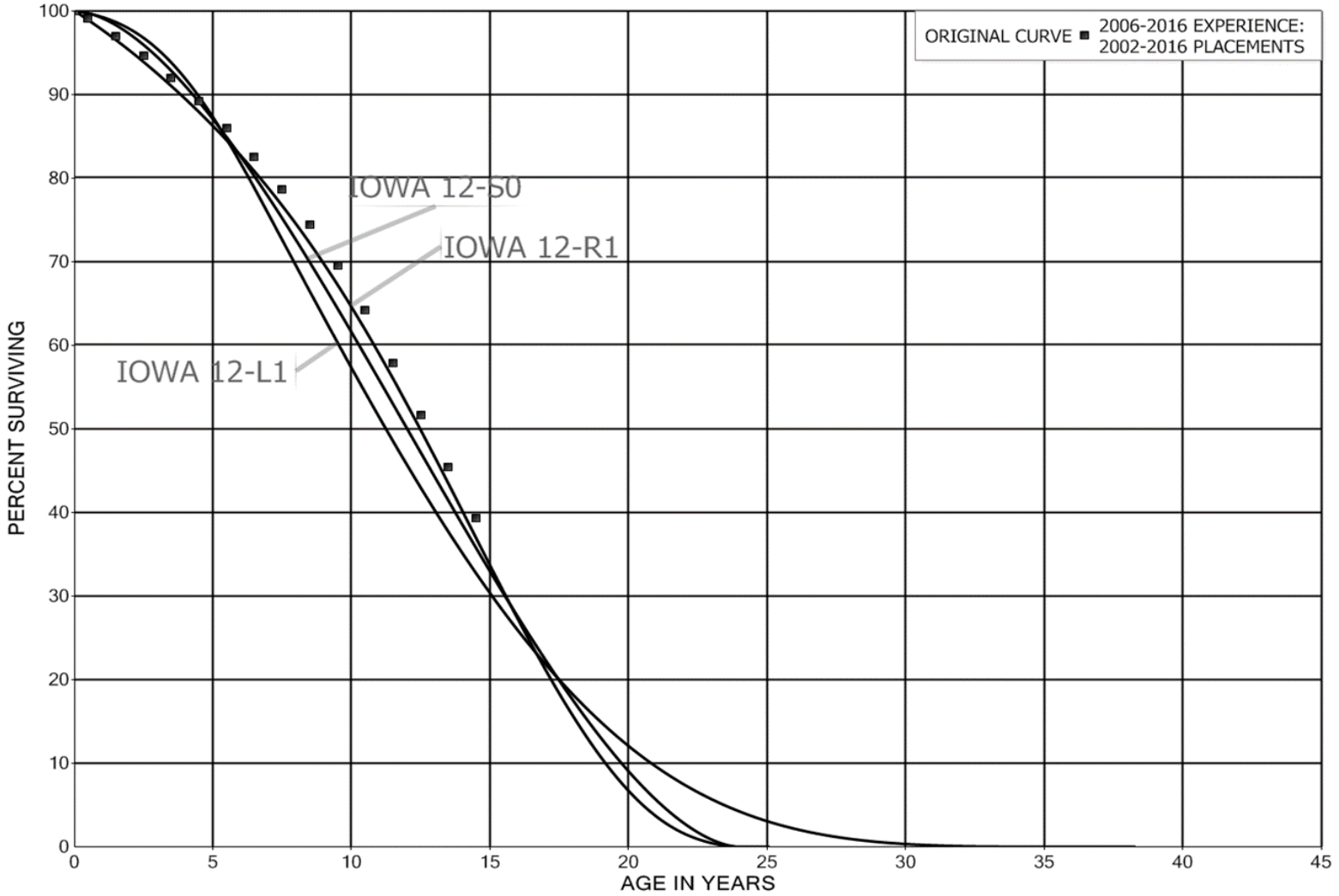


FIGURE 9: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES



DERECOGNITION OF ASSETS

Article 410 of the OEB Accounting Procedures Handbook for Electricity Distributors requires property, plant and equipment ("PP&E") and intangible assets to be derecognized upon disposal, or when their use is no longer expected to offer future economic benefits. The gain or loss arising from the derecognition of PP&E and intangible assets is calculated as the difference between the net disposal proceeds (if any) and the carrying amount of the item, and is included in the utility's profit or loss during the period in which the item is derecognized.

Table 1 below summarizes 2020-2022 actual and 2023-2024 forecasted derecognition. Table 2 summarizes the forecasted derecognition for the 2025-2029 period. The forecast is informed by the utility's capital expenditure proposals outlined in the Distribution System Plan (Exhibit 2B, Section E4), and calculated on the basis of the net book values associated with assets that the utility expects to remove from service as part of its planned capital program. The methodology to forecast derecognition is consistent with the last rebasing application.[1]

Table 1: 2020-2024 Derecognition ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge
Derecognition	23.2	24.0	25.0	28.0	33.5

Table 2: 2025-2029 Derecognition ($ Millions)

	2025	2026	2027	2028	2029
Derecognition	37.5	38.7	40.8	41.9	42.6

/C

[1] EB-2018-0165 at Exhibit 4B, Tab 1, Schedule 2; and 9-Staff-156 at page 3.

WORKING CAPITAL ALLOWANCE ("WCA")

Toronto Hydro determined the Working Capital Allowance ("WCA") included in the calculation of the 2025 to 2029 rate base, based on a Lead-Lag Study performed by Guidehouse Inc. ("Guidehouse"), which is filed at Exhibit 2A, Tab 3, Schedule 2.

Guidehouse used 12 months of Toronto Hydro's financial information to determine the revenue lag and expense leads for various detailed revenue and cost components. Guidehouse's methodology is consistent with the last three Lead-Lag studies performed for Toronto Hydro with one key exceptions. Because the collections data for the three most recent historical years (i.e. 2020-2022) was skewed by the effects of the COVID-19 pandemic, Guidehouse applied the collection lag days it used in the previous study as a proxy for normal business conditions.[1]

Toronto Hydro intends to ask Guidehouse to re-run the Lead-Lag study based on 2023 actuals, including collections data, to asses the impacts to the WCA and rate base. If the utility determines, based on the results of the updated Study, that there are material variances to the WCA and rate base, this information (including an updated Lead-Lag study) would be filed with interrogatory responses or technical conference undertakings depending on the timing of these procedural steps.

The Cost of Power is one of the components in the WCA calculations and determined based on the following data inputs: RPP prices, the Hourly Ontario Energy Price ("HOEP"),[2] the Transmission rates,[3] Smart Metering Entity charge[4] and Regulatory charges.[5] The Cost

[1] Please refer to Schedule 5 of DRO Update for EB-2018-0165 application submitted on January 21, 2020
[2] Regulated Price Plan report issued by the OEB (October 21, 2022).
[3] OEB Decision and Rate Order, EB-2023-0101, 2023 Uniform Transmission Rates Update (June 1, 2023) and

of Power calculation also includes the impact of the latest Ontario Electricity Rebate,[6] available at the time of the quantification. Details of the 2025-2029 Cost of Power, serving as the input to the Revenue Requirement workform to calculate WCA and rate base, are provided in Appendix A. Table 1 below presents a summary calculation of the WCA.

Table 1: WCA Summary Calculation

	2025 Expenses ($ Millions)	Working Capital Factor		Expenses times Working Capital Factor ($ Millions)
Cost of Power	2,871.1	5.60%		160.7
OM&A	343.0	4.47%		15.3
Interest on Long Term Debt	131.9	11.15%		14.7
Income and Capital Taxes	27.9	12.40%		3.5
Sub-Total Working Capital Requirement				**194.2**
HST at 13%		**Net Lag Days**	**Expenses * Net Lag Days/365 * 13% HST**	
Revenue	3,891.0	-7.45	-10.3	
Cost of Power	2,871.1	44.38	45.4	
Eligible OM&A Expenses	142.6	43.06	2.2	
HST Working Capital Requirement				**37.2**
Total Working Capital				**231.5**
Working Capital as % of Cost of Power and Controllable Expenses				**7.20%**

Hydro One Networks Inc., EB-2021-0110 (November 29, 2022)
[4] OEB Decision and Order, Smart Meter Charge, EB-2022-0137, (September 8, 2022).
[5] OEB Decision and Order, In the matter of regulatory charges for the Wholesale Market Services rate and the Rural or Remote Electricity Rate Protection charge, EB-2022-0269 (December 8, 2022)
[6] Amendments as of November 1, 2022 to Ontario Regulation 363/16 under the Ontario Rebate for Electricity Consumers Act, 2016

Table 2 below presents 2020 approved, 2020-2022 actuals and 2023-24 bridge WCA.

Table 2: 2020-2024 Working Capital Allowance ($ Millions)

	OEB Approved	Actuals			Bridge	
	2020	2020	2021	2022	2023	2024
Working Capital Allowance	216.2	249.8	217.2	220.7	221.1	230.3

Variances in the working capital allowance show in Table 2 above are primarily driven by changes in commodity expenses.

Table 3 below present the 2025 to 2029 forecasted WCA based on the updated Lead-Lag study at Exhibit 2A, Tab 3, Schedule 2.

Table 3: 2025-2029 Working Capital Allowance ($ Millions)

	Forecast				
	2025	2026	2027	2028	2029
Working Capital Allowance	231.5	237.1	242.5	250.8	255.6

Working Capital Requirements of Toronto Hydro-Electric System Limited

2025-2029

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Executive Summary

Guidehouse was retained by Toronto Hydro-Electric System Limited ("THESL") to calculate the working capital requirements of THESL using a lead-lag study.

Working capital is the amount of funds that are required to finance the day-to-day operations, and which are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for the determination of working capital and was used by Guidehouse for this purpose. The results of this study are provided in this report.

The lead/lag days calculated in this study are based on THESL's revenue and expense data from 2022. The working capital requirement of THESL's distribution business is shown below.

Table 1: THESL Summary of Working Capital Requirement

	Test Year 2022
Percentage of OM&A and Cost of Power	7.02%
Working Capital Requirement ($M)	$197.87

The working capital requirements shown in Table 1 above are based upon the revenue lag and expense lead days shown in Table 2.

Table 2: THESL Working Capital Requirements (Test Year 2022)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days
Cost of Power	53.15	32.72	20.43
OM&A Expenses	53.15	36.84	16.31
PILS	53.15	7.88	45.27
Interest Expense	53.15	12.45	40.70

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1. Introduction and Methodology

Guidehouse Inc. was retained by Toronto Hydro-Electric System Limited ("THESL") to calculate its working capital requirements. This report provides the results of the assessment and the resulting working capital requirements.

Working capital is the amount of funds that are required to finance the day-to-day operations, and which are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for the determination of working capital and was used by Guidehouse for this purpose.

A lead-lag study analyzes the time between the date customers receive service and the date that customers' payments are available to THESL (or "lag") together with the time between the date THESL receives goods and services from its vendors and the date that THESL pays for them (or "lead").

"Leads" and "Lags" are both measured in days and are dollar-weighted where appropriate. The dollar-weighted net lag (lag minus lead) days is then divided by 365 (or 366 for leap years) and then multiplied by the annual test year expenses to determine the amount of working capital required. The resulting amount of working capital is then included in THESL's rate base for the purpose of determining revenue requirement.

THESL provided revenue and expense data to support the lead-lag study for both the 2021 and the 2022 calendar years. Generally, Guidehouse utilized the revenue and expense data for the 2022 calendar year, as it was the most recent source of data provided.

1.1 Key Concepts

The following section outlines the key concepts used throughout this report to assess the working capital requirements of THESL's business. This includes the mid-point method, statutory approach, revenue lag components, expense lead components and dollar weighting.

1.1.1 Mid-Point Method

When a service is provided to (or by) THESL over a period of time, the service is deemed to have been provided (or received) evenly over the period, unless specific information regarding the provision (or receipt) of that service indicates otherwise. If both the service end date ("Y") and the service start date ("X") are known, the mid-point of a service period can be calculated using Equation 1-1.

Equation 1-1

$$Mid - Point = \frac{(Y - X) + 1}{2}$$

When specific start and end dates are unknown, but it is known that a service is evenly distributed over the mid-point of a period, an alternative formula that is generally used is shown below. Equation 1-2 uses the number of days in a year ("A") and the number of periods in a year ("B"):

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Equation 1-2

$$Mid - Point = \frac{A/B}{2}$$

1.1.2 Statutory Approach

In conjunction with the mid-point method, it is important to note that not all areas of this study may utilize dates on which actual payments were made to (or by) THESL. In some instances, the due dates for payments are established by statute or by regulation. In these instances, the due date established by statute has been used in lieu of when payments were made.

1.1.3 Revenue Lag Components

As used in this study, revenue lags are comprised of Retail Revenue, IESO Credits and Other Revenues. The lag associated with Retail Revenue consist of four components:

- Service Lag component (the average time from the provision of electricity to a customer until the meter is read);
- Billing Lag component (the average time from when the meter is read to when the bill is generated and provided to customers);
- Collections Lag component (the average time from when a bill is provided to the customer until the customer initiates payment to the utility); and,
- Payment Processing Lag component (the average time from when the customer provides payment to the utility until when the payment is made liquid and available to the utility).

1.1.4 Expense Lead Components

As used in this study, expense leads are defined to consist of two components:

- Service Lead component (services are assumed to be provided to THESL evenly around the mid-point of the service period); and,
- Payment Lead component (the time period from the end of the service period to the time payment was made and when funds have left THESL's possession).

1.1.5 Dollar Weighting

Both leads and lags should be dollar-weighted where appropriate and where data is available to accurately reflect the flow of dollars. For example, suppose that a particular transaction has a lead time of 100 days and has a dollar value of $100. Further, suppose that another transaction has a lead time of 30 days with a dollar value of $1 million. A simple un-weighted average of the two transactions would give us a lead time of 65 days ([100+30]/2). However, when these two transactions are dollar weighted, the resulting lead time would be closer to 30 days which is more representative of how the dollars flow.

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1.2 Methodology

Performing a lead-lag study requires two key undertakings:

1. Developing an understanding of how the regulated distribution business operates in terms of products and services sold to customers/purchased from vendors, and the policies and procedures that govern such transactions; and,
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of THESL's operations, interviews with personnel within THESL's Accounts Receivable, Customer Service, Wholesale Market Operations, Payroll, Treasury, and Tax Departments were conducted. Key questions that were addressed during the course of the interviews included:

1. What is being sold (or purchased)? If a service is being provided to (or by) THESL, over what time period was this service provided;
2. Who are the buyers (or sellers);
3. What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment;
4. Are any changes to the terms for payment expected? Are these terms driven by industry or internally? What is the basis for any such changes;
5. Are there any new rules or regulations governing transactions relating to transmission operations that are expected to materialize over the time frame considered in this report; and,
6. How are payments made (or received)? Payment types have different payment lead times (i.e., internet payments have shorter deposit times than cheque deposit times)

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2. Revenue Lags

This section of the report provides the revenue lag days for THESL. A revenue lag represents the number of days from the date that is service is rendered by THESL until the date payments are received and funds are available to THESL.

THESL receives revenue from the following funding streams:

- **Retail Revenue:** a distribution utility providing service to its customers typically derives its revenues from bills paid for service by its customers;
- **IESO Credits:** THESL also receives revenue in the form of IESO reimbursement credits for Ontario Electricity Support Program ("OESP"), Ontario Electricity Rebate ("OER"), Renewable Energy Standard Offer Program ("RESOP"), Feed-in Tariff ("FIT"), and Micro Feed-in Tariff ("MFIT");
- **Other Revenue:** THESL staff indicated that it receives additional external revenue.

A summary of the revenue lags for THESL's distribution business is shown below.

Table 3: Summary of Retail Revenue Lag (2022)

Description	Amounts ($M)	Lag Time Days	Weighting Factor	Weighted Lag Time Days
Retail Revenue	$3,226.79	52.62	85.00%	44.73
IESO Credits	$432.31	63.32	11.39%	7.21
Other Revenue	$136.91	33.53	3.61%	1.21
Total	**$3,796.01**		**100.00%**	**53.15**

2.1 Retail Revenue Lag

Retail revenue lag consists of the following components:

- Service Lag;
- Billing Lag;
- Collections Lag; and,
- Payment Processing Lag

Service Lag
The service lag is defined as the midpoint of the service period; the halfway point between the beginning of the service period and the end of the service period. The service period end is typically defined as the date the meter is read. All THESL customers are billed monthly The Service Lag is calculated to be 15.21 days.

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Billing Lag
The billing lag is defined as the time period from period end (meter read) to the time that the customer's bill is generated in the customer information system. An analysis of THESL meter billing data indicated that THESL customers have an average billing lag of 11.79 days.

Collections Lag
The collections lag is defined as the time period from when the bill is generated in the customer information system to the time when the customer provides payment to THESL and when that payment is recorded in THESL's billing system. The collections lag is measured by analyzing the receivables aging data provided by THESL. THESL's collection lag was calculated to be 24.32 days, carried forward from the most recent study performed.[1]

Payment Processing Lag
The payment processing lag represents the average time from when the customer provides payment to the utility until when the payment is made liquid and available to the utility. THESL's payment processing lag was calculated to be 1.31 days

2.2 IESO Credits

Table 4 below summarizes the amounts and revenue lag times associated with the components that make up IESO credits revenue.

Table 4: Summary of IESO Credits (2022)

Description	Revenues ($M)	Lag Days	Weighting	Weighted Lag Days
OER	$348.05	63.29	80.51%	50.95
FIT	$58.26	63.58	13.48%	8.57
OESP	$21.71	63.17	5.02%	3.17
MFIT	$4.16	63.58	0.96%	0.61
RESOP	$0.13	62.70	0.03%	0.02
Total	**$432.31**		**100.00%**	**63.32**

2.3 Other External Revenue

THESL Distribution collects revenues from a variety of other sources, in addition to the retail revenue and IESO credits discussed above. THESL staff provided monthly data and payment

[1] Lead-lag studies use the most recent and accurate historical data available for calculating results. For this study revenue and expense data from 2022 was generally used. However, for purposes of calculation of collection lag days Guidehouse used the days calculated in the 2020 Addendum ("2020 Update") to the filed 2017 Lead Lag Study ("2017 Study"). Due to significant balances outstanding more than 120 days arising from the Covid-19 pandemic and resulting policy response by the Ontario Electric Board, calculating the collection lag days using receivables aging as of the end of 2022 would have inflated that calculation and the resulting Cash Working Capital percentage. It is Guidehouse' opinion that collection data from the 2020 Update is more reflective of normal business operations going forward over the period 2025 to 2029.

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information for the other external revenue. The table below summarizes revenue lag time associated this other external revenue.

Table 5: Summary of Other External Revenue (2022)

Description	Revenues ($M)	Lag Days	Weighting	Weighted Lag Days
Other External Revenue	$136.91	33.53	100.00%	33.53
Total	**$136.91**		**100.00%**	**33.53**

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3. Expense Leads

The determination of working capital requires both a measurement of the lag in the collection of revenues for services provided by THESL, and the lead times associated with payments for services provided to THESL. Expense Leads are defined as the time period between when a service is provided to THESL and when payment is required for that service.

The following expense leads were calculated in this study:

- Cost of Power;
- Operations, Maintenance and Administration ("OM&A") expenses;
- Payments in Lieu of Taxes ("PILs");
- Interest on THESL'S debt;
- Harmonized Sales Tax ("HST").

3.1 Cost of Power

For the purpose of the lead-lag study, cost of power expenses were considered to consist of payments made by THESL to the following providers:

1. Independent Electricity System Operator ("IESO") cost of power expenses (includes the purchasing of power supply requirements on a monthly basis from the IESO on a schedule defined by the IESO's billing and settlement procedures);
2. Hydro One Low Voltage Charges;
3. Payments to Non-Utility Generators,
4. Distributed Generation

Expense lead times were calculated individually for each of the items listed above and dollar-weighted to derive the expense lead time of 32.72 days, as seen in Table 6 below.

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Table 6: Cost of Power Expenses* (2022)

Delivery Month	Amounts ($M)	Lead Time Days	Weighting Factor	Weighted Lead Time Days
Dec-21	$196.82	34.5	8.21%	2.83
Jan-22	$196.51	31.5	8.20%	2.58
Feb-22	$189.63	30.0	7.91%	2.37
Mar-22	$201.79	35.5	8.42%	2.99
Apr-22	$180.54	32.0	7.53%	2.41
May-22	$195.98	31.5	8.17%	2.57
Jun-22	$219.74	34.0	9.16%	3.12
Jul-22	$241.67	32.5	10.08%	3.28
Aug-22	$236.13	34.5	9.85%	3.40
Sep-22	$185.34	34.0	7.73%	2.63
Oct-22	$172.50	32.5	7.19%	2.33
Nov-22	$180.99	31.0	7.55%	2.34
Total	**$2,397.64**		100.00%	**32.85**

**This table does not include Distributed Generation charges of $62.55, Hydro One Low Voltage Charges of $.52 and payments to Non-Utility Generators of $.70. These lower the weighted-average cost of power slightly to 32.72.*

3.2 Operations, Maintenance and Administration ("OM&A")

The following expenses are included in the calculation of lead days for OM&A expenses:

- **Payroll and Benefits**; this line item includes basic payroll, payroll withholdings, and benefit expenses related to the regulated utility. THESL staff provided the breakdown of payroll, payroll withholding and benefits expenses.
- **Consulting and Contracting Services;** this line item includes the provision of outside services to THESL.
- **Miscellaneous OM&A;** this line item includes miscellaneous OM&A expenses non-related to the procurement of Outside Services.
- **Property Tax;** this line item includes property tax payments to municipalities or taxing authorities in the Province of Ontario. These payments are typically made in installments.
- **Corporate Procurement Card**; this line item includes credit card expenses related to OM&A.
- **Lease Payments;** this line item includes payments made on the properties THESL uses for their operations.

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 36.83 days for OM&A expenses.

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Table 7: Summary of OM&A Expenses (2022)

Description	Amounts ($M)	Weighting	Expense Lead Time	Weighted Lead Time
Payroll & Benefits	$209.47	58.43%	32.61	19.05
Consulting and Contract Staff	$100.21	27.96%	44.29	12.38
Miscellaneous OM&A	$42.80	11.94%	47.45	5.67
Property Tax	$5.05	1.41%	-24.44	-0.34
Corporate Procurement Card	$.73	0.20%	33.28	0.07
Lease Payments	$.22	0.06%	15.62	0.01
Total	**$358.48**	**100.00%**		**36.84**
Total Excluding Payroll & Benefits	$149.01			
Percent OM&A that attracts HST	**41.57%**			

3.2.1 Payroll and Benefits

In addition to basic and management payroll the following benefits were considered as expenses THESL's business:

1. Three types of payroll withholdings including the Canada Pension Plan, Employment Insurance, and Income Tax withholdings
2. Contributions made to the THESL Pension Plan;
3. Payments made to the Worker Safety Improvement Board ("WSIB");
4. Payments made for the Employer Health Tax ("EHT");
5. Group Health, Dental, and Life Insurance related administrative fees and claims;

When all payroll, withholdings and benefits were dollar-weighted using actual payment data, the weighted average expense lead time associated with payroll and benefits was determined to be 32.61 days as shown in the table below.

Table 8: Summary of Payroll & Benefits Expenses (2022)

Description	Amounts ($M)	Weighting	Expense Lead Time	Weighted Lead Time
Payroll	$101.46	48.44%	23.10	11.19
Payroll Withholdings	$51.18	24.43%	46.80	11.43
Pensions	$33.03	15.77%	55.04	8.68
Benefits	$19.37	9.25%	11.04	1.02
Other Benefits	$4.43	2.11%	13.60	0.29
Total	**$209.47**	**100.00%**		**32.61**

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3.2.2 Consulting and Contract Staff

THESL engages consulting and contract staff to provide assistance in the areas of engineering, environmental services, receivables management, accounting, and general consulting. A dollar-weighted expense lead time of 44.29 days was determined based on a review of invoices rendered and payments made by THESL in 2022.

3.2.3 Miscellaneous OM&A

This category of expense includes items such as product purchases, equipment rentals, and provision of general services to THESL. Based on transactions in THESL's accounts payable system under this category, a dollar-weighted expense lead time of 47.45 days was derived.

3.2.4 Property Taxes

THESL makes property tax payments to the City of Toronto in installments. Using actual payment dates and amounts associated with THESL's distribution business for calendar year 2022, a dollar-weighted expense lead (lag) time of (24.44) days was determined.

3.2.5 Corporate Procurement Card

Procurement (or charge) cards are used by THESL's employees primarily for purchases of vehicle fuel. Based on actual invoices from THESL's charge card provider and payments made by THESL, a dollar-weighted expense lead time of 33.28 days was determined.

3.2.6 Lease Payments

THESL leases office space to support its ongoing operations. Using actual invoices and payments for 2022, a dollar-weighted expense lead time of 15.62 days was determined.

3.3 Payments in Lieu of Taxes ("PILs")

THESL makes payments in lieu of taxes in installments to the relevant taxing authorities. Table 7, below summarizes the components of the PILS expense lead calculation.

Table 9: Summary of Payments in Lieu of Taxes Expenses (Average 2019-2022)[2]

Description	Costs ($M)	Weighting (%)	Total Lead Time	Weighted Lead
PILS	$13.39	100.00%	7.88	7.88
Total	**$13.39**	**100.00%**		**7.88**

[2] Guidehouse used an average as 2022 did not represent normal PILs activity.

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3.4 Interest on Debt

THESL makes interest payments on its long and short-term debt. Such payments are generally made twice a year. Considering the various bonds and other long-term debt instruments, a dollar-weighted expense lead time of 12.45 days was determined for the 2022 calendar year.

Table 10: Interest Expense (2022)

Description	Amounts ($M)	Lead Time Days	Weighting Factor	Weighted Lead Time Days
Interest Expense	$91.13	12.45	100.00%	12.45
Total	**$91.13**		**100.00%**	**12.45**

3.5 Harmonized Sales Tax

The expense lead times associated with the following items that attract HST were considered in THESL's distribution lead-lag study.

1. Revenues;
2. Cost of Power;
3. OM&A; and,

A summary of the expense lead times and working capital amounts associated with each of the above items is provided in the table below. Note that the statutory approach described at the outset was used to determine the expense lead times associated with THESL's remittances and disbursements of HST (*i.e.,* both remittances and collections are generally on the last day of the month following the date of the applicable invoice).

Table 11: Summary of HST Working Capital Amounts

Description	HST Lead Time	Working Capital Factor	Expenses Eligible	HST Amount	Test Year ($M)
Revenues	-7.45	-2.04%	$3,363.70	$437.28	-$8.93
Cost of Power	44.38	12.16%	$2,461.42	$319.98	$38.87
OM&A Expenses[3]	43.06	11.80%	$149.01	$19.37	$2.29
Total					**$32.23**

[3] Costs within OM&A that attract HST include Corporate Procurement Card, Lease Payments, Consulting and Contract Staff and Miscellaneous OM&A. These represent 41.57% of OM&A Expenses included in the study. See Table 7 for a breakdown.

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4. Working Capital Requirements

The table below summarizes THESL's working capital requirements for the test year.

Table 12: THESL Working Capital Requirements (Test Year 2022)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	53.15	32.72	20.43	5.60%	$2,461.42	$137.80
OM&A Expenses	53.15	36.84	16.31	4.47%	$358.48	$16.02
PILS	53.15	7.88	45.27	12.40%	$13.39	$1.66
Interest Expense	53.15	12.45	40.70	11.15%	$91.13	$10.16
Total					**$2,924.42**	**$165.64**
HST						$32.23
Total - Including HST						**$197.87**
Working Capital as a Percentage of OM&A incl. Cost of Power						**7.02%**

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5. Findings and Conclusions

The purpose of this section is to compare the results from this study to THESL's prior working capital study as completed by Guidehouse.

5.1 Comparison with Prior Study (2020 Update)

Table 13: THESL Working Capital Requirements (2020 Update)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	54.07	32.62	21.45	5.86%	$2,691.04	$157.70
OM&A Expenses	54.07	35.19	18.88	5.16%	$272.20	$14.04
PILS	54.07	-10.05	64.12	17.57%	$9.70	$1.70
Interest Expense	54.07	25.34	28.73	7.85%	$89.15	$7.00
Total					**$3,062.09**	**$180.44**
HST						$35.81
Total - Including HST						**$216.25**
Working Capital as a Percent of OM&A incl. Cost of Power						**7.30%**

Table 14: THESL Working Capital Requirements (Test Year 2022)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	53.15	32.72	20.43	5.60%	$2,461.42	$137.80
OM&A Expenses	53.15	36.84	16.31	4.47%	$358.48	$16.02
PILS	53.15	7.88	45.27	12.40%	$13.39	$1.66
Interest Expense	53.15	12.45	40.70	11.15%	$91.13	$10.16
Total					**$2,924.42**	**$165.64**
HST						$32.23
Total - Including HST						**$197.87**
Working Capital as a Percentage of OM&A incl. Cost of Power						**7.02%**

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Table 15: THESL Working Capital Requirements (Current versus Prior)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	-.92	0.10	-1.02	-0.26%	-$229.62	-$19.90
OM&A Expenses	-.92	1.65	-2.57	-0.69%	$86.28	$1.98
PILS	-.92	17.93	-18.85	-5.11%	$3.69	-$0.04
Interest Expense	-.92	-12.89	11.97	3.30%	$1.98	$3.16
Total					**-$137.66**	**-$14.80**
HST						-$3.58
Total - Including HST						**-$18.38**
Working Capital as a Percentage of OM&A incl. Cost of Power						-0.28%

Overall, the difference between the prior study and the current one is a decrease of .28%. The principal drivers of this decrease are described below.

5.1.1 Revenue Lag Days

As shown in the table above, the overall revenue lag in the current study has decreased by approximately one day since the prior study. Revenue lag has a large impact on the overall result of working capital studies, as it is considered in the working capital factor for all expense items. Minor variations in revenue lag can have large impacts on directional results. When the revenue lag is updated to the new results (53.15) and everything else from the previous study is held constant, the working capital percentage from the 2020 update would have been 7.04%. This is nearly equivalent to the results from the current study. Meaning revenue lag days are driving the majority of the difference between the studies.

Revenue lag is approximately .92 days shorter than the prior study, principally driven by billing lag being .71 days shorter. This is because the highest weighted class, General Service 50-999 kW – Interval, had billing lag approximately three days shorter in the current study versus the prior one (13 vs 16).

5.1.2 Expense Lead Days

Although there are differences in expense lead days as calculated in this study versus the prior one, their combined effect is negligible. Updating the expense lead days to the newly calculated days in this study increases the working capital percentage a minimal .02%. The effects of additional OM&A Expense lead days (36.83 current study vs 35.19 previous study) and fewer Interest Expense lead days (12.45 current study vs 25.34 previous study) mostly offset.

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5.1.3 Updated Expense Amounts

For purposes of the 2020 Update study the expense amounts were updated with actuals for 2020. The combined impact updating the amounts to those of the current study is a decrease in working capital percentage of .04%.

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CAPITALIZATION POLICY

This schedule addresses s. 2.2.9 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022) ("Filing Requirements"), which requires an applicant to file a copy of its capitalization policy and identify any changes to its capitalization policy since filing the last rebasing application.

1. BACKGROUND

Consistent with the OEB's expectations, Toronto Hydro converted to International Financial Reporting Standards ("IFRS") effective January 1, 2015. This application represents Toronto Hydro's third rebasing application under Modified IFRS ("MIFRS"). Toronto Hydro confirms that, for purposes of calculating the 2025-2029 rate base (Exhibit 2A, Tab 1, Schedule 1), its capitalization practices conform to MIFRS.

2. CAPITALIZATION POLICY

A copy of the utility's current capitalization policy is filed in Appendix A to this schedule.

3. CHANGES TO CAPITALIZATION POLICY

Since the 2020-2024 Rate Application (EB-2018-0165), Toronto Hydro made a number of changes to its IFRS-compliant capitalization policy to simplify aspects of the policy regarding thresholds for capitalization, reflect updated accounting pronouncements, revise frequency of review and reflect updated titles of responsible persons. The paragraphs that follow summarize these changes.

Toronto Hydro simplified section 7.1, which sets out the detailed minimum threshold dollar amount for capitalization, by removing Appendix A to the policy and inserting the following paragraph to identify the minimum threshold amount:

> "Once it has been established that an expenditure has the characteristics of a capital asset, for practical purposes, only those expenditures equal to or exceeding $1,000 will be recorded as a capital asset. Expenditures below $1,000 will be recorded as an expense. Note that for expenditures related to "major" projects, such as overhauls, major renovations, etc., it may not be appropriate to look at monetary threshold amounts on an itemized basis (i.e. per project, per expenditure/item). For those instances, the expenditure will be reviewed on a case by case basis in order to assess the appropriate accounting treatment."

Further, in section 7.1, Toronto Hydro refined to the definition of PP&E from "used" to "held for use" and the definition of intangible assets to include "identifiable non-monetary assets without physical substance."

Section 7.2 discusses subsequent recognition for capitalization versus expensing. In this section, Toronto Hydro clarified that where subsequent costs have attributes of both enhancement and maintenance, only the enhancement portion is capitalized.

In section 8, the utility made the following changes:

- Expanded the definition of capital asset cost to include "cash or cash equivalents paid or the fair value of the other consideration given to acquire, construct, or develop a capital asset."
- Provided more specificity in the definition of costs as follows:

i. "Purchase price, including imported duties and non-refundable purchase taxes, after deducting trade discounts and rebates (IAS 16, para 16(a))."

ii. "Initial estimate of costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period (IAS 16, para 16(c))."

- Within section 8.1:
  i. Replaced the term "purchased" capital assets with "acquired" capital assets, and specified "handling costs" within the costs of acquiring assets (8.1.1)
  ii. Specified "site preparation" amount within the costs directly attributable to self-constructed electrical plant (8.1.2).
  iii. Elaborated further on the definition of the software development research activities, which cannot be capitalized (8.1.3).
  iv. For cloud computing arrangements in 8.1.4, expanded references to IAS 38, and added Appendix C: Decision Tree-Implementation costs for a service contract of cloud computing arrangements, for additional guidance regarding the treatment of cloud computing arrangements.
- Within section 8.3:
  i. Simplified the definition of employee types used in the calculation of standard labour rate, to include all employee groups: inside workers and outside workers.
  ii. For On-cost, replaced the term "responsibility" centers with "cost" centers and the term "budgeted" expenses with "operating" expenses.

iii. Enhanced the definition of vehicle hire rate to specify all costs within the fleet cost centre such as operating and maintenance costs, vehicle licensing costs, insurance, fuel costs, depreciation, etc.

iv. Specified that total available hours consist of: a) total working days in a year less b) leaves (as the vehicles are not operated when employees are on leaves such as vacation and statutory holidays) as well as c) time not spent working on specific operating or capital jobs (such as safety training, inclement weather, etc.).

Toronto Hydro made various changes regarding the frequency of review and Designated Responsible Persons (DRP).

- Sections 11.1 and 11.2 were amended to "every 3 years" instead of "annually".
- Sections 11.3 was amended to change the DRP to "Director, Corporate Accounting External Reporting" instead of "Manager, External Financial Reporting".
- The title of "Manager, Capital Planning and Reporting" in section 11.4 has been updated to "Senior Manager, Capital Planning and Reporting". Additionally, in section 11.4, the DRP to whom violations of the policy should be reported to has been updated to "Director, Corporate Accounting & External Reporting and the Executive Vice-President and Chief Financial Officer" instead of "Controller and the Executive Vice-President and Chief Financial Officer."
- The party responsible for communicating policy updates, per section 12, has been updated to Director, Corporate Accounting & External Reporting. Section 13.4 has been updated to state the "Director, Corporate Accounting & External Reporting" as being responsible for tracking and collecting applicable data measuring compliance and reporting upon the request of the Corporation's General Counsel.

The appendices included in the policy changed as follow:

- Removed the previous Appendix A which listed the dollar thresholds for capitalization, as this information is now contained in section 7.1.
- Modified the previous "Appendix B- Decision Tree- Classification of an Expenditure" (which is now Appendix A) as follows:
    i. Expanded the term "provide future economic benefits" to "present potential to produce future economic benefits."
    ii. Expenses that do not meet the definition of PP&E or Intangible assets, but will be consumed over time and an advance payment has been made to be treated as a deferred asset and expensed over the term of the contract.
- Added Appendix C which provides a decision tree with regard to the implementation costs for a service contract of cloud computing arrangements.

POLICY

CAPITALIZATION	**Policy Owner:** Executive Vice-President and Chief Financial Officer
	Policy Approver: Policy Administration Steering Committee
	Version Approval Date: V9.0 2023-10-18
	Last Review by PASC: V9.0 2023-10-18
The most recent version of this policy can be obtained from https://pluggedin.torontohydro.com/policy/Pages/allpolicies.aspx	
The distribution of this policy is not restricted.	

Anthony Haines
President and CEO, Toronto Hydro Corporation

October 24, 2023
Date

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1 DOCUMENT REVIEW & REVISION HISTORY

This policy is reviewed every three years.

Version Number	Date of Review	Reviewed By	Brief Description of Change
V1.0	2008-06-27	PASC	V1.0 approved by PASC
V2.0	2010-07-29	PASC	V2.0 approved by PASC
V3.0	2011-06-30	PASC	V3.0 approved by PASC
V4.0	2013-09-24	PASC	V4.0 approved by PASC
V5.0	2015-12-14	PASC	Reflect accounting policies in accordance with IFRS, revisions to policy administration and responsibilities, addition of compliance monitoring
V6.0	2017-10-16	PASC	Added clarifying guidance including additional intangible asset treatment, updated roles and responsibilities, added OEB AP Handbook related excerpts and other minor wording changes
V7.0	2018-10-22	PASC	Update Section 11 – Policy Administration Ownership, Approval and Responsibilities
V8.0	2020-10-15	PASC	Added clarifying guidance for cloud arrangements, simplified specific minimum threshold guidance with general $1,000 minimum threshold, title updates and minor wording changes
V9.0	2023-10-18	PASC	Including additional definitions and examples from relevant IFRS, added clarifying guidance for implementation costs for a service contract of cloud computing arrangements, update on application of burdens, title updates and minor wording changes and change to policy review of every 3 years

2 DISTRIBUTION HISTORY

Version Number	Date of Issue	Recipients
V1.0	2008-06-27	Toronto Hydro @ Home Employee Extranet
V2.0	2010-08-30	Toronto Hydro @ Home Employee Extranet
V3.0	2011-09-16	http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx
V4.0	2013-09-30	http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx
V5.0	2015-12-14	http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx
V6.0	2017-10-16	http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx
V7.0	2018-10-22	http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx
V8.0	2020-10-15	https://pluggedin.torontohydro.com/policy/Pages/allpolicies.aspx
V9.0	2023-10-18	https://pluggedin.torontohydro.com/policy/Pages/allpolicies.aspx

3 POLICY OVERVIEW

This document describes the accounting policy and specific criteria used to determine the appropriate classification of expenditures, in particular, whether expenditures should be capitalized on the balance sheet (capital assets) or expensed to operations in the period incurred (expense), and the conditions for derecognition.

The purpose of recording expenditures as capital assets is to provide for an equitable allocation of costs among current and future periods. As capital assets are expected to provide future economic benefits for more than a year, expenditures incurred for the acquisition, construction or development of capital assets should be capitalized and allocated over the estimated useful lives[1] of the associated capital assets in the form of amortization/depreciation expense. All other expenditures should be expensed in the accounting period incurred.

4 DEFINITIONS AND ABBREVIATIONS

TERM or ACRONYM	DESCRIPTION
AP Handbook	Accounting Procedures Handbook for Electricity Distributors issued by the OEB
Borrowing Costs	Interest and other costs incurred in connection with the borrowing of funds
CWIP	Construction Work In Progress
Corporation	Toronto Hydro Corporation and its subsidiaries
IFRS	International Financial Reporting Standards
ISA	In-Service Additions
Qualifying asset	An asset that necessarily takes a substantial period of time to get ready for its intended use
OEB	Ontario Energy Board

[1] Estimates of useful life are reviewed annually and whenever events or changes in circumstances indicate that the current estimates or depreciation method are no longer appropriate. Changes in estimates are accounted for on a prospective basis.

TERM or ACRONYM	DESCRIPTION
On-cost	Materials handling costs
PASC	Policy Administration Steering Committee
PP&E	Property, Plant and Equipment
SLR	Standard Labour Rate
VHR	Vehicle Hire Rate

5 SCOPE

5.1 This policy applies to the capitalization of assets by the Corporation.

5.2 This policy is designed to augment other corporate policies and is not intended to replace or preclude them. Should an overlap arise between the application of this policy and any other policy, the policy most specific to the situation will apply.

6 OBJECTIVE

6.1 To ensure proper classification of the Corporation's expenditures in accordance with IFRS and the regulatory reporting standards included in the AP Handbook.

7 CRITERIA FOR CAPITALIZATION

7.1 Initial Recognition – Capitalization versus Expensing

Expenditures will be capitalized only if:

i) It is probable that future economic benefits will flow to the entity; and
ii) The cost can be measured reliably.

Capital assets comprise of PP&E and intangible assets, and are expected to be used for more than one year. PP&E consists typically of long-lived tangible assets held for use in the production or supply of goods or services, for rental to others, or for administrative purposes, such as distribution assets, equipment, land and buildings. Intangible assets are identifiable non-monetary assets without physical substance, such as computer software and capital contributions paid.

For additional guidance, **Appendix A: Decision Tree – Classification of an expenditure** illustrates the criteria that must be met in order for expenditures to be capitalized. Expenditures not meeting the criteria will be expensed in the period incurred. Additionally, **Appendix B: Capital asset and repair and maintenance expense definitions** includes excerpts from the OEB AP Handbook outlining capital asset and expense account definitions. A review of these definitions provides practical references and examples to assist in the classification of various expenditures.

For complex transactions, when capital/operating decisions may be ambiguous and/or estimates of useful lives are not known, the Business Units should consult with the Finance group.

Once it has been established that an expenditure has the characteristics of a capital asset, for practical purposes, only those expenditures equal to or exceeding $1,000 will be recorded as a capital asset. Expenditures below $1,000 will be recorded as an expense. Note that for expenditures related to "major" projects, such as overhauls, major renovations, etc., it may not be appropriate to look at monetary threshold amounts on an

itemized basis (i.e. per project, per expenditure/item). For those instances, the expenditure will be reviewed on a case by case basis in order to assess the appropriate accounting treatment.

7.2 Subsequent recognition - Capitalization versus Expensing

When expenditures are incurred relating to existing capital assets, they should be evaluated against the recognition criteria (i.e., it is probable that future economic benefits will flow to the entity and the cost can be measured reliably). Subsequent costs should be capitalized only if they meet the recognition criteria. Otherwise, costs should be expensed.

Costs to be capitalized are costs incurred to enhance the service potential of an existing capital asset. The service potential of an existing capital asset may be enhanced when:

i) there is an increase in the previously assessed physical output or service capacity;
ii) associated operating costs are lowered;
iii) the life or useful life is extended; or
iv) the quality of output is improved.

Costs to be expensed are costs incurred in the maintenance of the service potential of a capital asset. Frequently referred to as repair and maintenance expenses, they are costs incurred more or less on a continuous basis to keep the capital asset in normal operating condition, but do not improve the value of the asset, nor prolong its life appreciably. They are the result of an activity that encompasses actions of a detective, preventive, and/or monitoring nature. They are normally planned or scheduled. They can also be reactionary, in response to an unscheduled breakdown in service function.

If a cost has the attributes of both enhancement and maintenance of the service potential of a capital asset, the portion considered to be enhancement is capitalized.

For those instances when professional judgement has to be exercised to determine the proper classification of the Corporation's expenditures, the Business Units should confirm the classification with the Finance group.

8 ASSET COST

Capital asset cost is the amount of cash or cash equivalents paid or the fair value of the other consideration given to acquire, construct, or develop a capital asset, which includes:

i. purchase price, including imported duties and non-refundable purchase taxes, after deducting trade discounts and rebates (IAS 16, para 16(a)).

ii. any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management (IAS 16, para 16(b)).

The "directly attributable" criteria should not be interpreted as "directly attributable to an asset". It means "directly attributable to getting the asset ready to operate as intended". Further, the directly attributable costs for a self-constructed asset are determined using the same principles as those for an acquired asset.

iii. the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period (IAS 16, para 16(c)).

8.1 Cost

8.1.1 For acquired capital assets, costs should include the purchase price and other acquisition costs, such as brokers' commissions, and all the costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management, such as: costs of employee benefits arising directly from the acquisition of the asset; installation costs, including architectural, design and engineering fees; legal fees; survey costs; site preparation costs; freight charges; handling costs; transportation insurance costs; duties; the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located; and testing and preparation charges.

8.1.2 For an electrical plant that is self-constructed, construction costs should include where applicable: the cost of directly attributable labour; materials and supplies; site preparation; transportation; work done by others for the utility; damages incurred in the construction work; privileges and permits; special machinery services; borrowing costs applied to construction work in progress; the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located; and such portion of directly attributable general engineering, salaries and expenses, insurance, taxes and other similar items as may be properly included in construction. The cost of abnormal amounts of wasted material, labour, or other resources incurred in self-constructing an asset is not included in the cost of the asset.

8.1.3 For information technology ("IT") projects related to computer software, costs should only include the expenditures incurred in the development phase of a project.

Software development involves two stages: [IAS 38.52]

i) the research phase. Examples of activities are: [IAS 38.56]
   a. activities aimed at obtaining new knowledge;
   b. the search for, evaluation and final selection of, applications of research findings or other knowledge;
   c. the search for alternatives for materials, devices, products, processes, systems or services; and
   d. the formulation, design, evaluation and final selection of possible alternatives for new or improved materials, devices, products, processes, systems or services.

ii) All costs incurred during this phase should be expensed as they are incurred.

iii) the development phase. Examples of activities which might be incurred in this stage are design of chosen alternative, including software configuration and interfaces, coding, installation on computer hardware, and testing. Costs incurred during this phase should start being capitalized only after the IT group demonstrates all of the following:
   a. the technical feasibility of completing the software so that it will be available for use;
   b. the intention to complete the software and use it (i.e., commit resources for the project in the budget);
   c. the ability to use the software;
   d. how the software will generate probable future economic benefits (i.e., demonstrate the usefulness of the software);
   e. the availability of adequate technical, financial and other resources to complete the development and to use the software (i.e., a business plan

showing the technical, financial and other resources needed and how they will be secured);

f. the ability to measure reliably the expenditure attributable to the software during its development (i.e., use of time sheets).

If the research phase of an internal project to create/modify a software cannot be distinguished from the development phase, the expenditure for that project should be treated as if it were incurred in the research phase only.

Capitalization should cease no later than when substantial testing is complete and the software is capable of operating in the manner intended by management, or when it is no longer probable that the computer software project will be completed and placed in service.

8.1.4 For cloud computing arrangements with third party service providers to use their software applications over the internet, the costs should be assessed against the general capitalization criteria based on IAS 38 set out in **Appendix A – Decision Tree – Classification of an expenditure**. The service provider hosts the hardware, software, servers, storage and other components to varying degrees in cloud-specific arrangements. These arrangements include but are not limited to infrastructure as a service, platform as a service and software as a service. As there is often no asset that the Corporation controls on its own premises in these types of arrangements, the capitalization criteria would need to be applied to the rights provided through the individual contractual arrangement with the third-party service provider. If the cloud arrangement only conveys the right to receive access to the software over the contract term, the arrangement is considered a service contract. If the definition of an asset is met, the Corporation should consider the nature of asset that has been acquired in order to determine the appropriate accounting treatment (e.g., prepaid, other asset, or intangible asset). Otherwise, the costs should be expensed as a service fee. As each arrangement may be unique, each individual contract should be assessed separately.

The accounting for implementation costs related to the cloud solution should also be assessed separately and would depend on whether the cloud solution is a software intangible asset or a service contract. When the underlying cloud computing arrangement itself is determined to be a service contract, its implementation costs are generally unlikely to be capitalizable as an intangible asset and should be assessed against the criteria based on IAS 38 set out in **Appendix C: Decision Tree – Implementation costs for a service contract of cloud computing arrangements**. Configuration costs generally relate to tailoring or configuring existing functionality in the cloud solution to meet the Corporation's specific requirements and are considered an operating expense. Customization differs in the fact that it generally involves actual modification to the software code to change or create additional functionalities for the Corporation that is typically performed by the service provider. If the customization is paid upfront, these costs can be recognized as a deferred asset and expensed over the period of the access to the software. In some limited cases, the Corporation incurs costs to develop a customized user interface which is housed on its premises in order to access the cloud solution. Any development costs related to the development of the user interface or other type of implementation costs should be assessed using the same criteria as the IT projects related to computer software above.

8.1.5 Other costs that are not costs of an item of PP&E or intangible asset:

i) costs incurred while an item capable of operating in the manner intended by management has yet to be brought into use or is operated at less than full capacity;

ii) initial operating losses, such as those incurred while demand for the item's output builds up;

iii) costs of relocating or redeploying the item to a new location;

iv) administration and other general overhead costs; and
v) training costs.

8.2 Borrowing costs

Borrowing costs eligible for capitalization are determined by applying the weighted average cost of borrowing to the carrying amount of eligible CWIP during a period, including borrowing costs previously capitalized. Capitalization of borrowing costs will commence as soon as the expenditure on a qualifying asset is incurred and will cease when substantially all the activities necessary to prepare the qualifying asset for its intended use are complete.

8.3 Burdens

Four burden rates are specifically analyzed below with respect to the asset cost:

1. Time-sheeting of Indirect Labour

   One of the methods of capitalizing labour costs is to allocate employee labour costs through the process of time-sheeting of indirect labour. Field crews are supported, supervised and guided by those employees whose personnel costs are included in indirect labour.

   The process of capitalizing costs of indirect labour includes labour costing (i.e. time-sheeting) which differentiates the time spent between capital, operating, and "blended" activities (i.e. a mix of capital and operating), in order to appropriately allocate costs across projects based on identified cost drivers.

   Once time-sheeted hours are applied to specific activities, the calculated cost will be allocated to capital expenditures, operating expenses, or a blend of both based on the nature of the activity. Costs identified as capital or costs that are designated as capital in nature within a blend activity will be mapped to CWIP, while costs identified as operating or costs that are designated as operating in nature within a blend activity will be mapped to operating expense.

2. Standard labour rate

   Another method of capitalizing labour cost is to track direct labour costs for various employees and apply a SLR to time recorded to various jobs. The SLR is calculated for all employee groups who currently submit time-sheets for direct labour which includes both inside and outside workers.

   The SLRs are calculated by dividing the total employee burden (i.e. employee's total remuneration, including various types of benefits) by the total available hours (i.e. hours available for work during the course of the year on projects) for each SLR category. The total available hours consist of: a) the total working days in a year less b) leaves (such as vacation and statutory holidays) as well as c) time not spent working on a specific operating or capital jobs (such as safety training, inclement weather, etc.).

3. On-cost

   An on-cost charge is applied to material issuances from the warehouse. Examples include transformers, poles, cables, etc. If the items issued from the warehouse are associated with capital projects, the on-cost charge is capitalized, whereas if the items

issued are associated with operating projects, the on-cost charge is expensed in the period in which it is incurred.

The on-cost charge associates the cost of warehousing and handling to the items themselves. The on-cost rate is calculated as the sum of operating expenses in the specific material handling cost centers divided by the dollar value of materials moving through the warehouse in a given year. This rate is then applied to the dollar value of all materials when issued to capital and operating projects. Some of the operating expenses within the material handling responsibility centers are not capitalizable, thus should not be included in the on-cost calculation. The disallowed costs include:

- Payroll related to administrative staff supporting the procurement and warehousing functions;
- Inventory and direct purchases of materials used in the warehouse for internal purposes – i.e. not used for capital projects;
- Utilities and communications related expenses;
- Office supplies used in procurement and warehousing;
- Employee expenses (i.e. reimbursed expenses for employee purchases); and
- Allocated IT charges related to telephone and computing equipment used by the procurement and warehousing departments.

4. Vehicle Hire Rate

Vehicles used in the construction of capital assets can be capitalized into the item of PP&E. This capitalization is applied to projects based on time-sheets for the use of each vehicle. A VHR is calculated for each vehicle class and applied to the hours time-sheeted to determine the amount capitalized to each project.

The VHR is calculated as the sum of operating expenses in the specific fleet cost centers divided by the total available hours (i.e. hours available for work during the course of the year on projects) for each VHR category. Fleet operating costs include vehicle operating and maintenance costs, vehicle licensing costs, insurance, fuel costs, depreciation, etc. Whereas, the total available hours consist of: a) the total working days in a year less b) leaves (as the vehicles are not operated when employees are on leaves such as vacation and statutory holidays) as well as c) time not spent working on a specific operating or capital jobs (such as safety training, inclement weather, etc.).

8.4 Decommissioning cost

The Corporation recognizes a liability, known as a decommissioning provision, for future removal and handling costs for contamination in distribution equipment and for the future environmental remediation of certain properties, as assessed on a case-by-case basis. A decommissioning provision shall be recognized when there is a present legal or constructive obligation as a result of a past event and it is probable that there will be a future economic outflow that can be reliably measured. The liability is measured at present value and an offsetting amount is added to the carrying amount of the related asset. This cost is depreciated over the useful life of the related asset. Changes to an existing decommissioning provision are added to or deducted from the cost of the related asset and depreciated prospectively over the remaining useful life of the asset.

9 IN-SERVICE ADDITIONS

9.1 Once it has been established that an expenditure is part of the cost of a capital asset, it is recorded as CWIP until the asset is capable of operating in the manner intended by management (i.e., the capital asset is energized or connected to the distribution system),

at which point it is recorded as an item of PP&E or intangible asset and depreciation/amortization begins.

10 DERECOGNITION

10.1 Derecognition occurs when an item of PP&E or intangible asset no longer generates future economic benefits or when the item is disposed of.

10.2 When an item of PP&E or intangible asset no longer generates future economic benefits, the loss arising from derecognition equals its carrying amount and is recorded in the period in which the item is derecognized as depreciation or amortization expense.

10.3 When an item of PP&E or intangible asset is disposed of, the gain or loss arising from derecognition equals the difference between the net disposal proceeds (if any) and its carrying amount and is recorded in the period in which the item is derecognized as a gain or loss on disposal.

11 POLICY ADMINISTRATION OWNERSHIP, APPROVAL AND RESPONSIBILITIES

Policy Owner

11.1 This policy is owned by the *Executive Vice-President and Chief Financial Officer,* who is responsible for:

- Ensuring that this policy is comprehensive, clear and current.
- Approving any exceptions to this policy, as required.
- Reviewing this policy every 3 years or as necessary.

Policy Approver

11.2 This policy is approved by the *Policy Administration Steering Committee,* which is responsible for:

- Considering the impact of this policy to the associated risk.
- Approving this policy every 3 years or as necessary.

Designated Responsible Person

11.3 This policy is managed by the *Director, Corporate Accounting & External Reporting*, who is responsible for:

- Ensuring that this policy is in accordance with IFRS and OEB AP Handbook guidance.
- Ensuring consistency between referenced appendices and this document.
- Reviewing and updating this policy annually, as necessary, for changes in accounting standards, regulatory decisions, or processes impacting the capitalization of costs.

11.4 This policy is implemented by the *Senior Manager, Capital Planning and Reporting*, who is responsible for:

- Ensuring that this policy is communicated to all staff impacted.
- Ensuring on-going compliance with this policy.
- Immediately communicating any exceptions or violations of this policy to the *Director, Corporate Accounting & External Reporting* and the *Executive Vice-President and Chief Financial Officer*.

12 POLICY COMMUNICATION

COMMUNICATION TRIGGER	TYPE OF COMMUNICATION	PARTY RESPONSIBLE FOR POLICY COMMUNICATION	AUDIENCE	ACKNOWLEDGEMENT
Policy Update	E-Mail, Posted on Intranet	Director, Corporate Accounting & External Reporting	All affected employees	No
New Hire in Finance	Discussion, E-mail	Immediate Manager	New hire	No

13 POLICY COMPLIANCE AND VIOLATIONS

13.1 All of the Corporation's employees, officers and directors are required to comply with this policy.

13.2 Any employee who fails to comply with this policy could be subject to disciplinary action, up to and including dismissal.

13.3 Failure to comply with this policy could lead to a material misstatement of the Corporation's financial statements and other financial information and inaccurate submissions to regulatory agencies. This can result in legal, regulatory and reputational ramifications.

13.4 Compliance Monitoring

The Director, Corporate Accounting & External Reporting is responsible for tracking and collecting applicable data, measuring compliance and reporting in such format as may be required.

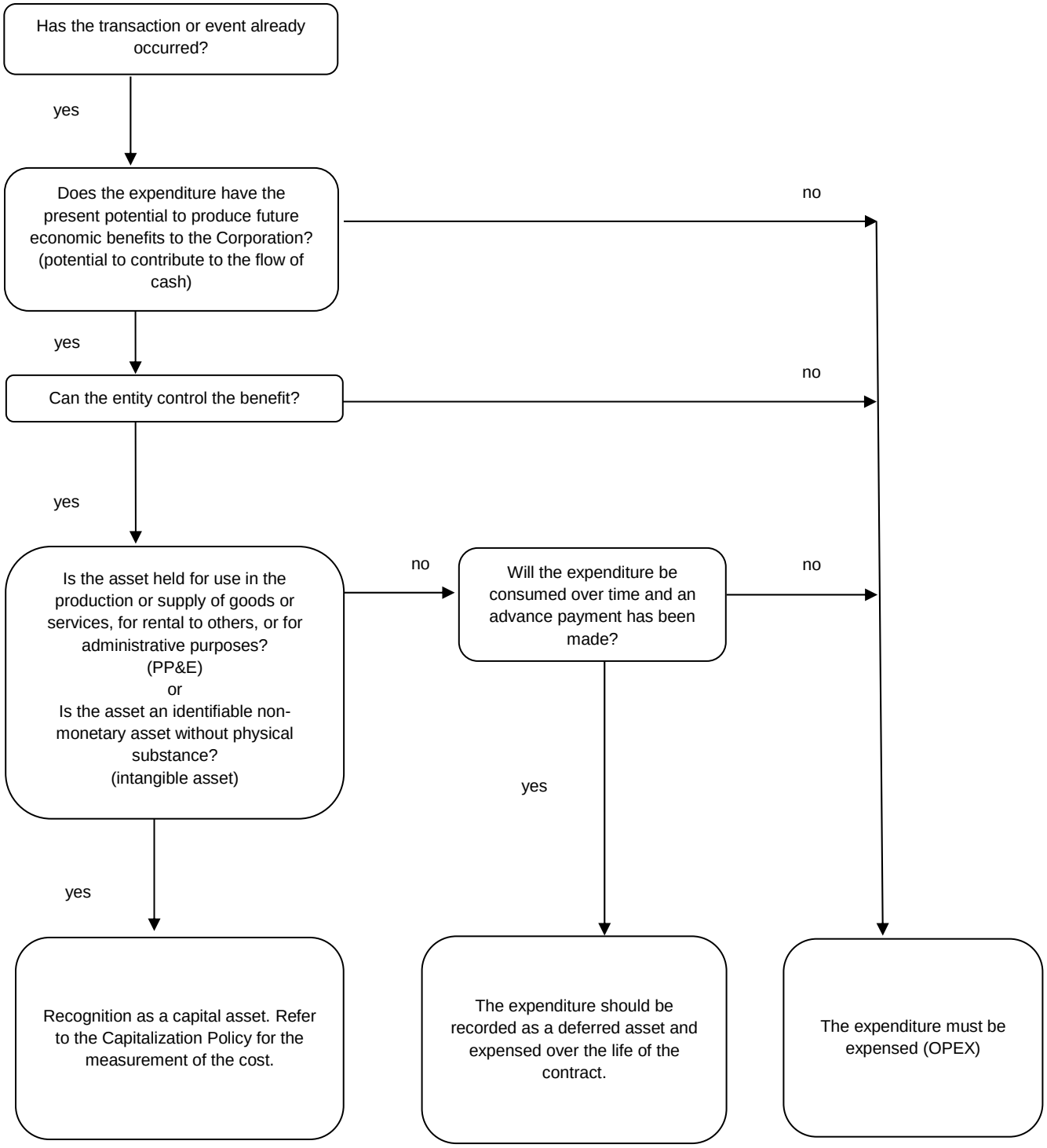
14 RELATED LAWS, REGULATIONS AND DOCUMENTATION

14.1 Refer to IAS 16 *Property, Plant and Equipment* and IAS 38 *Intangible Assets* for additional definitions and accounting principles. These standards are available from the Finance group.

14.2 The following appendices were referenced in this policy:

- Appendix A: Decision Tree – Classification of an expenditure
- Appendix B: Capital asset and repair and maintenance expense definitions – Excerpts from the OEB AP Handbook
- Appendix C: Decision Tree – Implementation costs for a service contract of cloud computing arrangements

These appendices can be found on the Toronto Hydro Plugged In intranet site at https://pluggedin.torontohydro.com/policy/Pages/allpolicies.aspx.


Has the transaction or event already occurred?
yes
Does the expenditure have the present potential to produce future economic benefits to the Corporation? (potential to contribute to the flow of cash)
no
yes
Can the entity control the benefit?
no
yes
Is the asset held for use in the production or supply of goods or services, for rental to others, or for administrative purposes? (PP&E)
or
Is the asset an identifiable non-monetary asset without physical substance? (intangible asset)
no
Will the expenditure be consumed over time and an advance payment has been made?
no
yes
yes
Recognition as a capital asset. Refer to the Capitalization Policy for the measurement of the cost.
The expenditure should be recorded as a deferred asset and expensed over the life of the contract.
The expenditure must be expensed (OPEX)

CAPITALIZATION POLICY
APPENDIX B: CAPITAL ASSET AND REPAIR AND MAINTENANCE EXPENSE DEFINITIONS – EXCERPT FROM OEB AP HANDBOOK (Issued: December 2011; Effective: January 1, 2012; Updates issued in March 2015 for new accounts)
(APPLICABLE TO THESL)

This appendix is governed by the Capitalization Policy.

Article 220 – Uniform System of Accounts
Electric Plant in Service - Detailed Accounts
D. Distribution Plant

1805 Land
This account shall include the cost of land used in connection with power distribution. (See Article 230, Definitions and Instructions No. 8 for detail guidance).

Note: Do not include in this account the cost of permits to erect poles, towers, etc., or to trim trees. See Account 1830, Poles, Towers and Fixtures, and Account 1835, Overhead Conductors and Devices.

1808 Buildings and Fixtures
This account shall include the cost in place of buildings and fixtures used in connection with distribution operations. (See Article 230 *Definitions and Instructions* No. 9.)

1810 Leasehold Improvements
This account shall include the cost of additions, improvements or alterations made to premises the utility leases from others. The cost of the leasehold improvements shall be amortized over the term of the lease or the service life of the improvement, whichever is shorter. Renewal provisions in the lease agreement shall be disregarded in amortizing leasehold improvements.

This account shall be subdivided into as many classifications as are required.

1815 Transformer Station Equipment - Normally Primary Above 50 kV
This account shall include the installed cost of transforming and switching equipment used for the purpose of stepping down from transmission voltages to subtransmission voltages and/or distribution voltages.

The account shall include all equipment used in the above operation from the high voltage feeder through to the delivery point outside the station or the connections within the confines of the station area. Included in the cost shall be all transformer equipment, control equipment, switching equipment, station metering equipment and the compartments or cubicles used to house such equipment, as well as general equipment such as cranes, hoists, test equipment, motors and the like. Moveable mountings or settings specially constructed for the particular equipment mounted therein shall also be included.

The detail of separate stations shall be entered in such a manner that an accurate record of their age, cost, location, and voltage characteristics will be evident.

1820 Distribution Station Equipment - Normally Primary Below 50 kV
This account shall include the installed cost of transforming and switching equipment used for the purpose of stepping down to distribution voltages.

The account shall include all equipment used in the above operation from the high voltage feeder through to the low voltage connection outside the station within the confines of the station area. Included in the cost shall be all transformer equipment, control equipment, switching equipment, station metering equipment and the compartments or cubicles used to house such equipment, as well as general equipment such as cranes, hoists, test equipment, motors and the like. Moveable mountings or settings specially constructed for the particular equipment mounted therein shall also be included.

The detail of separate stations shall be entered in such a manner that an accurate record of their age, cost, location, and voltage characteristics will be evident.

1825 Storage Battery Equipment
This account shall include the cost installed of storage battery equipment used for the purpose of supplying electricity to meet emergency or peak demands.

Example items:

- Batteries, including elements, tanks, tank insulators, etc
- Battery room connections, including cable or bus runs and connections
- Battery room flooring, when specially laid for supporting batteries
- Charging equipment, including motor generator sets and other charging equipment and connections, and cable runs from generator or station bus to battery room connections
- Miscellaneous equipment, including instruments, water stills, etc
- Switching equipment, including endcell switches and connections, boards and panels, used exclusively for battery control, not part of general station switchboard
- Ventilating equipment, including fans and motors, louvers, and ducts not part of building

Note: Storage batteries used for control and general station purposes shall not be included in this account but in the account appropriate for their use.

1830 Poles, Towers, and Fixtures
This account shall include the cost installed of poles, towers, and appurtenant fixtures used for supporting overhead distribution conductors and service wires.

Example items:

- Anchors, head arm, and other guys, including guy guards, guy clamps, strain insulators, pole plates, etc
- Brackets
- Crossarms and braces
- Excavation and backfill, including disposal of excess excavated material
- Extension arms
- Foundations
- Guards
- Insulator pins and suspension bolts
- Paving
- Permits for construction
- Pole steps and ladders
- Poles, wood, steel, concrete, or other material
- Racks complete with insulators
- Railings
- Reinforcing and stubbing
- Settings
- Shaving, painting, gaining, roofing, stenciling, and tagging

- Towers
- Transformer racks and platforms

Note: Sub-accounts should be used for sub-transmission Poles, Towers and Fixtures.

1835 Overhead Conductors and Devices
This account shall include the cost installed of overhead conductors and devices used for distribution purposes.

Example items:

- Circuit breakers
- Conductors, including insulated and bare wires and cables
- Ground wires, clamps, etc
- Insulators, including pin, suspension, and other types, and tie wire or clamps
- Lightning arresters
- Railroad and highway crossing guards
- Splices
- Switches
- Initial cost of tree trimming, including the cost of permits
- Other line devices

Note: The cost of conductors used solely for street lighting or signal systems shall not be included in this account but in account 1875, Street Lighting and Signal Systems.

1840 Underground Conduit
This account shall include the cost installed of underground conduit and tunnels used for housing distribution cables or wires.

Example items:

- Conduit, concrete, brick and tile, including iron pipe, fiber pipe, Murray duct, and standpipe on pole or tower
- Excavation, including shoring, bracing, bridging, backfill, and disposal of excess excavated material
- Foundations and settings specially constructed for and not expected to outlast the apparatus for which constructed
- Lighting systems
- Manholes, concrete or brick, including iron or steel frames and covers, hatchways, gratings, ladders, cable racks and hangers, etc., permanently attached to manholes
- Municipal inspection
- Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks
- Permits
- Protection of street openings
- Removal and relocation of subsurface obstructions
- Sewer connections, including drains, traps, tide valves, check valves, etc.
- Sumps, including pumps
- Ventilating equipment

Note: The cost of underground conduit used solely for street lighting or signal systems shall be included in Account 1875, Street Lighting and Signal Systems.

1845 Underground Conductors and Devices
This account shall include the cost installed of underground conductors and devices used for distribution purposes.

Example items:

- Armored conductors, buried, including insulators, insulating materials, splices, potheads, trenching, etc
- Armored conductors, submarine, including insulators, insulating materials, splices in terminal chamber, potheads, etc
- Cables in standpipe, including pothead and connection from terminal chamber or manhole to insulators on pole
- Circuit breakers
- Fireproofing, in connection with any items listed herein
- Hollow core oil filled cable, including straight or stop joints, pressure tanks, auxiliary air tanks, feeding tanks, terminals, potheads and connections, etc
- Lead and fabric covered conductors, including insulators, compound filled, oil filled or vacuum splices, potheads, etc
- Lightning arresters
- Municipal inspection and Permits
- Protection of street openings
- Racking of cables
- Switches
- Other line devices

Note: The cost of underground conductors and devices used solely for street lighting or signal systems shall be included in Account 1875, Street Lighting and Signal Systems.

1850 Line Transformers
A. This account shall include the cost installed of overhead and underground distribution line transformers and poletype and underground voltage regulators owned by the utility, for use in transforming electricity to the voltage at which it is to be used by the customer, whether actually in service or held in reserve.

B. The records covering line transformers shall be so kept that the utility can furnish the number of transformers of various capacities in service and those in reserve by:
a) type (underground or overhead);
b) capacity;
c) function.

Example items:

- Transformers
- Transformer cutouts
- Grounding equipment
- Other material and labour necessary for installation (first installation only)
- Transformer lightning arresters
- Transformers, line and network
- Capacitors
- Network protectors

Note: The cost of removing and resetting line transformers shall not be charged to this account but to Account 5035, Overhead Distribution Transformers - Operations or Accounts 5055**,** Underground Distribution Transformers - Operations. The cost of line transformers used solely for street lighting or signal systems shall be included in Account 1875, Street Lighting and Signal Systems.

1855 Services
This account shall include the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the transformers or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's electrical panel. Conduit used for underground service conductors shall be included herein.

Example items:

- Brackets
- Cables and wires
- Conduit
- Insulators
- Municipal inspection
- Overhead to underground, including conduit or standpipe and conductor from last splice on pole to connection with customer's wiring
- Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks
- Permits
- Protection of street openings
- Service switch
- Suspension wire

Records shall be maintained providing information on underground and overhead services separately and by capacity and function.

1860 Meters
A. This account shall include the cost installed of meters or devices and appurtenances thereto, for use in measuring the electricity delivered to its users, whether actually in service or held in reserve.

B. The records covering meters shall be so kept that the utility can furnish information as to the number of meters of various capacities in service and in reserve by:

a) type (underground or overhead);
b) capacity;
c) function.

Example items:

- Labour and expense of first installation
- Inspection fees
- Alternating current, watt hour meters
- Current limiting devices
- Demand indicators
- Demand meters
- Direct current watt hour meters
- Graphic demand meters
- Instrument transformers
- Maximum demand meters
- Meter badges and their attachments
- Meter boards and boxes
- Meter fittings, connections, and shelves (first set)
- Meter switches and cutouts
- Prepayment meters
- Protective devices
- Testing new meters
- Interval Meters

- Smart Meters

Note A: This account shall not include meters for recording output of a generating station, substation meters, etc. Generation station high voltage meters shall be recorded in Account 1815, Transformer Station Equipment - Normally Primary Above 50 kV and substation meters shall be recorded in Account 1820, Distribution Station Equipment - Normally Primary Below 50 kV.

Note B: Generation related meter costs for renewable energy standard offer program, Feed-in Tariff ("FIT") and microFIT generation activities shall be recorded in a separate sub-account by meter type under this account. The revenues collected for the recovery of the generator connection costs including the meter costs shall be treated as capital contributions and recorded in Account 2440, Deferred Revenues. The meter cost is offset by the capital contribution (recorded in Account 2440, Deferred Revenues) and the depreciation expense is offset by the amortized deferred revenue (recorded in Account 4245, Government and Other Assistance Directly Credited to Income) in profit or loss. (See Article 430 *Contributions in Aid of Construction.*)

Note C: The cost of removing and resetting meters shall be charged to Account 5065, Meter Expenses.

1865 Other Installations on Customer Premises
This account shall include the cost installed of equipment on the customer's side of a meter when the utility incurs such cost and when the utility retains title to and assumes full responsibility for maintenance and replacement of such property. This account shall not include expenses related to leased equipment (see Account 1870, Leased Property on Customer Premises).

Example items:
- Cable vaults
- Commercial lamp equipment
- Foundations and settings specially provided for equipment included herein
- Frequency changer sets
- Motor generator sets
- Motors
- Switchboard panels, high or low tension
- Wire and cable connections to incoming cables

Note A: Do not include in this account any costs incurred in connection with merchandising or contract work activities. (See Account 4330).

Note B: It is intended that only equipment used in furnishing special service or service of a character different from that normally supplied shall be included in this account.
Note C: Maintenance costs relating the items in this account are to be charged to Account 5195, Maintenance of Other Installations on Customer Premises.

1870 Leased Property on Customer Premises
This account shall include the cost of electric motors, transformers, and other equipment on customers' premises (including municipal corporations), leased or loaned to customers, but not including property held for sale.

Note A: The cost of setting and connecting such appliances or equipment on the premises of customers and the cost of resetting or removal shall not be charged to this account but to operating expenses, Account 5178, Customer Installations Expenses - Leased Property.

Note B: Do not include in this account any costs incurred in connection with merchandising. (See Account 4330).

1875 Street Lighting and Signal Systems
If street lighting and signal systems are authorized by the Board for ratemaking, this account shall include the cost installed of equipment used wholly for public street and highway lighting or traffic, fire alarm, police, and other signal systems.

Example items:

- Armored conductors, buried or submarine, including insulators, insulating materials, splices, trenching, etc
- Automatic control equipment
- Conductors, overhead or underground
- Lamps, incandescent, or other types, including glassware, suspension fixtures, brackets, etc
- Municipal inspection
- Ornamental lamp posts
- Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks
- Permits
- Posts and standards
- Protection of street openings
- Relays or time clocks
- Series contactors
- Switches
- Transformers, pole or underground

Article 220 - Uniform System of Accounts
Balance Sheet Accounts
Electric Plant in Service - Detailed Accounts
E. General Plant

1905 Land
This account shall include the cost of land used for utility purposes, the cost of which is not properly included in other land account. (See Article 230 *Definitions and Instructions* No. 8 for detail guidance.)

1908 Buildings and Fixtures
This account shall include the cost in place of buildings and fixtures used for utility purposes, the cost of which is not properly included in other Buildings and Fixtures accounts. (See Article 230 *Definitions and Instructions* No. 9.)

1910 Leasehold Improvements
This account shall include the cost of additions, improvements or alterations made to premises the utility leases from others. The cost of the leasehold improvements shall be amortized over the term of the lease or the service life of the improvement, whichever is shorter. Renewal provisions in the lease agreement shall be disregarded in amortizing leasehold improvements.

This account shall be subdivided into as many classifications as are required.

1915 Office Furniture and Equipment
This account shall include the cost of the general office furniture and equipment.
Articles of low value and/or relatively short life should be charged to the appropriate operating account when purchased.

The account shall be maintained in such a manner as to provide the cost of each piece of equipment, and be subdivided into as many classifications as are required.

1920 Computer Equipment - Hardware
This account shall include the costs of acquiring computer hardware. Hardware includes all physical equipment associated with input, processing, storage and output functions, also word processing equipment.

This account shall be subdivided as considered necessary.

1930 Transportation Equipment
These accounts shall include the cost of automobiles, small trucks, truck chassis, special truck bodies, aerial ladders, trailers and other mobile equipment.

These accounts shall be subdivided into the following:

- Automobiles
- Trucks - Under 3 tons
- Trucks - 3 tons and over.

The accounts shall be maintained in such a manner as to provide the cost of each piece of equipment.

Note: Work and service equipment is to be included in Account 1950, Power Operated Equipment.

1935 Stores Equipment
This account shall include the cost of equipment used for the receiving, shipping, handling, and storage of materials and supplies.

Example items:

- Chain falls
- Counters
- Cranes (portable)
- Elevating and stacking equipment (portable)
- Hoists
- Lockers
- Scales
- Shelving
- Storage bins
- Trucks, hand and power driven
- Wheelbarrows

1940 Tools, Shop and Garage Equipment
This account shall include the cost of tools, implements, and equipment used in construction, repair work, general shops and garages and not specifically provided for or included in other accounts.

Example items:

- Air compressors
- Anvils
- Automobile repair shop equipment
- Battery charging equipment
- Belts, shafts and countershafts
- Boilers
- Cable pulling equipment
- Concrete mixers
- Drill presses
- Derricks
- Electric equipment
- Engines
- Forges
- Furnaces
- Foundations and settings specially constructed
- Gas producers
- Greasing tools and equipment
- Hoists
- Ladders
- Lathes
- Machine tools
- Motor-driven tools
- Pneumatic tools
- Pumps
- Riveters
- Smithing equipment
- Tool racks
- Vises
- Welding apparatus
- Work benches
- Line belt and harness for line crews

- Chain saws

1945 Measurement and Testing Equipment
This account shall include the cost installed of laboratory equipment used for general laboratory purposes and not specifically provided for or included in other departmental or functional plant accounts.

Example items:

- Ammeters
- Current batteries
- Frequency changers
- Galvanometers
- Inductometers
- Laboratory standard millivolt meters and volt meters
- Meter testing equipment
- Millivolt meters
- Motor generator sets
- Panels
- Phantom loads
- Portable graphic ammeters, voltmeters, and wattmeters
- Portable loading devices
- Potential batteries
- Potentiometers
- Rotating standards
- Standard cell, reactance, resistor, and shunt
- Switchboards
- Synchronous timers
- Testing panels
- Testing resistors
- Transformers
- Voltmeters
- Other testing, laboratory, or research equipment not provided for elsewhere
- Telescopic guns

1950 Power Operated Equipment
This account shall include the cost of power operated equipment used in construction, repair and service work exclusive of equipment included in other accounts. Include, also, the tools and accessories acquired for use with such equipment and the vehicle on which such equipment is mounted.

Example items:

- Air compressors, including driving unit and vehicle
- Backhoe machines
- Boring machines
- Bulldozers
- Cranes and hoists
- Pipe cleaning machines
- Pipe coating or wrapping machines
- Tractors Crawler type
- Trenchers
- Other power operated equipment

Note: It is intended that this account include only such large units as are generally self-propelled or mounted on movable equipment.

1955 Communication Equipment
This account shall include the cost installed of telephone and wireless equipment for general use in connection with utility operations.

1960 Miscellaneous Equipment
This account shall include the cost of equipment, apparatus, etc., used in the utility operations, which is not included in any other account of this Uniform System of Accounts.

Example items:

- Kitchen equipment
- Employees' recreation equipment
- Operators' cottage furnishings
- Other miscellaneous equipment

Note: Miscellaneous equipment of the nature indicated above wherever practicable shall be included in the utility plant accounts on a functional basis.

1970 Load Management Controls - Customer Premises
This account shall include the cost of control equipment on customer premises in connection with the remote control of water heaters, and other customer equipment.

1975 Load-Management Controls - Utility Premises
This account shall include the cost of all control devices situated on utility premises, used for the purpose of controlling equipment in Account 1970 above.

1980 System Supervisory Equipment
This account shall include the costs of all control equipment used for the purposes of remote operation and control of utility transformer stations and distribution equipment.

1985 Sentinel Lighting Rental Units
These accounts shall include the installed cost of all Sentinel Lighting Rental Units. The accounts shall be subdivided into as many classifications as are required.

1990 Other Tangible Property
This account shall include the cost of tangible utility plant not provided for elsewhere.

1995 Contributions and Grants - Credit
Effective until December 31, 2011, (or date of IFRS adoption, if early adoption was elected) this account shall include amounts relating to contributions or grants in cash, services or property from governments or government agencies, corporations, individuals and others received in aid of construction or for acquisition of fixed assets.

This account shall be maintained so that the company can supply information as to the purpose of each contribution or grant, the conditions, if any, on which it was made, the amount of contributions or grants from governments or government agencies, corporations, individuals and others and the amount applicable to each Electric Plant in Service detail Account (i.e. Accounts 1606 to 1990).

Note A: Effective on January 1, 2012, (or date of IFRS adoption, if early adoption was elected) customer contributors will be recorded in Account 2440, Deferred Revenues.

Note B**:** Effective on the date of IFRS adoption on January 1, 2012, (or date of IFRS adoption, if early adoption was elected by the utility), the balance in this account should be adjusted to zero in accordance with the guidance in Article 510 *Transitional Issues Relating to the Adoption of IFRS.*

Note C**:** After the adoption of IFRS, the utility shall continue to maintain detail records as evidence in support of the amounts recorded in this account as at December 31, 2011 (or date of IFRS adoption, if early adoption was elected) relating to contributions or grants in cash, services or property from governments or government agencies, corporations, individuals and others received in aid of construction or for acquisition of fixed assets.

Article 220 - Uniform System of Accounts
Balance Sheet Accounts
Electric Plant in Service - Detailed Accounts
Other Capital Assets

2005 Property Under Finance Leases

A. This account shall include the amount recorded under finance leases for plant leased from others and used by the utility in its utility operations.

B. The electric property included in this account shall be classified separately according to the detailed Accounts (1606 to 1990) prescribed for Electric Plant in Service.

C. Records shall be maintained with respect to each finance lease reflecting: (1) name of lessor, (2) basic details of lease, (3) termination date, (4) original cost or fair market value of property leased, (5) future minimum lease payments, (6) executory costs, (7) present value of minimum lease payments, (8) the amount representing interest and the interest rate used, and (9) expenses paid.

Note: The related obligations shall be recorded in Account 2285, Obligations Under Finance Leases - Current and Account 2325, Obligations Under Finance Leases - Non-current.

2010 Electric Plant Purchased or Sold

A. This account shall be charged with the cost of electric plant acquired as an operating unit or system by purchase, merger, consolidation liquidation, or otherwise, and shall be credited with the selling price of like property transferred to others pending the distribution to appropriate accounts in accordance with Article 230 *Definitions and Instructions* No. 7.

B. Within six months from the date of acquisition or sale of property recorded herein, the utility shall file with the Board the proposed journal entries to clear from this account the amounts recorded herein.

2020 Experimental Electric Plant Unclassified

A. This account shall include the cost of electric plant which was constructed as a development plant under the provisions of paragraph C, Account 2055, Construction Work in Progress Electric, and due to the nature of the plant it is desirable to operate it for a period of time in an experimental status.

B. Amounts in this account shall be transferred to Electric Plant in Service Accounts 1606 to 1990, or Account 2075, Non Rate-Regulated Utility Property Owned or Under Finance Leases, as appropriate when the project is no longer considered as experimental.

C. The amortization of property in this account shall be charged to Account 5705, Amortization Expense, and credited to Account 2105, Accumulated Depreciation of Electric Utility Plant. The amounts herein shall be amortized over a period which would correspond to the estimated useful life of the relevant project considering the characteristics involved. However, when projects are transferred to relevant Electric Plant in Service accounts, the projects shall be reviewed and a new depreciation rate based on the revised service life and unamortized amounts will be established as required.

D. Records shall be maintained with respect to each unit of experiment so that full details may be obtained as to the cost, depreciation and the experimental status.

E. Should it be determined that experimental plant recorded in this account will fail to satisfactorily perform its function, the costs thereof shall be accounted for as directed or authorized by the Board.

2030 Electric Plant and Equipment Leased to Others
A. This account shall include the original cost of electric plant and equipment owned by the utility, but leased to others as operating units or systems, where the lessee has exclusive possession.

B. The property included in this account shall be classified according to the detailed Accounts (1606 to 1990) prescribed for Electric Plant in Service and this account shall be maintained in such detail as though the property were used by the owner in its utility operations.

2040 Electric Plant Held For Future Use
A. This account shall include the original cost of electric plant (for land and land rights see B below) owned and held for future use in electric service under a definite plan for such use, to include: (1) Property acquired (for land and land rights see B below) but never used by the utility in electric service, but held for such service in the future under a definite plan, and (2) property (for land and land rights see B below) previously used by the utility in service, but retired from such service and held pending its reuse in the future, under a definite plan, in electric service.

B. This account shall also include the original cost of land and land rights owned and held for future use in electric service under a plan for such use, to include land and land rights: (1) Acquired but never used by the utility in electric service, but held for such service in the future under a plan, and (2) previously held by the utility in service, but retired from such service and held pending its reuse in the future under a plan, in electric service. See Article 230 *Definitions and Instructions* No. 8 for detailed guidance.

C. In the event that property recorded in this account shall no longer be needed or appropriate for future utility operations, the company shall request Board approval of journal entries to remove such property from this account when the gain realized from the sale or other disposition of the property is material, prior to their being recorded. Such filings shall include the description and original cost of individual properties removed from this account, the accounts charged upon removal, and any associated gains realized upon disposition of such property.

D. Gains or losses from the sale of land and land rights or other disposition of such property previously recorded in this account and not placed in utility service shall be recorded directly in Accounts 4345 or 4350, as appropriate, except when determined to be significant by the Board. Upon such a determination, the amounts shall be transferred to Account 2410, Deferred Gains from Disposition of Utility Plant, or Account 1530, Deferred Losses from Disposition of Utility Plant, and amortized to Accounts 4345, Gains from Disposition of Utility Plant, or 4350**,** Losses from Disposition of Utility Plant, as appropriate.

E. The property included in this account shall be classified according to the detail Accounts (1606 to 1990) prescribed for Electric Plant in Service and the account shall be maintained in such detail as though the property were in service.

Note: Materials and supplies, meters and transformers held in reserve, and normal spare capacity of plant in service shall not be included in this account.

2050 Completed Construction Not Classified–Electric
At the end of the year or such other date as a balance sheet may be required by the Board, this account shall include the total of the balances of work orders for electric plant which has been completed and placed in service but which work orders have not been classified for transfer to the detailed electric plant accounts.

Note: For the purpose of reporting to the Board the classification of Electric Plant in Service by Accounts (1606 to 1990), the utility shall also report the balance in this account tentatively classified as accurately as practicable according to prescribed account classifications. The purpose of this provision is to avoid any significant omissions in reported amounts of Electric Plant in Service.

2055 Construction Work in Progress–Electric
A. This account shall include the total of the balances of work orders for electric plant in process of construction.

B. Work orders shall be cleared from this account as soon as practicable after completion of the job. Further, if a project, such as a hydroelectric project, a steam station or a transmission line, is designed to consist of two or more units or circuits which may be placed in service at different dates, any expenditures which are common to and which will be used in the operation of the project as a whole shall be included in Electric Plant in Service upon the completion and the readiness for service of the first unit. All expenditures which are identified exclusively with units of property not yet in service shall be included in this account.

C. Expenditures on development projects for construction of utility facilities are to be included in a separate subdivision in this account. Records must be maintained to show separately each project along with complete detail of the nature and purpose of the development project together with the related costs.

2060 Electric Plant Acquisition Adjustments
A. This account shall include the difference between (1) the cost to the accounting utility of electric plant acquired as an operating unit or system by purchase, merger, consolidation, liquidation, or otherwise, and (2) the original cost, estimated, if not known, of such property, less the amount or amounts credited by the accounting utility at the time of acquisition to accumulated provisions for amortization and contributions in aid of construction with respect to such property. The goodwill shall be recorded as a debit in this account and the credit is to Account 3030, Miscellaneous Paid-in Capital in the case of goodwill resulting from pushdown accounting by the parent to its subsidiary.

B. This account shall be subdivided so as to show the amounts included for each property acquisition and to Electric Plant in Service, Electric Plant Held for Future Use and Electric Plant Leased to Others. (See Article 230 *Definitions and Instructions* No. 7.)

C. Amounts recorded in this account related to an operating unit or system acquisition may be amortized to Account 5720, Amortization of Electric Plant Acquisition Adjustments, pursuant to an approval or order of the Board, over a period not longer than the estimated remaining life of the properties to which such amounts relate.

D. Amounts included in this account shall be disposed subject to Board approval.

Note: The provisions of this account shall not be construed as approving or authorizing the recording of appreciation of electric plant.

2065 Other Electric Plant Adjustments
A. This account shall include the difference between the original cost, estimated if not known, and the book cost of electric plant to the extent that such difference is not included in Account 2060, Electric Plant Acquisition Adjustments (See Article 230 *Definitions and Instructions* No. 7 under —”General classification of electric plant”.)

B. Amounts included in this account shall be classified in such manner as to show the origin of each amount and shall be disposed of as the Board may approve or direct. Note**:** The provisions of this account shall not be construed as approving or authorizing the recording of appreciation of electric plant.

2070 Other Utility Plant
This account shall include the cost of land, structures, equipment and other tangible and intangible plant assets owned by the utility, but not used in its utility operations and not included in Accounts 2030, Electric Plant and Equipment Leased to Others, 2040, Electric Plant Held for Future Use, and 2055, Construction Work in Progress - Electric.

Non rate-regulated utility assets shall not be included in this account but in Account 2075.

2075 Non Rate-Regulated Utility Property Owned or Under Finance Leases
A. This account shall include the book cost of land, structures, equipment, or other tangible or intangible property owned by the utility or under a finance lease, but not used in utility service and not included in Account 2040, Electric Plant Held for Future Use.

B. This account shall also include the amount recorded under finance leases for property leased from others and used by the utility in its non rate-regulated utility operations. Records shall be maintained with respect to each lease reflecting: (1) name of lessor, (2) basic details of lease, (3) terminal date, (4) original cost or fair market value of property leased, (5) future minimum lease payments, (6) executory costs, (7) present value of minimum lessee payments, (8) the amount representing interest and the interest rate used, and (9) expenses paid.

C. This account shall be subdivided so as to show the amount of property used in operations which are non-utility in character but nevertheless constitute a distinct operating activity of the company and the amount of miscellaneous property not used in operations. The records in support of each sub-account shall be maintained so as to show an appropriate classification of the property.

Note A**:** The gain from the sale or other disposition of property included in this account which had been previously recorded in Account 2040, Electric Plant Held for Future Use, shall be accounted for in accordance with paragraph C of Account 2040.

Note B**:** The related obligations shall be recorded in Account 2285, Obligations Under Finance Leases - Current and Account 2325, Obligations Under Finance Leases - Non-current.

2075 Non Rate-Regulated Utility Property Owned or Under Finance Leases, Sub-account Generation Facility Assets
A. This account shall include the book cost of qualifying generation facilities or assets owned by the utility or under a finance lease, but not used in utility service and not included in Account 2040, Electric Plant Held for Future Use.

B. This account shall also include the amount recorded under finance leases for generation property leased from others and used by the utility in its non rate-regulated utility operations. Records shall be maintained with respect to each lease reflecting: (1) name of lessor, (2) basic details of lease, (3) terminal date, (4) original cost or fair market value of property leased, (5) future minimum lease payments, (6) executory costs, (7) present value of minimum lessee payments, (8) the amount representing interest and the interest rate used, and (9) expenses paid.

C. This account shall be subdivided so as to show the amount of property used in operations which are non-utility in character but nevertheless constitute a distinct operating activity of the company and the amount of miscellaneous property not used in operations. The records in support of each sub-account shall be maintained so as to show an appropriate classification of the generation property.

Article 220 - Uniform System of Accounts
Income Statement
Distribution Expenses - Operations

5005 Operation Supervision and Engineering
This account shall include the cost of labour and expenses incurred in the general supervision and direction of the operation of the distribution system. Direct supervision of specific activities, such as station operation, line operation, meter department operation, etc., shall be charged to the appropriate operations account in the 5000 series based on the nature of the activity in relation to the account descriptions . (See Article 230 *Definitions and Instructions* No. 4.)

5010 Load Dispatching
This account shall include the cost of labour, materials used and expenses incurred in load dispatching operations pertaining to the distribution of electricity.

Example items:
Labour:

- Directing switching
- Arranging and controlling clearances for construction, maintenance, test and emergency purposes
- Controlling system voltages
- Preparing operating reports
- Obtaining reports on the weather and special events

Expenses:

- Communication service provided for system control purposes
- System record and report forms
- Meals, traveling and incidental expenses
- SCADA equipment related expenses

5012 Station Buildings and Fixtures Expenses
This account shall include the cost of labour, materials used and expenses incurred in operating distribution station building and fixtures recorded in Account 1808 Buildings and Fixtures and Account 1810 Leasehold Improvements.

Example items:
Labour:

- Standing watch, guarding and patrolling station and station yard
- Sweeping, mopping and tidying station
- Care of grounds, including snow removal, cutting grass, etc

Station Supplies and Expenses:

- Taxes (e.g. property taxes), light, heat, telephone
- Building service expenses
- Tool expenses
- Transportation expenses
- Meals, traveling and incidental expenses

The accounts shall be sub-divided to show the cost of operating individual stations.

5014 Transformer Station Equipment - Operating Labour
These accounts shall include labour with payroll burden incurred in operating the transformer station equipment recorded in Account 1815. The accounts shall be subdivided to obtain the cost of operating individual stations. General supervision shall be recorded in Account 5005.

Example items:

- Supervision specific to transformer station equipment operation
- Adjusting station equipment where such adjustment primarily affects performance, such as regulating the flow of cooling water, adjusting current in fields of a machine or changing voltage of regulators, changing station transformer taps
- Inspecting, testing and calibrating station equipment for the purpose of checking its performance
- Keeping station log and records and preparing reports on station equipment operation
- Operating switching and other station equipment

5015 Transformer Station Equipment - Operating Supplies and Expenses
These accounts shall include the cost of material, trucking and other expenses incurred in operating the transformer station equipment recorded in Account 1815.

Example items:

- Operating supplies, such as lubricants, commutator brushes, water, and rubber goods
- Station meter and instrument supplies, such as ink and charts
- Station record and report forms
- Small hand tools
- Transportation expenses
- Meals, traveling, and incidental expenses

5016 Distribution Station Equipment - Operating Labour
These accounts shall include labour with payroll burden incurred in operating the transformer station equipment recorded in Account 1820. The accounts shall be subdivided to obtain the cost of operating individual stations. General supervision shall be recorded in Account 5005.

Example items:

- Supervision specific to transformer station equipment operation
- Adjusting station equipment where such adjustment primarily affects performance, such as regulating the flow of cooling water, adjusting current in fields of a machine or changing voltage of regulators, changing station transformer taps
- Inspecting, testing and calibrating station equipment for the purpose of checking its performance
- Keeping station log and records and preparing reports on station equipment operation
- Operating switching and other station equipment

Note: If the utility owns storage battery equipment used for supplying electricity to customers in periods of emergency, the cost of operating labour should be recorded in this account and the cost of supplies, such as acid, gloves, hydrometers, thermometers, soda, automatic cell fillers, acid proof shoes, etc., shall be included in Account 5017. If significant in amount, a separate subdivision in each account shall be maintained for such expenses.

5017 Distribution Station Equipment - Operating Supplies and Expenses
These accounts shall include the cost of material, trucking and other expenses incurred in operating the transformer station equipment recorded in Account 1820.

Example items:

- Operating supplies, such as lubricants, commutator brushes, water, and rubber goods
- Station meter and instrument supplies, such as ink and charts
- Station record and report forms
- Small hand tools
- Transportation expenses
- Meals, traveling, and incidental expenses

5020 Overhead Distribution Lines and Feeders - Operation Labour
This account shall include labour with payroll burden incurred in operating overhead lines from the low voltage connection in the distribution station to the customers' premises but not operating labour incurred in relation to customer premises (Account 5070).

Example items

- Supervision specific to line operation
- Changing line transformer taps
- Inspecting and testing lightning arresters, line circuit breakers, switches and grounds
- Inspecting and testing line transformers for the purpose of determining load, temperature or operating performance
- Patrolling lines
- Load tests and voltages surveys of feeders and circuits

5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses
These accounts shall include the cost of material, trucking and other expenses incurred in operating overhead lines from the low voltage connection in the distribution station to the customer's premises but not operating supplies and expenses incurred in relation to customer premises (Account 5075).

Line Supplies and Expenses examples:

- Voltage surveys, either routine or upon request of customers, including voltage tests at customers' main switch
- Transferring loads, switching and reconnecting circuits and equipment for operation purposes
- Electrolysis surveys
- Inspecting and adjusting line testing equipment
- Tool expenses
- Transportation expenses
- Meals, traveling and incidental expense
- Operating supplies, such as instrument charts, rubber goods, etc

5030 Overhead Subtransmission Feeders - Operation
These accounts shall include labour with payroll burden, material, trucking and other expenses incurred in inspecting, patrolling and testing the overhead sub transmission feeder system.

5035 Overhead Distribution Transformers - Operation
This account shall include labour with payroll burden, material, trucking and other expenses incurred in removing and resetting overhead transformers and devices and also the inspection and testing while in service. The account shall be subdivided as necessary.

Note: The cost of the original setting shall be charged to Account 1850, Line Transformers.

5040 Underground Distribution Lines and Feeders - Operation Labour
These accounts shall include labour with payroll burden incurred in operating underground distribution lines from the low voltage connection in the municipal distribution station to the customers' premises but not operating labour incurred in relation to customer premises (Account 5070).

Line Labour examples:

- Supervision specific to line operation
- Changing line transformer taps
- Inspecting and testing lightning arresters, line circuit breakers, switches and grounds
- Inspecting and testing line transformers for the purpose of determining load, temperature or operating performance
- Patrolling lines
- Load tests and voltages surveys of feeders and circuits

5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses
These accounts shall include the cost of material, trucking and other expenses incurred in operating underground distribution lines from the low voltage connection in the municipal distribution station to the customers' premises but not operating supplies and expenses incurred in relation to customer premises (Account 5070).

Example items

- Voltage surveys, either routine or upon request of customers, including voltage tests at customers' main switch
- Transferring loads, switching and reconnecting circuits and equipment for operation purposes
- Electrolysis surveys
- Inspecting and adjusting line testing equipment
- Tool expenses
- Transportation expenses
- Meals, traveling and incidental expense
- Operating supplies, such as instrument charts, rubber goods, etc

5050 Underground Subtransmission Feeders - Operation
These accounts shall include labour with payroll burden, material, trucking and other expenses incurred in inspecting, patrolling and testing the underground subtransmission feeder system.

5055 Underground Distribution Transformers - Operation
This account shall include labour with payroll burden, material, trucking and other expenses incurred in removing and resetting underground transformers and devices and also the inspection and testing while in service. The account shall be subdivided as necessary.
Note: The cost of the original setting shall be charged to Account 1850, Line Transformers.

5060 Street Lighting and Signal System Expenses
This account shall include the cost of labour, materials used and expenses incurred in the operation of such plant owned by the utility, if authorized by the Board and where such work is done regularly as a part of the street lighting and signal system service.

Example items:
Labour:

- Supervision specific to street lighting and signal systems operation
- Replacing lamps and consequential cleaning of glassware and fixtures
- Routine patrolling for lamp outages, extraneous nuisances or encroachments, etc
- Testing lines and equipment including voltage and current measurement

- Winding and inspection of time switch and other controls

Materials and Expenses:

- Street lamp renewals
- Transportation and tool expense
- Meals, traveling, and incidental expenses

Note: Where the utility does not own the street lighting assets, the revenues and expenses from the provision or maintenance of street lighting services should be recorded in Account 4375, Revenues from Non-Utility Operations and 4380, Expenses from Non-Utility Operations, respectively.

5065 Meter Expenses

This account shall include the cost of labour, materials used and expenses incurred in the operation of customer meters and associated equipment.

Example items:

Labour:

- Supervision specific to meter operation
- Clerical work on meter history and associated equipment record cards, test cards, and reports
- Disconnecting and reconnecting, removing and reinstalling, sealing and unsealing meters and other metering equipment in connection with initiating or terminating services including the cost of obtaining meter readings, if incidental to such operation
- Consolidating meter installations due to elimination of separate meters for different rates of service
- Changing or relocating meters, instrument transformers, time switches, and other metering equipment
- Resetting time controls, checking operation of demand meters and other metering equipment, when done as an independent operation
- Inspecting and adjusting meter testing equipment
- Inspecting and testing meters, instrument transformers, time switches, and other metering equipment on premises or in shops excluding inspecting and testing incidental to maintenance
- Replacing or removing broken meters

Materials and Expenses:

- Meter seals and miscellaneous meter supplies
- Transportation expenses
- Meals, traveling, and incidental expenses
- Tool expenses
- Replacing or removing broken meters

Note: The cost of the first setting, including the government inspection fee, and testing of a meter is chargeable to utility plant Account 1860, Meters. The cost of removing and resetting for government inspection, including the fees, shall be a charge to this account.

5070 Customer Premises - Operating Labour

This account shall include labour with payroll burden related to providing service on assets on customers' premises which are included in Account 1855, Services.

Example items:

- Inspecting premises, including check of wiring for code compliance

- Investigating, locating, and clearing grounds on customers' wiring
- Investigating service complaints, including load tests of motors and lighting and power circuits on customers' premises; field investigations of complaints on bills or of voltage
- Radio, television and similar interference work including erection of new aerials on customers' premises and patrolling of lines, testing of lightning arresters, inspection of pole hardware, etc., and examination of customers' wiring to locate cause of interference
- Investigation of current diversion including setting and removal of check meters discovery and settlement of current diversion
- Changes in customer wiring and any other labour cost identifiable as caused by current diversion

Note A: Amounts billed customers for any work, the cost of which is charged to this account, shall be transferred to Account 4235, Miscellaneous Service Revenues.

Note B: Do not include in this account expenses incurred in connection with merchandising.

5075 Customer Premises - Materials and Expenses
This account shall include trucking, materials and other expenses related to providing services to assets on customers' premises which are included in Account 1855, Services.

Examples of services include inspection, voltages tests and the like related to labour examples listed in 5070, Customer Premises - Operating Labour.

Example items:
Materials and Expenses:

- Lamp and fuse renewals
- Materials used in the course of performing inspection, voltage tests, etc
- Tool expense
- Transportation expense, including pickup and delivery charges
- Meals, traveling and incidental expenses
- Rewards paid for discovery of current diversion

Note A: Amounts billed customers for any work, the cost of which is charged to this account, shall be transferred to Account 4235, Miscellaneous Service Revenues.

Note B: Do not include in this account expenses incurred in connection with merchandising and contract work.

5085 Miscellaneous Distribution Expenses
This account shall include the cost of labour, materials used and expenses incurred in distribution system operation not provided for elsewhere.

Example items:
Labour:

- General records of physical characteristics of lines and substations, such as capacities, etc
- Ground resistance records
- Joint pole maps and records
- Distribution system voltage and load records
- Preparing maps and prints
- Service interruption and trouble records

- General clerical and stenographic work except that chargeable to account 5065, Meter expenses

Material and Expenses:

- Operating records covering poles, transformers, manholes, cables, and other distribution facilities. Exclude meter records chargeable to Account 5065, Meter Expenses and station records chargeable to Account 5012, Station Building and Fixtures Expenses
- Janitorial work at distribution office buildings including snow removal, cutting grass, etc
- Communication service
- Building service expenses
- Miscellaneous office supplies and expenses, printing, and stationery, maps and records and first aid supplies
- Research, development, and demonstration expenses

5090 Underground Distribution Lines and Feeders - Rental Paid

This account shall include rents of property of others used, occupied, or operated in connection with the distribution system, including payments to the government authorities and others for the use and occupancy of public lands and reservations for underground distribution line rights of way. (See Article 230 *Definitions and Instructions* No. 5.) Records should permit identification of payments and parties to whom they were made.

5095 Overhead Distribution Lines and Feeders - Rental Paid

This account shall include rents of property of others used, occupied, or operated in connection with the distribution system, including payments to the government authorities and others for the use and occupancy of public lands and reservations for overhead distribution line rights of way. (See Article 230 *Definitions and Instructions* No. 5.) Records should permit identification of payments and parties to whom they were made.

5096 Other Rent

This account shall include rents for property of others used, occupied or operated in connection with the operation of the distribution system. Include rentals paid for railroad crossings, rights of ways, payments to government bodies and others for use of public or private land, etc., not otherwise included in Accounts 5090, Underground Distribution Lines and Feeders Rental Paid or 5095, Overhead Distribution Lines and Feeders - Rental Paid.

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Income Statement
Distribution Expenses - Maintenance

5105 Maintenance Supervision and Engineering
This account shall include the cost of labour and expenses incurred in the general supervision and direction of maintenance of the distribution system that cannot be directly allocated to any particular job/project. Direct field supervision of specific jobs shall be charged to the appropriate maintenance account in the 5100 series based on the nature of the activity in relation to the account descriptions. (See Article 230 *Definitions and Instructions* No. 4.)

5110 Maintenance of Buildings and Fixtures - Distribution Stations
This account shall include the cost of labour, materials used and expenses incurred in maintenance of structures, the book cost of which is included in Account 1808, Buildings and Fixtures, and 1810, Leasehold Improvements.

5112 Maintenance of Transformer Station Equipment
This account shall include the cost of labour, materials used and expenses incurred in maintenance of plant, the book cost of which is included in Account 1815, Transformer Station Equipment - Normally Primary above 50kV.

5114 Maintenance of Distribution Station Equipment
This account shall include the cost of labour, materials used and expenses incurred in maintenance of plant, the book cost of which is included in Account 1820, Distribution Station Equipment - Normally Primary below 50kV, and Account 1825, Storage Battery Equipment.
Records should permit the identification of expenses relating to each type of equipment listed above.

5120 Maintenance of Poles, Towers and Fixtures
This account shall include the cost of labour, materials used and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is included in Account 1830, Poles, Towers and Fixtures.

Example items:

Work of the following character on poles, towers, and fixtures:

- Installing additional clamps or removing clamps or strain insulators on guys in place.
- Moving line or guy pole in relocation of pole or section of line.
- Painting poles, towers, cross arms, or pole extensions.
- Readjusting and changing position of guys or braces.
- Realigning and straightening poles, cross arms, braces, pins, racks, brackets, and other pole fixtures.
- Reconditioning reclaimed pole fixtures.
- Relocating crossarms, racks, brackets, and other fixtures on poles.
- Repairing pole supported platform.
- Repairs by others to jointly owned poles.
- Shaving, cutting rot, or treating poles or crossarms in use or salvaged for reuse.
- Stubbing poles already in service.
- Supporting conductors, transformers, and other fixtures and transferring them to new poles during pole replacements.
- Maintaining pole signs, stencils, tags, etc.

The accounts shall be subdivided to show costs for subtransmission feeders and distribution lines and feeders separately.

5125 Maintenance of Overhead Conductors and Devices
This account shall include the cost of labour, materials used and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is included in Account 1835, Overhead Conductors and Devices.

Example items:
Work of the following character on overhead conductors and devices:

- Overhauling and repairing line cutouts, line switches, line breakers, and capacitor installations
- Cleaning insulators and bushings
- Refusing line cutouts
- Repairing line oil circuit breakers and associated relays and control wiring. Repairing grounds
- Resagging, retying, or rearranging position or spacing of conductors
- Standing by phones, going to calls, cutting faulty lines clear or similar activities at times of emergency
- Sampling, testing, changing, purifying, and replenishing insulating oil
- Transferring loads, switching, and reconnecting circuits and equipment for maintenance purposes
- Repairing line testing equipment

The accounts shall be subdivided to show costs for subtransmission feeders and distribution lines and feeders separately.

5130 Maintenance of Overhead Services
This account shall include the cost of labour, materials used and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is included in Account 1855, Services.

Example items:
Work of the following character on overhead services:

- Moving position of service either on pole or on customers' premises
- Pulling slack in service wire
- Retying service wire
- Refastening or tightening service bracket

5135 Overhead Distribution Lines and Feeders - Right of Way
These accounts shall include labour with payroll burden, material, trucking, and other expenses incurred in connection with tree trimming, etc. and other costs incurred in maintaining right of way subsequent to construction of a line.

These accounts may be further subdivided as follows:

- Labour and Payroll Burden
- Material
- Truck Expense
- Other Expense

5145 Maintenance of Underground Conduit
This account shall include the cost of labour, materials used and expenses incurred in the maintenance of underground distribution line facilities, the book cost of which is included in account 1840, Underground Conduit.

5150 Maintenance of Underground Conductors and Devices
This account shall include the cost of labour, materials used and expenses incurred in the maintenance of underground distribution line facilities, the book cost of which is included in Account 1845, Underground Conductors and Devices.

Example items:
Work of the following character on underground conductors and devices:

- Repairing circuit breakers, switches, cutouts, network protectors, and associated relays and control wiring
- Repairing grounds
- Retraining and reconnecting cables in manholes including transfer of cables from one duct to another
- Repairing conductors and splices
- Repairing or moving junction boxes and potheads
- Refireproofing cables and repairing supports
- Repairing electrolysis preventive devices for cables
- Repairing cable bonding systems
- Sampling, testing, changing, purifying and replenishing insulating oil
- Transferring loads, switching and reconnecting circuits and equipment for maintenance purposes
- Repairing line testing equipment
- Repairing oil or gas equipment in high voltage cable systems and replacement of oil or gas

The accounts shall be subdivided to show costs for sub transmission feeders and distribution lines and feeders separately.

5155 Maintenance of Underground Services
This account shall include the cost of labour, materials used and expenses incurred in the maintenance of underground distribution line facilities, the book cost of which is included in the underground portion of Account 1855, Services.

Example items:
Work of the following character on underground services:

- Cleaning ducts
- Repairing any underground service plant

5160 Maintenance of Line Transformers
This account shall include the cost of labour, materials used and expenses incurred in maintenance of distribution line transformers, the book cost of which is included in Account 1850, Line Transformers. The cost shall include renewing oil, painting and the like, necessary to keep the equipment in service.

Note: All lightning arresters on the distribution system, excluding pothead arresters, are considered to be transformer equipment or devices and the maintenance thereof is chargeable to this account. Records shall be kept to separately show costs related to overhead and underground transformers.

5165 Maintenance of Street Lighting and Signal Systems
This account shall include the cost of labour, materials used and expenses incurred in maintenance of plant, the book cost of which is included in Account 1875, Street Lighting and Signal Systems.

5170 Sentinel Lights - Labour
This account shall include labour related to servicing rental sentinel lights.

5172 Sentinel Lights - Materials and Expenses
This account shall include trucking, materials and other expenses related to servicing rental sentinel lights.

5175 Maintenance of Meters
This account shall include the cost of labour, materials used and expenses incurred in the maintenance of meters and meter testing equipment, the book cost of which is included in Account 1860, Meters, and Account 1945, Measurement and Testing Equipment, respectively.

The cost shall include cleaning and painting and other work necessary to keep the equipment in service. The labour and expenses incident to the operation of the meter repair department shall be a charge to these accounts.

5178 Customer Installations Expenses - Leased Property
This account shall include the cost of labour, materials used and expenses incurred in work on customer installations of leased property included in account 1870, Leased Property on Customer Premises and in rendering services to customers of the nature of those indicated by the list of items hereunder.

Example items:
Labour:

- Supervision specific to customer installations work
- Installing, connecting, reinstalling, or removing leased property on customers' premises
- Testing, adjusting, and repairing customers' fixtures and appliances in shop or on premises
- Cost of changing customers' equipment due to changes in service characteristics

Materials and Expenses:

- Materials used in servicing customers' fixtures, appliances and equipment
- Power, light, heat, telephone, and other expenses of appliance repair department
- Tool expense
- Transportation expense, including pickup and delivery charges
- Meals, traveling and incidental expenses

5195 Maintenance of Other Installations on Customer Premises
This account shall include the cost of labour, materials used and expenses incurred in maintenance of plant the book cost of which is included in Account 1865, Other Installations on Customer Premises.

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Income Statement
Other Expenses

5205 Purchase of Transmission and System Services
This account will be used to record expenses related to purchase of transmission and system services.

5210 Transmission Charges
This account will be used to record Transmission Charges incurred.

5215 Transmission Charges Recovered
This account will be used to record Transmission Charges recovered from customers. Records shall be maintained so that the quantity of electricity supplied each party and the related revenues shall be readily available.

1606 Organization
This account shall include all fees paid to federal or provincial governments for the privilege of incorporation and expenditures incident to organizing the corporation, and putting it into readiness to do business.

Example items

- Cost of obtaining certificates authorizing an enterprise to engage in the public utility business
- Fees and expenses for incorporation
- Fees and expenses for mergers or consolidations
- Office expenses incident to organizing the utility
- Stock and minute books and corporate seal.

Note A: This account shall not include any discounts upon securities issued or assumed; nor shall it include any costs incident to negotiating loans, selling bonds or other evidences of debt or expenses in connection with the authorization, issuance or sale of capital stock.

Note B: When charges are made to this account for expenses incurred in mergers, consolidations, or reorganizations, etc. amounts previously included herein or in similar accounts in the books of the entities concerned shall be excluded from this account.

Note C: This account shall include amounts related to transfer by-laws.

1608 Franchises and Consents
A. This account shall include amounts paid to the federal, provincial, or other government in consideration for franchises, consents, water power licenses, or certificates, running in perpetuity or for a specified term of more than one year, together with necessary and reasonable expenses incident to procuring such franchises, consents, water power licenses, or certificates of permission and approval.

B. If a franchise, consent, water power license or certificate is acquired by assignment, the charge to this account shall not exceed the amount paid by the utility.

C. The amortization related to any item in this account shall be recorded in Account 2120, Accumulated Amortization of Electric Utility Plant - Intangibles.

D. Records supporting this account shall be kept so as to show separately the book cost of each franchise or consent.

Note: Annual or other periodic payments under franchises shall not be included herein but in the appropriate operating expense account.

1609 Capital Contributions Paid
This account shall include capital contributions paid by a distributor to a host distributor, a transmitter or a generator for capital expenditures (e.g., under a Connection and Cost Recovery Agreement) that meet the IAS 38 Intangible Assets requirements for classification as an intangible asset. The amortization related to any item in this account shall be recorded in Account 2120, Accumulated Amortization of Electric Utility Plant – Intangibles.

1610 Miscellaneous Intangible Plant
A. This account shall include the cost of patent rights, licenses, privileges, capitalizable load profile development costs and other intangible property necessary or valuable in the conduct of utility operations and not specifically chargeable to any other account.

B. The amortization related to any item in this account shall be recorded in Account 2120, Accumulated Provision for Amortization of Electric Utility Plant - Intangibles.

C. This account shall be maintained in such a manner that the utility can furnish full information with respect to the amounts included herein.

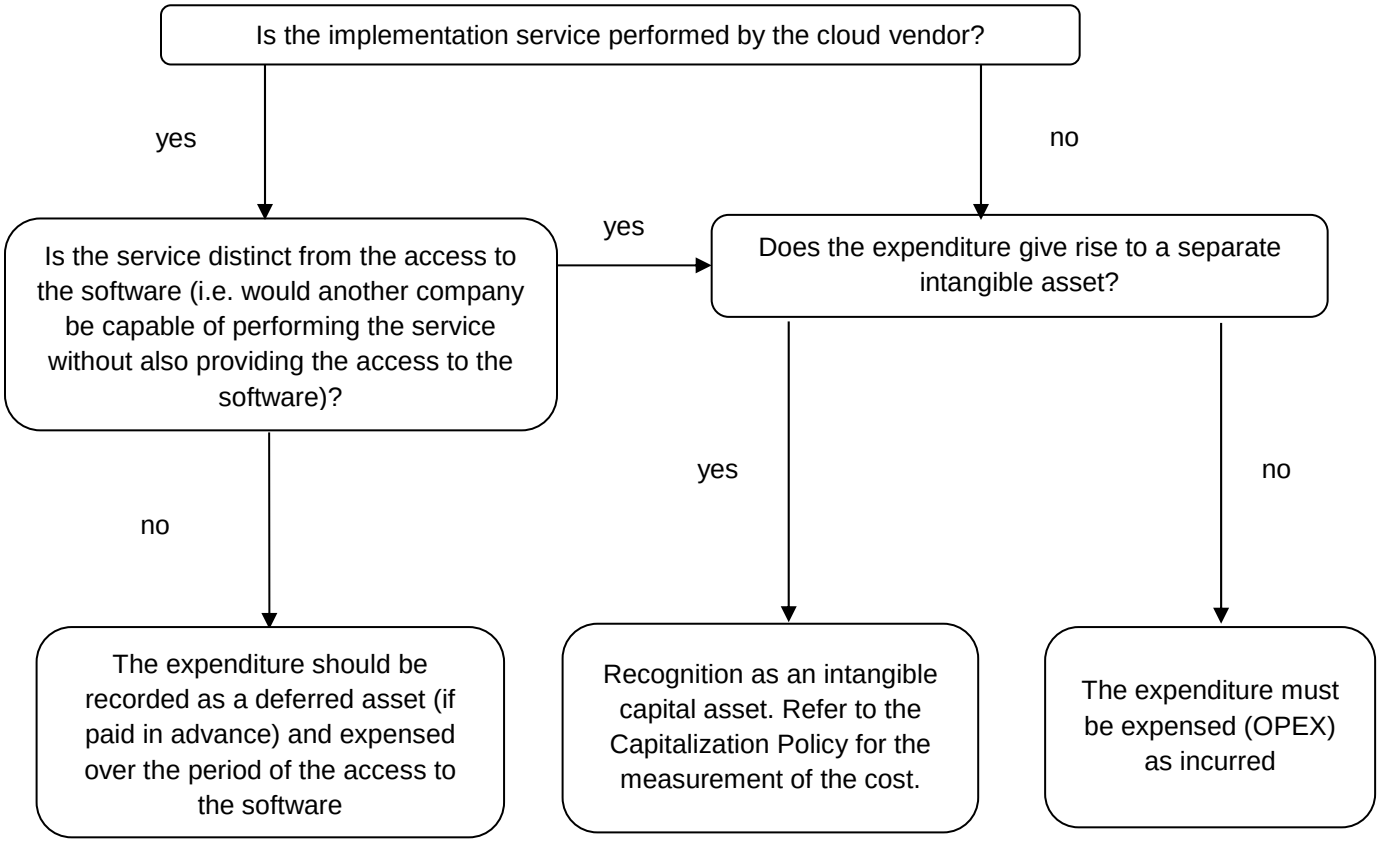
1611 Computer Software
This account shall include the cost of developed or purchased computer operating and application software that is material in amount.

Example items:

- Accounting packages
- Customer Information System (CIS)
- Groupware packages (e.g. e-mail, scheduling & conferencing programs, etc.)
- Database management system packages
- Software development tools.
- Primary development tools.

1612 Land Rights
This account(s) shall include the cost of rights, interests and privileges held by the utility in land owned by others. See Article 230 Definitions and Instructions No. 8 for detail guidance.

Note: Do not include in this account the cost of permits to erect poles, towers, etc., or to trim trees. See Account 1830, Poles, Towers and Fixtures, and Account 5135, Overhead Distribution Lines and Feeders - Tree Trimming.


Is the implementation service performed by the cloud vendor?
yes
no
Is the service distinct from the access to the software (i.e. would another company be capable of performing the service without also providing the access to the software)?
yes
Does the expenditure give rise to a separate intangible asset?
no
yes
no
The expenditure should be recorded as a deferred asset (if paid in advance) and expensed over the period of the access to the software
Recognition as an intangible capital asset. Refer to the Capitalization Policy for the measurement of the cost.
The expenditure must be expensed (OPEX) as incurred

OVERHEAD COSTS

This schedule provides a breakdown of operational, maintenance and administrative (OM&A) expenses before capitalization, in accordance with section 2.2.9 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022). OEB Appendix 2-D (Overhead Costs) is attached to this schedule.

1. BURDEN RATES

Toronto Hydro's capital work is bundled into projects which are compromised primarily of labour, material and vehicle costs. As set out in Toronto Hydro's Capitalization Policy filed at Exhibit 2A, Tab 4, Schedule 1, Appendix A, and consistent with the utility's last rebasing application, Toronto Hydro charges these costs directly to projects as they are incurred. This section details each of these three cost activities, and explain how the costs are allocated across projects.

1.1 Labour Costs

Toronto Hydro uses a standard labour rate ("SLR") to allocate labour costs to projects by using timesheets, consistent with the common industry practice. The SLR is a fully burdened hourly rate which is calculated by dividing the total compensation costs by total available hours. The total available hours consist of: (i) total working hours in a year less: (ii) leaves (e.g. vacation, sick time, and statutory holidays), as well as (iii) time not spent working on a specific operating or capital project (e.g. legislative training requirements, safety meetings, downtime, etc.).

Toronto Hydro calculates SLRs for each role in its workforce. These rates are updated on an annual basis and are initially derived based on the inputs gathered during the annual

planning process, which are subsequently adjusted for actuals at the year-end for any variances to the budgeted amounts.

As described in Exhibit 4, Tab 4, Schedule 3, Toronto Hydro has a diverse workforce of highly-skilled employees responsible for executing different types of work. The utility organizes its workforce under multiple labour classes based on management and operational needs and as such, different labour rates apply to each workforce segment. The methodology for calculating Toronto Hydro's SLRs is consistent with the last rate application.

1.2 Material Handling On-cost

A material handling on-cost charge is applied to material issuances from the warehouse to allocate the fully burdened rate of material costs to projects. Toronto Hydro applies a standard fixed on-cost rate on material moving average price to recover costs associated with procurement, and warehousing activities. The methodology for calculating on-cost rate, described in more detail below, is consistent with the last rebasing application.[1]

The on-cost rate is calculated by dividing procurement and warehousing related operating expenses that meet the capitalization criteria as described in Toronto Hydro's Capitalization Policy[2] with the dollar value of material moving through the warehouse in a given year. This rate is applied as a fixed percentage on all material issuances to capital and operating projects to recover cost of supply chain services to projects. The costs recovered in the material surcharge include costs as described in the Supply Chain Services program (Exhibit 4, Tab 2, Schedule 13), the Facilities Management program (Exhibit 4, Tab 2, Schedule 12), and the Allocations and Recoveries schedule (Exhibit 4, Tab 2, Schedule 21).

[1] EB-2018-0165, Exhibit 4A, Tab 2, Schedule 13.
[2] Exhibit 2A, Tab 4, Schedule 1, Appendix A.

Toronto Hydro calculates the on-cost rate on an annual basis, initially derived based on the inputs gathered during the annual planning process, and subsequently adjusted for actuals at the year-end process.

1.3 Vehicle Costs

Toronto Hydro uses a standard vehicle hire rate ("VHR") to allocate vehicle costs to projects by using timesheets, consistent with the common industry practice. The VHR is a fully burdened hourly rate which is calculated by dividing: (i) operation, maintenance, and repair costs as described in the Fleet and Equipment Services program (Exhibit 4, Tab 2, Schedule 11), (ii) fuel costs, and (iii) depreciation by total available hours. The methodology for calculating VHR is consistent with the last rebasing application with minor changes described in more detail below.

The total available hours consist of: (i) total working hours in a year less: (ii) leaves (as the vehicles are not operated when employees are on leaves such as vacation and statutory holidays), as well as (iii) time not spent working on a specific operating or capital projects (e.g. legislative training requirements, safety meetings, downtime, etc.).

Toronto Hydro calculates the VHR for each of the vehicles in its fleet. These rates are updated on an annual basis, initially derived based on the inputs gathered during the planning process, which subsequently adjusted for actuals at the year-end process.

Since the last rebasing application, Toronto Hydro updated its approach for the calculation of available hours to deduct leaves and time not spent working on specific operating or capital jobs from total working hours; previously total working hours were deducted for a factor for vehicle repairs and maintenance.

2. CAPITALIZED OVERHEAD COSTS

Tables 1 and 2 below summarize Toronto Hydro's capitalized overhead costs for the current 2020-2024 and the future 2025-2029 rate period.

Table 1: 2020-2024 Actual and Bridge Overhead Capitalization Costs ($ Millions)

Capitalized OM&A	2020 Actuals	2021 Actuals	2022 Actuals	2023 Bridge	2024 Bridge
Labour Capitalization	(117.7)	(99.0)	(117.5)	(115.0)	(130.9)
Vehicle Capitalization	(4.2)	(5.7)	(6.0)	(5.4)	(5.6)
Material Handling On-cost	(12.4)	(12.0)	(14.1)	(15.8)	(17.8)
Total Capitalized OM&A	**(134.3)**	**(116.7)**	**(137.6)**	**(136.2)**	**(154.3)**

Table 2: 2025-2029 Forecast Overhead Capitalization Costs ($ Millions)

Capitalized OM&A	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Labour Capitalization	(140.9)	(151.9)	(162.4)	(172.7)	(183.9)
Vehicle Capitalization	(5.6)	(5.7)	(5.8)	(5.8)	(5.9)
Material Handling On-cost	(20.3)	(22.1)	(23.5)	(24.0)	(25.6)
Total Capitalized OM&A	**(166.8)**	**(179.7)**	**(191.7)**	**(202.5)**	**(215.4)**

Tables 3 and 4 below summarize the percentage of OM&A capitalized during the current 2020-2024 rate period and the future 2025-2029 rate period, respectively.

Table 3: 2020-2024 Actual and Bridge Percentage of Capitalized OM&A

OM&A ($ Millions)	2020 Actuals	2021 Actuals	2022 Actuals	2023 Bridge	2024 Bridge
Total OM&A Before Capitalization (B)	422.4	394.2	418.0	437.7	479.8
Total Capitalized OM&A (A)	(134.3)	(116.7)	(137.6)	(136.2)	(154.3)
% of Capitalized OM&A (A/B)	**-32%**	**-30%**	**-33%**	**-31%**	**-32%**

Table 4: 2025-2029 Forecast Percentage of Capitalized OM&A

OM&A ($ Millions)	2025	2026	2027	2028	2029
Total OM&A Before Capitalization (B)	509.8	537.7	561.9	588.0	615.0
Total Capitalized OM&A (A)	(166.8)	(179.7)	(191.7)	(202.5)	(215.4)
% of Capitalized OM&A (A/B)	**-33%**	**-33%**	**-34%**	**-34%**	**-35%**

In the current 2020-2024 rate period, capitalized OM&A averages at 32 percent per year, whereas in the next rate period the average is forecasted at 34 percent. This is primarily attributed to greater labour capitalization driven by increased headcount as set out in the utility's workforce plan at Exhibit 4, Tab 4. At a macro level, this trend shows that the utility's workforce plan is driven in large part by the need to support the execution of a larger capital plan as outlined in Exhibit 2B. Since not all workforce-related costs can be directly attributed to the construction or creation of capital assets, a corresponding increase in OM&A (after capitalization) is also necessary to enable the execution of a larger capital work program. Please see Exhibit 4, Tab 1, Schedule 1 for a further discussion of the relationship between OM&A, capital expenditures and workforce.

COST OF ELIGIBLE INVESTMENTS FOR THE CONNECTION OF QUALIFYING GENERATION FACILITIES

This schedule summarizes the treatment of costs incurred to connect, or enable the connection, of Renewable Energy Generation ("REG") facilities to Toronto Hydro's distribution system, as eligible investments for provincial rate recovery under section 79.1 of the *Ontario Energy Board Act, 1998.*[1] Chapter 5.3 and Appendix A of the OEB's Filing Requirements for Electricity Distributor Rate Applications invites distributors to apply for provincial rate protection associated with costs incurred to make eligible investments.[2]

1. REG CONNECTIONS

As of December 31, 2022, Toronto Hydro connected 2,280 REG projects representing over 116.2 MW of capacity, and completed approximately 751 MW of pre-assessment capacity reviews. Toronto Hydro anticipates over 1,700 new REG connections during the 2023 through 2029 period, with a corresponding capacity of 74 MW. By the end of the decade, the utility forecasts approximately 200 MW of total REG capacity connected to its grid.[3]

As part of its capacity planning process outlined in Exhibit 2B, Section D4, the utility identified a number of constraints that impact DER (including REG) connections to the distribution grid, including: limited breaker and station equipment capacity due to short circuit capacity constraints; reverse power flow limitations based on transformer thermal capacity and minimum load requirements; anti-islanding conditions for DG; and system thermal limits and load transfer capability.

[1] Cost Recovery re Section 79.1 of the Act, O. Reg. 330/09, at s. 1(2).
[2] See also O. Reg. 330/09 made under the Act.
[3] For further information, please refer to Customer Connections (Exhibit 2B, Section E5.1).

Short circuit capacity constraints on station equipment are the primary constraint for REG connections. To determine the short circuit capacity at stations and other locations on the distribution system, Toronto Hydro employs sophisticated fault and power flow simulation models. These models predict how much fault current will flow to a specific location from generators located throughout the distribution system. The presence of REG on distribution feeders can contribute to fault current that can cause station equipment, such as circuit breakers, to exceed short circuit capacity limits. Toronto Hydro completes a study for each new REG application to monitor the available existing short circuit capacity of the system.

2. REI INVESTMENT SUMMARY

To address the above-noted constraints at the distribution level, Toronto Hydro intends to undertake a number of Renewable Enabling Improvement ("REI") investments as part of its 2025-2029 Distribution System Plan ("DSP") filed at Exhibit 2B.

2.1 Generation Protection, Monitoring, and Control (GPMC) Program

The GPMC program includes two types of REI investments:

- **Bus-Tie Reactors**: Bus-tie reactors lower the short circuit current on the station bus and distribution system by insertion of an impedance at the bus-tie point. Toronto Hydro proposes to work with Hydro One to install bus-tie reactors at Richview, Runnymede, Cecil, Esplanade, Leslie and Woodbridge TS to eliminate the existing fault current constraint, which will enable REG connections. For additional details, please refer to the Generation Protection, Monitoring, and Control (GPMC) Program (Exhibit 2B, Section E5.5).
- **Remote Monitoring and Control of Generation (SCADA)**: During the 2020-2024 plan period, Toronto Hydro is installing monitoring and control systems for all new distributed generation ("DG") connections. These real-time monitoring and control

systems communicate with REG resources via communication networks connected to the utility's supervisory control and data acquisition ("SCADA") system to enable safe operation of the distribution system and feeder management of bi-directional distribution grid flows. The technology provides system planners and operators real-time visibility to manage generation-to-load ratios within tolerable levels and ensure that the anti-islanding feature of DG facilities operate in the event of a distribution system fault.

Toronto Hydro must continue to invests in the GPMC program to enable safe and reliable connection and integration of REG resources in the 2025-2029 rate period. In accordance with the DSC, the utility's costs associated with installing monitoring and control technology are limited to REG resources, as non-renewable generation projects bear the cost of this technology.

2.2 Energy Storage

Studies show that significant penetration of REG can lead to destabilizing grid parameters.[4] Energy storage systems ("ESS") can be leveraged to stabilize the grid by balancing the minimum load to generation ratios ("MLGR") on feeders with REG connections. Rather than curtailing the generation output of REG facilities connected to feeders where minimum load is low, renewable enabling ESS can be deployed (as a load) to increase the load to generation ratio to the recommended threshold. Toronto Hydro plans to deploy nine energy storage systems with an aggregate capacity of 10.2 MW on nine distribution feeders that are forecast to have high generator to minimum load ratios over the 2025-2029 period.

[4] M. Begovic et. al., *Impact of Renewable Distributed Generation on Power Systems*, Proceedings of the 34th Hawaii International Conference on System Sciences (2001), available at <https://pserc.wisc.edu/ecow/get/publicatio/2000public/CSSAR01.PDF>.

In the 2020-2024 Decision (EB-2018-0165), the OEB directed Toronto Hydro to provide an assessment of the appropriate share of benefits for ESS projects as a part of future requests for funding for provincial rate application when ESS projects may provide additional benefits to the distribution system, like demand response and grid capacity relief.[5] However, Toronto Hydro notes that the 2020-2024 ESS program included proposed investments in grid performance ESS and customer-specific ESS, in addition to renewable enabling ESS.[6] In the 2025-2029 rate period, Toronto Hydro's ESS program targets the enablement of REG connections and does not contemplate additional use cases to support the distribution system. As a result, Toronto Hydro proposes to apply the generic 6 percent direct benefit assumption for enabling improvement investments in accordance with the Chapter 2 Filing Requirements. [7]

2.3 Stations Expansion

Over the 2025-2029 period, Toronto Hydro needs to expand Sheppard TS to alleviate system constraints for connecting DERs in this area. The currently available short circuit capacity of the Sheppard TS EZ bus in 2023 is -57.3 MVA, indicating a significant lack of short circuit capacity which will persist into the future. By 2029, the constraints are expected to worsen to -91.4MVA. The new bus at Sheppard TS will introduce an estimated 126 MVA of new short circuit capacity at the station to enable DER growth. The utility selected this option due to the technical limitations of installing a bus-tie reactor to the Gas Insulated Switchgear (GIS) bus at Sheppard TS.[8] /C

[5] EB-2018-0165, Decision and Order (December 19, 2019) at pages 117 and 119.
[6] Ibid. at pages 109-110.
[7] Ontario Energy Board, Filing Requirements for Electricity Distributor Rate Applications, Chapter 2 (December 15, 2022), Appendix A.
[8] For more details regarding the limitations, please refer to Exhibit 2B, Section E5.5 – Generation, Protection, Monitoring and Control and Exhibit 2B, Section E7.4 – Stations Expansion. /C

2.4 IESO Letter of Comment Regarding REG Investments

The IESO reviewed Toronto Hydro's REG investment plans, and confirmed that the forecasted REG and other DER connections are an input to the regional planning process. For more information, please refer to Exhibit 2B, Section B at Appendix G.

3. ELIGIBLE INVESTMENTS COSTS

Table 1 summarizes the cost of planned REI investments in 2025 to 2029 rate period.[9]

Table 1: Renewable Enabling Improvements ("REI") from 2025-2029 ($ Millions)

Capital Program	2025	2026	2027	2028	2029	Total
Generation, Protection, Monitoring, and Control	5.9	6.1	6.3	6.5	10.3	35.0
Energy Storage	3.6	3.6	7.5	3.8	4.0	22.5
Stations Expansion – Sheppard TS Bus Expansion	-	0.5	4.5	5.0	5.0	15.0
Totals	**9.5**	**10.2**	**18.3**	**15.3**	**19.3**	**72.5**

/C

/C

4. PROVINCIAL RATE PROTECTION

Toronto Hydro applied the six percent direct benefit percentage provided by the OEB with respect to REI investments to calculate the provincial rate protection amounts. The detailed breakdown is provided in the OEB Appendices 2-FA and 2-FB at Exhibit 2A, Tab 5, Schedules 2 to 6.[10] Three versions of the OEB Appendices 2-FA and 2-FB are filed: one for Energy Storage, one for Generation, Protection, Monitoring, and Control systems, and one for Stations Expansion. This is necessary, as the useful lives of these assets are different. Further, the OEB Appendices reflect the 2020 opening balances, which arise from the REI in

/C

[9] Toronto Hydro is not proposing any specific Renewable Expansion investments during 2025-2029.
[10] Appendix 2-FC provided in Schedule 4 is not applicable.



TORONTO HYDRO®

DISTRIBUTION SYSTEM PLAN

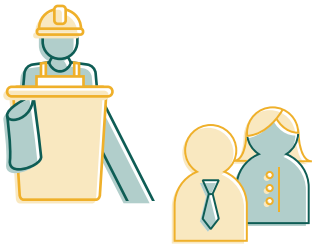
2025 – 2029

SERVICE AREA





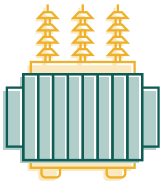
18%
of the provincial demand



1,245[1]
employees



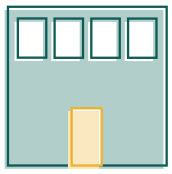
37
terminal stations



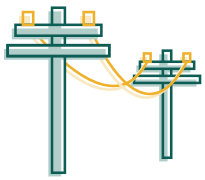
17,060[1]
primary switches



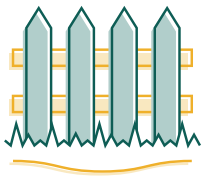
61,300[1]
distribution transformers



139
in-service municipal substations



15,393[1]
circuit kilometres of overhead wires



13,765[1]
circuit kilometres of underground wires



183,620[1]
poles



4
operation centres



1
control centre



790,000[1]
Total customers



707,178
Residential Service customers
(includes houses, apartments and condominiums)



82,820
General Service customers with monthly peak demand of less than 5,000 kW
(includes schools, restaurants and most shopping malls)



42
Large Users with monthly peak demand of 5,000 kW or greater[2]
(includes hospitals, universities and large manufacturers)

[1] Figures are approximate.

[2] Averaged over a 12-month period.

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A Distribution System Plan Overview

A1 Introduction

Toronto Hydro's Distribution System Plan ("DSP") provides a detailed and comprehensive view of the utility's capital investment plans and supporting information for the 2025-2029 period. The capital programs described and justified in this plan address urgent and necessary work related to the distribution system assets that safely power the City of Toronto, as well as the general plant assets that keep the utility's "24/7" operations running and responsive to customer needs and requests.

This plan continues the utility's effort to renew a significant backlog of deteriorated and obsolete assets at risk of failure, and to adapt to the continuously evolving challenge of serving and operating within a dense, mature, and growing major city. In addition, this plan allows Toronto Hydro to meet the demands of a more dynamic environment driven by evolving customer preferences and increases in future customer demand due to an unprecedented energy transition.

Toronto Hydro is on track to successfully complete its previous plan for 2020-2024, with adjustments for typical changes and evolving circumstances, including the final rates approved by the Ontario Energy Board ("OEB") for that period. Due to the imposition of a 0.9 percent stretch-factor on Toronto Hydro's capital related revenue requirement, along with other drivers such as extraordinary inflation and increases in customer connections and load demand needs, the utility had to manage its 2020-2024 capital plan with a constrained level of funding relative to the needs and the costs of the plan. To do so, the utility reprioritized projects and adjusted program pacing as needed. Where possible, Toronto Hydro balanced the execution of the plan to deliver on high-priority objectives, and manage performance across numerous outcomes. Key objectives and outcomes included:

- Removing assets containing or at risk of containing PCB from the system by 2025 to comply with environmental obligations;
- Removing box construction framed poles from the system by 2026 to advance public and employee safety outcomes;
- Ensuring that the grid has sufficient capacity to serve areas of high-growth and development in the city and to connect customers in a timely and efficient manner;
- Installing monitoring and control equipment in areas like the network system to increase system observability and drive operational productivity;

- Replacing assets at a pace sufficient to maintain reliability with historical levels of performance and to maintain system health in line with 2017 condition; and
- Staying on track to complete the Copeland TS – Phase 2 project and the Control Operations Reinforcement program on time and within budget.

Despite the progress achieved during the 2020-2024 rate period, investing in the short-term performance and long-term viability of an aged, deteriorated, and highly utilized system, while preparing the system to meet the demands of increased electrification, remains a priority for the utility. Extreme weather events, accompanied by growing evidence of the impact of climate change on weather patterns in Toronto, have amplified this need, underscoring the challenge to build a resilient system for the long-term. At the same time, evolving energy needs driven by decarbonization efforts, increased electrification, the proliferation of Distributed Energy Resources ("DERs"), the digitalization of the economy, increasing technology and innovation are driving a more dynamic system that is transitioning away from the usual patterns of supply and demand. This is adding additional complexity and urgency to the challenge of modernizing the grid, which in turn is driving investment needs in information technology and cyber security solutions.

The 2025-2029 DSP strikes a balance between these system needs and customer preferences, including:

- Price and reliability as top priorities, with reliability becoming increasingly important to residential customers, especially reducing the length of outages during extreme weather events;
- Expectations to invest in new technology to reduce costs and make the system better even if the benefits are not immediate, as long as the costs and benefits are clear; and
- Proactive investment in system capacity to ensure high growth areas do not experience a decrease in service levels.

The resulting five-year capital expenditure plan represents the minimum level of investment needed to confront the many and diverse challenges that the utility faces as a steward of the grid. Through an outcomes-oriented, customer-focused integrated planning process, this plan was designed to achieve balance between price and service quality performance both in the near-and longer-term, while readying the grid with least regrets investments to serve the needs of an increasingly electrified economy.

Toronto Hydro developed the DSP in full accordance with Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (2022), and in alignment with the principles and objectives of the OEB's *Renewed Regulatory Framework* ("RRF"), including the guidance in the OEB's Handbook for Utility Rate Applications (2016). In addition to the expenditure plan and forecast information for 2025-2029, the DSP provides historical and bridge year information for 2020-2022 and 2023-2024 respectively, including information on expenditures and accomplishments, material variances, and measured performance during the 2020-2024 plan period. In developing this DSP, Toronto Hydro built upon the experience of its last DSP (covering the 2020-2024 period) and the OEB's findings in the 2020 Custom IR Application, including refining successful elements (e.g. customer engagement, outcomes framework) and making substantial enhancements to certain fundamental elements (e.g. Asset Condition Assessment).

A2 DSP Organization

The 2025-2029 DSP consists of the following five major sections:

- **Section A – Distribution System Plan Overview:** Provides an overview of the key elements of the 2025-2029 DSP, including brief summaries of the 2025-2029 Capital Expenditure Plan and its drivers and outcomes; the Asset Management System including the principles, processes, and methodologies that underpin the plan; and the Customer Engagement results that informed the plan.
- **Section B – Coordinated Planning with Third Parties:** Provides an overview of how Toronto Hydro coordinates infrastructure planning with third parties, including information regarding broad regional planning efforts, and consultation with customers and telecommunication entities.
- **Section C – Performance Measurement for Continuous Improvement:** Provides an overview of Toronto Hydro's performance measurement framework and describes Toronto Hydro's historical reliability performance.
- **Section D – Asset Management Process:** Describes Toronto Hydro's asset management system, the current state of the assets and system performance challenges, and the utility's asset lifecycle optimization and risk management practices and methodologies. It also includes details on the utility's strategy to manage system capacity and modernize the grid effectively; as well as its Net Zero 2040 strategy.[1] The processes, tools, and information in this section were used to derive the 2025-2029 Capital Expenditure Plan.
- **Section E – Capital Expenditure Plan:** Describes how Toronto Hydro leveraged various substantive inputs – including Customer Engagement findings – to develop the 2025-2029 Capital Expenditure Plan and its customer-focused objectives. This section also contains detailed justifications and business cases for the 20 capital programs that constitute the plan.[2]

[1] These strategies are provided in Sections D4, D5, and D7 respectively.
[2] The vintage of asset data used within the DSP is primarily from year end 2022, unless noted otherwise, with the exception of the system peak load forecast, which was as of Oct, 2022.

A2.1 Concordance with the Chapter 5 Filing Requirements

The structure of Toronto Hydro's DSP generally concords with the headings of the OEB's Chapter 5 Filing Requirements. This concordance is summarized in Table 1 below.

Table 1: Concordance between DSP Sections and Chapter 5 Headings

DSP Sections	Filing Requirement Headings
Section A	5.2.1 – Distribution System Plan Overview
Section B	5.2.2 – Coordinated Planning with Third parties
Section C	5.2.3 – Performance Measurement for Continuous Improvement
Section D	5.3 – Asset Management Process
Section E	5.4 – Capital Expenditure Plan

There are minor exceptions to the concordance between Chapter 5 and DSP headings as follows:

- With respect to requirements under section 5.2.3, Toronto Hydro does address reliability-related requirements within section C, but Service Quality Requirements ("SQR"), including OEB Appendix 2-G, are addressed outside the DSP within the utility's overall Historical Performance Results evidence at Exhibit 1B, Tab 3, Schedule 2. Toronto Hydro briefly discusses achievement of objectives for continuous improvement from the 2020-2024 DSP in section C, but provides amore detailed discussion in section E4 and Exhibit 1B, Tab 3, Schedule 2.
- Toronto Hydro addresses transmission or high voltage assets deemed as distribution assets (under section 5.3 of filing requirements) in Exhibit 2A, Tab 1, Schedule 1.
- Although touched on in section D4, the main narrative addressing "System Capability Assessment for Renewable Energy Generation and Distributed Energy Resources" requirements under section 5.3 remains in the Capital Expenditure Plan section of the DSP (Section E3) for continuity with Toronto Hydro's 2020-2024 DSP structure.
- CDM Activities to Address System Needs under 5.3 are discussed at a high-level within section D (e.g. see D3.3.2.3, D4.2, or D5.2.2), and a more comprehensive discussion of these activities (i.e. demand response/flexibility services) and how they were integrated in planning is provided within the Non-Wires Solutions ("NWS") program evidence within the Capital Expenditure Plan (E7.2).

A3 System Challenges and Trends

This section provides an overview of the system and operational investment needs facing Toronto Hydro during the 2025-2029 forecast period. For a comprehensive discussion of Toronto's existing distribution system assets, configurations, climate, and utilization please refer to Section D2.

A3.1 Deteriorating and Obsolete Assets

Toronto Hydro owns and operates a mature distribution system. Despite its achievements in renewing the grid and improving reliability over the last decade, defective equipment continues to be a leading contributor to the duration of outages on the grid, representing approximately 40 percent of annual power interruptions experienced by customers based on duration (excluding Loss of Supply and Major Events).[3]

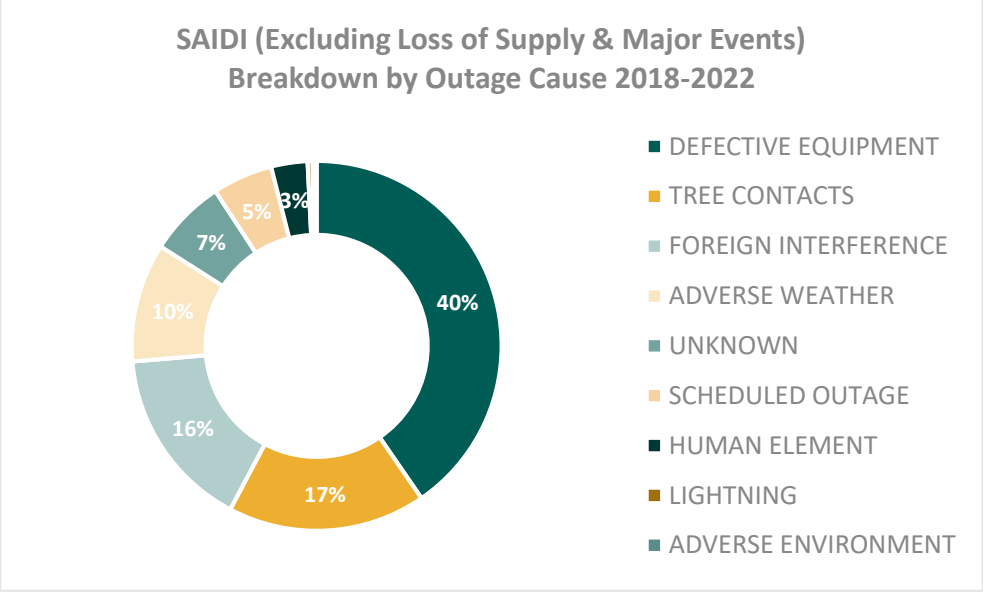

Figure 1: SAIDI (Excluding Loss of Supply & Major Events) Breakdown by Outage Cause 2018-2022

Toronto Hydro continues to face asset condition pressures across all parts of its system over the next rate period. The utility's Asset Condition Assessment ("ACA") demographic results, based on its Condition Based Risk Management ("CBRM") methodology, indicate substantial asset investment needs for a number of critical asset classes over the plan period. For Toronto Hydro's high-volume overhead and underground asset populations, the rate of asset deterioration expected by the end

[3] For more information on Toronto Hydro's historic reliability performance see Exhibit 2B, Section C

of the next rate period is projected to be roughly the same as it was in the equivalent analysis performed in 2018. While the rate of deterioration is somewhat lesser for network and stations assets, these smaller asset populations are still exhibiting significant projected deterioration and will require sustained investment to manage failure risks and other obsolescence-related risks (e.g. heightened risk of flood damage).[4]

In addition to asset condition, approximately a quarter of the utility's grid equipment continues to operate past useful life. An additional 11 percent is expected to reach that point by 2030, unless the utility invests in upkeeping system infrastructure in the 2025-2029 period.

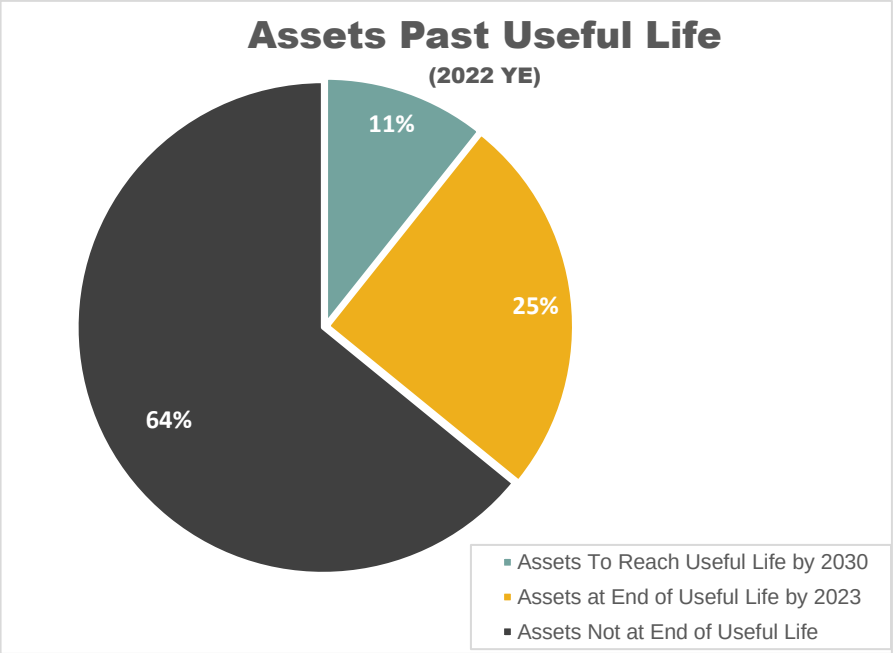

Figure 2: Percentage of Assets Past Useful Life

Allowing the number of assets past useful life, or in deteriorated condition, to grow increases the likelihood of power outages due to equipment failure, puts public and employee safety at risk, and leads to negative environmental outcomes. To manage these risks, Toronto Hydro must regularly inspect equipment to maintain its condition, or replace equipment that is in bad condition or performing poorly, before a failure occurs.[5]

[4] Refer to Exhibit 2B, Section E2.2.1.1 for an overview of asset condition demographics.
[5] Exhibit 2B, Section E2

The utility also continues to face challenges related to higher-risk, obsolete, legacy assets, and asset configurations such as rear lot plant, box construction, non-submersible network equipment, and direct-buried cable. Legacy assets are specific asset types, configurations, or sub-systems that do not meet current Toronto Hydro standards, often featuring obsolete components with limited or no suppliers or skilled labour to support maintenance, repair, or replacement. Due to asset-specific defects or deficiencies, these assets typically carry elevated reliability, safety, or environmental risks. For example, direct-buried cable and non-submersible network protectors are highly susceptible to moisture-related damage and continue to be significant contributors to reliability and safety risk.

In light of the age, condition, and legacy asset risks discussed above, Toronto Hydro developed a risk-calibrated plan to invest the minimum required to prevent a decline in reliability over the short- and long-term while investing to reduce potentially significant impacts for customers in areas served by legacy assets such as direct-buried cable and rear-lot plant.

A3.2 Complex Operating Conditions

Toronto Hydro operates in a complex urban environment based on the dense nature of the city's population, the age of the city's infrastructure, and the nature of its customer base. These each pose material challenges in the utility's day-to-day operations.

Toronto is an urban service territory with a population density of 4,428 people per kilometer.[6] Table 2 below compares Toronto's population density with the five largest cities in Ontario:

Table 2: Ontario Cities Population Density[7]

Ontario's 5 Largest Cities by Population	Population (People)	Land Mass (km^2)	Population Density (People/km)
Toronto	2,794,356	631.1	4,428
Ottawa	1,017,449	2788.2	365
Mississauga	717,961	292.74	2,453
Brampton	656,480	265.89	2,469
Hamilton	569,353	1118.31	509

Based on Census Subdivision data from 2021 Census

[6] The City of Toronto is home to approximately three million people within a land mass of 631.1km per Statistics Canada, Canada's Large Urban Centres Continue to Grow and Spread (February 9, 2022) https://www150.statcan.gc.ca/n1/daily-quotidien/220209/dq220209b-eng.htm; Statistics Canada, Defining Canada's Downtown Neighbourhoods: 2016 Boundaries (May 11, 2021)

[7] Statistics Canada, Table 98-10-0002-01 Population and dwelling counts: Canada and census subdivisions (municipalities) https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=9810000201

The density of Toronto Hydro's service territory is unique even within an international context due to the ever-increasing number of high-rise buildings. As seen in Table 3 below, New York City is the only urban centre in the world with more high-rise buildings than Toronto:

Table 3: International Cities High-Rise Buildings[8]

Rank	City	Country	Highrise Buildings
1	New York City	United States	6,223
2	**Toronto**	**Canada**	**2,598**
3	Seoul	South Korea	2,578
4	Dubai	United Arab Emirates	2,360
5	Hong Kong	China	1,916
6	Tokyo	Japan	1,533
7	Busan	South Korea	1,311
8	Kyiv	Ukraine	1,275
9	Chicago	United States	1,247
10	Shanghai	China	1,236

As a dense and old city by North American standards, Toronto also suffers from a challenging combination of legacy standards, limited availably of rights of way for locating distribution equipment, underground congestion which drives a need for increased co-ordination with other utility providers (e.g. water, transit, natural gas, telecommunications), complex permitting and approval processes, longer drive times due to traffic congestion, limitations on the size and scale of distribution assets, and disruptions related to large-scale local events. All of these considerations translate into significant planning and coordination requirements, adding both time and costs to system maintenance, renewal and enhancement investments.[9]

Beyond challenges created by service territory, density and asset vintage, the unique customer base in the downtown core places additional weight on Toronto Hydro's responsibility as a system operator. This customer composition – which includes major hospitals, the provincial legislature, and headquarters of banks, businesses and other critical financial institutions – necessitates elevated requirements for reliability and continuity of service to customers whose operations are critical to

[8] Highrise building categorized as a multi-floor building at least 12 stories or 35m in height. As per data from SkyscraperPage, Global Cities & Buildings Database https://skyscraperpage.com/cities/#notes
[9] Exhibit 1B, Tab 3, Schedule 3

the sound functioning of the provincial and federal economy. As a result, Toronto Hydro's downtown system is designed and operated with a high-level of redundancy, which in turn requires that additional prudent costs be incurred.[10]

A3.3 A Growing City

The population of Toronto is also increasing and expected to grow by approximately 23.8 percent between 2021 and 2031, a marked increase from the 6.8 percent growth over the prior decade (from 2011 to 2021).[11] The growth is concentrated in certain pockets, namely the downtown core and along the transit corridors, and is oriented vertically with a continuing trend of high-rise developments. This has resulted is a marked need for new housing, transit solutions, and infrastructure, all of which needs to be serviced by Toronto Hydro in the years to come.[12]

This growth is underscored by the fact that Toronto has led the North American crane count since 2015 by a margin that is almost equivalent to the rest of the cities combined.[13]

[10] Ibid
[11] City of Toronto, Toronto's Population Health Profile (February 2023) https://www.toronto.ca/wp-content/uploads/2023/02/940f-Torontos-Population-Health-Profile-2023.pdf
[12] Exhibit 2B, Section D2
[13] Urbanize Toronto, RLB Crane Index Records 238 Cranes in Toronto During Q1 2023 (April 15, 2023) https://toronto.urbanize.city/post/rlb-crane-index-records-238-cranes-toronto-during-q1-2023#:~:text=According%20to%20the%20latest%20report,%2C%20Chicago%20(14)%2C%20Honolulu

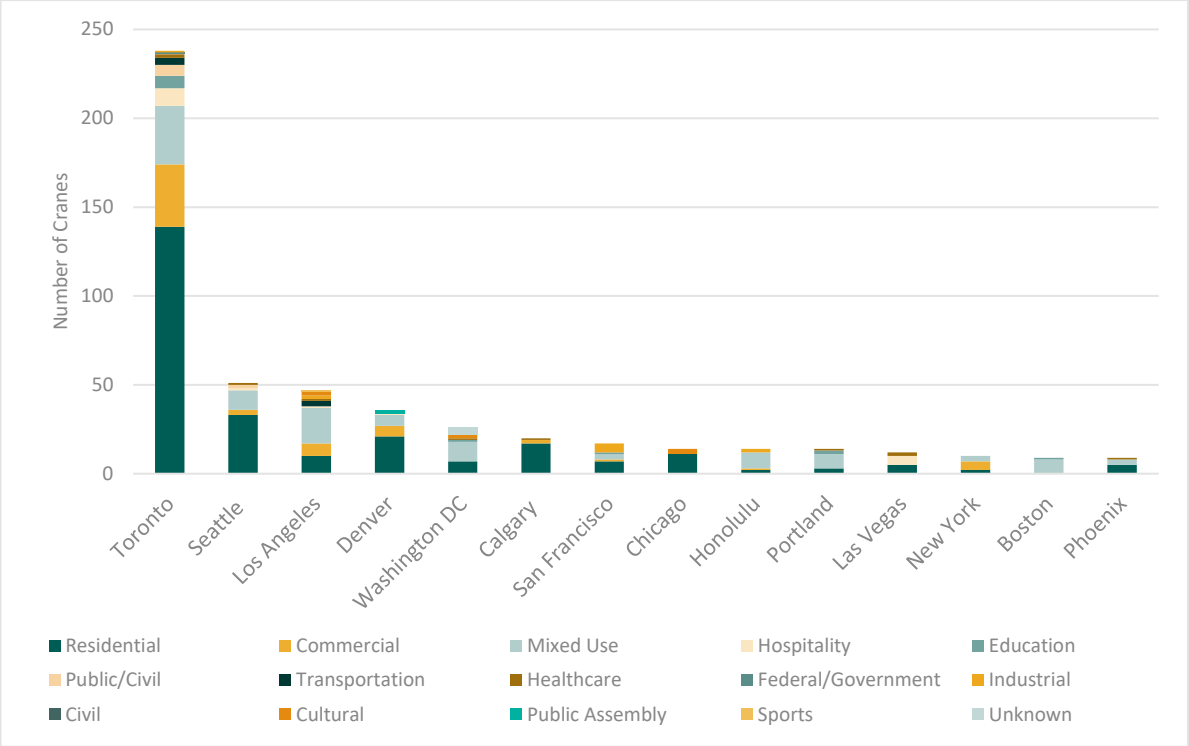

Figure 3: RLB Crane Index - Q1 2023

In addition to high-rise buildings, this growth is also driving the development of new housing communities through the redevelopment of areas such as Downsview, the Golden Mile and the Port Lands, some of which are planned as net zero communities and to meet the highest performance measures of the Toronto Green Standard.[14]

The significant expansion of transit networks is also needed to support this population growth and there are numerous new projects under construction in the city including the Yonge North Subway Extension, Finch West LRT, Scarborough Subway Extension, Eglington Crosstown LRT, Eglinton Crosstown West Extension, and the Ontario Line.[15]

Finally, this growth is also putting additional stress on the system through the incremental loads associated with technology and digitalization. In addition to organic growth, Toronto has become

[14] Exhibit 2B, Section D4
[15] Exhibit 2B, Section E5.2

Canada's largest data center market, with 107 MVA of incremental demand load connected during the 2020-2024 period and 207 MVA forecasted to come online from 2025-2029.[16]

A3.4 Climate Change and Adverse Weather

Climate change is a significant factor influencing Toronto Hydro's planning and operations. Scientists worldwide overwhelmingly agree that the planet is warming. By the year 2050, Toronto's climate is forecasted to be significantly different than the already changing climate seen today. For example, in Toronto, daily maximum temperatures of 25°C are expected to occur 110 times per year as opposed to 87 times per year currently.[17] A warmer climate will also allow the atmosphere to hold more moisture, which is expected to lead to more frequent and severe extreme weather events. These extreme events can cause major disruptions to Toronto Hydro's distribution system.

Extreme weather amplifies the challenge of distributing electricity to a mature, dense, and rapidly growing urban city. Heat, high winds, heavy rainfall, freezing rain, and heavy snowfall can cause major system damage and result in prolonged power outages. As evidenced by recent events outlined in Table 4 below, extreme weather has become a regular operating condition that the utility must consider and manage in its day-to-day operations and long-term planning activities. With the frequency and intensity of adverse weather increasing due to climate change, Toronto Hydro's grid and operations must become more resilient to this challenge.

Table 4: Extreme Weather (January 2020 through May 2022)

Event	Description of Impact
High Winds Storm (May 2022)	• 142,052 Customers impacted at its peak • 5 days to restore power to all customers
Flash Storm (August 2021)	• 20,000 customers impacted at peak • 2 days to restore power to impacted customers
Thunderstorm High Volume Event (July 2021)	• A line of thunderstorms with windspeeds in excess of 75 km/h. • 12,000 customers were impacted at its peak • Service restored for the majority of customers within 2 days
High Wind Event (April 2021)	• Wind expected to reach ~95hm/hr • 22,000 customers impacted at its peak • 1 day to restore power to impacted customers

[16] Exhibit 2B, Section E5.1
[17] Toronto Hydro engaged Stantec to update its Climate Change Vulnerability Assessment, which is filed at Exhibit 2B, Section D2, Appendix A.

Event	Description of Impact
High Wind Event (November 2020)	• Winds in excess of 100 km/h • Estimated 8000 customers impacted and 101 outages at its peak
Flash Storm (July 2020)	• Approximately 50-70mm of rain • 50,000 customers impacted at peak • Impacted customers restored within 2 days
Adverse Weather (January 2020)	• Approximately 60mm of rain, 5-15mm of ice and 90 km/h winds • 4900 customers impacted at its peak • Impacted customers restored within 3 days

Adverse weather affects the distribution system in different ways. The underground system is vulnerable to flooding from extreme rainfall, while the overhead system is susceptible to extreme winds, freezing rain, and wet snow, resulting in damage and outages. Broken trees and the weight of ice and snow accretions can bring lines, poles, and associated equipment to the ground. For instance, in May 2022, an extreme wind event known as the Derecho Storm struck Southern Ontario and Quebec with 120+km/h winds. These extreme winds caused substantial damage to vegetation, which in turn damaged overhead distribution wires and equipment leaving approximately 142,000 customers (18 percent of Toronto Hydro's total customer base) without power at the peak of the storm. While the majority of customers were restored within 48 hours, it took approximately 5 days and cost approximately $2.35 million to restore power to all customers.[18]

In addition to extreme weather events, Toronto experiences a wide range of weather conditions that may not be classified as extreme, but nevertheless have the potential to adversely affect the distribution system at various times during the year. Weather conditions of high heat, high winds, heavy rainfall, and heavy snowfall have the potential to cause major system damage and extensive outages. Not only are these weather conditions projected to occur more frequently and with greater severity in the future due to climate change, but trends from the past 25 years suggest that these changes are already affecting the system. Figure 4 below contains two charts depicting cumulative rainfall and the number of high wind days (i.e. with wind gusts exceeding 70 kilometres per hour) in Toronto over the past 25 years. In both cases it is observed that there is an increasing trendline over the period. With respect to high wind days, an even steeper increase has been observed, and seven

[18] Exhibit 2B, Section D2

of the 10 years with the greatest number of days of wind gusts above 70 kilometres per hour have occurred in the last 10 years (these years are highlighted in orange).

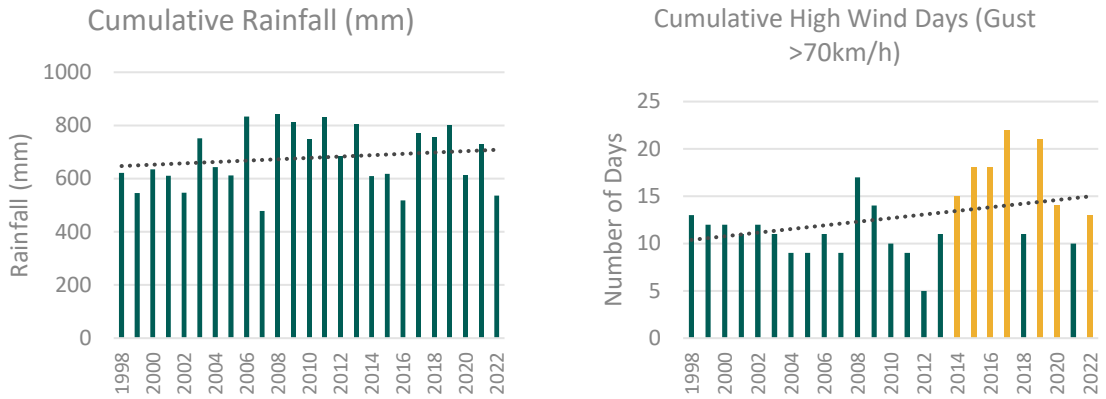

Figure 4: Cumulative Rainfall (left) and Number of High Wind Days (right) in Toronto[19]

These trends are expected to continue through the 2030s and 2050s with the frequency of extreme rainfall events of 100 mm in less than 1-day antecedent increasing by 11 percent and 20 percent respectively. In terms of high winds, climate projections show that 10-year wind speeds are to increase by 0.7 percent and 2.7 percent in the 2030s and 2050s respectively.[20]

These weather trends have increased reliability risks for the distribution system. Toronto Hydro analyzed system reliability data to understand the correlation between wind speed above 70 kilometres per hour, the number of forced outages on the overhead system, and SAIDI performance. This revealed a high correlation between wind speed above 70 kilometres per hour and the number of forced outages on the overhead system. It was also determined that higher wind speeds were correlated with increased SAIDI.

Toronto Hydro has recognized that existing codes, standards, and regulations with regard to historical weather data do not always account for ongoing and future changes to climate. To address this, Toronto Hydro now incorporates climate data projections into its equipment specifications and station load forecasting. In 2016, Toronto Hydro updated its major equipment specifications to adapt

[19] Government of Canada, Weather, Climate and Hazard Historical Data, http://climate.weather.gc.ca/historical_data/search_historic_data_e.html
Weather data compiled using Toronto Lester B. Pearson INTL A for January 1998 to June 2013 and Toronto INTL A for July 2013 to December 2022.
[20] *Supra* note 16.

to climate change, such as using stainless steel construction for submersible transformers and replacing air-vented, padmounted switches with more robust designs. As part of the ongoing efforts, Toronto Hydro has planned various activities between 2025 and 2029, including reconfiguring feeders and relocating assets away from the ravines in the Overhead System Renewal program, replacing submersible transformers, and implementing flood mitigation systems at vulnerable stations.

In addition to these system hardening measures, Toronto Hydro's Grid Modernization Strategy for 2025-2029 has been developed in part to improve long-term system reliability and resiliency in the face of external pressures from both future increases in system utilization and evolving climate impacts. For more information on the Grid Modernization Strategy, please refer to Exhibit 2B, Section D5.

A3.5 Technology Advancement

Technology and innovation are also driving the need for a more dynamic system that is transitioning away from usual patterns of supply and demand towards more complex interactions and inputs in electricity generated and consumed. The role of the utility continues to evolve to support the new smart grid ecosystem, comprising renewable and other distributed energy resources (DER), such as electric vehicles, solar panels, and battery energy storage systems.

Customers are showing a continued interest in participating in the electricity system as both consumers and producers of power. DER connections have grown in recent years as result of government policies and declining costs of technologies such as solar panels. By the end of the decade, Toronto Hydro expects to have over 4,400 DER connection projects representing a total installed capacity of approximately 517 MW, an increase of approximately 67 percent compared to 2022.[21]

Integrating DERs into the grid provides customers more tools to actively manage their energy needs, and enables the grid to be supplied by locally-generated renewable electricity resources. To advance these outcomes, Toronto Hydro must address the significant challenge of accommodating electrons that flow bi-directionally within a grid that was not built for this type of supply and demand. Equipment that has a high number of DER connections is more likely to experience unstable conditions that pose significant reliability and safety risks to the system and its users. Toronto Hydro

[21] Exhibit 2B, Section E5.1

monitors all DER connections closely for these factors to ensure that the grid remains safe and reliable for all customers, and is building advanced grid capabilities to mitigate against these risks and enable efficient DER adoption by customers in the future.[22]

Technological advancement also poses the challenge of managing a heightened risk of digital security threats, as cyber-crime intensifies across Canada due to changing geopolitical dynamics. While smart grid systems, infrastructure automation, and other technological advancements being used by the utility and its customers offer many benefits, they also increase the exposure of the grid and those connected to it to greater risk of attack by hostile actors. This intensifying global challenge is particularly acute in major economic centers such as Toronto. Electric utilities are targets for security breaches because of the critical role they play in enabling essential service providers (e.g. hospitals, public transit, water treatment systems, communications, and traffic management) and the databases of confidential customer information they possess.[23]

Toronto Hydro needs to prepare itself to assist customers in taking advantage of technological innovation and advancements, while also protecting itself and its customers from the risks they introduce.

[22] Exhibit 2B, Section A
[23] Exhibit 2B, Section D8; Exhibit 2B, Section E8.4

A4 Development of the 2025-2029 DSP

A4.1 Business Planning & Customer Engagement

In developing a multi-year investment plan, Toronto Hydro begins from the principle that the utility is entrusted by customers and stakeholders to prepare a responsible plan that balances both price and service quality outcomes. The 2025-2029 Plan achieved that balance through an integrated and iterative business planning process that considered customer feedback from start to finish.

Toronto Hydro's 2025-2029 DSP, including the 2025-2029 Capital Expenditure Plan, was an output of its outcomes-oriented, customer-focused business planning activities. The plan was derived from the utility's distribution system asset management system ("AMS") and other operational planning activities, discussed in detail in Section D of the DSP. A high-level view of business planning as it relates to the Capital Expenditure Plan is shown in Figure 5, below.

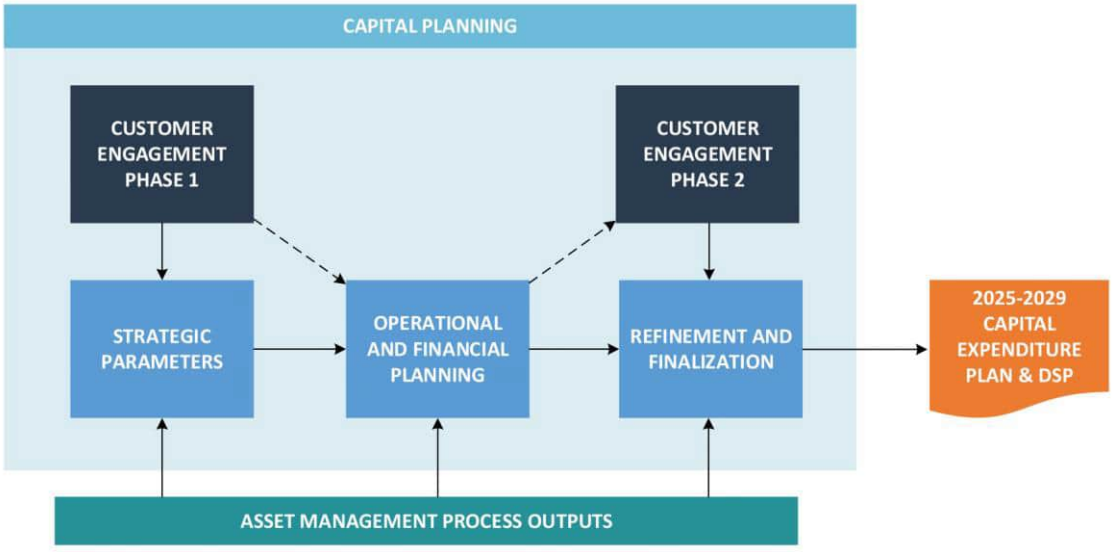

Figure 5: Capital Planning in Business Planning

Toronto Hydro began planning by engaging customers to ascertain their needs and priorities for the 2025-2029 planning period (i.e. Phase 1 of Customer Engagement), and used the customer feedback received to provide strategic direction to the planning process.

The common themes of customer priorities centered around the following:

1. **Price and reliability are the top customer priorities:** Relative to price, reliability has become increasingly important to residential customers. When it comes to reliability, customers prioritize reducing the length of outages, with a particular focus on extreme weather events for residential and small business customers. Key Account customer are more sensitive to power interruptions and prioritize reducing the total number outages.
2. **New Technology:** Almost equally to price and reliability, customers expect the utility to invest in new technology that will reduce costs and make the system better, even if the benefits aren't immediate, as along as the costs and benefits are clear.
3. **System Capacity:** Customers expect Toronto Hydro to invest proactively in system capacity to ensure that high growth areas do not experience a decrease in service levels. The majority of Key Account customers surveyed have Net Zero goals to reduce their business' net greenhouse gas emissions to zero—and expect Toronto Hydro to support them in meeting their climate action objectives by ensuring that the system has capacity for growth and by providing them advisory services.

With consideration for customers' needs, priorities and other inputs, Toronto Hydro organized its plan around the following investment priorities.

1) **Sustainment and Stewardship:** Risk-based investments in the renewal of aging, deteriorating and obsolete distribution equipment to maintain the foundations of a safe and reliable gird.
2) **Modernization:** Developing advanced technological and operational capabilities that enhance value and make the system better and more efficient over time.
3) **Growth & City Electrification:** Necessary investments to connect customers (including Distributed Energy Resources ("DERs") and build the capacity to serve a growing and electrified local economy.
4) **General Plant:** Investments in vehicles, work centers and information technology ("IT") infrastructure to keep the business running and reduce Toronto Hydro's greenhouse gas emissions.

For each of these strategic priorities, Toronto Hydro set performance objectives that provide value for customers and are meaningful to its operations.

Table 5: 2025-2029 Performance Objectives

Investment Priority	Key Performance Objectives
Sustainment and Stewardship	• Maintain recent historical system reliability • Manage asset risk by maintaining overall health demographics of the asset population in 2025-2029 • Adhere to previous commitments for safety and environmental compliance activities (e.g. removal of at-risk PCBs by 2025; complete Box Conversion by 2026) • Optimize the pace of renewal investment from year-to-year using risk-based decision-making tools. • Ensure investment pacing contributes to stable long-term investment requirements for all assets (2030+)
Modernization	• Prioritize investments that will deliver demonstrable benefits to customers, especially enhancements that will improve value-for-money in the long-term (i.e. efficiency) • Improve system reliability through enhanced fault management, leveraging automation and advanced metering through Advanced Metering Infrastructure ("AMI") 2.0 • Enhance system observability across the system, enabling better asset management and operational decision making • Leverage technology to improve customer experience (e.g. reliability, power quality, customer tools, DER integration) • Enhance resiliency and security of the system through advanced grids, targeted undergrounding of critical overhead assets, and enhancements to distribution schemes for critical loads downtown
Growth & City Electrification	• Connect customers efficiently and with consideration for an increase in connections volumes due to electrification • Expand stations capacity to alleviate future load constraints, with consideration for increased EV uptake, decarbonization drivers, and other growth factors (digitization and redevelopment) • Optimize near-term system capacity through load transfers, bus balancing, cable upgrades and the targeted use of non-wires solutions such as demand response and energy efficiency • Alleviate constraints on restricted feeders to accommodate the proliferation of DER connections • Install control and monitoring capabilities for all generators > 50kW • Accommodate relocations for committed third-party developments, including priority transit projects

Investment Priority	Key Performance Objectives
General Plant	• Replace critical facilities assets in poor condition • Improve stations site conditions and physical security to meet legislative requirements (Ontario's Building Code,[24] *Occupational Health and Safety Act,*[25] CSF, etc.) • Achieve emissions reduction by implementing Toronto Hydro's NZ40 strategy • Support modernization objectives including grid automation and customer experience. • Minimize cybersecurity risks associated with IT/OT infrastructure • Ensure IT infrastructure is available and reliable with minimal service disruption

To ensure that price was kept top-of-mind, the utility also adopted top-down financial constraints for the development of the plan:

1. **Price Limit:** Toronto Hydro set an upper limit of approximately 7 percent as a cap on the average annual increase to distribution rates and charges.[26]
2. **Budget Limits**: Toronto Hydro set upper limits of $4,000 million for the capital plan and $1,900 million for the operational plan over the 2025-2029 period.

In developing these strategic parameters, Toronto Hydro considered a number of inputs including but not limited to:[27]

- customer priorities and preferences identified in Phase 1 of the utility's planning-specific Customer Engagement activities;
- historical and forecast system health demographics and performance;
- long term asset stewardship needs;
- forecasted system use profiles and pressures;
- safety and environmental risks; etc.

Based on the aforementioned inputs, through an iterative process that spanned over a year, Toronto Hydro system planners and experts worked diligently to identify the minimum investments necessary to meet these objectives and balance near-and long-term service quality performance with price

[24] Ontario Regulation 332/12: Building Code, under Building Code Act, 1992, S.O. 1992, c. 23.
[25] *Occupational Health and Safety Act,* RSO 1990, c. O.1
[26] As calculated for the monthly bill of a Residential customer using 750 kWh.
[27] For a more exhaustive list, please refer to Exhibit 2B, Section E2.1.1.

impacts for customers, as informed by the feedback in Phase 1. Toronto Hydro selected the $4,000 million capital budget limit to achieve this balance of keeping rates reasonable without compromising performance.

These parameters guided the operational and financial planning activities that produced the Capital Expenditure Plan for 2025-2029. Over the course of these iterative planning activities, the utility worked to develop and optimize its program-level capital (and OM&A) expenditure plans to align with its short- and long-term performance objectives, while remaining within the financial constraints established for the 2025-2029 period. This exercise led to a $480 million reduction between the initial plan proposals and the draft plan, as described in Section E2.

Toronto Hydro's consultant Innovative presented the draft plan to customers in the Phase 2 customer engagement to solicit feedback on (i) pacing and bill impacts for key investments areas in Toronto Hydro's plan; and (ii) the price of the overall draft plan and whether customers are willing to accept it. Overall, a majority (84 percent) of customers in all customer classes supported the price increase associated with the draft plan or an accelerated version of it.

Overall, Toronto Hydro reprioritized investments to produce an optimized and customer-aligned capital expenditure plan of $4 billion over the 2025-2029 period.[28] The program outcomes in Sections E5 through E8, as well as the 2025-2029 Performance Outcomes for the plan as whole (discussed in Exhibit 1B, Tab 3, Schedule 1 and Exhibit 2B, Section E2 respectively), have been developed and calibrated to reflect customer feedback, ensuring the performance and accomplishments of the DSP are tracked over the 2025-2029 period in relation to outcomes that are meaningful to customers.

These investment priorities are driven by critical needs that, if not adequately addressed, could impair Toronto Hydro's ability to deliver the outcomes that customers value. In some cases, these risks will materialize in the near term, such as lack of capacity to support urban intensification and economic development. However, in many cases, the risks will materialize in the medium to long term as the grid becomes more heavily-utilized and more susceptible to longer and more frequent outages that are complex and costly to resolve. Toronto Hydro must invest in the priorities described below to manage these risks.

[28] This figure includes inflation and other allocations, and excludes Renewable Enabling Improvement ("REI") expenditures funded through provincial rate relief.

A4.2 Asset Management Process and Enhancements

Toronto Hydro's distribution system AM Process is explained in detail in Section D and is generally aligned with the AM Process described in the 2020-2024 DSP, with some enhancements as discussed below. The objective of Toronto Hydro's AMS is to realize sustainable value from the organization's assets for the benefit of customers and stakeholders, while meeting all of the utility's mandated service and compliance obligations. This requires continuously balancing near-term customer preferences with the need to ensure predictable performance and costs over the long-term for both current and future customers.

Toronto Hydro is continually monitoring and improving AM decision-support systems, enterprise systems and various inputs that support effective asset management. Recent Improvements to Toronto Hydro's AMS over the 2020-2024 period are highlighted in Figure 6 below. For more information on these improvements, please refer to Section D of the DSP.

As highlighted in Figure 6 and Section D1.3, Toronto Hydro has an extensive track record of continuous improvement in asset management. Looking ahead, the utility recognizes that the coming acceleration in decarbonization, digitalization (e.g. automation), and decentralization (i.e. two-way energy flows) within the energy economy will result in much greater asset management complexity and a more urgent need for adaptive flexibility within the utility's management systems. The utility believes that success in this more complex environment will depend in large part on having a strong management foundation in the form of a rigorous and comprehensive AMS that consistently tracks toward industry best practices.

With this context in mind, Toronto Hydro is committing to aligning its AMS to the ISO 55001 standard for asset management, with the goal of achieving certification within the 2025-2029 rate period. ISO 55001 was developed by the International Organization for Standardization and is the most recognized standard for asset management globally. It provides terminology, requirements and guidance for establishing, implementing, maintaining and improving an effective asset management system, and represents a global consensus on asset management and how it can increase the value generated by organizations like Toronto Hydro.

Fundamental to the ISO 55001 framework are the concepts of strategic alignment, risk-based decision-making and continuous improvement. By pursuing certification, Toronto Hydro is volunteering to be held accountable through independent audits for the continuous improvement of its AMS and the maturation of its risk-based decision-making frameworks. The utility believes that

the effort of pursuing certification will provide the additional rigor and discipline required to deliver greater value and performance, including greater cost-efficiency, as customer and stakeholder needs rapidly evolve and operating challenges become more intense (e.g. climate risk).

To streamline Toronto Hydro's asset management process, the utility is also embarking on a transformative project to implement an Engineering Asset Investment Planning ("EAIP") solution to support investment planning and project development activities. This strategic initiative is poised to elevate Toronto Hydro's annual project portfolio and long-term asset investment strategies, while simultaneously revitalizing asset management methodologies and simplifying the scope formulation procedures. As part of its multi-year efforts to adopt the EAIP solution, Toronto Hydro is developing a custom and robust value framework to evaluate relative value of its investments, leading to more well-informed and strategic asset management decisions as discussed in Section D3 of the DSP.

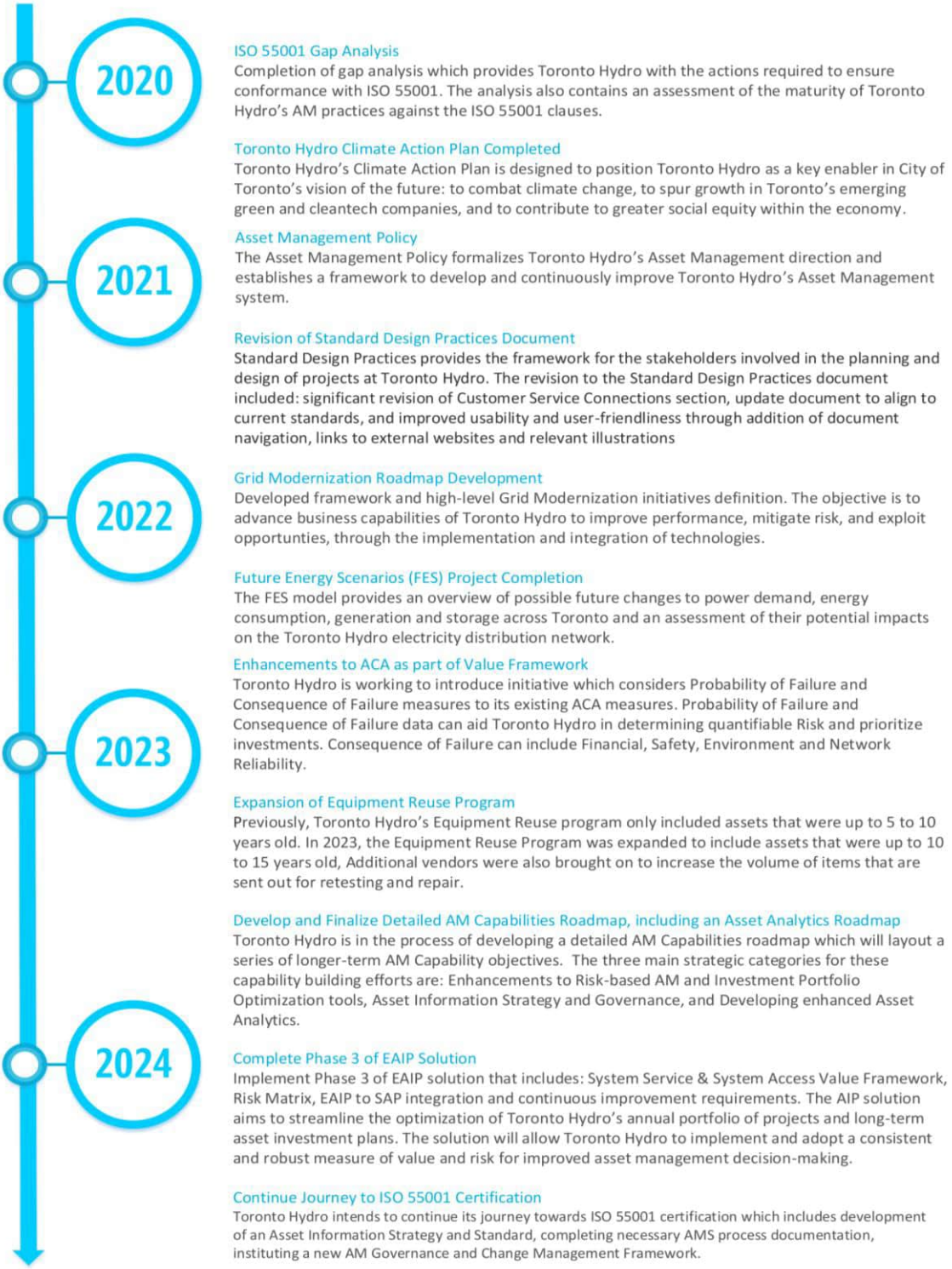

Figure 6: Recent Enhancements of the AM Process (2020-2024)

In addition to the distribution system AMS, Toronto Hydro has similarly robust AM processes for its facilities, fleet, and IT assets. The AM approach for facilities and IT are summarized in Sections D6 to D8, while the AM strategy for fleet can found in the Fleet and Equipment Services program in Section E8.3.

A5 Investment Priorities

A5.1 Sustainment & Stewardship

Sustainment investments to renew aging and deteriorating infrastructure and standardize outdated equipment continue to be the largest part of the 2025-2029 Investment Plan. These investments must be made to maintain system performance, mitigate reliability, safety, and environmental risks, and enhance the grid's capability to serve electrified technologies such as electric vehicles, solar panels, energy storage batteries, and electric heat pumps and boilers.

Past investments in the grid and operations have resulted in improvements in reliability, safety and environmental outcomes – the average duration of outages customers experience now compared to a decade ago was reduced by 26 percent over the last decade, the injury rate for employees has decreased by 60 percent, oil spills have been avoided, and the utility is on track to eliminate at risk PCB transformer from its system by 2025.[29,30] Investing in the performance and long-term stewardship of an aging, deteriorated, and more highly-utilized system remains an urgent priority for the utility, alongside getting the grid ready to serve Toronto's growing electricity needs.

System health is a leading indicator of a safe and reliable grid. Allowing system health metrics – age and condition – to deteriorate would lead to the gradual but steady degradation of system performance. As an example, underground cables are the largest contributor to defective equipment outages and continue to present significant demographic challenges in the coming years with approximately 73 percent of direct buried cables in the horseshoe area expected to be past their serviceable life by the end 2022.[31] Proactive investment in the replacement of these assets is a key part of sustaining the short and long-term performance of the grid.

[29] Exhibit 1B, Tab 3, Schedule 2
[30] Exhibit 4, Tab 4, Schedule 1
[31] Exhibit 2B, Section E6.2

Recognizing that customers are generally satisfied with current levels of reliability, and expect the utility to invest in new technology for the future,[32] Toronto Hydro right-sized the sustainment objectives of the Investment Plan to maintain (rather than improve) the overall health of the grid over the 2025-2029 period. Maintaining system health metrics is necessary to sustain grid performance and prevent the accumulation of a backlog of equipment at risk of failure, or otherwise needing to be upgraded. Renewal investment backlogs are problematic not only because they greatly heighten system reliability risk: they also result in rate instability for customers, as well as high-inefficiencies in work execution. Such inefficiencies stem in part from performing more work reactively – which is typically higher cost – and in part because planned work becomes more expensive due to surges in material and labour needs that could otherwise be smoothed out through paced proactive investment.[33]

Keeping pace on renewal is also important for hardening the grid against more frequent extreme weather events, and standardizing outdated equipment that poses barriers to electrification. For example, legacy 4 kilovolt stations and feeder equipment, restricts the connection of large electrified loads and distributed energy resources. To prepare the grid for electrification these assets must be gradually converted to new standards, and that work is being done in a paced way through sustainment investments that also deliver safety, reliability and environmental outcomes.[34]

Table 6 below provides a summary of Toronto Hydro's sustainment capital programs:

Table 6: Sustainment Capital Programs

Capital Program/Segment	Investment ($ Millions)
Area Conversions[35]	**$237**
Underground Renewal – Horseshoe[36]	**$476**
Underground Renewal – Downtown[37]	**$165**
Network System Renewal[38]	**$123**

[32] Exhibit 1B, Tab 5, Schedule 1, Appendix A
[33] Exhibit 2B, Section E2
[34] *Ibid.*
[35] Exhibit 2B, Section E6.1
[36] Exhibit 2B, Section E6.2
[37] Exhibit 2B, Section E6.3
[38] Exhibit 2B, Section E6.4

Capital Program/Segment	Investment ($ Millions)
Overhead Renewal[39]	**$273**
Stations Renewal[40]	**$218**
Reactive and Corrective Capital[41]	**$328**
Sustainment Capital	**$1,820**

A5.2 Growth and City Electrification

The obligation to serve customers who want to connect to the grid is at the heart of Toronto Hydro's mandate as an electricity distributor. What accompanies that core obligation is the responsibility to make reasonable investments to prepare for future growth. This responsibility is more important than ever, as customers, communities and governments at all levels are actively embarking on an unprecedented transformation of the energy system to mitigate the worst impacts of climate change.

It is clear from studies that have been done locally, provincially, and internationally that decarbonization-through-electrification imperatives are expected to drive demand for electricity in the next two decades. Experts indicate that demand could increase up to 2 to 3 times depending on the range of technologies and policy tools that are adopted.[42]

The particular drivers of demand are subject to dynamic forces of technological advancement, public policy imperatives and consumer behaviour. As an example, the decarbonization of existing housing

[39] Exhibit 2B, Section E6.5
[40] Exhibit 2B, Section E6.6 – includes HONI Switchgear renewal costs of $29M.
[41] Exhibit 2B, Section E6.7
[42] Toronto Hydro's own Future Energy Scenarios forecast a doubling in Toronto's electricity demand by the year 2050 across multiple scenarios (for more information please refer to Exhibit 2B – Section D4, Appendix A). The IESO's Pathways to Decarbonization report forecasts that demand could more than double by 2050 (https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization), while Enbridge's Pathways to Net Zero forecasts an increase in demand of over three times in its electrification scenario (https://www.enbridgegas.com/en/sustainability/pathway-to-net-zero). In the US, utilities such as National Grid (https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan-sept2023.pdf), Eversource (https://www.mass.gov/doc/gmacesmp-drafteversource/download?_gl=1%2Ako8zfs%2A_ga%2ANzUwNDI5MDE3LjE2NTA5ODEyMjQ.%2A_ga_SW2TVH2WBY%2AMTY5MzkyMDE2OS4zNi4xLjE2OTM5MjM1NzQuMC4wLjA.), and Unitil (https://unitil.com/ma-esmp/en) all published modernization plans forecasting demand increases of over 2 times by 2050. ISO New England also completed a study which forecasts a doubling in system peak by 2050 (https://www.iso-ne.com/static-assets/documents/100004/a05_2023_10_19_pspc_2050_study_pac.pdf). National Grid ESO (Great Britain's system operator), also forecasts in an increase of about 2 times across many of its future energy scenarios (https://www.nationalgrideso.com/document/283101/download).

and industrial buildings remains a policy puzzle, and a number of options are being considered to find suitable paths.[43] To manage this uncertainty and the cost-consequences for customers, the utility must be measured-but-proactive in its investment plan (as both asset and human capital investments are long lead-time), and must be deliberate in sustaining and modernizing its grid and operations to ensure that it is ready to serve and enable customer choice in all scenarios.

As outlined above, Toronto Hydro has embraced this uncertainty by prioritizing investments that can provide value under all scenarios under the "least regrets" approach. This enables the utility to meet emerging challenges without having to wait for all unknown variables to stabilize. Based on its least regrets investment philosophy, the 2025-2029 Investment Plan accommodates an increase of 23 percent in system peak demand, which includes electrification of transportation (EVs) across residential, industrial and commercial sectors, as well as major transit projects like the Ontario Line and Scarborough Subway Extension, and redevelopment plans for the Downsview, The Port Lands and Green Mile communities.[44]

The 2025-2029 Investment Plan anticipates a material increase to the customer connection portfolio (consistent with the trend observed in recent years) and expands stations capacity to alleviate future load constraints due to growth resulting from EV uptake, digitalization of the economy (e.g. data centers and digital transformations of existing sectors), and city growth and redevelopment (e.g. urban densification and transit expansion). The 2025-2029 Investment Plan also optimizes near-term system capacity through active management measures such as load transfers and balancing, equipment upgrades, and the targeted use of non-wires solutions – both demand-side measures that leverage customer DERs as well as grid-side technologies such as renewable enabling energy storage systems.[45]

By the end of this decade, DER capacity is expected to increase by approximately 67 percent.[46] Getting these resources safely connected to the grid is necessary to enable greater choice and support customers in achieving their electrification objectives (e.g. ESG, net zero, environmental conscientiousness, home/business resiliency). Moreover, integrating these resources into the system is critical to right-sizing system expansion investments, and developing a grid that is more

[43] City of Toronto, Net Zero Existing Buildings Strategy https://www.toronto.ca/wp-content/uploads/2021/10/907c-Net-Zero-Existing-Buildings-Strategy-2021.pdf
[44] Exhibit 2B, Section D4
[45] Exhibit 2B, Section D4
[46] Exhibit 2B, Section E5.1

resilient in the future as a result of greater levels of local power supply. To accommodate increasing volumes of connections in this area, the 2025-2029 Investment Plan ensures control and monitoring capabilities for all distributed generation and addresses constraints on restricted feeders through traditional investments such as station bus-ties and alternative technologies such as energy storage.[47]

While there is certainty that fundamental change is ahead, there are still degrees of uncertainty about how that change will unfold. For example, government incentives or market evolution could further accelerate customer adoption of electric vehicles or other fuel switching technologies. Similarly, provincial procurement programs could create expanded role for DERs in the deployment of coordinated infrastructure solutions to meet Ontario's energy needs.[48] As a result of such external factors, the pacing and level of certain demand-driven expenditures and revenues can change and materially deviate from the forecast. To that end, Toronto Hydro proposes a flexibility mechanism (known as a variance account) to reconcile differences between forecasted and actual demand-driven costs and revenues. During a time of unprecedented change and transformation in the economy and energy system, it is key to protect both ratepayers and the utility from structural unknowns that could have a material impact on the plan.[49]

Table 7 below outlines the programs that enable growth and city electrification:

Table 7: City Growth and Electrification Capital Programs

Capital Program	Investment ($ Millions)
Customer Connections[50]	$476
Externally Initiated Plant Relocations & Expansions[51]	$76
Load Demand[52]	$236
Generation Protection, Monitoring, and Control[53]	$35
Non-Wires Solutions[54]	$23

[47] Exhibit 2B, Section D4
[48] Exhibit 2B, Section D4
[49] Exhibit 1B, Tab 4, Schedule 1
[50] Exhibit 2B, Section E5.1
[51] Exhibit 2B, Section E5.2
[52] Exhibit 2B, Section E5.3
[53] Exhibit 2B, Section E5.5
[54] Exhibit 2B, Section E7.2

Capital Program	Investment ($ Millions)
Stations Expansion (Exhibit 2B, Section E7.4)	$173
Growth Capital	**$1,020**

A5.3 Grid Modernization

Toronto Hydro's grid modernization strategy focuses on accelerating the deployment pace of digital field and operational technologies that can deliver future benefits to customers. These benefits include better outage restoration capabilities to improve grid reliability and resilience, and enhanced operational flexibility to manage a more heavily utilized system with increasing bi-directional power flows. Grid modernization investments, once fully implemented and integrated in the next decade, are expected to yield a material step-change improvement in reliability and operational efficiency, to help offset the added reliability and cost pressures associated with electrification.[55]

The modernization plan lays the groundwork for grid automation (commonly known as the self-healing grid) in the horseshoe area of the system starting in 2030 to provide the enhanced levels of reliability and resilience that customers will expect as they electrify their homes and business at a lower cost compared to traditional alternatives. To improve resiliency against major disruptions (e.g. extreme weather; loss of supply) for vulnerable parts of the system, the modernization plan also includes investment in: (a) the targeted undergrounding of equipment to harden vulnerable areas of the overhead system against more frequent and extreme weather events, and (b) enhanced configuration options for the downtown network which serves critical loads such as major hospitals and financial institutions.

Toronto Hydro's journey towards an intelligent self-healing grid is being implemented through an Advanced Distribution Management System ("ADMS"), a multi-faceted software platform with advanced capabilities and connected applications that integrate analytics, real-time data and control algorithms to optimize distribution network operation. The system provides a holistic view of the grid and encompasses advanced applications such as Outage Management System ("OMS"), Fault Location Isolation and Service Restoration ("FLISR"), Volt/Var Optimization, which allow swift detection and response to outages and grid disturbances, and enable reliable and efficient

[55] Exhibit 2B, Section D5

management of DERs by optimizing voltage levels and reactive power flows throughout the distribution system.[56]

Through operational technology such as sensors and switches and software, Toronto Hydro can better monitor, predict, and control the flow of electricity across the system. These capabilities enable the utility to reduce the number and length of outages customers experience, and also pave the way for a more interactive, bi-directional grid that enables customers to choose various technologies to produce, store and sell power back to the grid.[57] In addition, Toronto Hydro plans to invest in overhead and underground line sensors and other condition monitoring and control equipment that provide the utility real-time information about critical assets in the field, and enable more cost-effective system planning and operational decisions.[58]

Modernization investments also create a foundation for the kinds of advanced, real-time and predictive analysis that would be fundamental to Toronto Hydro's evolution toward Distribution System Operator ("DSO") model, if and when such a model is either imposed or offered to distributors in an effort to further enable energy transition outcomes. In such a model, Toronto Hydro would be expected to safely and reliably coordinate, dispatch, and optimize thousands of behind-the-meter generators and flexible loads in order to help maximize the value created by the local energy system for customer, including maximizing the penetration and utilization of non-emitting energy sources. While the policy environment surrounding the role of DERs in the energy transition remains unsettled, the grid modernization capabilities advanced by the 2025-2029 Investment Plan create the foundation for this possible future while also delivering many other tangible benefits to customers irrespective of the DSO policy framework.[59]

Table 8 below outlines Toronto Hydro's modernization capital programs:

Table 8: Modernization Capital Programs

Capital Program/Segment	Investment ($M)
System Enhancement[60]	$151

[56] Exhibit 2B, Section E8.4, Appendix A
[57] Exhibit 2B, Section D5
[58] Exhibit 2B, Section E7.1
[59] Exhibit 2B, Section D5
[60] Exhibit 2B, Section E7.1

Capital Program/Segment	Investment ($M)
Network Condition Monitoring and Control[61]	$6
Metering[62]	$248
Overhead Resiliency[63]	$86
Stations Control and Monitoring[64]	$65
IT Cyber Security & Software Enhancements[65]	$95
Modernization Capital	**$651**

In addition, to the modernization capital investments summarized above, Toronto Hydro proposed to establish a $16 million 2025-2029 Innovation Fund to support the design and execution of pilot projects focused testing of innovative technologies, advanced capabilities, and alternative strategies that enable electrification grid readiness and facilitate DER integration. The Innovation Fund supports utility investment in innovation work that is more early stage, exploratory and developmental in nature, where the outcomes are less certain, but the potential benefits for the system and customers could be significant. While the benefits of individual projects may not be immediate or certain, and some initiatives may prove to be more or less fruitful than others, this type of work is nevertheless critical to achieving real innovation during a time of transformation in the energy sector.[66]

A5.4 General Plant

Toronto Hydro needs to maintain facilities, fleet and information technology ("IT") assets and infrastructure to enable efficient business operations. To get maximum value of its work centers, stations buildings, physical security systems, and fleet, the utility monitors and manages asset age and condition with a view to optimizing total lifecycle costs.

[61] Exhibit 2B, Section E7.3
[62] Exhibit 2B, Section E5.4
[63] Exhibit 2B, Section E6.5
[64] Exhibit 2B, Section E6.6
[65] Exhibit 2B, Section E8.4
[66] Exhibit 1B, Tab 4, Schedule 2

In addition to four work centers that provide the necessary conditions for employees to work effectively, Toronto Hydro manages a broad portfolio of approximately 185 stations which house and protect critical equipment such as cables and transformers. Like electrical equipment, facilities assets that are in poor condition pose an increased risk of failure putting key outcomes such as safety, reliability, customer service and productivity at risk. For example, if a station building has a leaking roof or foundation that allows water to infiltrate, there could be permanent damage to distribution equipment leading to lengthy and costly power interruptions and posing hazards to workers and the public.[67]

Investments in the renewal and maintenance of facilities assets enable the utility deliver its services in a safe, reliable, and sustainable manner. In addition to these table stakes, Toronto Hydro must also address emerging needs to provide greater resilience against physical threats such as vandalism and natural threats such as extreme weather. The utility plans to address these needs through targeted investments in renewing stations buildings and work centres (e.g. exterior cladding, windows, and roofs where critical equipment is housed), and physical security systems (e.g. network-based cameras and access card readers).

Toronto Hydro crews also need safe and reliable vehicles to execute a wide-range of system capital and operations and maintenance work programs. Toronto Hydro's fleet investments include heavy duty and light duty vehicles and equipment (e.g. forklifts and trailers). These vehicles transport employees and materials to and from job sites, perform distribution work onsite, and serve as working space for field employees. Fleet vehicles must be available to support these operations in a safe and efficient manner. Toronto Hydro's fleet investments aim to optimize vehicle operating costs, minimize fleet downtime due to repairs, increase vehicle efficiency and safety, and importantly reduce emissions.[68]

Toronto Hydro is committed to reducing its direct greenhouse gas ("GHG") emissions (referred to as Scope 1 emissions) in order to mitigate the impacts of climate change and reach "net zero" by 2040. The utility intends to reduce the emissions produced by its fleet by gradually increasing the complement of electric and hybrid vehicles. Similarly, Toronto Hydro has a paced plan to reduce its buildings emissions by decreasing its natural gas consumption using a combination of energy

[67] Exhibit 2B, Section E8.2
[68] Exhibit 2B, Section E8.3

efficiency measures and fuel switching projects to replace natural gas fueled heaters with electric heating systems.[69]

Finally, General Plant includes investments in information and operational technology ("IT/OT") assets that support a number of business applications and systems which are essential to conducting day-to-day operations such as managing field crews, responding to outages and enabling customer self-serve tools. When these systems are not available, customers service levels decrease, power outages and operational disruptions take longer to fix, and safety of the public and employees is put at risk. Toronto Hydro must invest in upkeeping its IT/OT assets highly reliable and available for conducting critical operations.[70]

Table 9 below outlines Toronto Hydro's general plant capital programs:

Table 9: General Plant Capital Programs

Capital Program/Segment	Investment ($M)
Enterprise Data Centre (Exhibit 2B, Section E8.1)	$72
Facilities Management and Security (Exhibit 2B, Section E8.2)	$145
Fleet and Equipment Services (Exhibit 2B, Section E8.3)	$44
Information and Operational Technology (Exhibit 2B, Section E8.4)	$206
General Plant Capital	**$467**

A5.5 Expected Sources of Cost Savings during the Plan Period

Throughout the plan period, and in the course of executing its DSP, Toronto Hydro will continue to evaluate its operational efficiencies and seek ways to reduce and avoid costs, while increasing value for ratepayers. Toronto Hydro's Productivity evidence at Exhibit 1B, Tab 3, Schedule 3, describes a number of specific productivity initiatives with cost savings and/or other qualitative benefits. The capital program narratives in Sections E5 through E8, and the OM&A narratives in Exhibit 4, Tab 2,

[69] Exhibit 2B, Section D7
[70] Exhibit 2B, Section E8.4

provide several examples of the investments and initiatives that will support the utility's efforts to control costs and increase productivity. The following list highlights some of these activities.

- **Grid Modernization:** Many of Toronto Hydro's planned investments in the 2025-2029 period will support the ongoing modernization of the grid, through the introduction of technologies that support remote monitoring, sensing, protection, and control. A key example of this is the System Enhancement program (Section E7.1). Like all of the capital programs that introduce remote switching and monitoring capabilities, this program is expected to improve the productivity of field employees and system controllers when operating the system and responding to outages (for example, by allowing system controllers to perform switching operations remotely instead of relying on field crews for manual switching). In addition, Toronto Hydro anticipates cost savings related to network system maintenance due to the Network Condition Monitoring and Control program (Section E7.3), as the need for inspections will be reduced by the ability to monitor network vault condition remotely. The modernization of the network will also support more cost-effective customer connections by providing real-time load monitoring that will allow the utility to lift some of the connection capacity limitations on existing secondary networks. Further information on grid modernization benefits can be found throughout all investment categories, and summarized within Toronto Hydro's Grid Modernization Narrative (Section D5).

- **Capacity Improvements:** Capacity improvements from the utility's Load Demand (Section E5.3) and Stations Expansion (Section E7.4) programs are expected to allow for more flexibility in scheduling planned outages for maintenance at the affected stations and for the delivery of Toronto Hydro's capital plans generally.

- **Standardization:** By eliminating obsolete asset types across the system through programs such as Area Conversions (Section E6.1), Underground Renewal – Downtown (Section E6.3), and Stations Renewal (Section E6.6), Toronto Hydro expects to improve operational efficiency in a number of ways, including by improving safe and efficient employee access to the system, reducing costs associated with refurbishing and supporting non-standard assets, optimizing procurement and supply chain by reducing the number of different equipment standards on the system, and reducing line losses on 4 kV feeders. The upgrade of feeders from 4 kV to 13.8 kV or 27.6 kV feeders is expected to improve the capacity to connect customers, resulting in more cost-efficient connections. The replacement of deteriorating and obsolete cable types from the system is anticipated to reduce the potential exposure to

lead and asbestos classified as Designated Substances under the *Occupational Health and Safety Act*.[71] Furthermore, this initiative is also expected to reduce costs associated with maintaining non-standard assets (e.g., PILC and AILC cable), reduce line losses and increase feeder capacity to connect customers as legacy undersized cable 250 or 350 PILC cables are upgraded to standard 500 kcmil TRXLPE.

- **Area Rebuilds:** When planning projects, Toronto Hydro uses cost-benefit and risk evaluation principles to identify opportunities to bundle multiple assets of different types into area rebuild projects. This approach reduces the risk of needing to travel and set-up in a project area on multiple occasions in a short timeframe, thereby reducing the overall cost of replacing the relevant assets and the frequency of disruption to customers. By taking this approach in programs such as Overhead System Renewal (Section E6.5) and Underground System Renewal – Horseshoe (E6.1), the utility aims to mitigate the overall cost of its System Renewal program over time.

- **Flexibility Services:** Flexibility Services at Toronto Hydro refers to programs that address localized distribution issues through targeted procurements with customers or other third-parties. From the 2025-2029 period Toronto Hydro will aim to procure up to 30 MW of demand response capacity in the Horseshoe North area. This could help defer or avoid anywhere between 23 percent to 54 percent of the total load required to be transferred in this area. This translates to deferred and more likely avoided capital expenditures in the range of $10 million, at a projected cost of about $5.7 million in operating expenditures.

- **Safety and Environmental Costs:** Employee and public safety is paramount for Toronto Hydro and a significant driver of capital investment during the 2025-2029 period. By investing in the sustainment and improvement of safety outcomes, the utility supports secondary financial benefits, such as a decrease in Workplace Safety Insurance Board premiums resulting from the utility's safety record. Toronto Hydro's emphasis on safety not only protects its workforce and the public but also generates significant cost savings. With an exemplary safety record, the utility benefits from reduced Workplace Safety Insurance Board premiums, allowing for more resources to be allocated to vital projects and innovations. Additionally, their commitment to environmental sustainability through investments in renewable energy and eco-friendly practices not only reduces their

[71] RSO 1990, c. O.1

environmental impact but also leads to lower operating costs, ensuring both financial stability and responsible resource management.

- **Advanced Technological Solutions**: By effectively harnessing advanced technology solutions, such as infrared thermography for early anomaly detection, electronic maintenance sheets for streamlined data handling, and online partial discharge testing for proactive maintenance. Toronto Hydro can significantly enhance its work coordination during maintenance outages. This approach allows for timely identification and resolution of potential issues, leading to reduced equipment failures and unplanned downtime. Ultimately, the adoption of these cutting-edge tools fosters cost-saving measures while bolstering the overall reliability and performance of the electrical grid.

- **Facilities Asset Management System:** Toronto Hydro has a robust facilities management system that records assessments and maintenance plans for all assets located in Toronto Hydro's work centres and stations. Through this proactive facilities management system, Toronto Hydro minimizes unnecessary expenditures on premature asset replacements, translating into significant cost savings. By precisely identifying assets in poor condition and approaching replacements strategically, Toronto Hydro can allocate its financial resources more effectively, investing in critical areas that contribute to the overall reliability and performance of its infrastructure. This approach not only emphasizes cost saving but also underscores Toronto Hydro's commitment to responsible and efficient asset management, benefiting both the organization and its customers in the long run.

- **Procurement:** Toronto Hydro maintains a strategic approach by utilizing a combination of internal and external resources to execute its extensive capital and maintenance programs. The utility employs a competitive procurement process to determine the majority of costs associated with its capital work program. Despite anticipated challenges like rising construction costs due to labor market pressures and increased congestion in Toronto, the utility's competitive procurement strategy remains instrumental in securing essential resources at reasonable rates, ensuring the successful execution of the capital plan while emphasizing cost-effectiveness. This strategic approach enables Toronto Hydro to manage financial resources efficiently, ultimately benefiting both the organization and its customers. Additionally, major world events like the COVID-19 pandemic, changes to work patterns, geopolitical conflict, and high inflation significantly disrupted the global supply chain. This led to risks in timely and cost-effective material procurement. To address these challenges

and ensure a reliable supply, Toronto Hydro updated its strategy. This revised approach includes a comprehensive assessment of supply chain risks and a mix of proactive long-term measures and reactive short-term actions. The strategy takes a 360-degree view of Toronto Hydro's current and into the short- and medium-term, as informed by engagements with business units, while simultaneously keeping track of market conditions through touchpoints with vendors and manufacturers.

In addition to the above initiatives, Toronto Hydro's overall risk-based approach to system renewal and enhancement is expected to drive value, including cost savings, over the long-term by ensuring that decisions on when to replace assets are informed by quantitative analysis and measurement. In the context of Toronto Hydro's large asset renewal backlog, risk-based approaches allow the utility to target assets that carry the greatest amount of risk cost based on age, condition, configuration, loading, and other considerations, ensuring that priorities are set in a manner that maximizes value-for-money over the long-term. For more information on Toronto Hydro's asset management lifecycle optimization and risk management approaches, please see Section D3.

A6 Capital Expenditure Plan

A6.1 Capital Programs and Drivers

The 2025-2029 Capital Expenditure Plan in the DSP consists of 20 unique capital programs. These programs are allocated to each of the OEB's four major investment categories, as defined in Table 10, based on their trigger drivers, which represent the primary reason a program must be carried out.

Table 10: Capital Investment Categories

System Access	• Toronto Hydro fulfills its obligation by undertaking necessary modifications, such as asset relocation, to ensure that customers, including generators, or groups of customers, can seamlessly access and benefit from reliable electricity services through the distribution system.
System Renewal	• Toronto Hydro optimizes its distribution system by strategically replacing and refurbishing system assets. This proactive approach ensures the reliability of electricity services for customers by managing failure risk as the utility maintains a robust infrastructure capable of meeting their energy needs in the short and long terms, while also investing in improving system resiliency.

System Service	• Toronto Hydro proactively modifies its system to effectively meet operational objectives, improve efficiency, and anticipate future customer electricity service requirements. The utility modernizes its grid to ensure reliable and efficient service delivery for its customer in line with evolving demands.
General Plant	• Toronto Hydro proactively undertakes modifications, replacements, or additions to assets beyond the distribution system, encompassing land, buildings, tools, equipment, rolling stock, and electronic devices and software. These efforts are geared towards supporting the utility's day-to-day business and operational activities, fostering efficiency, reliability, security, and adaptability in delivering energy services to its customers.

Each capital program is defined by a single trigger driver and a number of secondary drivers. The trigger drivers for Toronto Hydro's 2025-2029 DSP programs are summarized in Table 11, below. Although safety is not listed as a trigger driver, it is a significant secondary driver for many programs – especially those that are triggered by asset Failure or Failure Risk in the System Renewal category. Secondary drivers may be as, or more, consequential than the trigger drivers. Details on the trigger and secondary drivers for each program are provided in the detailed program justifications in Sections E5 through E8 of the DSP.

Table 11: Investment Category Trigger Drivers

Category	Driver	Description
System Access	***Customer Service Requests***	• Toronto Hydro strives to connect demand and distributed energy resource ("DER") customers to its system as efficiently as possible in alignment with its obligation under the *Distribution System Code*. This obligation holds unless it poses safety concerns for the public or employees or compromises the reliability of the distribution system. In situations where the existing infrastructure falls short of enabling a connection, the utility undertakes system expansions or enhancements to accommodate the customer's needs.
	Mandated Service Obligation	• Toronto Hydro prioritizes full compliance with all legal and regulatory requirements and government directives.
System Renewal	***Functional Obsolescence***	• Specific asset types and configurations can become obsolete for a variety of technical and operational reasons. Typically, functionally obsolete assets can no longer be effectively maintained or utilized as intended. Toronto Hydro will act to

Category	Driver	Description
		retrofit or replace these assets within a timeframe that is specific to the unique circumstances of the asset population in question.
	Failure	• Toronto Hydro must reactively repair or replace assets or critical components that have failed while in service.
	Failure Risk	• Toronto Hydro takes proactive measures to identify, assess, and mitigate failure risk within its asset populations. Failure risk is determined by evaluating the likelihood of failure (e.g., by leveraging asset condition assessments) and the likely impact of failure ("criticality") on various outcomes, including safety, reliability, cost, and the environment. By prioritizing service reliability and ensuring the safety of workers and the public, the utility strives to maintain a robust infrastructure that meets the evolving needs of its customers.
System Service	***Reliability***	• Toronto Hydro strives to maintain and improve reliability at local, feeder-wide, and system-wide levels by continuously optimizing its system and deploying cost-effective technologies and solutions.
	Capacity Constraints	• Expected load changes can impact service consistency and demand requirements for the system. To address this, Toronto Hydro proactively adjusts and expands its infrastructure to optimize reliability and meet evolving customer needs.
General Plant	***Operational Resilience***	• Toronto Hydro prioritizes the ability to mitigate and recover from disruptions to core business functions. Through robust strategies, contingency plans, and proactive risk management, the utility ensures prompt restoration of operations, minimizing impact and maintaining service continuity.
	System Maintenance and Capital Investment Support	• Toronto Hydro recognizes the significance of investing in day-to-day operational activities, as doing so enables the utility to prioritize the safety and well-being of its employees while maintaining an environment that fosters efficiency and reliability in delivering essential services.

A6.2 2020-2029 Capital Expenditure Plan

Table 12 shows the level of spending for the System Access, System Renewal, System Service, and General Plant investment categories, as well as the System O&M expenditures over the historical period from 2020 to 2024 and over the forecast period from 2025 to 2029. A detailed discussion of expenditure variances and trends over the 10-year 2020-2029 period is provided in Section E4.

Table 12: Historical (2020 to 2024) and Forecast (2025 to 2029) Expenditures ($ Millions)

Category	Actuals			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Access	80.4	140.3	128.4	127.1	153.7	226.5	239.3	228.3	192.8	184.8
System Renewal	261.5	247.3	276.5	314.0	358.8	359.7	366.5	391.3	423.7	429.1
System Service	32.8	68.4	67.2	32.8	24.3	38.3	35.3	83.0	95.1	101.2
General Plant	56.1	72.4	112.9	96.5	80.7	103.9	119.1	124.9	116.1	98.6
Other	17.4	4.6	12.8	12.6	7.7	6.3	7.0	8.7	10.3	12.0
Total CapEx	448.1	533.2	597.9	582.9	625.3	734.6	767.3	836.2	837.9	825.7
System O&M	117.1	117.5	124.1	127.1	135.0	144.1	148.9	153.0	159.0	164.5

Detailed analysis for each program is included in Sections E5 through E8 of the DSP, including analysis of historical expenditures and accomplishments, justifications for 2025-2029 expenditures, and options analysis.

A7 Outcomes and Performance Measurement

In developing its approach to performance measurement for the Distribution System Plan ("DSP"), Toronto Hydro considered the Ontario Energy Board's guidance, including the *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the "RRF").[72] A key theme of the Ontario Energy Board's guidance is that utilities should align their investment plans with customer needs, and adopt an outcomes-based approach to tracking their performance.

Toronto Hydro's 2025-2029 performance measurement framework consists of (1) performance outcomes consistent with the Ontario Energy Board's Renewed Regulatory Framework ("RRF") categories, and (2) a custom scorecard that is tied to an innovative Performance Incentive Mechanism ("PIM") as part of the 2025-2029 custom rate framework (Exhibit 1B, Tab 2, Schedule 1).

In respect of the first component – RRF outcomes – Toronto Hydro intends to continue delivering high-performance on the Electricity Distributor Scorecard ("EDS") and the Electricity Service Quality Requirements ("ESQR") consistent with the historical results presented in Exhibit 1B, Tab 3, Schedule 2. To that end, each capital and operational program outlined in the DSP and Exhibit 4, Tab 2 (operations) includes a performance outcomes table that explains how the program advances specific RRF objectives.

The utility developed its capital programs to maintain and improve reliability and safety, meet service and compliance obligations, address load capacity and growth needs, improve contingency constraints, or make necessary day-to-day operational investments. The choices made reflect a balance between customer preferences, affordability, and prioritized outcomes (as described in Exhibit 2B, Section E2), with the overriding objective of delivering value for money.

Toronto Hydro sets asset management objectives that are aligned with the overall investment plan objectives, and are a result of the detailed, iterative, and customer engagement-driven planning process summarized in Section E2 of the DSP. Section D1.2.1 explains the link between Toronto Hydro's distribution system Asset Management System ("AMS") and its performance measurement framework with respect to the investment priorities of the plan.

As further detailed in Exhibit 1B, Tab 3, Schedule 1, Toronto Hydro's 2025-2029 Custom Scorecard tracks performance across four performance categories. By monitoring and managing the

[72] Ontario Energy Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (October 18, 2012).

performance measures identified in each category of the custom scorecard (see Table 13 below), in addition to the EDS, ESQR and Asset Management performance measures noted above, the utility expects to drive continuous and sustained improvement across the organization in the next rate period in a manner that aligns with Ontario Energy Board and customer feedback, and also reflects the key objectives and underpinnings of the plan.

Table 13: 2025 – 2029 Performance Incentive Scorecard Measures

Performance	Measure
System Reliability & Resilience	**Outage Duration:** System Average Interruption Duration Index (SAIDI) excluding MEDs, Loss of Supply and Planned Outages
	Outage Frequency: System Average Interruption Frequency Index (SAIFI) - Defective Equipment
	System Security Enhancements: Deliver initiatives that enhance Toronto Hydro's physical and cyber security posture against the NIST framework
Customer Service & Experience	**New Services Connected on Time:** Percentage of new connections and service upgrades completed on time consisting of Low Voltage Connections (70%), High Voltage Connections (20%) and DER Connections (10%)
	Customer Satisfaction: Customer post-transactional surveys for Phone Inquiries, E-Mail Inquiries, Key Accounts engagements, Construction Communications, Outages Communications, and Customer Connections
	Customer Escalations Resolution: Percentage of customer escalations resolved within 10 business days.
Environment, Safety and Governance	**Total Recordable Injury Frequency (TRIF):** Injuries per 100 employees (or 200,000 hours worked) per year.
	Emissions Reductions: CO2e emissions produced by the utility's fleet and facilities.
	ISO Compliance and Certification: Achieve and maintain certification with select ISO governance standards, specifically achieve ISO 55001 (60%), and maintain ISO14001 (20%) and ISO45001 (20%).
Efficiency & Financial Performance	**Efficiency Achievements:** Sustained benefits for customers in the form of reduced or avoided costs or other benefits that will produce a lower revenue requirement in the next rebasing
	Grid Automation Readiness: Completion of technology milestones that will enable the implementation of fully automated, self-healing grid operations beginning in 2030
	System Capacity (Non-Wires): Flexible system capacity procured through demand response offerings.

A8 Third-Party Studies and Reports

The 2025-2029 DSP is supported by a several expert studies and reports.

Table 14: Third-Party Studies Filed in Support of the 2025-2029 DSP

Study	Vendor	Description/Reference
Econometric Benchmarking of Historical and Projected Total Cost and Reliability	Clearspring	Clearspring was retained to apply econometric modelling to benchmark the utility's historical and projected costs and reliability. The purpose of this review was to assess the reasonableness of Toronto Hydro's revenue forecasts and inform the appropriate stretch factor in the utility's Application. Clearspring compared Toronto Hydro's historical and projected total costs against its benchmark costs i.e. the Toronto Hydro's expected costs in any given year based on the econometric model. Clearspring's results indicated that (i) the historical average total costs for the utility, from 2020 to 2022, are 28.0 percent below benchmark expectations; and (ii) the projected total cost levels during the 2025-2029 period are 22.9 percent below benchmark expectations. Based on their findings, Clearspring states that Toronto Hydro is not a poor total cost performer and recommends a stretch factor of 0.15 percent. Clearspring also benchmarked Toronto Hydro's reliability performance, finding that the average frequency of interruptions (SAIFI) was above the predicted benchmark by 98.8 percent, but the customer average interruption duration (CAIDI) was below benchmark by 104.1 percent. The study can be found at Exhibit 1B, Tab 3, Schedule 3, Appendix A.
Unit Costs Benchmarking Study	UMS Group	UMS Group was retained to perform a capital and maintenance unit cost benchmarking exercise. The utility provided UMS with actual, all-in unit costs for major asset classes and maintenance activities for the 2020-2022 period. UMS compared these results to those of peer utilities across North America, considering dollar and metric conversions and accounting differences. Overall, UMS found that Toronto Hydro's unit costs ranged from minus 12.2 percent to plus 1.9 percent relative to the median. UMS also noted that if certain qualitative considerations, such as customer density, were statistically normalized for, Toronto Hydro's comparative ranking would be better than shown. The study can be found at Exhibit 1B, Tab 3, Schedule 1, Appendix C.

Study	Vendor	Description/Reference
Climate Change Vulnerability Assessment Update	Stantec	To better understand the risks related to increases in extreme and severe weather due to climate change, in June 2015, Toronto Hydro completed a vulnerability assessment following Engineers Canada's Public Infrastructure Engineering Vulnerability Committee ("PIEVC") protocol. The assessment identified areas of vulnerability to Toronto Hydro's infrastructure as a result of climate change. Following this study, a climate change adaptation road map was developed, along with initiatives relating to climate data validation, review of equipment specifications, and review of the load forecasting model. In 2022, Toronto Hydro retained Stantec to update the 2015 study, which recommended not relaxing any adaptation measures from the previous study. This information informed the development of Toronto Hydro's 2025-2029 DSP. The study can be found at Exhibit 2B, Section D2, Appendix A.
Enterprise IT Cost Benchmark & Functional Maturity Assessment	Gartner Inc.	To assess the reasonableness of the utility's level of overall IT/OT expenditures, Toronto Hydro procured an independent benchmarking study by Gartner Consulting ("Gartner"). Gartner concluded that Toronto Hydro's IT expenditures as of 2022 benchmark competitively against industry peers and the increase in Toronto Hydro's 2022 IT spending compared to 2017 is similar to industry peers. Gartner also concluded that, in both years, the distribution of Toronto Hydro's IT investments "by cost category, investment category, and functional area are all comparable to the peer group, with the exception of higher allocations to Applications spending (51.2 percent of IT spend for Toronto Hydro versus 41.9 percent for peers, largely due to the Customer Information System ("CIS") Upgrade and IT Management and Administration (14.8 percent of IT spend for Toronto Hydro versus 10.8 percent for peers, largely due to increased investment in Cyber Security services)." The study can be found at Appendix A to Exhibit 2B, Section D8.

Study	Vendor	Description/Reference
Future Energy Scenarios Report	Element Energy	To better understand the challenges posed by the changing energy landscape, Toronto Hydro engaged a leading UK consultant Element Energy, who has developed a Future Energy Scenarios modelling tool. The Future Energy Scenarios provide an overview of possible future changes to power demand, energy consumption, generation, and storage across Toronto and an assessment of their potential impacts on the Toronto Hydro electricity distribution network. The Future Energy Scenarios confirms that Toronto can expect significant changes to its energy system resulting from electrification, renewable generation deployment, and improvements in energy efficiency. The report can be found at Appendix B, to Exhibit 2B, Section D4.
Review of ACA Modelling Enhancements and Customisations	EA Technology	Toronto Hydro retained EA Technology to guide and review improvements to its ACA methodology, to ensure that it continues to align with the core principles of the Common Network Asset Indices Methodology ("CNAIM"), as well as to identify opportunities for continuous improvement. EA Technology found that Toronto Hydro has made significant progress, while retaining alignment with CNAIM, but expects it to continue to evolve as part of natural process, providing specific areas for improvement. The report can be found at Exhibit 2B, Section D3, Appendix B.

B Coordinated Planning with Third Parties

B1 Introduction

This section provides an overview of how Toronto Hydro coordinates infrastructure planning with third parties, and how those consultations affect Toronto Hydro's Distribution System Plan ("DSP"). Toronto Hydro has a robust approach to coordinating and integrating third-party infrastructure planning information into its distribution system planning process. The utility coordinates infrastructure planning with a wide-range of external stakeholders including: customers (e.g., large customers, subdivision developers, and municipalities), the Independent Electricity System Operator (IESO), the transmitter ("Hydro One") and other distributors as part of regional planning process, and other entities and agencies such as telecommunication and transit providers (e.g. Metrolinx).

Generally, Toronto Hydro coordinates with third parties by participating in forums and processes that are organized and led by governmental or delegated authorities. For example, Toronto Hydro exchanges planning documents and project execution information with large developers and telecommunication entities through municipal planning and permitting processes. The City of Toronto requires infrastructure entities to circulate their plans in order to obtain permits to carry out work. Please see Section B2 Customer Coordination below for further details about Toronto Hydro's participation in the City of Toronto's infrastructure planning coordination activities.

Similarly, Toronto Hydro engages with the transmitter and other distributors, along with other local stakeholders through the IESO's Regional Planning Process ("RPP"). The RPP is part of the IESO's statutory mandate to conduct independent planning for electricity generation, demand management, conservation and transmission.[1] Given the high degree of technical alignment needed between upstream transmission assets and downstream distribution assets, the RPP requires close coordination between the IESO and transmission and distribution utilities. Please see Section B3 Electricity System Planning below for further details about Toronto Hydro's participation in RPP.

Regulations recently came into effect requiring distributors to consult any telecommunication entity that operates within its service area for the purpose of distribution system planning.[2] Please see

[1] Section 6(1) of the *Electricity Act, 1998,* S.O. 1998, c. 15, Sched. A
[2] *Supporting Broadband and Infrastructure Expansion Act, 2021.* Ontario Regulation. 842/21 made under the *Ontario Energy Board Act,* S.O. 1998, Ch 15, Sched. B.

Section B4 – Telecommunication Entities below for an overview of the utility's processes for coordinating infrastructure planning with telecommunication entities within its service territory.

B2 Customer Coordination

B2.1 Overview

Toronto Hydro coordinates infrastructure planning with customers including large developers and infrastructure agencies, as well the City of Toronto. These engagements provide Toronto Hydro key planning information that can be integrated into the utility's Peak Demand Forecast described in Section D4 - Capacity Planning and Electrification. They also enable effective operational planning and execution of major infrastructure relocation projects, as well as capital projects more generally.

B2.2 Proactive Customer Engagement

Toronto Hydro's Development Planning team leverages the City of Toronto's development pipeline to engage large customers and developers with upcoming projects to understand their needs, determine their load requirements and timelines, provide technical guidance, explore innovation opportunities, and provide support in understanding the connection process.[3] These engagements usually occur up to five to eight years before an intended connection materializes, enabling a smoother connection experience for customers and providing Toronto Hydro with valuable insight into emerging technologies that customers are adopting behind-the-meter, that can drive significant load growth or change in demand patterns in certain parts of the grid. Accordingly, these engagements enable Toronto Hydro to incorporate anticipated connections into its Peak Demand Forecast with a higher degree of confidence. Based on this forecast, Toronto Hydro determines investment needs in demand-driven program such Stations Expansion and Load Demand, to manage capacity constraints and plan for future load growth on the distribution system. For further information please refer to sections E5.3 Load Demand and E7.4 Stations Expansion.

B2.3 External Requests

Toronto Hydro manages a large number of requests by third parties to relocate distribution assets in order to accommodate public infrastructure such as city works, roads and highways and other types of development projects such as public transit. When a request for relocation is received, Toronto

[3] The Development Planning team works with the Key Accounts team who is responsible for managing relationships with customers and developers. For more information about Key Accounts please refer to Exhibit 4, Tab 2, Schedule 9.

Hydro also reviews load demand projections in the vicinity of the project(s) to evaluate whether there are opportunities to efficiently increase capacity in conjunction with the relocation work. When capacity needs are identified in the surrounding area, Toronto Hydro integrates expansion work into the third party's relocation project. For more information please refer to section E5.2 Externally Initiated Plant Relocations and Expansion.

B2.4 Capital Program Delivery

Toronto Hydro coordinates the execution of its capital work with the City of Toronto through use of the City of Toronto Project Tracking Portal ("PTP") as well as regular meetings with the City of Toronto's Infrastructure Coordination Unit ("ICU") and the City of Toronto's Toronto Public Utilities Coordination Committee ("TPUCC").[4][5] The ICU acts as a coordinating body for all groups – not just City agencies – that perform construction work in the city. This coordination often enables construction by different groups to be bundled together, avoiding additional disruption.[6] The TPUCC is a consortium established by the City of Toronto and utility companies to provide a forum for discussion in order to table ideas, encourage safety and implement innovative ways of reducing the impact and inconvenient of construction projects. Membership of the TPUCC consists of utilities that provide transportation, telecommunication, energy (gas), and water services in the City of Toronto including, Toronto Hydro, Enbridge Gas Distribution, Enwave Energy Corporation, Hydro One Networks Inc. Bell Canada, Beanfield Metroconnect, Rogers Cable Communications Inc., Telus, and Toronto Transit Commission. These engagements allow Toronto Hydro to resolve conflicts between its capital program and the City of Toronto, including by fast tracking or postponing projects to better align with other scheduled projects.

Toronto Hydro also responds to requests to adjust its work in response to social and cultural programs, such as filming requests and City of Toronto programs that permanently or temporarily affect the use of public sidewalks and roadways including CaféTO (for restaurant and bar spaces) and ActiveTO (for physical activity, community safety, and cycling spaces).

[4] City of Toronto, Infrastructure Viewer, online, https://map.toronto.ca/toinview/
[5] More information on the TPUCC and construction coordination in the City can be found here: https://www.toronto.ca/services-payments/building-construction/infrastructure-city-construction/understanding-city-construction/construction-coordination-in-the-city/
[6] City of Toronto, Construction Coordination in the City, online, https://www.toronto.ca/services-payments/building-construction/infrastructure-city-construction/understanding-city-construction/construction-coordination-in-the-city/

B3 Electricity System Planning

Toronto Hydro participates in the electricity system planning processes, particularly the Regional Planning Process, which produces the Toronto Region Integrated Regional Resource Plan ("IRRP"), led by the Independent Electricity System Operator ("IESO"), and in the Regional Infrastructure Plans ("RIP") for the Toronto Region and Greater Toronto Area ("GTA") North Region, led by Hydro One Networks Inc. Toronto Hydro's DSP has been informed by the results of the completed regional plans, and Toronto Hydro continues to coordinate with the aforementioned parties with respect to plans that are under development. The following sections describe the coordinated planning approach and results from the ongoing Regional Planning Process.

B3.1 Regional Planning Process Consultations

Regional planning looks at supply and reliability issues at regional and local levels with a focus on the 115 kV and 230 kV portions of the provincial system. The provincial grid is divided into several regions or zones for which plans are developed.

Regional planning focuses on the facilities that provide electricity to transmission-connected customers such as distributors and large directly-connected customers. This typically includes the transformer stations that supply the load and the transmission circuits between the stations. It also includes the 115 kV and 230 kV auto-transformers and their associated switchyards. From a resource perspective, regional planning considers local distributed generation, Conservation and Demand Management ("CDM"), as well as other forms of Non-Wires Solutions ("NWS") that could be developed to address supply and reliability issues in a region or local area.

Local Distribution Companies ("LDCs") conduct wires and NWS planning at the distribution level and coordinate with the transmitter and the IESO mainly on transmission supply facilities. Toronto Hydro has coordinated new or enhanced transmission supply facilities for some of its stations. These are discussed in more detail below in Section B3.2.

Regional planning can overlap with provincial system planning and distribution system planning. At Toronto Hydro, the same people responsible for the planning that informs the distribution system plan are also involved in regional planning. Overlaps with distribution system planning occur largely at the transformer stations that supply distributors, and at large directly-connected customers. For example, co-ordination is necessary when planning for the construction of new transformer stations such as the recently completed Copelands TS that serves the expanded downtown core. Regional

planning may also require coordination with distribution planning when a distribution solution can address needs of the broader local area or region, for example, by providing load transfers between transformer stations.

The following subsections describe key elements of the regional planning consultations. This is an iterative process and consultations occur at different points throughout the regional planning process.

B3.1.1 Stakeholder Consultations

The Regional Planning Process includes community and stakeholder engagement, including webinars, led by the IESO. The IESO invites the City of Toronto, First Nations, and Métis communities, stakeholders, community groups and the general public to provide input on the Scoping Assessment Outcome Report and development of the IRRP that is currently underway. The inaugural webinar occurred in March 2023, and coincided with the publication of the Scoping Assessment Outcome Report. Based on discussions with the IESO, Toronto Hydro understands that stakeholder consultation on the demand forecast and supply/delivery options and recommendations will take place after the filing of the Application.

B3.1.2 Transmitter Consultations

Toronto Hydro consults with Hydro One through regional planning processes, and in particular the RIP which is led by the transmitter.

Hydro One launched the new regional planning cycle in August 2022, starting with a Needs Assessment update. The Toronto Region Needs Assessment Report was completed in December 2022, and is provided as Appendix A to this section.

The most recent Metro Toronto RIP, that covers Toronto Hydro's service area, was completed in March 2020.[7] The most recent GTA North RIP, that covers a neighbouring region important to Toronto Hydro's operations, was completed in October 2020.[8] Both reports are being updated through the regional planning cycle currently underway.

[7] Exhibit 2B, Section B, Appendix B – Toronto Regional Infrastructure Plan (March 2020).
[8] Exhibit 2B, Section B, Appendix C – GTA North Regional Infrastructure Plan (October 2020).

B3.1.3 Other Distributor Consultations

Toronto Hydro is not an embedded LDC, and does not supply any embedded LDCs. Therefore, the utility's planning consultations with other LDCs typically occur in the context of regional planning.

B3.1.4 IESO Consultations

Toronto Hydro actively consults with the IESO as part of Integrated Regional Resource Plan ("IRRP"). The most recent IRRP was completed in 2019.[9] The IESO launched a new IRRP process for the Toronto Region in the spring of 2023. Toronto Hydro is the host distributor for that IRRP and is actively consulting with the IESO, Hydro One and other stakeholders, including the City of Toronto and the public.

B3.1.5 Municipality Consultations

As part of the Regional Planning process, Toronto Hydro, the IESO, and Hydro One engage with the City of Toronto. Through these engagements, the planners put their demand forecasts and supply/delivery options and recommendations to the municipal government for feedback with the goal of aligning expectations based on the plans and priorities of the City of Toronto.

B3.2 Regional Planning Process

Distribution system planning provides inputs to regional planning through peak demand forecast that triggers a needs assessment. Planning considerations in the Toronto Region include:

- A large load that is dynamic in the city area;
- A significant number and density of transmission lines and stations;
- The presence of large generation; and
- A customer base that has experienced, and is sensitive to, major events that disrupt continuity of service.

To facilitate infrastructure planning, the IESO divides Ontario into planning regions. As planning considerations change, the boundaries of these regions are revised. In the past, Toronto Hydro's service area was split between Central Toronto and Northern Toronto. More recently, regional planning considers Toronto Hydro's service area, the City of Toronto, on a consolidated basis as the Toronto Region. Planning documents and reports that have been developed, issued, and relied upon

[9] Exhibit 2B, Section B, Appendix D – Toronto IRRP Report (August 2019).

for Toronto Hydro's plans for the 2025-2029 period are based on the planning region being the Toronto Region. Planning triggers such as changes in demand or asset condition, initiate the regional planning process and progresses through the following phases:

i. Needs Assessment (NA);
ii. Scoping Assessment;
iii. Integrated Regional Resource Plan (IRRP); and
iv. Regional Infrastructure Plan (RIP).

B3.2.1 Needs Assessment

The lead transmitter in a given region, in this case Hydro One, coordinates and leads the Needs Assessment phase with input from the local LDC(s) and the IESO. Combined, they constitute what is known as the Study Team. The Study Team is provided with a range of inputs from both the LDC, in the form of a peak demand forecast, and the IESO in the form of CDM and DER penetration forecasts. The needs of the various high voltage assets in the region are then identified over the medium and long term to ensure adequate capacity is available to connect forecasted load while continuing to operate the grid in a reliable and safe manner. At the conclusion of the Needs Assessment, the Study Team will categorize asset needs as either requiring further regional planning coordination involving more advanced stages of the process or local planning between the affected LDC and lead transmitter only. Toronto Hydro and Hydro One completed a Needs Assessment in December 2022, the details of which are in Appendix A. This report reflects key aspects of the Stations Expansion Program in section E7.4

B3.2.2 Scoping Assessment

If the Study Team recommends that additional planning is required to assess a particular need or group of needs, the IESO then initiates a Scoping Assessment phase and leads the process in collaboration with the host LDC, in this case Toronto Hydro, and the lead transmitter, Hydro One. A thorough review of the needs identified in the Needs Assessment phase is conducted with an aim to determine if a mix of wires and non-wires solutions – which may comprise conservation and demand management, and distributed generation or energy storage – can address the identified needs. Needs that can benefit from an integrated (wires plus non-wires) solution proceed to an IRRP, while those that can only benefit from a wires solution proceed to the RIP process led by Hydro One. The

IESO completed the Scoping Assessment report in March 2023, which can be found in Appendix E to this section.[10]

B3.2.3 Toronto Integrated Regional Resource Plan

The Toronto Region IRRP is currently underway. The IESO is the lead, working with Hydro One (the transmitter) and Toronto Hydro (the sole LDC).

The purpose of the IRRP is to ensure that the electricity service requirements of the Toronto Region are served by an appropriate combination of demand and supply options that reflect the priorities of the community. Planning activities include forecasting the expected growth in electricity demand for 25 years, and investigating the costs and benefits of conservation, distributed generation, and transmission and distribution options in meeting the future electricity needs of customers in the Toronto Region**.** The result of the planning process is an integrated plan, with a long-term perspective, which recommends a balance of options that account for costs, reliable electricity service, and mitigation of environmental impacts. The regional planning cycle underway for the Toronto Region is scheduled for completion in August 2024, and the impact of the regional plan on the DSP is discussed in Section E2.4.1.

B3.2.4 Toronto Regional Infrastructure Plan

The previously prepared Metro Toronto RIP was completed in March 2020 and is attached as Appendix B to this section.

The Toronto RIP for the current cycle is scheduled for completion in March 2025. This plan is the final phase of the regional planning process following the completion of the Toronto Region's IRRP by the IESO in August 2024. The RIP may be triggered earlier if a particular need identified in the IRRP cannot be met by a non-wires solution. At that point, the IESO requests Hydro One to initiate a RIP.

B3.2.5 GTA North Regional Infrastructure Plan

The GTA North RIP was completed in October 2020. The plan is attached as Appendix C to this section.

The RIP was the final phase of the regional planning process for the GTA North Region which consists of the York Sub-Region and the Western Sub-Region. It followed the completion of the York Sub-

[10] Exhibit 2B, Section B, Appendix E – Toronto Scoping Assessment Outcome (March 2023).

Region Integrated Regional Resource Plan by the IESO in February 2020. Because Toronto Hydro also receives supply from the GTA North Region, Toronto Hydro is a participant of the process.

Participants of the RIP included:

- Alectra Utilities;
- Hydro One Networks Inc. (Distribution);
- Independent Electricity System Operator;
- Newmarket-Tay Power Distribution Ltd.; and
- Toronto Hydro Electric System Limited.

Toronto Hydro provided input to the GTA North Region Needs Assessment. The purpose of the Needs Assessment report is to assess if there were regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a "wires" only solution is necessary, such needs will be addressed between the relevant LDCs and Hydro One and other parties as required.

Hydro One launched a new GTA North regional planning cycle in March 2023, starting with a Needs Assessment update. The Needs Assessment Report for the GTA North Region was completed on July 14. 2023, and is attached in Appendix F to this section.[11] Impacts to the DSP are described in Section E2.4.1.

B4 Telecommunication Entities

B4.1 Overview

Toronto Hydro mainly relies on two consultation processes to ensure comprehensive, timely, and efficient coordination of infrastructure planning and capital project execution with telecommunication entities ("telecoms") that operate within its service area.

The first consultation process is facilitated through the City of Toronto's Toronto Public Utilities Coordination Committee ("TPUCC"), which meets once a month. Any telecom that operates within the City of Toronto is required to participate in the TPUCC in order to obtain construction permits. This forum provides Toronto Hydro a comprehensive view and opportunity to engage all telecoms that operate within its service area. The second consultation process is Toronto Hydro's attachment

[11] Exhibit 2B, Section B, Appendix F – GTA North Region Needs Assessment (July 2023).

process. Telecoms who seek to attach their infrastructure to Toronto Hydro's assets must apply and coordinate with Toronto Hydro to obtain approval.

Sections B4.2 and B4.3 below provide further details about these processes and insight into how Toronto Hydro effectively and efficiently coordinates with telecommunications entities that operate within its service area. Section B4.4 explains how telecom consultations affect the utility's capital plan.

B4.2 Municipal Forums

The City of Toronto imposes permitting requirements for the installation of infrastructure within the city of Toronto.[12] In order to maximize the efficiency of infrastructure coordination, the City of Toronto formed the TPUCC.[13] The TPUCC consists of utilities that provide transportation, telecommunication, energy (gas), and water services in the City of Toronto. In addition to Toronto Hydro, other members of the TPUCC include Bell Canada, Beanfield Metroconnect, Rogers Cable Communications Inc., Telus, and Hydro One Networks Inc.

In order to be granted permits from the City of Toronto, telecoms must submit "circulations", containing plans mapping out telecom facilities and details around the execution of the capital projects. These plans are circulated to other members, including Toronto Hydro. The utility examines the plans and ensures that they are compliant with Toronto Hydro's design and construction standards, especially where they are adjacent, or directly affixed to, Toronto Hydro's infrastructure. The circulations process provides a robust forum for consultation and co-ordination between Toronto Hydro and telecommunications entities operating in its service territory.

Since 2020, telecoms including Beanfield, Bell Canada, Rogers Cable and Cogeco have submitted over 3,200 circulations containing plans on capital project design and execution. Toronto Hydro processes these requests within an average of 5.4 days, reviewing and identifying whether there are any conflicts or contraventions of Toronto Hydro's design and construction standards (e.g., if adjacent infrastructure is planned to be constructed in close proximity to Toronto Hydro's poles). The utility typically resolves conflicts or contraventions identified in an average of four days.

[12] More information on Municipal Consent Requirements can be found here: https://www.toronto.ca/services-payments/building-construction/infrastructure-city-construction/construction-standards-permits/standards-for-designing-and-constructing-city-infrastructure/?accordion=utility-cut-permit-applications-and-municipal-consent-requirements-mcr.
[13] *Supra* Note 5

This information sharing process occurs on a rolling basis as TPUCC members upload data on the City of Toronto's Project Tracking Portal ("PTP") and Infrastructure Viewer application ("T.O.INview"). This means that Toronto Hydro regularly accesses the most up-to-date information on telecom capital project plans and similarly, telecoms can readily access Toronto Hydro's capital project plans. Toronto Hydro, Rogers Cable, and Bell Canada are also members of the Digital Map Owners Group ("DMOG"), which is responsible for the sharing of costs and maintenance of a comprehensive database mapping out underground utility features across the City of Toronto.

B4.3 Attachment Process

Separately, Toronto Hydro manages an attachment permitting process, where third-parties including telecoms, proactively request to affix their facilities onto Toronto Hydro's assets. Initially, Toronto Hydro requests advance notice and details of attachment applications from all telecoms operating within the City of Toronto for the upcoming year. However, the bulk of the permit applications are submitted on an ongoing basis. Toronto Hydro processes the applications and assesses whether the targeted assets are capable of physically supporting third-party fixtures or whether additional work is required in the form of "hydro make-ready" (HMR) work.

Toronto Hydro cross-references the HMR projects submitted through the attachment permitting process with projects in queue on the City's PTP and T.O.INview systems, and other Toronto Hydro programs, falling mainly under System Renewal category at Section E6. Where cost-effective and efficient, Toronto Hydro incorporates the HMR work into existing projects or otherwise assigns it to a contractor pre-approved by Toronto Hydro to complete the work on behalf of the telecom in accordance with Toronto Hydro's design and construction standards.

B4.4 Effects of Telecom Consultations on Capital Plans

Inputs gathered through the telecom consultations processes described above are reflected in programs under the System Renewal category of Toronto Hydro's capital plan. Specifically:

- **Area Conversions (Exhibit 2B, Section E6.1)**: This program converts pole-top box constructions to new designs, to which third-party assets – including telecom fixtures – are often attached. Toronto Hydro cross-references its program execution plans with telecom information obtained through the attachment process in order to come up with a schedule and plan that is responsive to the needs of telecoms.

- **Underground Renewal – Horseshoe (Exhibit 2B, Section E6.2)**: This program replaces underground network assets to manage failure risk. In order to complete this work, Toronto Hydro accesses its underground assets through trenches. Telecoms often situate their fibre optic networks in Toronto Hydro's underground cable chambers in the ducts. Therefore, Toronto Hydro often cross references information from telecoms that come through TPUCC circulations, which may result in, for example, modifications to trench routes to accommodate any telecom projects.
- **Overhead System Renewal (Exhibit 2B, Section E6.5)**: This program replaces poles that are in poor condition. Toronto Hydro cross references applications for wireline attachments with its own project execution plans to coordinate the pacing and order, and if needed plan any required transfers of existing telecom assets to an alternative pole.

B5 IESO Comment on Renewable Energy Generation

B5.1 IESO Comment Letter

In accordance with section 5.2.2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications, Toronto Hydro requested and obtained a letter of comment from the IESO with respect to planned renewable energy generation ("REG") investments. This letter is filed at Appendix G to this section.

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Toronto Region

Date: December 19, 2022

Prepared by: Toronto Region Technical Working Group

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Toronto Region and to recommend which need: a) does not require further regional coordination and b) identify needs requiring further assessment and/or regional coordination. The results reported in this Needs Assessment are based on the input and information provided by the Technical Working Group ("TWG") for this region.

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION	Toronto Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	August 23, 2022	**END DATE**	December 19, 2022

1. INTRODUCTION

The second Regional Planning ("RP") cycle for the Toronto Region was completed in March 2020 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the third RP cycle for this Region, which begins with the Needs Assessment ("NA") phase. The purpose of this NA is to:

a) Identify any new needs and reaffirm needs identified in the previous RP cycle; and
b) Recommend which needs:
   i. require further assessment and regional coordination (and hence, proceed to the next phases of RP); and
   ii. do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted Local Distribution Companies ("LDC") to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle.

2. REGIONAL ISSUE/TRIGGER

In accordance with the RP process, the RP cycle should be triggered at least once every five years. Considering these timelines, the third Regional Planning cycle was triggered in August 2022 for the Toronto Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the Toronto Region NA includes:
a) Reaffirm and update needs/plans identified in the previous RP cycle;
b) Identify any new needs resulting from this assessment;
c) Recommend which need(s) require further assessment and regional coordination in the next phases of the RP cycle; and
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle).

The Technical Working Group ("TWG") may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP") and RIP, based on updated information available at that time.

The planning horizon for this NA is 10 years.

4. INPUTS/DATA

The TWG representatives from LDCs, the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the Toronto Region regarding capacity needs, system reliability needs, operational issues, and major high-voltage ("HV") transmission assets requiring replacement over the planning horizon. The information was based on what was available and provided at the time of the NA, which does not include the impact from the IESO's "Pathways to Decarbonization" report published on December 15, 2022. The electricity demand and new infrastructure need in the longer term could be substantially higher than anticipated and discussed in this report. This will be further assessed in the next phase of this RP cycle.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the study period. The assessment methodology includes a review of planning information such as load forecast, conservation and demand management ("CDM") forecast, available distributed generation ("DG") information, system reliability and operation issues, and major HV transmission assets requiring replacement.

A technical assessment of needs was undertaken based on:

a) Station capacity and transmission adequacy;
b) System reliability and any operational concerns;
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and
d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification. (which does not consider the impact from the "Pathways to Decarbonization" report published by the IESO on December 15, 2022, but will be assessed in the next phase of this RP cycle)

6. NEEDS

Needs that were identified in the last RP cycle with associated projects recently done or currently underway are:

- Second DESN at Horner TS and refurbishment projects at Runnymede TS (T3/T4), Sheppard TS (T3/T4), and Strachan TS (T12) were completed in 2021-2022.
- Copeland MTS phase 2 is expected to be in-service in 2024 to address the station capacity need.
- Bridgman TS transformer replacement (T11/T12/T13/T14) is expected to be done in 2024.
- Fairbank TS transformer replacement (T1/T2/T3/T4) is expected to be completed in 2024.
- Main TS transformer replacement (T3/T4) is expected to be completed in 2024.
- John TS transformer replacement (T5/T6) is expected to be complete in 2025. Transformer T1, T2 and T4 have been replaced in 2019-2021. The condition of transformer T3 and the 115 kV breakers are reviewed and considered in fair condition; no replacement in the near/medium term is needed.
- Circuits C5E/C7E underground cable replacement between Esplanade TS and Terauley TS is underway and expected to be completed in 2026.

Other near/medium-term needs identified in the previous RP cycle and the new near/medium-term needs identified in this NA are:

Identified in the previous RP cycle	Identified in this NA
Line Capacity (Refer to section 7.2 for more details) • Richview to Manby 230 kV Corridor [2026] • Manby to Riverside Jct 115 kV Corridor [2026, with a line upgrade expected by 2028] Transformers / Autotransformers Requiring Replacement (Refer to section 7.1 for more details) • Charles TS: T3/T4 [2026] • Duplex TS: T1/T2 [2026] • Scarboro TS: T23 [2027] • Fairchild TS: T1 [2028] • Bermondsey TS: T3/T4 [2029] • Manby TS: autotransformers T7, T9, and T12, and step-down transformer T13 [2029-2030] • Leslie TS: T1 [2030] Transmission Lines Requiring Replacement (Refer to section 7.1 for more details) • H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. 115 kV overhead section [2025] • L9C/L12C: Leaside TS to Balfour Jct. 115 kV overhead section [2027]	Transformers / Autotransformers Requiring Replacement (Refer to section 7.1 for more details) • Strachan TS: T14 & T13/T15 [2025, 2031] • Basin TS: T3/T5 [2027] • Scarboro TS: T23 [2027] • Fairchild TS: T3/T4 [2028] • Malvern TS: T3 [2029] • Manby TS: T14 [2029] • Duplex TS: T3/T4 [2031] Load Restoration (Refer to section 7.4) • Loss of C14L/C17L • Loss of C18R/P22R

The long-term needs that were identified in the previous RP cycle and this NA are [beyond 2031]:

Identified in the previous RP cycle	Identified in this NA (Potential)
Station Capacity • Fairbank TS • Sheppard TS • Strachan TS • Basin TS Transformation Capacity • Manby W TS • Leaside TS Line Capacity • Leaside TS to Wiltshire TS 115 kV Corridor	Station Capacity • Glengrove TS • Finch TS / Bathurst TS • Warden TS Line Capacity • Parkway TS to Richview TS 230 kV Corridor

7. RECOMMENDATIONS

The TWG's recommendations are as follows:

a) No further regional coordination is required for the following need:
- Asset renewal needs for replacing the major HV equipment as listed in the table below. These needs will be addressed directly by Hydro One and THESL to develop a preferred replacement plan giving consideration to "right-sizing";

b) Further assessment and regional coordination is required in the next phases of the RP cycle to review and/or develop a preferred plan for the follow needs:
- The line capacity need for the 115 kV corridor between Manby TS and Riverside Jct. Hydro One will initiate the development work for reconductoring the overhead line section; and
- The load restoration and long-term needs as listed in the following table.

<table>
<tr><th>Further Regional Coordination Not Required</th><th>Further Regional Coordination Required</th></tr>
<tr><td rowspan="2">Asset Renewal Needs (Stations):
• Strachan T14 & T13/T15
• Charles TS: T3/T4
• Duplex TS: T1/T2 & T3/T4
• Basin TS: T3/T5
• Scarboro TS: T23
• Fairchild TS: T1 & T3/T4
• Bermondsey TS: T3/T4
• Malvern TS: T3
• Manby TS: T7, T9, T12 autotransformers, T13/T14 step-down transformer
• Leslie TS: T1

Asset Renewal Needs (Lines):
• 115 kV H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. overhead section
• 115 kV L9C/L12C: Leaside TS to Balfour Jct. overhead section

Line Capacity Need:
• 230 kV Richview TS to Manby TS Corridor

Station Capacity Need:
• Fairbank TS
• Strachan TS</td><td>Line Capacity Need:
• 115 kV Manby TS to Riverside Jct. Corridor

Load Restoration:
• Loss of C14L/C17L
• Loss of C18R/P22R</td></tr>
<tr><td>Long-Term Needs:
• Sheppard TS – Station Capacity
• Basin TS – Station Capacity
• Glengrove TS – Station Capacity
• Finch TS / Bathurst TS – Station Capacity
• Warden TS – Station Capacity
• 230/115kV Manby W Autotransformers – Transformation Capacity
• 230/115kV Leaside TS Autotransformers – Transformation Capacity
• 230 kV Parkway TS to Richview TS Corridor – Line Capacity
• 115kV Leaside TS to Wiltshire TS Corridor – Line Capacity</td></tr>
</table>

This NA assessment does not include or consider the impact from the IESO's "Pathways to Decarbonization" report published on December 15, 2022. The electricity demand and new infrastructure need in the longer term could be substantially higher than anticipated and discussed in this report. The TWG recommends that this be assessed in the next phase of this RP cycle.

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1 INTRODUCTION

The second cycle of the Regional Planning ("RP") process for the Toronto Region was completed in March 2020 with the publication of the Regional Infrastructure Plan ("RIP") report.

The purpose of this Needs Assessment ("NA") is to identify new needs in the region, reaffirm and update needs identified in the previous Toronto RP cycle, and recommend which needs require further assessment and regional coordination and which do not.

This report was prepared by the Toronto Region Technical Working Group ("TWG"), led by Hydro One Networks Inc. Participants of the TWG are listed below in Table 1. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies ("LDC") and the Independent Electricity System Operator ("IESO").

Table 1: Toronto Region TWG Participants

Company
Alectra Utilities Corporation
Elexicon Energy Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator ("IESO")
Toronto Hydro-Electric System Limited ("THESL")
Hydro One Networks Inc. (Lead Transmitter)

2 REGIONAL ISSUE/TRIGGER

In accordance with the RP process, the RP cycle should be triggered at least once every five years. Considering these timelines, the third RP cycle was triggered for the Toronto Region.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Toronto Region and includes:

- Reaffirm and update needs/plans identified in the previous RP cycle;
- Identify any new needs resulting from this assessment;
- Recommend which need(s) require further assessment and regional coordination in the next phases of the RP cycle; and

- Recommend which need(s) that do not require further regional coordination (i.e. can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle).

The TWG may identify additional needs during the next phases of the RP process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), and/or RIP based on updated information available at that time.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Toronto Region covers the area roughly bordered geographically by Lake Ontario on the south, Steeles Avenue on the north, Highway 427 on the west and Regional Road 30 on the east. It includes the City of Toronto, which is the largest City in Canada and the fourth largest in North America. Please see Figure 1 for the Toronto Region map. Electrical supply to this Region is provided by thirty-five 230kV and 115kV transmission and step-down stations as shown in Figure 2. The eastern, northern, and western parts of the Region are supplied by seventeen 230/27.6kV step-down transformer stations. The central area is supplied by two 230/115kV autotransformer stations (Leaside TS and Manby TS) and sixteen 115/13.8kV and two 115/27.6kV step-down transformer stations. The region is also supplied locally by Portlands Energy Centre, a 550 MW combined-cycle power generating station. The sum of 2021 non-coincident summer station peak load of the Region was about 4,850 MW.

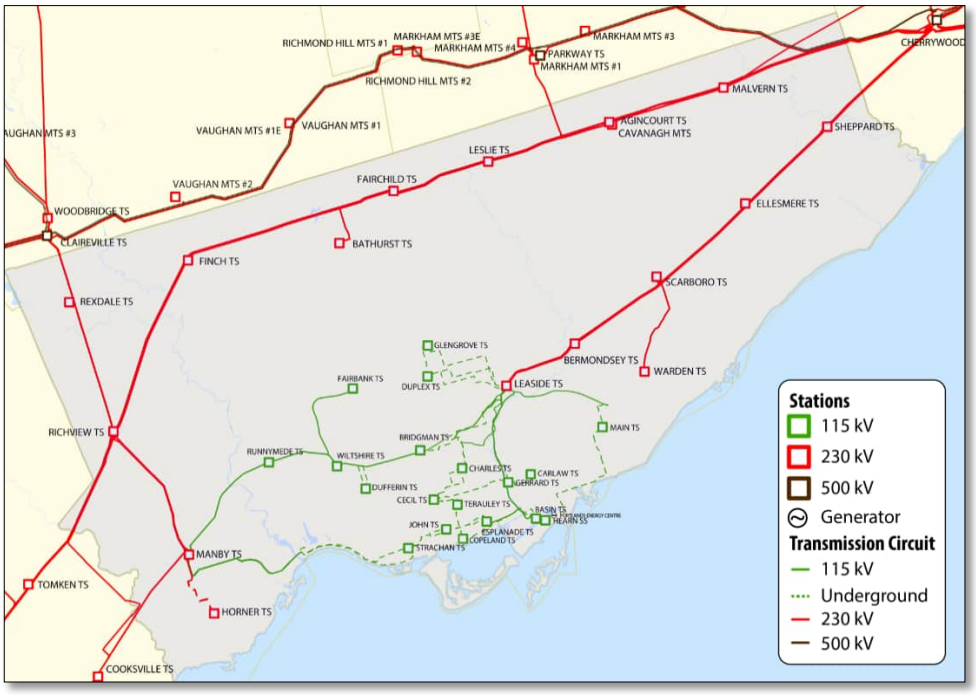

Figure 1: Toronto Region Map

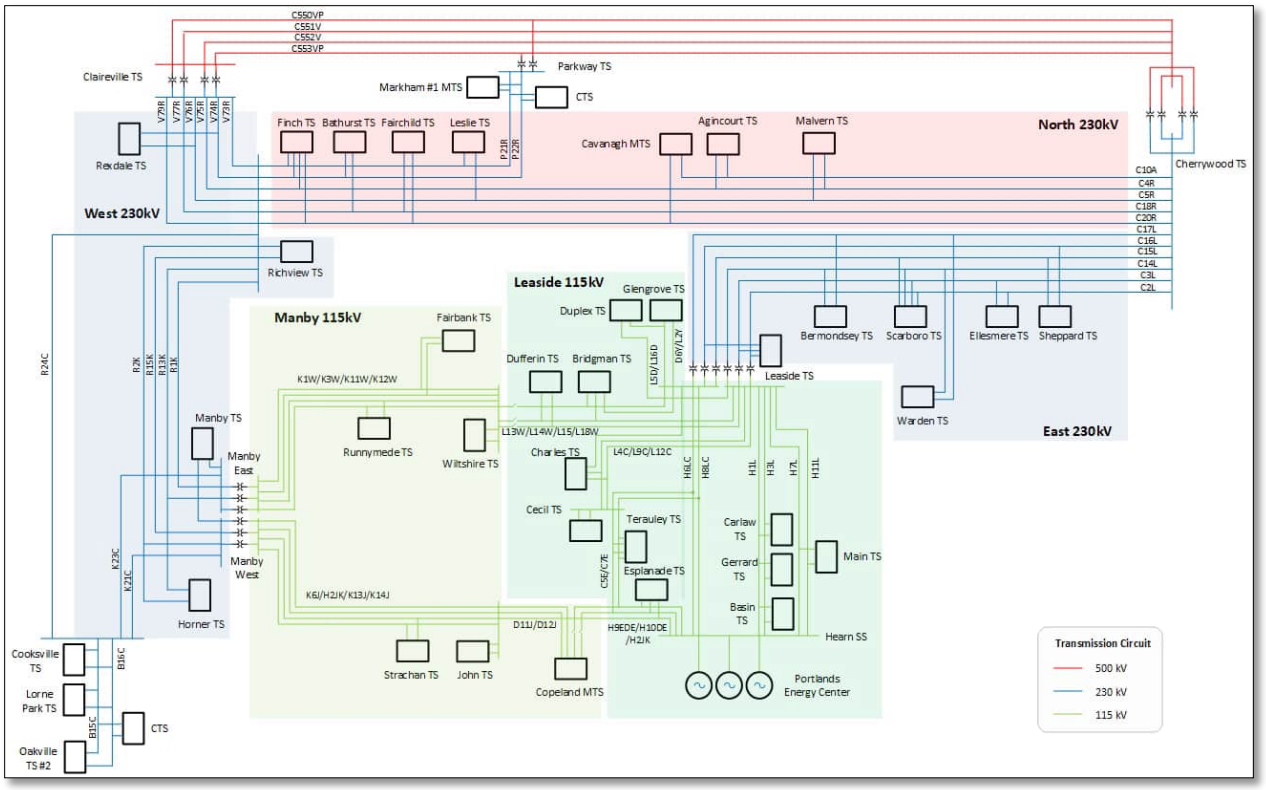

Figure 2: Toronto Region – Single Line Diagram

5 INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the Toronto Region NA. The information provided includes the following:

- Load Forecast for all supply stations in the Toronto Region;
- Known capacity and system reliability needs, operational issues, and/or major HV transmission equipment requiring replacement over the study period; and
- Planned/foreseen transmission and distribution investments that are relevant to the Toronto RP process.

The information provided was the most recent information available and provided at the time of the NA phase. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in October 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the RP process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP) (in cases where it has been produced by the municipality and the information can be translated by the LDC into the impact on peak demand). Accordingly, the OEB

RPPAG also recently developed a guideline called "Improving the Electricity Planning Process in Ontario: Enhanced Coordination between Municipalities and Entities in the Electricity Sector", which lists the key MEP/CEP outputs to improve LDC load forecasts going forward. THESL has been closely coordinating with developers, provincial agencies and the City of Toronto on energy plans impacting various sections of the grid across the Toronto region. This NA report is recommending that further engagement be undertaken during the next phase of the RP cycle.

Also, it is important to be noted that, the IESO has just published the "Pathways to Decarbonization" on December 15, 2022, which evaluates a moratorium on the procurement of new natural gas generating stations in Ontario and develops an achievable pathway to decarbonization in the electricity system. It recommends that development work for priority transmission investments be identified to support decarbonization in the RP process. With this increasing focus on decarbonization and electrification, the electricity demand and new infrastructure need in the longer term could be substantially higher than anticipated and discussed in this NA report. The TWG recommends that the "Pathways to Decarbonization" report and its subsequent impact on the need and/or the timing for additional electrical supply facilities in the Toronto Region be considered and assessed in the next phase of this RP cycle.

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

- Load forecast: The LDCs provided their load forecast for all the stations supplying their loads in the Toronto Region for the 10-year study period. The IESO provided a Conservation and Demand Management ("CDM") forecast and Distributed Generation ("DG") contract information for the Toronto Region. The region's extreme summer non-coincident peak gross load forecast for each station were prepared by applying the growth rates from the LDC load forecast to the actual 2021 summer peak extreme weather corrected loads. The extreme summer weather correction factor was provided by Hydro One. The net extreme weather summer load forecast was produced by reducing the gross load forecast for each station by the percentage CDM from the IESO for that station. It is to be noted that even though the IESO did not have information on new and contracted DG coming into service within the planning horizon, THESL has assumed the existing DGs are to remain in-service in the base year when developing their load forecast. The extreme summer weather corrected net non-coincident peak and coincident peak load forecasts for the individual stations in the Toronto region are given in Appendices A-1 and A-2;
- Relevant information regarding system reliability and operational issues in the region;
- List of major HV transmission equipment planned and/or identified to be replaced based on asset condition assessment, and relevant for RP purposes. The scope of equipment considered is given in Section 7.1.

A technical assessment of needs was undertaken based on:

- Station capacity and transmission adequacy assessment;
- System reliability and operational considerations;
- Asset renewal for major HV transmission equipment requiring replacement with consideration to "right-sizing"; and
- Sensitivity analysis to capture uncertainty in the load forecast (which does not consider the impact from the "Pathways to Decarbonization" report published by the IESO on December 15, 2022, but will be assessed in the next phase of this RP cycle).

The following other assumptions are made in this report.

- The study period for this NA is 2022-2031.
- Transmission system adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage (LV) capacitor banks and 95% lagging power factor for stations having LV capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

7 NEEDS

This section identifies any new needs in the Toronto Region, and reaffirms and provides an update on the near, medium, and long-term needs already identified in the previous RIP.

Needs that were identified in the previous RP cycle with associated projects recently completed or currently underway were reaffirmed and are briefly described below with relevant updates. These are not further discussed in later sections of this report.

- Second DESN at Horner TS and refurbishment projects at Runnymede TS (T3/T4), Sheppard TS (T3/T4), and Strachan TS (T12) were completed in 2021-2022.
- Copeland MTS phase 2 is expected to be in-service in 2024 to address the station capacity need.
- Bridgman TS transformer replacement (T11/T12/T13/T14) is expected to be completed in 2024.
- Fairbank TS transformer replacement (T1/T2/T3/T4) is expected to be completed in 2024.
- Main TS transformer replacement (T3/T4) is expected to be completed in 2024.
- John TS transformer replacement (T5/T6) is expected to be completed in 2025. Transformer T1, T2 and T4 were replaced in 2019-2021. Based on asset condition assessment, transformer T3 and the 115 kV breakers are not recommended for replacement in the near/medium term.
- Circuits C5E/C7E underground cable replacement between Esplanade TS and Terauley TS is underway and expected to be completed in 2026. A 2.5 km tunnel between Esplanade TS and Terauley TS is to be built.

The planned in-service year for the above underway projects is tentative and is subject to change.

All the other near/medium-term needs and long-term needs are summarized in Table 2 and Table 3 respectively. The load restoration need was also reviewed and is discussed in Section 7.4.

Table 2: Near/Medium Term Needs Identified in Previous RIP [1] and/or this NA

Type of Needs	Near/Medium-Term Needs	NA Section	Timing	Recommended Plan / Status	RIP Report Section
Line Capacity	Richview TS to Manby TS 230 kV Corridor	7.2.1	2026	Project in estimate phase.	7.5
	Manby TS to Riverside Jct 115 kV Corridor	7.2.2	2028 [3]	Timing is advanced to 2026.	7.9.5
Asset Renewal Needs (Stations) [2]	Strachan TS: Transformers T14 & T13/T15	7.1.1	2025 2031	• T14 requires replacement with higher rated unit. • T13/T15 need replacement with higher rated unit in medium term.	NEW
	Charles TS: Transformer T3/T4	7.1.2	2026	T3/T4 require replacement with higher rated units.	2nd cycle NA
	Duplex TS: Transformers T1/T2 & T3/T4	7.1.3	2026 2031	• T1/T2 require replacement with higher rated units. • T3/T4 need replacement with higher rated unit in medium term.	2nd cycle NA NEW
	Basin TS: Transformers T3/T5	7.1.4	2027	T3/T5 require replacement with higher rated units.	NEW / 7.9.4
	Scarboro TS: Transformer T23	7.1.5	2027	T23 requires replacement with like-for-like unit.	NEW
	Fairchild TS: Transformer T1 & T3/T4	7.1.6	2028	T1 and T3/T4 require replacement with like-for-like units.	2nd cycle NA (T1), NEW (T3/T4)
	Bermondsey TS: Transformers T3/T4	7.1.7	2029	T3/T4 require replacement with like-for-like units.	7.7
	Malvern TS: Transformer T3	7.1.8	2029	T3 requires replacement with like-for-like unit.	NEW
	Manby TS: Autotransformers (T7, T9, T12), Step-down transformer (T13/T14)	7.1.9	2029 2030	• T13/T14 need replacement with similar unit per current standard. • T7/T9/T12 need replacement with similar unit per current standard. • 230 kV breakers are in fair condition; will not be replaced in the near term.	7.6, NEW (T14)
	Leslie TS: Transformer T1	7.1.10	2030	T1 requires replacement with similar unit per current standard.	2nd cycle NA
Asset Renewal Needs (Lines) [2]	H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. overhead section	7.1.11	2025	Development and estimate work to initiate in 2023.	7.2
	L9C/L12C: Leaside TS to Balfour Jct. overhead section	7.1.12	2027	Development and estimate work to initiate in 2023.	7.3

(1) Includes needs identified in the previous RIP that do not have projects in execution yet.

(2) The replacement/refurbishment scope, timing, and prioritization are based on the best available information at the time, and are subject to change.

(3) Earliest in-service of reconductoring the overhead line K13J/K14J is expected to be around 2028 if the development and estimate work is to be initiated in 2023.

Table 3: Long-Term Needs Identified in Previous RIP and/or this NA

Type of Needs	Long-Term Needs	NA Section	Timing (2nd Cycle RIP)	Description / Update	RIP Report Section
Station Capacity	Fairbank TS	7.3.1	2030-2035	New Runnymede DESN and the underway transformers replacement at Fairbank TS will provide relief.	7.9.1
	Sheppard TS	7.3.2	2030-2035	Consideration may be given to utilizing the idle winding on transformers T1/T2.	7.9.2
	Strachan TS	7.3.3	2030-2035	Transformer T12 has been replaced with a 60/100 MVA unit. Station capacity will increase after T14 is replaced by 2025 and T13/T15 are replaced in the medium term.	7.9.3
	Basin TS	7.3.4	2030-2035	Station capacity will increase when transformers T3/T5 will be replaced with 60/100 MVA units by 2027.	7.9.4
	Glengrove TS	7.3.5	Beyond 2031	Glengrove TS is almost at capacity in 2031. The transformer replacement with higher rated units at Duplex TS will provide relief.	NEW
	Finch TS / Bathurst TS	7.3.6	Beyond 2031	Total load at Finch TS and Bathurst TS is almost reaching the combined station capacity in 2031. To be managed by load transfer between DESNs and nearby stations at distribution level in the near/medium term.	NEW
	Warden TS	7.3.7	Beyond 2031	Load demand near Warden TS exceeds its capacity from 2024. To be managed by load transfer to Scarboro TS at distribution level in the near/medium term.	NEW
Transformation Capacity	Manby W TS Autotransformers (T12)	7.3.8	2030-2035	Restricted by the lowest rated autotransformer unit T12. This unit is planned to be replaced by 2030 and will provide relief to this constraint.	7.9.6
	Leaside TS Autotransformers (T16)	7.3.9	2035-2040	Autotransformer T16 is potentially overloaded following circuit C14L, C15L, or C17L contingency, assuming that two of the three units at Portlands Energy Centre GS are out-of-service, and total plant generation is 160 MW. Post-contingency control action is currently available to resolve this issue by transferring Dufferin TS to Manby supply if needed.	7.9.8
Line Capacity	230 kV Parkway TS to Richview TS Corridor	7.3.10	Beyond 2031	Some sections of the 230 kV circuits P21R and P22R near the Parkway TS end are approaching limit by 2031. The baseline forecast does not reflect several customers that show interest in connecting new load near the Steeles / Hwy 404 area. This need may arise sooner.	NEW
	115 kV Leaside TS to Wiltshire TS Corridor		2035-2040	The Bayview Jct. x Balfour Jct. underground section of the 115 kV circuit L15 is potentially overloaded in the long term.	7.9.7

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second RP cycle, Hydro One and the TWG have identified some new major HV equipment replacement needs over the next 10 years in the Toronto Region, as shown in Table 4 below. These needs are determined by asset condition assessment, which is based on a range of considerations such as equipment deterioration; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. The scope, timing, and prioritization of these replacement needs are based on the current available information and are subject to change.

The major HV transmission equipment considered in this assessment includes the following:

- 230 / 115 kV autotransformers;
- 230 kV and 115 kV load serving step-down transformers;
- 230 kV and 115 kV breakers where:
  - Replacement of six breakers or more than 50% of station breakers, the lesser of the two; and
- 230 kV and 115 kV transmission lines requiring refurbishment where:
  - Leave to Construct (i.e., Section 92) approval is required for any alternatives to like-for-like.

The asset renewal assessment considers options for "right-sizing" the equipment such as:

1. Maintaining the status quo;
2. Replacing equipment with similar equipment with lower ratings and built to current standards;
3. Replacing equipment with similar equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all the load to other existing facilities;
5. Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement); and
6. Replacing equipment with higher ratings and built to current standards.

Table 4: New Major HV Transmission Equipment Replacement Needs Identified in this NA

Station	Timing	Need Description
Strachan TS: Transformers T14 & T13/T15	2025* 2031	T14 requires replacement in the medium term with higher rated unit. T13/T15 need replacement in the medium term with higher rated units.
Basin TS: Transformers T3/T5	2027	T3/T5 require replacement in the near term with higher rated units.
Scarboro TS: Transformer T23	2027	T23 requires replacement in the near term with like-for-like unit.
Fairchild TS: Transformer T3/T4	2028	T3 requires replacement in the medium term with like-for-like unit.
Malvern TS: Transformer T3	2029	T3 requires replacement in the medium term with like-for-like unit.
Manby TS: Transformer T14	2029	T14 need replacement in the medium term with similar unit per current standard.
Duplex TS: Transformers T3/T4	2031	T3/T4 require replacement in the medium term with higher rated units.

* Need date is advanced to support planned work at the other DESN in Strachan TS.

The newly identified major HV transmission equipment replacement need in this NA will be discussed in detail in the following subsections. The previously identified asset renewal needs from the last RP cycle, for which project execution has not yet been initiated, will also be reviewed and discussed in the following. The TWG recommends continuation of addressing all the identified needs for the Toronto Region as per the recommended plan described in each subsection. THESL has also confirmed that there is no plan to replace any major HV transmission equipment under its under ownership over the study period.

For the 115-13.8 kV 45/75 MVA step-down transformers where replacement is required, and upsizing is recommended, the largest standard size (60/100MVA) units for this voltage class will be used. The 115-13.8 kV 60/100 MVA transformer has two secondary windings and each winding has an LTR of 72 MVA which matches the 3000 A or 72 MVA metal clad switchgear that THESL has standardized on and used at 13.8 kV. Even if a larger custom size transformer is procured, no additional station capacity will be provided as it is limited by the metal clad switchgear. The estimated incremental cost of upsizing a 45/75 MVA unit to a 60/100 MVA unit is approximately $300k based on current dollars.

7.1.1 Strachan TS

Strachan TS comprises two DESN units, T12/T14 (T12 replaced in 2022: 60/100 MVA; T14: 45/75 MVA) and T13/T15 (45/75 MVA), having a summer 10-Day LTR of 171 MW. The station's 2021 actual non-coincident summer peak load was about 135 MW and is forecasted to be approximately 140 MW (net adjusted for extreme weather) in 2031.

Transformer T14 is currently about 47 years old and requires replacement in the medium term based on asset condition assessment. It is planned to replace it with a 60/100MVA unit as the companion transformer T12 was recently replaced with a 60/100 MVA unit thereby increasing the station capacity. Transformers T13 and T15 are currently about 40 years old and will also require replacement in the medium term based on their condition. The station capacity will be further increased after they are replaced with 60/100 MVA units. This will provide the additional capacity required to support the transformers and switchgear replacement work planned for Strachan TS in the medium term and accommodate the long-term growth and development need anticipated in the area subsequent to the Ontario Line subway project. Replacing the transformers with similar size equipment is not recommended since upgrading later within the lifetime of the transformer due to eventual load growth will be significantly more costly. It should also be noted that increasing capacity, as opposed to maintaining it, is a more resilient option as it provides additional flexibility during emergency conditions or any planned outages through load transfers. With new T12 installed this year, replacing the remaining three transformers with 60/100 MVA units will provide an additional station capacity of approximately 98 MVA at Strachan TS.

Based on the above, the TWG recommends that transformers T14, T13 and T15 be replaced with 60/100MVA units. Hydro One and THESL will coordinate the replacement plan for these transformers. The planned in-service date is 2025 for T14 and 2031 for T13 and T15.

7.1.2 Charles TS

Charles TS comprises two DESN units, T1/T2 (60/100 MVA) and T3/T4 (45/75 MVA), having a summer 10-Day LTR of 211 MW. The station's 2021 actual non-coincident summer peak load was about 127 MW and is forecasted to be approximately 165 MW (net adjusted for extreme weather) in 2031. Transformers T3 and T4 are currently about 55 years old and require replacement based on asset condition assessment.

The load at Charles TS is forecasted to be almost 80% of its LTR in the medium term. The load at three of the closest stations, Bridgman TS, Cecil TS and Terauley TS, is also forecasted to be about 80%, 65%, and 80% in the medium term.

As discussed in the 2nd cycle NA, the TWG recommends that transformer T3 and T4 be replaced with 60/100MVA units because this is the most cost-effective option that addresses the replacement need and maintains reliable long-term supply to the existing and potential customers in the area. Hydro One and THESL are coordinating this replacement work and the planned in-service date is 2026.

7.1.3 Duplex TS

Duplex TS comprises two DESN units, T1/T2 (45/75 MVA) and T3/T4 (45/75 MVA), having a summer 10-Day LTR of 128 MW. The station's 2021 actual non-coincident summer peak load was about 88 MW and is forecasted to be approximately 112 MW (net adjusted for extreme weather) in 2031.

Transformers T1 and T2 are currently about 54 years old and require replacement in the near term based on asset condition assessment. As discussed in the second cycle NA, replacing T1/T2 with 60/100 MVA units is recommended to allow for effective planning for long-term electricity needs, reliability and system resiliency. The forecast developed in this NA reaffirms this recommendation as the load at Duplex TS and its nearby stations Bridgman TS and Glengrove TS are to be over 85%, 80% and 95% of their station LTR respectively in 2031.

Transformer T3 and T4 are currently about 46-48 years old and require replacement in the medium term based on asset condition assessment. With the same reasons discussed above and the growing demand in the area, the TWG recommends that these transformers be replaced with 60/100 MVA units.

Hydro One and THESL will coordinate the replacement plan for transformers T1/T2 and T3/T4. The current planned in-service dates are 2026 and 2031 respectively.

7.1.4 Basin TS

Basin TS comprises one DESN unit, T3/T5 (45/75 MVA), having a summer 10-Day LTR of 88 MW. The station's 2021 actual non-coincident summer peak load was about 57 MW and is forecasted to be approximately 85 MW (net adjusted for extreme weather) in 2031.

Transformers T3 and T5 are currently about 39 years old and require replacement in the near term based on asset condition assessment. The load at Basin TS is forecasted to be over 95% of its station LTR in 2031.

The load at its nearby stations Carlaw TS, Gerrard TS and Esplanade TS is also forecasted to be over 70-85% of their station LTR by 2031.

The City of Toronto is planning to re-develop the East Harbour land which is located in the Lakeshore and Don Roadway area in the near and medium term, as well as the Port Lands area in the longer term. These areas may see additional load in the longer term, beyond what is currently forecast in this NA. The scale and timing of additional load will depend upon the City's plan. However, the City's current re-development plans may impact the continued operation of Basin TS and several high voltage lines in their current locations in the Port Lands area. If implemented, this would significantly impact both Hydro One infrastructure and THESL infrastructure within and outside of Basin TS. No potential sites for a replacement transformer station or high voltage line routes have been identified by the City at this time. Hydro One and THESL have requested the City to revise its plans to avoid the conflicts with Basin TS and high voltage lines, and joined others in a legal appeal of the City's land plans. In December 2020, the appeal was settled provided that all parties will continue to reassess different options with and without the relocation or reconfiguration of the electricity infrastructure in the Port Lands area. There is no update or change in status at this time, but Hydro One and THESL will provide updates to the TWG as information becomes available.

Based on asset condition assessment of the existing transformers at Basin TS, the TWG recommends that transformers T3/T5 be replaced with 60/100 MVA units to address the replacement need and avoid any extended forced outages due to potential failure of these existing transformers. This will also provide an additional station capacity of approximately 46 MVA at Basin TS to help accommodate expected load growth in this area. Hydro One and THESL coordinate the replacement work.

The TWG also recommends that the long-term supply need in the Basin / Port Lands area be reviewed as part of the next phase in the RP process because of the uncertainty associated with the long-term growth plans as well as the potential impacts on the electricity infrastructure in this area resulting from the City's redevelopment plans. This is consistent with the finding and the recommendation from the previous RP cycle and as discussed in Section 7.3.4 of this report.

7.1.5 Scarboro TS

Scarboro TS comprises two DESN units, T21/T22 (75/125 MVA) and T23/T24 (75/125 MVA), having a summer 10-Day LTR of 340 MW. The station's 2021 actual non-coincident summer peak load was about 217 MW and is forecasted to be approximately 257 MW (net adjusted for extreme weather) in 2031.

Transformer T23 is currently about 48 years old and require replacement in the near term based on asset condition assessment. The load at Scarboro TS is forecasted to be over 75% of its station LTR in 2031. Its nearby stations Warden TS is forecasted to exceed its station capacity in the near term and need relief by transferring load to Scarboro TS. The load at other closest stations Bermondsey TS and Ellesmere TS is also forecasted to be about 80% and 85% of their station LTR by 2031.

Downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly costlier. It should also be noted that maintaining capacity, as opposed to

downsizing, is a more resilient option as it provides additional flexibility during emergency conditions or any planned outages through load transfers. Therefore, downsizing T23 is not a viable option. Upgrading the transformer is also not an option since it is already at the maximum standard size.

The TWG has recommended that transformer T23 be replaced with the same type and size unit (75/125 MVA). Hydro One and THESL will coordinate the replacement plan for the transformer and the planned in-service date is 2027.

7.1.6 Fairchild TS

Fairchild TS comprises two DESN units, T1/T2 (75/125 MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 346 MW. The station's 2021 actual non-coincident summer peak load was about 216 MW and is forecasted to be approximately 243 MW (net adjusted for extreme weather) in 2031. Transformers T1 is 52 years old but was rebuilt 36 years ago. The companion DESN transformer T2 failed and was replaced under emergency in 2017 with a similar 75/125 MVA unit. Transformers T3 and T4 in the other DESN are 39 years old. Transformers T1, T3 and T4 require replacement in the medium term based on asset condition assessment.

The load at Fairchild TS is forecasted to be over 70% of its LTR in the medium term. The load at the two closest stations, Bathurst TS and Leslie TS, is also forecasted to be about 95% and 90% of their respective LTR's in the medium term. Downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly costlier. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions or any planned outages through load transfers. Therefore, downsizing the transformers at Fairchild TS and consolidating load within the station and/or with area stations is not a viable option given medium term load growth at these stations. Upgrading the transformers is also not an option since they are already at the maximum standard size.

Based on the above, the TWG recommends that transformers T1, T3 and T4 be replaced like-for-like. Hydro One and THESL will coordinate the replacement plan for these transformers. The planned in-service date is 2028.

7.1.7 Bermondsey TS

Bermondsey TS comprises two DESN units, T1/T2 (75/125MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 348 MW. The station's 2021 actual non-coincident summer peak load was about 153 MW and is forecasted to increase significantly in the near term due to new load customers in the area. The load is forecasted to be approximately 275 MW (net adjusted for extreme weather) in 2031. Transformers T3 and T4 are currently about 57 years old and require replacement in the near term based on asset condition assessment.

The load at Bermondsey TS is forecasted to be almost 80% of its LTR in the medium term. The load at the three closest stations, Scarboro TS, Warden TS, and Leaside TS is forecasted to be over 75%, 100%[1], and 67% respectively of their LTR's in the medium term.

As evaluated in the 2nd cycle RIP and reaffirmed in this NA, transformer T3 and T4 are to be replaced with similar type and size equipment as per current standard because this is the most cost effective option that addresses the replacement need and maintains reliable long-term supply to the customers in the area. The planned in-service date of this refurbishment work is 2029.

7.1.8 Malvern TS

Malvern TS comprises one DESN unit, T3/T4 (75/125 MVA), having a summer 10-Day LTR of 176 MW. The station's 2021 actual non-coincident summer peak load was about 110 MW and is forecasted to be approximately 119 MW (net adjusted for extreme weather) in 2031. Transformers T3 is currently 36 years old and requires replacement in the medium term based on asset condition assessment.

The load at Malvern TS is forecasted to be almost 70% of its LTR in the medium term. The load at the three closest stations, Agincourt TS, Cavanagh MTS, and Sheppard TS is forecasted to be over 60%, 90%, and 90% respectively of their LTR's in the medium term. Downsizing capacity today and then later upgrading within the lifetime of the transformer due to eventual load growth will be significantly costlier. It should also be noted that maintaining capacity, as opposed to downsizing, is a more resilient option as it provides additional flexibility during emergency conditions or any planned outages through load transfers. Therefore, downsizing the transformer at Malvern TS and consolidating load within the station and/or with area stations is not a viable option given medium term load growth at these stations.

Based on the above, the TWG recommends that transformer T3 be replaced with the same type and size unit (75/125 MVA). Hydro One and THESL will coordinate the replacement plan for this transformer. The planned in-service date is 2029.

7.1.9 Manby TS

Manby TS is a major bulk electric switching and autotransformer station in the Toronto region. Station facilities include the Manby West and Manby East 230 kV and 115 kV switchyards, six 230/115 kV autotransformers (T1, T2, T7, T8, T9, T12), and six 230/27.6 kV step-down transformers supplying three DESNs (T3/T4, T5/T6, T13/T14).

Three of the autotransformers, T7, T9, and T12, and two of the step-down transformers, T13 and T14, are close to 55 years old and require replacement in the medium term based on asset condition assessment. It is to be noted that T14 was not identified as a candidate for replacement in the previous RP cycle. The autotransformers continue to be critical to the load supply to the downtown and west Toronto area and will

[1] The net demand at Warden TS exceeds its station LTR by 2024. THESL will manage the station overload by transferring some load to Scarboro TS in the near/medium term.

be replaced with similar 250 MVA units, consistent with recommendations from previous RP cycle. The expected in-service date for the autotransformer replacement is 2030.

The total summer 10-Day LTR of the six step-down transformers is 226 MW. The station's 2021 actual non-coincident summer peak load was about 237 MW which exceeds the station capacity and will be relieved in the near and medium term by transferring load to the second DESN at Horner TS recently built. The total DESN load at Manby TS, after the load transfer, is forecasted to be approximately 204 MW (net adjusted for extreme weather) in 2031, i.e. over 90% of its LTR in the medium term. Therefore, the TWG recommends transformers T13 and T14 (56/93 MVA units, non-standard size) be replaced with the current standard size units (75/125 MVA units) to address the replacement need and maintain reliable long-term supply to the customers in the area. This will potentially increase the station LTR by approximately 60 MVA. Hydro One and THESL will coordinate the replacement plan for these transformers. The planned in-service date of this refurbishment work is 2029.

Previously, the 230 kV oil breakers were considered as candidates for replacement. Since then, the condition of these breakers has been reviewed and based on this assessment, they are not required for replacement in the near or medium term. Hydro One will continue to monitor the condition of these breakers and coordinate the future replacement plan with the phase 2 work of the Richview TS x Manby TS 230 kV Corridor Upgrade project as described in Section 7.2.1 of this report. Updates will be provided to the TWG in the next RP cycle as required.

7.1.10 Leslie TS

Leslie TS comprises two DESN units, T1/T2 (75/125 MVA) and T3/T4 (75/125 MVA), having a summer 10-Day LTR of 323 MW. The station's 2021 actual non-coincident summer peak load was about 221 MW and is forecasted to be approximately 249 MW (net adjusted for extreme weather) in 2031. Transformer T1 is currently about 59 years old and require replacement based on asset condition assessment. The companion DESN transformer T2 is currently 25 years old and does not require replacement in the near or medium term.

It should be noted that transformers T1 and T2 are non-standard units with dual LV voltages (230-27.6-13.8 kV 75/125 MVA units). The 13.8 kV load that are currently supplied from Leslie TS will be diminished and the 13.8 kV supply will not be needed from Leslie TS. Excluding the capacity for the 13.8kV winding, the total station LTR for the 27.6kV load is about 280 MW. The 27.6kV load at Leslie TS will be at almost 90% of its LTR in the medium term. The load at the three closest stations, Fairchild TS, Cavanagh MTS, and Agincourt TS, is also forecasted to be over 70%, 90%, and 60% respectively of their LTR's in the medium term. THESL is also anticipating additional new load connection in the longer term at Leslie TS and Agincourt TS.

Based on the above and consistent with the recommendation from the last NA, the TWG recommends that transformer T1 be replaced with a standard unit of same size without dual LV voltages (i.e. a 230-27.6-27.6 kV 75/125 MVA unit). Hydro One and THESL will coordinate the replacement plan for this transformer. When more capacity is required at Leslie TS, the companion transformer T2 can be replaced with the same

230-27.6-27.6 kV 75/125 MVA unit to provide an increase of approximately 70 MVA for the 27.6 kV supply capacity. The planned in-service date for transformer T1 is 2030.

7.1.11 Overhead Transmission Line H1L/H3L/H6LC/H8LC

The 115 kV circuits H1L/H3L/H6LC/H8LC provide connections between Leaside TS, Hearn SS, and Cecil TS, and supply transformer stations in the eastern part of central Toronto including Gerrard TS, Carlaw TS, and Basin TS. Based on their asset condition, conductors along the overhead section between Leaside 34 Jct. and Bloor St. Jct. (about 2 route km) are required to be replaced in the near term.

As recommended by the TWG from the previous RIP, the conductor in this overhead section will be replaced with largest size possible conductor while retaining existing tower structures. The expected in-service date for this line replacement work is around 2025.

7.1.12 Overhead Transmission Line L9C/L12C

The 115 kV circuits L9C/L12C provide connections between Leaside TS and Cecil TS, and supply to central downtown area including Charles TS and Cecil TS. The overhead section of this 115 kV double-circuit line between Leaside TS and Balfour Jct. (about 3.6 route km) is over 90 years old and require replacement in the near term.

As recommended by the TWG from the previous RIP, the conductor in this overhead section will be replaced with largest size possible conductor while retaining existing tower structures. The expected in-service date for this line replacement work is around 2027.

7.2 Station and Transmission Capacity Needs in the Near / Medium Term

The Station and Transmission supply capacities have been reviewed. No near or medium-term station capacity need has been identified in the Toronto region. However, two transmission line capacity needs are identified below during the study period of 2022 to 2031.

7.2.1 Richview TS x Manby TS 230 kV Corridor – Line Capacity

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the Western Sector of Central Toronto. Along this corridor there are two double-circuit 230 kV lines R1K/R2K and R13K/R15K. Together with circuit R24C between Richview TS and Cooksville TS, this corridor also supplies the load in the southern Mississauga and Oakville areas via Manby TS. The need and options to increase transfer capability of this transmission corridor to support the continuous load growth in these areas has been identified and discussed in the past RP cycles. This need was also reaffirmed in an IRRP addendum done in 2021.[2]

[2] The IRRP addendum for the Richview TS x Manby TS Circuit Upgrade need has not been published or shared outside of the TWG yet. However, since it was just reviewed last year, this need is not to be re-evaluated in this NA.

As previously documented, the recommendation is to proceed with:

Phase 1: Rebuilding the existing idle 115 kV overhead line on the transmission corridor between Richview TS and Manby TS to 230 kV standards. The new line will operate in parallel with the existing four 230 kV circuits from Richview TS to Manby TS, which will initially be reconfigured to create two "supercircuits" R2K and R15K. This configuration avoids the need to build new terminations and new breakers at Manby TS. This project is currently in estimate and public consultation phase. The planned in-service date is 2026.

Phase 2: Unbundling the "supercircuits" with one new circuit connected to Manby West and one to Manby East with new termination installed at Manby TS. At Richview TS, the new circuits will be tapped to existing 230 kV circuits V73R and V79R from Claireville TS. This configuration allows Richview TS to be bypassed and permits continued supply to Manby TS should there be an emergency at Richview TS. The timing of Phase 2 will be planned to coincide with Manby TS 230kV breakers replacement work when the time comes. As discussed in Section 7.1.9 of this report, the 230 kV breakers at Manby TS are currently in good condition and not planned to be in replaced in the coming 10 years. Their condition will be monitored and this phase 2 work will be coordinated with the replacement work. Updates will be provided to the TWG in the next RP cycle as required.

7.2.2 Manby TS x Riverside Junction 115 kV Corridor – Line Capacity

The 115 kV transmission corridor between Manby TS and John TS comprises four circuits K13J, K14J, K6J and H2JK, and provides supply to Downtown Toronto via three transformer stations John TS, Strachan TS and Copeland MTS. The 2021 actual total coincident summer peak load of these stations was about 370 MW and is forecasted to be approximately 513 MW and 500 MW (net adjusted for extreme weather) in 2026 and 2031 respectively. This corridor also provides backup supply to other stations that are normally connected to the Leaside / Hearn subsystem, such as Esplanade TS and Terauley TS.

The 7 km overhead section of the circuits K13J/K14J between Manby TS and Riverside Jct., as shown in Figure 3, is potentially overloaded under the contingency of the loss of the other circuits on this corridor. This need was identified as a long-term need (2030-2035) in the previous RIP. However, the new forecast in this NA has reflected the load demand increase from the Ontario Line subway and other residential and commercial development projects expected in the near term at Copeland MTS and John TS, and therefore this need is advanced to 2026.

The companion overhead line K6J/H2JK was upgraded in 2000 and currently has a higher ampacity rating than the K13J/K14J line. The capacity of this corridor could potentially be increased by approximately 100 MVA if the overhead section of the circuits K13J/K14J between Manby TS and Riverside Jct. is upgraded. A line upgrade project of this scope may take over 5-6 years to carry out the required work before it is in-service which includes, but not limited to, the development and estimate work, public consultation, environmental assessment, internal and external approvals, construction, outage planning and commissioning work. The earliest in-service date of the reconductoring work could be in 2028 if the development and estimate work is to begin in 2023. It is also to be noted that extended outages may be required to reconductor the line. As a result of limited load transfer capability between the Manby West

and Leaside / Hearn subsystems, obtaining the said outages to complete this work could be very challenging, and worsen further as the load increases in these areas.

Considering the long timeline of the corridor upgrade and that more load could potentially be affected during construction, the TWG recommends Hydro One proceed on the development work for reconductoring the circuits K13J/K14J to higher ampacity conductors without replacing the existing towers. This need will continue to be reviewed as part of the next phase of this RP cycle.

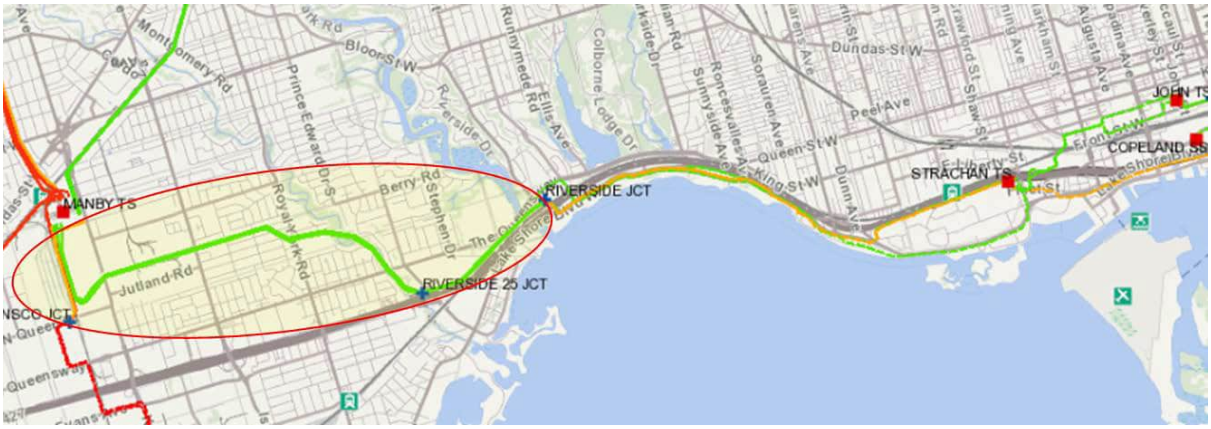

Figure 3: 115 kV Corridor between Manby TS and John TS (overhead section is circled)

7.3 Long-Term Capacity Needs

This section describes the long-term capacity needs identified from the previous RIP as well as the potential ones that are observed from this NA review.

This NA focuses on assessing and identifying the needs in the Toronto Region within the 10-year timeframe (up to 2031). It is observed that there are some transformer stations and 230 kV circuits that are approaching their limits by 2031 as listed in Table 5 below. This finding is consistent with the information shared by the TWG that the Toronto Region is about to embark on a period of growth over the short and medium term driven by electrification, and that the large-scale development and customer connection projects are expected in several areas within the Toronto Region in the coming years.

Table 5: Potential Long-Term Capacity Needs to be Further Assessed

Station / Circuit	Need Description
Glengrove TS	Total net demand is forecasted to be about 98% of station LTR by 2031.
Finch TS / Bathurst TS	Total net demand at Finch TS and Bathurst TS is forecasted to be about 100% and 97% of station LTR respectively by 2031.
Warden TS	The net demand at Warden TS exceeds its station LTR by 2024. THESL will manage the station overload by load transfer to Scarboro TS in the near/medium term.
Parkway TS to Richview TS 230 kV Corridor (P21R/P22R)	Markham #1 Jct. x Leaside Jct. section of the overhead 230 kV circuits P21R and P22R, connecting Parkway TS and Richview TS, is approaching limit by 2031.

These potential long-term capacity needs will be further reviewed in the next phases of this RP cycle.

7.3.1 Fairbank TS – Station Capacity

The long-term capacity need at Fairbank TS was identified in the previous RIP. The load at Fairbank TS was expected to exceed LTR within the 2030-2035 time period.

Fairbank TS comprises two DESN units, T1/T3 and T2/T4 (all 115/27.6 kV 50/83 MVA units), having a summer 10-Day LTR of 182 MW. The station's 2021 actual non-coincident summer peak load was about 197 MW. The excess load is planned to be transferred to Runnymede TS where a new DESN was built in 2019 and the old DESN was rebuilt in 2021. The Fairbank TS load is forecasted to be approximately 170 MW (net adjusted for extreme weather) or 93% of its station LTR in 2031. The transformer replacement work at Fairbank TS (T1/T2/T3/T4) is also underway with planned in-service date of 2024. The station LTR at Fairbank TS is expected to increase after the transformer replacement and provide some additional capacity. Together with the new and refurbished DESNs recently built at Runnymede TS, it is expected that the existing facilities will be adequate to supply the long-term growth in the area. The TWG recommends the loading be monitored and reviewed in the next RP cycle.

7.3.2 Sheppard TS – Station Capacity

The long-term capacity need at Sheppard TS was identified in the previous RIP. The load at Sheppard TS was expected to exceed LTR within the 2030-2035 time period.

Sheppard TS comprises two DESN units, T1/T2 (75/125 MVA units with idle winding) and T5/T6 (50/83 MVA units), having a summer 10-Day LTR of 204 MW. The station's 2021 actual non-coincident summer peak load was about 167 MW, and is forecasted to be approximately 187 MW (net adjusted for extreme weather) or 92% of its station LTR in 2031. Consideration may be given to utilizing the idle winding on transformers T1/T2. The TWG recommends the Sheppard TS loading be monitored and reviewed in the next phases of this RP cycle.

7.3.3 Strachan TS – Station Capacity

The long-term capacity need at Strachan TS was identified in the previous RIP. The load at Strachan TS was expected to exceed LTR within the 2030-2035 time period.

As discussed in Section 7.1.1, the transformer T12 at Strachan TS has been replaced recently with a 60/100 MVA unit. The station capacity at Strachan TS will increase after the transformer T14, and T13/T15 are also replaced with 60/100MVA units. This will provide adequate capacity to accommodate the long-term growth. The TWG recommends the loading be monitored and reviewed in the next RP cycle.

7.3.4 Basin TS – Station Capacity

The long-term capacity need at Basin TS was identified in the previous RIP. The load at Basin TS was expected to exceed LTR within the 2030-2035 time period.

As discussed in Section 7.1.4, the load at Basin TS is forecasted to be over 95% in 2031 and expected to increase further in the longer term due to the development plan in the Port Lands area as well as the East Harbor area. The transformers T13/T15 (45/75 MVA units) require replacement in the near term based on asset condition assessment. The TWG recommends that Hydro One and THESL coordinate and initiate the development work for replacing the transformers T3/T5 with 60/100 MVA units, and that the long-term supply need in the Basin / Port Lands area be reviewed as part of the next phase in the RP process. This will include consideration of the uncertainty associated with the long-term growth plans as well as the potential impacts on the electricity infrastructure in this area resulting from the City's redevelopment plans. This is consistent with the finding and the recommendation from the previous RP cycle.

7.3.5 Glengrove TS – Station Capacity

Glengrove TS comprises two DESN units, T1/T3 and T2/T4 (all 25/42 MVA units), having a summer 10-Day LTR of 88 MW. The station's 2021 actual non-coincident summer peak load was about 47 MW and is forecasted to be approximately 86 MW (net adjusted for extreme weather) or 98% of its LTR in 2031.

As discussed in Section 7.1.3, its closet station Duplex TS also has two DESN units, T1/T2 (45/75 MVA) and T3/T4 (45/75 MVA), having a summer 10-Day LTR of 128 MW. The load at Duplex TS is forecasted to be approximately 112 MW (net adjusted for extreme weather) or 88% of its LTR in 2031. The transformers T1/T2 and T3/T4 require replacement in the near and medium term. The TWG has recommended that these transformers be replaced with 60/100 MVA units to provide additional capacity in this area, and that the Glengrove TS and Duplex TS loading be monitored and reviewed in the next phases of this RP cycle.

7.3.6 Finch TS / Bathurst TS – Station Capacity

THESL has identified an emerging load growth in the Northwest Toronto area near Finch TS and Bathurst TS due to re-development plan in the Downsview area located in the Keele and Sheppard area.

Finch TS comprises two DESN units, T1/T2 and T3/T4 (all 75/125 MVA units), having a summer 10-Day LTR of 366 MW. The station's 2021 actual non-coincident summer peak load was about 253 MW and is forecasted to be approximately 367 MW (net adjusted for extreme weather) in 2031.

Bathurst TS also comprises two DESN units, T1/T2 and T3/T4 (all 75/125 MVA units), having a summer 10-Day LTR of 361 MW. The station's 2021 actual non-coincident summer peak load was about 241 MW and is forecasted to be approximately 350 MW (net adjusted for extreme weather) or 97% of its LTR in 2031. The TWG recommends this need be reviewed in the next phases of this RP cycle.

7.3.7 Warden TS – Station Capacity

Warden TS comprises one DESN unit, T3/T4 (75/125 MVA), having a summer 10-Day LTR of 182 MW. The station's 2021 actual non-coincident summer peak load was about 150 MW and is forecasted to be approximately 195 MW and 185 MW (net adjusted for extreme weather) in 2024 and 2031.

The demand at Warden TS exceeds its station LTR in 2024 due to new large customer connection request in the south Toronto. THESL will manage it in the near/medium term by transferring load to its closest station Scarboro TS as discussed in Section 7.1.5. The TWG recommends this need be reviewed in the next phases of this RP cycle.

7.3.8 Manby W TS Autotransformers – Transformation Capacity

The long-term transformation capacity need at Manby West TS was identified in the previous RIP. Manby West TS 230/115 kV autotransformers were found to be restricted by the lowest rated unit T12 in the fleet, and is potentially overloaded within the 2030-2035 time period, following T1 or T2 contingency. This NA also affirms this transformation capacity need and the autotransformer replacement plan for T12 that is expected to provide relief to this constraint as discussed in Section 7.1.9. The current planned in-service date of the T12 autotransformer replacement is around 2030. The TWG recommends that the long-term supply need in this area be reviewed as part of the next phase of this RP cycle.

7.3.9 Leaside TS Autotransformers – Transformation Capacity

The long-term transformation capacity need at Leaside TS was identified in the previous RIP. Leaside TS 230/115 kV autotransformers were found to be restricted by the lowest rated unit T16 in the fleet, and is potentially overloaded within the 2035-2040 time period, following T15 or T17 contingency, assuming that two of the three units at Portlands Energy Centre GS are out-of-service, and total plant generation is 160 MW. Post-contingency control action is currently available to resolve this issue by transferring Dufferin TS to Manby supply. The TWG recommends this need be monitored and reviewed in the next phases of this RP cycle.

7.3.10 Parkway TS to Richview TS 230 kV Corridor – Line Capacity

The 230 kV circuits P21R/P22R provide the transmission network connection between Parkway TS and Richview TS. These circuits also supply two transformer stations in the City of Markham as well as three transformer stations in the Northwest Toronto area (Leslie TS, Bathurst TS, and Finch TS) together with the other 230 kV circuits on the "Finch Corridor" between Cherrywood TS and Richview TS.

With the increasing demand forecasted on this corridor, some sections of the circuits P21R/P22R[3] are over 90% of their ratings under certain contingencies in the medium term and are potentially overloaded in the long term. Consideration may be given to reconductoring part of the circuits close to the Parkway TS end. It is to be noted that the baseline NA forecast does not reflect a number of customers that show interest in connecting new load near the Steeles / Hwy 404 area. The need for this corridor upgrade may become sooner. The TWG recommends this need be monitored and reviewed in the next phase of this RP cycle.

[3] The line section between Markham #1 Jct. and CTS Jct. of the circuits P21R/P22R is found to be the most restrictive in this NA review; however, the scope and timing of the preferred plan for this need will be reviewed and determined in the next phases of this RP cycle when a more certain and longer term load forecast will become available and considered.

7.3.11 Leaside TS to Wiltshire TS 115 kV Corridor – Line Capacity

The 115 kV transmission corridor between Leaside TS and Wiltshire TS comprises four circuits L13W, L14W, L18W and L15. It provides supply to Midtown Toronto area via two transformer stations Bridgman TS and Dufferin TS. The 2021 actual total coincident summer peak load of these stations was about 257 MW and is forecasted to be approximately 280 MW (net adjusted for extreme weather) in 2031. This corridor also provides backup supply to other stations that are normally connected to the Manby East subsystem such as Wiltshire TS, Fairbank TS and/or Runnymede TS.

The line capacity need on this corridor was identified as a long-term need (2035-2040) in the previous RIP, that the 1.8 km underground section of the circuit L15 between Bayview Jct. and Balfour Jct. is potentially overloaded in the long term. In this NA review, the contingency flow on this line section is about 80% of its limited time emergency rating in 2031. The TWG recommends the loading and the line capacity need on this Leaside TS x Wiltshire TS corridor be monitored and reviewed in the next phase of this RP cycle.

7.4 Load Restoration Analysis

The contingencies from the previous load restoration analysis in the 2nd cycle IRRP are reviewed along with this new NA forecast. The potential load interrupted by configuration for the following contingencies is significantly higher than the amount from the 2nd cycle IRRP.

For the loss of 230kV circuits C14L and C17L[4] (stations connected are Warden TS and Bermondsey TS), a total load of 379 MW in 2031 will be interrupted by configuration and 129 MW of it will need to be restored within 30 minutes based on the load restoration criteria in the ORTAC.

For the loss of 230kV circuits C18R and P22R[5] (Bathurst TS), a total load of 350 MW in 2031 will be interrupted by configuration and 100 MW of it will need to be restored within 30 minutes based on the load restoration criteria in the ORTAC.

THESL has indicated that the current distribution feeder configuration and spare capacity from the nearby stations will not be adequate to resupply all of the aforementioned amount of load in excess of 250 MW within 30 minutes and recommends that these load restoration scenarios and options be reviewed in the next phase of this RP cycle.

8 SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended

[4] The circuits C14L and C17L only share the same towers along a 4 km overhead line tap supplying Warden TS.
[5] The circuits C18R and P22R only share the same towers along a 2 km overhead line tap supplying Bathurst TS.

investments. The TWG has determined that the key electric demand driver in the Toronto Region to be considered in this sensitivity analysis is electric vehicle (EV) penetration and electrified heating.[6]

A high demand growth forecast was developed by applying + 5% on the extreme summer corrected Normal Growth net load forecast. The TWG has also considered a slower EV and electrified heating change and developed a low demand growth forecast by applying - 2.5% on the extreme summer corrected Normal Growth net load forecast.

The impact of sensitivity analysis for the high and low growth scenarios on the capacity needs identified in Section 7 is summarized in Table 6.

Table 6: Impact of Sensitivity Analysis on the Identified Capacity Needs

Need	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario (1)
Manby TS to Riverside Jct 115 kV Corridor	2026	2026	2026
Fairbank TS	Beyond 2031	Beyond 2031	-
Sheppard TS	Beyond 2031	Beyond 2031	-
Strachan TS	Beyond 2031	Beyond 2031	-
Basin TS	Beyond 2031	2031	-
Glengrove TS	Beyond 2031	2031	-
Finch TS / Bathurst TS	Beyond 2031	2028	-
Warden TS	Beyond 2031	TBD (2)	-
Manby W TS Autotransformers (T12)	Beyond 2031	Beyond 2031	-
Leaside TS Autotransformers (T16)	Beyond 2031	2031	-
230 kV Parkway TS to Richview TS Corridor	Beyond 2031	Beyond 2031 (3)	-
115 kV Leaside TS to Wiltshire TS Corridor	Beyond 2031	Beyond 2031	-

(1) The objective of a low growth scenario analysis is to identify any deferment in the timing of needs identified in this NA. Therefore, the long-term needs will not be looked at in the low growth scenario analysis.

(2) Forecasted load demand at Warden TS exceeds its capacity from 2024 but THESL plans to manage it by transferring the excess load to Scarboro TS. A higher load growth scenario will certainly advance the need to relieve Warden TS and further assessment will be carried out during the next phases of this Regional Planning cycle.

(3) Like the normal growth scenario, the high growth scenario does not reflect several customers that show interest in connecting new load near the Steeles / Hwy 404 area. The need for this corridor upgrade may be advanced to the medium term. The TWG recommends this need be monitored and reviewed in the next phases of this RP cycle.

In the high growth scenario, the timing of some of the long-term station capacity needs (Basin TS, Glengrove TS, Finch TS / Bathurst TS, and potentially Warden TS as well) is advanced to the medium-term timeframe. The timing of the long-term transformation capacity needs at Leaside TS is also advanced to 2031. The TWG recommends these needs be assessed during the next phases of this RP cycle.

The timing of the near-term capacity need on the 115 kV corridor between Manby TS and Riverside Jct. does not change in the sensitivity analysis. As discussed in Section 7.2.2, the TWG recommends Hydro One proceed on the development work for reconductoring the circuits K13J/K14J to higher ampacity conductors without replacing the existing towers and this need be reviewed as part of the next phase of this RP cycle.

[6] The sensitivity analysis does not consider the impact from the IESO's "Pathways to Decarbonization" report published on December 15, 2022. The electricity demand and new infrastructure need in the longer term could be substantially higher than anticipated in this report, and will be assessed in the next phase of this RP cycle.

9 RECOMMENDATIONS

The TWG's recommendations to address the needs identified are as follows:

a) No further regional coordination is required for the following need:
   - Asset renewal needs for replacing the major HV equipment as listed in Table 7 below. These needs will be addressed directly by Hydro One and THESL to develop a preferred replacement plan giving consideration to "right-sizing";

b) Further assessment and regional coordination is required in the next phases of the RP cycle to review and/or develop a preferred plan for the follow needs:
   - The line capacity need for the 115 kV corridor between Manby TS and Riverside Jct. Hydro One will initiate the development work for reconductoring the overhead line section; and
   - The load restoration and long-term needs as listed in the following table.

Table 7 summarizes the above recommendations.

Table 7: Summary of Recommendations

Further Regional Coordination Not Required	Further Regional Coordination Required
Asset Renewal Needs (Stations): • Strachan T14 & T13/T15 • Charles TS: T3/T4 • Duplex TS: T1/T2 & T3/T4 • Basin TS: T3/T5 • Scarboro TS: T23 • Fairchild TS: T1 & T3/T4 • Bermondsey TS: T3/T4 • Malvern TS: T3 • Manby TS: T7, T9, T12 autotransformers, T13/T14 step-down transformer • Leslie TS: T1 **Asset Renewal Needs (Lines):** • 115 kV H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. overhead section • 115 kV L9C/L12C: Leaside TS to Balfour Jct. overhead section **Line Capacity Need:** • 230 kV Richview TS to Manby TS Corridor **Station Capacity Need:** • Fairbank TS • Strachan TS	**Line Capacity Need:** • 115 kV Manby TS to Riverside Jct. Corridor **Load Restoration:** • Loss of C14L/C17L • Loss of C18R/P22R **Long-Term Needs:** • Sheppard TS – Station Capacity • Basin TS – Station Capacity • Glengrove TS – Station Capacity • Finch TS / Bathurst TS – Station Capacity • Warden TS – Station Capacity • 230/115kV Manby W Autotransformers – Transformation Capacity • 230/115kV Leaside TS Autotransformers – Transformation Capacity • 230 kV Parkway TS to Richview TS Corridor – Line Capacity • 115kV Leaside TS to Wiltshire TS Corridor – Line Capacity

This NA assessment was performed before the publication of the IESO's "Pathways to Decarbonization" report on December 15, 2022, and does not include its impact on the need and/or the timing for additional electrical supply facilities in the Toronto Region. The TWG recommends that the "Pathways to Decarbonization" and its subsequent impact be considered and assessed in the next phase of this RP cycle.

10 REFERENCES

[1]. Hydro One, "Toronto Regional Infrastructure Plan", March 6, 2020. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/Toronto%20Regional%20Infrastructure%20Plan_Mar6%202020.pdf

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[3]. IESO, "Toronto Region: Integrated Regional Resource Plan", August 9, 2019. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/toronto/Documents/Toronto-IRRP-20190809-Report.pdf

[4]. Planning Process Working Group Report to the Board, 17 May 2013. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPTECHNICAL__STUDY TEAM_Regional_Planning_Report_to_the_Board_App.pdf

[5]. IESO, Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0, August 22, 2007 https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/connecting/IMO-REQ-0041-TransmissionAssessmentCriteria.ashx

Appendix A-1: Non-Coincident Summer Peak Net Load Forecast (2022 to 2031)

STATIONS	DESN ID	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NORTH 230kV		**1902**	**1249**	**1317**	**1388**	**1459**	**1483**	**1513**	**1525**	**1553**	**1573**	**1575**	**1577**
Agincourt TS	T5/T6	174	88	89	91	98	102	105	106	106	108	108	108
Bathurst TS	T1/T2	183	131	120	123	125	142	160	178	176	175	174	172
	T3/T4	178	110	135	131	146	148	146	146	163	181	179	178
Cavanagh MTS	T1/T2	157	120	117	118	121	121	127	130	141	141	141	142
Fairchild TS	T1/T2	174	108	119	131	134	134	134	134	133	132	132	132
	T3/T4	172	108	118	117	116	114	114	113	112	112	112	112
Finch TS	T1/T2	180	129	144	167	176	178	181	182	182	183	184	185
	T3/T4	186	124	132	156	179	178	178	178	177	179	181	182
Leslie TS	T1/T2 13.8	43	9	13	14	13	10	11	0	0	0	0	0
	T1/T2 27.6	96	85	86	92	100	102	88	91	91	92	93	93
	T3/T4 27.6	184	127	139	141	141	143	157	157	158	157	157	156
Malvern TS	T3/T4	176	110	106	108	108	109	112	112	113	114	115	119
EAST 230kV		**1475**	**962**	**1018**	**1059**	**1154**	**1156**	**1158**	**1186**	**1207**	**1209**	**1212**	**1213**
Bermondsey TS	T1/T2	186	60	75	103	109	109	127	143	142	142	141	140
	T3/T4	162	93	120	124	129	132	113	131	130	129	132	135
Ellesmere TS	T3/T4	189	124	123	131	152	157	157	156	165	165	164	163
Leaside TS	T19/T20/T21 13.8	100	67	70	70	69	70	71	71	71	71	71	71
	T19/T20/T21 27.6	110	83	81	80	78	78	77	76	75	75	74	74
Scarboro TS	T21/T22	189	109	113	111	137	139	138	136	150	150	151	150
	T23/T24	151	108	112	111	112	109	108	108	108	108	108	107
Sheppard TS	T1/T2	95	76	69	70	70	70	70	70	70	81	81	82
	T5/T6 (was T3/T4)	109	91	98	100	103	105	106	108	109	103	104	105
Warden TS	T3/T4	182	150	156	160	195	187	191	188	186	186	186	185
WEST 230kV		**1239**	**768**	**752**	**796**	**837**	**810**	**828**	**864**	**862**	**870**	**879**	**889**
Horner TS	T1/T2	184	0	30	31	39	40	96	95	95	95	95	95
	T3/T4	182	147	126	147	145	145	117	115	115	114	114	113
Manby TS	T13/T14	106	85	81	82	98	98	83	83	84	84	86	86
	T3/T4	60	73	58	58	59	60	53	53	53	55	56	58
	T5/T6	60	79	64	66	65	53	55	56	57	59	59	61
Rexdale TS	T1/T2	187	102	104	108	108	93	93	140	144	148	154	160
Richview TS	T1/T2	159	111	114	112	111	109	108	106	105	104	103	102
	T5/T6	188	103	104	121	142	141	150	140	132	132	132	133
	T7/T8	113	68	70	71	71	72	74	76	77	79	80	81
LEASIDE 115kV		**1779**	**1141**	**1265**	**1318**	**1339**	**1365**	**1365**	**1369**	**1382**	**1389**	**1403**	**1416**
Basin TS	T3/T5	88	57	74	59	67	69	72	77	81	82	82	85
Bridgman TS	T11/T12/T13/T14/T15	189	133	145	146	148	147	147	147	147	147	148	150
Carlaw TS	T1/T2	73	63	43	43	42	47	49	50	51	52	53	53
Cecil TS	T1/T2	85	55	61	60	59	58	57	55	54	55	57	57
	T3/T4	130	92	91	89	89	87	86	84	82	81	81	82
Charles TS	T1/T2	130	70	86	91	95	93	98	97	98	97	96	95
	T3/T4	81	57	62	64	60	71	71	72	71	70	70	70
Dufferin TS	T1/T3	94	46	53	64	59	63	65	66	66	67	67	67
	T2/T4	86	80	71	70	68	69	68	66	66	65	65	65
Duplex TS	T1/T2	81	55	66	68	70	70	72	73	73	75	76	78
	T3/T4	47	35	36	33	32	32	33	33	33	33	33	34
Esplanade TS	T11/T12/T13	187	125	145	150	155	157	156	155	157	158	158	158
Gerrard TS	T1/T2	128	30	55	78	80	79	80	80	84	88	91	91
Glengrove TS	T1/T3	44	17	31	33	35	35	35	35	36	36	37	37
	T2/T4	44	30	32	36	39	39	41	42	44	46	47	49
Main TS	T3/T4	77	56	60	62	62	63	63	64	64	65	66	67
Terauley TS	T1/T4	108	53	61	91	95	99	85	85	87	87	88	89
	T2/T3	108	88	92	81	86	86	88	88	88	88	88	89
MANBY E 115kV		**579**	**362**	**374**	**399**	**421**	**428**	**430**	**428**	**429**	**430**	**432**	**436**
Fairbank TS	T2/T4	90	90	96	86	89	90	91	88	89	89	90	91
	T1/T3 (to be T5/T6)	92	107	89	81	74	74	75	75	76	77	78	79
Runnymede TS	T1/T2	108	78	80	95	108	110	106	105	104	103	103	102
	T5/T6 (was T3/T4)	111	32	28	44	49	53	57	59	60	61	62	65
Wiltshire TS	T1/T6	48	25	34	34	34	34	35	35	35	35	36	36
	T7X/T2X	129	30	47	59	67	67	66	65	65	64	64	64
MANBY W 115kV		**611**	**374**	**375**	**380**	**423**	**425**	**518**	**516**	**511**	**508**	**506**	**505**
Copeland MTS	T1/T3	130	80	104	114	120	121	182	179	177	175	174	173
John TS	T1/T2/T3/T4	187	83	39	37	61	59	98	99	143	142	141	140
	T5/T6	123	75	92	92	99	99	101	101	54	53	53	52
Strachan TS	T12/T14	74	52	59	56	57	57	87	86	86	86	86	87
	T13/T15	97	84	81	81	86	89	50	50	51	52	52	53
TOTAL REGIONAL LOAD		**7586**	**4856**	**5100**	**5341**	**5633**	**5667**	**5812**	**5887**	**5944**	**5979**	**6008**	**6036**

Appendix A-2: Coincident Summer Peak Net Load Forecast (2022 to 2031)

STATIONS	DESN ID	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NORTH 230kV		**1902**	**1173**	**1240**	**1309**	**1376**	**1401**	**1430**	**1444**	**1470**	**1490**	**1492**	**1493**
Agincourt TS	T5/T6	174	72	73	74	80	83	86	86	87	88	89	88
Bathurst TS	T1/T2	183	127	116	119	121	138	156	173	171	170	169	168
	T3/T4	178	110	135	131	146	148	146	145	163	180	179	178
Cavanagh MTS	T1/T2	157	96	93	94	97	97	101	104	113	113	113	113
Fairchild TS	T1/T2	174	106	117	129	132	132	132	131	131	130	130	129
	T3/T4	172	108	118	117	116	114	114	113	112	112	112	112
Finch TS	T1/T2	180	128	143	166	175	177	180	180	181	181	182	183
	T3/T4	186	124	133	156	179	178	178	178	177	179	181	182
Leslie TS	T1/T2 13.8	43	5	7	8	7	6	6	0	0	0	0	0
	T1/T2 27.6	96	74	75	80	87	89	76	79	80	80	81	81
	T3/T4 27.6	184	127	139	141	141	143	157	157	158	157	157	156
Malvern TS	T3/T4	176	96	92	94	94	95	97	98	98	99	100	104
EAST 230kV		**1475**	**865**	**915**	**950**	**1029**	**1033**	**1031**	**1056**	**1075**	**1076**	**1079**	**1080**
Bermondsey TS	T1/T2	186	48	60	82	87	87	101	114	113	113	113	112
	T3/T4	162	88	114	117	122	125	107	124	123	122	125	128
Ellesmere TS	T3/T4	189	116	115	122	141	147	146	145	154	154	153	152
Leaside TS	T19/T20/T21 13.8	100	66	69	69	68	69	70	70	70	70	70	70
	T19/T20/T21 27.6	110	79	77	76	74	74	73	72	72	71	71	70
Scarboro TS	T21/T22	189	94	97	96	118	119	118	117	129	129	129	129
	T23/T24	151	107	111	110	111	109	108	107	108	107	107	107
Sheppard TS	T1/T2	95	65	60	60	60	60	60	60	60	69	70	70
	T5/T6 (was T3/T4)	109	89	96	97	100	102	104	105	106	101	102	103
Warden TS	T3/T4	182	113	118	120	147	141	144	141	140	140	140	140
WEST 230kV		**1239**	**648**	**640**	**680**	**711**	**685**	**710**	**745**	**743**	**749**	**756**	**764**
Horner TS	T1/T2	184	0	30	31	39	40	96	95	95	95	95	95
	T3/T4	182	144	123	144	142	142	115	112	112	112	111	111
Manby TS	T13/T14	106	58	55	56	67	67	57	57	57	57	59	58
	T3/T4	60	36	29	29	29	30	26	26	26	27	28	29
	T5/T6	60	75	60	62	62	50	52	53	54	56	55	57
Rexdale TS	T1/T2	187	97	99	103	102	89	88	133	137	141	147	152
Richview TS	T1/T2	159	109	112	110	108	107	106	104	103	102	101	100
	T5/T6	188	83	84	98	114	114	121	113	106	106	107	107
	T7/T8	113	46	47	48	48	49	50	51	53	54	54	55
LEASIDE 115kV		**1779**	**1131**	**1253**	**1305**	**1326**	**1352**	**1351**	**1355**	**1368**	**1375**	**1389**	**1401**
Basin TS	T3/T5	88	57	74	59	67	69	72	77	81	82	82	85
Bridgman TS	T11/T12/T13/T14/T15	189	133	145	146	148	148	147	147	147	147	149	151
Carlaw TS	T1/T2	73	62	43	42	41	46	49	49	50	51	52	52
Cecil TS	T1/T2	85	55	61	61	59	58	57	56	54	55	57	57
	T3/T4	130	92	91	89	89	87	86	84	82	80	81	82
Charles TS	T1/T2	130	70	86	91	94	93	97	97	97	96	95	94
	T3/T4	81	57	61	64	60	70	71	71	70	70	70	70
Dufferin TS	T1/T3	94	46	53	63	58	63	64	65	66	66	66	66
	T2/T4	86	78	69	68	66	67	66	65	64	64	63	63
Duplex TS	T1/T2	81	55	67	68	70	71	72	73	74	75	76	78
	T3/T4	47	34	35	33	31	31	32	32	32	32	33	33
Esplanade TS	T11/T12/T13	187	125	145	150	155	156	156	155	157	157	157	158
Gerrard TS	T1/T2	128	29	53	76	77	77	77	77	81	85	88	88
Glengrove TS	T1/T3	44	16	30	32	34	34	34	34	34	35	35	36
	T2/T4	44	29	31	35	37	38	40	41	43	44	45	47
Main TS	T3/T4	77	54	58	60	61	61	62	62	62	63	64	65
Terauley TS	T1/T4	108	52	60	89	94	97	83	84	85	86	87	88
	T2/T3	108	87	91	80	85	85	87	87	87	87	88	88
MANBY E 115kV		**579**	**293**	**336**	**362**	**384**	**390**	**392**	**390**	**391**	**392**	**394**	**398**
Fairbank TS	T2/T4	90	79	84	75	78	79	80	77	78	78	79	80
	T1/T3 (to be T5/T6)	92	91	75	69	62	63	63	64	64	65	66	67
Runnymede TS	T1/T2	108	69	71	83	95	97	94	93	92	91	90	90
	T5/T6 (was T3/T4)	111	1	28	44	49	53	57	59	60	61	62	65
Wiltshire TS	T1/T6	48	23	32	32	32	32	33	33	33	33	34	34
	T7X/T2X	129	30	46	59	66	66	65	65	64	64	64	63
MANBY W 115kV		**611**	**370**	**371**	**376**	**418**	**420**	**512**	**510**	**506**	**503**	**501**	**500**
Copeland MTS	T1/T3	130	79	102	112	119	119	180	177	175	173	171	170
John TS	T1/T2/T3/T4	187	83	39	37	61	59	98	99	143	142	140	140
	T5/T6	123	74	91	91	98	98	100	99	53	53	52	52
Strachan TS	T12/T14	74	51	58	56	56	56	85	85	85	85	85	85
	T13/T15	97	83	80	80	85	88	49	50	50	51	52	53
TOTAL REGIONAL LOAD		**7586**	**4480**	**4756**	**4982**	**5245**	**5281**	**5426**	**5500**	**5553**	**5585**	**5611**	**5636**

Appendix B: Lists of Step-Down Transformer Stations (Current)

Station (DESN)	Voltage (kV)	Supply Circuits
Agincourt TS T5/T6	230/27.6	C4R/C10A
Basin TS T3/T5	115/13.8	H3L/H1L
Bathurst TS T1/T2	230/27.6	P22R/C18R
Bathurst TS T3/T4	230/27.6	P22R/C18R
Bermondsey TS T1/T2	230/27.6	C17L/C14L
Bermondsey TS T3/T4	230/27.6	C17L/C14L
Bridgman TS T11/T12/T13/T14/T15	115/13.8	L14W/L15/L18W
Carlaw TS T1/T2	115/13.8	H1L/H3L
Cavanagh MTS T1/T2	230/27.6	C20R/C10A
Cecil TS T1/T2	115/13.8	Cecil Buses H & P
Cecil TS T3/T4	115/13.8	Cecil Buses P & H
Charles TS T1/T2	115/13.8	L4C/L9C
Charles TS T3/T4	115/13.8	L12C/L4C
Copeland MTS T1/T3	115/13.8	D11J/D12J
Dufferin TS T1/T3	115/13.8	L13W/L18W
Dufferin TS T2/T4	115/13.8	L13W/L18W
Duplex TS T1/T2	115/13.8	L16D/L5D
Duplex TS T3/T4	115/13.8	L5D/L16D
Ellesmere TS T3/T4	230/27.6	C2L/C3L
Esplanade TS T11/T12/T13	115/13.8	H2JK/H10DE(C5E)/H9DE(C7E)
Fairbank TS T1/T3 (to be T5/T6)	115/27.6	K3W/K1W
Fairbank TS T2/T4	115/27.6	K3W/K1W

Station (DESN)	Voltage (kV)	Supply Circuits
Fairchild TS T1/T2	230/27.6	C18R/C20R
Fairchild TS T3/T4	230/27.6	C18R/C20R
Finch TS T1/T2	230/27.6	C20R/P22R
Finch TS T3/T4	230/27.6	P21R/C4R
Gerrard TS T1/T2	115/13.8	H3L/H1L
Glengrove TS T1/T3	115/13.8	D6Y/L2Y
Glengrove TS T2/T4	115/13.8	D6Y/L2Y
Horner TS T3/T4	230/27.6	R13K/R2K
Horner TS T1/T2	230/27.6	R13K/R2K
John TS T1/T2/T3/T4	115/13.8	John Buses K1 & K2 & K3 & K4
John TS T5/T6	115/13.8	John Buses K1 & K4
Leaside TS T19/T20/T21 13.8	230/13.8	Leaside Buses HL2, HL3, HL16
Leaside TS T19/T20/T21 27.6	230/27.6	Leaside Buses HL2, HL3, HL16
Leslie TS T1/T2 13.8	230/13.8	P21R/C5R
Leslie TS T1/T2 27.6	230/27.6	P21R/C5R
Leslie TS T3/T4 27.6	230/27.6	P21R/C5R
Main TS T3/T4	115/13.8	H7L/H11L
Malvern TS T3/T4	230/27.6	C4R/C5R
Manby TS T13/T14	230/27.6	Manby W Buses A1 & H1
Manby TS T3/T4	230/27.6	Manby W Buses A1 & H1
Manby TS T5/T6	230/27.6	Manby E Buses H2 & A2
Rexdale TS T1/T2	230/27.6	V74R/V76R
Richview TS T1/T2	230/27.6	Richview Buses H1 & A1

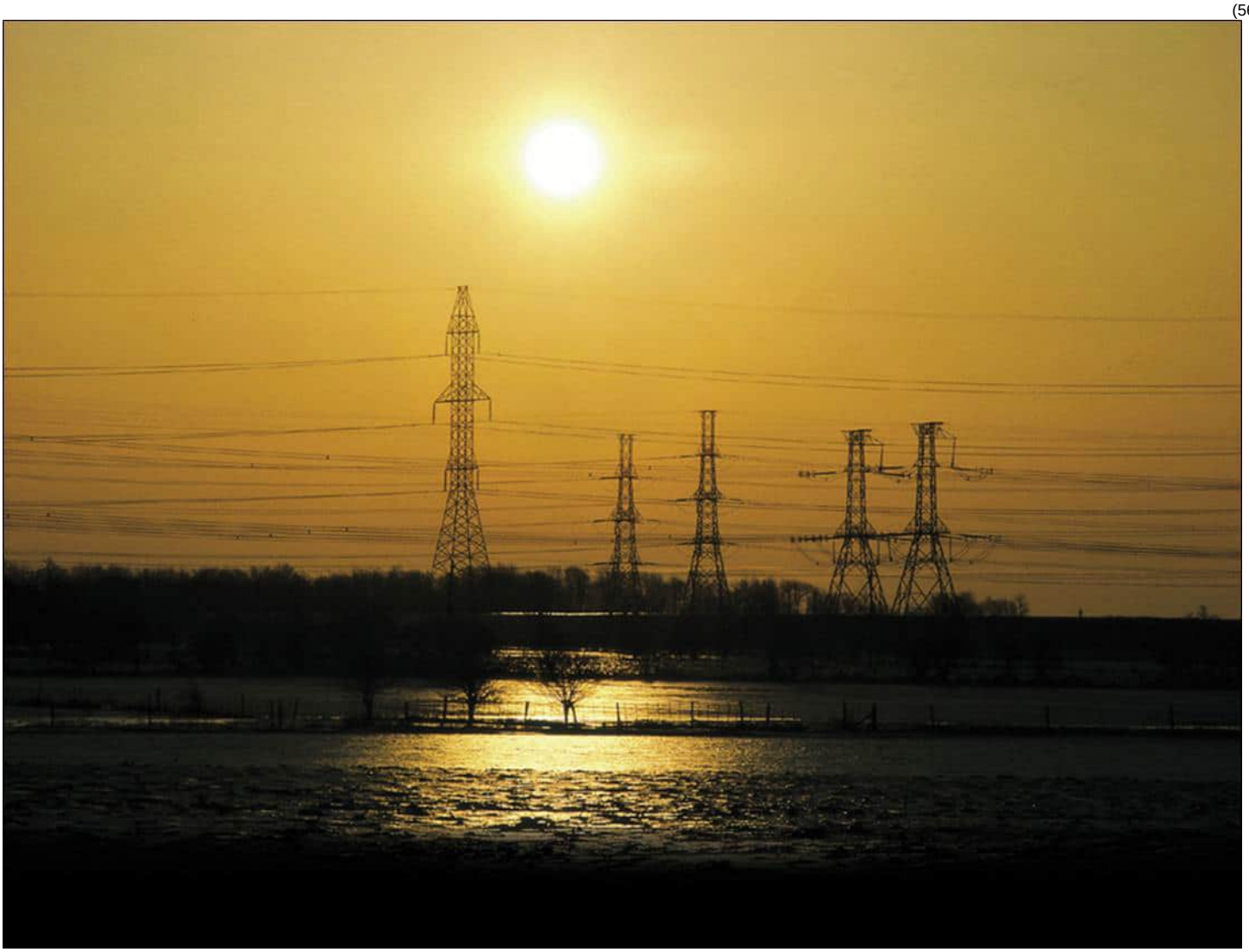
Station (DESN)	Voltage (kV)	Supply Circuits
Richview TS T5/T6	230/27.6	V74R/V72R
Richview TS T7/T8	230/27.6	Richview Buses H2 & A2
Runnymede TS T1/T2	115/27.6	K12W/K11W
Runnymede TS T5/T6 (was T3/T4)	115/27.6	K12W/K11W
Scarboro TS T21/T22	230/27.6	C14L/C2L
Scarboro TS T23/T24	230/27.6	C15L/C3L
Sheppard TS T1/T2	230/27.6	C16L/C15L
Sheppard TS T5/T6 (was T3/T4)	230/27.6	C15L/C16L
Strachan TS T12/T14	115/13.8	H2JK/K6J
Strachan TS T13/T15	115/13.8	K6J/H2JK
Terauley TS T1/T4	115/13.8	C7E/C5E
Terauley TS T2/T3	115/13.8	C7E/C5E
Warden TS T3/T4	230/27.6	C14L/C17L
Wiltshire TS T1/T6	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T7X/T2X	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)

Appendix C: Lists of Transmission Circuits

Location	Circuit Designations	Voltage (kV)
Richview x Manby	R1K, R2K, R13K, R15K	230
Richview x Cooksville	R24C	230
Manby x Cooksville	K21C, K23C	230
Cherrywood x Leaside	C2L, C3L, C14L, C15L, C16L, C17L	230
Cherrywood x Richview	C4R, C5R, C18R, C20R	230
Cherrywood x Agincourt	C10A	230
Parkway x Richview	P21R, P22R	230
Claireville x Richview	V72R, V73R, V74R, V76R, V77R, V79R	230
Manby East x Wiltshire	K1W, K3W, K11W, K12W	115
Manby West x John	K6J, K13J, K14J	115
Manby West x John x Hearn	H2JK	115
John x Esplanade x Hearn	D11J, D12J, H9DE, H10DE	115
Esplanade x Cecil	C5E, C7E	115
Hearn x Cecil x Leaside	H6LC, H8LC	115
Hearn x Leaside	H1L, H3L, H7L, H11L	115
Leaside x Bridgman x Wiltshire	L13W, L14W, L15, L18W	115
Leaside x Charles	L4C	115
Leaside x Cecil	L9C, L12C	115
Leaside x Duplex	L5D, L16D	115
Leaside x Glengrove	L2Y	115
Duplex x Glengrove	D6Y	115

Appendix D: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PEC	Portland Energy Centre
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
RP	Regional Planning
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TPS	Traction Power Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme



Toronto

REGIONAL INFRASTRUCTURE PLAN

March 6, 2020

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Prepared and supported by:

Company
Alectra Utilities Corporation
Elexicon Energy Inc.
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Toronto Hydro-Electric System Limited
Hydro One Networks Inc. (Lead Transmitter)

DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Study Team.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Study Team.

Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE RIP STUDY TEAM IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE TORONTO REGION.

The participants of the Regional Infrastructure Plan ("RIP") Study Team included members from the following organizations:

- Alectra Utilities ("Alectra")
- Elexicon Energy Inc. ("Elexicon")
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- Toronto Hydro-Electric System Limited ("THESL")
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the second cycle of Toronto regional planning process, which follows the completion of the Toronto Integrated Regional Resource Plan ("IRRP") in August 2019 and the Toronto Region Needs Assessment ("NA") in October 2017. This RIP provides a consolidated summary of the needs and recommended plans for Toronto Region over the planning horizon (1 – 20 years) based on available information.

This RIP discusses needs identified in the previous regional planning cycle, the Needs Assessment and IRRP reports for this cycle, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, the following projects have been completed:

- Midtown Transmission Reinforcement Project (completed in 2016)
- Clare R. Copeland 115 kV Switching Station and Copeland MTS (completed in 2019)
- Manby SPS Load Rejection (L/R) Scheme (completion in 2019)

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in the Table 1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 1. Recommended Plans in Toronto Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate(1)
1	Main TS: End-of-life of transformers T3/T4	Replace the end-of-life transformers with similar type and size equipment as per current standard	2021	$33M
2	H1L/H3L/H6LC/H8LC: End-of-life of Leaside Jct. to Bloor St. Jct. overhead section	Refurbish the end-of-life H1L/H3L/ H6LC/H8LC section	2023	$11M
3	L9C/L12C: End-of-life of Leaside TS to Balfour Jct. overhead section	Refurbish the end-of-life L9C/L12C section	2023	$3M
4	C5E/C7E: End-of-life of underground cables between Esplanade TS and Terauley TS	Replace the end-of-life C5E/C7E cables	2024	$128M
5	Richview TS to Manby TS 230 kV Corridor Reinforcement	Replace existing idle 115 kV double circuit line with new 230 kV double circuit line between Richview TS and Manby TS	2023	$21M
6	Manby TS: End-of-life of autotransformers (T7, T9, T12), step-down transformer (T13), and the 230 kV switchyard	Replace the end-of-life transformers with similar type and size equipment as per current standard, and refurbish/reconfigure Manby 230 kV switchyard	2025	$85M
7	Bermondsey TS: End-of-life of transformers T3/T4	Replace the end-of-life transformers with similar type and size equipment as per current standard	2025	$27M
8	John TS: End-of-life of transformers (T1, T2, T3, T4, T5, T6), 115 kV breakers, and LV switchgear	Replace with similar type and size equipment as per current standard	2026	$102M

(1) Budgetary estimates are provided for Hydro One's portion of the work

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 1 while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

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1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE TORONTO REGION BETWEEN 2019 AND 2039.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Study Team that consists of Hydro One, Alectra Utilities ("Alectra"), Elexicon Energy Inc. ("Elexicon"), Hydro One Networks Inc. (Distribution), the Independent Electricity System Operator ("IESO"), and Toronto Hydro-Electric System Limited ("THESL") in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The Toronto Region is comprised of the area within the municipal boundary of the City of Toronto. Electrical supply to the region is provided by thirty-five 230 kV and 115 kV step-down transformer stations ("TS") as shown in Figure 1-1. The outer parts of the region to the east, north, and west are supplied by fifteen 230/27.6 kV and two 230/27.6-13.8 kV step-down transformer stations. The central area is supplied by two 230/115 kV autotransformer stations at Leaside TS and Manby TS, and sixteen 115/13.8 kV and two 115/27.6 kV step-down transformer stations.

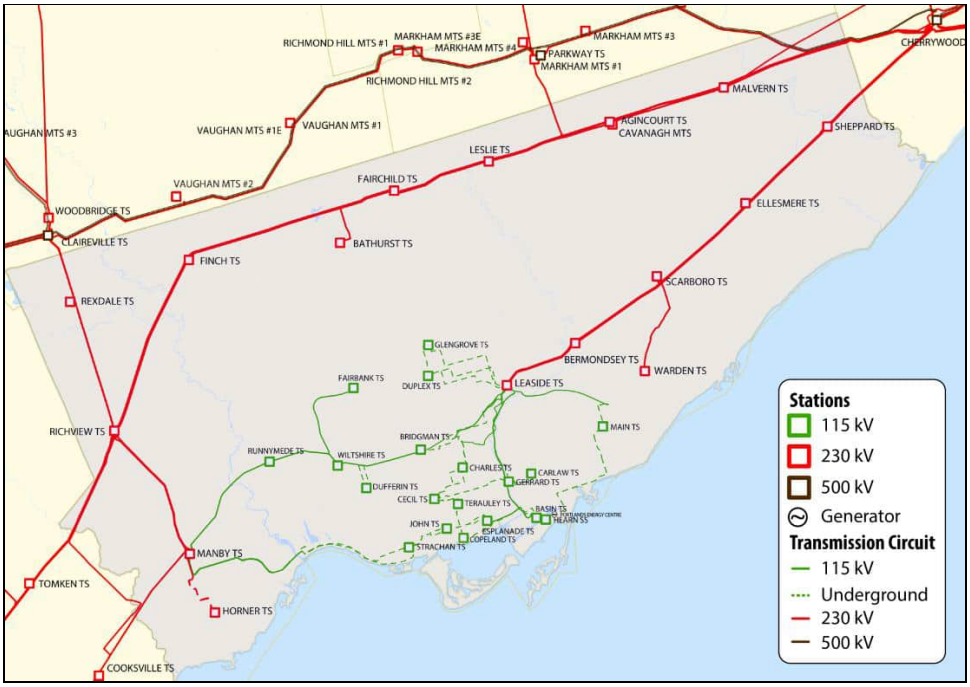


Figure 1-1: Toronto Region Map

1.1 Objectives and Scope

The RIP report examines the needs in the Toronto Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs;

- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), and/or Integrated Regional Resource Plan ("IRRP");
- Assess and develop a wires plan to address these needs; and
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the near, mid- and long-term horizon, transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the relevant wires plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, and/or Integrated Regional Resource Plan);
- Discussion of any other major transmission infrastructure investment plans over the planning horizon;
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Study Team.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the adequacy of the transmission facilities in the region over the study period.
- Section 7 discusses the needs and provides the alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2 REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

[1] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region;
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

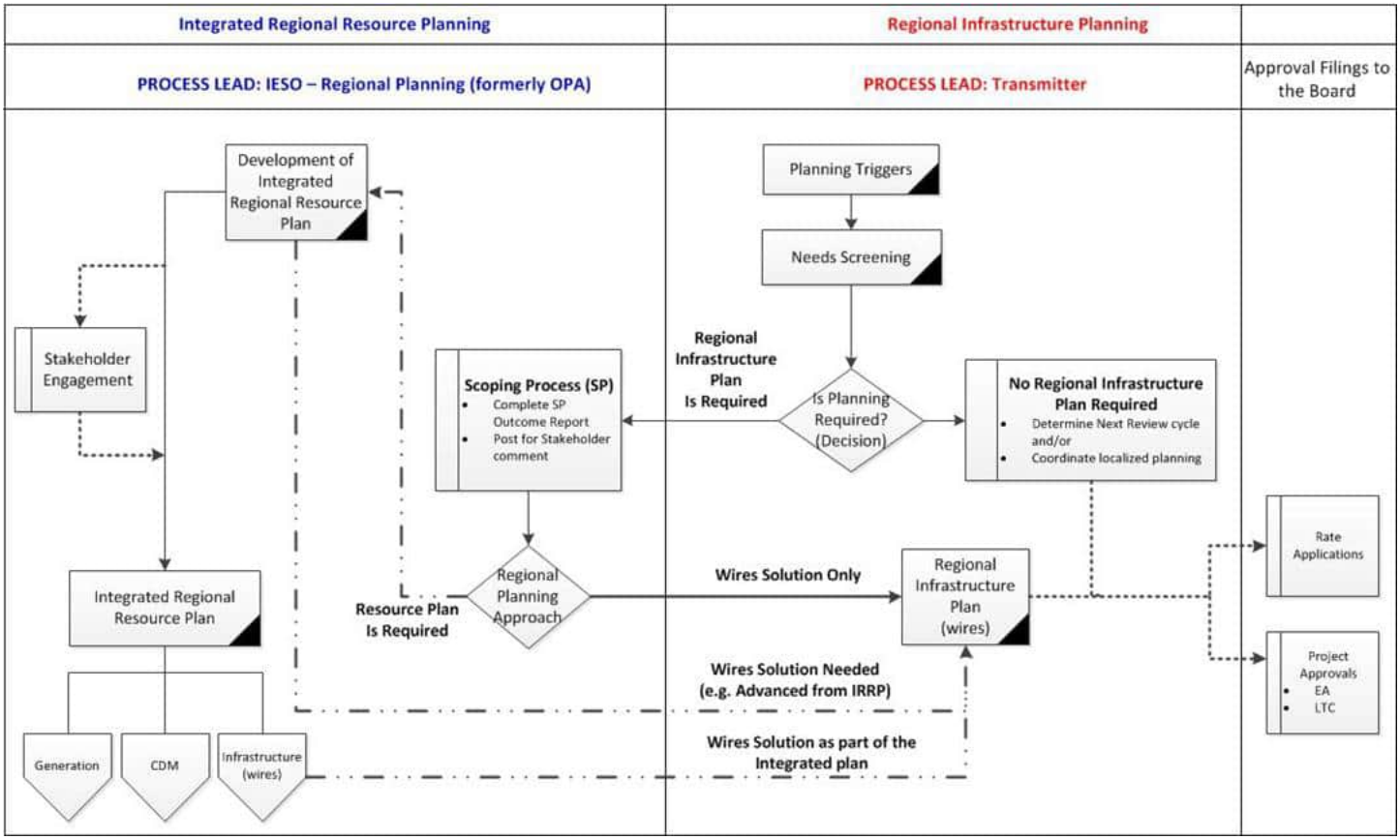


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required

or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.

3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

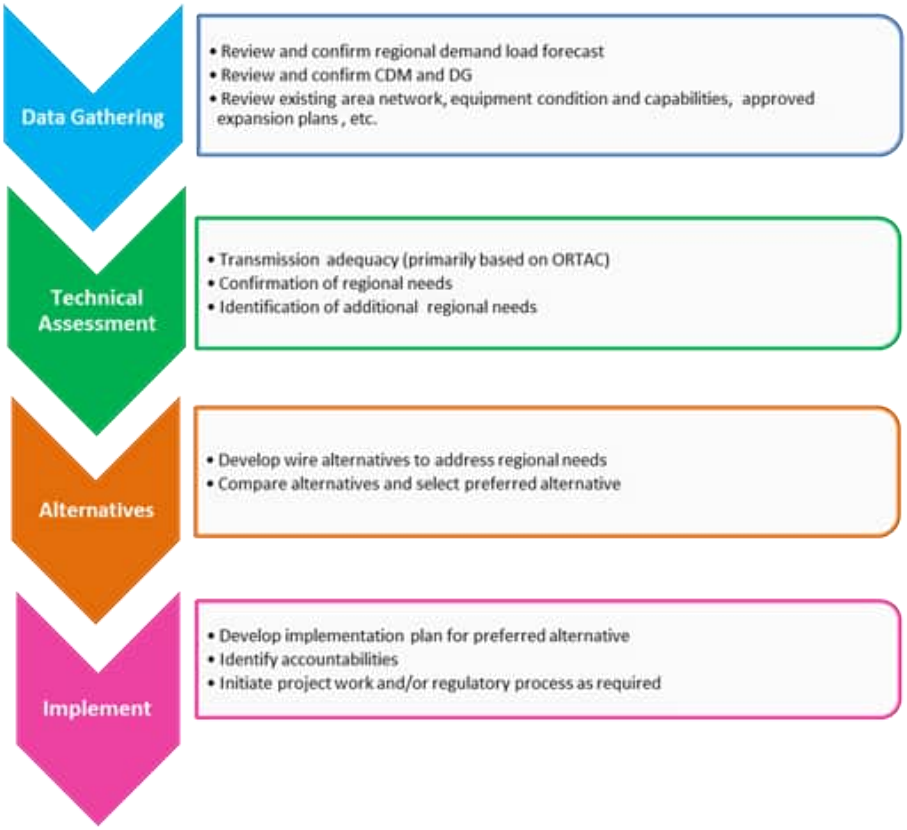


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE TORONTO REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY LAKE ONTARIO ON THE SOUTH, STEELES AVENUE ON THE NORTH, HIGHWAY 427 ON THE WEST, AND REGIONAL ROAD 30 ON THE EAST. IT CONSISTS OF THE CITY OF TORONTO, WHICH IS THE LARGEST CITY IN CANADA AND THE FOURTH LARGEST IN NORTH AMERICA.

Bulk electrical supply to the Toronto Region is provided through three 500/230 kV transformers stations at Claireville TS, Cherrywood TS, and Parkway TS and a network of 230 kV and 115 kV transmission lines and step-down transformation facilities. Local generation in the area consists of the 550 MW Portlands Energy Centre located near the Downtown area and connected to the 115 kV network at Hearn Switching Station ("SS"). The Toronto Region summer coincident peak demand in 2018 was about 4,660 MW which represents about 20% of the gross total demand (23240 MW) in the province.

Toronto Hydro-Electric System Limited ("THESL") is the main Local Distribution Company ("LDC") which serves the electricity demand in the Toronto Region. Other LDCs supplied from electrical facilities in the Toronto Region are Hydro One Networks Inc. Distribution, Alectra Utilities and Elexicon Energy Inc. The LDCs receive power at the step-down transformer stations and distribute it to the end-users – industrial, commercial and residential customers.

A single line diagram showing the electrical facilities of the Toronto Region is provided in Figure 3-1. Copeland MTS is a new THESL owned transformer station which serves the Downtown area and came into service in Q1 2019.

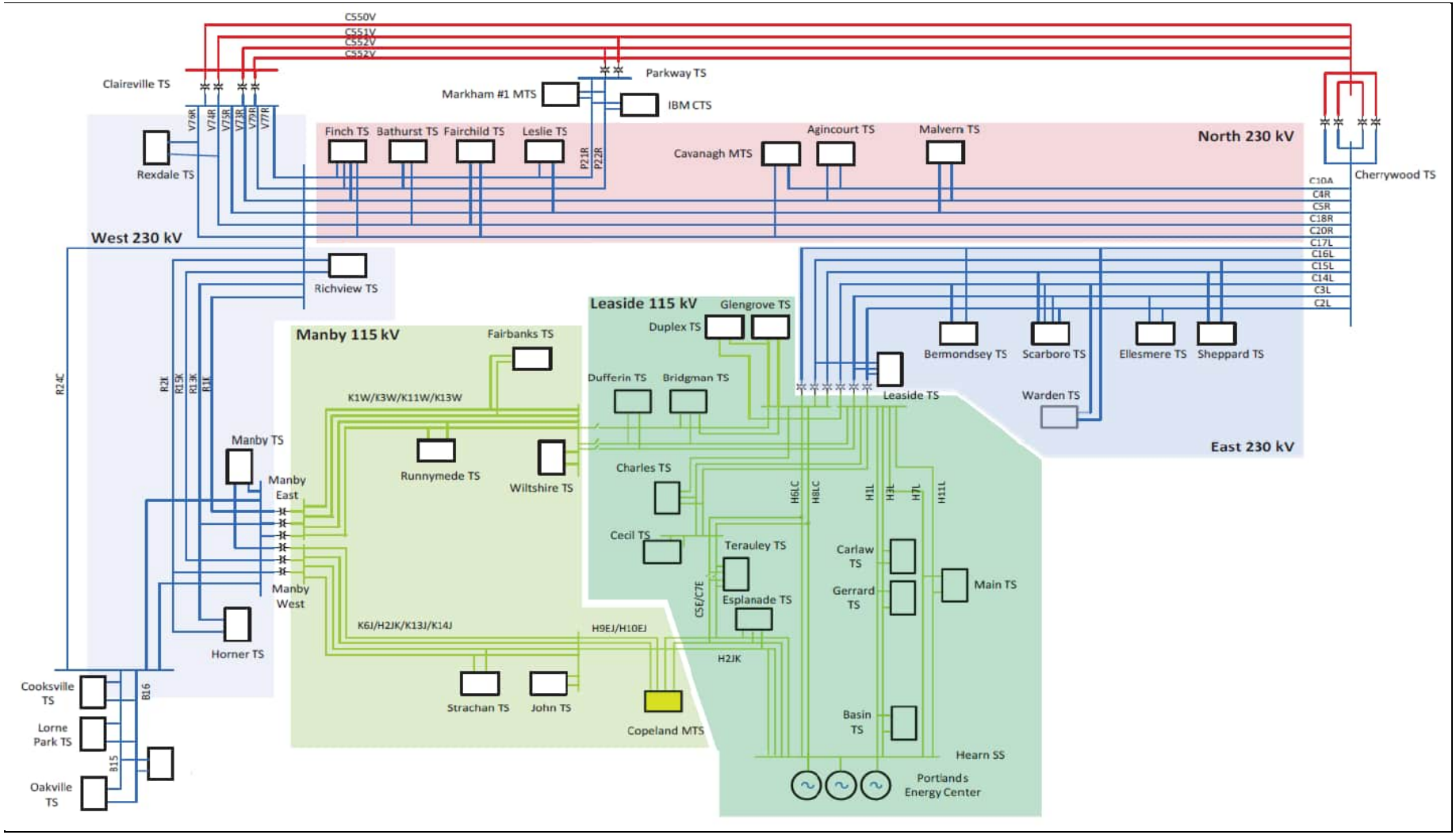


Figure 3-1: Single Line Diagram of Toronto Region's Transmission Network

The thirty-five Toronto's transformer stations can be grouped into five electrical zones based on their HV supply network:

1. **Leaside 115 kV Area:** The transformer stations in this area are supplied by the Leaside TS 230/115 kV autotransformers, and serve roughly the customers in the eastern part of Central Toronto. A list of the transformer stations in this area is provided below.
    - Basin TS
    - Bridgman TS
    - Carlaw TS
    - Cecil TS
    - Charles TS
    - Dufferin TS
    - Duplex TS
    - Esplanade TS
    - Gerrard TS
    - Glengrove TS
    - Main TS
    - Terauley TS

2. **Manby 115 kV Area:** This area covers the western part of Central Toronto which is supplied by the Manby TS 230/115 kV autotransformers. The transformer stations in this area is listed below.
    - Copeland MTS
    - Fairbank TS
    - John TS
    - Runnymede TS
    - Strachan TS
    - Wiltshire TS

3. **East 230 kV Area:** This area includes transformer stations connected to the 230 kV circuits between Cherrywood TS and Leaside TS C2L/C3L, C14L/C15L, and C16L/C17L, serving customers in the outer-eastern part of Toronto and Scarborough areas. Below are the transformer stations in East 230 kV area.
    - Bermondsey TS
    - Ellesmere TS
    - Leaside TS
    - Scarboro TS
    - Sheppard TS
    - Warden TS

4. **North 230 kV Area:** This area covers the outer northern part of Toronto bordering the York Region. The transformer stations in this area, listed below, are supplied by the 230kV circuits connecting Richview TS, Cherrywood TS, and/or Parkway TS C4R/C5R, C18R/C20R, P21R/P22R.
    - Agincourt TS
    - Bathurst TS
    - Cavanagh MTS
    - Fairchild TS
    - Finch TS
    - Leslie TS
    - Malvern TS

5. **West 230 kV Area**: The transformer stations in this area serve customers in the outer western part of Toronto including Etobicoke, and includes stations supplied by the Claireville TS to Richview TS 230 kV circuits V73R/V74R/V75R/V76R/V77R/V79R and the Richview TS to Manby TS 230 kV circuits R1K/R2K and R13K/R15K. Below are the transformer stations in West 230 kV area.
    - Horner TS
    - Manby TS
    - Rexdale TS
    - Richview TS

4 TRANSMISSION FACILITIES/PROJECTS COMPLETED AND/OR UNDERWAY OVER THE LAST TEN YEARS

OVER THE LAST TEN YEARS, A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND UNDERTAKEN BY HYDRO ONE AIMED TO MAINTAIN THE RELIABILITY AND ADEQUACY OF ELECTRICITY SUPPLY TO THE TORONTO REGION.

A summary and description of the major projects completed and/or currently underway over the last ten years is provided below.

- Incorporation of the 550 MW Portland's Energy Centre (2009) – Covered modification to the Hearn 115 kV switchyard to connect the new generation.

- 115 kV Switchyard Work at Hearn SS, Leaside TS, and Manby TS (2013, 2014) – Includes replacement of the aging 115 kV switchyard at Hearn SS with a new gas-insulated switchgear ("GIS") and replacement of all 115 kV oil breakers at Leaside TS and Manby TS.

- Manby 230 kV Reconfiguration (2014) – Re-tapped Horner TS from the circuit R15K to R13K at Manby TS to balance and improve the distribution of loading on the 230 kV Richview TS to Manby TS system.

- Lakeshore Cable Refurbishment project (2015) – Covered replacement of the aging K6J/H2JK 115 kV circuits between Riverside Jct. and Strachan TS.

- Midtown Transmission Reinforcement Project (completed in 2016) – Covered replacement of the aging L14W underground cable and addition of a new 115 kV circuit between Leaside TS and Bridgman TS.

- Clare R. Copeland 115 kV Switching Station (completed in 2019) – Built to connect a new THESL owned 115/13.8 kV step-down transformer station (Copeland MTS) in Downtown Toronto.

- Runnymede TS DESN#2 and Manby TS to Wiltshire TS Circuits Upgrade Project (2018) – covered building of a second 50/83MVA, 115/27.6kV DESN at Runnymede TS and reinforcement of the Manby TS to Wiltshire TS 115kV circuits to accommodate increasing load demand in the area.

- Manby SPS Load Rejection (L/R) Scheme (2019) – Built to ensure that loading on in-service equipment at Manby TS is not exceeded for loss of two out of three autotransformers in the Manby East TS and Manby West switchyards.

- Horner TS DESN #2 Project (2022) – covers construction of a second 75/125MVA, 230/28 kV, DESN at the Horner TS site to meet the load growth in the south west Toronto area.

- Richview to Manby Corridor Reinforcement (R X K) Project (2023)– Adding a third double-circuit line between Richview TS and Manby TS, aimed to increase the transmission line capacity between the two stations to meet forecast load demand in the South West GTA.

- Multiple Station Refurbishment Projects – Work is also under way on refurbishing Bridgman TS, Fairbank TS, Main TS and Runnymede TS DESN#1. These projects are expected to be completed between 2021 and 2024.

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The electricity demand in the Toronto Region is anticipated to grow at an average rate of 0.9% over the next ten years. Figure 5-1 shows the Toronto Region's summer peak load forecast developed during the Toronto IRRP process. This IRRP forecast was used to determine the loading that would be seen by transmission lines and autotransformer stations and to identify the need for additional line and auto-transformation capacity. Figure 4-1 also shows the Toronto region's non-coincident load forecast developed using the individual station's peak loads and which was used to determine the need for station capacity.

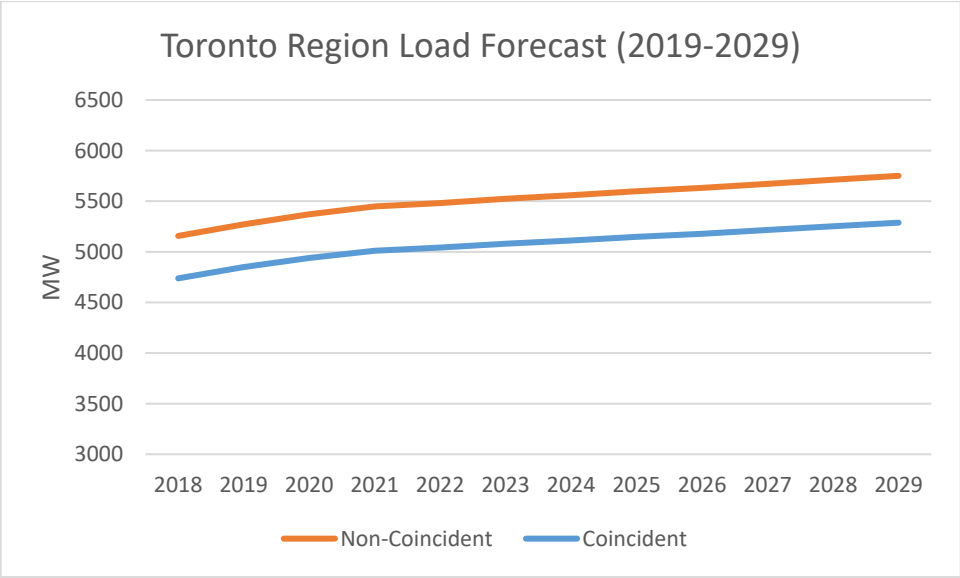


Figure 5-1: Toronto Region Load Forecast

The IRRP forecast shows that the Region peak summer load increases from 4850 MW in 2019 to 5290 MW by 2029. The corresponding non-coincident summer peak loads increase from 5270 MW to about 5750 MW over the same period. The IRRP and non-coincident load forecasts for the individual stations in the Toronto Region is given in Appendix D, Table D-1 and Table D-2.

The IRRP had provide an estimated of the energy-efficiency savings resulting from building codes and equipment standards improvement in Ontario. This has the potential to lower the demand growth in the region to approximately 0.6% annually. Details for the individual stations peak loads considering the energy-efficiency are given in Appendix D, Table D-3 and Table D-4.

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2029.
- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period are assumed to be in-service.

- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low voltage capacitor banks. Normal planning supply capacity for transformer stations is determined by the summer 10-day Limited Time Rating (LTR).
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- Metrolinx plans to connect three Traction Power Substation (TPSS) to Hydro One's 230 kV circuits in Toronto area for GO Transit electrification – Mimico TPSS to K21C and K23C close to Manby TS; City View TPSS to V73R and V77R north of Richview TS; and Scarborough TPSS to C2L and C14L at Scarboro TS. Metrolinx have advised that their current electrification schedule is uncertain and new facilities would be built likely beyond 2023. Appendix F of the 2019 Toronto IRRP ("Richview TS x Manby TS Study") verified that the reinforcement of Richview TS to Manby TS Transmission Corridor is required by 2021 and that Metrolinx new load do not affect the need and timing of the project. After the completion of Richview TS to Manby TS Transmission Reinforcement, the new TPSS loads can be connected without need of any new facilities.

6 ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND TRANSFORMER STATION FACILITIES SUPPLYING THE TORONTO REGION OVER THE PLANNING PERIOD (2019-2039). ALL PROJECTS CURRENTLY UNDERWAY ARE ASSUMED IN-SERVICE.

Within the current regional planning cycle two regional assessments have been conducted for the Toronto Region. The findings of these studies are input to this Regional Infrastructure Plan. The studies are:

- 2017 Toronto Region Needs Assessment ("NA") Report
- 2019 Toronto Integrated Regional Resource Plan ("IRRP") and Appendices

This section provides a review of the adequacy of the transmission lines and stations in the Metro Toronto Region. The adequacy is assessed using the latest regional load forecast provided in Appendix D from a loading perspective. Sustainment aspects were identified in the NA report and are addressed in Section 7 of this report. The review assumes that the following projects shown in Table 6-1 are in-service. Sections 6.1 to 6.4 present the results of this review.

Table 6-1: New Facilities Assumed In-Service

Facility	In-Service Date
Second DESN at Horner TS	2022
Richview to Manby 230 kV Corridor Reinforcement	2023
Copeland MTS Phase 2	2024

6.1 230 kV Transmission Facilities

The Metro Toronto 230 kV transmission facilities consist of the following 230 kV transmission circuits (please refer to Figure 3-1):

a) Cherrywood TS to Leaside TS 230 kV circuits: C2L, C3L C14L, C15L, C16L, and C17L
b) Cherrywood TS to Agincourt TS 230 kV circuit C10A
c) Cherrywood TS to Richview TS 230 kV circuits: C4R, C5R, C18R, and C20R
d) Parkway TS to Richview TS 230 kV circuits: P21R and P22R
e) Claireville TS to Richview TS 230 kV circuits: V73R, V74R, V75R, V76R, V77R, and V79R
f) Richview TS to Manby TS 230 kV circuits: R1K, R2K, R13K, and R15K

The Cherrywood TS to Richview TS circuits, the Parkway TS to Richview TS circuits, and the Claireville TS to Richview TS circuits carry bulk transmission flows as well as serve local area station loads within the Sub-Region. These circuits are adequate[2] over the study period.

The Cherrywood TS to Agincourt TS circuit C10A is a radial circuit that supplies Agincourt TS and Cavanagh MTS. The circuit is adequate over the study period.

The Cherrywood TS to Leaside TS 230 kV circuits supply the Leaside TS 230/115 kV autotransformers as well as serve local area load. These circuits are adequate over the study period.

The Richview TS to Manby TS circuits supply the Manby TS 230/115 kV autotransformer station as well as Horner TS. With the Richview to Manby 230 kV Corridor Reinforcement in-service in 2023, the circuits will be adequate over the study period.

6.2 230/115 kV Autotransformers Facilities

The autotransformers at Manby TS and Leaside TS serve the 115 kV transmission network and local loads in Central Toronto. A 550 MW generation facility Portlands Energy Centre ("PEC") is situated in Central Toronto, connecting to the 115 kV transmission system at Hearn Switching Station ("SS").

The 230/115 kV autotransformers facilities in the region consist of the following elements:

a. Manby East TS 230/115 kV autotransformers: T7, T8, T9
b. Manby West TS 230/115 kV autotransformers: T1, T2, T12
c. Leaside TS 230/115 kV autotransformers: T11, T12, T14, T15, T16, T17

Manby East and West TS autos supply two distinct 115 kV load pockets. Manby East TS autos supply Runnymede TS, Fairbank TS, and Wiltshire TS through the Manby TS to Wiltshire TS circuits. Manby West TS autos normally supply the Strachan TS, John TS, and Copeland MTS through Manby TS to John TS circuits. The Manby TS autotransformer facilities are adequate over the study period.

Leaside TS autos supply the rest of the 115kV transformer stations – Basin TS, Bridgman TS, Carlaw TS, Cecil TS, Charles TS, Dufferin TS, Duplex TS, Esplanade TS, Gerrard TS, Glengrove TS, Main TS, and Terauley TS. The Leaside TS autotransformer facilities are adequate over the study period.

6.3 115 kV Transmission Facilities

The 115 kV transmission facilities in the Metro Toronto Region serve local station loads in the Central Toronto area and are connected to the rest of the grid via Manby TS and Leaside TS autotransformers. The 115 kV transmission facilities can be divided into nine main corridors summarized below.

a. Manby East TS x Wiltshire TS – Four circuits K1W, K3W, K11W, and K12W

[2] Adequate – means that current flows are with conductor or equipment thermal limits and all area bus voltages meet the Ontario Resource and Transmission Assessment Criteria (ORTAC) under normal and contingency conditions.

b. Manby West TS x John TS – Six circuits H2JK, K6J, K13J, K14J, D11J, and D12J
c. Leaside TS x Cecil TS – Three circuits L4C, L9C, and L12C
d. Leaside TS x Hearn SS – Six circuits H6LC, H8LC, H1L, H3L, H7L, and H11L
e. Leaside TS x Wiltshire TS – Four circuits L13W, L14W, L15, and L18W
f. Leaside TS x Duplex TS and Glengrove TS – Four circuits L5D, L16D, L2Y, and D6Y
g. Cecil TS x Esplanade TS – Two circuits C5E and C7E
h. John TS x Esplanade TS x Hearn SS – Three circuits H2JK, H9DE/D11J, and H10DE/D12J

The Manby East TS to Wiltshire TS 115 kV circuits supply Runnymede TS, Fairbank TS, and Wiltshire TS and were identified as requiring reinforcement in the 2016 Metro Toronto RIP. This work was completed in November 2018. With the completion of this work, the corridor circuits are adequate over the study period.

The Manby West TS to John TS 115 kV circuits supply Strachan TS, John TS and Copeland MTS. The corridor circuits are adequate over the study period.

The Leaside TS to Cecil TS 115 kV circuits and the Leaside TS to Hearn SS 115 kV circuits supply Basin TS, Carlaw TS, Cecil TS, Charles TS, Gerrard TS, and Main TS. The circuits are adequate over the study period.

The Leaside TS to Wiltshire TS corridor supply Bridgman TS and Dufferin TS. It has been recently reinforced with the addition of the L18W circuit in 2016 (Midtown transmission reinforcement). With the completion of this work the existing corridor circuits are adequate over the study period.

The Leaside TS to Duplex TS and Glengrove TS circuits (L5D, L16D, L2Y, and D6Y) are radial circuits that supply loads at Duplex TS and Glengrove TS. The circuits are adequate over the study period.

The Cecil TS to Esplanade TS circuits supply Terauley TS. The circuits are adequate over the study period.

The John TS to Esplanade TS and Hearn SS supply Esplanade TS. The circuits are adequate over the study period.

6.4 Step-Down Transformer Station Facilities

There are a total of 35 step-down transformers stations in the Toronto Region, connected to the 230 kV and 115 kV transmission network as listed below. The stations summer peak load forecast are given in Appendix D Table D-1.

Table 6-2: Toronto Step-Down Transformer Stations

230 kV Connected		115 kV Connected		
Agincourt TS	Leslie TS	Basin TS	Esplanade TS	Fairbank TS
Bathurst TS	Malvern TS	Bridgman TS	Gerrard TS	Copeland MTS
Bermondsey TS	Rexdale TS	Carlaw TS	Glengrove TS	John TS
Cavanagh MTS	Scarboro TS	Cecil TS	Main TS	Strachan TS
Ellesmere TS	Sheppard TS	Charles TS	Terauley TS	Horner TS
Fairchild TS	Warden TS	Dufferin TS	Wiltshire TS	Manby TS
Finch TS	Richview TS	Duplex TS	Runnymede TS	
Leaside TS				

With the construction of the second DESN at Runnymede TS (completed in 2018) and the second DESN at Horner TS (planned to be in-service by 2022), there will be adequate transformer station capacity over the study period.

6.5 Longer Term Outlook (2030-2040)

While the RIP was focused on the 2019-2029 period, the Study Team has also looked at longer-term loading between 2030 and 2040. The results indicate that the following facilities may be overloaded or reach capacity over this period.

- Manby West TS 230/115 kV autotransformers, which is limited by the lowest rated unit T12 in the fleet. T12 autotransformer replacement, planned to be completed by 2025, is expected to relieve this constraint.
- Leaside TS 230/115 kV autotransformers. This capacity need is based on the assumption that two of the three units at Portlands Energy Centre GS are out-of-service, and total plant generation is 160 MW. Post-contingency control action is currently available to resolve this issue by transferring Dufferin TS to Manby supply. Refer to Appendix D of 2019 Toronto IRRP ("Planning Study Results") for more details.
- Table 6.3 and 6.4 provide the adequacy summary of the transmission circuits and transformer stations potentially requiring relief within the 2030-2040 period.

Table 6-3: Longer Term Adequacy of Transmission Facilities

Facilities	Area MW Load (1)			MW Load Meeting Capability	Limiting Element	Limiting Contingency	Need Date
	2030	2035	2040				
115 kV Leaside TS x Wiltshire TS corridor	309	332	342	340	L15	L14W	2035-2040
115 kV Manby W TS x Riverside Jct. corridor	487	517	547	510	K13J	H2JK	2030-2035

(1) The sum of station's coincident summer peak load adjusted for extreme weather, excluding energy-efficiency savings, assuming normal supply configuration, without load transfer

Table 6-4: Longer Term Adequacy of Step-Down Transformer Stations

Facilities	Station MW Load (1)			Station Limited Time Rating (LTR) MW	Need Date
	2030	2035	2040		
Fairbank TS	182	188	193	182	2030-2035
Sheppard TS	203	216	224	204	2030-2035
Strachan TS	167	182	193	169	2030-2035
Basin TS	85	91	95	88	2030-2035

(1) Station's non-coincident summer peak load, adjusted for extreme weather, excluding energy-efficiency savings

7 REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE TORONTO REGION AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses electrical infrastructure needs in the Toronto Region and plans to address these needs. The electrical infrastructure needs in the Toronto Region are summarized below in Table 7.1 and Table 7.2. Except for the Richview to Manby Reinforcement, these needs are primarily associated with the replacement of end-of-life equipment.

Table 7-1: Identified Near and Mid-Term Needs in Toronto Region

Section	Facilities	Need	Timing
7.1	Main TS	End-of-life of transformers T3 and T4	2021
7.2	H1L/H3L/H6LC/H8LC	End-of-life of overhead line section between Leaside 34 Jct. & Bloor St. Jct.	2023
7.3	L9C/L12C	End-of-life of overhead line section between Leaside TS & Balfour Jct.	2023
7.4	C5E/C7E	End-of-life underground cables between Esplanade TS & Terauley TS	2024
7.5	Richview TS to Manby TS 230 kV Corridor	Additional load meeting capability upstream of Manby TS (Richview TS to Manby TS 230 kV corridor)	2023
7.6	Manby TS	End-of-life of autotransformers T7, T9, T12, step-down transformer T13, and the 230 kV switchyard at Manby TS	2025
7.7	Bermondsey TS	End-of-life of transformers T3, T4 at Bermondsey TS	2025
7.8	John TS	End-of-life of T1, T2, T3, T4, T5, T6 transformers, 115 kV breakers, and LV switchgear at John TS	2026

Table 7-2: Identified Long-Term Needs in Toronto Region

Section	Facilities	Need	Timing
7.9.1	Fairbank TS	Station capacity exceeded	2030-2035
7.9.2	Sheppard TS	Station capacity exceeded	2030-2035
7.9.3	Strachan TS	Station capacity exceeded	2030-2035
7.9.4	Basin TS	Station capacity exceeded	2030-2035
7.9.5	115 kV Manby W TS x Riverside Jct. corridor	Manby TS x Riverside Jct section of circuit K13J overloaded for circuit H2JK contingency	2030-2035
7.9.6	Manby W TS Autotransformers	Autotransformer T12 overloaded for T1 or T2 contingency	2030-2035
7.9.7	115 kV Leaside TS x Wiltshire TS corridor	Leaside TS to Balfour Jct. section of circuit L15 overloaded for circuit L14W contingency	2035-2040
7.9.8	Leaside TS Autotransformers	Autotransformer T16 overloaded for circuit C15L or C17L contingency, assuming 160 MW at Portlands GS	2035-2040

7.1 Main TS: End-of-Life Transformers

7.1.1 Description

Main TS is a 115/13.8 kV transformer station serving the eastern part of Central Toronto including the Beaches and Danforth area. The station is electrically situated within the Leaside 115 kV zone, supplied via 115 kV circuits H7L/H11L (see Figure 7-1). Peak demand at Main TS has been on average 59 MW over the last 3 years and is expected to increase to 62 MW over the next 10 years.

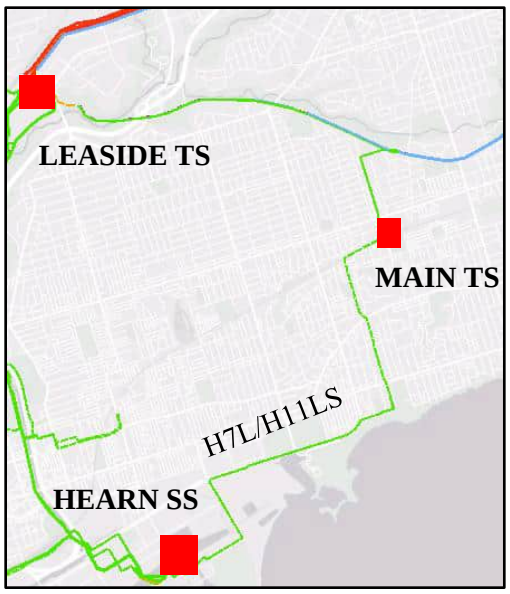


Figure 7-1: Main TS

The two transformers at Main TS (T3 and T4) are 46-51 years old 75 MVA units and are reaching their end-of-life. In addition, other equipment in the station, such as 115 kV line disconnect switches, current and voltage transformers, are also reaching their end-of-life.

7.1.2 Alternatives and Recommendation

The following alternatives were considered to address Main TS end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
2. **Alternative 2 - Replace with similar type and size equipment as per current standard:** Under this alternative the existing transformers at Main TS are replaced with new 115/13.8 kV transformers. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.
3. **Alternative 3 - Converting Main TS to 230 kV operation:** This alternative would require replacing the existing transformers with new 230/13.8kV transformers and building a new 230kV supply to Main TS from either Warden TS or Leaside TS. The existing H7L/H11L circuits cannot be used as they are required for Hearn TS x Leaside TS use. This alternative is significantly more costly (3-4 times) compared to Option 2 as it would require building the new 230 kV supply in addition to replacing the transformers. It was therefore not considered further.
4. **Alternative 4 - Supplying Main TS switchgear from new transformers at Warden TS:** Under this alternative instead of replacing the existing aging transformers at Main TS, new 230/13.8 kV transformers will be installed at Warden TS, a 230/27.6 kV transformer station located approximately 4.5 km north-east of Main TS. This alternative is significantly more (3-4 times) costly compared to Option 2 due to the excessive amount of distribution cables required to connect the transformers at Warden TS to the switchgear at Main TS. It was therefore not considered further.

The Study Team recommends Alternative 2 as the technically preferred and most cost-effective alternative to refurbish Main TS. Further given the longer term potential for growth; need to provide system resiliency and flexibility; and insignificant incremental cost difference between 45/75 MVA and 60/100 MVA transformers, the Study Team recommends that Hydro One replace the existing transformers with larger 60/100 MVA units. The plan cost is estimated to be about $33 million, and is expected to in-service by end 2021.

7.2 H1L/H3L/H6LC/H8LC: End-of-Life Overhead Section (Leaside 34 Jct. to Bloor St. Jct.)

7.2.1 Description

The 115 kV circuits H1L/H3L/H6LC/H8LC provide connections between Leaside TS, Hearn SS, and Cecil TS, and supply transformer stations in the eastern part of central Toronto including Gerrard TS, Carlaw TS, and Basin TS. Based on their asset condition, conductors along the overhead section between Leaside 34 Jct. and Bloor St. Jct. are determined to be approaching their end-of-life. Figure 7.2 shows the location of the end-of-life section.

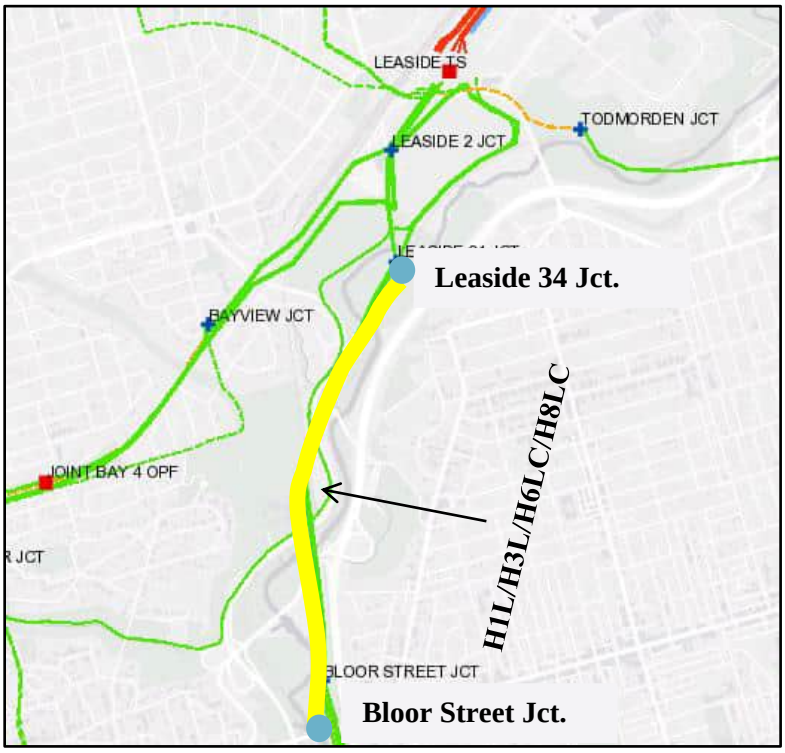


Figure 7-2: H1L/H3L/H6LC/H8LC Section between Leaside 34 Jct. and Bloor St. Jct.

7.2.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
2. **Alternative 2 – Refurbish the end-of-life overhead section as per current standard:** Under this alternative the existing end-of-life overhead section will be refurbished and the conductor will be replaced with largest size possible while retaining existing tower structures. This alternative addresses the end-of-life assets need, minimizes losses and maintains reliable supply to the customers in the area.
3. **Alternative 3 –Replace and rebuild line for future 230 kV operation:** Under this alternative the line would be rebuilt to 230kV standards so as to be able for future 230kV operation. This alternative would be significantly more costly than Alternative 2 and with no plans to utilize the line at the higher operating voltage, was rejected and not considered further.

The Study Team recommends that Hydro One proceed with Alternative 2 – the refurbishment of the end-of-life overhead section. The line refurbishment work is expected to be complete by 2023.

7.3 L9C/L12C: End-of-Life Overhead Section (Leaside TS to Balfour Jct.)

7.3.1 Description

The overhead section of 115 kV double circuit line L9C/L12C between Leaside TS and Balfour Jct. is over 80 years old and has been determined to be approaching its end-of-life. Figure 7.3 shows the location of the end-of-life section.

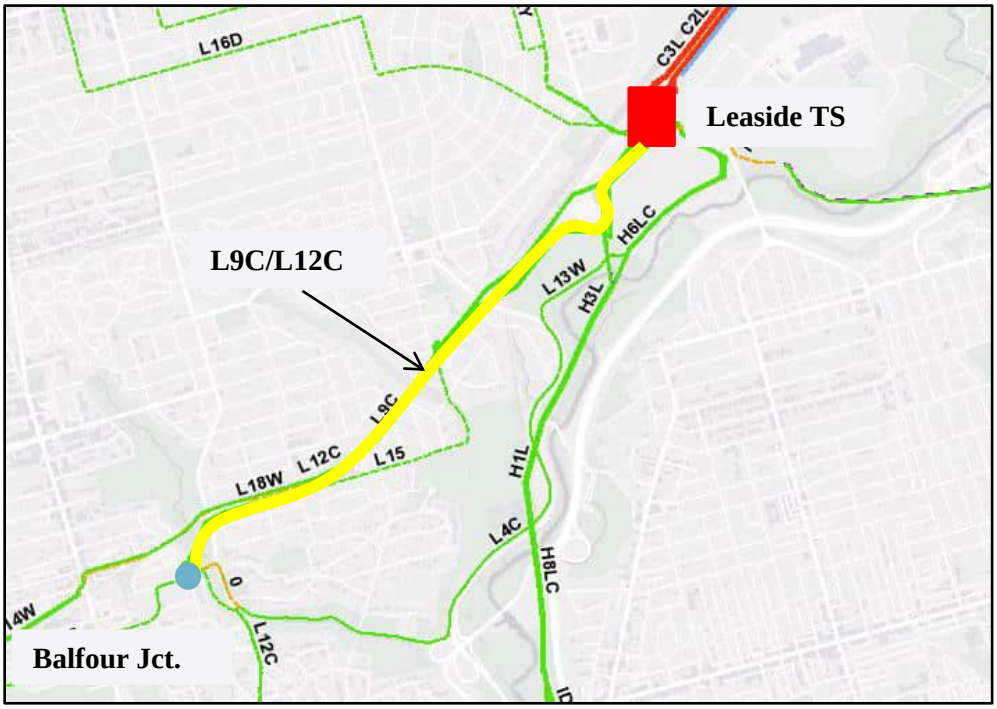


Figure 7-3: L9C/L12C Section between Leaside TS and Balfour Jct.

7.3.2 Alternatives and Recommendation

The following alternatives are considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
2. **Alternative 2 – Refurbish the end-of-life overhead section as per current standard:** Refurbish the end-of-life overhead section and replace conductors with the largest size possible while retaining existing tower structures. This alternative is recommended as it addresses the end-of-life assets need and maintains reliable supply to the customers in the area.

The Study Team recommends that Hydro One proceed with Alternative 2 – the refurbishment of the end-of-life overhead section of L9C/L12C between Leaside TS and Balfour Jct. The line refurbishment work is planned to be completed by 2023.

7.4 C5E/C7E: End-of-Life Underground Cables (Esplanade TS to Terauley TS)

7.4.1 Description

Circuits C5E and C7E between Esplanade TS to Terauley TS are 115 kV paper insulated low pressure oil filled underground transmission cables that provide a critical 115 kV supply to Toronto's downtown core and are partially routed along Lake Ontario.

These circuits, put into service in 1959, are among the oldest cable circuits in the Hydro One's transmission system. Based on condition test results, the cable jackets and paper insulation were found to be in deteriorated condition which can lead to overheating, oil leaks, and cable failure. Figure 7.3 shows the location of the end-of-life section.

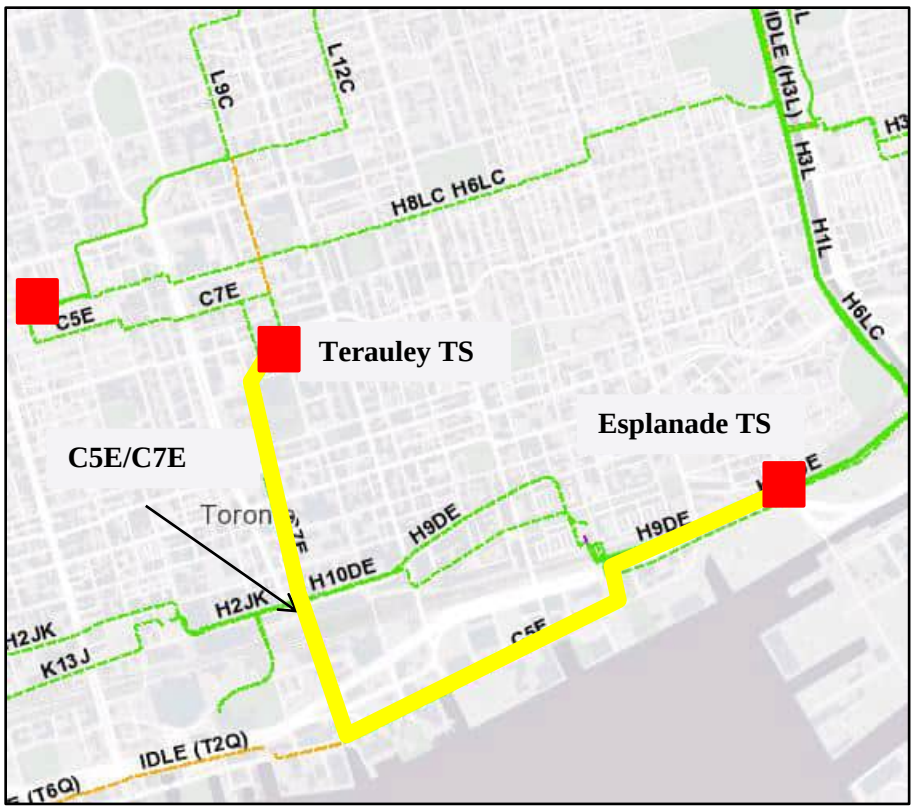


Figure 7-4: C5E/C7E Underground Cable Section between Esplanade TS and Terauley TS

7.4.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition. Failure to these cables can impact the power supply to critical facilities in Downtown Toronto. A large oil leak would have significant environmental impact and require costly environmental remediation.
2. **Alternative 2 - Replace with similar type and size equipment as per current standard:** Under this alternative, the existing cables will be replaced with new 230 kV rated cables. The 230 kV rated cables have higher insulation and are less prone to failure. This alternative is recommended as it addresses the end-of-life assets need and maintains reliable supply to the customers in the area.

The Study Team recommends that Hydro One proceed with Alternative 2 – the replacement of the end-of-life underground cables between Esplanade TS and Terauley TS. Hydro One is currently proceeding with detailed estimation of options including tunneling for evaluating the most appropriate routes and construction options. This will be an input for public consultations to obtaining permit and necessary approvals along with environmental assessments. A final route and installation option will be selected as part of the open EA process. The cable refurbishment work is planned to be completed by 2024.

7.5 Richview TS to Manby TS 230 kV Corridor

7.5.1 Description

The 230 kV transmission corridor between Richview TS and Manby TS is the main supply path for the Western Sector of Central Toronto. Along this corridor there are two double-circuit 230 kV lines R1K/R2K and R13K/R15K. Together with circuit R24C between Richview TS and Cooksville TS, this corridor also supplies the load in the southern Mississauga and Oakville areas via Manby TS. The first cycle Metro Toronto Regional Infrastructure Plan has identified the need to increase transfer capability of this transmission corridor to support the continuous load growth in these areas.

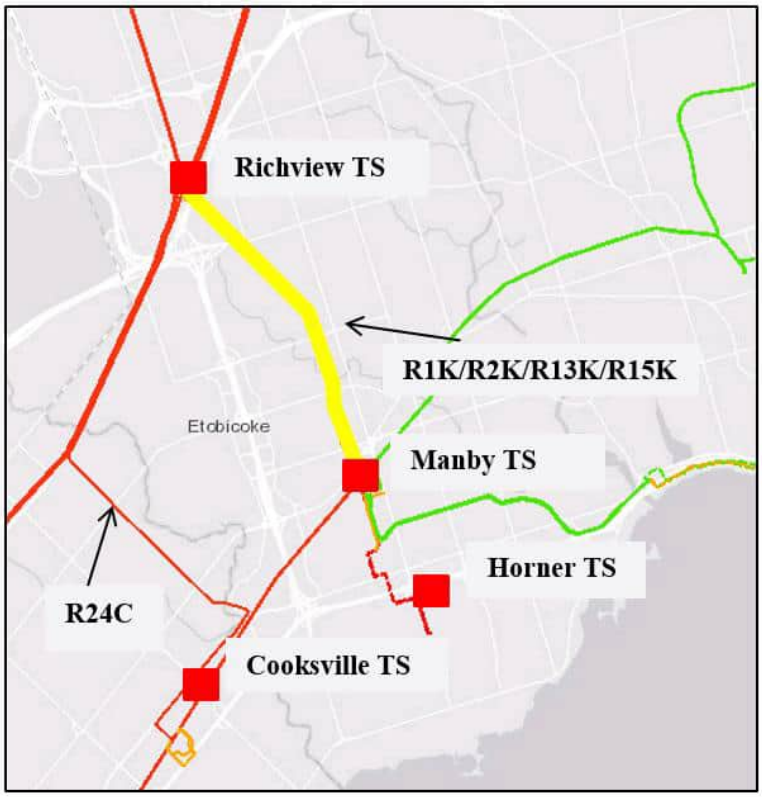


Figure 7-5: Richview TS to Manby TS 230 kV Corridor

7.5.2 Alternatives and Recommendation

A detailed assessment of the Richview TS to Manby TS corridor need was carried out in the Appendix F of the Toronto IRRP to reconfirm the capacity need of this corridor based on the changes in assumptions and the up-to-date load forecast. The assessment confirmed the need, and the Study Team continues to recommend that the reinforcement of the Richview TS to Manby TS 230 kV circuits to be completed as soon as possible.

Evaluation of alternatives was completed by the Study Team as documented in the 2015 Toronto Regional Infrastructure Plan. As per the Study Team's recommendation, Hydro One is proceeding with the Richview TS to Manby TS 230 kV transmission reinforcement project, which will be carried out in two phases:

- **Phase 1:** This phase covers rebuilding the existing idle 115 kV overhead line on the transmission corridor between Richview TS and Manby TS to 230 kV standards. The new line will operate in parallel with the existing four 230 kV circuits from Richview TS to Manby TS, which will initially be reconfigured to create two "supercircuits." This configuration avoids the need to build new terminations and new breakers at Manby TS. The IRRP noted the need for Phase 1 is in 2021 but the expected in-service is Q4 2023. Figure 7-6 below shows the transmission configuration after Phase 1 is completed.

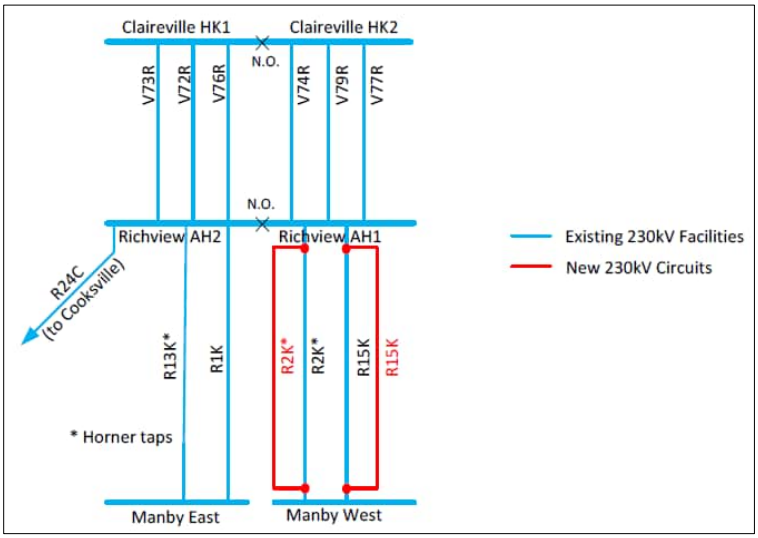


Figure 7-6: Richview TS to Manby TS 230 kV Corridor – Phase 1

i. **Phase 2:** In the second phase the super circuits will be unbundled with one new circuit connected to Manby West and one to Manby East with new termination installed at Manby TS. At Richview TS, the new circuits will be tapped to existing 230 kV circuits V73R and V79R from Claireville TS. This configuration allows Richview TS to be bypassed and permits continued supply to Manby TS should there be an emergency at Richview TS. The timing of Phase 2 will be planned to coincide with Manby TS end of life refurbishment, all of which is planned to be complete by 2025. Figure 7-7 below shows the transmission configuration after Phase 2 is completed. Note that the nomenclature shown for the new circuits are for illustrative purposes only and subject to change.

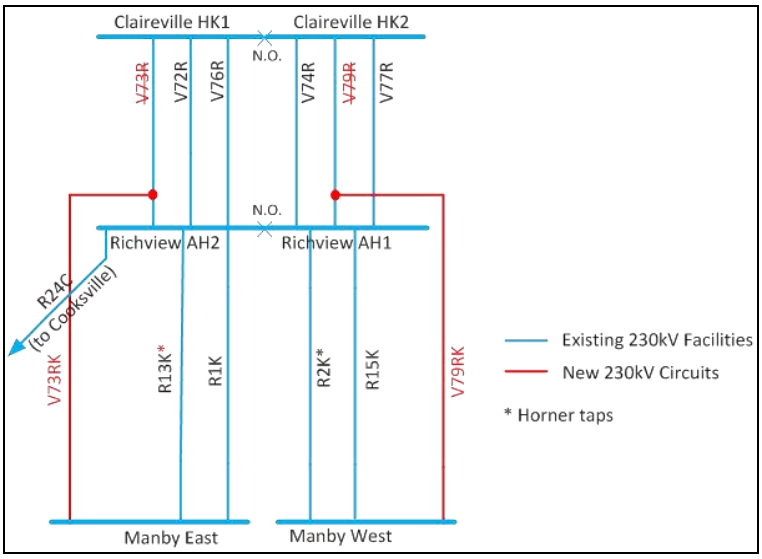


Figure 7-7: Richview TS to Manby TS 230 kV Corridor – Phase 2

7.6 Manby TS: End-of-Life Transformers and 230 kV Switchyard

7.6.1 Description

Manby TS is a major bulk electric switching and autotransformer station in the Toronto region. Station facilities include the Manby West and Manby East 230 kV and 115 kV switchyards, six 230/115 kV autotransformers (T1, T2, T7, T8, T9, T12), and six 230/27.6 kV step-down transformers supplying three DESNs (T3/T4, T5/T6, T13/T14).

The Manby TS autotransformers T7, T9, and T12 and step down transformer T13 are about 50 years old and all four have been identified to be nearing the end of their useful life and require replacement in the next 5 years. All three DESNs at Manby TS are currently at capacity, and the new second DESN at nearby Horner TS (I/S 2022) is expected to pick-up the load growth in the area.

The 230 kV oil breakers have also been identified to be nearing end-of-life and require replacement over the next 5-year period. As part of breaker replacement work, the 230 kV Manby West and Manby East switchyards will be modified and an additional three breakers added to terminate the two new circuits to Richview TS described above in Section 7.5 under Phase 2 for the Richview TS to Manby TS corridor reinforcement.



Figure 7-8: Manby TS

7.6.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability for customers.
2. **Alternative 2 - Replace the end-of-life transformers with similar type and size equipment as per current standard, and rebuild/modify the 230 kV switchyard:** This alternative involves the replacement of Manby East T7, T9, and Manby West T12 autotransformers with 250 MVA units; Manby T13 DESN transformers with 75/93 MVA unit; replacement of end-of-life 230 kV oil breakers; as well as 230 kV switchyard modification and installing three new breakers to accommodate the new circuits to Richview TS (as part of the Richview TS to Manby TS Corridor Reinforcement). This alternative is recommended as it addresses the end-of-life asset needs and maintains reliable supply to customers in the area by:
    - reducing the risk of breaker failure events at Manby TS;
    - providing relief to the autotransformer capacity constraints in the long-term at Manby West TS by replacing the lowest rated unit T12; and
    - connecting the new circuits to Richview TS to support the continuous load growth in these areas.

The Study Team recommends that Hydro One proceed with Alternative 2 – the end-of-life transformer replacement and rebuilding of the Manby TS 230 kV switchyard. The project is expected to be completed by 2025.

7.7 Bermondsey TS: End-of-Life Transformers

7.7.1 Description

Bermondsey TS along with Ellesmere TS, Scarborough TS, Sheppard TS and Warden TS supply the Scarborough area and comprises of two DESNs. The T1/T2 DESN was built in 1990, has 6 feeders, an LTR

of 185.8 MW and supplied a summer 2018 peak load of 43 MW. The T3/T4 DESN was built in 1965, has 12 feeders, an LTR of 162.5 MW and supplied a 2018 summer peak load of 117 MW.

The T3 and T4 transformers are about 55 years old, have been identified as nearing the end of their useful life and requiring replacement in the next 5 years.

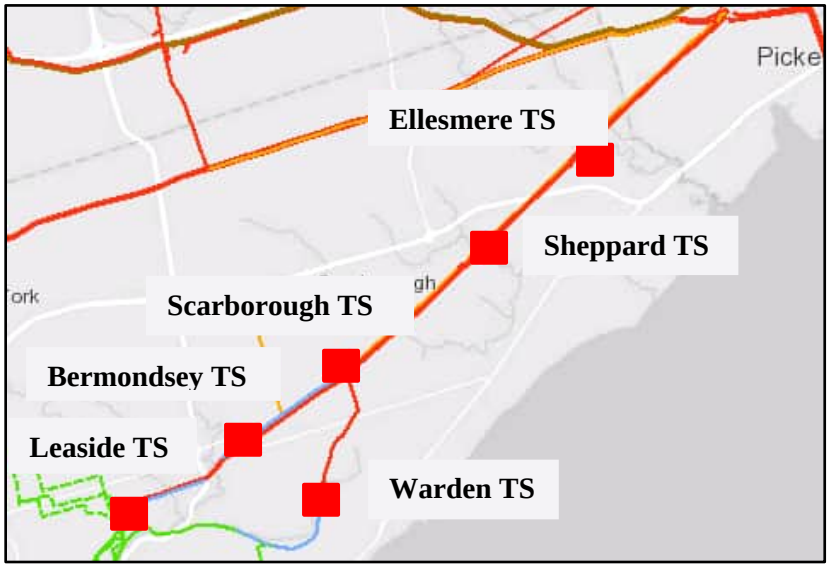


Figure 7-9: Bermondsey TS and Surrounding Stations

7.7.2 Alternatives and Recommendation

The recommendation for the end of life replacement is as follows:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.
2. **Alternative 2 - Decommission the T3/T4 DESN at its end-of-life:** This alternative is not viable as there would be insufficient feeder capacity to supply the existing load. It was not considered further.
3. **Alternative 3 - Downsize (replace with smaller 83 MVA transformers):** This alternative would require extensive feeder transfers, and reconfiguration of the station including addition of new feeders on the T1/T2 DESN. The cost of the station reconfiguration work is expected to exceed $5M and significantly exceeds the $500-600k cost savings resulting from using the smaller size transformers.
4. **Alternative 4 - Replace with similar type and size equipment as per current standard:** This alternative is recommended as this is the most cost effective option, and addresses the end-of-life assets need and maintains reliable supply to the customers in the area.

Considering above options, the Study Team recommends that Hydro One proceed with Alternative 4 – the refurbishment of the T3/T4 DESN of Bermondsey TS and build to current standard. The refurbishment plan is expected to be in-service by 2025.

7.8 John TS: End-of-Life Transformers, 115 kV Breakers, and LV Switchgear

7.8.1 Description

John TS (also referred to as Windsor TS) is connected to the 115 kV Manby West system and supplies the western half of City of Toronto's downtown district. Station facilities include a 115 kV switchyard and six 115/13.8 kV step-down transformers (T1, T2, T3, T4, T5, T6) supplying six Toronto Hydro low voltage metalclad switchgears. The summer 10-day LTR is 311 MW. The station's 2018 actual non-coincident summer peak load (adjusted for extreme weather) was about 261 MW.



Figure 7-10: John TS

The T1 and T4 step-down transformers at John TS, both over 50 years old and in poor condition, were replaced in 2019. The step down transformers (T2, T3, T5 and T6) which range in age from 44-50 years are also at, or nearing, end of life. It is expected that these transformers will need to be replaced in the next 3-5 years. The 115 kV breakers are mostly oil type and are about 44 years old. They are also nearing end of useful life and are expected to require replacement in the next 5-10 years.

Toronto Hydro has also identified the need for renewal of their switchgear facilities at John TS. This work will be done over multiple phases and is expected to take 20-25 years to fully complete. The first phase involves relocating the feeders from switchgear at John TS to new switchgear at Copeland MTS so as to permit of the replacement of switchgear at John TS. The presence of Copeland MTS, which went into service in 2019, enables the switchgear replacement due to the capacity (transformation and feeder positions) at Copeland MTS that are not available at John TS or other neighboring stations. The load transfer to Copeland MTS is necessary to reduce load at John TS to facilitate the transformer and switchgear replacement work at John TS.

Toronto Hydro plan to initiate the switchgear renewal process starting with the Windsor Station A5-A6 and the A3-A4 metalclad switchgear buses. These buses are expected to be replaced by the new A19-A20 bus

in 2022-2023 and later followed by A21-A22 bus. Hydro One will replace associated low voltage transformer breaker disconnect switches and cables in coordination with Toronto Hydro.

7.8.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the customers.

2. **Alternative 2 – Reducing the Number of Transformers from Six to Four Units:** As part of the John TS refurbishment work and the consequent reduction in loading at the station, Hydro One investigated the opportunity for reducing the number of 115/13.8 kV transformer units at John TS from the current six units to four units. Hydro One assessed with Toronto Hydro the feasibility of the following two options:
    i. Reducing the number of switchgear pairs in the station from the current six to four to match the supply from four transformers. The assessment concluded that Copeland MTS has only enough feeder positions available to pick up one bus (typically 14-16 feeders) from John TS, and therefore there are no additional feeder positions available at Copeland MTS to further eliminate another bus at John TS. As such this option is not feasible.
    ii. Reducing the number of transformer supply points to the existing six switchgear pairs through switchgear bus bundling (while not reducing the number of feeder positions at the station). This involved looking at opportunities of electrically joining presently distinct switchgear pairs while at the same time respecting equipment ratings. No opportunities were found that would respect equipment ratings. If opportunities that would respect equipment ratings had been found these would then be reviewed based upon operational factors involving customers impacted by a contingency, restoration times, etc. A first review of these operational factors found that Toronto Hydro's ability to perform bus load transfers would be limited than what it is today and its restoration times would be lengthened compared to what exists today due to the increased concentration of customers per bus. Given the lack of opportunities and the negative operational impacts even if opportunities were to be found, this option is not feasible.
    iii. Consistent with the IRRP load forecast, Toronto Hydro has cited continued electricity demand along with higher reliability from customers for new connections to its distribution system in the downtown core. The growth in new connections coupled with Toronto Hydro's distribution system for reliable service is leading to the demand for feeder positions outpacing the peak demand growth. Six switchgear pairs along with six transformer supply points are still required for John/Windsor TS.

    Based on the findings of above assessments, this alternative is not viable as Toronto Hydro feeder requirements are such that all of the six transformers are needed to supply load in the area via the six pairs of Toronto Hydro buses as described above.

3. **Alternative 3 - Similar Connection Arrangement with 60/100 MVA Transformers:** This alternative is recommended as it addresses the end-of-life assets need and maintains reliable supply

to the customers in the area. This alternative involves the replacement of the remaining T2, T3 (45/75 MVA), and T5, T6 (75/125 MVA) transformers with 60/100 MVA units, replacement of the LV switchgear in coordination with Toronto Hydro, and replacement of the existing oil filled breakers with SF6 breakers in the 115 kV switchyard. Minor modifications may be made (to the extent practically possible) to improve operational flexibility under outage conditions. Several options as described below were considered into the scope of the John TS refurbishment:

i. Downsize (replace with smaller size transformers): The renewal of John TS switchgear facilities is expected to be completed over multiple phases within the next 20-25 years. Over this time period, the load of an existing switchgear will be transferred from one transformer winding pairs to another to connect to the new switchgear. Since some of the switchgear is heavily loaded, all of the transformer windings should be able to handle the maximum load of a single switchgear (i.e., 3000 Amps). For this reason, downsizing of John TS transformers is not viable.

ii. Rebuild/reconfigure the 115 kV switchyard to a "Breaker-and-Half" configuration: The existing 115 kV breakers and buses are currently arranged in a ring-bus configuration and consideration was given to rebuilding and reconfiguring the 115 kV switchyard using a breaker and half arrangement. However, this alternative is not viable due to physical space constraints and clearances required for equipment and personnel safety. Although, practically constrained, this option will also require rerouting and retermination of high voltage cables and the cost of investment required for this reconfiguration significantly outweigh the incremental benefits.

The Study Team therefore recommends that Hydro One to proceed with Alternative 3 as described above. The John TS refurbishment plan is expected to be in service by 2026.

7.9 Long-Term Capacity Needs

A number of longer term capacity needs have been identified as described in Section 6.5 and Table 7.2. The Study team recommends that these needs be monitored and evaluated in future planning cycles. No investment is required at this time due to the forecast uncertainty and the longer-term timing of need. Preliminary comments are given below.

7.9.1 Fairbank TS Capacity Need

Fairbank TS load is expected to exceed LTR within the 2030-2035 time period. Consideration may be given to load transfer to the neighboring Runnymede TS. The Study Team recommends reviewing the loading in the next planning cycle.

7.9.2 Sheppard TS Capacity Need

Sheppard TS is also forecast to exceed capacity within the 2030-2035 time period. Consideration may be given to utilizing the idle winding on transformers T1/T2. The Study Team recommends reviewing the loading in the next planning cycle.

7.9.3 Strachan TS Capacity Need

Strachan TS is forecast to exceed capacity within the 2030-2035 time period. Consideration maybe given to provide relief to Strachan TS through permanent load transfers to Copeland MTS and/or John TS. The Study Team recommends reviewing the loading in the next planning cycle.

7.9.4 Basin TS Capacity Need

Basin TS is located in the Portlands area in Downtown Toronto. The need for additional capacity at Basin TS is expected to arise in the long-term (within the 2030-2035 time period). The timing of the need is dependent on the pace of development in the area. Physical space is available at the current Basin TS site to plan and build a second DESN to meet long term needs.

The City of Toronto is planning the re-development of the Portlands. The area may see additional load beyond that which has been included in the present forecasts. The timing of any new needs will depend upon the timing of the City's plan.

However, the City's current re-development plans will end the continued operation of Basin TS and several high voltage lines in their current locations in the Portlands. This will significantly impact both Hydro One infrastructure and Toronto Hydro infrastructure within and outside of Basin TS. No sites for a replacement transformer station or high voltage line routes have been identified by the City.

Hydro One and Toronto Hydro have requested the City to revise its plans so as to avoid the conflicts with Basin TS and high voltage lines. Hydro One and Toronto Hydro have also joined others in a legal appeal of the City's land plans.

Given the appeal and lack of information currently available to Hydro One and Toronto Hydro from the City, the Study Team recommends that Hydro One and Toronto Hydro continue to monitor the situation and update the Study Team as appropriate. Plans for supplying the Portlands area will be developed as more information becomes known.

7.9.5 Manby West TS to Riverside Jct. Corridor Capacity Need

The Manby TS x Riverside Jct. section of K13J/K14J is potentially overloaded under certain contingency conditions within the 2030-2035 time period. Consideration may be given to reconductor circuit with a higher ampacity conductor. The Study Team recommends reviewing the loading in the next planning cycle.

7.9.6 Manby West TS Autotransformers T12 Capacity Need

Manby West TS 230/115 kV autotransformers is restricted by the lowest rated unit T12 in the fleet, and is potentially overloaded within the 2030-2035 time period, following T1 or T2 contingency. T12 autotransformer replacement, planned to be completed by 2025, is expected to provide relieve to this constraint and meet the capacity requirement at Manby West TS autotransformers facility. See Section 7.5 for more details.

7.9.7 Leaside TS to Wiltshire TS Corridor Capacity Need

The Leaside TS x Balfour Jct. section of the underground 115 kV circuit L15, connecting Leaside TS and Wiltshire TS, is potentially overloaded in the long-term within the 2035-2040 time period. The Study Team determines that no further investment is required to address this need at this time due to the level of uncertainties and amount of lead time available. This need will be reevaluated in the next planning cycle.

7.9.8 Leaside TS Autotransformers T16 Capacity Need

Leaside TS autotransformer T16 is potentially overloaded in the long-term within the 2035-2040 time period, following circuit C15L or C17L contingency, assuming that two of the three units at Portlands Energy Centre GS are out-of-service, and total plant generation is 160 MW. Post-contingency control action is currently available to resolve this issue by transferring Dufferin TS to Manby supply. The Study Team determines that no further investment is required to address this need at this time due to the level of forecast uncertainty and amount of lead time available. The Study Team recommends reviewing the loading in the next planning cycle.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE TORONTO REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 8-1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 8-1: Recommended Plans in Toronto Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate(1)
1	Main TS: End-of-life of transformers T3/T4	Replace the end-of-life transformers with similar type and size equipment as per current standard	2021	$33M
2	H1L/H3L/H6LC/H8LC: End-of-life of Leaside Jct. to Bloor St. Jct. overhead section	Refurbish the end-of-life H1L/H3L/ H6LC/H8LC section	2023	$11M
3	L9C/L12C: End-of-life of Leaside TS to Balfour Jct. overhead section	Refurbish the end-of-life L9C/L12C section	2023	$3M
4	C5E/C7E: End-of-life of underground cables between Esplanade TS and Terauley TS	Replace the end-of-life C5E/C7E cables	2024	$128M
5	Richview TS to Manby TS 230 kV Corridor Reinforcement	Replace existing idle 115 kV double circuit line with new 230 kV double circuit line between Richview TS and Manby TS	2023	$21M
6	Manby TS: End-of-life of autotransformers (T7, T9, T12), step-down transformer (T13), and the 230 kV switchyard	Replace the end-of-life transformers with similar type and size equipment as per current standard, and refurbish/reconfigure Manby 230 kV switchyard	2025	$85M
7	Bermondsey TS: End-of-life of transformers T3/T4	Replace the end-of-life transformers with similar type and size equipment as per current standard	2025	$27M
8	John TS: End-of-life of transformers (T1, T2, T3, T4, T5, T6), 115 kV breakers, and LV switchgear	Replace with similar type and size equipment as per current standard	2026	$102M

(1) Budgetary estimates are provided for Hydro One's portion of the work

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 8-1 while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

9 REFERENCES

[1] **Metro Toronto Regional Infrastructure Plan (2016)**
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/RIP%20Report%20Metro%20Toronto.pdf

[2] **Toronto Region Needs Assessment (2017)**
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/metrotoronto/Documents/Needs%20Assessment%20-%20Toronto%20Region%20-%20Final.pdf

[3] **Toronto Region Scoping Assessment (2018)**
http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/Toronto-Scoping-Assessment-Outcome-Report-February-2018.pdf?la=en

[4] **Toronto Integrated Regional Resource Plan (2019)**
http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/engagement/Toronto-IRRP-20190809-Report.pdf?la=en

[5] **Toronto Integrated Regional Resource Plan - Appendices (2019)**
http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Toronto/engagement/Toronto-IRRP-Appendices.pdf?la=en

APPENDIX A. STATIONS IN THE TORONTO REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Agincourt TS T5/T6	230/27.6	C4R/C10A
Basin TS T3/T5	115/13.8	H3L/H1L
Bathurst TS T1/T2	230/27.6	P22R/C18R
Bathurst TS T3/T4	230/27.6	P22R/C18R
Bermondsey TS T1/T2	230/27.6	C17L/C14L
Bermondsey TS T3/T4	230/27.6	C17L/C14L
Bridgman TS T11/T12/T13/T14/T15	115/13.8	L13W/L15/L14W
Carlaw TS T1/T2	115/13.8	H1L/H3L
Cecil TS T1/T2	115/13.8	Cecil Buses H & P
Cecil TS T3/T4	115/13.8	Cecil Buses P & H
Charles TS T1/T2	115/13.8	L4C/L9C
Charles TS T3/T4	115/13.8	L12C/L4C
Dufferin TS T1/T3	115/13.8	L13W/L15
Dufferin TS T2/T4	115/13.8	L13W/L15
Duplex TS T1/T2	115/13.8	L16D/L5D
Duplex TS T3/T4	115/13.8	L5D/L16D
Ellesmere TS T3/T4	230/27.6	C2L/C3L
Esplanade TS T11/T12/T13	115/13.8	H2JK/H10EJ(C5E)/H9EJ(C7E)
Fairbank TS T1/T3	115/27.6	K3W/K1W
Fairbank TS T2/T4	115/27.6	K3W/K1W
Fairchild TS T1/T2	230/27.6	C18R/C20R
Fairchild TS T3/T4	230/27.6	C18R/C20R

Station (DESN)	Voltage (kV)	Supply Circuits
Finch TS T1/T2	230/27.6	C20R/P22R
Finch TS T3/T4	230/27.6	P21R/C4R
Gerrard TS T1/T3/T4	115/13.8	H3L/H1L
Glengrove TS T1/T3	115/13.8	D6Y/L2Y
Glengrove TS T2/T4	115/13.8	D6Y/L2Y
Horner TS T3/T4	230/27.6	R13K/R2K
John TS T1/T2/T3/T4	115/13.8	John Buses K1 & K2 & K3 & K4
John TS T5/T6	115/13.8	John Buses K1 & K4
Leaside TS T19/T20/T21 13.8	230/13.8	C2L/C3L/C16L
Leaside TS T19/T20/T21 27.6	230/27.6	C2L/C3L/C16L
Leslie TS T1/T2 13.8	230/13.8	P21R/C5R
Leslie TS T1/T2 27.6	230/27.6	P21R/C5R
Leslie TS T3/T4	230/27.6	P21R/C5R
Main TS T3/T4	115/13.8	H7L/H11L
Malvern TS T3/T4	230/27.6	C4R/C5R
Manby TS T13/T14	230/27.6	Manby W Buses A1 & H1
Manby TS T3/T4	230/27.6	Manby W Buses A1 & H1
Manby TS T5/T6	230/27.6	Manby E Buses H2 & A2
Rexdale TS T1/T2	230/27.6	V74R/V76R
Richview TS T1/T2	230/27.6	Richview Buses H1 & A1
Richview TS T5/T6	230/27.6	V74R/V72R
Richview TS T7/T8	230/27.6	Richview Buses H2 & A2
Runnymede TS T3/T4	115/27.6	K12W/K11W

Station (DESN)	Voltage (kV)	Supply Circuits
Scarboro TS T21/T22	230/27.6	C14L/C2L
Scarboro TS T23/T24	230/27.6	C15L/C3L
Sheppard TS T1/T2	230/27.6	C16L/C15L
Sheppard TS T3/T4	230/27.6	C15L/C16L
Strachan TS T12/T14	115/13.8	H2JK/K6J
Strachan TS T13/T15	115/13.8	K6J/H2JK
Terauley TS T1/T4	115/13.8	C7E/C5E
Terauley TS T2/T3	115/13.8	C7E/C5E
Warden TS T3/T4	230/27.6	C14L/C17L
Wiltshire TS T1/T6	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T2/T5	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Wiltshire TS T3/T4	115/13.8	K1W/K3W (Wiltshire Buses H1 & H3)
Cavanagh MTS T1/T2	230/27.6	C20R/C10A
IBM Markham CTS T1/T2	230/13.8	P21R/P22R
Markham MTS #1 T1/T2	230/27.6	P21R/P22R
Copeland MTS T1/T3 (Future)	115/13.8	D11J/D12J

APPENDIX B. TRANSMISSION LINES IN THE TORONTO REGION

Location	Circuit Designations	Voltage (kV)
Richview x Manby	R1K, R2K, R13K, R15K	230
Richview x Cooksville	R24C	230
Manby x Cooksville	K21C, K23C	230
Cherrywood x Leaside	C2L, C3L, C14L, C15L, C16L, C17L	230
Cherrywood x Richview	C4R, C5R, C18R, C20R	230
Cherrywood x Agincourt	C10A	230
Parkway x Richview	P21R, P22R	230
Claireville x Richview	V72R, V73R, V74R, V76R, V77R, V79R	230
Manby East x Wiltshire	K1W, K3W, K11W, K12W	115
Manby West x John	K6J, K13J, K14J	115
Manby West x John x Hearn	H2JK	115
John x Esplanade x Hearn	D11J, D12J, H9DE, H10DE	115
Esplanade x Cecil	C5E, C7E	115
Hearn x Cecil x Leaside	H6LC, H8LC	115
Hearn x Leaside	H1L, H3L, H7L, H11L	115
Leaside x Bridgman x Wiltshire	L13W, L14W, L15, L18W	115
Leaside x Charles	L4C	115
Leaside x Cecil	L9C, L12C	115
Leaside x Duplex	L5D, L16D	115
Leaside x Glengrove	L2Y	115
Duplex x Glengrove	D6Y	115

APPENDIX C. DISTRIBUTORS IN THE TORONTO REGION

Distributor Name	Station Name	Connection Type
Toronto Hydro-Electric System Limited	Agincourt TS	Tx
	Basin TS	Tx
	Bathurst TS	Tx
	Bermondsey TS	Tx
	Bridgman TS	Tx
	Carlaw TS	Tx
	Cecil TS	Tx
	Charles TS	Tx
	Dufferin TS	Tx
	Duplex TS	Tx
	Ellesmere TS	Tx
	Esplanade TS	Tx
	Fairbank TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Gerrard TS	Tx
	Glengrove TS	Tx
	Horner TS	Tx
	John TS	Tx
	Leaside TS	Tx
	Leslie TS	Tx
	Main TS	Tx
	Malvern TS	Tx
	Manby TS	Tx
	Rexdale TS	Tx
	Richview TS	Tx
	Runnymede TS	Tx
	Scarboro TS	Tx
	Sheppard TS	Tx
	Strachan TS	Tx
	Terauley TS	Tx
	Warden TS	Tx
	Wiltshire TS	Tx
	Cavanagh MTS	Tx
	Copeland MTS	Tx

Distributor Name	Station Name	Connection Type
Hydro One Networks Inc. (Dx)	Agincourt TS	Tx
	Fairchild TS	Tx
	Finch TS	Tx
	Leslie TS	Tx
	Malvern TS	Tx
	Richview TS	Tx
	Sheppard TS	Tx
Alectra Utilities	Agincourt TS	Dx
	Fairchild TS	Dx
	Finch TS	Dx
	Leslie TS	Dx
	Richview TS	Dx
Elexicon Energy Inc.	Malvern TS	Dx
	Sheppard TS	Dx

APPENDIX D. TORONTO REGION LOAD FORECAST

Table D-1: Toronto IRRP Load Forecast, without the Impacts of Energy-Efficiency Savings

		Near & Mid-Term Forecast												Long-Term Forecast		
Area & Station	**LTR (MW)**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2035**	**2040**
North 230 kV																
Agincourt TS	174	92	95	98	100	101	102	103	104	104	105	106	106	107	110	114
Bathurst TS	334	210	220	226	229	231	233	235	236	238	239	242	245	247	265	274
Cavanagh MTS	157	91	92	93	94	95	95	95	96	97	98	98	99	100	108	112
Fairchild TS	346	235	237	239	241	243	245	247	249	250	250	252	254	255	260	265
Finch TS	365	249	254	258	260	261	262	263	265	267	269	271	272	273	279	284
Leslie TS	325	233	241	249	250	254	255	258	260	261	262	264	265	266	283	293
Malvern TS	176	83	84	85	86	86	86	87	88	88	91	93	95	96	103	106
East 230 kV																
Bermondsey TS	348	148	152	154	156	159	160	161	162	164	164	165	165	165	166	172
Ellesmere TS	189	124	126	128	129	130	131	131	132	133	133	134	134	134	135	138
Leaside TS	202	151	156	160	163	164	165	165	167	168	168	169	169	169	171	178
Scarboro TS	340	204	207	209	211	212	213	214	216	218	218	218	219	219	230	236
Sheppard TS	205	141	144	146	148	148	150	151	153	153	153	156	159	161	171	177
Warden TS	182	106	108	109	110	111	112	113	113	113	117	120	122	124	132	136
West 230 kV																
Horner TS	365	133	137	138	140	140	142	143	144	145	149	154	158	161	177	187
Manby TS	226	191	202	205	211	212	215	216	217	219	220	222	224	226	240	251
Rexdale TS	187	123	124	125	125	127	127	129	129	129	129	127	127	125	118	110
Richview TS	460	227	213	217	219	220	222	223	224	226	224	222	219	218	213	204
Leaside 115 kV																
Basin TS	88	65	71	75	76	77	77	78	79	79	81	83	84	85	91	95
Bridgman TS	212	154	154	156	157	157	160	161	161	162	163	164	165	167	180	186
Carlaw TS	73	66	67	67	67	68	68	69	69	70	70	70	70	72	72	72
Cecil TS	215	162	170	175	177	179	181	182	183	184	182	180	178	177	177	177
Charles TS	211	145	151	154	155	156	158	158	159	159	161	164	166	167	175	176
Dufferin TS	170	136	121	124	125	125	126	127	128	130	134	135	139	142	152	156
Duplex TS	128	99	101	100	98	97	94	94	96	97	98	99	100	102	108	113
Esplanade TS	187	162	142	145	146	146	148	148	149	150	149	147	146	143	147	148
Gerrard TS	102	35	44	47	49	49	50	50	50	51	51	51	51	51	52	53
Glengrove TS	88	48	50	50	51	51	51	51	51	51	52	54	55	56	60	62
Main TS	77	56	57	57	58	59	59	59	60	60	62	62	63	64	65	65
Terauley TS	249	175	188	194	190	188	188	191	191	191	190	187	185	184	181	182
Manby E 115 kV																
Fairbank TS	182	141	125	132	135	139	142	144	145	146	147	148	149	149	154	158
Runnymede TS	219	96	136	141	143	143	146	146	148	148	149	149	151	151	158	164
Wiltshire TS	133	55	71	72	72	72	73	73	73	75	75	76	76	76	83	86
Manby W 115 kV																
Copeland MTS	130	0	0	52	93	93	94	94	96	96	98	99	100	102	107	112
John TS	314	263	266	215	201	202	203	204	206	206	210	212	215	218	228	242
Strachan TS	169	139	143	145	146	147	147	149	149	150	155	159	163	167	182	193

Table D-2: Toronto Non-Coincident Load Forecast, without the Impacts of Energy-Efficiency Savings

		Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
Area & Station	**LTR (MW)**	**2018 (1)**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2035**	**2040**
North 230 kV																
Agincourt TS	174	112	115	119	121	122	124	125	126	126	127	128	128	130	133	138
Bathurst TS	334	227	238	244	248	250	252	254	255	257	258	262	265	267	287	296
Cavanagh MTS	157	108	109	110	112	113	113	113	114	115	116	116	117	119	128	133
Fairchild TS	346	268	270	272	274	277	279	281	284	285	285	287	289	290	296	302
Finch TS	365	290	296	301	303	304	305	306	309	311	313	316	317	318	325	331
Leslie TS	325	233	241	249	250	254	255	258	260	261	262	264	265	266	283	293
Malvern TS	176	105	106	108	109	109	109	110	111	111	115	118	120	122	130	134
East 230 kV																
Bermondsey TS	348	160	164	166	169	171	173	173	175	177	177	178	178	178	179	186
Ellesmere TS	189	124	126	128	129	130	131	131	132	133	133	134	134	134	135	138
Leaside TS	202	163	169	174	177	178	179	179	181	182	182	183	183	183	186	194
Scarboro TS	340	222	225	227	229	231	232	233	235	237	237	237	238	238	250	257
Sheppard TS	205	178	182	184	187	187	189	191	193	193	193	197	201	203	216	224
Warden TS	182	123	125	126	127	129	130	131	131	131	135	139	141	144	153	157
West 230 kV																
Horner TS (2)	365	141	145	146	148	193	199	202	204	208	213	221	228	234	268	292
Manby TS (2)	226	245	258	262	269	225	225	225	225	225	225	225	225	225	225	225
Rexdale TS	187	136	138	139	139	141	141	143	143	143	143	141	141	139	131	122
Richview TS	460	279	263	268	270	271	274	275	276	279	276	274	270	269	263	252
Leaside 115 kV																
Basin TS	88	65	71	75	76	77	77	78	79	79	81	83	84	85	91	95
Bridgman TS	212	154	154	156	157	157	160	161	161	162	163	164	165	167	180	186
Carlaw TS	73	66	67	67	67	68	68	69	69	70	70	70	70	72	72	72
Cecil TS	215	166	174	179	181	183	185	186	187	188	186	184	182	181	181	181
Charles TS	211	145	151	154	155	156	158	158	159	159	161	164	166	167	175	176
Dufferin TS	170	136	120	123	124	124	125	126	127	129	133	134	138	141	151	155
Duplex TS	128	99	101	100	98	97	94	94	96	97	98	99	100	102	108	113
Esplanade TS	187	163	143	146	147	147	149	149	150	151	150	148	147	144	148	149
Gerrard TS	102	37	46	49	51	51	52	52	52	54	54	54	54	54	55	56
Glengrove TS	88	51	53	53	54	54	54	54	54	54	55	57	58	59	63	65
Main TS	77	60	61	61	63	64	64	64	65	65	67	67	68	69	70	70
Terauley TS	249	175	188	194	190	188	188	191	191	191	190	187	185	184	181	182
Manby E 115 kV																
Fairbank TS	182	171	151	159	164	169	173	176	177	178	179	181	182	182	188	193
Runnymede TS	219	96	136	141	143	143	146	146	148	148	149	149	151	151	158	164
Wiltshire TS	133	56	74	75	75	75	76	76	76	78	78	79	79	79	86	90
Manby W 115 kV																
Copeland MTS	130	0	0	52	93	93	94	94	96	96	98	99	100	102	107	112
John TS	314	264	267	217	203	204	205	206	208	208	212	214	217	220	230	244
Strachan TS	169	139	143	145	146	147	147	149	149	150	155	159	163	167	182	193

(1) Non-coincident station peak, adjusted to extreme weather

(2) Load transferred to the new Horner TS DESN #2 in 2022

Table D-3: Toronto IRRP Load Forecast, with the Impacts of Energy-Efficiency Savings

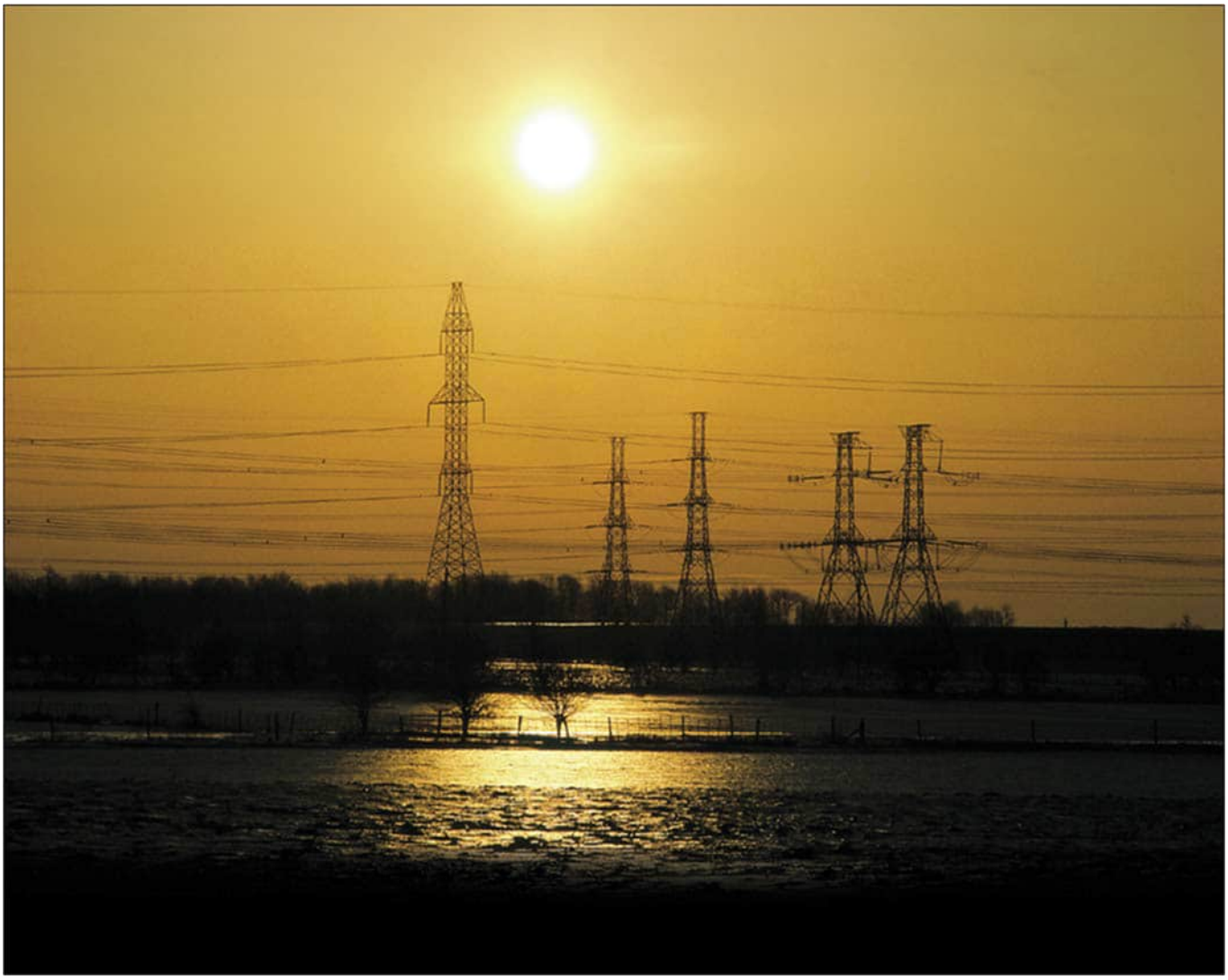
		Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
Area & Station	**LTR (MW)**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2035**	**2040**
North 230 kV																
Agincourt TS	174	91	94	96	98	99	100	100	101	101	102	102	102	103	105	108
Bathurst TS	334	208	217	222	225	226	227	229	229	231	231	233	235	237	252	260
Cavanagh MTS	157	90	91	92	92	93	93	93	93	94	95	95	95	96	103	107
Fairchild TS	346	232	233	234	236	237	238	239	241	241	240	241	242	242	244	249
Finch TS	365	247	251	254	256	256	256	257	258	260	261	263	263	263	267	272
Leslie TS	325	230	237	244	245	248	248	250	251	252	252	253	253	253	266	276
Malvern TS	176	82	83	84	85	84	84	85	86	86	88	90	92	93	99	101
East 230 kV																
Bermondsey TS	348	146	150	151	153	155	156	156	157	159	158	159	158	157	157	162
Ellesmere TS	189	123	124	126	127	127	128	128	128	129	128	129	129	128	128	131
Leaside TS	202	149	154	157	160	160	161	160	162	162	162	162	162	161	161	168
Scarboro TS	340	202	204	206	208	208	208	209	210	212	211	211	211	211	219	225
Sheppard TS	205	140	141	143	145	144	146	146	148	148	147	150	152	153	161	167
Warden TS	182	105	106	107	108	109	109	110	109	109	113	115	117	118	125	129
West 230 kV																
Horner TS	365	132	135	136	138	137	139	139	140	141	144	148	152	154	168	177
Manby TS	226	189	199	202	207	208	210	210	211	212	212	214	215	216	227	238
Rexdale TS	187	121	122	123	122	124	123	125	124	124	123	121	120	118	110	102
Richview TS	460	224	209	213	214	215	216	216	216	218	215	213	209	207	200	192
Leaside 115 kV																
Basin TS	88	64	70	74	75	75	75	76	77	76	78	80	80	81	86	90
Bridgman TS	212	152	151	153	154	153	156	156	156	156	157	157	157	159	169	175
Carlaw TS	73	62	63	63	63	64	63	64	64	65	64	64	64	66	65	65
Cecil TS	215	160	167	172	174	175	176	177	177	178	175	173	170	169	167	167
Charles TS	211	143	149	151	152	152	154	153	154	153	155	157	158	159	165	166
Dufferin TS	170	134	119	122	123	122	123	123	124	126	129	130	133	135	143	147
Duplex TS	128	98	99	98	96	95	91	91	93	94	94	95	95	97	102	106
Esplanade TS	187	160	140	142	143	143	144	144	144	145	144	141	140	136	139	140
Gerrard TS	102	32	41	43	45	45	46	46	46	47	46	46	46	46	46	47
Glengrove TS	88	47	49	49	50	50	50	49	49	49	50	52	52	53	56	58
Main TS	77	55	56	56	57	58	57	57	58	58	60	59	60	61	61	61
Terauley TS	249	173	185	190	186	184	183	185	185	184	183	179	177	175	171	172
Manby E 115 kV																
Fairbank TS	182	139	123	130	132	136	138	140	141	141	142	142	143	142	146	149
Runnymede TS	219	95	134	139	140	140	143	142	144	143	144	144	145	144	150	155
Wiltshire TS	133	54	70	71	71	70	71	71	71	73	72	73	73	73	78	81
Manby W 115 kV																
Copeland MTS	130	0	0	51	91	91	92	91	93	93	94	95	96	97	101	106
John TS	314	256	258	207	193	194	194	194	196	195	198	200	202	204	211	224
Strachan TS	169	137	141	142	143	144	143	145	144	145	149	152	156	159	172	182

Table D-4: Toronto Non-Coincident Load Forecast, with the Impacts of Energy-Efficiency Savings

		Near & Mid-Term Forecast (MW)												Long-Term Forecast (MW)		
Area & Station	**LTR (MW)**	**2018 [1]**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2035**	**2040**
North 230 kV																
Agincourt TS	174	112	115	118	120	121	122	123	124	124	124	125	125	126	128	133
Bathurst TS	334	227	237	243	246	247	249	250	251	252	252	255	257	259	275	285
Cavanagh MTS	157	108	109	110	111	112	111	111	112	113	114	113	114	115	123	128
Fairchild TS	346	268	269	270	272	273	275	276	277	278	277	278	279	279	282	287
Finch TS	365	290	295	299	301	302	302	303	304	306	307	309	309	310	314	320
Leslie TS	325	233	240	247	248	251	251	253	255	255	255	256	256	256	270	279
Malvern TS	176	105	106	107	108	108	108	109	110	110	113	115	117	118	126	130
East 230 kV																
Bermondsey TS	348	160	164	165	168	169	170	170	171	173	172	173	172	172	171	178
Ellesmere TS	189	124	126	127	128	129	129	129	130	130	130	130	130	130	129	132
Leaside TS	202	163	169	173	176	176	176	176	178	178	177	178	177	177	177	185
Scarboro TS	340	222	224	226	228	228	229	229	231	233	232	231	232	231	241	247
Sheppard TS	205	178	180	182	185	184	186	187	189	188	188	191	194	196	206	213
Warden TS	182	123	124	125	126	127	128	129	128	128	132	135	137	139	146	151
West 230 kV																
Horner TS [2]	365	141	145	146	147	189	194	195	196	199	203	209	214	219	247	271
Manby TS [2]	226	245	257	260	267	225	225	225	225	225	225	225	225	225	225	225
Rexdale TS	187	136	137	138	137	139	138	140	140	139	139	136	135	133	123	115
Richview TS	460	279	262	266	268	268	270	270	270	272	269	266	261	259	250	240
Leaside 115 kV																
Basin TS	88	65	71	75	75	76	76	77	77	77	79	81	81	82	87	91
Bridgman TS	212	154	153	155	156	155	158	158	158	158	159	159	159	161	171	177
Carlaw TS	73	66	67	67	67	67	67	68	68	69	68	68	68	70	69	69
Cecil TS	215	166	173	178	180	181	183	183	183	184	182	179	176	175	173	173
Charles TS	211	145	150	153	154	154	155	155	156	155	157	159	160	161	167	168
Dufferin TS	170	136	119	122	123	123	123	124	124	126	129	130	133	136	144	148
Duplex TS	128	99	101	99	97	96	93	92	94	95	95	96	96	98	103	108
Esplanade TS	187	163	143	145	146	146	147	147	147	148	147	144	143	139	142	143
Gerrard TS	102	37	47	50	52	52	53	53	53	54	53	53	53	53	53	54
Glengrove TS	88	51	52	52	53	53	53	53	53	52	53	55	56	57	60	62
Main TS	77	60	61	61	62	63	63	62	63	63	65	65	66	66	67	67
Terauley TS	249	175	187	193	188	186	185	188	187	187	185	181	179	177	173	174
Manby E 115 kV																
Fairbank TS	182	171	150	158	162	167	171	173	173	174	175	176	176	175	179	184
Runnymede TS	219	96	63	115	157	156	158	157	160	159	161	161	162	164	170	178
Wiltshire TS	133	56	74	75	74	74	75	75	75	76	76	77	77	77	83	86
Manby W 115 kV																
Copeland MTS	130	0	0	51	91	91	92	91	93	93	94	95	96	97	101	106
John TS	314	264	265	215	200	200	201	201	202	202	205	207	209	211	219	232
Strachan TS	169	139	143	144	145	146	145	147	146	147	151	155	158	161	174	184

(1) Non-coincident station peak, adjusted to extreme weather

(2) Load transferred to the new Horner TS DESN #2 in 2022



GTA North

REGIONAL INFRASTRUCTURE PLAN

October 22, 2020

hydro one

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Prepared by:

Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Alectra Utilities Corporation
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Newmarket-Tay Power Distribution Ltd.
Toronto Hydro-Electric System Limited

DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address near and mid-term needs identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Study Team.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Study Team.

Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE RIP STUDY TEAM IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GTA NORTH REGION.

The participants of the Regional Infrastructure Plan ("RIP") Study Team included members from the following organizations:

- Alectra Utilities
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Newmarket-Tay Power Distribution Ltd.
- Toronto Hydro-Electric System Limited
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the second cycle of GTA North regional planning process, which follows the completion of the GTA North Integrated Regional Resource Plan ("IRRP") in February 2020 and the GTA North Region Needs Assessment ("NA") in March 2018. This RIP provides a consolidated summary of the needs and recommended plans for GTA North Region over the planning horizon (1 – 10 years) based on available information.

This RIP discusses needs identified in the previous regional planning cycle, the Needs Assessment and IRRP reports for this cycle, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, the following projects have been completed:

- Vaughan #4 MTS (completed in 2017)
- Holland breakers, disconnect switches and special protection scheme (completed in 2017)
- Parkway belt switches at Grainger Jct. (completed in 2018)

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in the Table 1 below, along with their planned in-service date and budgetary estimates for planning purposes.

Table 1. Recommended Plans in GTA North Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate
1	Markham Area: Step-down Transformation Capacity	Build new Markham #5 MTS	2025	$30M
2	Increase Capability of 230kV Circuits P45+P46 (these supply Buttonville TS, Markham #4 MTS, and future Markham #5 MTS)	Reconductor circuits P45/46 from Parkway to Markham #4 MTS, and connect Markham #5 MTS – 2025	2025	$2-3M
3	High voltages on 230kV circuits M80B/M81B	No action required	---	---
4	Northern York Area: Step-down Transformation Capacity	Build new Northern York Station	2027	$35-40M
5	Woodbridge TS: End-of-life of transformer T5	Replace the end-of-life transformer with similar type and size equipment as per current standard	2027	$13
6	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan #5 MTS	2030	$30M

Note: LDC distribution network costs are not included in the above Table.

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 1 while keeping the Study Team apprised of project status;
- All the other long term needs/options identified in Section 6.4 will be further reviewed by the Study Team in the next regional planning cycle.

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1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE GTA NORTH REGION BETWEEN 2020 AND 2030.

The report was prepared by Hydro One Networks Inc. ("Hydro One") and documents the results of the study with input and consultation with Alectra, Hydro One Distribution, the Independent Electricity System Operator ("IESO"), Newmarket-Tay Power Distribution Ltd. ("NTPDL") and Toronto Hydro-Electric System Limited ("THESL") in accordance with the Regional Planning process established by the Ontario Energy Board ("OEB") in 2013.

The GTA North Region includes most of the Regional Municipality of York and parts of the City of Toronto, Brampton, and Mississauga (see Figure 1-1). Electrical supply to the Region is provided through 230 kV transmission circuits, sixteen step-down transformer stations ("TS"), and the York Energy Centre ("YEC") generating station ("GS").

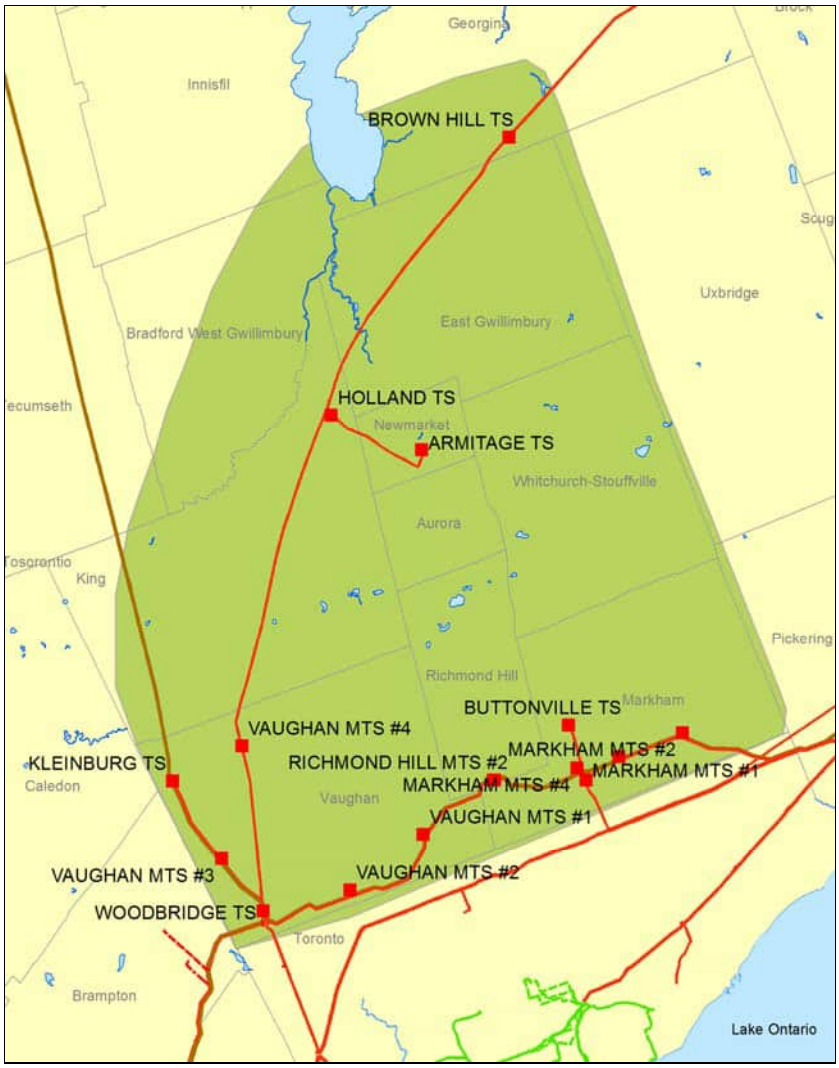


Figure 1-1: GTA North Region Map

1.1 Objectives and Scope

This RIP report examines the needs in the GTA North Region. Its objectives are to:

- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan);
- Assess and develop a wires plan to address these needs, as appropriate;
- Provide the status of wires planning projects currently underway or completed for specific needs; identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviews factors such as the load forecast, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable

and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of all the needs and relevant plans to address near, mid and long-term needs as identified in previous planning phases (Needs Assessment and Integrated Regional Resource Plan).
- Identification of any new needs over the planning horizon and a plan to address them, as appropriate.
- Consideration of long-term needs identified in the York Region IRRP.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the adequacy of the transmission facilities in the region over the study period.
- Section 7 discusses the needs and provides the alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2 REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

[1] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by Hydro One and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in Hydro One's rate filing submissions and as part of LDC rate applications with a planning status letter provided by Hydro One.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region;
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

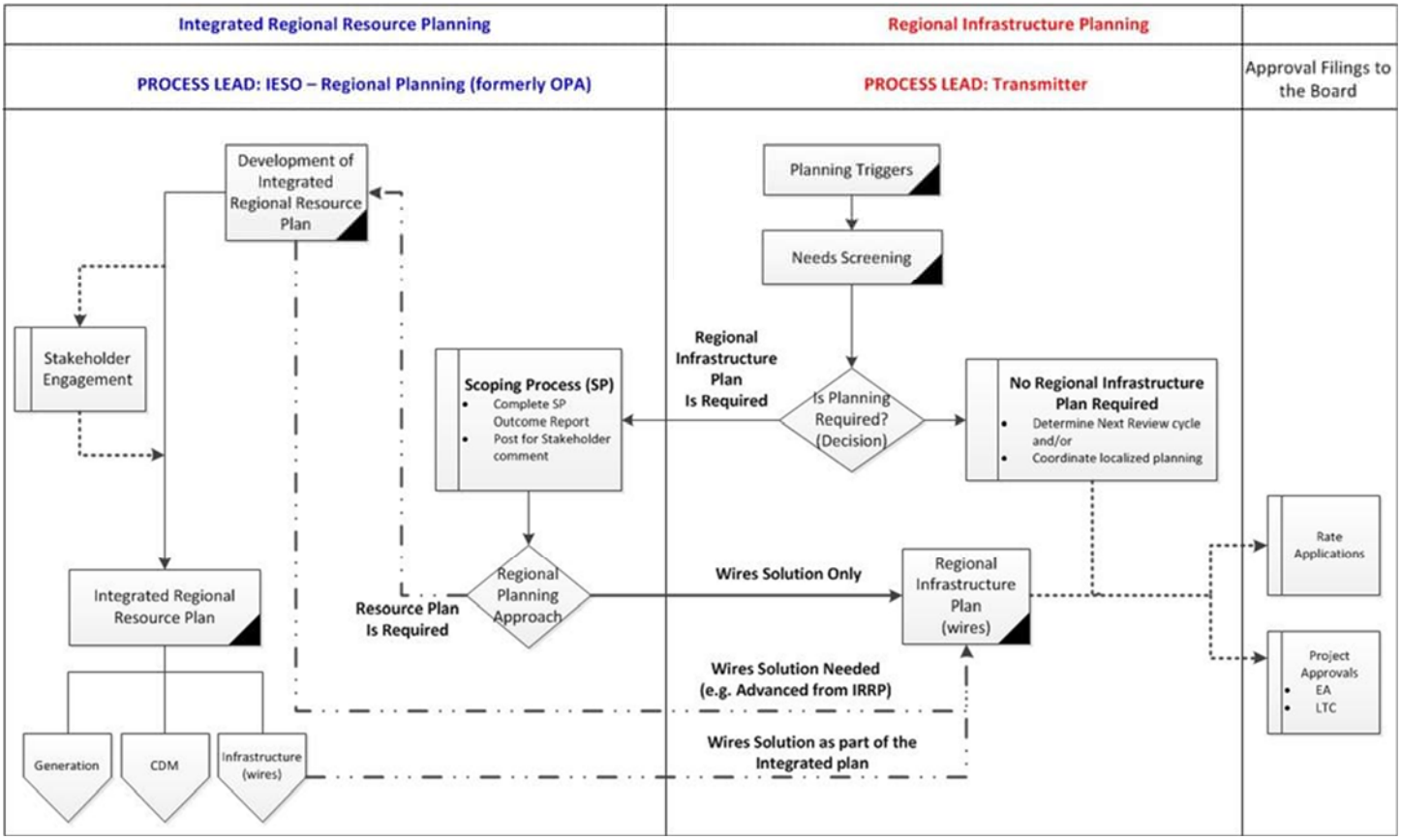


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:

   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.

2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other

relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.

3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

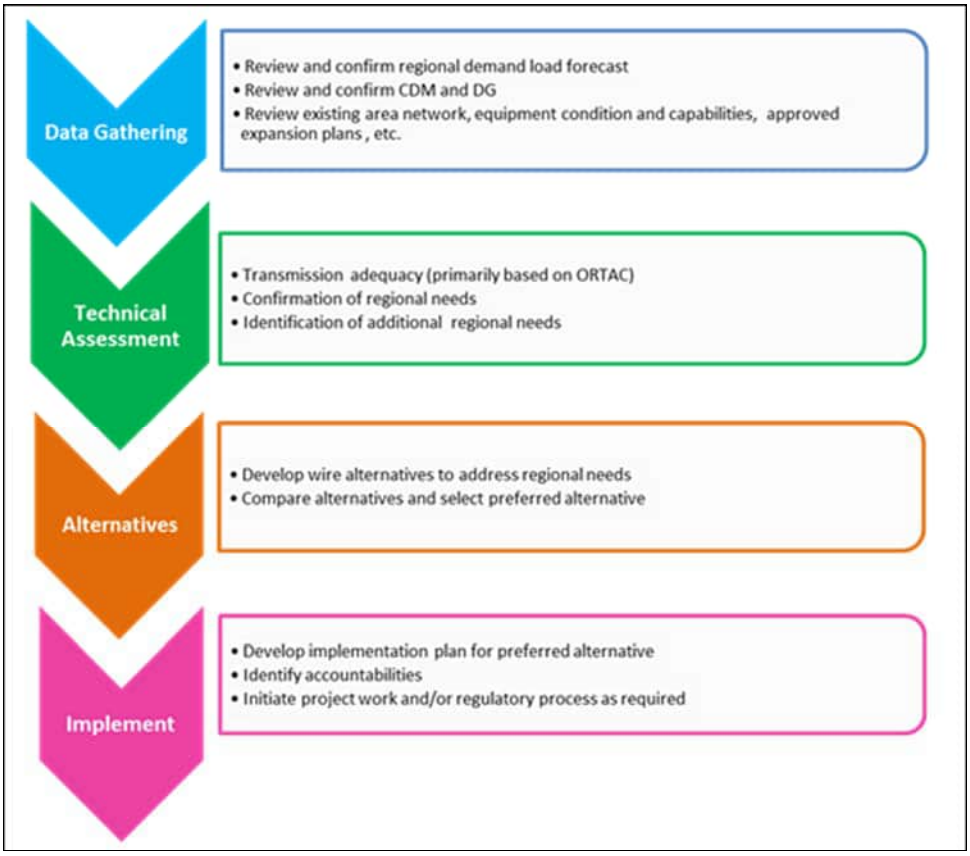


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE GTA NORTH REGION IS COMPRISED OF THE NORTHERN YORK AREA, SOUTHERN YORK AREA AND THE WESTERN AREA. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM SIXTEEN 230 KV STEP-DOWN TRANSFORMER STATIONS. THE 2019 SUMMER PEAK AREA LOAD OF THE REGION WAS APPROXIMATELY 2000 MW.

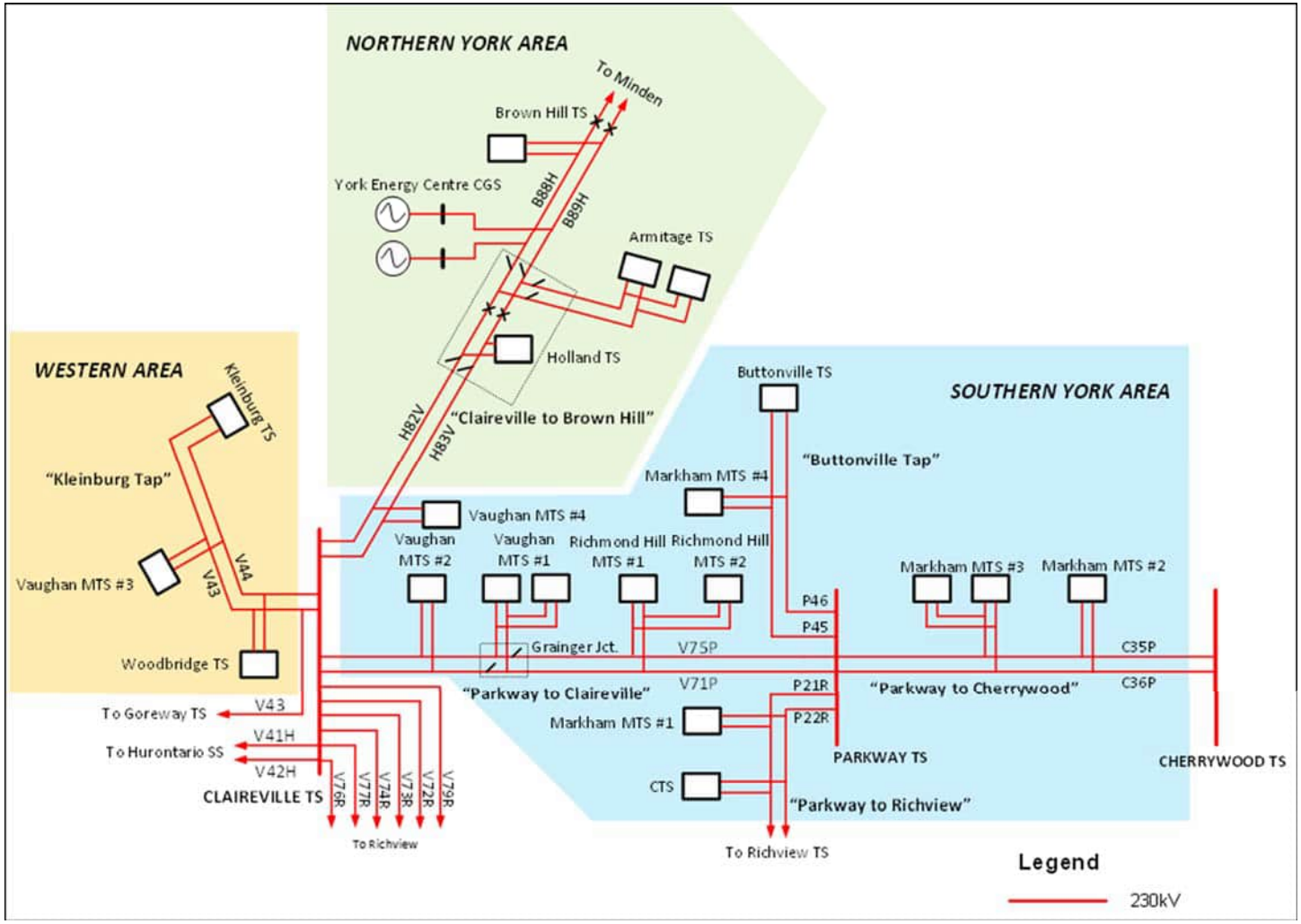
Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B88H/B89H in King Township. Refer to Appendix A, Appendix B and Appendix C for further details.

The Northern York Area encompasses the municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, as well as some load in Simcoe County that is supplied from the same electricity infrastructure. It is supplied by Claireville TS, a 500/230 kV autotransformer station, and four 230 kV transformer stations stepping down the voltage to 44 kV. The York Energy Centre provides a local supply source in Northern York Area. The LDCs supplied in the Northern York Area are Hydro One Distribution, Newmarket-Tay Power Distribution, and Alectra.

The Southern York Area includes the municipalities of Vaughan, Markham and Richmond Hill. It is supplied by three 500/230 kV autotransformer stations (Claireville TS, Parkway TS, and Cherrywood TS), nine 230 kV transformer stations (includes seven municipal transformer stations) stepping down the voltage to 27.6 kV, and one other direct transmission connected load customer. The LDC supplied in the Southern York Area is Alectra. Please refer to Figure 3-1.

The Western Area comprises the Western portion of the municipality of Vaughan. Electrical supply to the area is provided through Claireville TS, a 500/230 kV autotransformer station, and a 230 kV tap (namely, the “Kleinburg tap”) that supplies three 230 kV transformer stations (including one municipal transformer station) stepping down the voltage to 44 kV and 27.6 kV. The LDCs directly supplied are Alectra and Hydro One Distribution. Embedded LDCs include Alectra and Toronto Hydro. Please refer to Figure 3-1

Figure 3-1: Single Line Diagram of GTA North Region's Transmission Network



4 TRANSMISSION FACILITIES/PROJECTS COMPLETED AND/OR UNDERWAY OVER THE LAST TEN YEARS

OVER THE LAST TEN YEARS, A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND UNDERTAKEN BY HYDRO ONE AIMED TO MAINTAIN THE RELIABILITY AND ADEQUACY OF ELECTRICITY SUPPLY TO THE GTA NORTH REGION.

A summary and description of the major projects completed and/or currently underway over the last ten years is provided below.

- Connect the York Energy Centre generation facility (2012) – to provide a local source of supply for the Northern York Area.
- Vaughan MTS #4 (2017) – to increase transformation capacity for the Southern York Area.
- Holland breakers, disconnect switches and special protection scheme (2017) – to increase the transmission supply capacity and load restoration capability of the Northern York area.
- Inline switches on the Parkway belt (V71P/V75P) at Grainger Jct. (2018)

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The load in the GTA North Region is forecast to increase at an average rate of about 2% annually from 2020 to 2030, with average rate of about 2.5% between 2020 and 2025 and about 1.50% between 2025 and 2030.

Figure 5-1 shows the GTA North Region extreme summer weather coincident peak net load forecast ("load forecast"). The load forecast for the individual stations in the GTA North Region is given in Appendix D. The net load forecast takes into account the expected impacts of conservation programs and distributed generation resources.

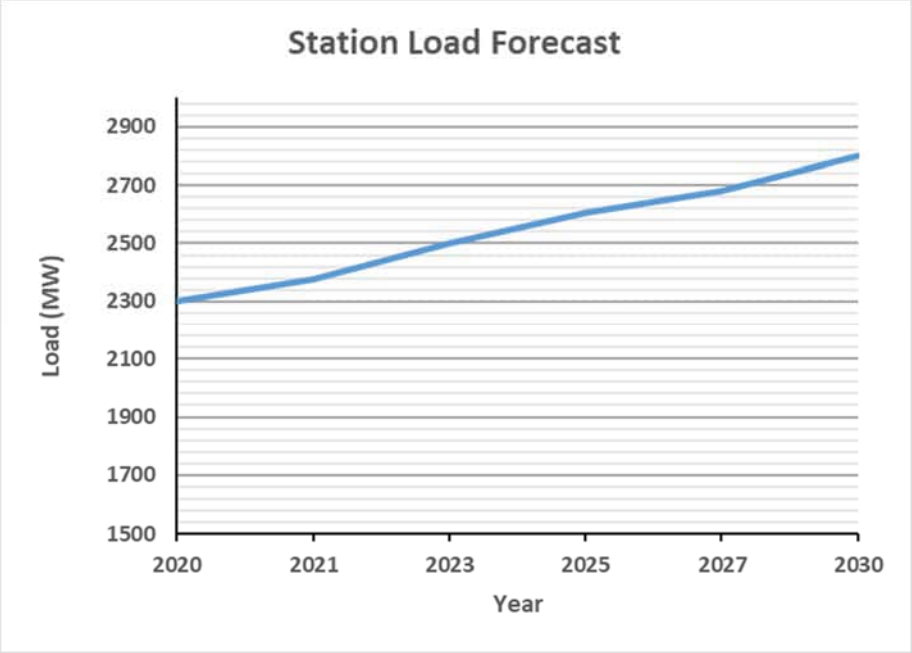


Figure 5-1: GTA North Region Load Forecast

The station coincident peak net loads used in the RIP are consistent with the York Region IRRP. However, as a result of the COVID-19 pandemic, this forecast may require review and updates as the long term impacts on customer demand become better known. The Study Team will be monitoring actual loading in York areas over the coming years and will recommend if updates to need dates or a revised forecast is required. However, based on the available information any change is not expected to materially impact any of the needs identified, but the dates to implement solutions may be affected.

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for this RIP is established from 2020-2030.

- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations, which is consistent with Ontario Resource Transmission Assessment Criteria (ORTAC). Normal planning supply capacity for transformer stations is determined by the summer 10-day Limited Time Rating (LTR).
- Line capacity adequacy is assessed by using peak loads in the area.

6 ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND TRANSFORMER STATION FACILITIES SUPPLYING THE GTA NORTH REGION OVER THE PLANNING PERIOD (2020-2030).

Within the current regional planning cycle two regional assessments have been conducted for the GTA North Region. The findings of these studies are input to this Regional Infrastructure Plan. The studies are:

- 2018 GTA North Region Needs Assessment Report ("NA")
- 2018 York Region Scoping Assessment Outcome Report ("SA")
- 2020 York Region Integrated Regional Resource Plan and Appendices ("IRRP")

This section provides a review of the adequacy of the transmission lines and stations in the GTA North Region. The adequacy is assessed using the latest regional load forecast provided in Appendix D.

This RIP reviewed the loading on transmission lines and stations in the GTA North Region based on the forecast in Appendix D.

6.1 Adequacy of Northern and Southern York Area Facilities

6.1.1 500 and 230 kV Transmission Facilities

All 500 and 230 kV transmission circuits in the GTA North are classified as part of the Bulk Electricity System ("BES"). The 230 kV circuits also serve local area stations within the region. The Northern and Southern York Areas are comprised of the following 230 kV circuits. Refer to Figure 3-1.

Southern York Area:

a) Parkway TS to Cherrywood TS 230 kV circuits: C35P and C36P.
b) Parkway TS to Claireville TS 230 kV circuits: V71P and V75P.
c) Parkway TS to Buttonville TS **(**"Buttonville Tap") 230 kV circuits: P45 and P46.
d) Parkway TS to Richview TS 230 kV circuits: P21R and P22R.

Northern York Area:

- Claireville TS to Holland TS 230 kV circuits: H82V and H83V.
- Holland TS to Brown Hill TS 230 kV circuits: B88H and B89H.

The RIP review shows that based on current forecast station loadings and bulk transfers, circuits P45 and P46 need to be uprated due to the future connection of Markham MTS #5. The other 230 kV circuits are expected to be adequate over the study period.

6.1.2 Step down Transformer Station Facilities

There are a total of thirteen step-down transformers stations in the Northern and Southern York Areas as follows in Table 6-1 Step-Down Transformer Stations below:

Table 6-1 Step-Down Transformer Stations

Northern York Area		
Armitage TS	Brown Hill TS	Holland TS
Southern York Area		
Buttonville TS	Markham MTS #1*	Markham MTS #2*
Markham MTS #3*	Markham MTS #4*	Richmond Hill MTS #1, #2*
Vaughan MTS #1*	Vaughan MTS #2*	Vaughan MTS #4*
Industrial Customer		

*Stations owned by Alectra

Based on the LTR of these load stations, additional capacity was required in Vaughan and was addressed by Vaughan MTS #4. Based on the forecast in Appendix D, additional capacity is required in Markham as early as 2025, and additional capacity will be needed in Northern York Area and Vaughan as early as 2027 and 2030, respectively. The station loading in each area and the associated station capacity and need dates are summarized in Table 6-2**.**

Table 6-2 Adequacy of the Step-Down Transformation Facilities

Area/Supply	LTR-Capacity (MW)	2020 Summer Forecast (MW)	Need Date
Markham / Richmond Hill transformation Capacity	957	877	2025
Northern York Area (Armitage TS, Holland TS)	485	444	2027
Vaughan Transformation Capacity (Vaughan MTS #1, 2, 4)	612	461	2030
Northern York Area (Brown Hill)	184	94	-

6.2 Adequacy of Western Area Facilities

6.2.1 230 kV Transmission Facilities

The Western Area is comprised of one 230 kV double circuit line V43/V44 between Claireville TS and Kleinburg TS. Refer to Figure 3-1. The line supplies Kleinburg TS, Vaughan MTS #3, and Woodbridge TS. Loading on the V43/V44 line is adequate over the study period.

6.2.2 Step down Transformation Facilities

There are three step-down transmission connected transformation stations in the Western Area as follows:

Table 6-3 Step-Down Transformation Facilities in the Western Area

Kleinburg TS
Woodbridge TS
Vaughan MTS#3*

*Station owned by Alectra

The load forecast in Table 6-4 shows that there is adequate transformation capacity available at these three transformer stations to meet GTA North demand over the study period. Note that these facilities also serve load in the neighbouring GTA West Region. An IRRP is currently underway to determine long term infrastructure needs to serve GTA West, which may affect this region.

Table 6-4 Adequacy of Step-Down Transformation Facilities in the Western Area

	LTR-Capacity (MW)	2020 Summer Forecast (MW)	Need Date
Western Area	509	425	Beyond 2030

6.3 Other Needs Identified During Regional Planning

6.3.1 Load Restoration in the Western Area

There is a load restoration need for the loss of the Claireville TS to Kleinburg TS 230 kV double circuit line V43/V44. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The needs and the Study Team recommendations to address the needs are discussed in more detail in Section 7.4.1.

6.3.2 Load Restoration in the Northern York Area

There is a load restoration need for the loss of the Claireville to Holland double circuit line, H82V/H83V. Loads in excess of 250 MW cannot be restored in less than 30 minutes as per the ORTAC restoration criteria. The needs and the Study Team recommendations to address the needs are discussed in more detail in Section 7.4.2.

6.3.3 Load Security and Restoration in the Southern York Area

There is a load security need for loss of the Claireville TS to Parkway TS 230 kV double circuit line V71P/V75P. Loading on this line exceeds the 600 MW limit as per ORTAC security criteria. The Study Team recommendations to address the needs are discussed in more detail in Section 7.5.

6.3.4 High Voltages on Circuits M80B/ M81B

Post-contingency voltages on M80B/M81B may exceed 250 kV during future high load conditions. High voltages at Beaverton and Lindsay may occur following contingencies that leave these stations radially connected to Minden TS. The Study Team recommendations to address the needs are discussed in more detail in Section 7.3.2.

6.3.5 End of Life of Woodbridge TS- Transformer-T5

Transformer T5 is currently about 47 years old and is approaching End of Life (EOL). This need is further discussed in Section 7.1.

6.4 Longer Term Regional Needs (2030-2040)

The IRRP considers longer-term needs and alternatives that are expected to occur between 2030 and 2040, which are outside the study period of the RIP. Table 6-5 summarizes the long term need for the Claireville to Minden circuits.

Table 6-5: Longer Term Adequacy of Transmission Facilities

Facilities	Area MW Load (1)			MW Load Meeting Capability (Approximate)	Need Date
	2025	2030	2035		
230 kV Claireville to Minden Circuits	727	765	943	850(2)	Beyond 2030

(1) The sum of station's (Vaughan#4 MTS, Holland TS, Armitage TS, Brown Hills TS, Northern York TS, Vaughan#5 MTS excluding Beaverton TS and Lindsay TS) summer peak load adjusted for extreme weather.
(2) 2020 York Region IRRP. Actual capability is dependent on distribution of loads across stations and other system assumptions.

7 REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE GTA NORTH REGION AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

The electrical infrastructure near and mid-term needs in the GTA North Region are summarized below in Table 7-1 and Table 7-2.

Table 7-1: Identified Near and Mid-Term Needs in the GTA North Region

Section	Facilities	Need	Details	Expected Timing
7.1	Woodbridge TS	End of Life (T5)	Transformer T5 is currently about 47 years old and is approaching End of Life (EOL)	2027
7.2.1	Markham# 5 MTS	Step Down Transformation Capacity	Loading at Markham & Richmond Hill area stations exceeded.	2025
7.2.2	Northern York TS		Loading at Armitage TS and Holland TS exceeded.t.	2027
7.2.3	Vaughan#5 MTS		Loading at Vaughan area stations exceeded.	2030
7.3.1	P45/P46 (Parkway TS to Markham #4 Jct.)	Supply Capability	Thermal limits are exceeded on a 1.1km section of the circuits between Parkway MTS and Markham #4 MTS due to the future connection of Markham MTS # 5.	2029
7.3.2	Claireville TS to Minden TS Corridor	Voltage Rise	Voltage rise on stations along M80B/M81B following loss of B88H/B89H	2025
7.4.1	Kleinburg radial pocket (V43/44)	Load Restoration	Restoration of loads supplied by V43/V44 does not meet the 30 minute load restoration criteria	Existing
7.4.2	H82V/H83V – Holland, Vaughan #4 and #5		Restoration of loads supplied by H82V/H83V does not meet the 30 minute load restoration requirement	Existing
7.5	Parkway TS to Claireville TS Circuits V71P/V75P	Load Security	Load security needs have previously been identified for the V71/75P Parkway corridor.	Existing

Table 7-2: Identified Long-Term Needs in GTA North Region

Section	Facilities	Need	Details	Timing
7.3.3	Claireville TS x Minden TS Corridor	Supply Capability	Thermal ratings & Voltage drop limits exceeded	Beyond 2030

7.1 Woodbridge TS: T5 End-of-Life Transformers

7.1.1 Description

Woodbridge TS comprises one DESN unit, T3/T5 (75/125 MVA), with two secondary winding voltages at 44 kV and 27.6 kV, each with a summer 10-Day LTR of 80 MW, supplying both Alectra and THESL. The station's 2019 actual peak load was 149 MW. Transformer T5 is currently about 47 years old and has been identified to be at its EOL.

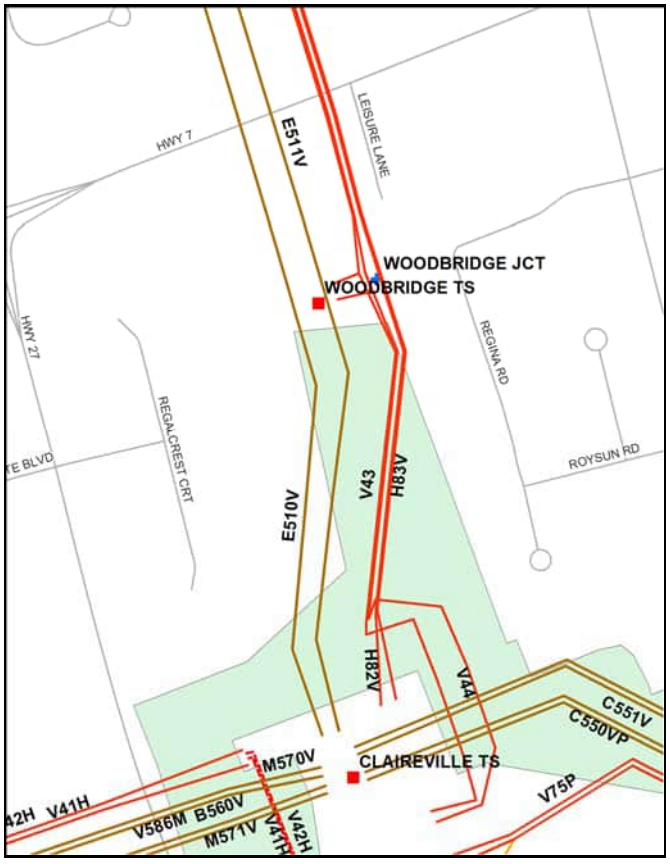


Figure 7-1: Woodbridge TS

7.1.2 Alternatives and Recommendation

The following alternatives were considered to address the Woodbridge T5 end-of-life need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.
2. **Alternative 2 - Replace with similar type and size equipment as per current standard:** Under this alternative the existing transformer T5 at Woodbridge TS is replaced with a new 75/125 MVA 230/44-27.6 kV transformer. This alternative would address the need and would maintain reliable supply to the customers in the area.
3. **Alternative 3 – Re-configure Woodbridge TS as two separate 44 kV and 27.6 kV DESNs:** Hydro One has not considered this option further since there is currently no need for the additional transformation capacity, and there are limitations on the high voltage supply circuits. The cost of rebuilding the station would also be high.

The Study Team recommends that Hydro One proceed with Alternative 2 and coordinate the replacement plan with affected LDCs. The expected completion date for this work is 2027.

7.2 Station Supply Capacity Needs and Plans

Needs assessment and IRRP have identified three new station capacity needs in the medium term, one in the Markham –Richmond Hill region, designated as Markham MTS#5, the second in the Vaughan Area, designated as Vaughan MTS#5 and third in the Northern York Area, location and designation to be determined. The timelines associated with these needs require all the stakeholders to monitor station loadings and ascertain pace of the growth including energy efficiency (EE) and other Distributed Energy Resource (DER) impacts. Below are the options for the above needs to finalize the suitable location and explore the long-term options.

7.2.1 Markham MTS #5 Transformer Station

In April 2017, the IESO issued a letter of support to Hydro One Transmission and Alectra to proceed with wires planning for a new 230/27.6kV DESN and the associated distribution and/or transmission lines to connect the new transformer station in the north Markham area. Based on the current load forecast, the additional transformation capacity is required by the year 2025.

7.2.1.1 Alternatives and Recommendation

Three alternative locations for connecting the new Markham MTS #5 have been considered by the Study Team and shown in Figure 7-2.

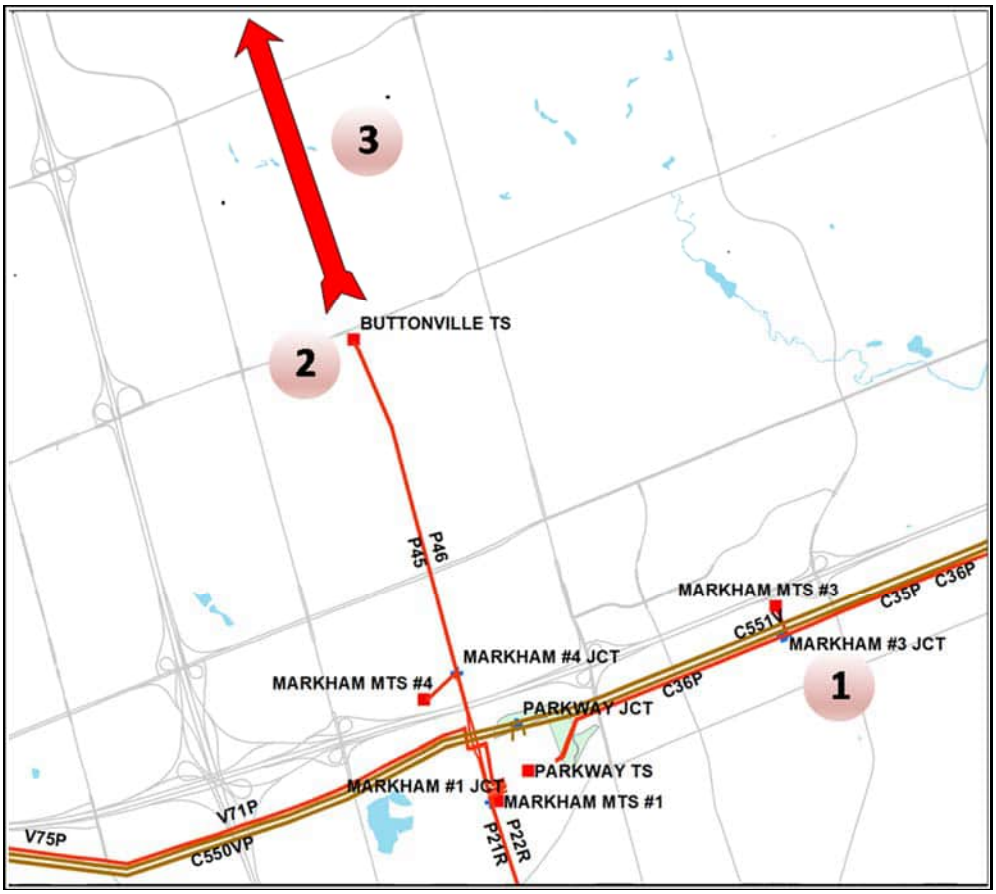


Figure 7-2: Location options for Markham #5 MTS

1- **Alternative 1- Building the new station along the Parkway belt and connecting to the C35P/ C36P circuits:** The C35P/C36P transmission circuits are capable of supplying the full capacity of the station, but the alternative has been ruled out because the physical location of the station would be too far from the area of anticipated growth resulting in high distribution costs. There is also a risk that the capacity of this station will become stranded if it becomes technically infeasible to supply load concentrated along Markham's northern border

2- **Alternative 2- Building the station at the existing Buttonville TS and connecting to the P45/P46 circuits:** This alternative is closer to the area of anticipated load growth than alternative 1, and lesser distribution infrastructure is required as compared to Alternative 1. A 1.1 km section between Parkway TS and the Markham MTS#4 Jct would need to be uprated.

3- **Alternative 3 - Building the station in north Markham and extending circuits P45/P46 from Buttonville TS to connect the new station:** This location is nearest to the area of anticipated load growth. However, this option requires rebuilding approximately 6 km of a single circuit 115 kV transmission line as a 230 kV double circuit transmission line. Most of the 6 km corridor is adjacent to residential areas and the previous plan to upgrade this infrastructure resulted in community opposition. It is likely that some portion of the transmission line would need to be undergrounded. A new station property would also need to be acquired.

Alternative 1 was not considered further due to the high distribution costs. Of the remaining two alternatives, the Study Team recommends Alternative 2 - building the new station at Buttonville TS. While the distribution costs are higher under this option, the higher costs of extending the transmission line north from Buttonville for Alternative 3, made these two alternatives comparable for the overhead option only. Alternative 2 was selected as the preferred option in response to community preferences.

Alectra will be building the station and Hydro One will be building the line tap connection from the P45/P46. The current planned in-service date for the new station is 2025.

7.2.2 Northern York Area Transformer Station

Additional step down transformation capacity is needed for the areas supplied by Armitage TS and Holland TS. There is transfer capability between these stations, so their combined LTR of 485 MW is used to determine the need. Based on the load forecast, it is expected that additional step down transformation capacity will be needed by 2027. Refer to Table 7-3 below.

Table 7-3: Northern York Area Peak Loading

Final Peak Demand Forecast, extreme weather by Station (MW)							
Station	**LTR (MW)**	**2020**	**2021**	**2023**	**2025**	**2027**	**2030**
Armitage	317	302	307	312	312	312	312
Holland	168	142	145	154	166	168	168
Northern York Area	153	0	0	0	0	12	32
Grand Total		**444**	**452**	**466**	**478**	**492**	**512**

7.2.2.1 Alternatives and Recommendation

It is anticipated that the new station will be supplied by circuits B88H/B89H which are in the vicinity of the forecasted load growth. Further discussions between Hydro One and the LDCs are recommended to determine the final location and connection point in order to meet an in-service date of 2027.

7.2.3 Vaughan Area Transformer Station

The Vaughan area station load in the Southern York Area is expected to increase from 461 MW in 2020 to 614 MW by 2030 exceeding the combined area stations capacity of 612 MW. Additional transformation capacity will therefore be needed in Vaughan by 2030. Alectra has sufficient space at Vaughan #4 MTS to accommodate another station there. However, there isn't sufficient transmission capacity available on the Claireville to Minden corridor to fully supply a second new transformation station, given that a new station in Northern York is anticipated by 2027. Therefore a plan to increase transmission supply capability to the

area will be required before a plan for the new transformation station in Vaughan can be committed. This is discussed further in Section 7.3.3.

7.2.3.1 Alternatives and Recommendation

The location chosen for and the land allocated to Vaughan MTS#4 is well suited to cater the load growth and provides enough land to build another step-down station. Building a new station at the same site would have an incremental cost of approximately $30 million.

7.3 System Capacity Needs and Plans

The Study Team has identified the following system capacity needs

7.3.1 Transmission Line uprate- P45/P46

The connection of the new Markham MTS#5 to the Parkway TS x Buttonville TS circuit P45/P46 circuits (see Figure 7-3 below) will increase the loading on these circuits. The forecast loading along with the long term emergency circuit rating is given in Table 7-4.

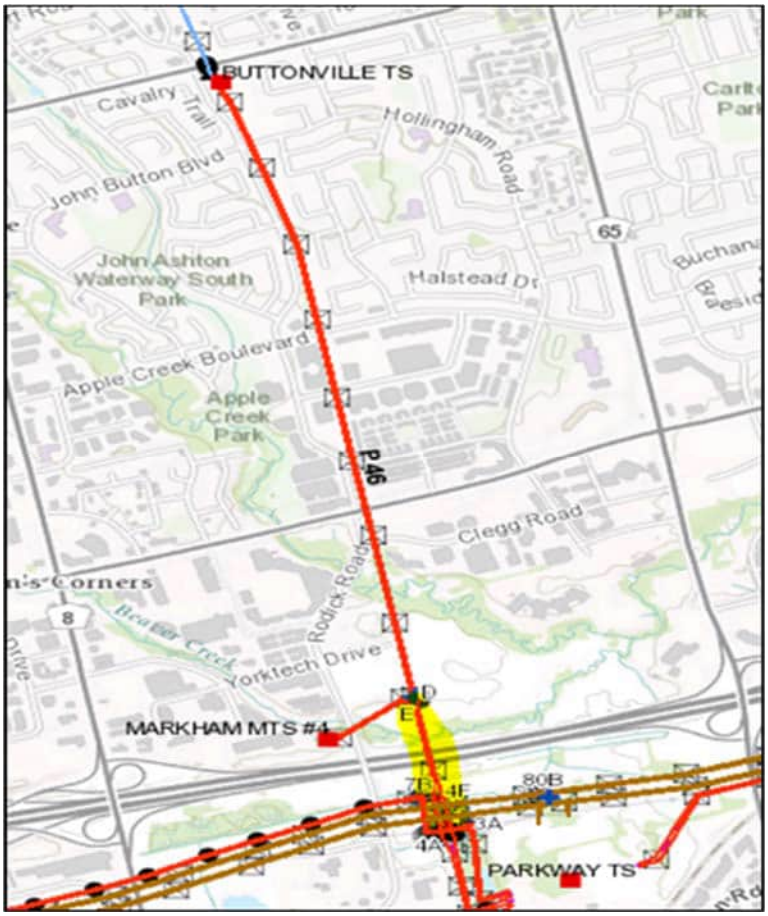


Figure 7-3: Buttonville Tap P45/P46 Limiting Section

The transmission capacity is thermally limited by an approximately 1.1 km long section between Parkway TS and Markham #4 Jct. Loading is expected to exceed the rating by 2029. This section will need to be uprated by 2029 to fully supply Markham MTS#5.

Table 7-4: Loading on Buttonville Tap Circuits

Final Peak Demand Forecast, extreme weather by Station (MW)							
	Circuit Rating (MW)	**2020**	**2021**	**2023**	**2025**	**2027**	**2030**
Buttonville TS		148	148	147	156	156	154
Markham MTS #4		99	128	153	153	153	153
Markham MTS #5		0	0	0	26	77	153
Grand Total	**420**	**247**	**276**	**300**	**335**	**386**	**460**

7.3.1.1 Alternatives and Recommendation

Two alternatives were considered to provide adequate capacity on the P45/P46 circuits.

1- **Alternative 1 - Increase thermal capability of existing line.** It is expected that the thermally limiting section of this line can be increased by changing the conductor to be capable of supplying the forecasted load on these circuits. A high level estimate for this work is $2-3 million.
2- **Alternative 2 – Reduce loading on the P45/P46 circuits by transferring Markham MTS#4 to the Cherrywood TS x Parkway TS C35P/C36P circuits:** This alternative frees up capacity on the P45/P46 circuits to supply MTS#5. It requires building a new 1.5 km long 230kV double circuit line from Markham MTS#4 Jct to the C35P/C36P. This alternative was ruled out due to higher cost and greater disruption to the local community.

The Study Team recommends Alternative 1 as the technically preferred and most cost-effective alternative to increase the supply capability on P45/P46. It is also prudent to consider uprating these circuits before 2029 to reduce the amount of load at risk during construction outages. Completing this upgrade in time for the Markham MTS#5 in service date will also allow for the LDC to make full use of this facility's capacity to manage distribution operations including restoration, optimizing feeder loading, and accommodating maintenance.

7.3.2 High Voltages on M80B/M81B

Post-contingency voltages on M80B/M81B may exceed 250 kV during future high load conditions. High voltages at Beaverton and Lindsay may occur following contingencies that leave these stations radially

connected to Minden TS. These high voltages are observed when low voltage capacitor banks at Beaverton and Lindsay are dispatched under heavy load. In the long term, it is expected that infrastructure solutions required to meet anticipated post 2030 capacity needs will also address this need, though advancing this type of solution to address voltage needs is not recommended due to much lower cost and lower impact alternatives. The IRRP recommends identifying and implementing the solution not later than 2025 to mitigate the voltage rise issue.

7.3.2.1 Alternatives and Recommendations

Two alternatives were considered for the mitigation of the high voltages:

1- **Alternative 1 – Switch LV caps manually at Beaverton and Lindsay:** The high voltage equipment is capable of withstanding voltages up to 5% above nominal voltage (i.e. 262.5 kV) for up to 30 minutes. This capability provides sufficient time for operators to manually adjust the system. Under this alternative the operator will remotely switch out capacitor banks at Beaverton and Lindsay to mitigate high voltages when required.
2- **Alternative 2 - Expanding the York Region Special Protection Scheme (SPS):** The problem of overvoltage can be mitigated by modifying the York Region SPS to automatically remove capacitor banks at Lindsey TS and/or Beaverton TS under high load conditions following specific contingencies.

The Study Team agreed that Alternative 1 will meet the need as the system can withstand the expected voltages and manual action is adequate.

7.3.3 Long Term Need - Supply Capability of the Clairvelle TS to Minden TS Corridor

The Claireville-Minden corridor is comprised of three sections which are defined by inline breakers at Holland TS and Brown Hill TS:

- Section 1 - Claireville TS x Holland TS - H82V/H83V, supplying Holland TS and Vaughan MTS #4.
- Section 2 - Holland TS x Brown Hill TS - B88H/B89H, supplying Armitage TS and Brown Hill TS and connects the York Energy Centre generation. The station service supply to York Energy Centre is normally supplied by a distribution feeder from Holland TS.
- Section 3 - Brown Hill TS x Minden TS - M80B/M81B, supplying Beaverton TS and Lindsay TS. These two stations are not part of the GTA North Region.

The York Region SPS increases the load supply capability of the Claireville –Minden Circuits. The SPS enables controlled load rejection at Vaughan#4 MTS, Holland TS, Armitage TS, Brown Hill TS following certain contingencies. The scheme can also reject generation at YEC, as required. The York Region SPS ensures that the transmission system does not get overloaded following certain contingences, consistent with ORTAC.

In the long term, the supply capability of the corridor is limited by both thermal and voltage capability of the transmission system. These needs arise after 2030 and consistent with the IRRP, the wires needs and alternatives identified are summarized below.

Thermal Limitations

The southern (Claireville TS x Brown Hill TS) section of the corridor supplies Vaughan MTS#4, Holland TS, Armitage TS and Brown Hill TS. Future proposed stations - Northern York area and Vaughan MTS#5 – will also be connected to this corridor. The forecast loading on the corridor is given in Table 7-5. Loading on the corridor will exceed its thermal limits of approximately 850 MW by about 2035.

Table 7-5: Loading on Claireville TS to Minden TS Circuits

Final Peak Demand Forecast, extreme weather by Station (MW)								
Station	**Loading Limit (MW)**	**2020**	**2021**	**2023**	**2025**	**2027**	**2030**	**2035**
Armitage TS		302	307	312	312	312	312	312
Brown Hill TS		94	95	95	96	97	98	100
Holland TS		142	145	154	166	168	168	168
Northern York Area TS		0	0	0	0	12	32	62
Vaughan MTS #4		54	63	108	153	153	153	153
Vaughan MTS#5		0	0	0	0	0	2	147
Grand Total	**850**	**592**	**610**	**670**	**727**	**743**	**765**	**942**

Voltage Limitations

Post-contingency voltage drop will exceed ORTAC limits on the Claireville to Minden corridor after 2030. The limiting contingency is H82V/H83V which drops Holland TS, Vaughan #4 MTS and the future Vaughan #5 MTS by configuration. In addition, up to 150 MW of load rejection is permitted by ORTAC. YEC station service is normally supplied from Holland TS, so the generation is lost coincident with the contingency.

7.3.3.1 Alternatives and Recommendations

The IRRP includes two alternatives to deal with long term needs:

- New Line between Kleinberg TS and Kirby Jct.
- New Line between Buttonville TS and Armitage TS.

The Study Team agrees that the preferred plan will be developed during the next planning cycle as the need date is beyond 2030.

7.4 Load Restoration

Load restoration describes the electricity system's ability to restore power to a customer affected by a transmission outage within specified time frames. Both transmission and distribution (transfer) measures are considered when evaluating restoration capability. The load restoration criteria is defined in ORTAC and summarized in Figure 7-4.

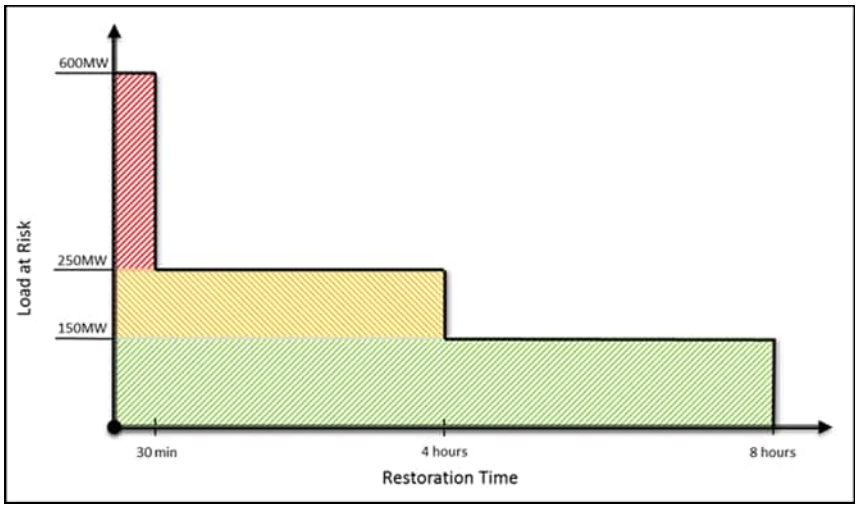


Figure 7-4: Load Restoration Criteria as per ORTAC

There is less risk of violation of ORTAC load restoration criteria especially within the municipalities of Vaughan, Markham, and Richmond Hill due to the availability of transfer capability between adjacent service territories. The Northern York and Western areas are prone to restoration risks which include the service areas served by Holland TS, Armitage TS, and Brown Hill TS and also in the Kleinburg TS area.

7.4.1 Load Restoration on Kleinburg Radial Tap (V43/44)

Load restoration was assessed for 230 kV radial double circuit line V43/V44 supplying Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS that primarily supply rural and urban communities in Vaughan and Caledon and, to a lesser degree, Brampton, Mississauga and Toronto. In case of a double circuit outage of the V43/V44 line, not all loads in excess of 250 MW can be restored within 30 minutes, as per the ORTAC restoration criteria. The V43/V44 line is approximately 12 km long with good accessibility by maintenance crews and Hydro One expects all load to be restored within 4 hours with at least one circuit back into service.

Table 7-6: Load Restoration on Kleinburg Radial Tap

V43/V44-Restoration	Limit	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Interrupted Load		426	436	444	449	453	450	453	454	455	456	475
Remaining after 30 minutes	250	347	357	366	370	355	352	356	357	358	359	376
Remaining after 4 hours	150	0	0	0	0	0	0	0	0	0	0	0

7.4.1.1 Alternatives and Recommendations

The Study Team agreed that no further action is required at this time. However the need will be reviewed in the next iteration of the regional planning cycle. The historical reliability of these circuits has been good with no coincident outages of the two circuits; there have only been two direct outages[2] to circuit V43 since 2008 and no direct outages to circuit V44 since 2009. While there are no short term plans to address this need, the Kleinburg to Kirby option to address supply capacity needs in the long term would also improve the load restoration capability for these circuits. Based on the long term forecast the supply capacity needs will arise between 2030 and 2035. This alternative is discussed in further detail in Section 7.3.3. Until such time as a preferred long term solution is identified for the Claireville to Minden corridor, there is no need to pursue other alternatives.

7.4.2 Load Restoration on Claireville TS to Holland TS circuits (H82V/H83V)

Load restoration was assessed for 230 kV circuits H82V/H83V supplying Vaughan #4 MTS and Holland TS. In case of a double circuit outage of H82V/H83V, not all loads exceeding 250 MW can be restored within 30 minutes per the ORTAC criteria. However, Hydro One expects all loads to be restored within 4 hours with one circuit back in service. Refer to Table 7-7.

Table 7-7: Load Restoration on Claireville TS to Holland TS circuit (H82V/H83V)

H82V/H83V-Restoration	Limit	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load loss by configuration		196	208	225	262	300	319	321	321	321	320	323
Load loss by SPS		90	96	101	101	101	101	106	113	120	126	132
Total Interrupted Load		286	304	326	363	401	420	427	434	441	447	456
Remaining after 30 minutes	250	250	268	290	327	347	366	373	380	387	393	402
Remaining after 4 hours	150	0	0	0	0	0	0	0	0	0	0	0

[2] A direct outage is reported whenever a major component is in the outage state due to a condition or equipment failure directly associated with it.

7.4.2.1 Alternatives and Recommendations

Following the loss of H82V/H83V, the normal station service supply to YEC generation will also be lost. Holland TS cannot be restored from B88H/B89H until YEC generation is restored. Transferring YEC to an alternate source of station service supply cannot be completed within 30 minutes. Therefore the Study Team recommends that the IESO identify and consider the possibility of a new station service supply arrangement at YEC to enable faster restoration of load on H82V/H83V, consistent with the load restoration criteria.

7.5 Improve Load Security on the Parkway to Claireville Line

The Parkway to Claireville line (V71P/V75P) is located on the Parkway Belt and supplies five load stations with a combined load of approximately 700 MW under current summer peak loading conditions. The load security criteria in ORTAC limits the amount of load that can be interrupted due to the loss of two elements (e.g.: a double circuit line outage) to 600 MW under peak load. On the Parkway to Claireville line, that limit is exceeded.

7.5.1 Alternatives and Recommendations

The previous RIP recommended the installation of inline switches on the V71P/V75P circuits at the Vaughan MTS #1 junction to improve load restoration capability following loss of both V71P/V75P circuits. The switches do not reduce the amount of load that is interrupted, however the project enables Hydro One to quickly isolate the problem and allow the resupply of load to occur expeditiously.

Hydro One completed this project in 2018 at a cost of $5.1 million.

The Study Team accepts that the load security criteria is not met, but agrees that no further action is required at this time since the switches permit quick restoration of the load.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE GTA NORTH REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 8-1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 8-1: Recommended Plans in GTA North Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate
1	Markham Area: Step-down Transformation Capacity	Build new Markham #5 MTS	2025	$30M
2	Increase Capability of 230kV Circuits P45+P46 (these supply Buttonville TS, Markham #4 MTS, and future Markham #5 MTS)	Reconductor circuits P45/46 from Parkway to Markham #4 MTS, and connect Markham #5 MTS – 2025	2025	$2-3M
3	High voltages on 230kV circuits M80B/M81B	No action required	---	---
4	Northern York Area: Step-down Transformation Capacity	Build new Northern York Station	2027	$35-40M
5	Woodbridge TS: End-of-life of transformer T5	Replace the end-of-life transformer with similar type and size equipment as per current standard	2027	$13M
6	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan #5 MTS	2030	$30M

Note: LDC distribution network costs are not included in the above Table.

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 8-1 while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

9 REFERENCES

[1] GTA North Regional Infrastructure Plan – February 2016

[2] GTA North Needs Assessment – March 2018

[3] York Region Scoping Assessment Outcome Report - 2018

[4] Integrated Regional Resource Plan (IRRP) - February, 2020

[5] Integrated Regional Resource Plan (IRRP) - Appendices - March, 2020

[6] IESO Ontario Resource Transmission Assessment Criteria (ORTAC)

10 APPENDIX A. STATIONS IN THE GTA NORTH REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Kleinburg TS T1/T2 27.6	230/27.6	V44/V43
Kleinburg TS T1/T2 44	230/44	V44/V43
Vaughan MTS #3 T1/T2	230/27.6	V44/V43
Woodbridge TS T3/T5 27.6	230/27.6	V44/V43
Woodbridge TS T3/T5 44	230/44	V44/V43
Armitage TS T1/T2	230/44	B88H/B89H
Armitage TS T3/T4	230/44	B88H/B89H
Brown Hill TS T1/T2	230/44	B88H/B89H
Holland TS T1/T2, T3/T4	230/44	H82V/H83V
Buttonville TS T3/T4	230/27.6	P45/P46
Markham MTS #1 T1/T2	230/27.6	P21R/P22R
Markham MTS #2 T1/T2	230/27.6	C35P/C36P
Markham MTS #3 T1/T2	230/27.6	C35P/C36P
Markham MTS #3 T3/T4	230/27.6	C35P/C36P
Markham MTS #4 T1/T2	230/27.6	P45/P46
CTS	230/13.8	P21R/P22R
Richmond Hill MTS #1 T1/T2	230/27.6	V71P/V75P
Richmond Hill MTS #2 T3/T4	230/27.6	V71P/V75P
Vaughan MTS #1 T1/T2	230/27.6	V71P/V75P
Vaughan MTS #1 T3/T4	230/27.6	V71P/V75P
Vaughan MTS #2 T1/T2	230/27.6	V71P/V75P
Vaughan MTS #4 T1/T2	230/27.6	H82V/H83V

11 APPENDIX B. TRANSMISSION LINES IN THE GTA NORTH REGION

Location	Circuit Designations	Voltage (kV)
Claireville TS to Holland TS	H82V/H83V	230
Holland TS to Brown Hill TS	B88H / B89H	230
Claireville TS to Kleinburg TS	V43/V44	230
Claireville TS to Parkway TS	V71P/V75P	230
Parkway TS to Markham MTS #1 and CTS	P21R/P22R	230
Parkway TS to Buttonville TS	P45/P46	230
Parkway TS to Cherrywood TS	C35P/C36P	230

12 APPENDIX C. DISTRIBUTORS IN THE GTA NORTH REGION

Distributor Name	Station Name	Connection Type
Alectra Utilities Corporation	Armitage TS	Tx/Dx
	Buttonville TS	Tx
	Holland TS	Dx
	Kleinburg TS	Tx
	Markham MTS #1	Tx
	Markham MTS #2	Tx
	Markham MTS #3	Tx
	Markham MTS #4	Tx
	Richmond Hill MTS #1	Tx
	Richmond Hill MTS #2	Tx
	Vaughan MTS #1	Tx
	Vaughan MTS #2	Tx
	Vaughan MTS #3	Tx
	Vaughan MTS #4	Tx
	Woodbridge TS	Tx/Dx
Distributor Name	**Station Name**	**Connection Type**
Newmarket-Tay Power Distribution Ltd	Armitage TS	Tx/Dx
	Holland TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Hydro One Distribution	Armitage TS	Tx
	Brown Hill TS	Tx
	Holland TS	Tx
	Kleinburg TS	Tx
	Woodbridge TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Toronto Hydro Electric System Limited	Woodbridge TS	Dx

13 APPENDIX D. GTA NORTH REGION LOAD FORECAST

Station	Summer LTR (MW)	2020	2021	2023	2025	2027	2030	2035
Armitage	317	302	307	312	312	312	312	312
Brown Hill	184	94	95	95	96	97	98	100
Northern York Area	153	0	0	0	0	12	32	62
B88H/B89H Total		396	402	407	408	421	442	474
Holland	168	142	145	154	166	168	168	168
H82V/H83V Total	168	142	145	154	166	168	168	168
Northern York Area Sub-Total		**538**	**547**	**561**	**574**	**589**	**610**	**642**
Markham #2	101	101	101	101	101	101	101	101
Markham #3	202	202	202	202	202	202	202	202
C35P/C36P Total		303	303	303	303	303	303	303
Markham #1	81	81	81	81	81	81	81	81
P21R/P22R Total		81	81	81	81	81	81	81
Buttonville	166	148	148	147	156	156	156	154
Markham #4	153	99	128	153	153	153	153	153
Markham #5	153	0	0	0	26	77	153	153
P45/P46 Total		247	276	300	335	386	462	460
Richmond Hill	254	246	246	245	250	254	254	254
Vaughan #1	306	265	275	300	306	306	306	306
Vaughan #2	153	142	151	153	153	153	153	153
V71P/V75P Total		653	672	698	709	713	713	713
Vaughan #4	153	54	63	108	153	153	153	153
Vaughan #5	153	0	0	0	0	0	2	147
H82V/H83V Total		54	63	108	153	153	155	300
Southern York Area Sub-Total		**1338**	**1395**	**1490**	**1581**	**1636**	**1714**	**1857**

Station	Summer LTR (MW)	2020	2021	2023	2025	2027	2030	2035
Kleinburg	196	144	145	146	147	148	169	170
Vaughan #3	153	132	141	153	153	153	153	153
Woodbridge	160	149	149	150	150	153	154	153
V43/V44 Total		425	435	449	450	454	476	476
Western Area Sub-Total		**425**	**435**	**449**	**450**	**454**	**476**	**476**
GTA North Region Total		**2301**	**2377**	**2500**	**2605**	**2679**	**2800**	**2975**

Toronto Region:

Integrated Regional Resource Plan

August 9, 2019

ieso
Connecting Today.
Powering Tomorrow.

Toronto Region
Integrated Regional Resource Plan

This Integrated Regional Resource Plan (IRRP) was prepared by the Independent Electricity System Operator (IESO) pursuant to the terms of its Ontario Energy Board license, EI-2013-0066.

The IESO prepared the IRRP on behalf of the Toronto Regional Planning Working Group (Working Group), which included the following members:

- Independent Electricity System Operator
- Toronto Hydro-Electric System Limited (Toronto Hydro)
- Hydro One Networks Inc. (Hydro One)

The Working Group developed a plan that considers the potential for long term electricity demand growth and varying supply conditions in the Toronto region, and maintains the flexibility to accommodate changes to key conditions over time.

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List of Acronyms

Acronym/ Alternative	Description
CHP	Combined Heat and Power
DER	Distributed Energy Resource
DESN	Dual Element Spot Network
DR	Demand Response
EA	Environmental Assessment
FIT	Feed-in Tariff
GTA	Greater Toronto Area
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTE	Long-term Emergency Rating
LTR	Limited Time Rating
MVA	Mega Volt Ampere
MW	Megawatt
NWA	Non-wires Alternative
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PEC	Portlands Energy Centre
PV	Photo-voltaic (Solar)
RAS	Remedial Action Scheme
RIP	Regional Infrastructure Plan
SS	Switching Station

Acronym/ Alternative	Description
STE	Short-term Emergency Rating
Toronto Hydro	Toronto Hydro-Electric System Limited
TPSS	Traction Power Sub-station
TS	Transmission Station or Transformer Station
Working Group	Technical Working Group for Toronto Region IRRP

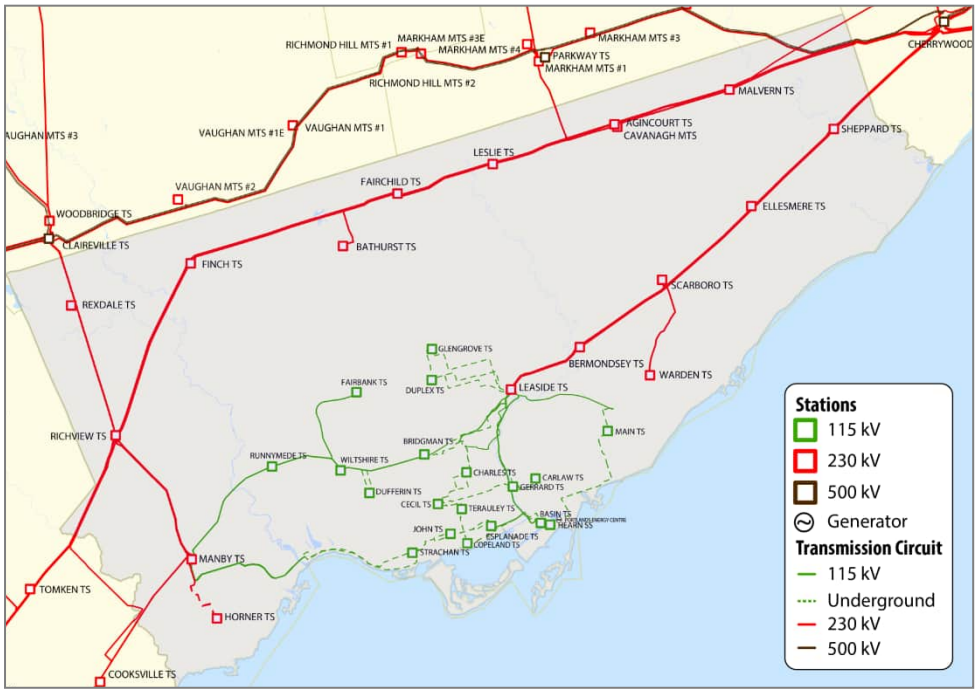
1. Introduction

This Integrated Regional Resource Plan (IRRP) addresses the regional electricity needs for the City of Toronto (Toronto region) between 2019 and 2040.[1] This report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Working Group comprising the IESO, Toronto Hydro-Electric System Limited (Toronto Hydro), and Hydro One Networks Inc. (Hydro One).

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is carried out through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for 21 electricity planning regions across Ontario, at least once every five years. The Toronto region, shown in Figure 1-1, corresponds with the municipal boundaries of the City of Toronto. Other electricity planning regions adjacent to the Toronto region include Greater Toronto Area (GTA) West, GTA East, and GTA North.

[1] The planning horizon year is 2040: the different time frames within the plan period include the near term (up to five years out); medium term (six to 10 years out); and long term (11 to 20 years out).

Figure 1-1: Location of the Toronto Region



This IRRP reaffirms the needs and plans previously identified in the Metro Toronto Regional Infrastructure Plan (RIP) published in January 2016, and the Needs Assessment report completed in 2017. It identifies new capacity and reliability needs of the electric transmission system, and recommends approaches to ensure that Toronto's electricity needs can be met over the planning horizon. Specifically, the plan recommends approaches for addressing a number of end of life asset replacement needs and potential longer-term capacity needs to accommodate growth and city development.

For needs that may emerge in the longer term (11 to 20 years out), the plan maintains flexibility for new solutions. As the long term needs highlighted by the technical studies are subject to uncertainty related to future electricity demand and technological change, this IRRP does not recommend specific investments to address them at this time.

The plan identifies some near term actions to monitor demand growth, explore possible long term solutions, engage with the community, and gather information to lay the groundwork for determining options for future analysis. The near term actions recommended are intended to be completed before the next regional planning cycle, scheduled for 2024 or sooner, depending on demand growth or other factors that could trigger early initiation of the next planning cycle.

This report is organized as follows:

- A summary of the recommended plan for the Toronto region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for regional electricity planning in the Toronto region and the study scope are discussed in Section 4;
- The demand outlook scenarios, and energy efficiency and distributed energy resource (DER) assumptions, are described in Section 5;
- Electricity needs in the Toronto region are presented in Section 6;
- Options and recommendations for addressing the needs are described in Section 7;
- A summary of engagement activities to date, and moving forward, is provided in Section 8; and
- A conclusion is provided in Section 9.

2. Summary of the Recommended Plan

The recommendations in this IRRP are focused on replacement of assets at their end of life, and preparing to address local and regional capacity needs emerging in the longer term.

The successful implementation of the recommended actions summarized below is expected to address the region's electricity needs until at least the late 2020s.

2.1 The Plan

This plan re-affirms the needs and plans identified in the previous regional planning cycle that concluded in January 2016, and recommends the actions described below to address the region's transmission needs until at least the late 2020s or early 2030s.

The recommendations set forth in this plan are summarized as follows:

Replace end of life overhead line sections H1L/H3L/H6LC/H8LC and L9C/L12C

The Working Group recommends that Hydro One proceed with planning for the like for like replacement of these overhead line sections.

Replace end of life transformers at Main TS

The Working Group recommends that Hydro One proceed with planning to replace the existing transformers with 60/100 MVA transformers.

Continue planning for replacement of C5E/C7E underground transmission cables

The Working Group recommends that Hydro One continue planning to replace the existing cables.

Continue planning to determine end of life approaches for Manby TS, John TS, and Bermondsey TS

Manby TS and John TS: The Working Group recommends that detailed planning for end of life of these assets continue, starting with the RIP.[2]

Bermondsey TS: The Working Group recommends that the plan to replace the two end of life transformers at Bermondsey TS be completed within the scope of the RIP.

Gather information to inform future capacity planning for Basin TS

Since there is currently insufficient information to characterize the needs at Basin TS and inform specific recommendations in this IRRP, the Working Group proposes that any recommendation on potential solutions be deferred until the next cycle of regional planning, or earlier, as required.

Specifically, the Working Group recommends that Toronto Hydro coordinate continued planning activities related to defining the nature, scope and timing of the future capacity need at Basin TS, and assessment of possible wires and non-wires alternative (NWA) solutions to address the need.

Proceed with reinforcement of the Richview TS to Manby TS 230 kV corridor

The Working Group recommends that Hydro One proceed with the reinforcement of the Richview TS to Manby TS 230 kV corridor and begin community engagement, as well as initiate the environmental assessment (EA).

Keep options available to address long term regional supply capacity needs

For the longer-term regional capacity needs, including the Leaside TS and Manby TS autotransformers, Manby TS to Riverside Junction lines, and Bayview Junction to Balfour Junction circuit section, the Working Group recommends that the IESO coordinate continued planning work and engagement with stakeholders and the community to:

- Define and communicate, as soon as practicable, the longer-term capacity needs

[2] The RIP is described in Section 3.1.

- Identify opportunities for a range of cost-effective solutions, including NWAs such as DERs and energy efficiency
- Identify potential wires solutions and avoidable costs should these needs be deferred through NWAs

The information and insights developed through these activities will be used to inform the next regional planning cycle.

3. Development of the Plan

3.1 The Regional Planning Process

In Ontario, planning to meet an area's electricity needs at a regional level is completed through the regional planning process, which assesses regional needs over the near, medium, and long term, and develops a plan to ensure cost-effective, reliable electricity supply. A regional plan considers the existing transmission electricity infrastructure in an area, local supply resources, forecast growth and area reliability; evaluates options for addressing needs; and recommends actions to be undertaken.

The current regional planning process was formalized by the OEB in 2013, and is conducted for each of the province's 21 electricity planning regions by the IESO, transmitters and local distribution companies (LDCs) on a five-year cycle.

The process consists of four main components:
1) A needs assessment, led by the transmitter, which completes an initial screening of a region's electricity needs;
2) A scoping assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3) An IRRP, led by the IESO, which identifies recommendations to meet needs requiring coordinated planning; and/or
4) An RIP led by the transmitter, which provides further details on recommended wires solutions.

More information on the regional planning process and the IESO's approach to regional planning can be found in Appendix A: Overview of the Regional Planning Process.

3.2 Toronto Region Working Group and IRRP Development

Development of the Toronto region IRRP was initiated in late 2017 with the release of a needs assessment prepared by Hydro One on behalf of the Toronto Regional Planning Working Group comprised of the IESO, Toronto Hydro, Alectra Utilities, Veridian Connections (now elexicon energy) and Hydro One Distribution. The report identified transmission needs that may require coordinated planning in the Toronto region, with needs limited to the electrical system within the municipal boundaries of the City of Toronto.

Subsequent to the Needs Assessment Report, the IESO prepared a Scoping Assessment Outcome Report, which recommended that an IRRP be undertaken to address a number of needs, owing to the potential for coordinated solutions. No sub-regions were identified for the purpose of carrying out this IRRP. Given the location of the needs identified, the IRRP Working Group was determined at the scoping assessment stage to include the IESO, Toronto Hydro and Hydro One.[3]

In 2018, the Working Group began gathering data, conducting assessments to identify near term to long term needs in the area, and recommending actions to address Toronto's electricity transmission needs.

[3] Distribution system planning does not fall within the scope of a regional planning study, though regional plans may inform distribution system plans. Distribution system plans are undertaken by local distribution companies and reviewed and approved by the OEB under a separate process.

4. Background and Study Scope

This is the second cycle of regional planning for the Toronto region. When the OEB formalized the regional planning process in 2013, planning was already underway in the Central Toronto area, a sub-region of Toronto that includes the downtown core. As such, Central Toronto became one of the Group 1 planning regions, and the first to participate in the formalized regional planning process.

The first cycle of regional planning for the Toronto region was completed in January 2016 with the publication of Hydro One's RIP for the Central Toronto area. Subsequent to the completion of an IRRP for Central Toronto (in April 2015), the IESO published an update to the IRRP that accounted for plans to convert commuter heavy rail in the GTA from diesel to electric power.

The second cycle of regional planning for Toronto was initiated by Hydro One in mid-2017. Following publication of a needs assessment in October 2017, a scoping assessment, released in February 2018, identified a number of needs requiring further regional coordination, and recommended that an IRRP for the Toronto region be initiated. No sub-regions within Toronto were recommended for this IRRP.

Building on past regional studies and taking into account updates to activities, including investments in electricity infrastructure and Toronto Hydro's long term outlook for electricity, this IRRP focuses on:

- Identifying recommendations for replacing assets that are reaching end of life
- Supporting and enabling growth and planned urban development
- Maintaining a high level of reliability performance

To set the context for this IRRP, the scope of the planning study and the area's existing electricity system are described in Section 4.1.

4.1 Study Scope

This IRRP, prepared by the IESO on behalf of the Working Group, recommends options to meet the regional electricity needs of the Toronto region. Guided by the principle of maintaining an adequate level of reliability performance as per the *Ontario Resource and Transmission Assessment Criteria* (ORTAC), this study recognizes the importance of electricity service to the functioning of a large urban centre. The Toronto Region Scoping Assessment Outcome Report established the objectives, scope, roles and responsibilities, and timelines for this IRRP. The plan considers the long term outlook for electricity peak demand, energy efficiency, and transmission system capability and transmission asset condition. Options for addressing needs also considered relevant transmission and distribution system projects and capabilities, community plans, and distributed energy resources (DERs).

The transmission facilities that were included in the scope of this study are presented in Table 4-1 (stations) and Table 4-2 (circuits).

Table 4-1: Summary of Station Facilities (230 kV and 115 kV)

Leaside 115 kV	Manby 115 kV	East 230 kV	North 230 kV	West 230 kV
Basin TS	Copeland TS	Bermondsey TS	Agincourt TS	Horner TS
Bridgman TS	Fairbanks TS	Ellesmere TS	Bathurst TS	Manby TS[3]
Carlaw TS	John TS	Leaside TS[4]	Cavanagh TS	Rexdale TS
Cecil TS	Runnymede TS	Scarboro TS	Fairchild TS	Richview TS
Charles TS	Strachan TS	Sheppard TS	Finch TS	
Dufferin TS	Wiltshire TS	Warden TS	Leslie TS	
Duplex TS			Malvern TS	
Esplanade TS				
Gerrard TS				
Glengrove TS				
Main TS				
Terauley TS				
Hearn SS[5]				

[4] Includes the step-down transformers and 230/115 kV autotransformers
[5] Hearn Switching Station (SS)

Table 4-2: Summary of Transmission Circuits (230 kV and 115 kV)

230 kV	115 kV	
C10A	C5E	K11W
C14L	C7E	K12W
C15L	D11J	K13J
C16L	D12J	K14J
C17L	D6Y	K1W
C20R	H10DE	K3W
C2L	H11L	K6J
C3L	H12P	L12C
C4R	H13P	L13W
R1K	H14P	L14W
R2K	H1L	L15
R13K	H2	L16D
R15K	H2JK	L18W
R24C	H3L	L2Y
K21C	H6LC	L4C
K23C	H7L	L5D
	H8LC	L9C
	H9DE	

Transmission supply is provided to Toronto Hydro from 35 step-down transformer stations that are supplied by transmission voltages operating at either 230 kV or 115 kV. Toronto Hydro delivers electricity from these transmission supply points to its customers through its own electricity distribution system. Eighteen 230 kV step-down transformer stations supply the eastern, western and northern parts of Toronto (18 of these stations supply 27.6 kV voltage and two also supply 13.8 kV electricity to the distribution system); and 17 115 kV step-down stations supply the Central Toronto area (15 at 13.8 kV and two at 27.6 kV on the distribution side). The supply to these central 115 kV stations comes from two 230 kV/115 kV autotransformer stations (Leaside TS and Manby TS). The Toronto region also includes the Portlands Energy Centre (PEC) connected to the 115 kV transmission system (within the Leaside TS sector). The PEC 550 MW combined-cycle power plant plays an important role locally, and for the provincial electricity system, in providing reliable capacity to meet electricity demand, as well as reactive power and voltage support. Hearn SS provides 115 kV switching facilities for the Leaside area and also connects PEC to this system.

The Toronto region and its transmission supply infrastructure are shown in Figure 4-1 (map) and Figure 4-2 (single line diagram). Transmission circuit nomenclature used throughout this report (e.g., H1L, H3L, etc.) can be referenced using the single line diagram.

Figure 4-1: The Regional Transmission System Supplying Toronto

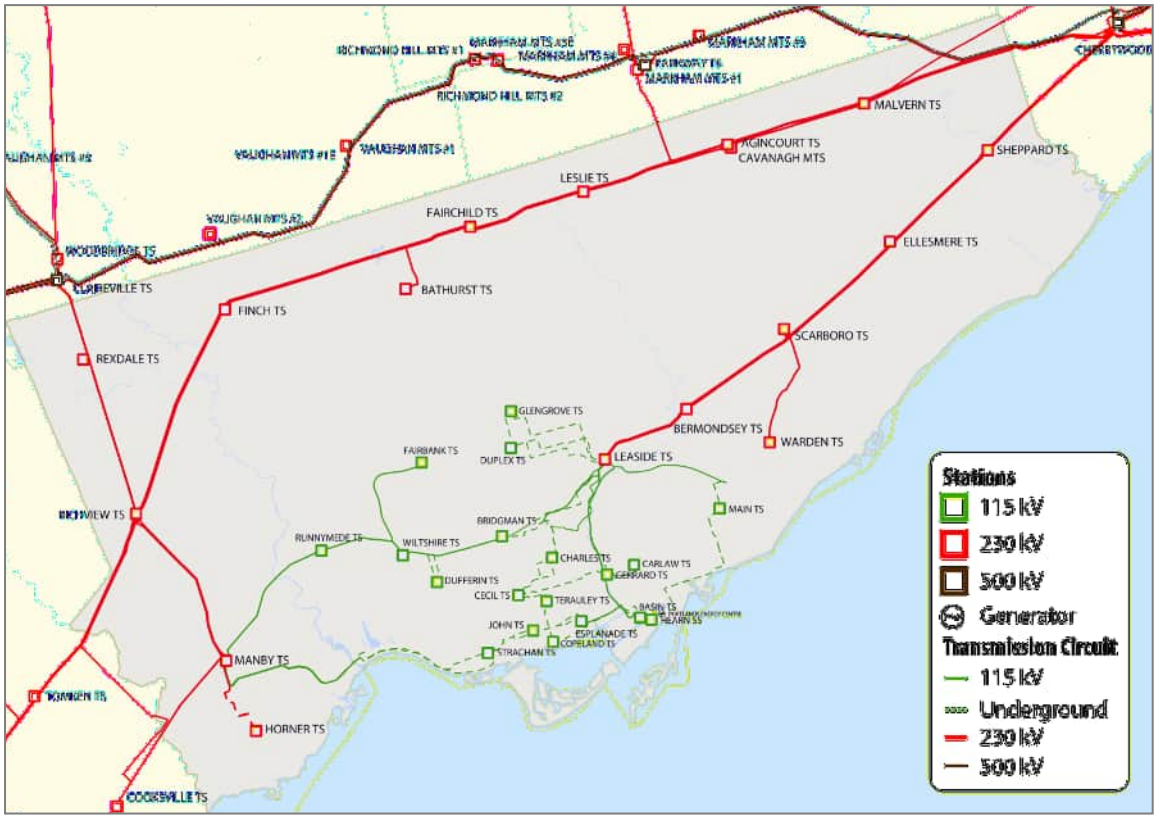
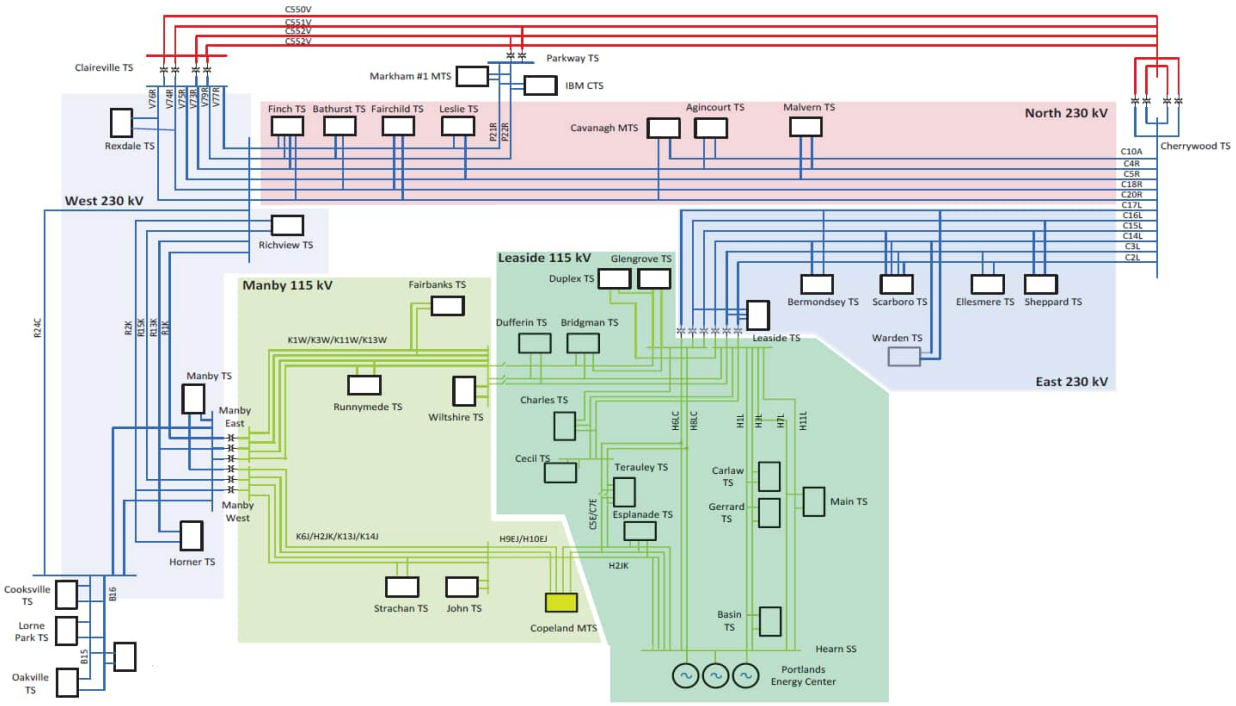


Figure 4-2: The Toronto Region Electrical System (Single-Line Diagram)



Completing the Toronto IRRP involved:

- Preparing a long term electricity peak demand outlook (forecast);
- Examining the load meeting capability and reliability of the transmission system supplying the region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities (such as reactive power devices);
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid as described in Section 7 of ORTAC;
- Confirming identified end of life asset replacement needs and timing with Hydro One;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible energy efficiency, generation, transmission and/or distribution, and other approaches such as NWAs;
- Engaging with the community on needs, findings, and possible alternatives;
- Evaluating alternatives to address near and long term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5. Peak Demand Outlook

The electricity system needs that are in scope for regional planning are driven by the limits of the transmission infrastructure supplying an area, which is sized to meet peak demand requirements (rather than energy demand requirements).[6] Peak demand requirements appearing at the station level are aggregated to understand the limits of the regional transmission system supplying the area as well as individual stations. Regional planning typically focuses on the regional-coincident peak demand to assess regional transmission needs, and individual station peaks to assess local transformer station capacity needs (the demand outlook is broken down spatially by transformer station, or each dual element spot network (DESN) that makes up a station[7]).

Individual stations within the Toronto study area typically experience peak loading at around the same time (e.g., weekdays, generally between 4 and 6 p.m. in summer, after consecutive hot days). There is also a high degree of coincidence between when individual stations peak and when the region peaks.

5.1 Demand Outlook Methodology

Toronto Hydro, in consultation with the Working Group, prepared a peak demand outlook at the transformer station bus level per IESO requirements for performing this study.

The outlook was developed in two parts:

1. Development of the Gross Peak Demand Outlook (Gross Outlook)
2. Development of the Net Peak Demand Outlook (Net Outlook)

The Gross Outlook recognizes the strengths of different forecasting methodologies for different time periods. The first 10 years is based upon the linear regression of past peak demands combined with known load additions and load redistributions. The period beyond 10 years is

[6] Peak demand of the electric system is typically measured in terms of megawatts (MW) capacity; energy is the capacity needed over a period of time, for example, one megawatt used over one hour is a megawatt-hour (MWh).
[7] A DESN refers to a standard station layout, where two supply transformers are configured in parallel to supply one or two medium-voltage switchgear (for example, 13.8 kV or 27.6 kV), which the distributor uses to supply load customers. This parallel dual supply ensures reliability can be maintained in the event of an outage or planned maintenance. A single local transformer station can have one, two, or more individual DESNs.

based upon the growth rates predicted from an econometric model that takes population, employment, and long term weather into account.

The Gross Outlook is a "business-as-usual" peak demand forecast under extreme weather. The Net Outlook considers load drivers that are over and above those considered in the "business as usual" Gross Outlook. These "new and emerging" load drivers were:

- electric vehicles
- electrification of mass transit
- fuel switching from natural gas to electric for space heating and water heating
- energy storage

The result was a station-by-station outlook of annual peak demand through to 2041. More details may be found in Appendix B: Peak Demand Outlook for Toronto 2017-2041.

5.2 The Outlook for Energy Efficiency

The outlook for future peak demand savings is based on mandated efficiencies from Ontario building codes and equipment standards, which set minimum energy efficiency levels through codes and regulations. To estimate the impact of efficiency codes and standards in the Toronto region, the peak demand savings for the residential, commercial and industrial sectors were estimated at the provincial level, compared with Toronto's station-based peak demand forecast, and expressed as a percentage of peak demand offset on an annual basis. This estimation took into account the breakdown of the peak demand at the station of residential, commercial, and industrial sector demand. Estimated peak demand savings, in MW, were calculated based on the percentage demand offset and the Demand Outlook described in Section 5.1.

These savings were subtracted from the demand outlook, and this forecast with efficiency codes and standards was used to test the sensitivity of the need dates as identified by the Net Outlook described in Section 5.1.

Table 5-1 shows the total peak demand savings attributable to efficiency codes and standards for the Toronto area, for selected years within the planning horizon.

Table 5-1: Estimated Peak Demand Savings from Codes and Standards

Year	2020	2025	2030	2040
Estimated savings (MW)	86	159	242	311

Source: IESO

A more detailed methodology on the outlook for energy efficiency, including assumptions and a breakdown by station and year, is provided in Appendix C: Energy Efficiency Forecast.

5.3 Outlook for Distributed Energy Resources

In addition to energy efficiency, DERs in the Toronto region have previously offset, and are expected to continue to offset peak demand. Previous procurements, including the Feed-in Tariff (FIT) Program, have helped to increase the amount of renewable DERs in Toronto. Other competitive generation procurements have also resulted in additional DER types, such as combined heat and power (CHP) projects.[8] The DERs under contract with the IESO include a mix of solar photovoltaics (PV), CHP, and wind resources.

Further to these, competitive procurement pilots run by the IESO for energy storage resources have resulted in some energy storage projects in the region, and are supporting efforts to better understand the barriers related to integration of energy storage into Ontario's electricity market.

The peak demand impact of DERs that were connected to the system at the time the demand outlook was produced would be implicitly accounted for in the outlook. Given the difficulty of predicting where future DERs may be located, and uncertainty around future DER uptake, no further assumptions have been made regarding future DER growth. Instead of assuming future DER growth implicitly as a load modifier in the demand outlook, the potential of future DERs will be considered as potential solution options.

While the FIT Program and other competitive procurements for small-scale generation, including CHP, have ended, the IESO has been engaged in developing market-based mechanisms to enable a variety of electricity resources to compete in the electricity market. In addition, the IESO is engaged in several activities to enable DERs as alternatives to wires-based solutions. This includes working with other sector participants to identify and overcome

[8] Since the IRRP forecast was developed, contracts for some generators included in the 2017 list have been terminated.

barriers to DER participation and implementation, as many of the issues extend beyond the IESO's mandate.

The IESO's work and other electricity sector initiatives related to DER barriers are expected to inform ongoing discussions on possible future DER options in Toronto, as per the recommendations made in this IRRP.

6. Power System Needs

Based on the demand outlook, system capability, identified end of life asset replacement needs, and application of provincial planning criteria, the Working Group identified electricity needs in the Toronto region in the near, medium, and long term.

6.1 Needs Assessment Methodology

ORTAC,[9] the provincial criteria for assessing the reliability of the transmission system, was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of both the bulk transmission system and local or regional reliability requirements. See Appendix D: Toronto IRRP Study Results, and Appendix E: Station Capacity Assessment, for more details.

In applying ORTAC, three broad categories of needs can be identified:

- **Local Capacity** describes the electricity transmission system's ability to deliver power to LDCs through regional step-down transformer stations. This is determined by the Limited Time Rating (LTR) of the station, which is typically determined by the rating of its smallest transformer(s), under the assumption that the largest transformer is out of service.[10]
- **Regional Capacity** is the electricity transmission system's ability to provide continuous supply to LDCs in a local area, which is limited by the load meeting capability (LMC) of the transmission facilities in the area. The LMC is determined by evaluating the maximum peak demand that can be supplied to an area accounting for limitations of the transmission element(s) (e.g., a transmission line, group of lines or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC. LMC studies are conducted using power system simulations analysis (see Appendix D, Toronto IRRP Study Results, for more details). Regional capacity needs are identified when the peak demand for the area exceeds the LMC of regional transmission facilities.
- **Load Security and Restoration** is the electricity transmission system's ability to minimize the impact of potential supply interruptions in the event of a credible contingency (e.g., a transmission outage considered for planning purposes), such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security

[9] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

[10] A station's rating is determined by its most limiting component(s), which may not always be the transformer(s).

describes the maximum limit of load interruption that is permissible in the event of a transmission outage considered for planning. These limits reflect past planning practices in Ontario. Load restoration describes the electricity transmission system's ability to restore power to a transmission customer (e.g., LDC) affected by a transmission outage within specified time frames. Specific requirements can be found in ORTAC, Section 7, Load Security and Restoration Criteria.

The plan also identifies requirements related to the end of life of transmission assets. End-of-life asset replacement needs are identified by the transmitter based on a variety of factors, such as asset age, condition, expected service life, and risk associated with the failure of the asset. Replacement needs identified in the near and early medium term time frame typically reflect the assessed condition of the assets, while replacement needs identified in the longer term are often based on the equipment's expected service life. As such, any recommendations for medium term needs or those farther out reflect a potential for the need date to change based on priority and/or updates to asset condition.

6.2 Power System Needs

Through the planning studies for the Toronto IRRP, the Working Group identified four main categories of needs: (1) end of life asset replacement, (2) local transformer station capacity, (3) regional supply capacity, and (4) load security and restoration. In addition, pursuant to ORTAC provisions, maintaining a higher level of reliability performance (i.e., above the minimum standards) was also considered which identified some 'discretionary' reliability needs.[11] The specific needs under each of these categories are explained in the sections that follow.

6.2.1 End-of-life Asset Replacement Needs

Hydro One identified a number of end of life transmission asset replacement needs for the Toronto region in the needs assessment phase of this regional planning cycle, with several needs arising in the near to medium term.

[11] 'Discretionary' reliability needs are transmission system issues that are flagged through the application of a uniform set of planning criteria for all of Toronto's transmission system (e.g., by applying 'bulk power system' criteria to 'local area' facilities). This identifies issues that are discretionary in the sense that the reliability performance of the system complies with the criteria; but may represent opportunities to improve reliability to an area if cost-effective opportunities are available.

Since end of life needs are based on the best available asset condition information at a given point, the timing of asset replacement can change, as more recent asset condition results become available. If asset deterioration occurs faster than predicted, need dates may need to be advanced. As a result, the scope and timing of some of these needs have been updated since the needs and scoping assessments were completed.

6.2.1.1 Near-term Asset End-of-life Replacement Needs

Three near term asset end of life replacement needs were addressed within the scope of this plan (Table 6-1). These needs are described further in this Section. The options considered for addressing these needs are described in Section 7.1.1.

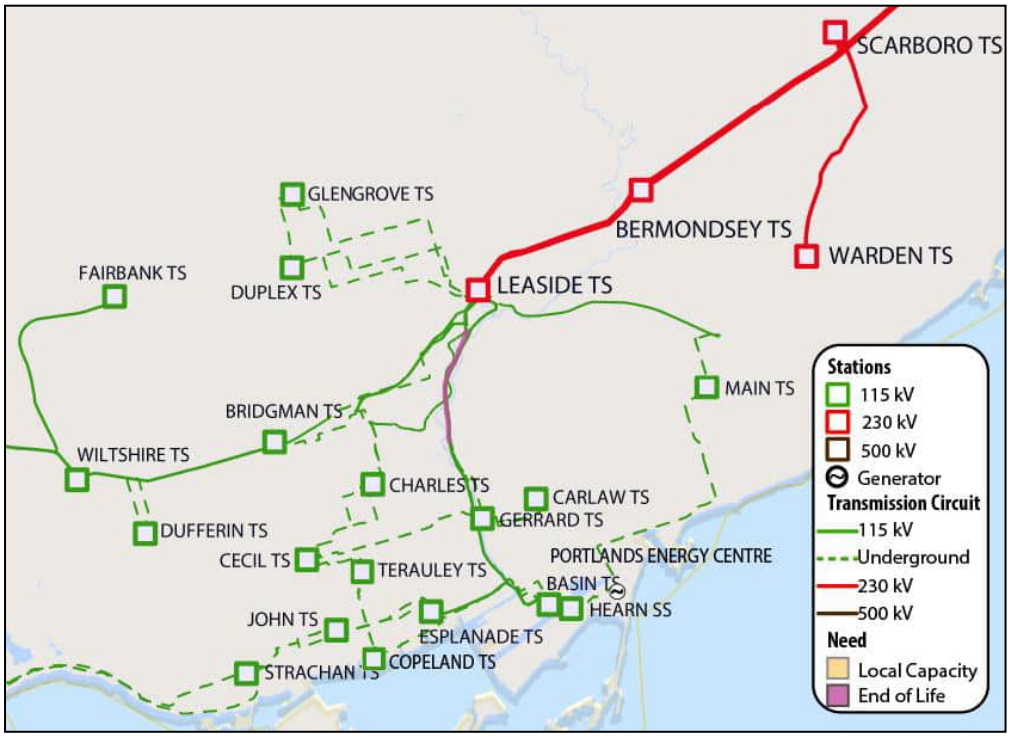
Table 6-1: Toronto Region End-of-life Asset Replacement Needs (Near term)

Facilities	Need	Expected Timing
Leaside Junction to Bloor Street 115 kV overhead transmission lines (H1L/H3L/H6LC/H8LC)	End of life of the approximate 2-km overhead line sections	2022-2023
Leaside TS to Balfour Junction 115 kV overhead transmission lines (L9C/L12C)	End of life of the approximate 3.6-km overhead line sections	2023-2024
Main TS	End of life of transformers T3 and T4, 115 kV line disconnect switches, and 115 kV current voltage transformers	2021-2022

Leaside to Bloor Street 115 kV overhead transmission lines (H1L/H3L/H6LC/H8LC)

The 115 kV overhead transmission lines H1L, H3L, H6LC, and H8LC provide supply to the eastern part of central Toronto from Leaside TS. The end of life part of the line is a 2-km section that runs from Leaside Junction to Bloor Street Junction in the Don Valley, and is on a common tower with four circuits (Figure 6-1). Hydro One has determined the conductors are reaching the end of their useful life, and will need to be replaced by 2022-2023 to maintain safety and reliability.

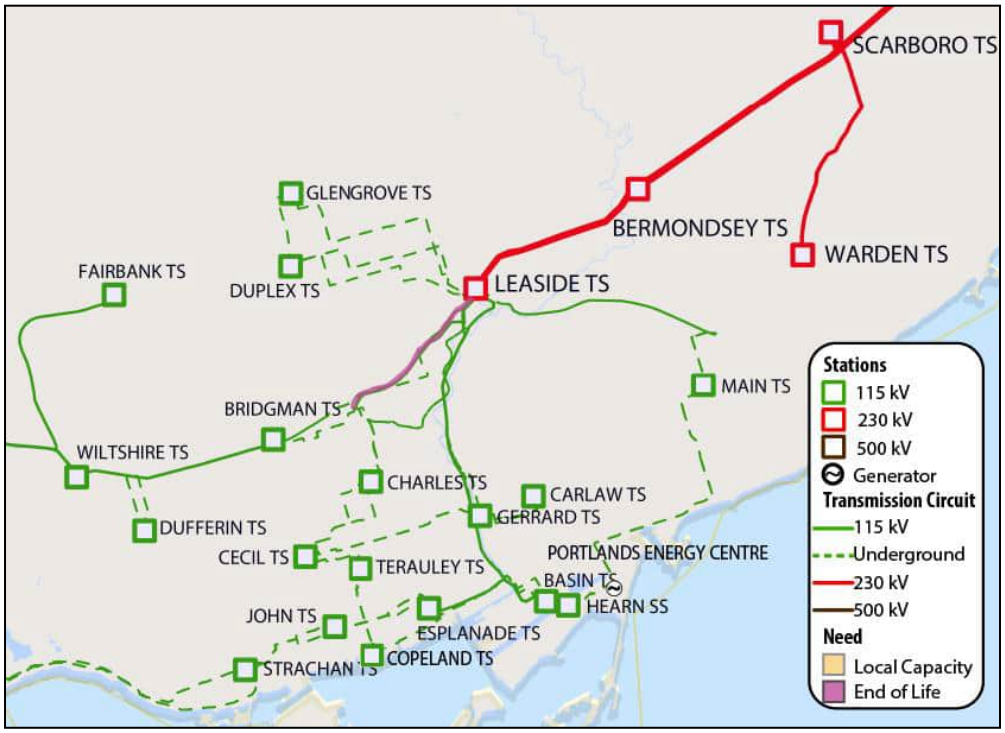
Figure 6-1: Leaside to Bloor Street Junction 115 kV Overhead Transmission Lines



Leaside to Balfour 115kV overhead transmission lines (L9C/L12C)

The 115 kV overhead transmission lines L9C and L12C provide supply to central Toronto from Leaside TS (to Cecil TS). The section of the line that runs between Leaside TS and Balfour Junction is about 3.6 km in length, and runs through the Don Valley and along an existing rail corridor (Figure 6-2). This line is more than 80 years old and the conductors have been identified by Hydro One as reaching the end of their useful life, and requiring replacement by 2023-2024 to maintain safety and reliability.

Figure 6-2: Leaside to Balfour 115kV Overhead Transmission Lines



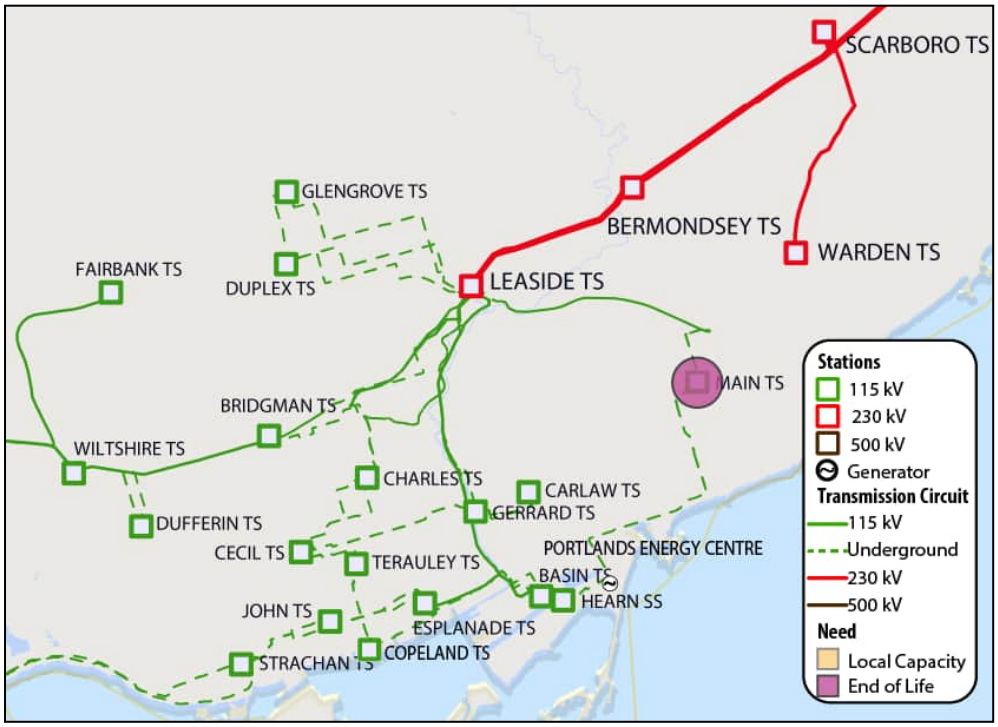
Main TS transformers and associated station equipment

Main TS is a local transformer station serving approximately 60 MW of load in east-central Toronto, including the Danforth and Beach neighbourhoods (Figure 6-3). The two transformers at the station, T3 and T4, are currently about 50 years old. Hydro One is currently working with Toronto Hydro to replace the end of life transformers, along with other equipment, such as 115 kV line disconnect switches, current transformers and voltage transformers.

Main TS is supplied by a combination of overhead and underground 115 kV circuits from Leaside TS to Hearn TS (H7L and H11L). Two sections of the original underground cable supply circuits are currently undergoing refurbishment due to their age (about 60 years old) and condition.

The station is currently more than 70 per cent utilized and resupplying the area load via adjacent station facilities is not possible. As with many established areas of the city, urban growth and development is likely in the Main TS area.

Figure 6-3: Location of Main TS



6.2.1.2 Medium-term Asset End-of-life Replacement Needs

Four asset end of life replacement needs occurring in the medium term were considered within the scope of this plan (Table 6-2). These needs are described further in this Section. The options considered for addressing these needs are described in Section 7.1.1.

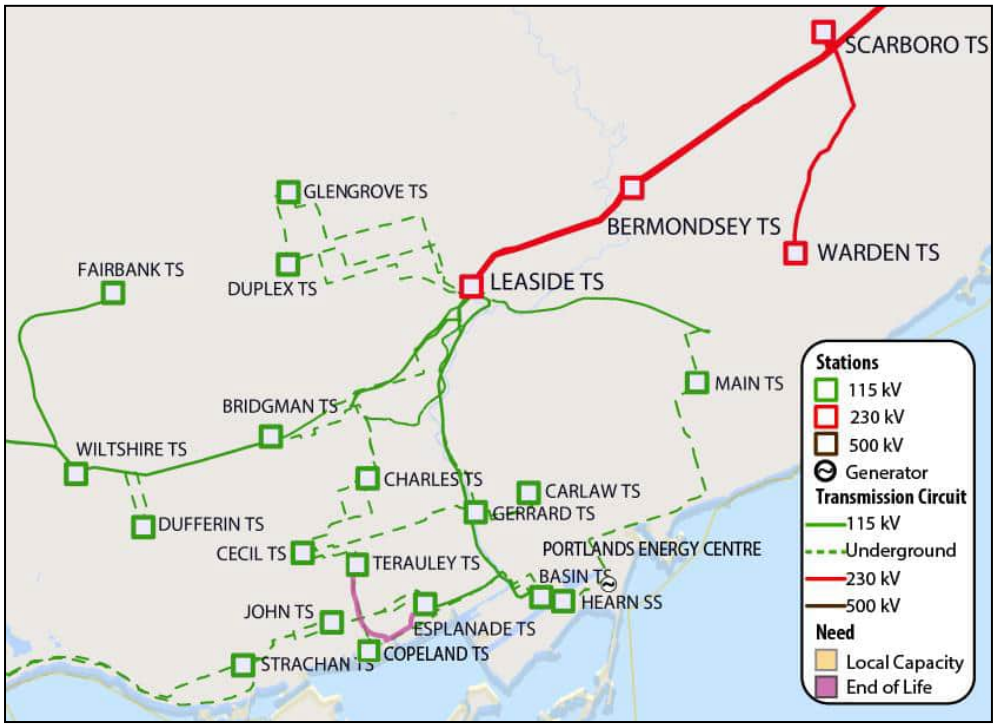
Table 6-2: Toronto Region End-of-life Asset Replacement Needs (Medium term)

Facilities	Need	Expected Timing
Esplanade TS to Terauley TS 115 kV underground transmission cables (C5E and C7E)	End of life of underground cables from Esplanade TS to Terauley TS in downtown Toronto	2024-2025
Manby TS	End of life of major station equipment, including: autotransformers T7, T9, and T12, step-down transformer T13, and the 230 kV yard	2025-2026
John TS	End of life of transformers T1, T2, T3, T4, T6, and 115 kV breakers	2026-2027
Bermondsey TS	End of life of transformers T3 and T4	2025-2026

C5E/C7E 115 kV underground transmission cables

The 115 kV underground transmission cables C5E and C7E provide supply to Terauley TS in Toronto's downtown core. Installed more than 58 years ago, these paper-insulated, low-pressure oil filled cables extend about 3.6 km from Esplanade TS to Terauley TS, and are partially routed near Lake Ontario (Figure 6-4). They have been deemed by Hydro One to be at the end of their useful life, and requiring replacement as soon as possible, given that the risk of cable failure resulting in oil leaks and adverse environmental impacts is increasing with time.

Figure 6-4: C5E/C7E 115 kV Underground Transmission Cables

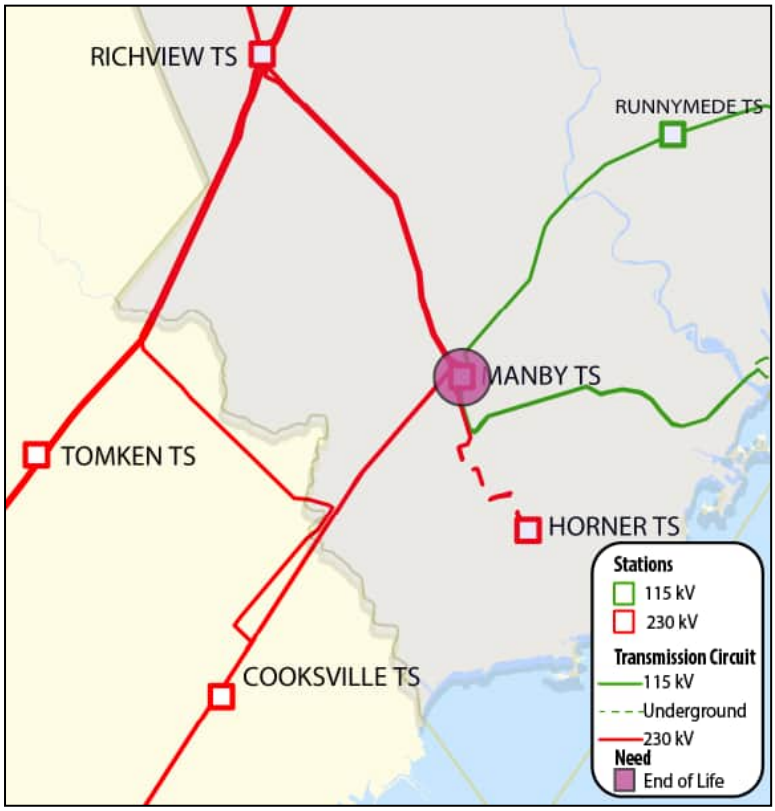


Manby TS

Manby TS is a major switching and autotransformer station supplying the western portion of the central Toronto 115 kV transmission system (Figure 6-5). Station facilities include six 230 kV/ 115 kV autotransformers (T1, T2, T7, T8, T9 and T12), a 230 kV switchyard, a 115 kV switchyard, and three DESNs with six 230/27.6 kV step-down transformers that supply customers in the immediate vicinity of the station. Three of the autotransformers (T7, T9 and T12) and one of the step-down transformers (T13) are close to 50 years old and, along with the 230 kV oil circuit breakers, have been identified to be at the end of their useful life. All of this end of life equipment is scheduled to be replaced in 2025-2026.

Addressing end of life needs at Manby TS represents a major undertaking that needs to be well coordinated in consideration of Toronto's long term needs and future supply options.

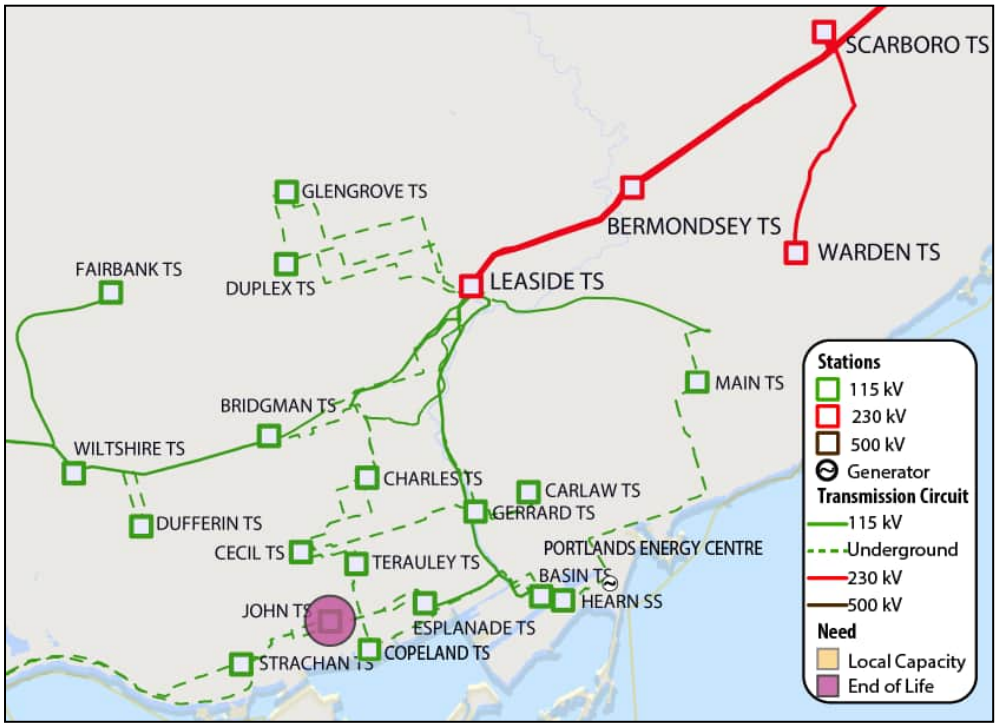
Figure 6-5: Location of Manby TS



John TS

Built in the 1950s, John TS is connected to the 115 kV Manby West system and supplies much of Toronto's downtown financial district (Figure 6-6). Station facilities include six 115/13.8 kV step-down transformers (T1, T2, T3, T4, T5 and T6) and a 115 kV switchyard. Toronto Hydro's switchgear at the station has reached the end of its useful life, and is expected to be replaced starting in 2024-2025. In addition, Hydro One has identified the step-down transformers at John TS (T1, T2, T3, T6), as well as the 115 kV breakers to be at the end of their useful life and require replacement within the near to medium term. Because of their deteriorated condition, transformer T4 has already been replaced and T1 is scheduled to be replaced in Q4 2019. The approximate timing for the station refurbishment is 2026-2027.

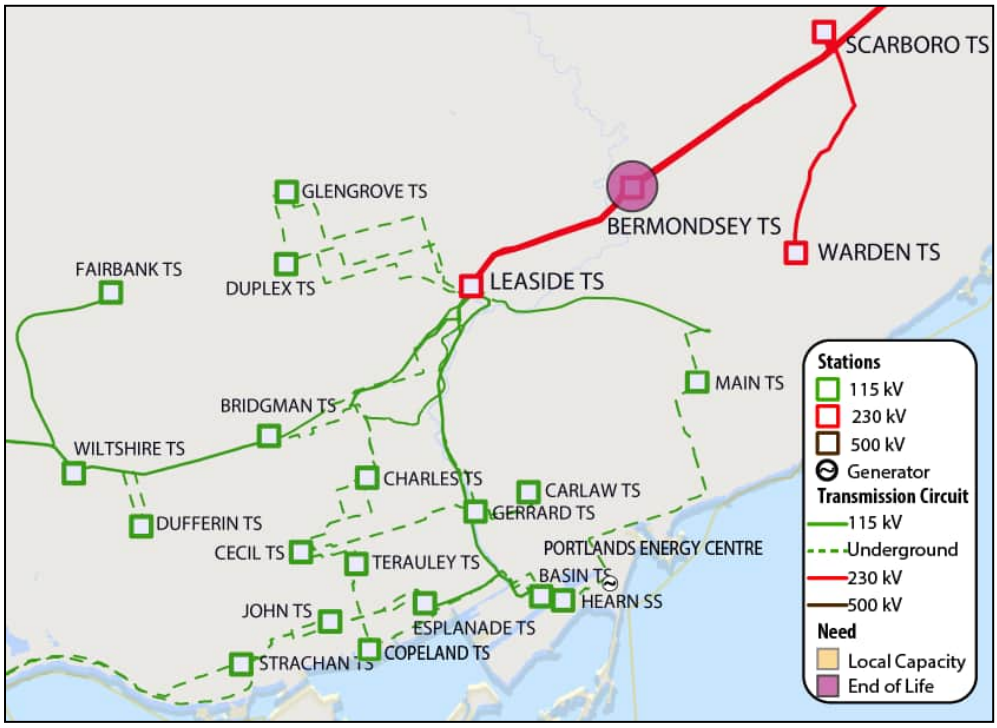
Figure 6-6: Location of John TS



Bermondsey TS

Bermondsey TS supplies customers in the western part of Scarborough (Figure 6-7). The station is comprised of two DESNs, one of which (T3/T4 DESN 2) was built in 1965, and the other (T1/T2 DESN 1) in 1990. DESN 2 has been identified by Hydro One to be at its end of life and is expected to be replaced by 2025-2026. Bermondsey TS has a total of 18 distribution feeders supplying Toronto Hydro customers: the older T3/T4 DESN 2 has 12 feeders, while the newer T1/T2 DESN 1 has six feeders. The total loading on the station is forecast to remain below its capacity over the planning horizon. This provides an opportunity to review configuration and component sizes to best meet future needs.

Figure 6-7: Location of Bermondsey TS



6.2.2 Supply Capacity Needs

Supply capacity needs at local step-down transformer stations were found at five transformer stations. A breakdown by year of the forecasted station loadings, as well as a more detailed description of the methodology for carrying out this assessment, is provided in Appendix E: Station Capacity Assessment.

6.2.2.1 Local Transformer Station Capacity Needs

Table 6-3: Toronto Region Transformer Station Capacity Needs

Station	Description	Timing[12,13]
Manby TS	A transformer capacity need was identified for the load supplied by all three DESNs[14]	2023 for T5/T6 2032 for T3/T4 2034 for T13/T14
Strachan TS	A transformer capacity need was identified for the load supplied by both DESNs	2030 for T13/T15 2033 for T12/T14
Basin TS	A transformer capacity need was identified for the load supplied by the T3/T5 DESN (the only DESN at Basin)	2033
Leslie TS	A transformer capacity need was identified for the load supplied by the T3/T4 DESN	2033
Wiltshire TS	A transformer capacity need was identified for the load supplied by the T1/T6 DESN	2035

The locations of the local capacity needs are shown in Figure 6-8; four of the five local capacity needs are situated in the Central Toronto area.

[12] The timing presented in the table is consistent with the demand outlook provided by Toronto Hydro (net of new energy efficiency and distributed energy resources until the end of 2020); the timing of these capacity needs inclusive of future energy efficiency codes and standards is discussed in the subsections following the table.
[13] Even though local transformer station capacity needs are presented in terms of the individual DESNs within the station, for the purpose of planning and implementing solutions, the needs at each station are generally addressed as one need requiring a holistic solution.
[14] This need was identified and a solution was recommended in the 2015 Central Toronto IRRP. The status of the 2015 recommendation is discussed in Section 7.2.

Figure 6-8: Location of Local (Transformer Station) Capacity Needs



Manby TS (step-down transformation capacity)

Manby TS currently consists of three DESNs connected to the 230 kV system. This step-down transformer station, which supplies customers in the area surrounding Islington Town Centre from the Humber River west to the Toronto City limit, shares a yard with, but is separate from, the larger Manby 230/115 kV autotransformer station that provides 115 kV supply to the western portion of downtown Toronto. With a combined capacity of 240 MVA (216 MW), all three DESNs are forecast to exceed their capacity, starting in 2023 for the T5/T6 DESN 2, 2032 for the T3/T4 DESN 1, and 2034 for T13/T14 DESN 3.

The peak demand impacts of efficiency codes and standards were not taken into account for the timing of this need. Demand at Manby TS has already exceeded the station's capacity in several recent years. This issue was discussed in the 2015 Central Toronto IRRP, solutions were evaluated, and the recommendations to address the need are currently being implemented by Hydro One and Toronto Hydro. These include building a second DESN at Horner TS in south Etobicoke, and transferring load from Manby TS to the new Horner DESN.

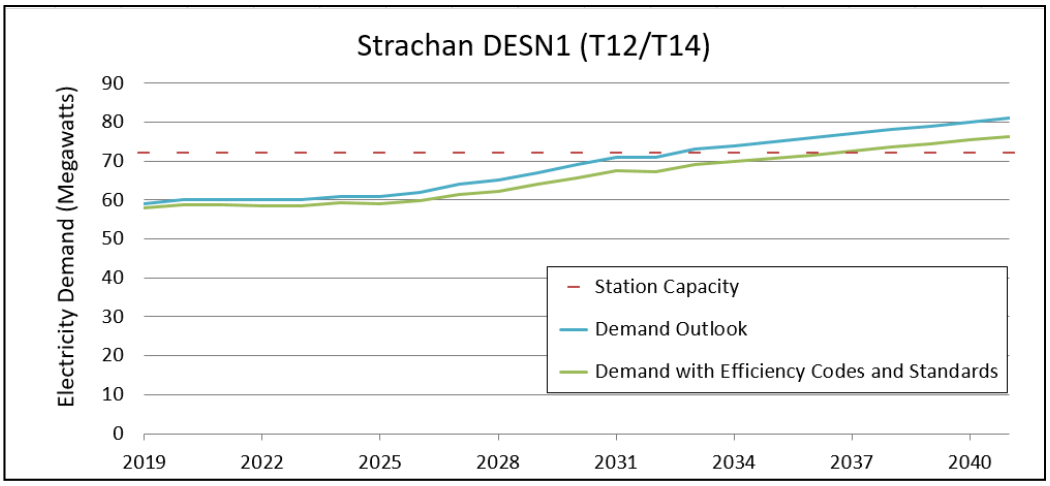
Strachan TS

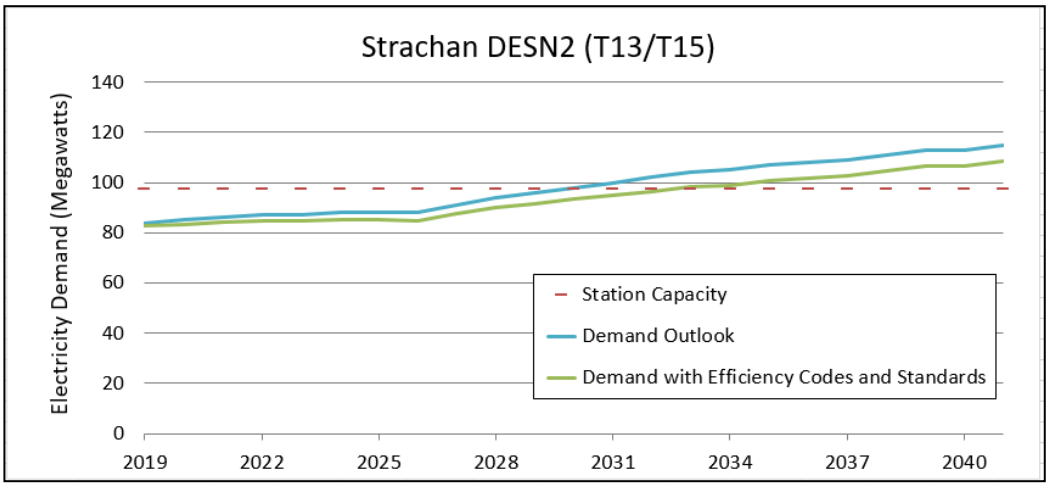
Strachan TS consists of two DESNs connected to the 115 kV system supplied from Manby TS (West Yard). Strachan TS supplies load to the west of the downtown core at 13.8 kV distribution voltage. The two DESNs have a combined capacity of 188 MVA, or 169 MW (80 MVA for T12/T14 DESN 1, and 108 MVA for T13/T15 DESN 2).

The T13/T15 DESN 2 is forecast to reach its capacity as early as 2030, while the T12/T14 DESN 1 is forecast to reach its capacity as early as 2033. Assuming the future potential impact of efficiency codes and standards, the timing of this need is deferred to 2033 and 2038 for the T13/T15 DESN 1 and T12/T14 DESN 2, respectively.

Figure 6-9 shows the demand outlook for the two DESNs at Strachan TS, as compared to the individual capacity of each DESN.

Figure 6-9: Demand Outlook for Strachan TS DESNs Compared to Capacity





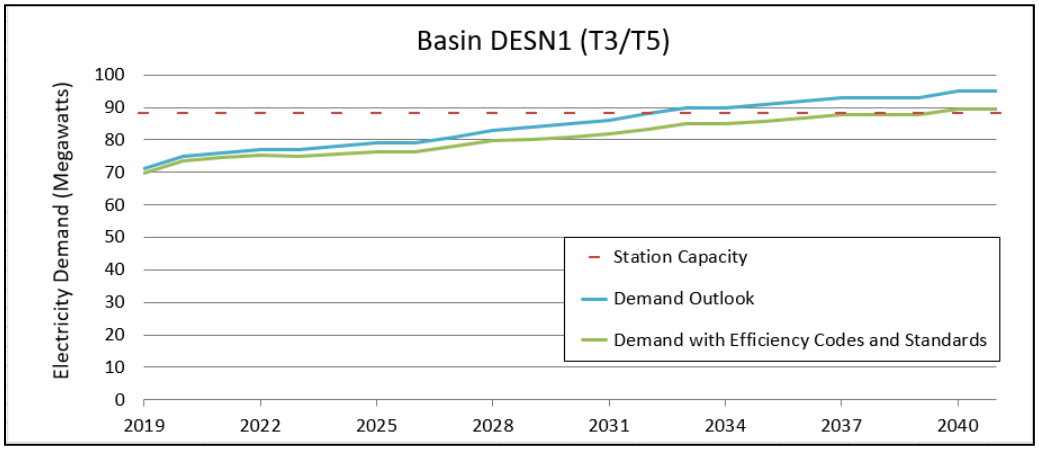
Basin TS

Basin TS has a single DESN (T1/T2) connected to the 115 kV system, supplying two low-voltage switchgear at a distribution voltage of 13.8 kV. The station has a total capacity of 98 MVA, or approximately 88 MW.

Basin TS is forecast to reach its capacity as early as 2033. Assuming the future potential impact of efficiency codes and standards (post-2020), the timing of this need is deferred to 2040.

Figure 6-10 shows the demand outlook for Basin TS, as compared to the station capacity.

Figure 6-10: Demand Outlook for Basin TS DESN Compared to Capacity



In addition to the forecast growth, the City of Toronto and Waterfront Toronto have been engaged in a master planning exercise for the Port Lands neighbourhood redevelopment and

re-naturalization of the mouth of the Don River. These plans involve a number of requests to examine relocation or redesign parts of the 115 kV transmission network in and around Basin TS, including the possible relocation of Basin TS itself.

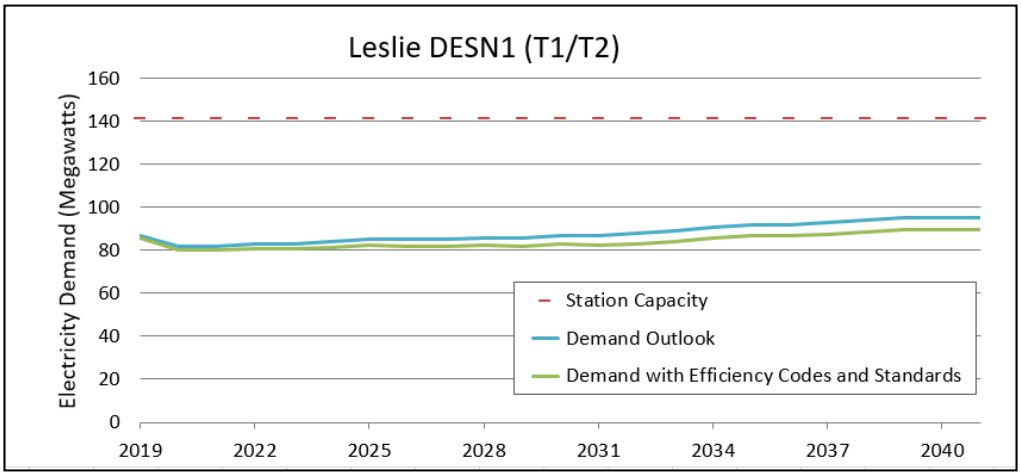
Given the absence of concrete plans and timelines for urban development in the area, the timing of the capacity need at Basin TS is uncertain.

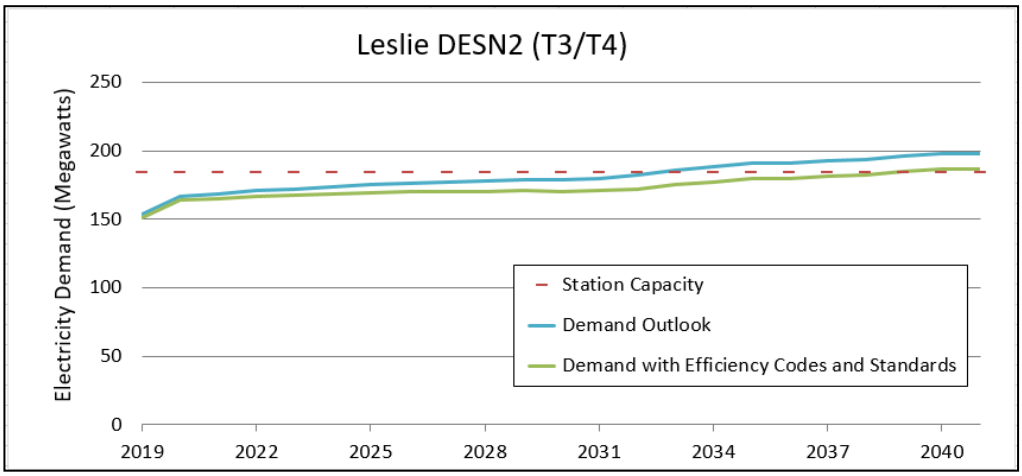
Leslie TS

Leslie TS has two DESNs connected to the 230 kV system. The T1/T2 DESN 1 supplies load at 27.6 kV and 13.8 kV, while the T3/4 DESN 2 supplies load at 27.6 kV. The total station capacity of Leslie TS is 325 MW. The T1/T2 DESN 1 has a capacity of 149 MVA (134 MW) and the T3/T4 DESN 2 has a capacity of 194 MVA (175 MW). While the other three transformers are relatively new (installed between 1988 and 2012), transformer T1, which was installed in 1963, may require replacement within the planning horizon of this IRRP, even though it has yet to be identified as being at the end of its life.

The T3/T4 DESN 2 is forecast to reach its capacity as early as 2033. Assuming the potential impact of future efficiency codes and standards, the timing of this need is deferred to 2039. Figure 6-11 shows the demand outlook for the two DESNs at Leslie TS, as compared to the individual capacity of each DESN.

Figure 6-11: Demand Outlook for Leslie TS Compared to Capacity





Wiltshire TS

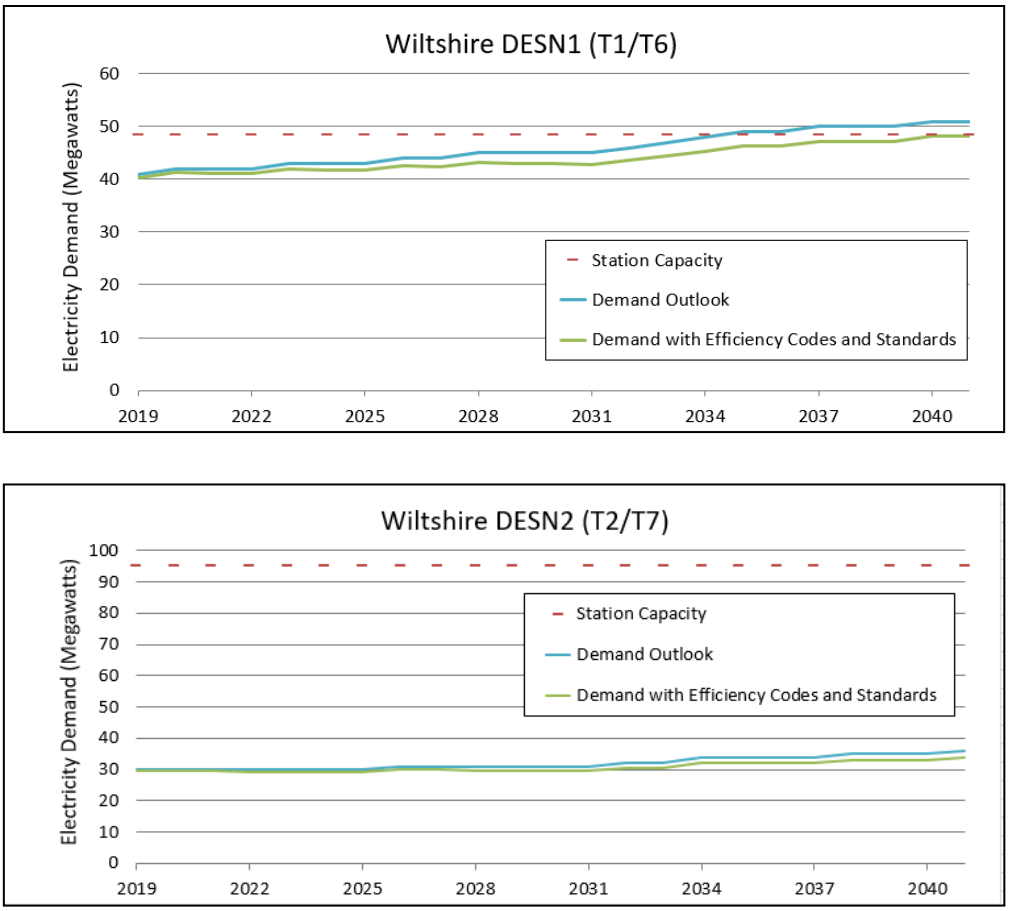
Wiltshire TS has two DESNs connected to the 115 kV system supplied from the Manby TS (East Yard). Wiltshire TS supplies customer demand to the northwest of the downtown core, including the Junction neighbourhood, at 13.8 kV distribution voltage. The two DESNs have a combined capacity of 151 MVA, or 136 MW: 51 MVA for the T1/T6 DESN 1, and 100 MVA for the T2/T7 DESN 2. These two DESNs supply three Toronto Hydro 13.8 kV buses.

The outlook is forecasting load growth at Wiltshire TS, which can be attributed to growth and urban redevelopment in the area.

The T1/T6 DESN 1 is forecast to reach its capacity as early as 2035. Assuming the future potential impact of efficiency codes and standards, the timing of this need is beyond the study period.

Figure 6-12 shows the demand outlook for the two DESNs at Wiltshire TS, as compared to the capacity of each DESN.

Figure 6-12: Demand Outlook for Wiltshire TS DESN Compared to Capacity



6.2.2.2 Regional Supply Capacity Needs

Regional capacity needs are related to the 230 kV or 115 kV transmission system that delivers electricity from the interconnected grid into Toronto. The planning studies re-tested the need for the Richview TS to Manby TS 230 kV corridor upgrades that were recommended in the previous planning cycle. The results of this assessment reaffirm this need and are reported in this section. In the longer term, regional supply capacity needs emerge at Leaside TS, Manby TS, and on some 115 kV circuits within the Manby and Leaside Sectors.

Richview TS to Manby TS 230 kV corridor

The previous cycle of regional planning recommended that the 230 kV bulk supply to Manby TS from Richview TS be reinforced to accommodate demand growth in Toronto, primarily driven in the near term by mass transit projects. The planning studies undertaken for this IRRP re-tested the need for this additional LMC upstream of Manby TS, accounting for changes in assumptions related to the revised demand outlook provided by Toronto Hydro for the purpose of undertaking this IRRP, and the peak demand outlook for Cooksville west stations from the 2015 GTA West Needs Assessment.

The assessment confirmed that, under normal system configuration, the most limiting contingency is the loss, in 2021, of circuit R15K, which would cause R2K (also running from Richview TS to Manby TS) to exceed its capacity rating. This limitation exists regardless of whether the Metrolinx traction power substation (TPSS) is in-service; however, the additional capacity will support further mass transit electrification.

Without reinforcement to the Richview TS to Manby TS 230 kV circuits, the ability to transfer Dufferin TS to Manby East supply can become limited during summer peak conditions, following the same R15K single contingency. As discussed below (under Leaside TS and Manby TS autotransformers), transferring Dufferin TS to Manby TS supply is a possible control action in a PEC out-of-service scenario (as well as other issues that could impact supply in the Leaside TS sector). Since having this control action available helps ensure a reliable and resilient transmission supply to Toronto, the Working Group continues to recommend reinforcement of the Richview TS to Manby TS 230 kV circuits with a target in-service date as soon as possible.

The detailed assessment of the Richview TS to Manby TS corridor need is provided in Appendix F: Richview TS to Manby TS Corridor Study.

Supply to downtown Toronto from Manby West (Manby to Riverside Junction)

The Manby West supply sector comprises four 115 kV supply circuits (H2JK, K6J, K13J, and K14J), which run from Manby TS to Riverside Junction on overhead lines, with two (and in some spans, up to four) circuits on a common structure. From Riverside Junction, these circuits

run underground to supply the downtown core.[15] The Manby West supply sector is considered "non-bulk" and is designed to continuously supply demand up to the loss of a single circuit.

The planning studies are showing that all four Manby TS to Riverside Junction circuits violate the reliability criteria between 2030 and 2040. Under the most severe single element loss, the remaining circuits can be as much as 120 per cent overloaded by 2040. This is a reliability concern that will need to be addressed in the long term.

Leaside TS and Manby TS autotransformers

The assessment of the Leaside autotransformer capacity is related to the presence and capacity of the 550 MW PEC facility, as both PEC and Leaside TS supply the Leaside sector. With an outage to the PEC steam turbine generator, the output of the plant would be reduced to 160 MW. Under this scenario, the Leaside autotransformers will begin to exceed their capacity limits by the 2030 to 2040 time frame, following outages on the 230 kV transmission lines that supply Leaside TS from Cherrywood TS upstream. With a full PEC outage, two of the six autotransformers at Leaside TS (T15 and T16) would be overloaded under peak demand conditions.[16]

During short-term outages of elements of PEC, system control actions to reduce the Leaside sector load through the transfer of Dufferin TS to the Manby sector will alleviate pressure on the Leaside autotransformers. While this is an acceptable short-term measure, it is not considered a permanent solution because it exposes the Manby sector, and Dufferin TS customers in particular, to supply security risks related to transmission outages in the Manby sector.

Manby TS autotransformer capacity needs were identified as emerging by the 2030 to 2040 time frame. This capacity constraint is related to the rating of the smallest autotransformer at Manby TS (T12) following the loss of a companion transformer. There may be value in factoring these findings into the end of life replacement of the Manby TS autotransformers in 2025-2026, if there is a cost-effective and technically feasible means of addressing this capacity constraint within the scope of the replacement.

[15] The underground section from Riverside Junction to Strachan Avenue have been recently refurbished due to its age and condition.

[16] The 2030 forecast year was used to assess the full PEC outage scenario; it is likely that if such a scenario were experienced today at the time of system peak, then the Leaside TS autotransformers could experience an overload.

Bayview Junction to Balfour circuit (L15W) thermal capacity

The planning assessment shows that following the loss of circuit L14W, the companion circuit L15 (from Bayview Junction to Balfour Junction in the Leaside sector[17]) is forecast to marginally exceed its Long term emergency rating (LTE) in 2040. This need is deferred beyond the planning horizon once the forecast efficiency codes and standards savings are taken into account.

6.2.3 Load Security Needs

The transmission system must exhibit acceptable performance while following specified design criteria contingencies. The load security criteria can be found in Section 7.1 of ORTAC, and a summary of the load security criteria can be found in Table 6-4. All transformer stations in the Toronto region have at least a dual transmission supply, which allows the load served at the station to remain uninterrupted in the event of a single element contingency. Supply interruptions may occur after multiple element contingencies, but under all possible interruption scenarios, the amount of load interrupted remains within the limits prescribed in ORTAC.

Table 6-4: Load Security Criteria

Number of transmission elements out of service	Local generation outage?	Amount of load allowed to be interrupted by configuration	Amount of load allowed to be interrupted by load rejection or curtailment	Total amount of load allowed to be interrupted by configuration, load rejection, and/or curtailment
One	No	≤ 150 MW	None	≤ 150 MW
	Yes	≤ 150 MW	≤ 150 MW	≤ 150 MW
Two	No	≤ 600 MW	≤ 150 MW	≤ 600 MW
	Yes	≤ 600 MW	≤ 600 MW	≤ 600 MW

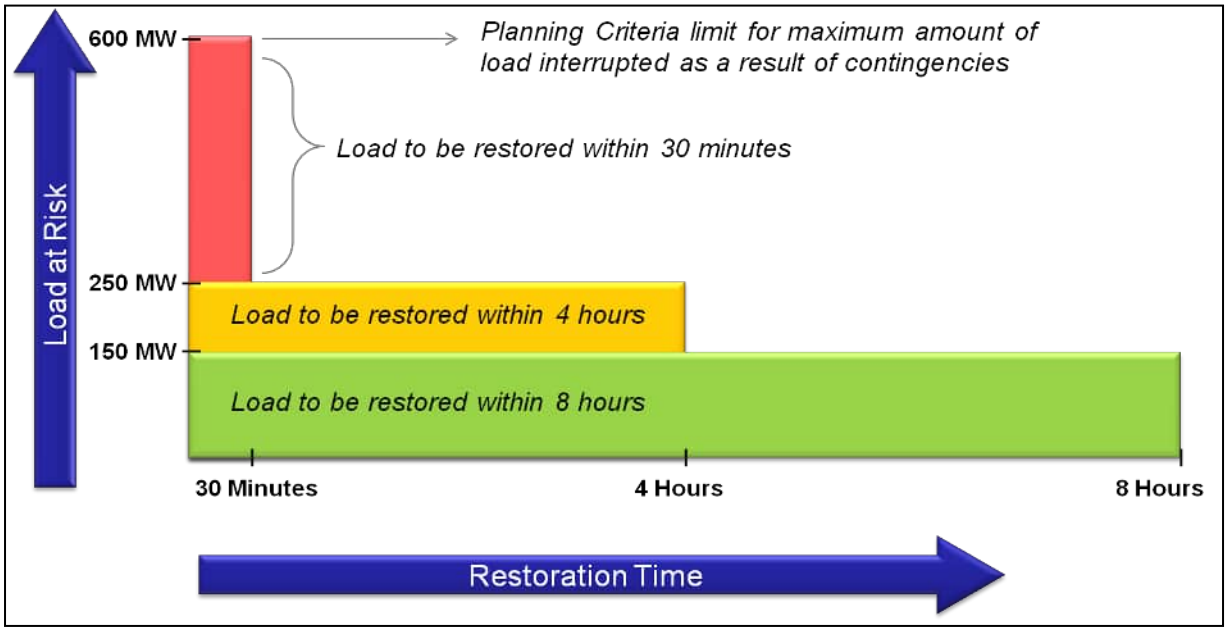
6.2.4 Load Restoration Needs

Described in Section 7.2 of ORTAC, load restoration criteria specify that the transmission system must be planned such that following design criteria contingencies, all interrupted load must be restored within approximately eight hours. When the load interrupted is greater than

[17] These circuits are part of the path supplying Wiltshire TS from Leaside TS.

150 MW, the amount of load in excess of 150 MW must be restored within approximately four hours. When the load interrupted is greater than 250 MW, the amount of load in excess of 250 MW must be restored within 30 minutes. A visual representation of the load restoration criteria is shown in Figure 6-13.

Figure 6-13: Load Restoration Criteria



No load restoration needs were identified in the Toronto region following the design criteria contingencies that were tested. Under a situation where load loss has occurred and the transmission system has been reconfigured to restore power, but some customers are still experiencing an outage, additional measures may be taken in the operational time frame. These measures may include dispatching crews to repair the transmission system, reconfiguring the transmission or distribution system to transfer load to another delivery point, and use of temporary facilities, etc. Although electricity interruptions can not be eliminated, where possible, the system operator, transmitter, and distributor will undertake measures in real time to respond to outages and restore load as quickly as possible.

6.2.5 Discretionary Reliability Needs

Reliability performance is, in part, a function of the criteria that the transmission system needs to meet. In other words, the planning criteria stipulate the functional requirements of the transmission system to ensure reliability performance. Within Toronto, specific criteria apply to different parts of the transmission system because of the function and resulting consequences of

the loss of those different parts. In other words, less stringent criteria generally apply to transmission facilities where the impact is only local. Conversely, more stringent criteria apply when the consequences of a loss have a wider impact on the interconnected grid. The stringency of the planning criteria is commensurate with the severity of the consequence of contingencies that can impact the interconnected grid.

While, for study purposes, this plan applied the more stringent criteria to all parts of Toronto's transmission system (e.g., by assessing 'local area' facilities against 'bulk power system' criteria), not all areas are required to meet the more stringent criteria. ORTAC (Section 7.4) permits higher levels of reliability to be adopted for specified reasons. The results of the assessment in this study highlighted some 'discretionary reliability needs' for the purpose of generating insights as to where there may be opportunities to improve performance, but for which actions to resolve them are not required by the performance criteria that govern the planning and design of the electric power system. The discretionary reliability needs are documented in Appendix D: Toronto IRRP Study Results.

6.2.6 System Resilience for Extreme Events

One of the key measures of a resilient transmission system is its ability to withstand interruption, or restore supply during or after extreme events that impact many parts of the system. This section summarizes the capability, following analysis, of Toronto's regional transmission system to maintain supply and manage the risk posed by low-probability, high-impact events.

In 2013, the IESO conducted an assessment of the amount of load that could be restored following specific extreme contingencies involving the system that supplies downtown Toronto. The results of this assessment have not been made public due to security concerns related to the disclosure of critical energy infrastructure information and possible system vulnerabilities.

For this IRRP, key scenarios from the 2013 study were re-examined for the years 2020 and 2025. These include the loss of:

- Manby TS 115 kV switchyard
- Leaside TS 115 kV switchyard
- Four circuit tower structures emanating from the Manby TS and Leaside TS 115 kV switchyards

The results of the updated analysis found that the impact of the extreme contingencies on the 115 kV transmission system was limited to load interruptions within the Toronto region.

6.3 Summary of Needs Identified

Table 6-5 summarizes the electric power system needs identified in this IRRP. Note that discretionary needs identified in Section 6.2.5 are not included because these issues are flagged as potential opportunities to enhance reliability to Toronto but they do not require actions to address them at the present time.

Table 6-5: Summary of Needs Identified

Facilities	Need	Expected Timing
End-of-Life Assets		
Leaside Junction to Bloor Street 115 kV overhead transmission lines (H1L/H3L/H6LC/H8LC)	End of life of the approximate 2 km overhead line sections	2022-2023
Leaside TS to Balfour Junction 115 kV overhead transmission lines (L9C/L12C)	End of life of the approximate 3.6 km overhead line sections	2023-2024
Main TS	End of life of transformers T3 and T4, 115 kV line disconnect switches, and 115 kV current voltage transformers	2021-2022
Esplanade TS to Terauley TS 115 kV underground transmission cables (C5E and C7E)	End of life of underground cables from Esplanade TS to Terauley TS in downtown Toronto	2024-2025
Manby TS	End of life of major station equipment, including: autotransformers T7, T9 and T12, step-down transformer T13, and the 230 kV yard	2025-2026
John TS	End of life of transformers and 115 kV breakers	2026-2027
Bermondsey TS	End of life of transformers T3 and T4	2025-2026
Local Transformer Station Capacity		
Manby TS (DESN)	A transformer capacity need was identified for the load supplied by all three DESNs	2023
Strachan TS	A transformer capacity need was identified for the load supplied by both DESNs	2030

Facilities	Need	Expected Timing
Basin TS	A transformer capacity need was identified for the load supplied by the T3/T5 DESN (the only DESN at Basin)	2033
Leslie TS	A transformer capacity need was identified for the load supplied by the T3/T4 DESN	2033
Wiltshire TS	A transformer capacity need was identified for the load supplied by the T1/T6 DESN	2035
Regional Capacity		
Richview TS to Manby TS 230 kV Corridor	Load meeting capability upstream of Manby TS	2021
Supply to downtown Toronto from Manby West (Manby to Riverside Junction)	Load meeting capability of the 115 kV lines supplying downtown Toronto	2030-2040
Leaside TS and Manby TS	A capacity need was identified for Leaside TS and Manby TS 230/115 kV autotransformers	2030-2040
Bayview Junction to Balfour Junction Circuits	Overloading of L15 circuit for the loss of its companion circuit, L14W	2040

7. Plan Options and Recommendations

This section outlines the options considered to address transmission needs in the Toronto region, as well as the recommended plan with respect to each of these needs.

In considering options and developing recommendations, the Working Group has been mindful of the interest and preference, communicated through engagement with stakeholders, such as the City of Toronto, a local advisory committee that was in place from 2016 to 2018, and the general public, to explore NWAs, such as DERs, for dealing with electricity system needs.

Given the interest in NWAs as possible solutions for addressing Toronto's regional transmission needs, additional context on the changing landscape with respect to these resources, and on the approach to considering them, is provided below.

DERs as options to address needs in Toronto

The uptake in DERs across the province over the last decade is having an impact on the electricity system, both in terms of system demand and operability. While centralized procurement programs that supported the development of most DERs[18] are no longer in place, DER deployment is expected to continue in Toronto. Toronto Hydro has filed investment plans for approval with the OEB to increase its ability to connect DERs to its system, and the IESO has expressed support for these plans.[19]

Much of the IESO's recent work with respect to DERs has focused on identifying the barriers to their development as alternatives to wires-based solutions, and options for reducing or overcoming those barriers. Specifically, the barriers to implementation of cost-effective NWAs, including DERs, in regional planning are being investigated as part of the IESO's regional planning review initiative.[20] Further, a number of DER-focused initiatives are being undertaken as part of the work plan associated with the IESO's *Innovation Roadmap*.[21] These initiatives

[18] Since 2006, nearly 2,000 distributed energy resources (DERs), including solar PV, CHP, energy storage and wind, have connected to Toronto's distribution system.
[19] See Toronto Hydro's rate application EB-2018-0165, Exhibit 2B, Section E7.2; and Exhibit 2B, Section B, Appendix F for IESO's Comment Letter.
[20] Launched in 2018, the regional planning review process is exploring a number of enhancements to regional planning, including potential barriers to non-wires solutions, opportunities for coordination between bulk system planning, community energy planning and market renewal, and a long term approach to replacing end-of-life transmission assets.
[21] http://www.ieso.ca/en/Get-Involved/Innovation/Innovation-Roadmap

include research and white papers, demonstration and evaluation projects, and capital projects and process improvements. For a full list and descriptions, visit the innovation projects page on ieso.ca.

The Working Group believes that DERs need to continue to be studied to build the necessary tools and experience required to consider and evaluate them as potential solutions to regional electricity needs. This work is being undertaken through the above mentioned work plan. In the meantime, continued dialogue with the community is expected to play an important role in defining the potential for cost-effective NWA solutions. Further details are provided in the plan recommendations.

7.1 Evaluating Plan Options for Addressing Needs Identified in Toronto

The following sections describe the options considered to address the needs identified in Section 6.2.

The evaluation of possible plan options takes into consideration a number of factors, including technical feasibility, timing, cost, and alignment with local priorities. In light of the importance of cost as a planning consideration, solutions that are cost-effective and that maximize the use of existing infrastructure and assets are typically given priority for inclusion in the evaluation.

To help ensure that solutions will be available in time to address pressing needs, the IRRP identifies specific actions to be undertaken and/or implemented in the near and medium term. Given forecast uncertainty and the potential for technological and policy changes, investment in longer-term needs is not prudent at this point in time. Instead, the long term plan focuses on developing and maintaining the viability of long term options, engaging with communities, and gathering information to lay the groundwork for making decisions on future options.

As discussed in Section 6, solutions are needed to address (1) end of life asset replacements; (2) local transformer station capacity, and (3) regional supply capacity needs. In addition, the plan identifies some discretionary needs related to maintaining a higher level of reliability performance than those prescribed in ORTAC. This recognizes Toronto's position as the largest urban centre in Canada, and the ORTAC provision allowing the transmission customer and transmitter to agree on higher (or lower) levels of reliability. Firm recommendations to address discretionary needs are dependent on the availability of cost-effective solutions and the risk of the need materializing.

In developing the plan, the Working Group examined a range of solutions to address the near term needs, as well as activities to begin to lay a foundation for addressing needs in the longer term. These options are discussed and evaluated in the following sections.

7.1.1 Options for Addressing End of Life Asset Replacement

When transmission equipment reaches end of life, a number of alternatives can be considered. Transmission or distribution facilities may have changed since the equipment was built, community needs may have evolved, equipment standards may have changed, and/or opportunities for other options, such as energy efficiency, may be able to play a role.

Options to address end of life asset replacement needs in the Toronto region included:

- Retiring the asset or facilities
- Replacing the assets to the "right size" (e.g., larger or smaller) based on considerations, including future electricity demand, or changes to the use of the asset to realize reliability, resilience, or other benefits that an alternate configuration may provide
- Replacing the assets "like for like" or with the closest current equivalent
- Implementing NWAs

Based on the assessments conducted in this IRRP, each of the assets reaching its end of life in this plan was deemed critical for maintaining a sufficient and reliable supply of electricity to customers. As such, and given the magnitude and persistence of the needs, complete retirement and replacement with NWAs was screened out as an alternative in favour of replacing the assets with the closest available equivalent.

Leaside Junction to Bloor Street Junction 115 kV overhead transmission lines (H1L/H3L/H6LC/H8LC)

Three options were assessed to inform the preferred approach for addressing this end of life overhead line section:

1. **Replace the existing lines with 230 kV capable lines to increase future capacity (but continue to operate at 115 kV, for now):** This approach was ruled out because assessment indicated that none of these circuits would be thermally limited within the planning horizon. Also, because there is no plan to increase the transmission supply voltage (e.g., to 230 kV) to any of the stations supplied by the HxL or HxLC circuits, there would be no benefit for investing in replacement circuits at a higher operating voltage (or any associated tower investments) within the planning horizon.

2. **Replace the existing lines with 115 kV lines (like for like, built to current standards):** The planning assessments show that the LMC of the 115 kV transmission lines is adequate to supply the needs of Toronto within the planning horizon. New 115 kV transmission lines along this path built to today's standards are expected to be able to carry more load, and operate in a more reliable manner, as compared to the existing equipment.

3. **Replace end of life assets with NWAs:** As NWAs, such as energy efficiency or DERs, would be very expensive compared to replacing end of life assets, the Working Group determined that they do not present a viable approach.

Table 7-1 summarizes the considerations related to the options. Based on the evaluation of the alternatives, this IRRP recommends that Hydro One proceed with like for like replacement of the end of life line sections.

Table 7-1: Options for Addressing Leaside Junction to Bloor Street Junction 115 kV Lines

	Replace with 230 kV capable	Replace like for like
Summary of Option	• Rebuild the existing line section to meet 230 kV standard	• Refurbish the existing line section with the equivalent voltage standard
Potential Benefits	• Maintain capacity (if energized at 115 kV) or increase capacity (if energized at 230 kV) • Maintains reliability • Contributes to introducing 230 kV supply to downtown	• Maintain or improve capacity and reliability • Better in-service date certainty
Potential Risks/ Issues	• If never energized at 230 kV, incremental costs for 230 kV capability will not provide value	• None if the work is scheduled and completed outside of the peak demand season

Leaside TS to Balfour Junction 115 kV overhead transmission lines (L9C/L12C)

These two lines are critical for supplying Toronto's electricity needs. Three options were assessed to inform a recommendation on the preferred approach to address this end of life overhead line section:

1. **Replace the existing lines with 230 kV capable lines (but continue to operate at 115 kV for now):** This approach was ruled out because assessment results indicated that none of these would be thermally limited within the planning horizon. Since there is not a plan to increase the transmission supply voltage to any of the stations supplied by these lines, it would not be beneficial to invest in replacement circuits at a higher operating voltage (or any associated tower investments).

2. **Replace the existing lines with 115 kV lines (like for like, built to current standards):** The planning assessments show that the LMC of the 115 kV transmission lines is adequate to supply the needs of Toronto within the planning horizon.

3. **Replace end of life assets with NWAs:** Given that energy efficiency, DERs and other NWAs would be very expensive compared to replacing end of life assets, the Working Group determined that NWAs do not present a viable approach.

Table 7-2 summarizes the considerations related to the options. Based on the evaluation of the alternatives, this IRRP recommends that Hydro One proceed with like for like replacement of the end of life line sections.

Table 7-2: Options for Addressing Leaside TS to Balfour Junction Transmission

	Replace with 230 kV	Replace like for like
Summary of Option	• Rebuild the existing line section to meet 230 kV standard	• Refurbish the existing line section with the equivalent voltage standard
Potential Benefits	• Maintain capacity (if energized at 115 kV) or increase capacity (if energized at 230 kV) • Maintain reliability • Contributes to introducing 230 kV supply to downtown	• Maintain or improve capacity and reliability • Better in-service date certainty
Potential Risks/ Issues	• If never energized at 230 kV, incremental costs for 230 kV capability will not provide value	• None if the work is scheduled and completed outside of the peak demand season

Main TS

The IRRP looked at different approaches for addressing end of life assets at Main TS, which include the two step-down transformers and associated medium-voltage switchgear. Eliminating the station outright was not considered to be a feasible option, as it is over 70 per cent utilized and resupplying the customer demand in the area from adjacent station facilities is not possible with the existing infrastructure.

NWAs, including energy efficiency or DERs, are not suitable options for addressing asset condition-related needs. As an alternative to the step-down station, energy efficiency or DERs would be cost prohibitive as compared to replacing end of life assets.

Other options were considered and are discussed below:

1. **Converting Main TS to 230 kV operation:** Providing a 230 kV connection to Main TS could be achieved by rebuilding the existing 115 kV supply circuits from Leaside TS (H7L and H11L), or by building a new 230 kV line. New 230 kV transformers and associated high-voltage switchgear would be needed at the existing station, or at a new station location. The 115 kV rebuild option would make the existing H7L and H11L circuits unavailable to supply Hearn station from Leaside TS, while building a new 230 kV connection would be very expensive. In addition, as Main TS is space constrained, the larger 230 kV transformers may not be accommodated on the existing site. As property for building a new station in the vicinity is also limited, this alternative was deemed not viable.

2. **Supplying Toronto Hydro's switchgear from new transformers at Warden TS:** As this approach would require the building of several new distribution cable circuits from Warden TS, which is 4.5 km from Main TS, the Working Group determined that this alternative would be expensive, and impractical, considering the number and length of new distribution cables required.

3. **Replacing the transformers at the existing Main TS location with new 115 kV transformers:** This approach is technically feasible and can be accommodated at the existing station location. Given the potential for future high density urban development in the Main TS service area, Toronto Hydro has recommended, that the existing 45/75 MVA transformers at Main TS be replaced with 60/100 MVA transformers. Even with the cost differential between the two transformer sizes – which Hydro One has estimated to be about $300,000 – the cost of this approach is far less than either option 1 or 2. The Working Group supports this recommendation.

Options 1 and 2 above would have the benefit of shifting load from the 230 kV/ 115 kV autotransformers at Leaside TS to the 230 kV system, providing capacity relief for the Leaside TS autotransformers. Option 3 is the most cost-effective, even with the marginal additional cost of replacing the existing 45/75 MVA transformers with 60/100 MVA transformers.

Table 7-3 summarizes the options assessed to address the end of life asset needs at Main TS.

Table 7-3: Options for Addressing Main TS End-of-life Assets

	Convert to 230 kV	Supply Main TS area from Warden TS	Replace Transformers at Main TS
Summary of Option	• Replace existing transformers with 230 kV transformers; rebuild the circuits supplying Main TS to 230 kV	• Install new 230 kV transformers at Warden TS and supply Main TS service area with new distribution cables from Warden TS	• Replace existing transformers at Main TS with new transformers; take the opportunity to install higher capacity transformers to supply future development in the area
Potential Benefits	• This option would provide relief to the Leaside TS 230 kV /115 kV transformers as it would move Main TS to 230 kV supply	• This option would provide relief to the Leaside TS 230 kV/ 115 kV transformers as it would move Main TS to 230 kV supply	• This option maximizes use of the existing infrastructure supplying the area • Provides capacity for area growth and development
Potential Risks/ Issues	• The cost would be very high • Capacity relief at Leaside TS may only be needed at or beyond the planning horizon • Main TS is a small station; this option may not be feasible	• The technical feasibility of running very long distribution feeders from Warden to Main TS load is uncertain; there may be reliability impacts • The cost would be very high • Capacity relief at Leaside TS may only be needed beyond the planning horizon	• This option does not provide capacity relief for Leaside TS, which may only be needed beyond the planning horizon • Does not preclude upgrading to 230 kV at a later date

C5E/C7E 115 kV underground transmission cables

Given the complexity and lead time required to implement underground infrastructure through downtown Toronto, Hydro One launched an EA process for the cable replacement in May 2018. Community engagement related to the options is currently underway, with five underground routes under consideration. The route investigation will consider stakeholder input, and assess existing easements and rights-of-way, costs, and other technical and environmental considerations. OEB Leave to Construct approval will also be required.

Since the Working Group has determined that there are no suitable alternatives to replacement, this IRRP recommends that Hydro One continue with actions to replace the existing 115 kV cables.

Manby TS

Given the extent of end of life assets at Manby TS, development of a well-coordinated plan will need to consider the capacity of the station to meet future growth needs in Toronto, accommodate additional short-term transfers to the Manby sector in the event of emergencies (such as a loss of Leaside sector supply or PEC outages), and maintain reliability. For example, the plan required to address the assets reaching end of life in the 230 kV switchyard should be coordinated with the remedial action scheme (RAS) recommended in the 2015 Central Toronto IRRP, with the new terminations required to accommodate the new Richview to Manby TS circuits, and the long term need for additional capacity to supply growth in downtown Toronto. NWAs were ruled out as feasible alternatives to address this end of life need.

The Working Group will continue to assess transmission options and develop a recommendation concerning the significant end of life asset needs at Manby TS. It is recommended that this work commence in the RIP.

John TS

The end of life needs at John TS represent a major undertaking that needs to be coordinated with other plans to reinforce step-down supply capacity in the downtown core, including Toronto Hydro's Copeland TS (Phase 1 and Phase 2). For example, Copeland TS will provide an opportunity to review the configuration and major equipment capacity (i.e., right sizing) at John TS, to ensure it meets future needs. Furthermore, the 115 kV station design is in a "ring-

bus" configuration and the end of life need provides an opportunity to review this configuration, while considering costs, operational flexibility, reliability to customers and transmission system development plans in the area.

Coordination of this work with Copeland TS is vital for providing the additional capacity to facilitate outage planning at John TS for the execution of a replacement plan, while maintaining reliable supply in Toronto's downtown district. Since this need is driven by the condition of the assets, NWAs were ruled out as feasible alternatives to address this end of life need.

The Working Group therefore recommends that the replacement plan for end of life equipment at John TS be further assessed through continued coordinated planning, commencing with the RIP.

Bermondsey TS

The station load is forecast to reach about 173 MW over the study period, after accounting for energy efficiency codes and standards. While there is a continuing requirement for the station to supply customers in the area, the total load on Bermondsey TS is forecasted to remain well below its current capacity over the planning horizon.

The options for addressing the asset end of life need at Bermondsey TS are summarized as follows:

1. **Retire (and decommission) the T3/T4 DESN at its end of life:** This option would mean supplying the entire load at Bermondsey TS from the T1/T2 DESN, and expanding the switchyard to accommodate new feeders (i.e., transferring the 12 feeders from the T3/T4 DESN to the T1/T2 DESN). However, this intra-station transfer would result in the remaining DESN nearing its capacity limit by the end of the study period.

2. **Replace the 84/140 MVA and 75/125 MVA end of life transformers with smaller 50/83 MVA transformers:** According to Hydro One, the cost of feeder work would be significantly more than the $600,000 savings for smaller size transformers ($300,000 per transformer).

3. **Replace like for like:** Based on the information available, this option will minimize the cost of end of life work at the station, while retaining some ability to grow and accommodate transfers within the station.

Based on the options put forth, NWAs were screened out at a feasible option to address this end of life need. Further assessment is needed to determine the cost and feasibility of option 2, above. The Working Group therefore recommends that a plan be developed within the scope of the RIP.

7.2 Options for Addressing Supply Capacity Needs

Based on the demand outlook, capacity needs in the Toronto region are centered on a number of transformer stations (DESNs) supplying local neighbourhoods in the city.

Local transformer station capacity needs at Manby TS, Strachan TS, Leslie TS and Wiltshire TS

For the need at Manby TS, the 2015 Central Toronto IRRP recommended that a second DESN be built at the adjacent Horner TS. Part of the rationale for the Horner TS expansion was to provide relief for Manby TS through permanent load transfers. The second DESN is expected to be in-service by late 2021.

The station capacity needs at Strachan TS, Leslie TS and Wiltshire TS are far enough into the future that there is sufficient time to monitor demand changes and revisit these needs in the next planning cycle. Further, based on a preliminary review of possible approaches, capacity is available either at other DESNs within the station, or at adjacent stations to permit planning for load transfers to provide relief to the DESNs that are forecast to reach their capacity. These transfers will require planning and investment to implement.[22]

To address the capacity need at Strachan TS, the capacity that is expected to be made available by Copeland TS (Phase 1 and Phase 2) is likely to allow for a permanent load transfer. While the feasibility of implementing such a transfer is not yet clear, there is sufficient time to monitor growth and assess the feasibility of various options. If demand grows faster than anticipated, or the forecast for energy efficiency changes, additional measures to address future capacity needs at Strachan TS – such as energy efficiency or other NWAs – can be explored and implemented, provided they are feasible and cost-effective.

[22] These types of actions are normally undertaken by the distributor as part of distribution system planning.

For the needs at Leslie TS and Wiltshire TS, capacity at other DESNs within the station is sufficient to accommodate additional load. This work will be undertaken by Toronto Hydro and Hydro One, with enough lead time to plan and implement intra-station transfers, if and when they are needed.

Local station capacity need at Basin TS

The capacity need at Basin TS arises as early as 2033; however, after considering the impact of efficiency codes and standards, the timing could be deferred to 2040. That said, a number of complicating factors related to the uncertainty of future demand growth at Basin TS must be taken into account. These relate to:

- Planned urban developments at the site and neighbourhood level
- City-led district energy plans
- The potential for economic growth, specifically related to intensification of commercial activity, for example, at the former Unilever site and the film studio district
- The relocation – proposed by the City of Toronto and Waterfront Toronto – of a significant number of existing high-voltage transmission facilities in the area

These uncertainties will impact the scope and timing of the needs, as well as the configuration of the electricity infrastructure in the area, including the ultimate size and location of Basin TS.

Cost-effective NWAs, including DERs and energy efficiency, should be explored to defer the needs at Basin TS, once they are further defined. Ongoing dialogue with stakeholders will be required to help identify feasible and cost-effective solutions, as well as prospective developments that could address the specific characteristics and timing of needs in the area. Since this is driven primarily by the need to supply local customers within Toronto Hydro's service territory, the Working Group agrees that the assessment of NWAs as potential solutions should be coordinated by Toronto Hydro.

7.3 Options for Addressing Regional Supply Capacity Needs

Options to address the regional supply capacity needs identified in Toronto are described below.

Richview TS to Manby TS 230 kV corridor

Options to address this need were assessed in the 2015 Central Toronto IRRP, the 2017 IRRP Addendum and the 2016 RIP by Hydro One. Since then, there have been no material changes to either the scope of the options or the preferred approach, which is planned to occur in the following two phases:

- **Phase One:** Rebuild the existing idle 115 kV overhead line on the transmission corridor between Richview TS and Manby TS to 230 kV. The new line will operate in parallel with the existing four 230 kV circuits from Richview TS to Manby TS, which will initially be reconfigured to create two "supercircuits." This will allow for the two additional circuits to supply Manby TS, but avoid the need to build new terminations, including new breakers at Manby.
- **Phase Two:** To be coordinated with the Manby TS end of life refurbishment, new circuits will be separately terminated on the Manby 230 kV bus, and at Richview TS they will connect to existing 230 kV circuits between Claireville TS and Richview TS, thereby unbundling the two supercircuits. The scope and timing for this work will be addressed starting with the RIP.

Based on the assessments undertaken by the IESO, the IRRP Working Group recommends that Hydro One proceed with the reinforcement of the Richview TS to Manby TS 230 kV transmission reinforcement project, including initiating community engagement, the EA, and OEB Section 92 Application for Leave to Construct.

Supply capacity at Leaside TS and Manby TS autotransformers, Manby TS to Riverside Junction lines, and Bayview Junction to Balfour Junction circuit section

These regional capacity needs do not emerge until between 2030 and 2040, depending on the assumptions around continued gains in energy efficiency resulting from efficiency codes and standards.

Leaside TS and Manby TS needs are related to the 230 kV/115 kV autotransformer capacity limits. The Manby TS to Riverside Junction line needs are related to the ability to supply the demand when there is a loss of a companion circuit. The Bayview Junction to Balfour Junction

needs emerge in 2040 and are related to the thermal rating of the 115 kV circuit, when there is a loss of the companion circuit.

Cost-effective NWAs, including DERs and energy efficiency, remain possible options to address each of these longer-term regional supply capacity needs. Ongoing engagement with stakeholders and the community will be important for understanding the potential for these types of options going forward. It will also be essential to gather enough information on the nature and timing of these needs to understand what performance and cost attributes NWA options will be required to address them.

7.4 Options for Addressing Discretionary Reliability Needs

These needs are included in Appendix D as discretionary because they represent possible opportunities to maintain and/or enhance the reliability of supply above the minimum performance standards prescribed in ORTAC. Their inclusion in this IRRP recognizes the importance of a reliable electricity supply to an urban centre like Toronto, should feasible, cost-effective options for improving reliability emerge as an outcome of continued planning, coordination, and engagement with electricity sector stakeholders and the community.

Although no specific solution options have been explored in the scope of this plan, these issues should be revisited in future plans, or as other opportunities arise to assess the adequacy and/or resilience of the system, including when assets approach their end of life.

7.5 The Recommended Plan

This IRRP re-affirms the needs and plans identified in the previous regional planning cycle that concluded in January 2016, and recommends the actions described below to address region's transmission needs until at least the late 2020s or early 2030s.

Replace end of life overhead line sections H1L/H3L/H6LC/H8LC and L9C/L12C

Both of these overhead line sections were deemed critical for maintaining a sufficient and reliable supply of electricity to customers in Toronto. The Working Group recommends that Hydro One proceed with planning for the like for like replacement of these overhead line sections.

Replace end of life transformers at Main TS

Both transformers at Main TS are at their end of life and need to be replaced. Considering the potential for future high density urban development in the area, the Working Group recommends that Hydro One proceed with planning to replace the existing transformers with 60/100 MVA transformers.

Continue planning for replacement of C5E/C7E underground transmission cables

When this regional plan was initiated, Hydro One was well into developing options to replace the existing C5E/C7E underground 115 kV cables running between Terauley TS and Esplanade TS in the downtown core. The Working Group recommends that Hydro One continue planning to replace the existing 115 kV cables.

Continue planning to determine end of life approaches for Manby TS, John TS, and Bermondsey TS

Manby TS and John TS: Planning for replacement of these critical electricity assets is a major undertaking that must consider a variety of factors and requires regional coordination. The Working Group recommends that detailed planning for the end of life of these assets continue, starting with the RIP.

Bermondsey TS: The Working Group recommends that the plan to replace the two end of life transformers at Bermondsey TS be completed within the scope of the RIP.

Gather information to inform future capacity planning for Basin TS

Since there is currently insufficient information to characterize the needs at Basin TS and inform specific recommendations in this IRRP, the Working Group proposes that any recommendation on potential solutions be deferred until the next cycle of regional planning, or earlier, as required.

Specifically, the Working Group recommends that Toronto Hydro coordinate continued planning activities related to defining the nature, scope and timing of the future capacity need at Basin TS, and assessment of possible wires and non-wires solutions to address the need. It is expected that this work will involve engaging with key stakeholders, including the City of Toronto and entities responsible for development in the Basin TS area.

If better information about the timing and nature of power system needs in the area indicates there is an urgent need, then Toronto Hydro will inform the Working Group of the need to initiate the next regional planning cycle early.

Proceed with reinforcement of the Richview TS to Manby TS 230 kV corridor

This IRRP re-affirms the need for the Richview TS to Manby TS 230 kV corridor reinforcement that was recommended in the previous regional planning cycle. The Working Group therefore recommends that Hydro One proceed with the reinforcement of the Richview TS to Manby TS 230 kV corridor and begin community engagement, as well as initiate the EA to ensure that the reinforced corridor is in-service as soon as possible.

Keep options available to address long term regional supply capacity needs

The IESO will monitor peak demand annually, along with achievement of energy efficiency and DER uptake, with a particular focus on the areas with forecasted capacity needs. This information will be used to determine when decisions on the long term plan are required, and to inform the next cycle of regional planning for the area. This work will include detailed planning and community engagement to define the needs and associated timing in a manner that will permit the evaluation of possible NWAs as solutions.

The Working Group therefore recommends that the IESO coordinate continued planning work and engagement with stakeholders and the community to define and communicate, as soon as practicable, the longer-term capacity needs; identify opportunities for a range of cost-effective solutions, including DERs and energy efficiency; and identify potential wires solutions and avoidable costs should these needs be deferred through NWAs. The information and insights developed through these activities will be used to inform the next regional planning cycle.

7.5.1 Implementation of Recommended Plan

To ensure that the near term electricity needs of the Toronto region are addressed, plan recommendations will need to be implemented as soon as possible. Specific actions and deliverables are outlined in Table 7-4, along with the recommended timing.

Table 7-4: Summary of Needs and Recommended Actions in Toronto Region

Need	Recommended Action(s)/Deliverable(s)	Lead Responsibility	Time frame/ Need Date
End-of-life of overhead line sections H1L / H3L / H6LC / H8LC and L9C / L12C	Proceed with replacement as needed to meet identified timelines	Hydro One	2022-2033 for HxL/HxLC circuits; 2023-2024 for LxC circuits
End-of-life of Main TS transformers, 115 kV disconnect switches and 115 kV current voltage transformers	Proceed with replacement as needed to meet identified timelines	Hydro One	2021-2022
End-of-life of C5E / C7E underground transmission cables	Continue with EA, and proceed with replacement to meet identified timelines	Hydro One	2024-2025
End-of-life assets at Manby TS, John TS and Bermondsey TS	Continue with detailed planning to make a decision in time to address the need; initiate in the Regional Infrastructure Plan	Working Group	2025-2027
Capacity to supply projected load at Manby TS	Continue with implementation of Horner TS expansion to provide relief	Hydro One	2021
Capacity to supply projected load at Basin TS	Continue to gather information to inform assessment of future need and timing; engage with key stakeholders; trigger regional planning if necessary	Toronto Hydro	2019 to next planning cycle
Richview to Manby TS 230 kV reinforcement	Initiate EA work, community engagement, and OEB Section 92 Application	Hydro One	2021 or as soon as possible

Need	Recommended Action(s)/Deliverable(s)	Lead Responsibility	Time frame/ Need Date
Leaside TS and Manby TS autotransformer capacity; Manby TS to Riverside Junction; and Bayview Junction to Balfour Junction	Further define characteristics of longer-term needs; define information needed from local stakeholders; identify DER and energy efficiency potential; develop wires-based alternatives; assess and compare wires and NWAs	IESO	2019 to next planning cycle

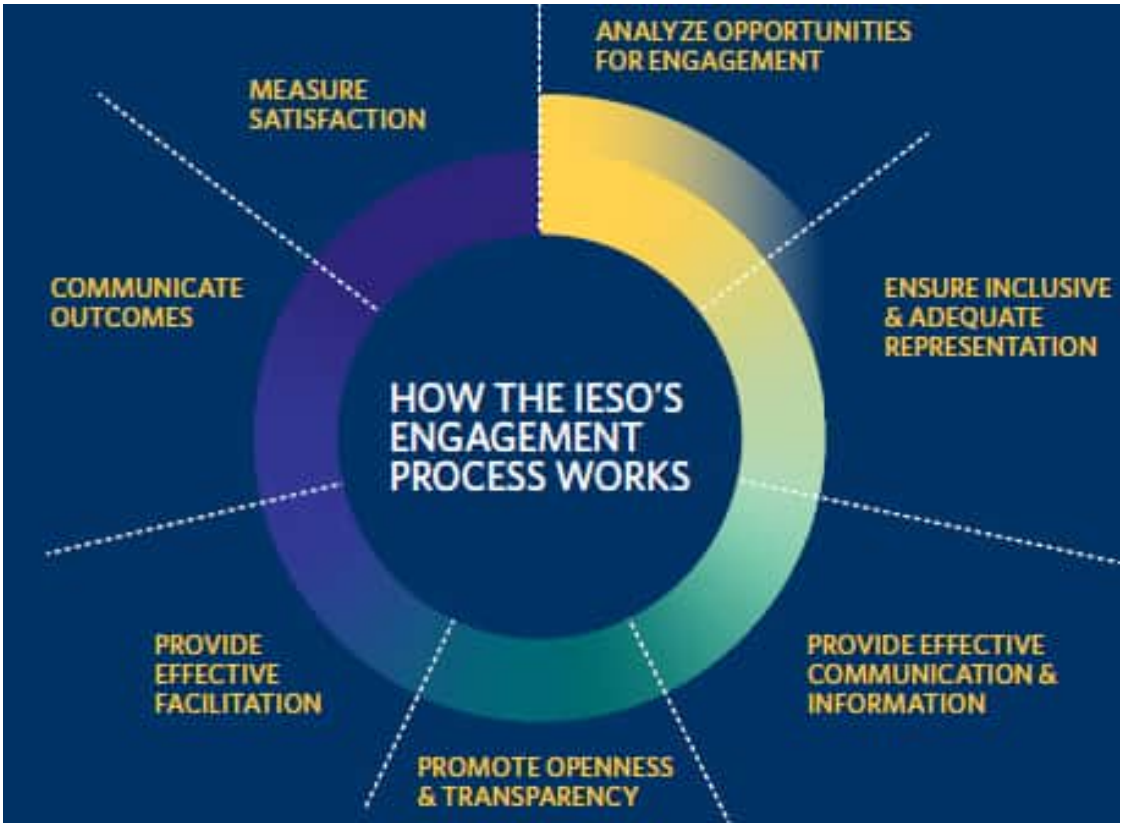
8. Community and Stakeholder Engagement

Community engagement is an integral component of the regional planning process. Providing opportunities for input in regional planning enables the views and preferences of the community to be considered in the development of an IRRP and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken for the Toronto IRRP.

8.1 Engagement Principles

The IESO's Engagement Principles[23] guided the process to help ensure that all interested parties were aware of and could contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, and to support its efforts to build trusted relationships.

Figure 9-1: IESO Engagement Principles



[23] http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Overview/Engagement-Principles

8.2 Creating an Engagement Approach

The outreach and engagement approach was designed to ensure the IRRP reflected input from key community and stakeholder representatives. A dedicated engagement web page[24] was also created to provide openness and transparency throughout the engagement process. This web page hosted all engagement activities, including background information, presentations and public meetings/webinars on the development of this IRRP, as well as previous plans for the area.

The IESO's email subscription service for the Toronto planning region was used to send information to interested communities and stakeholders who subscribed to receive updates. Targeted outreach to municipalities, Indigenous communities and other business sectors in the region was also conducted at the outset of this engagement and continued throughout the planning process.

In addition, regular communications were sent via the IESO's weekly Bulletin, which has subscribers from across Ontario's electricity sector.

8.3 Engage Early and Often

Leveraging relationships built during the previous planning cycle, the IESO held preliminary discussions to help inform the engagement approach during this second planning cycle – starting with the Scoping Assessment Outcome Report.

Early communication and engagement activities for the Toronto IRRP began with invitations to all subscribers and targeted communities to learn about and provide comments on the draft Toronto Region Scoping Assessment Outcome Report before it was finalized in February 2018. This scoping assessment identified the need for an IRRP for the Toronto region and included terms of reference to guide development of the plan. Following feedback, and the IESO's response to feedback – both of which are posted on the engagement web page – the final Scoping Assessment Outcome Report was also published.

Outreach then began with targeted communities to inform early discussions for the development of the IRRP. The launch of a broader engagement initiative followed with an

[24] http://ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Integrated-Regional-Resource-Plan-Toronto

invitation to subscribers to ensure that all interested parties were made aware of this opportunity for input.

A public engagement meeting, held to give interested parties an opportunity to learn about the draft IRRP and provide comments, attracted a cross-representation of stakeholder and community representatives. Following a 14-day comment period, no further comments were received for consideration during the development of the IRRP.

As a final step in this engagement, all participating parties were invited to comment on the proposed recommendations in this IRRP. Comments received during the engagement meeting and in response to the proposed recommendations related to six major themes:

1. Non-wires alternatives
2. Considerations to inform future electricity needs in electricity system planning
3. Electrification (e.g., electric vehicles)
4. Costs of the electricity system
5. Composition of the technical working group
6. Engagement/education

Based on this feedback, it is clear that there is a strong need for ongoing monitoring of capacity and local demand growth, as well as continued discussion and engagement with communities and stakeholders. While needs do not start to emerge until the 2030s or later, the IESO recognizes the importance of sustained dialogue to ensure alignment with local priorities, initiatives and developments. The full submissions can be found on the IESO's website. Reponses to specific feedback are provided as Appendix G: Responses to Public Feedback on Proposed Recommendations.

All background information, including engagement presentations and recorded webinars, are available on the IESO's Integrated Regional Resource Plan engagement web page.

8.4 Outreach with Municipalities

As the City of Toronto was a key stakeholder in the development of this IRRP, the IESO held a number of meetings with city representatives to seek input on municipal planning and to ensure that the city's plans were taken into consideration. Meetings began in June 2018 at the outset of these discussions and continued in April and May 2019. These meetings helped to inform the city's electricity needs and provided opportunities to strengthen this relationship for ongoing dialogue beyond this IRRP process.

9. Conclusion

This report documents an IRRP that has been developed for the Toronto region, and identifies regional electricity needs and opportunities to preserve or enhance electricity system reliability in Toronto from 2019 to 2040. The IRRP makes recommendations to address near term issues, and lays out actions to monitor, defer, and address long term needs.

To further review "wires" solutions that address end of life asset replacement and other transmission supply needs, the Working Group recommends that Hydro One initiate an RIP. The IESO will continue to provide input and support throughout the RIP process, and assist with any regulatory matters arising during plan implementation.

To support the development of the plan, this IRRP includes recommendations with respect to developing alternatives, monitoring load growth and efficiency achievements, and evaluating DER potential and value in the region. Responsibility for these actions has been assigned to the appropriate members of the Working Group. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the regional plan for the Toronto region.

The Toronto region Working Group will continue to meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.



Toronto Region Scoping Assessment Outcome Report

March 21, 2023

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1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's regional planning process, as defined through the Transmission System Code, Distribution System Code, and IESO license.

This is the third cycle of regional planning for the Toronto region, and it was initiated in fall 2022. Information and links to earlier products are available on the IESO webpage, here. The Needs Assessment is the first step in the regional planning process and was carried out by the Technical Working Group (TWG) led by Hydro One. The Needs Assessment Report was finalized on December 19, 2022 and identified some needs that may require further regional coordination. This need information was an input into the Scoping Assessment. The Technical Working Group reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach. It also considered past or ongoing initiatives in the region, including the recent Pathways to Decarbonization report.

The Scoping Assessment considers three potential planning approaches for the region (or sub-regions, if applicable), including: an IRRP – where both wires and non-wires options have potential to address needs; a Regional Infrastructure Plan (RIP) – which considers wires-only options; or a local plan undertaken by the transmitter and affected local distribution company – where no further regional coordination is needed.

This Scoping Assessment report:

- Lists the needs requiring more comprehensive planning, as identified in the Needs Assessment report;
- Reassesses the areas that need to be studied and the geographic grouping of the needs (if required);
- Considers impacts on planning assumptions and potential outcomes on needs resulting from local and provincial policy goals;
- Determines the appropriate regional planning approach and scope where a need for regional coordination or more comprehensive planning is identified;
- Establishes a terms of reference for an IRRP, if an IRRP is required; and
- Establishes the composition of the IRRP Technical Working Group.

2. Technical Working Group

The Scoping Assessment was carried out with the following participants:

- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Transmission)
- Toronto Hydro Electric Systems Limited (Toronto Hydro)
- Alectra Utilities Corporation
- Elexicon Energy Inc.
- Hydro One Networks Inc. (Distribution)

3. Categories of Needs, Analysis and Results

3.1 Overview of the Toronto Region

The Toronto electricity planning region includes the area within the municipal boundary of the City of Toronto. The electricity supply to the Toronto Region is shown in Figure 1. The region is supplied by a network of 230 kV lines that run along the northern and western edges of the city, and into the core from the east, providing supply points for step-down stations that supply these areas. The central core of the City of Toronto is supplied by a 115 kV network that connects to the 230 kV system through two 230/115 kV autotransformer stations (Leaside Transformer Station (TS) and Manby TS). A small number of distribution feeders from Toronto also supply customers in the City of Mississauga and City of Pickering.

In addition to the transmission infrastructure described above, the Portlands Energy Centre (550 megawatt [MW] summer capacity) is a natural gas-fired combined cycle power plant that provides a major source of supply to Toronto. This station is located near the Eastern waterfront and is connected to the Hearn Switching Station (SS) shown in Figure 1.

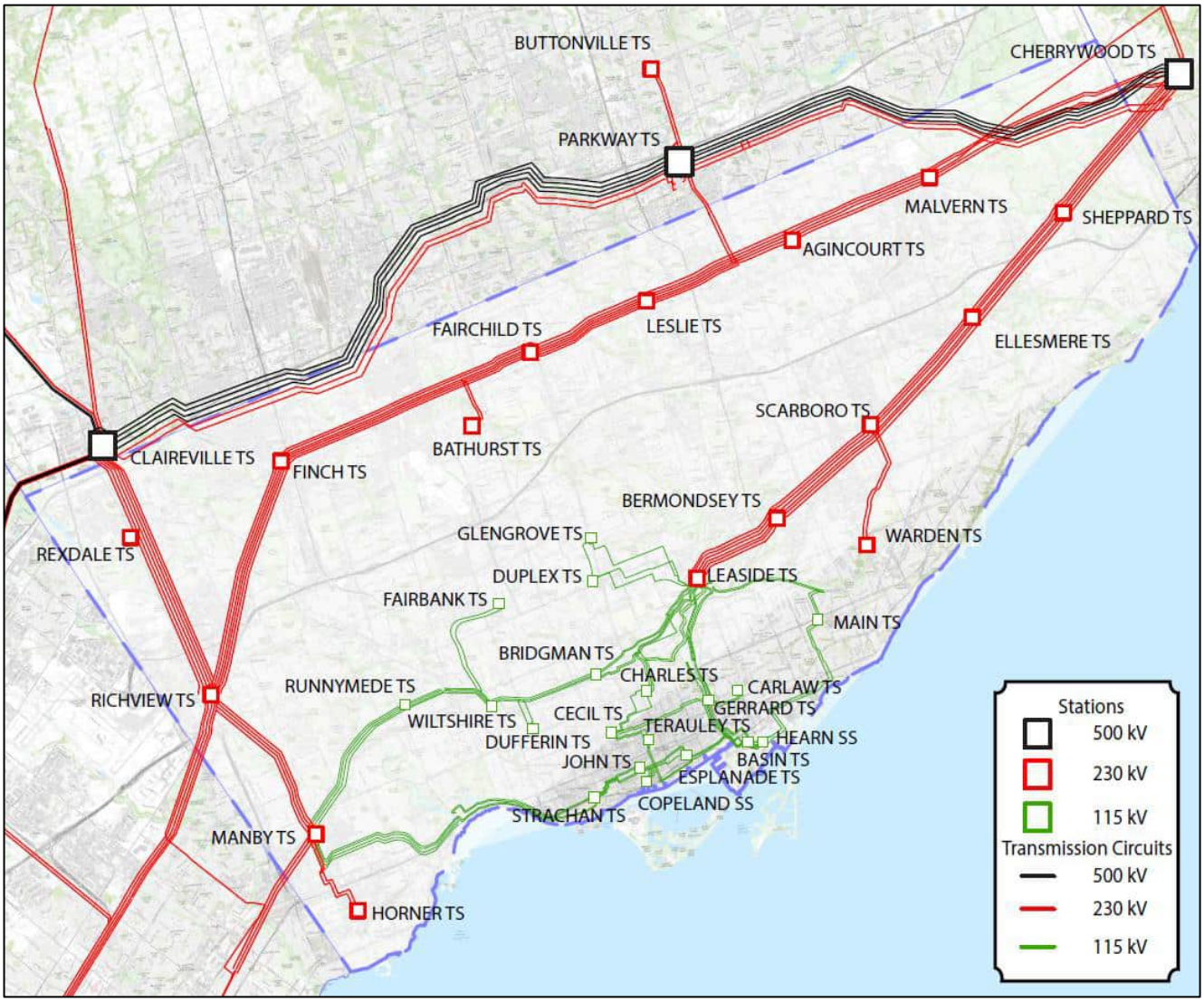
Numerous distributed energy resource (DER) facilities are located throughout the City. For example, through previous procurements such as the Feed-in Tariff program, Renewable Energy Standard Offer Program, and Combined Heat and Power (CHP) Standard Offer Program, approximately 1,900 individual renewable and CHP facilities have been placed in service in the City of Toronto. The total combined electrical supply capacity of these DERs is 106 MW.[1]

The region is summer peaking and the 2022 peak summertime electricity demand in the Toronto region was approximately 4,400 MW.[2]

[1] This translates to about 40 MW of "effective" capacity that system planners can count on during the peak demand period (assuming 34% capacity factor for solar PV, 13.6% for wind, and 100% for all other fuel types, including CHP).

[2] The peak electricity demand in summer 2006 was 5,305 MW; in summer 2022, demand was 4,356 MW.

Figure 1 | Electricity Infrastructure of the Toronto Region



3.1.1 Indigenous Communities

Toronto is home to Indigenous peoples from across Canada. Located near Toronto are the Mississaugas of the Credit, Six Nations of the Grand River, the Haudenosaunee Confederacy Chiefs Council (HCCC) and MNO Toronto and the York Region Métis Council. The Huron Wendat of Wendake, Quebec have archaeological resources in southern Ontario, including the Toronto area, due to their historical presence there. The IESO will notify the Mississaugas of the Credit, Six Nations, HCCC, York Region Métis Council and Huron Wendat that regional planning for Toronto is getting underway and invite them to participate in engagement activities.

3.2 Background of the Previous Planning Process

The first cycle of the regional planning process for the Toronto region was formally completed in January 2016 with the publication of Hydro One's Regional Infrastructure Plan (RIP) for the Central Toronto area, following the publication of an IRRP for Central Toronto in April 2015. In February 2017, an update was published to reflect plans to convert commuter heavy rail (Metrolinx - GO) from diesel to electric power.

In mid-2017, Hydro One identified a number of transmission asset renewal needs in Toronto over the next ten years. The scale and timing of these needs necessitated the initiation of another regional planning cycle. Hydro One initiated a Needs Assessment, which officially started the next regional planning cycle for the region. The Needs Assessment was completed in October 2017, and subsequent Scoping Assessment was completed in 2018. An IRRP was initiated in 2018, and released in 2019. This plan focused on transmission asset renewal needs, and preparing to address local and regional capacity needs emerging in the longer term.

The second round of regional planning for the Toronto region was completed in March 2020, with the release of the Hydro One led RIP.

An updated analysis for the Richview to Manby Upgrade project (now known as the "Etobicoke Greenway Project") was conducted in 2021. This analysis reaffirmed the findings in the 2019 IRRP and 2020 RIP and recommended the project go ahead.

3.3 Needs Identified

For this third cycle of regional planning, Hydro One's Needs Assessment provided an update on needs identified in the previous planning cycle and the implementation of projects recommended to address them. It also identified new needs in the Toronto region based on the most up-to-date sustainment plans and a new 10-year demand forecast. A summary of the current projects and plans underway to respond to existing needs, plus the new needs, are outlined below.

3.3.1 Projects and Plans Underway or Complete to Address Previously Identified Needs

The Needs Assessment report lists the needs identified from the previous planning cycle, and provides an update on the status of project implementation for the options recommended to address them (see Table 1). These projects provide a starting point for future assessments and will be accounted for in this planning cycle.

Table 1 | Needs Identified in the Previous Cycle with Implementation Plan Update

Need	Solution and Timing
Copeland TS Phase 2, address capacity need	In-service 2024
Bridgman TS transformer replacement (T11, T12, T13, T14)	Expected completion 2024

Need	Solution and Timing
Fairbank TS transformer replacement (T1, T2, T3, T4)	Expected completion 2024
Main TS transformer replacement (T3, T4)	Expected completion 2024
John TS transformer replacement (T5, T6)	Expected completion 2025
C5E/C7E underground cable replacement between Esplanade TS and Terauley TS	Expected completion 2026
Richview TS to Manby TS 230 kV Corridor Upgrade	Expected completion 2026

Since the previous regional planning cycle, the following additional projects have also been implemented by Hydro One:

- Second DESN at Horner TS, complete 2022
- Refurbishment projects at Runnymede TS (T3, T4), Sheppard TS (T3, T4), and Strachan TS (T12), complete 2021-2022
- Replacement of John TS transformers (T1, T2, T4), complete 2019-2021

3.3.2 Needs Requiring Further Coordination or Study in the Current Planning Cycle

The Needs Assessment then identified new or updated needs in the Toronto region using the 10-year station-level demand forecast provided by the local distribution companies (LDCs), updated asset condition information from Hydro One, as well as the conservation and demand management (CDM) and distributed generation (DG) forecast provided by the IESO. Several of these needs were determined through the Needs Assessment not to require further coordinated study through the regional planning process (see Table 2). However, many may still require a significant amount of planning or have a shared impact with other system assets or needs. For example, any needs dealing with major right of ways, even routine maintenance or like-for-like replacement, may have an impact on shared, downstream, or alternate facilities. Stepdown station asset renewal needs can also be linked to broader needs, if the station is located within a rapidly growing or supply constrained area. These types of needs do not require coordinated study through an IRRP, but should still be considered in scope of further regional planning activities to ensure that outage schedules and other shared impacts are appropriately accounted for.

Table 2 | Needs Determined in the Needs Assessment to not Require Further Coordinated Planning

Need #	Station/Circuit	Description of Need
1	Richview TS to Manby TS 230 kV Corridor[3]	• Line Capacity Need
2	Manby TS, autotransformers (T7, T9, T12)[4] and step-down transformers (T13/T14)	• Asset renewal need
3	115 kV H1L/H3L/H6LC/H8LC: Leaside Jct. to Bloor St. Jct. overhead section	• Asset renewal need
4	115 kV L9C/L12C: Leaside TS to Balfour Jct. overhead section	• Asset renewal need
5	Strachan TS: T14 & T13/T15	• Asset renewal need
6	Charles TS: T3/T4	• Asset renewal need
7	Duplex TS: T1/T2 & T3/T4	• Asset renewal need
8	Basin TS: T3/T5	• Asset renewal need
9	Scarboro TS: T23	• Asset renewal need
10	Fairchild TS: T1 & T3/T4	• Asset renewal need
11	Bermondsey TS: T3/T4	• Asset renewal need
12	Malvern TS: T3	• Asset renewal need
13	Fairbank TS	• Station Capacity Need
14	Strachan TS	• Station Capacity Need

[3] Further regional planning is not required as the project was recommended in the previous cycle of regional planning. Hydro One is developing the project, with an expected in-service date of mid-2026.

[4] Hydro One will proceed with development work for replacing autotransformers. However, the overall need for transformation capacity in Toronto as a whole will be assessed in the upcoming IRRP.

The remaining needs, which were determined through the Needs Assessment to require further coordinated study are listed in Table 3. Most needs deal directly with capacity constraints, or load restoration, as a range of solutions may be considered and the impact on broader system operation would need to be evaluated. Note that some step down station capacity needs (Fairbank TS and Strachan TS) were not included in this list, as solutions to address needs have already been identified.

Table 3 | Needs identified in the Needs Assessment as Requiring Further Study

Need #	Station/Circuit	Description of Need
1	115 kV Manby TS to Riverside Jct. Corridor	• Line capacity need
2	230 kV Parkway TS to Richview TS Corridor	• Line capacity need
3	115kV Leaside TS to Wiltshire TS Corridor	• Line capacity need
4	230/115kV Manby W Autotransformers[5]	• Autotransformer capacity need
5	230/115kV Leaside TS Autotransformers	• Autotransformer capacity need
6	Sheppard TS	• Station capacity need
7	Basin TS	• Station capacity need
8	Glengrove TS	• Station capacity need
9	Finch TS / Bathurst TS	• Station capacity need
10	Warden TS	• Station capacity need
11	Loss of C14L/C17L	• Load restoration need
12	Loss of C18R/P22R	• Load restoration need

[5] Hydro One will proceed with development work for replacing autotransformers. However, the overall need for transformation capacity will be looked at in the upcoming IRRP.

3.3.3 Analysis of Needs and Identification of Region

The Technical Working Group (TWG) has discussed the needs in the Toronto region and potential planning approaches to address them. The preferred planning approach is generally informed by:

- Timing of the need, including lead time to develop solutions
- The potential linkages between needs and their required coordination, particularly if across overlapping LDC territories or planning regions
- The opportunity for public engagement to inform outcomes
- The potential for exploring multiple types of options to meet the needs (including non-wires alternatives)
- The potential for regional changes having implications on the upstream bulk power system

In general, the more complex a series of needs are and the greater the need for coordination and engagement, the more likely an IRRP will be selected. If needs have few available solutions, are relatively straight forward, and can be implemented without affecting neighbouring areas or the bulk power system, then a more streamlined planning approach with a narrower scope may be appropriate.

The participants agreed that for each of the identified needs requiring further study, a range of alternatives including wires and non-wires solutions should be assessed. Additionally, several needs were identified which do not require further coordinated planning, but should still be considered in scope of further study as the implementation and timing of solutions have the potential to affect other needs in the area. These include needs whose previously recommended solutions are already underway, and asset renewal needs with the potential to affect overall capacity needs in the area.

Based on discussions, it was agreed that an IRRP should be undertaken to further assess these needs. The scope of an IRRP includes an assessment of CDM, DERs, and other community-based solutions. A Draft Terms of Reference for the IRRP is attached in Appendix B.

The participants also agreed, for the purpose of the next regional plan, that the City of Toronto should not be divided into sub-regions. While most of the needs identified impact electricity infrastructure in the downtown area, some needs have been identified in other parts of Toronto, outside of the central part of Toronto.

Lastly, because none of the needs identified directly impact facilities that supply customers of Alectra Utilities Corporation, Elexicon Energy Inc., or Hydro One Distribution, it was agreed that the core Working Group for the IRRP will include the IESO, Toronto Hydro, and Hydro One Transmission. The other utilities will be informed and invited to participate if any needs, or proposed solutions, may affect their facilities or customers.

3.3.4 Additional Considerations Associated with Growth and Electrification Targets

The City of Toronto has identified certain areas of the city that will undergo further development and growth. One of these areas is the Port Lands, located in the southern portion of Toronto at the mouth of the Don River. Together with Waterfront Toronto, the City has plans for the Port Lands to be "home to sustainable new communities that deliver affordable housing and job opportunities, along with renewed connections to the water and natural environment."[6] As such, the currently undeveloped portions of the Port Lands are expected to undergo a significant increase in electricity demand, affecting nearby infrastructure, in particular Basin TS.

Another area of interest is the Downsview area, particularly the area surrounding the Downsview Airport. An update to the secondary plan (known as "Update Downsview") aims to "plan for a new community within the City and reconnect the Downsview lands with the surrounding neighbourhoods" after Bombardier leaves the Downsview Airport by the end of 2023[7]. Update Downsview plans to facilitate new housing, jobs, parks and other community services in the area. This will likely affect the 230 kV stations located in northern Toronto, primarily Bathurst TS and Finch TS and the circuits that supply them.

For the upcoming IRRP, the Toronto Working Group will engage with stakeholders and communities to ensure growth plans in these areas are considered and reflected in the IRRP electricity demand forecast.

3.3.5 Pathways to Decarbonization Report

In December 2022, the IESO published its Pathways to Decarbonization Report. This report was created in response to the Ministry of Energy's request to evaluate a moratorium on new natural gas generating stations in Ontario and to develop an achievable pathway to decarbonization in the electricity system. The report considered the resource and bulk system implications for meeting two time specific scenarios:

- A "2035 Moratorium" scenario, which considers the potential results of a moratorium on natural gas generation in Ontario's electricity sector, with a phase out by 2035, where feasible. This scenario also considered the impact of greater uptake of electrified transportation options, among other electrification objectives
- A "2050 Pathways" scenario, which goes beyond the 2035 Moratorium case to consider the phase out of all GHG emitting generation resources, as well as significant demand growth based on theoretical, aggressive, policy-driven electrification in three major sectors: transportation, building heat and industrial process

In the report, the IESO committed to ensuring "that regional planning processes for Toronto and York Region address the unique challenges for local reliability of phasing out natural gas". Specifically, the Pathways to Decarbonization Report stated:

"The IESO will ensure that future bulk and regional planning activities… …further assess the identified needs and reinforcement options and make recommendations for next steps, including

[6] Waterfront Toronto: https://www.waterfrontoronto.ca/our-projects/scope-scale/port-lands

[7] Update Downsview: https://www.toronto.ca/city-government/planning-development/planning-studies-initiatives/update-downsview/

development work. In particular, upcoming regional planning activities for both Toronto and York Region will need to examine options for the eventual replacement of the local reliability benefits provided by existing gas."

The IESO recognizes the government of Ontario is actively consulting on the Pathways to Decarbonization report. Outcomes of that consultation may inform the IESO's approach to this regional plan. As such, the Terms of Reference for the Toronto IRRP may be amended at a future time to account for additional objectives, activities, and assumptions required to align deliverables with new provincial direction.

3.3.6 GTA Bulk Supply Study

In December 2022, the IESO also published the 2022 Annual Planning Outlook (APO). The APO is an annual report that provides a long-term view of Ontario's electricity system, forecasting system needs and exploring the province's ability to meet them. The 2022 APO identified potential issues in the bulk system (i.e. the system that transfers large amounts of power across the province) due to increasing demand and the planned retirement of the Pickering Nuclear Generating Station and indicated that the IESO would undertake a GTA Bulk Supply Study in 2023. This study will review the capability of the bulk power system to deliver power into the broader GTA load centre. As the GTA Bulk Supply Study will be conducted in parallel with regional planning in Toronto, its findings (i.e. needs and recommended solutions) will be coordinated with the Toronto IRRP, and vice-versa.

4. Conclusion and Next Steps

The Scoping Assessment concludes that:

- Based on the available information, an IRRP is to be undertaken for the Toronto region;
- No sub-regions within Toronto will be created for the IRRP; the region should be treated as a whole for the purpose of developing a comprehensive plan;
- The implementation of recommendations from the previous planning cycle should continue;
- The composition of the IRRP Working Group will include the IESO, Toronto Hydro, and Hydro One Transmission. Other Local Distribution Companies in the region will be informed of any needs or solutions that may affect their facilities or customers;
- Given the significant anticipated scope of the study, the full 18-month timeline for completion of the IRRP is expected to be required;
- In addition to addressing the needs identified in the Needs Assessment, two focus areas will be examined in detail in the IRRP: Port Lands and Downsview;
- The Toronto IRRP will co-ordinate its findings with the GTA Bulk Supply Study, and vice-versa;
- The IESO may amend the Terms of Reference for the Toronto IRRP as required to align with provincial direction following consultation related to the Pathways to Decarbonization Report.

All IRRPs will include opportunities for engagement with local communities and stakeholders, as well as include discussion of any local initiatives focused on energy and/or reducing GHG emissions, and how the IRRP can coordinate with these plans. This could include Community Energy Plans, Net-Zero strategies, or similar. Particular attention will be paid to opportunities for information sharing and/or coordination of goals and outcomes.

The draft Terms of Reference for the Toronto IRRP is attached in Appendix B.

Appendix A – List of Acronyms

Acronym	Definition
APO	Annual Planning Outlook
CDM	Conservation and Demand Management
DER	Distributed Energy Resource
DG	Distributed Generation
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station
TWG	Technical Working Group

Appendix B – Toronto Region Integrated Regional Resource Plan (IRRP) Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, roles and responsibilities, deliverables and timelines for an Integrated Regional Resource Plan (IRRP) for the Toronto region.

Based on the power system needs identified throughout the region (including a number of transmission stations and lines requiring replacement based on asset condition assessment in the near term and medium term), strong urban growth and intensification projections in the City of Toronto, expansion of electrified transit, and potential demand and resource pressures from decarbonization policies, an IRRP is the appropriate planning approach for this region.

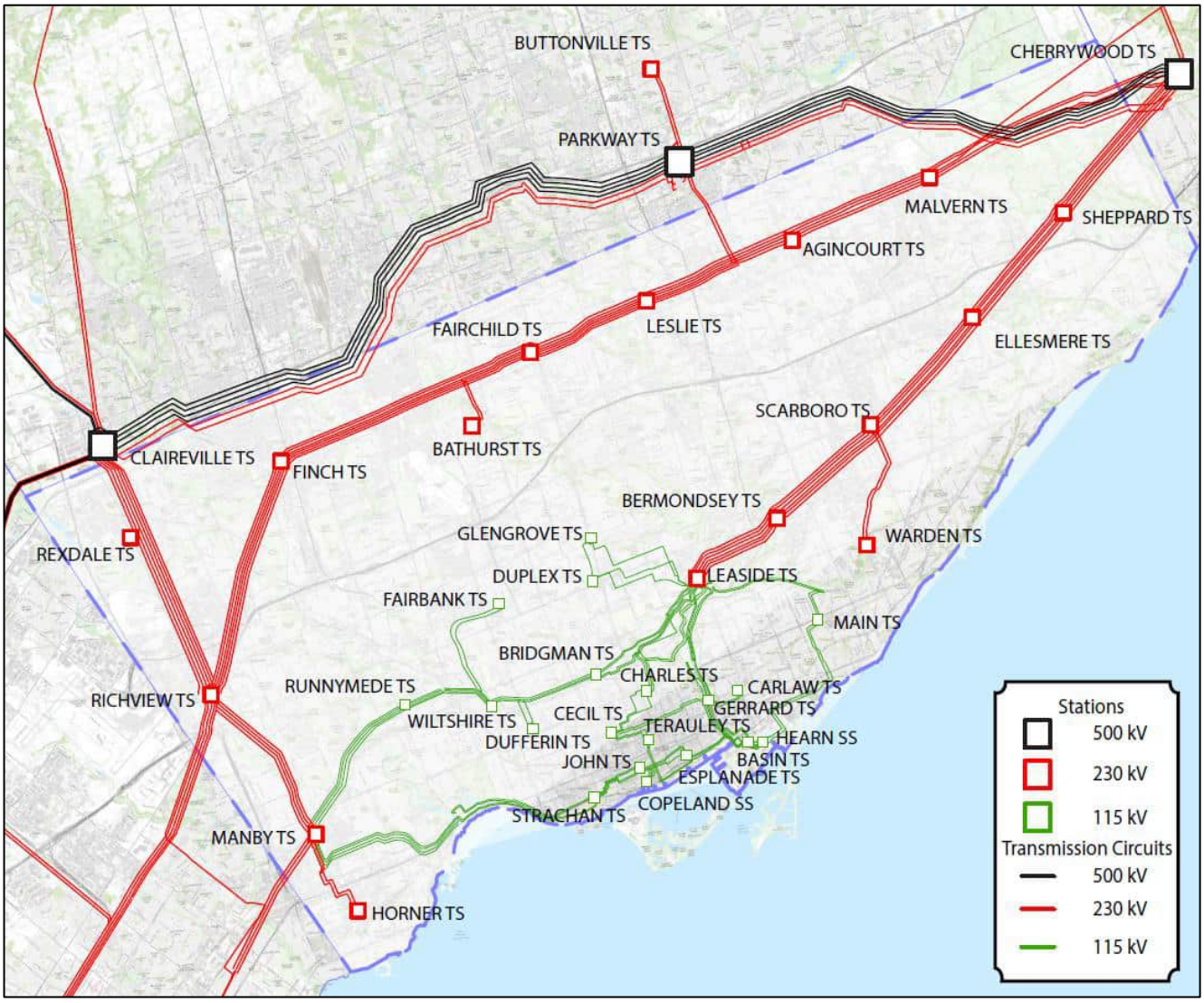
1.1 The Toronto Region

The Toronto electricity planning region includes the area within the municipal boundary of the City of Toronto. The electricity supply to the Toronto Region is shown in Figure 2. The region is supplied by a network of 230 kV lines that run along the northern and western edges of the city, and into the core from the east, providing supply points for step-down stations that supply these areas. The central core of the City of Toronto is supplied by a 115 kV network that connects to the 230 kV system through two 230/115 kV autotransformer stations (Leaside Transformer Station (TS) and Manby TS). A small number of distribution feeders from Toronto also supply customers in the City of Mississauga and City of Pickering.

Toronto is home to Indigenous peoples from across Canada. Located near Toronto are the Mississaugas of the Credit, Six Nations of the Grand River, the Haudenosaunee Confederacy Chiefs Council and MNO Toronto and the York Region Métis Council. The Huron Wendat of Wendake, Quebec have archaeological resources in southern Ontario, including the Toronto area, due to their historical presence there. The IESO will notify the Mississaugas of the Credit, Six Nations, HCCC, York Region Métis Council and Huron Wendat that regional planning for Toronto is getting underway and invite them to participate in engagement activities.

For the purpose of this IRRP, no divisions are proposed that would create any sub-regions to assess within the City of Toronto.

Figure 2 | Electricity Infrastructure of the Toronto Region



1.2 Background

In December 2022, Hydro One completed the Needs Assessment report for the Toronto region. Several needs were identified, and a Scoping Assessment was subsequently commenced to determine the preferred planning approach. An IRRP is ultimately recommended on the basis of the scale of load growth anticipated, potential for diverse types of solution (including wires and non wires), and long term uncertainty associated with city development plans and the potential impact of municipal, provincial, and federal decarbonization and electrification policies.

2. Objectives

1. Assess the adequacy and reliability of the portion of the IESO-controlled grid[8] that provides electricity supply to the Toronto region over the next 25 years.[9]
2. Account for major asset renewal needs, capacity needs, enhancing reliability and resilience, uncertainty in the outlook for electricity demand, and local priorities in developing a comprehensive plan.
3. Consider potential impacts of electrification targets and other policy decisions on needs identified and recommended outcomes, consistent with provincial direction.
4. Evaluate opportunities for cost effective non-wires alternatives, including conservation and demand management (CDM) and distributed energy resources (DER), as well as wires approaches for addressing the needs identified.
5. Develop an implementation plan that maintains flexibility in order to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for medium-term needs, and planning direction for the long-term.

3. Scope

3.1 Needs to be Addressed

The IRRP will develop and recommend an integrated plan to meet the needs of the Toronto region. The plan is a joint initiative involving Toronto Hydro, Hydro One Transmission, and the IESO,[10] and will account for input from the community through engagement activities. The plan will integrate the electricity demand outlook scenarios, CDM, DER uptake, transmission and distribution system capabilities, and align with relevant community plans, bulk system developments, and policy direction as applicable.

The scope of the Toronto IRRP includes the following needs, as identified in the Needs Assessment:

Table 4 | Needs Identified in the Needs Assessment as Requiring Further Study

Facilities	Type of Need	Expected Timing
115 kV Manby TS to Riverside Jct. Corridor	Line capacity need	2028
230 kV Parkway TS to Richview TS Corridor	Line capacity need	Beyond 2031
115kV Leaside TS to Wiltshire TS Corridor	Line capacity need	Beyond 2031
230/115kV Manby W Autotransformers	Autotransformer capacity need	Beyond 2031

[8] The scope of the assessment includes transmission stations.

[9] The typical planning horizon in a regional study is 20 years; however, Toronto Hydro produces a long-range forecast spanning 25 years and this forecast will be used as the basis for assessing long-term system needs in the IRRP.

[10] Alectra Utilities, Elexicon Energy Inc. and Hydro One Distribution are also supplied by feeders from Toronto. These utilities will not form part of the core Technical Working Group. However, they will be informed of any developments that may impact their facilities and/or customers.

Facilities	Type of Need	Expected Timing
230/115kV Leaside TS Autotransformers	Autotransformer capacity need	Beyond 2031
Sheppard TS	Station capacity need	Beyond 2031
Basin TS	Station capacity need	Beyond 2031
Glengrove TS	Station capacity need	Beyond 2031
Finch TS / Bathurst TS	Station capacity need	Beyond 2031
Warden TS	Station capacity need	Beyond 2031
Loss of C14L/C17L	Load restoration need	2031
Loss of C18R/P22R	Load restoration need	2031

Other identified needs in the Needs Assessment not listed in Table 4 above will proceed with Local Planning or Regional Infrastructure Planning as appropriate. Hydro One will keep the Working Group informed on project development.

3.2 Additional Considerations Associated with Growth and Electrification Targets

The City of Toronto has identified certain areas of the city that will undergo further development and growth. One of these areas is the Port Lands, located in the southern portion of Toronto at the mouth of the Don River. Together with Waterfront Toronto, the City has plans for the Port Lands to be "home to sustainable new communities that deliver affordable housing and job opportunities, along with renewed connections to the water and natural environment."[11] As such, the currently undeveloped portions of the Port Lands are expected to undergo a significant increase in electricity demand, affecting nearby infrastructure, in particular Basin TS.

Another area of interest is the Downsview area, particularly the area surrounding the Downsview Airport. An update to the secondary plan (known as "Update Downsview") aims to "plan for a new community within the City and reconnect the Downsview lands with the surrounding neighbourhoods" after Bombardier leaves the Downsview Airport by the end of 2023[12]. Update Downsview plans to facilitate new housing, jobs, parks and other community services in the area. This will likely affect the 230 kV stations located in northern Toronto, primarily Bathurst TS and Finch TS and the circuits that supply them.

For the upcoming IRRP, the Toronto Working Group will engage with stakeholders and communities to ensure growth plans in these areas are considered and reflected in the IRRP electricity demand forecast.

[11] Waterfront Toronto: https://www.waterfrontoronto.ca/our-projects/scope-scale/port-lands

[12] Update Downsview: https://www.toronto.ca/city-government/planning-development/planning-studies-initiatives/update-downsview/

3.3 Pathways to Decarbonization Report

In December 2022, the IESO published its Pathways to Decarbonization Report. This report was created in response to the Ministry of Energy's request to evaluate a moratorium on new natural gas generating stations in Ontario and to develop an achievable pathway to decarbonization in the electricity system. The report considered the resource and bulk system implications for meeting two time specific scenarios:

- A "2035 Moratorium" scenario, which considers the potential results of a moratorium on natural gas generation in Ontario's electricity sector, with a phase out by 2035, where feasible. This scenario also considered the impact of greater uptake of electrified transportation options, among other electrification objectives
- A "2050 Pathways" scenario, which goes beyond the 2035 Moratorium case to consider the phase out of all GHG emitting generation resources, as well as significant demand growth based on theoretical, aggressive, policy-driven electrification in three major sectors: transportation, building heat and industrial process

In the report, the IESO committed to ensuring "that regional planning processes for Toronto and York Region address the unique challenges for local reliability of phasing out natural gas". Specifically, the Pathways to Decarbonization Report stated:

"The IESO will ensure that future bulk and regional planning activities… …further assess the identified needs and reinforcement options and make recommendations for next steps, including development work. In particular, upcoming regional planning activities for both Toronto and York Region will need to examine options for the eventual replacement of the local reliability benefits provided by existing gas."

The IESO recognizes the government of Ontario is actively consulting on the Pathways to Decarbonization report. Outcomes of that consultation may inform the IESO's approach to this regional plan. As such, this Terms of Reference may be amended at a future time to account for additional objectives, activities, and assumptions required to align the Toronto IRRP deliverables with new provincial direction.

3.4 GTA Bulk Supply Study

In December 2022, the IESO also published the 2022 Annual Planning Outlook (APO). The APO is an annual report that provides a long-term view of Ontario's electricity system, forecasting system needs and exploring the province's ability to meet them. The 2022 APO identified potential issues in the bulk system (i.e. the system that transfers large amounts of power across the province) due to increasing demand and the planned retirement of the Pickering Nuclear Generating Station and indicated that the IESO would undertake a GTA Bulk Supply Study in 2023. This study will review the capability of the bulk power system to deliver power into the broader GTA load centre. As the GTA Bulk Supply Study will be conducted in parallel with regional planning in Toronto, its findings (i.e. needs and recommended solutions) will be coordinated with the Toronto IRRP, and vice-versa.

4. Activities

The IRRP process will consist of the activities as listed below. The activities and anticipated timelines are summarized in Table 5 at the end of this document. The first major planning activity following preparation of this Terms of Reference is the development of the electricity demand forecast to serve as the basis for conducting system assessments. The timing for initiating the assessment (Activity 3) and all subsequent plan development activities will be contingent on the Working Group agreeing on the demand forecast to be used.

1) Develop an electricity demand forecast for the Toronto region. This may be comprised of a number of electricity demand scenarios that account for uncertain elements that can affect (e.g., raise or lower) the need for electricity in the region:
2) Confirm baseline technical assumptions including infrastructure ratings, system topology and relevant base cases for simulating the performance of the electric power system. Collect information on:
    a. Transformer, line and cable continuous ratings, long-term and short-term emergency ratings;
    b. Known reliability issues and load transfer capabilities;
    c. Customer load breakdown by transformer station;
    d. Historical and present CDM peak demand savings and installed/effective DER capacity, by transformer station.
3) Perform assessments of the capacity, reliability and security of the electric power system under each demand outlook scenario.
    a. Confirm and/or refine the needs listed earlier in this section using the demand outlook; establish the sensitivity of each need to different demand outlook scenarios.
    b. Identify additional infrastructure capacity needs and any additional load restoration needs; if new needs are discovered, determine the appropriate planning approach for addressing them.
4) Identify options for addressing the needs, including, non-wires and wires alternatives. Where necessary, develop portfolios of solutions comprising a number of options that, when combined, can address a need or multiple needs.
    a. Collect information about the attributes of each option: cost, performance, timing, risk, etc.
    b. Develop cost estimates for all screened-in options as a means of informing further evaluations of alternatives.
    c. Seek cost-effective opportunities to manage growth, by identifying opportunities to reduce electricity demand.
5) Evaluate options using criteria including, but not limited to the areas of: technical feasibility and timing, economics, reliability performance, risk, environmental, regulatory, and social factors. Evaluation criteria will be informed through community engagement activities and reflect attributes deemed important to the community-at-large.
6) Develop recommendations for actions and document them in an implementation plan, to address needs in the near-term and medium-term.

7) Develop a long-term plan for the electricity system in Toronto to address the identified long-term needs, taking into account uncertainty inherent in long-term planning, local and provincial policy goals, commitments, and climate change action plans.
    a. Discuss possible ways the power system in Toronto could evolve to address potential long-term needs, support the achievement of local and provincial long-term policy goals and plans, and support the achievement of the long-term vision for the electricity sector.
    b. During the development of the plan, seek community and stakeholder input to confirm the long-term vision, expected impacts on the electricity system, and inform the recommended actions through engagement.
8) Complete an IRRP report documenting the near-term and medium-term needs, recommendations, and implementation actions; and long-term plan recommendations.

In order to carry out this scope of work, the Working Group will consider the data and assumptions outlined in section 4 below.

5. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
    - Historical coincident and non-coincident peak demand information and trends for the region
    - Historical weather correction, for median and extreme conditions
    - Gross peak demand forecast scenarios by TS, etc.
    - Coincident peak demand data
    - Identified potential future load customers, including transit expansions, electrification of personal vehicles, space heating/cooling, water heating, and other end-uses due to provincial and local GHG emissions reduction policies and targets

- Conservation and Demand Management
    - LDC CDM plans
    - Incorporation of verified LDC results and other CDM programs/opportunities in the area
    - Long-term conservation forecast for LDC customers, based on region's share of the provincial target found in the 2021-2024 CDM Framework
    - Conservation potential studies, if available
    - Potential for CDM at transmission-connected customers' facilities, if applicable
    - Load segmentation data for each TS based on customer type (residential, commercial, institutional, industrial)
    - Local building codes, energy performance requirements, etc.

- Local resources
    - Existing local generation resources, including distributed energy resources (DER), district energy resources, customer-based generation, as applicable
    - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
    - Expected performance/dependability/output of local generation resources coincident with the local peak demand period
    - Future district energy plans, combined heat and power, energy storage, or other generation proposals, including requirements for on-site back-up and emergency generation

- Relevant local and provincial plans and studies, as applicable
    - LDC Distribution System Plans
    - Community Energy Plans and Municipal Energy Plans
    - City policies with an impact on electricity usage, including TransformTO
    - Municipal Growth Plans
    - Future transit plans impacting electricity use, including personal vehicle electrification, transit expansion (e.g. Ontario Line), and transit electrification (e.g. GO train electrification)
    - Pathways to Decarbonization Report

- Criteria, codes and other requirements
    - Ontario Resource and Transmission Assessment Criteria (ORTAC)
        - Supply capability

        - Load security
        - Load restoration requirements
    - NERC Reliability Standards and NPCC Reliability Criteria and Directories, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Reliability considerations, such as the frequency and duration of interruptions to transmission delivery points
    - Other applicable requirements, including municipal requirements

- Existing system capability
    - Transmission line ratings as per transmitter records
    - System Limits as modelled, defined and determined by the IESO and incorporated into the IESO Power Flow base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capabilities
    - Technical and operating characteristics of local generation

- Asset renewal considerations/sustainment plans
    - Transmission assets
    - Distribution assets, as applicable

- Other considerations, as applicable

6. Technical Working Group

The IRRP Technical Working Group will consist of planning representatives from the following organizations:

- Independent Electricity System Operator *(Lead for the IRRP)*
- Toronto Hydro Electric System Limited (Toronto Hydro)
- Hydro One Networks Inc. (Transmission)

The following LDCs will not be part of the IRRP Technical Working Group but will be informed of any developments that may impact their facilities and/or customers:

- Alectra Utilities Corporation
- Elexicon Energy Inc.
- Hydro One Networks Inc. (Distribution)

6.1 Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

7. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the 2013 Long Term Energy Plan. As such, the Technical Working Group is committed to conducting plan-level engagement throughout the development of the Toronto IRRP.

The first step in engagement will consist of the development of a public engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 5.0 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

8. Activities, Timeline, and Primary Accountability

Table 5 | IRRP Timelines & Activities

Activity	Lead Responsibility	Deliverable(s)	Timeframe
1. Prepare Terms of Reference considering stakeholder input	IESO	Finalized Terms of Reference	March 2023
2. Develop the planning forecast for the region		Long-term planning forecast scenarios	Q2-Q4 2023
a. Establish historical coincident peak demand information	IESO		
b. Establish historical weather correction, median and extreme conditions	IESO		
c. Establish gross peak demand forecast	Toronto Hydro		
d. Establish existing, committed, and potential DG	IESO, Toronto Hydro		
e. Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	IESO		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
3. Confirm load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system needs and identifying options for addressing these needs	Toronto Hydro/ Hydro One	Load transfer capabilities under normal and emergency conditions	Q1 2024
4. Provide and review relevant community plans, if applicable	Toronto Hydro, communities, stakeholders, and IESO	Relevant community plans	Q1 2024
5. Complete system studies to identify needs over a 20-year time horizon Obtain PSS/E base case Apply reliability criteria as defined in ORTAC and other applicable criteria to demand forecast scenarios Confirm and refine the need(s) and timing/load levels	IESO	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q1-Q2 2024
6. Develop options and alternatives		Develop flexible planning options for forecast scenarios	Q2 2024
a. Conduct a screening to identify which wires and non-wires options warrant further analysis	IESO		
b. Verify the LMC of the system to better determine timing of needs and support options development	IESO		
c. Develop screened-in energy efficiency options	IESO and Toronto Hydro		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
d. Develop screened-in local generation/demand management options	IESO and Toronto Hydro		
e. Develop the screened-in transmission and distribution alternatives (i.e., alignment with EOL sustainment plans, load transfers)	IESO, Hydro One Transmission, and Toronto Hydro		
f. Develop portfolios of integrated alternatives	IESO, Hydro One Transmission, and Toronto Hydro		
g. Technical comparison and evaluation	IESO, Hydro One Transmission, and Toronto Hydro		
7. Plan and undertake community & stakeholder engagement		Community and Stakeholder Engagement Plan Input from local communities, First Nation communities, and Métis Nation of Ontario	Ongoing as required IRRP engagement to be launched in Q2-Q3 2023
a. Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	IESO, Hydro One Transmission, and Toronto Hydro		

Activity	Lead Responsibility	Deliverable(s)	Timeframe
b. Develop communications materials	IESO, Hydro One Transmission, and Toronto Hydro		
c. Undertake community and stakeholder engagement	IESO, Hydro One Transmission, and Toronto Hydro		
d. Summarize input and incorporate feedback	IESO, Hydro One Transmission, and Toronto Hydro		
8. Develop long-term recommendations and implementation plan based on community and stakeholder input	IESO	Implementation plan Monitoring activities and identification of decision triggers Procedures for annual review	Q1-Q2 2024
9. Prepare the IRRP report detailing the recommended near, medium, and long-term plan for approval by all parties	IESO	IRRP report	September 2024

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NEEDS ASSESSMENT REPORT

GTA North Region

Date: July 14, 2023

Prepared by: GTA North Region Technical Working Group

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the GTA North Region and to recommend which need: a) does not require further regional coordination and b) identify needs requiring further assessment and/or regional coordination. The results reported in this Needs Assessment are based on the input and information provided by the Technical Working Group ("TWG") for this region.

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

Region	GTA North Region (the "Region")		
Lead	Hydro One Networks Inc. ("Hydro One")		
Start Date	March 17, 2023	**End Date**	July 14, 2023

1. INTRODUCTION

The second Regional Planning ("RP") cycle for the GTA North Region was completed in October 2020 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the third RP cycle for this Region, which begins with the Needs Assessment ("NA") phase. The purpose of this NA is to:

a) Identify any new needs and reaffirm needs identified in the previous RP cycle; and
b) Recommend which needs:
   i. require further assessment and regional coordination (and hence, proceed to the next phases of RP); and
   ii. do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted Local Distribution Companies ("LDC") to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle.

2. REGIONAL ISSUE/TRIGGER

In accordance with the RP process, the RP cycle should be triggered at least once every five years. Considering these timelines, the third Regional Planning cycle was triggered in March 2023 for the GTA North Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the GTA North Region NA includes:

a) Reaffirm and update needs/plans identified in the previous RP cycle;
b) Identify any new needs resulting from this assessment.
c) Recommend which need(s) require further assessment and regional coordination in the next phases of the RP cycle; and
d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle).

The Technical Working Group ("TWG") may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP") and RIP, based on updated information available at that time.

The planning horizon for this NA is 10 years.

4. INPUTS/DATA

The TWG representatives from LDCs, the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the GTA North Region regarding capacity needs, system reliability needs, operational issues, and major high-voltage ("HV") transmission assets requiring replacement over the planning horizon.

The provincial push towards decarbonization as outlined in the IESO's "Pathways to Decarbonization" report published on December 15, 2022, is expected to impact the electricity demand over the longer term. As a result, the electricity demand, and the need for new infrastructure over the longer term could be higher than previously anticipated or as discussed in this report. The impact of decarbonization will be considered during the next phases of this regional planning cycle.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs in the Region over the study period. The assessment methodology includes a review of planning information such as load forecast, conservation, and demand management ("CDM") forecast, available distributed generation ("DG") information, system reliability and operation issues, and major HV transmission assets requiring replacement.

A technical assessment of needs was undertaken based on:

a) Station capacity and transmission adequacy;
b) System reliability and any operational concerns;
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing"; and
d) Sensitivity analysis to capture uncertainty in the load forecast and variability of demand drivers such as electrification.

6. NEEDS

Needs that were identified in the last RP cycle with current need dates are as follows:

- New Markham MTS #5 – need date is 2028
- Uprate 230kV circuits P45/46 from Parkway TS to Markham MTS #4 Jct. – need date is 2028
- New Northern York TS - need date is 2027
- Woodbridge TS: Replace transformer T5 with similar and size equipment as per current standard – need date is 2027
- New Vaughan MTS #5 – need date is 2030
- Claireville TS x Brown Hill TS Transmission circuit capacity need – need date is 2030
- Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, and V71P/V75P – Existing need[1]

New needs identified in this NA are:

- Kleinburg TS 44kV: Load transfer to Northern York TS – need date is 2027
- New Vaughan MTS #6 – need date is 2027
- New Toubner TS (CTS) – need date is 2027
- New Richmond Hill MTS #3 – need date is 2032
- Load Restoration needs for 230kV circuits P45/P46 – need date is 2027

7. RECOMMENDATIONS

The TWG's recommendations are as follows:

a) No further regional coordination is required for the following need and work will be proceeding as planned:
   - Woodbridge TS: Replace transformer T5
   - Toubner TS: Build new station
   - Vaughan MTS #6: Build new station

b) Further assessment and regional coordination is required in the next phases of the RP cycle to review and/or develop a preferred plan for the follow needs:
   - Kleinburg TS 44kV: Load transfer to Northern York TS
   - Markham MTS #5: Build new station
   - 230kV circuit P45/P46: Uprate circuits between Parkway TS and Markham MTS #4 Jct.
   - Northern York TS: Build new station
   - Vaughan MTS #5: Build new station
   - Richmond Hill MTS #3: Build new station
   - Claireville TS x Brown Hill TS Transmission circuit capacity need and load restoration needs
   - Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, P45/P46, and V71P/V75P

1. No action considered was considered necessary in the last regional planning cycle

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1 INTRODUCTION

The second cycle of the Regional Planning ("RP") process for the GTA North Region was completed in October 2020 with the publication of the Regional Infrastructure Plan ("RIP") report.

This is the third RP cycle for this Region, which begins with the Needs Assessment ("NA") phase. The purpose of this Needs Assessment ("NA") is to identify new needs in the region, reaffirm and update previously identified needs in the last GTA North RP cycle, and recommend which needs require further assessment and regional coordination.

This report was prepared by the GTA North Region Technical Working Group ("TWG"), led by Hydro One Networks Inc. Participants of the TWG are listed below in Table 1. The report presents the results of the assessment based on information provided by Hydro One, the Local Distribution Companies ("LDCs") and the Independent Electricity System Operator ("IESO").

Table 1-1: GTA North Region TWG Participants

Company
Alectra Utilities Corporation
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator ("IESO")
Newmarket-Tay Power Distribution Ltd
Toronto Hydro-Electric System Limited ("THESL")
Hydro One Networks Inc. (Lead Transmitter)

2 REGIONAL ISSUE/TRIGGER

In accordance with the RP process, the RP cycle should be triggered at least once every five years. Considering these timelines, the third RP cycle was triggered for the GTA North Region.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the GTA North Region and includes:

- Reaffirm and update needs/plans identified in the previous RP cycle.
- Identify any new needs resulting from this assessment.
- Recommend which need(s) require further assessment and regional coordination in the next phases of the RP cycle; and
- Recommend which need(s) that do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan, or no regional investment is required at this time and the need may be reviewed during the next RP cycle).

The TWG may identify additional needs during the next phases of the RP process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), and/or RIP based on updated information available at that time.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The GTA North Region is comprised of the Northern York Area, Southern York Area, and the Western Area. Electrical supply to the region is provided from sixteen 230kV step-down transformer stations. The 2022 Summer Peak area load of the region was approximately 2249MW. Please refer to Figure 4-1.

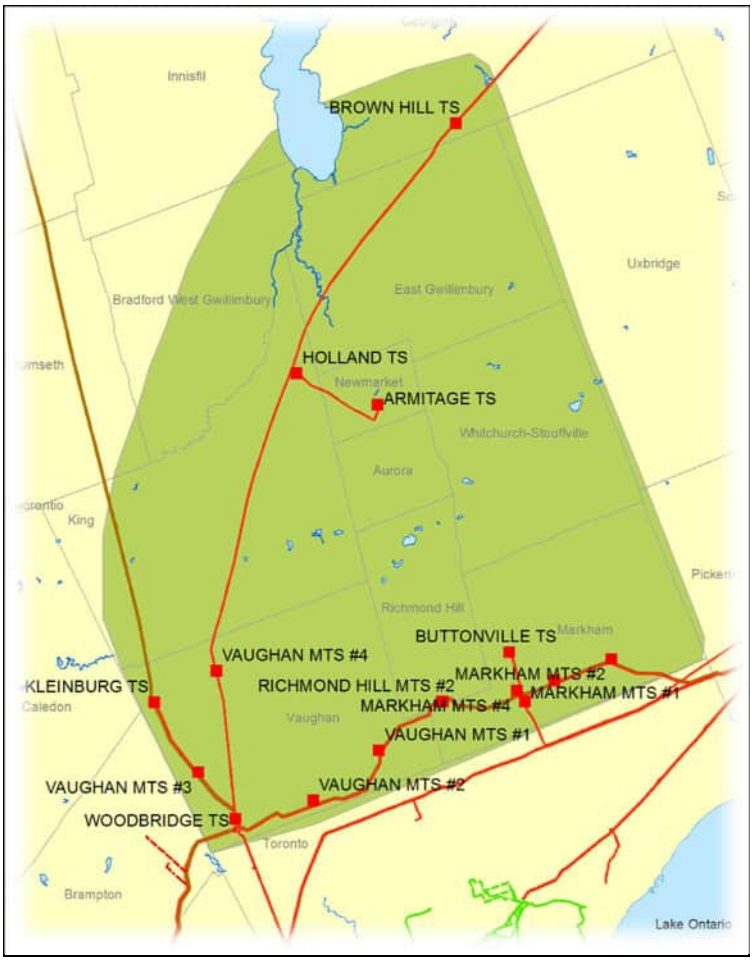

Figure 4-1: GTA North Region Map

Electrical supply to the GTA North Region is primarily provided from three major 500/230 kV autotransformer stations, namely Claireville TS, Parkway TS, and Cherrywood TS, and a 230 kV transmission network supplying the various step-down transformation stations in the region. Local generation in the Region consists of the 393 MW York Energy Centre connected to the 230 kV circuits B88H/B89H in King Township. Please refer to Figure 4-2.

The Northern York Area encompasses the municipalities of Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina, as well as some load in Simcoe County that is supplied from the same electricity infrastructure. It is supplied by Claireville TS, a 500/230 kV autotransformer station, and

three 230 kV transformer stations stepping down the voltage to 44 kV. The York Energy Centre provides a local supply source in Northern York Area. The LDCs supplied in the Northern York Area are Hydro One Distribution, Newmarket-Tay Power Distribution, and Alectra.

The Southern York Area includes the municipalities of Vaughan, Markham, and Richmond Hill. It is supplied by three 500/230 kV autotransformer stations (Claireville TS, Parkway TS, and Cherrywood TS), nine 230 kV transformer stations (includes eight LDC owned stations and one Hydro One owned) stepping down the voltage to 27.6 kV, and one other direct transmission connected load customer. The LDC supplied in the Southern York Area is Alectra.

The Western Area comprises the Western portion of the municipality of Vaughan. Electrical supply to the area is provided through Claireville TS, a 500/230 kV autotransformer station, and a 230 kV tap (namely, the "Kleinburg tap") that supplies three 230 kV transformer stations (including one LDC owned transformer station) stepping down the voltage to 44 kV and 27.6 kV. The LDCs directly supplied are Alectra and Hydro One Distribution. Embedded LDCs include Alectra and Toronto Hydro.

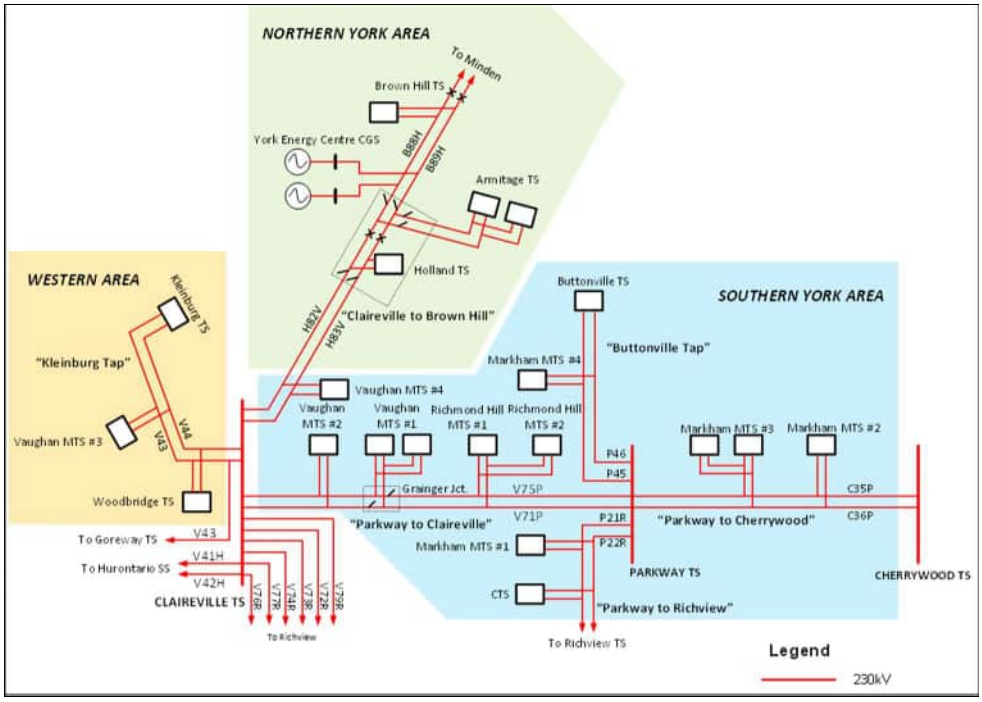

Figure 4-2: GTA North Region– Single Line Diagram

The transformer stations and circuits in the area are listed in Appendix A and Appendix B.

5 INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the GTA North Region NA. The information provided includes the following:

- Load Forecast for all supply stations in the GTA North Region.
- Known capacity and system reliability needs, operational issues, and/or major HV transmission equipment requiring replacement over the study period; and
- Planned/foreseen transmission and distribution investments that are relevant to the GTA North RP process.

In December 2022, the IESO published a report [1] on developing an achievable pathway to the decarbonization of the electricity system. As a result, the electricity demand, and the need for new infrastructure over the longer term could be higher than anticipated or discussed in this report. The impact of the decarbonization and resulting electrification will be considered during the next phase of this regional planning cycle.

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

- Load forecast: The LDCs provided their load forecast for all the stations supplying their loads in the GTA North Region for the 10-year study period. The IESO provided a Conservation and Demand Management ("CDM") forecast and Distributed Generation ("DG") contract information for the Toronto Region. The region's extreme summer non-coincident peak gross load forecast for each station was prepared by applying the growth rates from the LDC load forecast to the actual 2022 summer peak extreme weather corrected loads. The extreme summer weather correction factor was provided by Hydro One. The net extreme weather summer load forecast was produced by reducing the gross load forecast for each station by the percentage CDM from the IESO for that station. The extreme summer weather corrected net non-coincident peak for the individual stations in the GTA North Region are given in Appendix C.
- Relevant information regarding system reliability and operational issues in the region;
- List of major HV transmission equipment planned and/or identified to be replaced based on asset condition assessment, and relevant for RP purposes. The scope of equipment considered is given in Section 7.1.

A technical assessment of needs was undertaken based on:

- Station capacity and transmission adequacy assessment.
- System reliability and operational considerations.

[1] IESO Report, "Pathways-to-Decarbonization", Dec15, 2022

- Asset renewal for major HV transmission equipment requiring replacement with consideration to "right-sizing"; and
- Sensitivity analysis to capture uncertainty in the load forecast

The following other assumptions are made in this report.

- The study period for this NA is 2023-2032.
- Coincident loads have been assumed equal to non-coincident loads for the purpose of transmission line adequacy assessment.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage (LV) capacitor banks and 95% lagging power factor for stations having LV capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

7 ADEQUACY OF EXISTING FACILITIES

This section provides a review of the adequacy of the transmission lines and stations in the GTA North Region. The adequacy is assessed using the latest extreme weather peak summer regional load forecast provided in Appendix C.

7.1 Adequacy of Northern and Southern York Area Facilities

7.1.1 500 and 230 kV Transmission Facilities

All 500 and most 230 kV transmission circuits in the GTA North are classified as part of the Bulk Electricity System ("BES"). The 230 kV circuits also serve local area stations within the region. The Northern and Southern York Areas are comprised of the following 230 kV circuits. Refer to Figure 4-2.

Northern York Area:

- Claireville TS to Holland TS 230 kV circuits: H82V and H83V.
- Holland TS to Brown Hill TS 230 kV circuits: B88H and B89H.

Southern York Area:

- Parkway TS to Cherrywood TS 230 kV circuits: C35P and C36P.
- Parkway TS to Claireville TS 230 kV circuits: V71P and V75P.
- Parkway TS to Buttonville TS ("Buttonville Tap") 230 kV circuits: P45 and P46[2].
- Parkway TS to Richview TS 230 kV circuits: P21R and P22R.

Western Area:

- Claireville TS to Kleinburg TS 230 kV circuits: V43 and V44[3]

The NA review shows that all flows on all transmission lines are within rating during the 2023-2032 study period except for the Claireville x Brown Hill corridor and the Parkway TS to Buttonville TS line. These are discussed below:

1) Loading on the Claireville TS to Brown Hill TS 230kV Corridor comprising the double circuit line H82/H3V and B88H/B89H will exceed the thermal limits by summer 2030.

[2] Radial from Parkway TS
[3] Radial from Claireville TS

Table 7-1 Loading on Claireville TS x Brown Hill TS Corridor

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Need Date
Armitage TS (44kV)		285	290	296	301	305	303	305	308	311	313	
Brown Hill TS (44kV)		94	100	118	121	125	124	125	125	126	126	
Holland TS (44kV)		166	173	176	179	169	169	169	169	169	169	
Northern York Station						66	80	89	99	109	118	
Vaughan MTS #4 (28kV)		101	100	128	149	148	147	146	145	143	142	
Vaughan MTS #5 (28kV)									64	132	138	
Total	850	646	663	718	750	813	823	834	911	989	1007	2030

2) Loading on the Parkway TS x Markham MTS #4 Jct. section of the 230kV Parkway TS x Buttonville TS double circuit Line P45/P46 will exceed the rating of line by summer 2028

Table 7-2 Loading on the Parkway TS x Markham MTS #4 Jct. Section of 230kV Line P45/P46

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Need Date
Buttonville TS (28kV)		144	152	154	152	160	149	148	147	146	145	
Markham MTS #4(28kV)		116	117	141	162	191	177	175	174	173	171	
Markham MTS #5(28kV)							68	136	140	139	138	
Toubner TS (28kV)						32	31	50	52	55	72	
Total	420	260	269	294	314	384	425	509	513	513	526	2028

7.1.2 Step down Transformer Station Facilities

There are a total of fifteen Hydro One and LDC owned step-down transformers stations and one direct transmission connected industrial customer owned station in the GTA North Region as given in Table 7-3 Step-Down Transformer Stations in the GTA North Region below:

Table 7-3 Step-Down Transformer Stations in the GTA North Region

Northern York Area		
Armitage TS	Brown Hill TS	Holland TS
Southern York Area		
Buttonville TS	Markham MTS #1[1]	Markham MTS #2[1]
Markham MTS #3[1]	Markham MTS #4[1]	Richmond Hill MTS[1]
Vaughan MTS #1[1]	Vaughan MTS #2[1]	Vaughan MTS #4[1]
Industrial Customer		
Western Area		
Kleinburg TS	Vaughan MTS #3[1]	Woodbridge TS

1. Stations owned by Alectra

The loadings on these stations were reviewed. Based on the forecast in Appendix C, additional capacity is required in the Northern York, Markham, and Vaughan areas starting in 2027. The station loading in each area and the associated station capacity and need dates are summarized in Table 7-**.**

Table 7-4 Adequacy of the Step-Down Transformation Facilities in the GTA North Region

Area/Supply	LTR-Capacity (MW)	2023 Summer Forecast (MW)	Need Date
Northern York Area (Armitage TS, Holland TS)	485	452	2027
Northern York Area (Brown Hill)	184	94	-
Markham / Richmond Hill transformation Capacity (Buttonville TS, Markham MTS #1, 2, 3, 4, and Richmond Hill MTS #1, 2)[1]	957	847	2028
Vaughan Transformation Capacity (Vaughan MTS #1, 2, 4)	612	551	2030
Vaughan Transformation Capacity (Vaughan MTS #3)[2]	153	145	2027
Kleinburg Area (Kleinburg TS 44kV)	97	102	Note [3]
Woodbridge TS (44kV)	80	85	Note [4]

1. Two stations required Markham MTS #5 in 2028 and Richmond Hill MTS #3 in 2032
2. Vaughan MTS #6 is a station dedicated for a large customer.
3. Excess load to be transferred to Northern York TS when new station complete in 2027
4. Loads to be managed by Hydro One Distribution

7.2 Asset Renewal Needs

No asset renewal needs have been identified in the GTA North Region over the current study period other than replacement of transformer T5 at Woodbridge TS listed in the 2020 RIP.

7.3 Load Restoration and Load Security Needs

Load Restoration and /or security needs were identified for theV43/V44, H82V/H83V, and V71P/V75P circuits in the 2020 RIP. One new load restoration need has been identified for the P45/P46 circuits. The needs and the recommended plan to address them are summarized below:

1. Load restoration following loss of the Claireville TS x Kleinburg TS 230kV circuits (V43/V44).

Not all loads more than 250 MW and 150 MW can be restored within 30 minutes and 4 hours respectively, as per the ORTAC restoration criteria. The RIP recommended that this need would be addressed as part of the longer-term plan to reinforce the Claireville TS to Kleinburg TS corridor. No further action was proposed at the time. This will be re-visited in the next phase of this RP cycle.

2. Load Restoration following loss of the Claireville TS to Holland TS circuits (H82V/H83V).

All loads exceeding 250 MW cannot be restored within 30 minutes per the ORTAC criteria. Following the loss of H82V/H83V, the normal station service supply to YEC generation is also lost. Holland TS cannot be restored from B88H/B89H until YEC generation is restored. Transferring YEC to an alternate source of station service supply cannot be completed within 30 minutes. The RIP had recommended that the IESO pursue alternative station service configurations at YEC to facilitate faster restoration of load on H82V/H83V, consistent with the load restoration criteria. This will be re-visited in the next phase of this regional planning cycle.

3. Load Security Need for the Parkway TS to Claireville TS 230kV double circuit Line V71P/V75P

The loss of this line can result in an interruption to over the 600MW which is more than what is permitted under the ORTAC criteria. The RIP had recommended that no further action is required. While the load security criteria was not met, Hydro One has installed inline switches at Grainger Jct. – located just outside of Vaughan MTS #1 - which permits quick restoration of the loads. This will be re-visited in the next phase of this regional planning cycle.

4. Load Restoration Need for the Parkway TS to Buttonville TS 230kV double circuit Line P45/P46

The line loading is expected to reach 384MW by summer 2027. Not all loads more than 250 MW and 150 MW can be restored within 30 minutes and 4 hours respectively for a double circuit outage, as per the ORTAC restoration criteria. This is a new need and will be reviewed in the next phase of this regional planning cycle.

8 NEEDS

This section identifies any new needs in the GTA North Region and reaffirms and provides an update on the needs already identified in the previous RIP.

Table 8-1 Near and Medium Terms Needs in the GTA North Region

No.	Need	Recommended Action Plan	Need Date[1]
Needs as per last RIP[2]			
1	Northern York Area: Step-down Transformation Capacity	Build new Northern York Station	2027
2	Woodbridge TS: End-of-life of transformer T5	Replace the end-of-life transformer with similar type and size equipment as per current standard	2027
3	Markham Area: Step-down Transformation Capacity	Build new Markham #5 MTS and connect to 230kV circuits P45/P46	2028
4	Increase Capability of 230kV Circuits P45+P46 (supply Buttonville TS, Markham #4 MTS, and future Markham #5 MTS)	Uprate circuits P45/46 from Parkway to Markham MTS #4 Jct.	2028
5	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan MTS #5	2030
6	Claireville X Brownhill Circuit Upgrade	Uprate circuits- H82/H3V and B88H/B89H	2030
7	Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, and V71P/V75P[3]	To be reviewed in next phase of this regional planning cycle	Existing
New Needs identified			
8	Kleinburg TS Area	Transfer load to Northern York TS	2027
9	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan MTS #6 and connect to 230kV circuit V43/V44	2027
10	Markham Area: New Customer Connection	Build New Toubner TS and line tap to 230kV circuits P45/46	2027
11	Richmond Hill Area: Step-down Transformation Capacity	Build new Richmond Hill #3 MTS	2032
12	Load Restoration for 230kV circuits P45/46	To be reviewed in next phase of this regional planning cycle	2027

1. Need date based on current forecast
2. Please see Reference 1 in Section 11
3. No action was considered necessary for these needs in the last regional Planning cycle. Needs will be reviewed again in the IRRP and RIP phases of this regional planning cycle.

8.1 Station and Transmission Capacity Needs in the Near and Medium Term

As shown in the Table above, the 2020 RIP had identified three new station capacity needs, one in the Markham area designated as Markham MTS #5, the second in the Vaughan Area, designated as Vaughan MTS #5 and the third in the Northern York Area, designated as Northern York TS. Since then, based on

the current load forecast and customers' request, the need for three additional stations has been identified over the study period - Richmond Hill MTS #3, Vaughan MTS #6 and Toubner TS.

8.1.1 Markham Area - Build Markham MTS #5 and Uprate circuits P45/P46 -2028

Markham MTS #5 was previously identified to provide additional step-down transformation capacity in Markham-Richmond Hill area and planned to be built adjacent to the Buttonville TS and supplied from the same 230kV Parkway TS x Buttonville TS circuits P45/P46 (See Figure 8-1 below). The new station will have 2 x75/125MVA, 230/27.6kV transformers and a 27.6kV switchgear building.



Figure 8-1: Markham MTS #5 Location

The TWG reaffirmed the need to build the new Markham MTS #5 and to uprate the limiting section of the P45/P46 line between Parkway TS and Markham MTS #4 Jct. to provide the needed capacity. The station project need date based on current forecast is summer 2028 (See Table 7-4) and the lines project need date is summer 2028 (see Table 7-2). This will be re-visited in the next phase of this regional planning cycle.

8.1.2 Northern York Region - Build Northern York Area TS and supply from 230kV Line B88H/B89H - 2027

The Northern York Area TS was recommended to be built in the Northern York Region to provide additional step-down transformation capacity in the Bradford, East Gwillimbury, and Newmarket area. This area is currently supplied from Armitage TS and Holland TS and total area load is forecast to exceed the capacity of these existing two stations by summer 2027 as shown in Table 8-2 below.

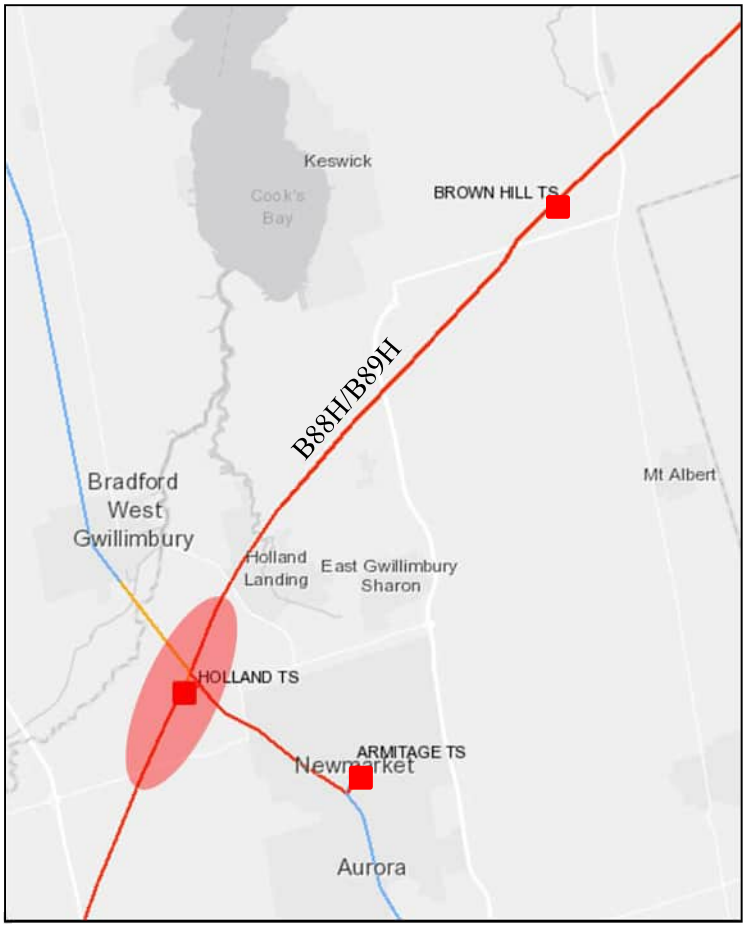

Figure-8-2 Northern York Area TS – Potential Location

Table 8-2: Northern York Area Capacity Need

Transformer Station	LTR	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Armitage TS (44kV)	317	285	290	296	301	305	303	305	308	311	313
Holland TS (44kV)[1]	169	166	173	176	179	169	169	169	169	169	169
Northern York Station	170					66	80	89	99	109	118
Total	485	451	463	472	480	540	552	564	577	589	600

1. Holland load above LTR to be transferred to new Northern York station.

The TWG has reaffirmed the need for building a new station close to these two stations, in the area shown in Figure 8-2. The new station is planned to be supplied from 230kV double circuit line H82V/H83V or B88H/B89H and planned to have 2x75/125MVA, 230/44-27.6kV transformers and 27.6kVand 44kV switchyards. The new station should increase the transformation capacity in Northern York Region by about 170 MW. The station location and timing will be further discussed with the area LDCs in the next phase of the regional planning process.

8.1.3 Vaughan Area – Build Vaughan MTS #5 and supply from 230kV Line H82V/H83V -2030

The Vaughan MTS #5 was previously identified to provide additional step-down transformation capacity in Vaughan area and planned to be built adjacent to the existing Vaughan MTS #4 – see Figure 8-3. The new station is planned to have 2 x75/125MVA, 230/27.6kV transformers, a 27.6kV switchgear building and is planned to be supplied from the 230kV double circuit line H82V/H83V.

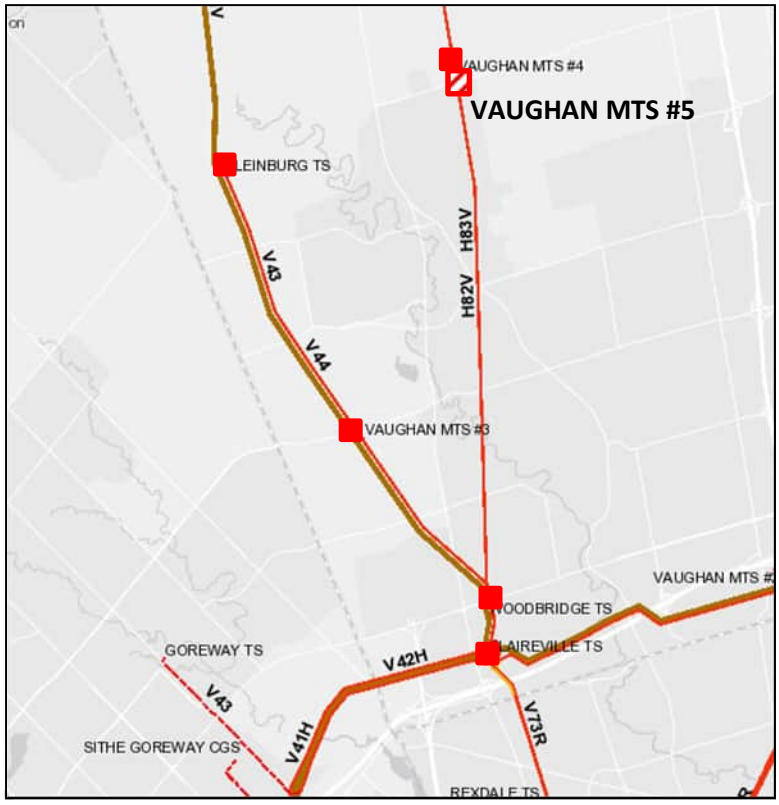

Figure-8-3 Vaughan MTS #5 Location

Table 8-3: Vaughan Area Station Capacity Need

Transformer Station	LTR	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Vaughan MTS #1 (28kV)	306	301	297	294	291	288	286	283	281	279	277
Vaughan MTS #2 (28kV)	153	149	148	147	145	144	143	141	141	139	138
Vaughan MTS #4 (28kV)	153	101	100	128	149	148	147	146	145	143	142
Vaughan MTS #5 (28kV)									64	132	138
Total	612	551	545	569	585	580	575	570	631	694	696

As mentioned in Table 7-1, there isn't sufficient transmission capacity available on the Claireville to Brown Hill corridor to fully supply Vaughan MTS #5, given that a new station in Northern York is anticipated by 2027. Therefore, a plan to increase transmission supply capability to the area will be required before a plan for the new transformation station in Vaughan can be committed. This will be addressed in the next phase of this regional planning cycle.

8.1.4 Kleinburg TS Area – Transfer Load to Northern York TS

Kleinburg TS 44kV loading is a newly identified need. Kleinburg TS has 2 x 75/125MVA, 230/44-27.6kV transformers with separate 44kV and 27.6kV switchyards. Significant new load is forecast to connect at 44kV in the 2023-2024 period as shown in Table 8-4 below.

Table 8-4 Kleinburg Area Station Capacity Load

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Kleinburg TS (28kV)	91	62	65	81	92	95	95	95	95	95	95
Kleinburg TS (44kV)	97	102	111	124	134	98	98	97	96	95	95
Load Transfer to be Managed		5	14	27	37						

To manage loading at Kleinburg TS, Hydro One DX intends to transfer loads in the northern area served by Kleinburg TS to the new Northern York TS planned to be in-service by 2027.The new Northern York TS is planned to be a 230/44-27.6kV station. The TWG will review this in the next phase of the regional planning cycle.

8.1.5 Vaughan Area – Build Vaughan MTS #6 and supply from 230kV Line V43/V44 - 2027

Vaughan MTS #6 is a new identified need. Alectra plans to build a new station to provide dedicated supply to a large customer. The new station will have 2 x 75/125MVA, 230/27.6kV transformers and a 27.6kV switchgear building. Alectra has requested that Hydro One build a short underground line tap to supply the new station from the 230kV Claireville TS x Kleinburg TS double circuit line V43/V44. The planned in-service date for the station is the end of 2027.

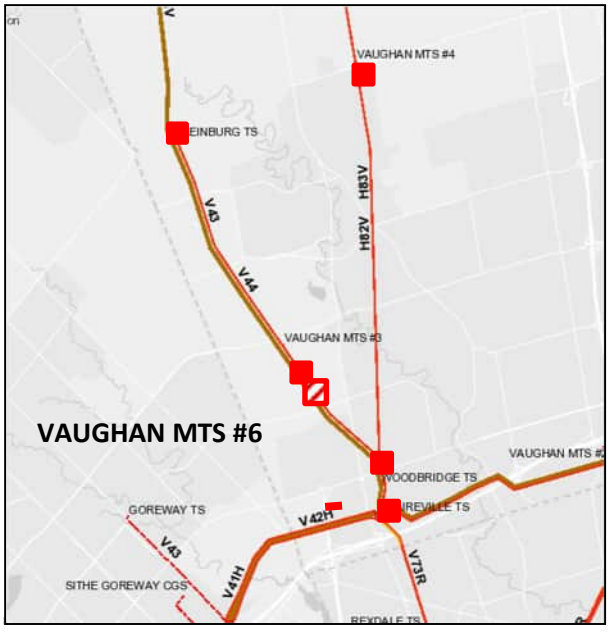

Figure-8-4 Vaughan MTS #6 Location

Table 8-5: Loading on the 230kV Claireville TS x Kleinburg TS line V43/V44

Transformer Station	Limit MW	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Kleinburg TS (28kV)		62	65	81	92	95	95	95	95	95	95
Kleinburg TS (44kV)		102	111	124	134	98	98	97	96	95	95
Vaughan MTS #3 (28kV)		117	118	118	145	145	145	145	145	145	145
Vaughan MTS #6 (28kV)						32	31	50	52	68	72
Woodbridge TS (28kV)		87	86	79	79	78	78	77	77	76	77
Woodbridge TS (44kV)		85	85	86	86	86	87	87	88	90	91
Total	620	453	465	487	536	534	533	552	553	569	575

Table 8-5 shows the forecast loads connected to the line. As shown, there is adequate capacity to supply the loads over the study period.

Hydro One is currently in initial consultations with Alectra on the connection. Further details will be discussed in the next phase of the regional planning cycle.

8.1.6 Richmond Hill Area – Build Richmond Hill MTS #3 and supply from 230kV Line V71P / V75P - 2032

Richmond Hill MTS #3 is a new identified need. Alectra plans to build a new station to meet forecast loads in the 2030s. The new station will have 2 x 75/125MVA, 230/27.6kV transformers and a 27.6kV switchyard. Alectra has requested Hydro One to connect the new station to the 230kV Claireville TS x Parkway TS double circuit line V71P/V75P. The planned in-service date is summer 2032.

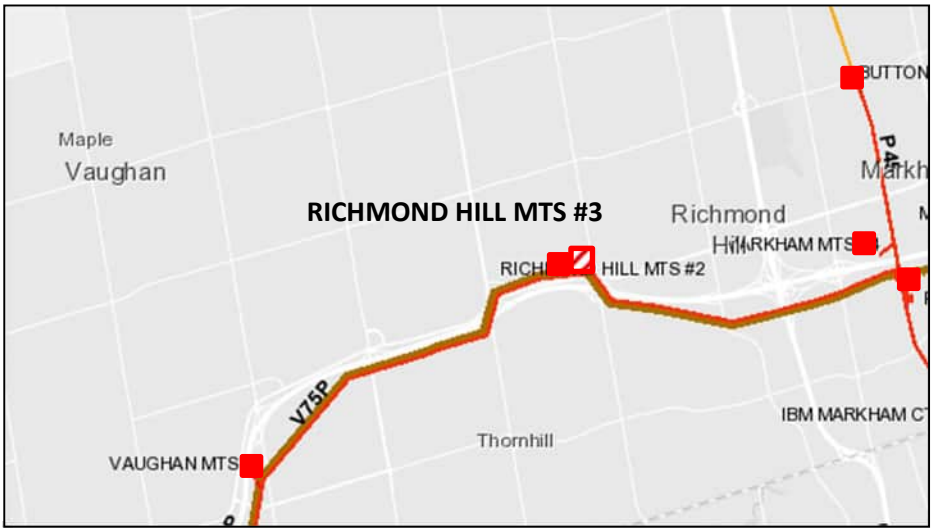

Figure-8-5 Richmond Hill MTS #3 Location

The 2020 RIP report had previously identified load security concerns with the V71P/V75P line as the connected loads exceed the 600 MW limit as per the ORTAC security criteria. However, as discussed in

Section 7.3, no action was recommended as Hydro One had installed sectionalizing switching on the line to restore load quickly in the event of a double circuit outage. The connection of the new station will further increase loading on the line. Alternatives to connect the station and address the load security need on the circuits will be developed and considered in the next phase of this RP cycle.

8.1.7 Toubner TS - 2027

Toubner TS is a new identified need. Hydro One has been requested to build a dedicated step-down transformer station for a direct industrial customer. The station will have 2 x 75/125 MVA, 230/27.6 kV transformers and a 27.6kV switchyard. The new station is in the Hwy. 7 and Hwy. 404 area and will be supplied from a tap for the 230kV line P45/P46 line tapped just north of Parkway TS. There is adequate capacity to supply the new station over the study period. The planned in-service date for the project is 2027.

Hydro One is currently in consultations with the customer to prepare connection estimates for the customer. Further details may be discussed in the current regional planning cycle.

8.1.8 Claireville x Brown Hill Transmission capacity Need- 2030

As described in Section 6.1 loading on the Claireville TS x Brown Hill TS corridor will exceed supply capacity by 2030. Alternatives to address this need will be developed and considered in the next phase of this regional planning cycle.

8.2 Long-Term Capacity Needs

With the provincial focus on decarbonization and the move away from fossil fuels, there will be a greater reliance on electricity. The GTA North region along with the rest of the province is about to embark on period of growth over the longer term driven by electrification, and large-scale development and customer connection projects are expected in several areas within the GTA North Region. The TWG will work with other stakeholders to ensure that all regional needs are met in a timely manner.

8.3 Asset Renewal Needs for Major HV Transmission Equipment – Woodbridge TS

As mentioned in Section 7.2 no asset renewal needs have been identified in the GTA North Region over the current study period other than Woodbridge TS identified in the last RIP.

Woodbridge TS comprises one DESN unit, T3/T5 (75/125 MVA), with two secondary winding voltages at 44 kV and 27.6 kV, each with a summer 10-Day LTR of 80 MW, supplying both Alectra and THESL. The station's 2022 44KV and 27.6kV actual peak loads were 55MW and 78 MW, respectively. Transformer T5 is currently about 51 years old and has been identified to be at its EOL.

The TWG is confirming the previous RIP identified need for the replacement of Woodbridge TS T5 transformer with similar type and size equipment as per current standard. Under this alternative the existing transformer T5 at Woodbridge TS is replaced with a new 75/125 MVA 230/44-27.6 kV transformer. This alternative would address the need and would maintain reliable supply to the customers in the area. The planned in-service date for the work is 2027.

8.4 Load Restoration and Security Needs

Load restoration need have been discussed earlier in Section 7.3, The TWG will consider these needs in the development of new plans to meet load growth and improve reliability of supply in the GTA North Region in the next phase of this regional planning cycle.

9 SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

The uncertainty can stem from varying factors ranging from changes considered in potential evolution of public policy, electrification (e.g., electrification of transportation or other sectors), Municipal Energy Plans, Community Energy Plans, and Climate Action Plans (for actions that are not firm/committed), non-committed customer connections (both distribution and transmission), DER scenarios (e.g., battery storage), continued operation of off-contract generation.

A high demand growth forecast was developed by assuming that the forecast growth was 50% higher than the extreme summer corrected normal growth net load forecast given in Appendix C. Similarly, a low demand forecast was developed assuming that the growth was half the extreme summer corrected Normal Growth net load forecast.

The impact of sensitivity analysis for the high and low growth scenarios on the capacity needs identified in Table 8-1 is summarized in Table 9-1.

Table 9-1: Impact of Sensitivity Analysis on the Identified Capacity Needs

No.	Need	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Toubner TS[1]	2027		
2	Vaughan MTS #6[1]	2027		
3	Northern York TS	2027	2026	2027
4	Markham MTS #5	2028	2027	2032
5	Vaughan MTS #5	2030	2030	2031
6	Richmond Hill MTS #3	2032	2029	Beyond 2032
7	Uprate circuits P45/P46[2]	2028	2028	Beyond 2032
8	Claireville X Brown Hill Corridor	2030	2027	Beyond 2032

[1]Customer requested work with defined in-service date.
[2]To be done along with the Markham MTS #5 project

Based on current equipment deliverability and construction schedules the earliest in-service dates for projects is summer 2027. The Toubner TS, Vaughan MTS #6 are customer driven projects and need to proceed. The remaining needs listed in Table 9-1will be addressed in the next phases of this planning cycle

in coordination with the additional identified network capacity and load security/restoration needs and considering a longer-term forecast for the area.

10 RECOMMENDATIONS

The TWG's recommendations are as follows:

a) No further regional coordination is required for the following needs and work will be proceeding as planned with all the three projects expected to be in-service by 2027.

- Woodbridge TS: Replace transformer T5
- Toubner TS: Build new station.
- Vaughan MTS #6: Build new station

b) Further assessment and regional coordination is required in the next phases of the regional planning cycle to review and/or develop a preferred plan for the follow needs:

- Markham MTS #5: Build new station
- 230kV circuit P45/P46: Uprate circuits between Parkway TS and Markham MTS #4 Jct.
- Northern York TS: Build new station
- Kleinburg TS 44kV: 44kV loads transfer to Northern York TS
- Vaughan MTS #5: Build new station
- Richmond Hill MTS #3: Build new station
- Claireville TS x Brown Hill TS Transmission circuit capacity need
- Load Restoration and/or Security needs for 230kV circuits V43/V44, H82V/H83V, P45/P46, and V71P/V75P.

11 REFERENCES

[1]. Hydro One, "GTA North Regional Infrastructure Plan", October 22, 2020.
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[3]. IESO, "York Region: Integrated Regional Resource Plan", February 28, 2020.
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12 APPENDIX A. STATIONS IN THE GTA NORTH REGION

No.	Station (DESN)	Voltage (kV)	Supply Circuits
1	Armitage TS T1/T2	230/44	B88H/B89H
	Armitage TS T3/T4	230/44	B88H/B89H
2	Brown Hill TS T1/T2	230/44	B88H/B89H
3	Buttonville TS T3/T4	230/27.6	P45/P46
4	CTS	230/13.8	P21R/P22R
5	Holland TS T1/T2, T3/T4	230/44	H82V/H83V
6	Kleinburg TS T1/T2 27.6	230/27.6	V44/V43
	Kleinburg TS T1/T2 44	230/44	V44/V43
7	Markham MTS #1 T1/T2	230/27.6	P21R/P22R
8	Markham MTS #2 T1/T2	230/27.6	C35P/C36P
9	Markham MTS #3 T1/T2	230/27.6	C35P/C36P
	Markham MTS #3 T3/T4	230/27.6	C35P/C36P
10	Markham MTS #4 T1/T2	230/27.6	P45/P46
11	Richmond Hill MTS #1 T1/T2	230/27.6	V71P/V75P
	Richmond Hill MTS #2 T3/T4	230/27.6	V71P/V75P
12	Vaughan MTS #1 T1/T2	230/27.6	V71P/V75P
	Vaughan MTS #1 T3/T4	230/27.6	V71P/V75P
13	Vaughan MTS #2 T1/T2	230/27.6	V71P/V75P
14	Vaughan MTS #3 T1/T2	230/27.6	V44/V43
15	Vaughan MTS #4 T1/T2	230/27.6	H82V/H83V
16	Woodbridge TS T3/T5 27.6	230/27.6	V44/V43
	Woodbridge TS T3/T5 44	230/44	V44/V43

13 APPENDIX B. TRANSMISSION LINES IN THE GTA NORTH REGION

Line	Circuit Designations	Voltage (kV)
Claireville TS to Holland TS	H82V/H83V	230
Holland TS to Brown Hill TS	B88H / B89H	230
Claireville TS to Kleinburg TS	V43/V44	230
Claireville TS to Parkway TS	V71P/V75P	230
Parkway TS to Markham MTS #1 and CTS	P21R/P22R	230
Parkway TS to Buttonville TS	P45/P46	230
Parkway TS to Cherrywood TS	C35P/C36P	230

14 APPENDIX C: NON-COINCIDENT SUMMER PEAK NET LOAD FORECAST (2023 TO 2032)

	LTR	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Armitage TS (44kV)	317	285	290	296	301	305	303	305	308	311	313
Brown Hill TS (44kV)	184	94	100	118	121	125	124	125	125	126	126
Buttonville TS (28kV)	166	144	152	154	152	160	149	148	147	146	145
Holland TS (44kV)	169	166	173	176	179	169	169	169	169	169	169
Kleinburg TS (28kV)	91	62	65	81	92	95	95	95	95	95	95
Kleinburg TS (44kV)[1]	97	102	111	124	134	98	98	97	96	95	95
Markham MTS #1 (28kV)	81	80	79	78	77	76	76	75	74	74	73
Markham MTS #2 (28kV)	101	88	98	97	96	106	94	93	93	92	91
Markham MTS #3 (28kV)	202	171	184	191	189	197	186	184	183	181	180
Markham MTS #4(28kV)	153	116	117	141	162	176	177	175	174	173	171
Markham MTS #5(28kV)	153						68	136	140	139	138
Northern York Station	170					66	80	89	99	109	118
Richmond Hill-1 MTS (28kV)	153	153	152	150	149	154	146	144	144	142	141
Richmond Hill-2 MTS (28kV)	101	95	105	104	104	111	104	104	104	105	105
Richmond Hill-3 MTS (28kV)	153										60
Toubner TS (28kV)	153					32	31	50	52	55	72
Vaughan MTS #1 (28kV)	306	301	297	294	291	288	286	283	281	279	277
Vaughan MTS #2 (28kV)	153	149	148	147	145	144	143	141	141	139	138
Vaughan MTS #3 (28kV)	153	117	118	118	145	145	145	145	145	145	145
Vaughan MTS #4 (28kV)	153	101	100	128	149	148	147	146	145	143	142
Vaughan MTS #5 (28kV)	153								64	132	138
Vaughan MTS #6 (28kV)	153					32	31	50	52	68	72
Woodbridge TS (28kV)	80	87	86	79	79	78	78	77	77	76	77
Woodbridge TS (44kV)	80	85	85	86	86	86	87	87	88	90	91
Grand Total		**2396**	**2459**	**2559**	**2652**	**2792**	**2814**	**2921**	**2997**	**3084**	**3173**

1. Kleinburg 44kV load exceeds LTR between 2023 and 2026. Excess load planned to be transferred to Northern York Region when station is built in 2027.

15 APPENDIX D: ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station (LDC owned)
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PEC	Portland Energy Centre
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
RP	Regional Planning
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TPS	Traction Power Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

IESO response to Toronto Hydro REG Investments Plan 2025 – 2029

As part of the OEB's Filing Requirements for Electricity Distribution Rate Applications, a distributor must submit a letter of comment from the Independent Electricity System Operator (IESO) on its Renewable Energy Generation (REG) Investments Plan, which is part of its Distribution System Plan (DSP).

The OEB issued the 2023 Edition of Chapter 5 for 2024 Rate Applications on December 15, 2022 wherein section 5.2 Distribution System Plans, under "Renewable Energy Generation (REG)" states:

"A distributor is expected to coordinate with the IESO in relation to REG investments and confirm if there are REG investments in the region.

If there are REG investments proposed in the DSP, a distributor is expected to demonstrate that it has coordinated with the IESO, other distributors, and/or transmitters, as applicable, and that the investments proposed are consistent with a Regional Infrastructure Plan. This coordination is demonstrated by a comment letter provided by the IESO, to be filed with the DSP."

On August 29, 2023, the IESO received a letter from Toronto Hydro-Electric System Limited (Toronto Hydro) outlining its REG Investments Plan (Plan) for comment. The IESO has reviewed Toronto Hydro's Plan and provides its comments as follows.

IESO Comments

The IESO notes that Toronto Hydro's service territory is within the Toronto region. The Toronto region is currently undergoing its third cycle of regional planning[1] and is currently at the Integrated Regional Resource Plan (IRRP) stage as of September 2023. The Toronto region completed its second cycle of regional planning with the publication of the Regional Infrastructure Plan (RIP) by Hydro One Networks Inc. in March 2020[2]. Toronto Hydro is an active, participating member of the regional planning study team.

[1] Toronto Regional Planning, IESO. https://www.ieso.ca/en/Get-Involved/Regional-Planning/GTA-and-Central-Ontario/Toronto

[2] Hydro One's Regional Infrastructure Plan, March 2020. https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/toronto/Documents/Toronto%20Regional%20Infrastructure%20Plan_Mar6%202020.pdf

Toronto Hydro – Renewable Energy Generation Investments (2025-2029)

Toronto Hydro states that there are currently 305 MW of installed distributed energy resource (DER) capacity on their distribution system as of end of 2022, 116 MW of which are considered as REG. Toronto Hydro anticipates that there will be 200 MW of REG connected to their distribution system by the end of the DSP planning period in 2029. The forecasted REG and other DER connections over the Plan period (2025-2029) is being coordinated as a planning input into the regional planning process currently underway.

With respect to investments in Toronto Hydro's Plan, the IESO confirms that although it includes renewable enabling improvements (REIs) investments of an estimated $57.5 million over the Plan period for installation of bus tie reactors to alleviate short circuit constraints, improving monitoring and control to ensure safe operation of DERs (particularly during faults), and deploying energy storage systems to alleviate distribution system constraints, these investments are not a result of outcomes from the regional planning processes as outlined above. These REI investments are proposed by Toronto Hydro to improve the ability of Toronto Hydro's distribution system to accommodate REG, which is not in scope of regional planning. Therefore, the IESO has no comment on these investments.

The IESO appreciates the opportunity provided to review Toronto Hydro's Plan and looks forward to continue working together in the regional planning process.

C Performance Measurement

C1 Overview of Performance Framework

In developing its approach to performance measurement for the Distribution System Plan ("DSP"), Toronto Hydro considered the Ontario Energy Board's guidance, including the *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the "RRF").[1] A key theme of the Ontario Energy Board's guidance is that utilities should align their investment plans with customer needs, and adopt an outcomes-based approach to tracking their performance.

Toronto Hydro's 2025-2029 performance measurement framework consists of (1) performance outcomes consistent with the Ontario Energy Board's Renewed Regulatory Framework (RRF) categories, and (2) a custom scorecard that is tied to an innovative Performance Incentive Mechanism ("PIM") as part of the 2025-2029 custom rate framework (Exhibit 1B, Tab 2, Schedule 1).

In respect of the first component – RRF outcomes – Toronto Hydro intends to continue delivering high-performance on the Electricity Distributor Scorecard ("EDS") and the Electricity Service Quality Requirements ("ESQR") consistent with the historical results presented in Exhibit 1B, Tab 3, Schedule 2. To that end, each capital and operational program outlined in the DSP and Exhibit 4, Tab 2 (operations) includes a performance outcomes table that explains how the program advances specific RRF objectives.

The utility developed its capital programs to maintain and improve reliability and safety, meet service and compliance obligations, address load capacity and growth needs, improve contingency constraints, or make necessary day-to-day operational investments. The choices made reflect a balance between customer preferences, affordability, and prioritized outcomes (as described in Exhibit 2B, Section E2), with the overriding objective of delivering value for money.

Toronto Hydro sets asset management objectives that are aligned with the overall investment plan objectives, and are a result of the detailed, iterative, and customer engagement-driven planning process summarized in Section E2 of the DSP. Section D1.2.1 explains the link between Toronto Hydro's distribution system Asset Management System ("AMS") and its performance measurement framework with respect to the investment priorities of the plan.

[1] Ontario Energy Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach (October 18, 2012).

As further detailed in Exhibit 1B, Tab 3, Schedule 1, Toronto Hydro's 2025-2029 Custom Scorecard tracks performance across four performance categories. By monitoring and managing the performance measures identified in each category of the custom scorecard (see Table 1 below), in addition to the EDS, ESQR and Asset Management performance measures noted above, the utility expects to drive continuous and sustained improvement across the organization in the next rate period in a manner that aligns with Ontario Energy Board and customer feedback, and also reflects the key objectives and underpinnings of the plan.

Table 1: Investment Category Trigger Drivers

Performance Category	Outcome and Measure
System Reliability & Resilience	**Outage Duration:** System Average Interruption Duration Index (SAIDI) excluding MEDs, Loss of Supply and Planned Outages
	Outage Frequency: System Average Interruption Frequency Index (SAIFI) - Defective Equipment
	System Security Enhancements: Deliver initiatives that enhance Toronto Hydro's physical and cyber security posture against the NIST framework
Customer Service & Experience	**New Services Connected on Time:** Percentage of new connections and service upgrades completed on time consisting of Low Voltage Connections (70%), High Voltage Connections (20%) and DER Connections (10%)
	Customer Satisfaction: Customer post-transactional surveys for Phone Inquiries, E-Mail Inquiries, Key Accounts engagements, Construction Communications, Outages Communications, and Customer Connections
	Customer Escalations Resolution: Percentage of customer escalations resolved within 10 business days.
Environment, Safety and Governance	**Total Recordable Injury Frequency (TRIF):** Injuries per 100 employees (or 200,000 hours worked) per year.
	Emissions Reductions: CO2e emissions produced by the utility's fleet and facilities.
	ISO Compliance and Certification: Achieve and maintain certification with select ISO governance standards, specifically achieve ISO 55001 (60%), and maintain ISO14001 (20%) and ISO45001 (20%).
Efficiency & Financial Performance	**Efficiency Achievements:** Sustained benefits for customers in the form of reduced or avoided costs or other benefits that will produce a lower revenue requirement in the next rebasing
	Grid Automation Readiness: Completion of technology milestones that will enable the implementation of fully automated, self-healing grid operations beginning in 2030
	System Capacity (Non-Wires): Flexible system capacity procured through demand response offerings.

The section that follows explains Toronto Hydro's reliability performance over the 2018-2022 period in accordance with Chapter 5 Filing Requirements.[2] For details regarding Distributor Specific Reliability Targets, please refer to Exhibit 1B, Tab 3, Schedule 1 for the reliability targets proposed as part of Toronto Hydro's 2025 Custom Scorecard.

C2 Historical Reliability Performance

Toronto Hydro tracks reliability performance indicators System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") in several ways:

1. All events – Including Major Event Days ("MEDs") and Loss of Supply ("LoS");
2. Excluding events relating to LoS;
3. Excluding events relating to MEDs;
4. Excluding MEDs and LoS; and
5. Excluding MEDs, LoS, and Scheduled Outages.

Scenarios 1, 2, 3, 4, and 5 provide SAIFI and SAIDI in the manner required by the Ontario Energy Board's prescribed Appendix 2-G, filed at Exhibit 1B, Tab 3, Schedule 2. Scenario 4 is also consistent with the Ontario Energy Board Electricity Distributor Scorecard and MD&A discussed in Exhibit 1B, Tab 3, Schedule 2. Scenario 5 provides SAIFI and SAIDI excluding MEDs, LoS, and Scheduled Outages as a more normalized reflection of total system reliability performance. Each scenario provides valuable information as to the causes, duration, and frequency of outages within Toronto Hydro's distribution system.

C2.1 System Overview

Figures 1 and 2 below show the system's total SAIFI and SAIDI between 2018 and 2022, respectively, under each of the five scenarios. The notably higher SAIFI and SAIDI in 2018 under Scenarios 1 and 2 can be attributed to a transformer fire at Finch Transformer Station ("TS") in July (counted as both a Loss of Supply event and a MED), in addition to multiple storms that occurred in April, May, and June of that year. These occurrences were outside the utility's control and met the definition of MEDs as set out in the Ontario Energy Board's Electricity Reporting and Record Keeping Requirements

[2] Ontario Energy Board, Filing Requirements for Electricity Distributor Rate Applications, Chapter 5 (December 15, 2022) at pages 7-8.

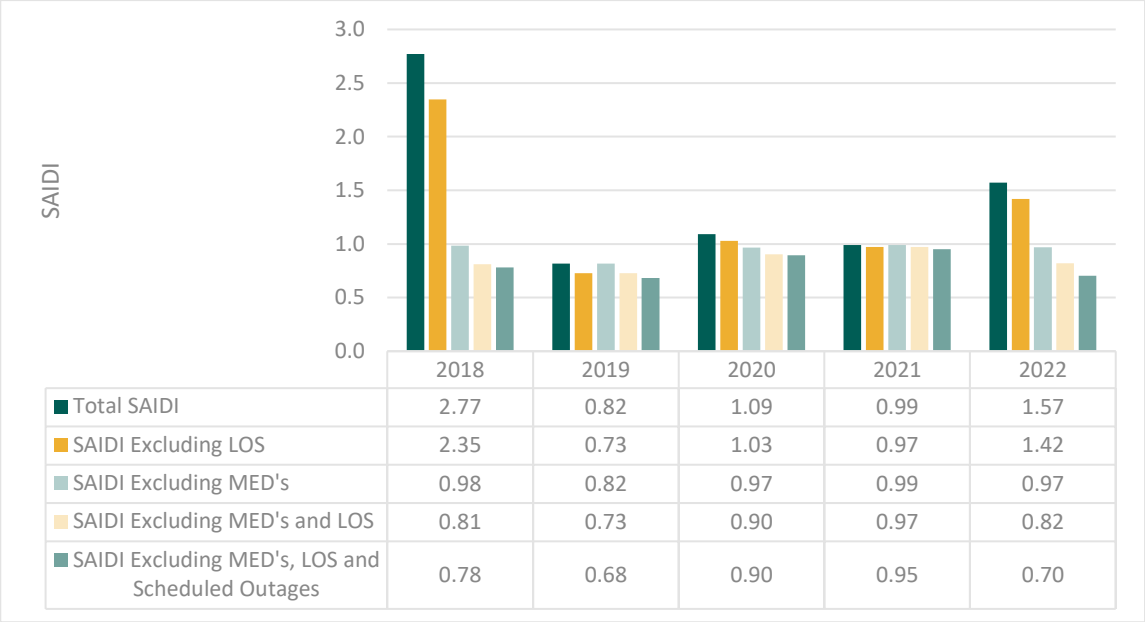
("RRR").[3] As a result, these MEDs caused the year-over-year fluctuations to be more drastic. In contrast, Scenario 3 (excluding MEDs), Scenario 4 (excluding MEDs and LoS), and Scenario 5 (excluding MEDs, LoS, and scheduled outages) illustrate more normalized SAIFI and SAIDI values with less fluctuations. Toronto Hydro considers these latter scenarios to offer greater insight into system reliability as they provide a better indication of the performance trend of the system and the impact of recent investments, and are the more commonly used indicators across the industry for benchmarking against distribution system performance. With the more normalized scenarios, there has been some worsening of performance, especially for SAIFI, over 2020-2022 and this is largely attributed to external factors, such as unknown causes or foreign interference, although defective equipment has also contributed. Additional discussion of this is provided in Sections 5-10 below.



	2018	2019	2020	2021	2022
Total SAIFI	2.04	1.30	1.69	1.55	1.82
SAIFI Excluding LOS	1.64	1.09	1.50	1.46	1.58
SAIFI Excluding MED's	1.48	1.30	1.62	1.55	1.63
SAIFI Excluding MED's and LOS	1.14	1.09	1.42	1.46	1.39
SAIFI Excluding MED's, LOS and Scheduled Outages	1.13	1.07	1.42	1.45	1.35

Figure 1: System Level SAIFI

[3] Ontario Energy Board, Electricity Reporting and Record Keeping Requirements ("RRR"), Section 2.1.4.2(4). (Effective March 31, 2020).



	2018	2019	2020	2021	2022
Total SAIDI	2.77	0.82	1.09	0.99	1.57
SAIDI Excluding LOS	2.35	0.73	1.03	0.97	1.42
SAIDI Excluding MED's	0.98	0.82	0.97	0.99	0.97
SAIDI Excluding MED's and LOS	0.81	0.73	0.90	0.97	0.82
SAIDI Excluding MED's, LOS and Scheduled Outages	0.78	0.68	0.90	0.95	0.70

Figure 2: System Level SAIDI

Since the early 2000s, Toronto Hydro has utilized its standalone Interruption Tracking Information System ("ITIS") to store historical reliability data. ITIS relies on manual entry of outage information, and its data is used to carry out reliability-driven analyses and to track reliability performance of the system.

Toronto Hydro upgraded its existing Outage Management System with Oracle's Network Management System ("NMS"). This new system provides Toronto Hydro with more robust data and enhanced visibility into near real-time system events.[4] As part of the multi-year NMS upgrade initiative, Toronto Hydro is implementing a new commercial solution, Oracle's Utility Analytics ("OUA"), which will serve as the future successor to ITIS. OUA will streamline Toronto Hydro's interruption and reliability reporting process and seamlessly integrate with NMS.

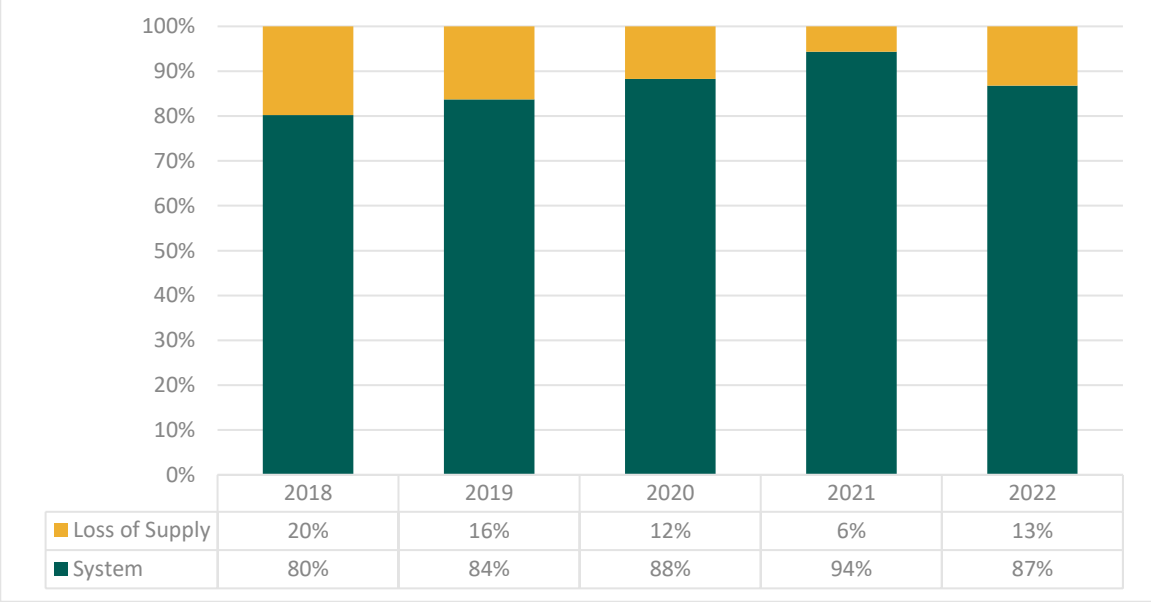
These upgrades have and will continue to improve the data quality and accuracy of Toronto Hydro's interruption tracking and reporting. Some of these changes have resulted in higher reliability trends in 2022 when compared to historical years. Furthermore, the following changes are expected over the course of the multi-year upgrade, leading to more interruptions being captured in 2023 to 2029:

[4] For more information refer to Emergency Response at Exhibit 4, Tab 2, Schedule 5 and Control Centre Operations at Exhibit 4, Tab 2, Schedule 7.

1. Increased number of outages affecting a small number of customers.
2. Improved resolution of outage duration, down to the second.
3. Increased number of scheduled outages reported; and
4. Changes in outage structuring: currently, outages are structured manually, typically broken down by feeder. OUA will streamline this process by automatically generating outage reports based on restoration actions recorded in NMS.

C2.2 Loss of Supply

Loss of Supply ("LoS") events have a significant impact on the overall reliability of Toronto Hydro's distribution system, and being external to Toronto Hydro's operations and control, are generally excluded from a system reliability analysis. On a system level, LoS events can contribute up to 20 percent of SAIFI and 15 percent of SAIDI (based on system reliability analysis beginning in 2018), although significant variations can occur year to year. There are also considerable variations between individual LoS events, which makes it difficult to perform trend analyses and forecast future reliability performance. For instance, 21 LoS events occurred in 2019, whereas 42 LoS events occurred in 2022. Nevertheless, the fewer events in 2019 affected SAIFI and SAIDI to a greater extent due to higher impacts of individuals events in that year. Figures 3 and 4 below show the SAIFI and SAIDI system impact due to LoS events.



	2018	2019	2020	2021	2022
Loss of Supply	20%	16%	12%	6%	13%
System	80%	84%	88%	94%	87%

Figure 3: Loss of Supply Impact on Total SAIFI

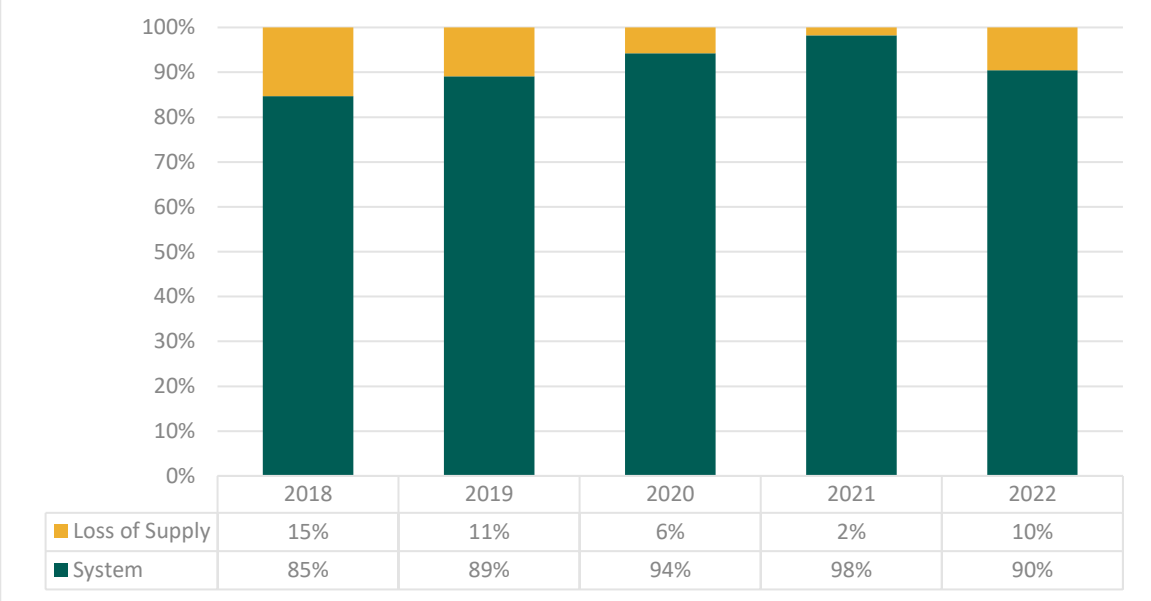


Figure 4: Loss of Supply Impact on Total SAIDI

C2.3 Major Event Days

Major Event is defined by the Institute of Electrical and Electronics Engineers ("IEEE") as "an event that exceeds reasonable design and/or operational limits of the electric power system",[5] where a Major Event Day ("MED") is defined as "a day in which the daily system SAIDI exceeds a Major Event Day threshold value."[5] The term Major Event is similarly defined by the Ontario Energy Board's RRR as "an event that is beyond the control of the distributor and is: unforeseeable, unpredictable, unpreventable, or unavoidable."[6] Similar to LoS events, MEDs are external to routine utility operation, and in addition, are highly volatile from year to year. The exclusion of MEDs and LoS events allows a utility to normalize its reliability data, making it possible to establish meaningful reliability performance trends and associated targets. Toronto Hydro follows the IEEE Standard 1366 Beta Method to derive the MED threshold value for the classification of MEDs.[7] Table 2 lists the MEDs experienced by Toronto Hydro since 2018 and Figure 5 shows the damage resulting from one such event.

[5] IEEE 1366-2022 – IEEE Guide for Electric Power Distribution Reliability Indices. Section 3. Definitions.
[6] Ontario Energy Board, Electricity Reporting and Record Keeping Requirements, Section 2.1.4.2(4) (Effective March 8, 2023).
[7] IEEE 1366-2022 – IEEE Guide for Electric Power Distribution Reliability Indices. Section 4.5 Major Event Day Classification.

Table 2: Major Event Days

Dates	Description	Number of Outages	Total Customers Interrupted	Total Customer Hours Interrupted
April 4, 2018	Wind Storm	68	97,378	112,230
April 15, 2018	Freezing Rain	47	85,281	164,214
May 4, 2018	Wind Storm	98	164,261	800,390
June 13, 2018	Wind Storm	31	35,366	96,504
July 28, 2018	Loss of Supply to Finch TS	22	45,475	192,195
July 8, 2020	Wind Storm	41	54,253	97,477
May 21, 2022	Wind Storm	92	145,313	469,876



Figure 5: Post-Fire Damage at Finch Transformer Station Months Following a Major Event Day

Figures 6 and 7, below, demonstrate the SAIFI and SAIDI system impacts resulting from MEDs.

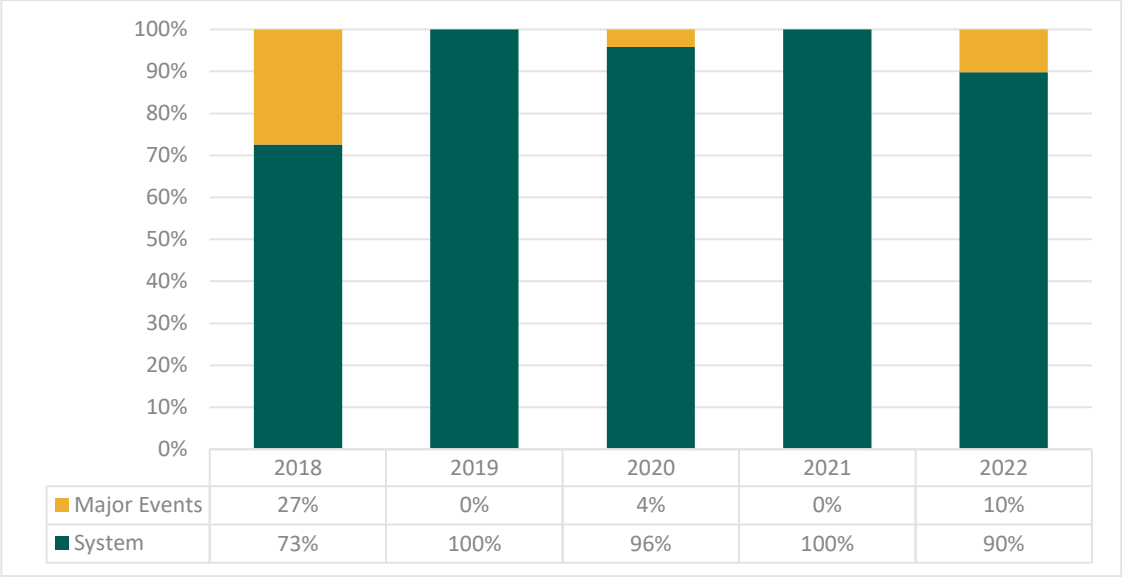


Figure 6: Major Event Days Impact on Total SAIFI

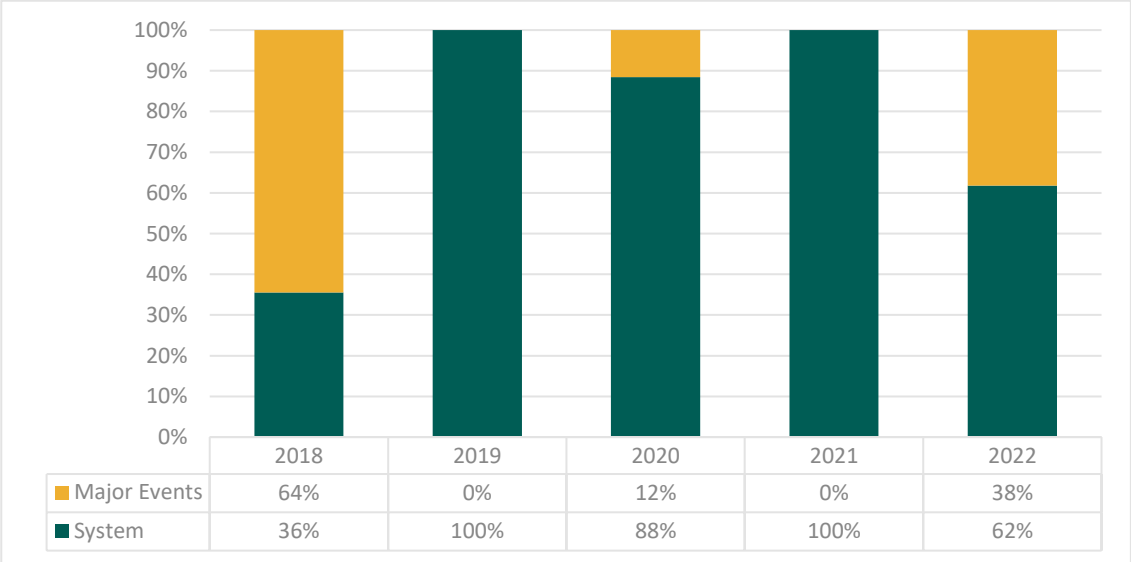


Figure 7: Major Event Days Impact on Total SAIDI

C2.4 Scheduled Outages

Scheduled outages are associated with construction and preventative maintenance activities. Assets that are at risk of failing in the near future may be taken out of service to be repaired or replaced. While this can lead to lengthy outages, the duration of the outage would generally be much shorter

than those caused by the asset failing while in-service. These planned replacements are also often required to mitigate safety risks to Toronto Hydro's employees and third-party contractors. Toronto Hydro provides customers advanced notification of any impeding work prior to executing the project, which gives them the opportunity to plan their activities around the repair work. Figures 8 and 9, below, demonstrate the SAIFI and SAIDI system impacts resulting from Scheduled Outages.

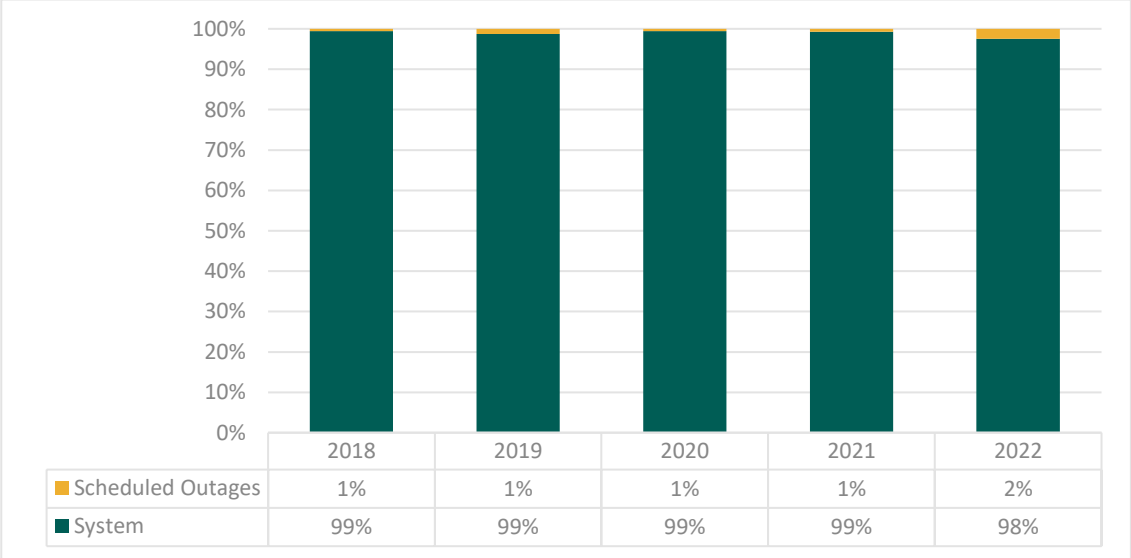


Figure 8: Scheduled Outages Impact on Total SAIFI

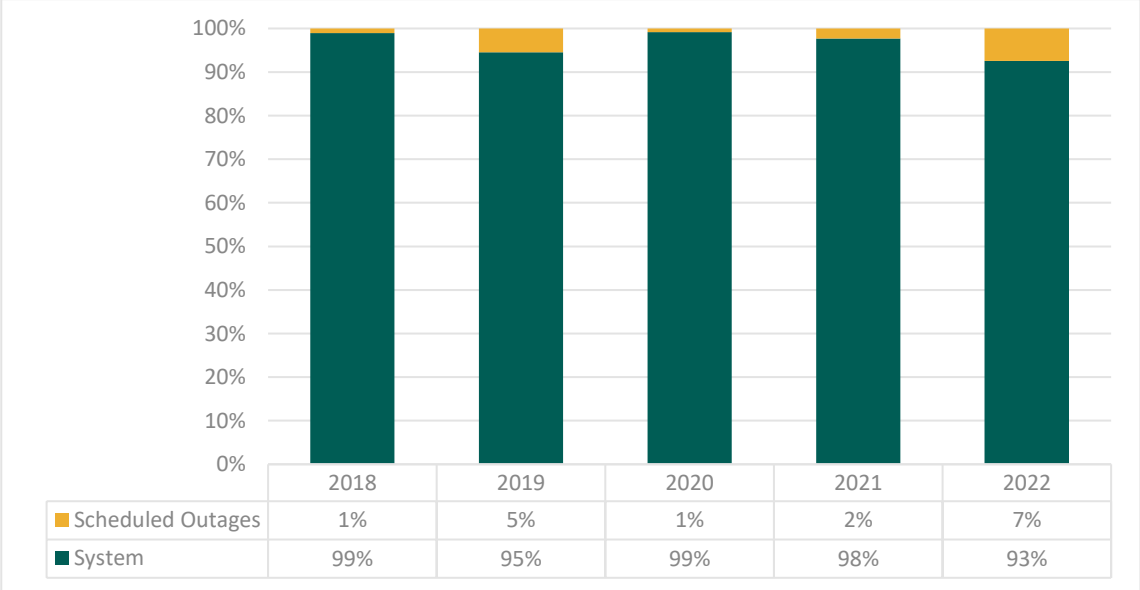


Figure 9: Scheduled Outages Impact on Total SAIDI

C2.5 System Reliability Excluding Loss of Supply, Major Event Days, and Scheduled Outages

As noted above, MEDs and LoS events are outside the utility's control. As a result, these factors are typically excluded from analysis of the overall system performance. In addition, scheduled outages are required to allow certain work to be completed on the distribution system such as replacing assets that are at their end of life or in deteriorated condition to prevent a future outage. The inclusion of scheduled outages in reliability analysis would not provide a true reflection of underlying distribution system performance. Figures 10 and 11, below, show the adjusted SAIFI and SAIDI (excluding LoS, MEDs, and scheduled outages).

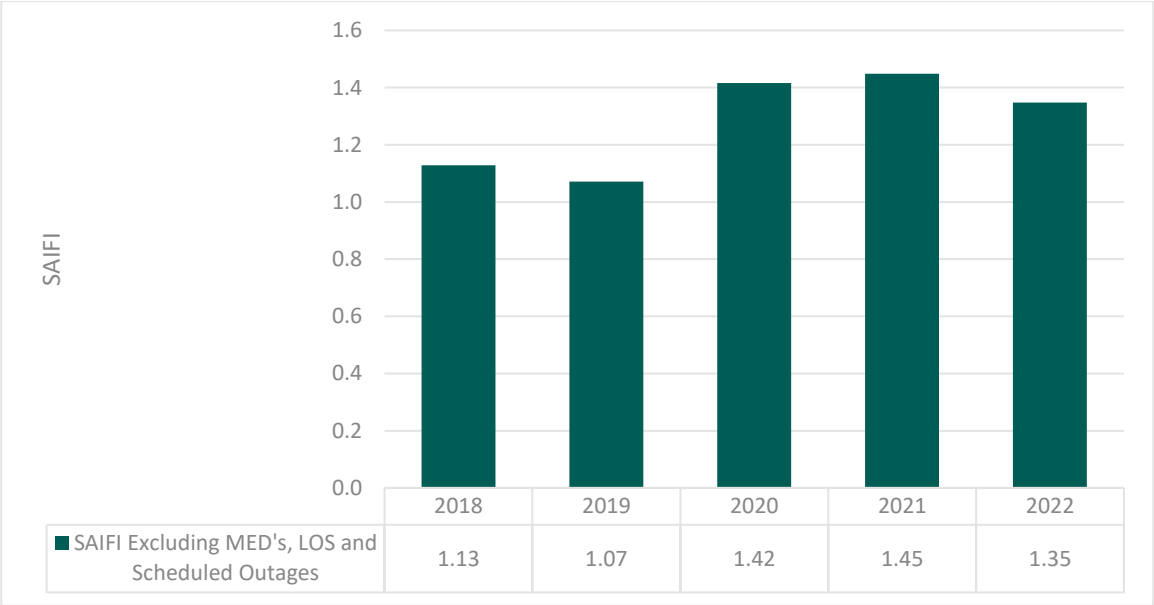


Figure 10: System SAIFI Excluding MEDs, Loss of Supply, and Scheduled Outages

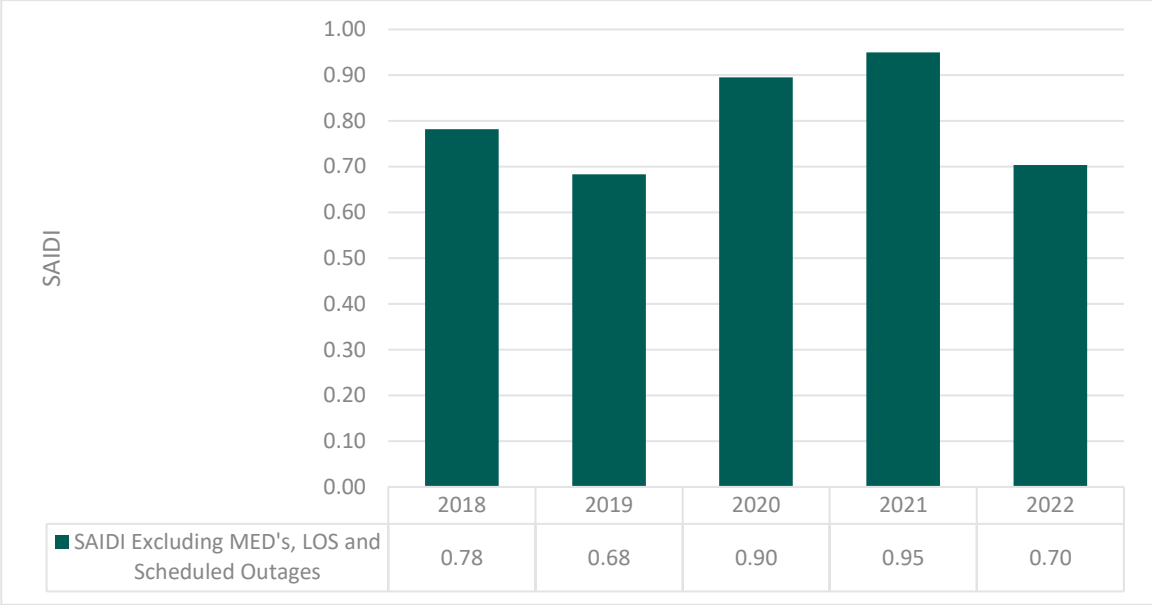


Figure 11: System SAIDI Excluding MEDs, Loss of Supply, and Scheduled Outages

The year-over-year adjusted values show that SAIFI has increased in 2020-2022 compared to 2018-2019 levels, while SAIDI showed a temporary uptick in 2020 and 2021, but decreased back down again in 2022. This recent rise in reliability impacts was caused by a range of factors. The predominant cause for the increase in SAIFI was unknown impacts, which consist of outages that have no apparent cause. However, outages caused by foreign interference (especially animal contacts), defective equipment (including outages attributed to underground cable and cable accessories, overhead switches, overhead conductors, as well as poles and pole hardware failures), and Tree Contacts have also contributed to the overall increase in SAIFI observed during the same period, albeit to a lesser extent.

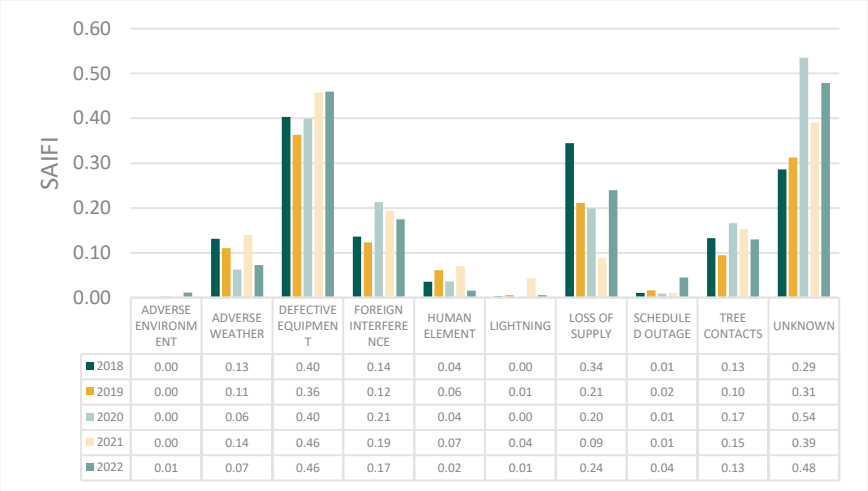
Similarly, foreign interference (including outages attributed to animal contacts, vehicles, and foreign objects) was the main contributor to the increase in SAIDI during the aforementioned period. Along with foreign interference, defective equipment (particularly underground cable and cable accessories, and overhead switch failures), unknown impacts, and tree contacts have also played a role in the observed increase in SAIDI.

The following sections provide breakdowns by cause code and more detailed discussions of trends within different cause codes and how they are impacted by Toronto Hydro's investments. More

generally, Toronto Hydro's core sustainment programs[8] mainly contribute to mitigating the probability of outages due to defective equipment by proactively replacing deteriorating assets at higher risk of failure. The utility's modernization investments serve to improve reliability by reducing the customers impacted and duration of outages due to all causes – for more information on these investments, please see the System Enhancements and Network Condition Monitoring programs[9] and Toronto Hydro's Grid Modernization Road Map.[10] Some programs, such as Area Conversions,[11] contribute to reducing both the probability and length of outages by renewing aging, deteriorating, and obsolete areas of the distribution system, which are at higher risk of failure and take more time to restore power in the event of an outage.

C2.6 Cause Code Analysis

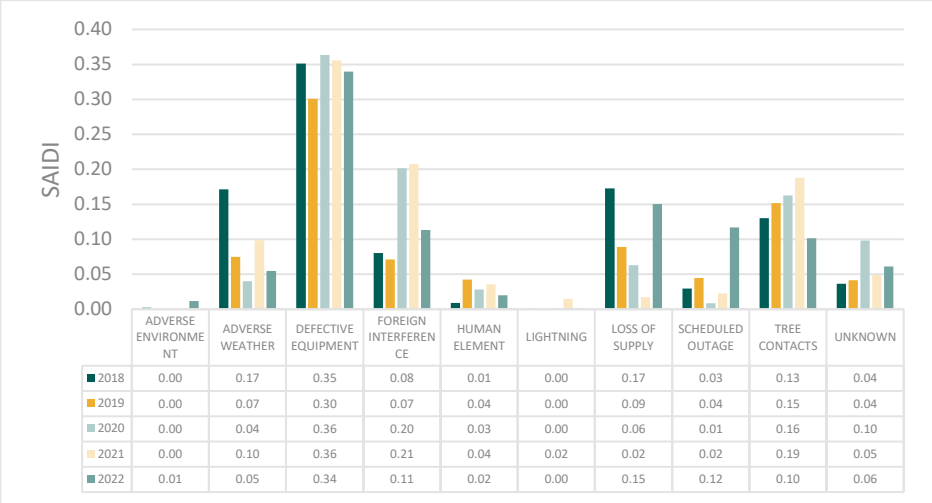
Toronto Hydro tracks causes of service interruptions using the ten primary cause codes as specified in the Ontario Energy Board's RRR.[12] Figures 12 and 13, below, show the utility's 2018-2022 SAIFI and SAIDI performance by cause code. Table 3, below, shows the percentage contribution of each cause code to overall system SAIFI and SAIDI (excluding MEDs).



	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2018	0.00	0.13	0.40	0.14	0.04	0.00	0.34	0.01	0.13	0.29
2019	0.00	0.11	0.36	0.12	0.06	0.01	0.21	0.02	0.10	0.31
2020	0.00	0.06	0.40	0.21	0.04	0.00	0.20	0.01	0.17	0.54
2021	0.00	0.14	0.46	0.19	0.07	0.04	0.09	0.01	0.15	0.39
2022	0.01	0.07	0.46	0.17	0.02	0.01	0.24	0.04	0.13	0.48

Figure 12: SAIFI Cause Code Breakdown (Excluding MEDs)

[8] E.g. Underground System Renewal – Horseshoe (Exhibit 2B, Section E6.2), Overhead System Renewal (Exhibit 2B, Section E6.5.
[9] Exhibit 2B, Section E7.1 and E7.3.
[10] Exhibit 2B, Section D5.
[11] Exhibit 2B, Section E6.1
[12] Ontario Energy Board, Electricity Reporting and Record Keeping Requirements, Section 2.1.4.2.5 - Reporting Cause Codes. (Effective March 8, 2023).



	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	LOSS OF SUPPLY	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN
2018	0.00	0.17	0.35	0.08	0.01	0.00	0.17	0.03	0.13	0.04
2019	0.00	0.07	0.30	0.07	0.04	0.00	0.09	0.04	0.15	0.04
2020	0.00	0.04	0.36	0.20	0.03	0.00	0.06	0.01	0.16	0.10
2021	0.00	0.10	0.36	0.21	0.04	0.02	0.02	0.02	0.19	0.05
2022	0.01	0.05	0.34	0.11	0.02	0.00	0.15	0.12	0.10	0.06

Figure 13: SAIDI Cause Code Breakdown (Excluding MEDs)

Table 3: Five-Year Average SAIFI and SAIDI Contribution by Cause Code (Excluding MEDs)

Cause Code	Contribution % to SAIFI	Contribution % to SAIDI
DEFECTIVE EQUIPMENT	27.5%	36.2%
UNKNOWN	26.4%	6.1%
LOSS OF SUPPLY†	14.3%	10.4%
FOREIGN INTERFERENCE	11.1%	14.3%
TREE CONTACTS	8.9%	15.5%
ADVERSE WEATHER	6.8%	9.3%
HUMAN ELEMENT	2.9%	2.9%
SCHEDULED OUTAGE‡	1.2%	4.7%
LIGHTNING	0.8%	0.4%
ADVERSE ENVIRONMENT	0.2%	0.3%

† Excluded when evaluating Toronto Hydro's system reliability performance under Scenarios 2, 4, and 5.

‡ Excluded when evaluating Toronto Hydro's system reliability performance under Scenario 5.

On average, between 2018 and 2022, defective equipment was the main contributor to SAIFI and SAIDI, at 27.5 percent and 36.2 percent respectively. However, in 2020 and 2022, defective equipment was surpassed by unknown caused outages as the top contributor to SAIFI. As shown in Figures 12 and 13, above, the majority of improvement in 2022 SAIFI and SAIDI results relative to prior years was with respect to adverse Weather, foreign interference, and tree contacts. Toronto Hydro views the defective equipment cause code as a primary indicator of the condition of its

distribution system and tracks the cause code as a measure of the effectiveness of its capital expenditure and maintenance investments. Additional analysis of certain cause codes is provided below. Tables 4-6 below also provide the number of interruptions, customer interruptions ("CI"), and customer hours interrupted ("CHI") by cause code (excluding MEDs).

Table 4: Number of Interruptions by Cause Code (Excluding MEDs)

Cause Code	2018	2019	2020	2021	2022
Adverse Environment	8	1	4	3	17
Adverse Weather	129	57	49	79	80
Defective Equipment	441	330	334	364	484
Foreign Interference	144	123	151	169	212
Human Element	19	24	23	38	31
Lightning	4	3	2	22	5
Loss of Supply	34	21	18	10	42
Scheduled Outage	143	102	137	142	907
Tree Contacts	81	48	70	104	120
Unknown/Other	135	135	224	145	233
Grand Total	1,138	844	1,012	1,076	2,131

Table 5: Number of Customer Interruptions by Cause Code (Excluding MEDs)

Cause Code	2018	2019	2020	2021	2022
Adverse Environment	988	5	2,164	249	8,786
Adverse Weather	100,462	84,803	48,318	108,474	56,744
Defective Equipment	308,064	279,474	308,633	354,985	359,936
Foreign Interference	103,812	94,716	165,199	150,885	136,878
Human Element	26,929	47,271	27,811	54,623	12,029
Lightning	1,738	4,346	273	33,840	4,151
Loss of Supply	263,344	162,433	153,684	68,259	187,464
Scheduled Outage	7,993	12,452	6,897	8,398	35,004
Tree Contacts	101,329	73,108	128,667	118,879	101,713
Unknown/Other	218,398	240,491	414,343	303,457	374,813
Grand Total	1,133,057	999,099	1,255,989	1,202,049	1,277,518

Table 6: Number of Customer Hours Interrupted by Cause Code (Excluding MEDs)

Cause Code	2018	2019	2020	2021	2022
Adverse Environment	1,664	9	116	420	9,353
Adverse Weather	131,115	57,672	30,890	76,673	42,846
Defective Equipment	268,452	231,449	281,347	276,297	265,983
Foreign Interference	61,487	54,799	155,980	161,211	88,595
Human Element	6,836	32,542	21,656	27,607	15,633
Lightning	346	601	630	11,684	914
Loss of Supply	131,949	68,436	48,574	13,329	117,641
Scheduled Outage	22,465	34,377	6,770	17,662	91,633
Tree Contacts	99,505	116,665	125,859	146,037	79,471
Unknown/Other	27,880	31,812	75,791	38,041	48,000
Grand Total	751,700	628,362	747,611	768,962	760,069

C2.7 Weather Impacts

The following three cause codes can generally be combined to provide a more accurate reflection of weather impacts on the system:

1. Adverse Weather,
2. Lightning, and
3. Tree Contacts.

Figures 14 and 15, below, illustrate the cumulative weather reliability impacts on the system.

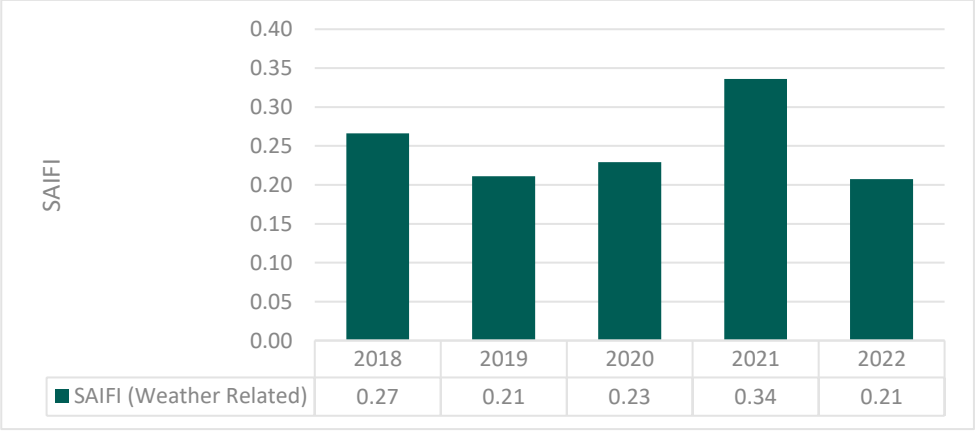


Figure 14: Weather Impacts to SAIFI (Excluding MEDs)



Figure 15: Weather Impacts to SAIDI (Excluding MEDs)

Weather impacts on the distribution system account for a significant portion of system SAIFI and SAIDI. For instance, in 2021 weather-related causes contributed 21.7 percent of the annual SAIFI and 30.5 percent of the annual SAIDI results (excluding MEDs). While in 2022, weather-related causes contributed 12.7 percent of the annual SAIFI and 16.2 percent of the annual SAIDI results (excluding MEDs). Figures 14 and 15, above, demonstrate that a large portion of the SAIFI and SAIDI improvements in 2022 can be attributed to relatively favorable weather conditions that year.

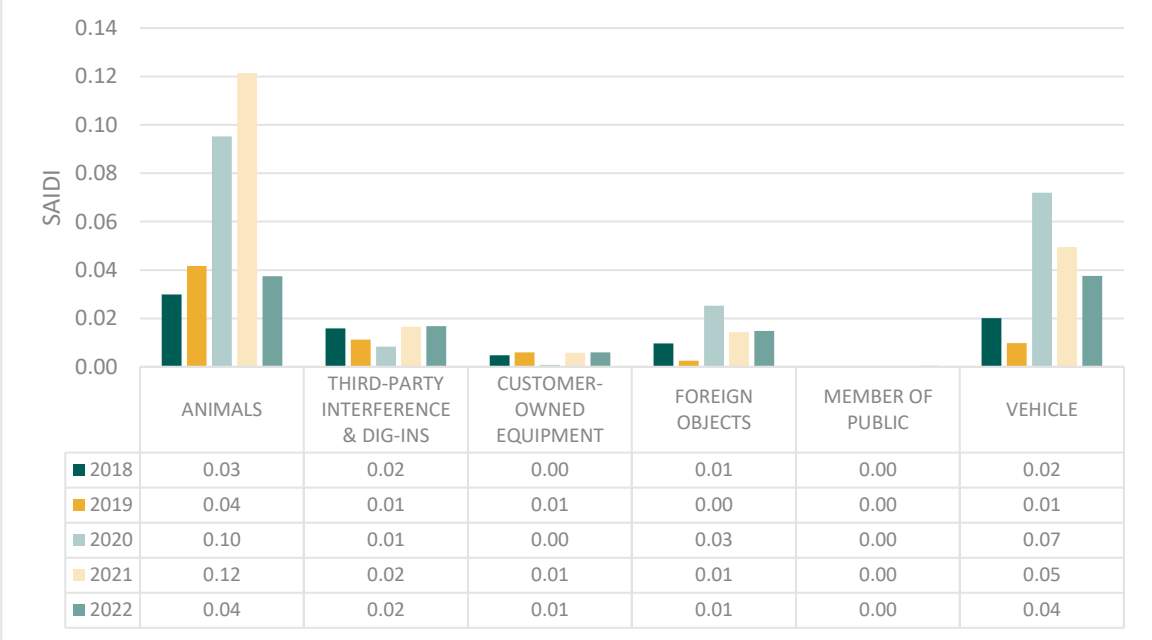
C2.8 Foreign Interference Impacts

Foreign interference consists of outages caused by animal contact, vehicles, foreign objects, third-party interference and dig-ins, customer-owned equipment, and members of the public. Although there are different ways to mitigate foreign interference, such as installing animal guards or moving assets to more secure locations, yearly performance is generally volatile and largely attributable to single isolated events. Figures 16 and 17, below, show the impacts of foreign interference on Toronto Hydro's distribution system.



	ANIMALS	THIRD-PARTY INTERFERENCE & DIG-INS	CUSTOMER-OWNED EQUIPMENT	FOREIGN OBJECTS	MEMBER OF PUBLIC	VEHICLE
2018	0.06	0.03	0.01	0.01	0.00	0.04
2019	0.06	0.02	0.02	0.01	0.00	0.02
2020	0.13	0.01	0.00	0.02	0.00	0.04
2021	0.11	0.02	0.02	0.02	0.00	0.03
2022	0.06	0.02	0.02	0.03	0.01	0.05

Figure 16: Foreign Interference – Root Cause SAIFI (Excluding MEDs)



	ANIMALS	THIRD-PARTY INTERFERENCE & DIG-INS	CUSTOMER-OWNED EQUIPMENT	FOREIGN OBJECTS	MEMBER OF PUBLIC	VEHICLE
2018	0.03	0.02	0.00	0.01	0.00	0.02
2019	0.04	0.01	0.01	0.00	0.00	0.01
2020	0.10	0.01	0.00	0.03	0.00	0.07
2021	0.12	0.02	0.01	0.01	0.00	0.05
2022	0.04	0.02	0.01	0.01	0.00	0.04

Figure 17: Foreign Interference – Root Cause SAIDI (Excluding MEDs)

Of the six sub-categories of foreign interference shown in Figures 16 and 17, above, animal contact is one of the more "controllable" factors, in that Toronto Hydro is able to install reasonable measures

to effectively mitigate this risk. More specifically, Toronto Hydro's capital programs include installing new animal guards as part of the overhead renewal program (see the Overhead System Renewal program, Exhibit 2B, Section E6.5), and conducting spot mitigation activity as part of the Worst Performing Feeder ("WPF") program (see the Reactive and Corrective Capital program Exhibit 2B, Section E6.7). Animal guards serve to eliminate a physical point of contact with live equipment and insulate all critical components.

The category of third-party interference and dig-ins, where third parties such as other utilities or contractors have interfered with Toronto Hydro's equipment by digging into the ground, causing a fault, has shown improvement. To improve reliability and public safety, Toronto Hydro's continues to install new TRXLPE cable in concrete-encased ducts instead of burying cable directly into the soil. This approach protects the cable from dig-ins, reducing the risk of damage and improving public safety (refer to Exhibit 2B, Section E6.2 Underground System Renewal – Horseshoe program).

In general, the foreign interference categories mentioned above are volatile and usually beyond Toronto Hydro's control. For instance, the number of animal contacts was similar in 2020 and 2021, with 101 and 104 events respectively, and slightly increased to 116 events in 2022. However, the impact of these animal contacts on SAIFI and SAIDI varied significantly over the years, as shown in Figures 16 and 17.

C2.9 Unknown Impacts

Unknown impacts consist of outages that have no apparent cause, where power is restored by simply closing a circuit breaker or replacing a fuse. As shown by Figures 18 and 19, below, unknown impacts have increased since 2018 in terms of SAIFI and SAIDI. Toronto Hydro leverages short interval control measures for the identification and mitigation of unknown events. This includes but is not limited to performing fault localization analysis as part of an effort to identify problematic areas where past faults may have occurred in the distribution system. Targeted feeder patrols based on these fault localization results are conducted under the Corrective Maintenance program (see Exhibit 4, Tab 2, Schedule 4). The insights garnered from feeder patrols also aid in the identification of near-term corrective actions, as part of the Worst Performing Feeder program (see the Reactive and Corrective Capital program Exhibit 2B, Section E6.7). Although Toronto Hydro makes best efforts to investigate these events, it is not always possible to pinpoint the exact cause.

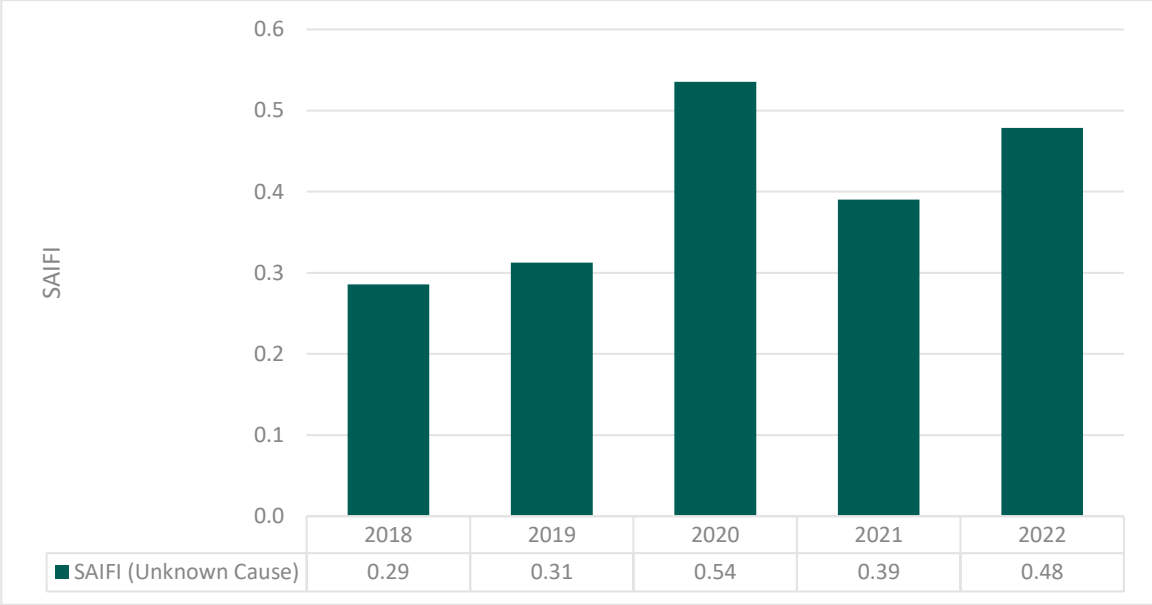


Figure 18: Unknown Impacts to SAIFI (Excluding MEDs)

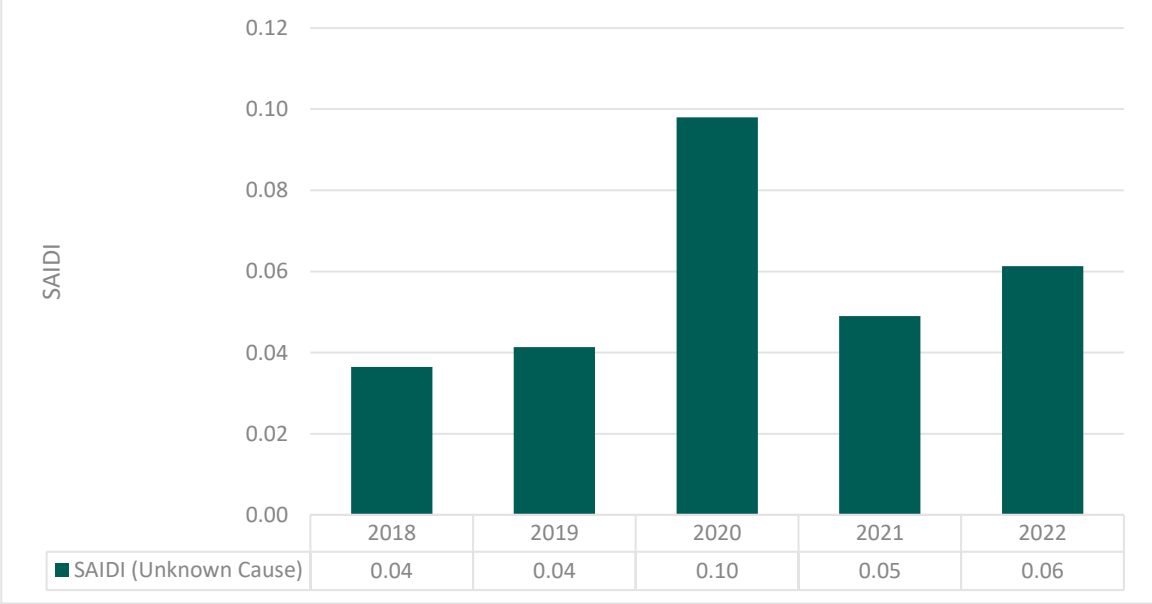
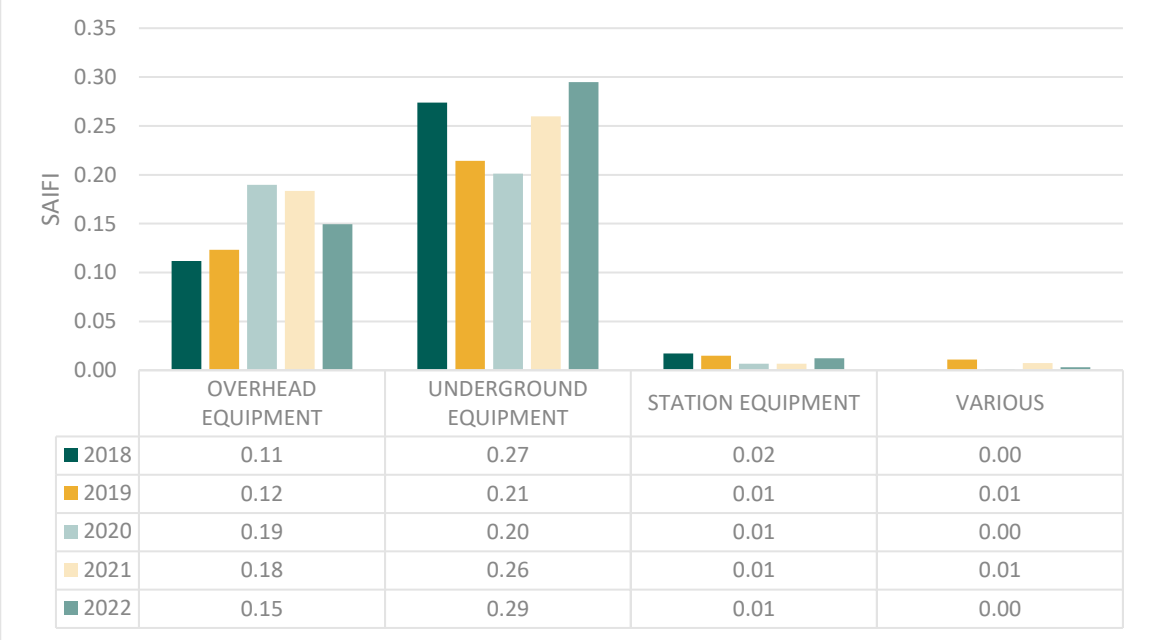


Figure 19: Unknown Impacts to SAIDI (Excluding MEDs)

C2.10 Defective Equipment Impacts

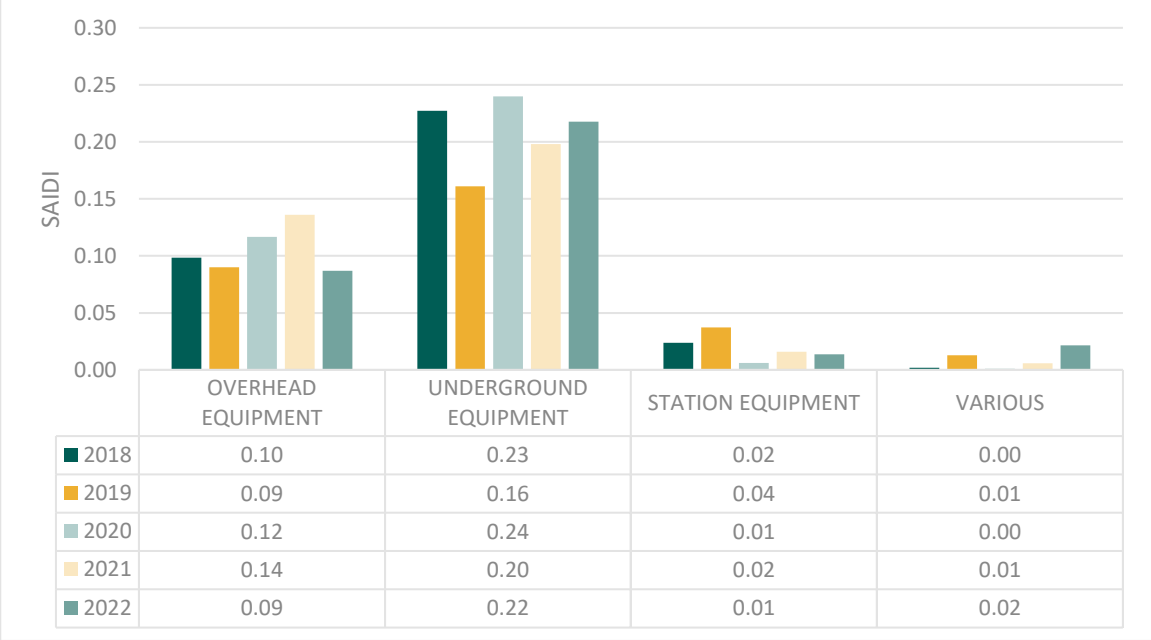
As shown in Figures 20 and 21, below, during the 2020-2022 period the contribution of defective overhead and underground equipment to Toronto Hydro's SAIFI has shown a rising trend. While the

contribution of overhead and underground equipment to Toronto Hydro's SAIDI has shown a generally stable trend with year-to-year variation.



	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	VARIOUS
2018	0.11	0.27	0.02	0.00
2019	0.12	0.21	0.01	0.01
2020	0.19	0.20	0.01	0.00
2021	0.18	0.26	0.01	0.01
2022	0.15	0.29	0.01	0.00

Figure 20: Defective Equipment SAIFI (Excluding MEDs)



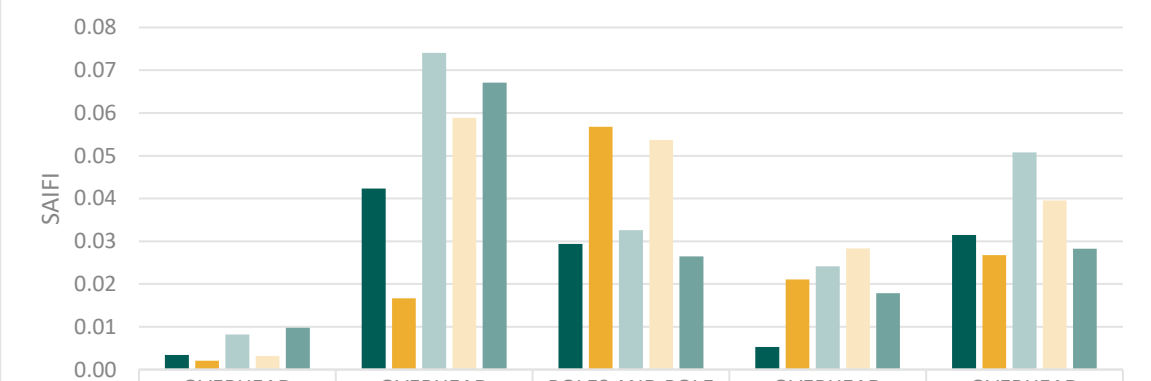
	OVERHEAD EQUIPMENT	UNDERGROUND EQUIPMENT	STATION EQUIPMENT	VARIOUS
2018	0.10	0.23	0.02	0.00
2019	0.09	0.16	0.04	0.01
2020	0.12	0.24	0.01	0.00
2021	0.14	0.20	0.02	0.01
2022	0.09	0.22	0.01	0.02

Figure 21: Defective Equipment SAIDI (Excluding MEDs)

C2.10.1 Overhead Defective Equipment

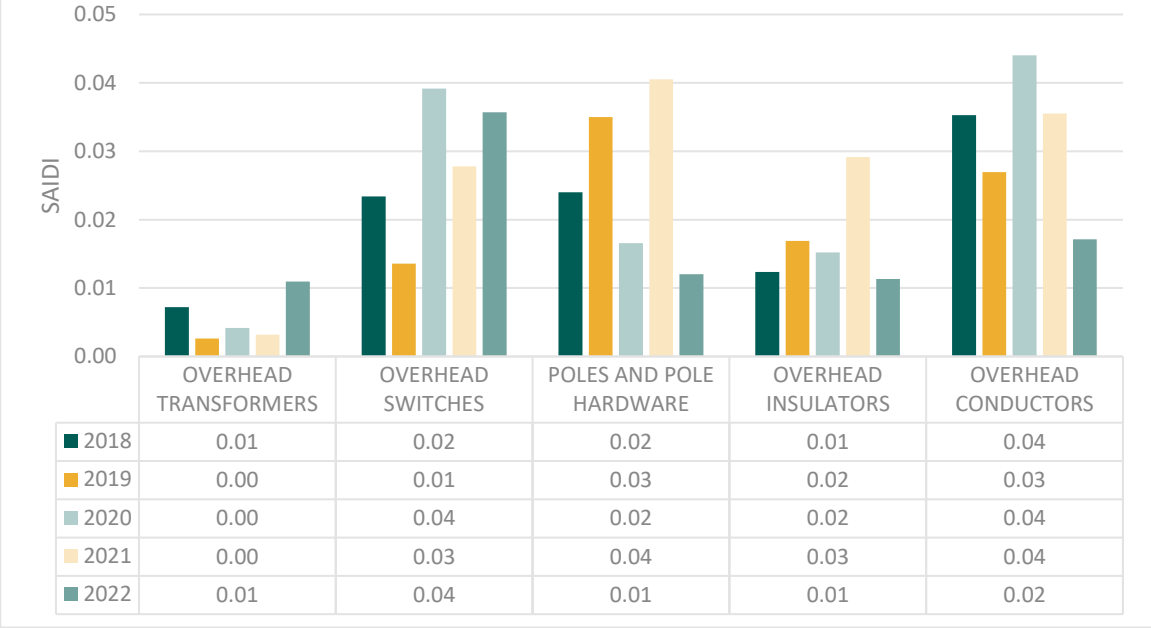
As shown by the Overhead Defective Equipment categories in Figures 22 and 23 below, the most significant SAIFI and SAIDI impacts between 2018 and 2022 are attributable to overhead switches, overhead conductors, as well as poles and pole hardware failures. This is mainly due to the magnitude of these types of failures, which often interrupt a large number of customers when they occur.

The rising SAIFI trend across the multiple sub-categories under Overhead Defective Equipment throughout the 2020-2022 period, as shown in Figure 22 below, reflects the recent focus on replacing overhead transformers at risk of containing PCBs and supports the need for continued investment in overhead system assets to maintain overall reliability, as well as to improve performance in poorly performing areas of the overhead distribution system (see Exhibit 2B, Section E6.5 Overhead System Renewal program). Other programs, such as Area Conversions (see Exhibit 2B, Section E6.1), which also renew and relocate overhead assets, have contributed to maintaining reliability on the overhead system and improving reliability in poorly performing areas. To address these trends, Toronto Hydro plans to continue investing in these important system renewal programs throughout the 2025-2029 plan period.



	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OVERHEAD INSULATORS	OVERHEAD CONDUCTORS
2018	0.00	0.04	0.03	0.01	0.03
2019	0.00	0.02	0.06	0.02	0.03
2020	0.01	0.07	0.03	0.02	0.05
2021	0.00	0.06	0.05	0.03	0.04
2022	0.01	0.07	0.03	0.02	0.03

Figure 22: Defective Equipment SAIFI – Overhead (Excluding MEDs)



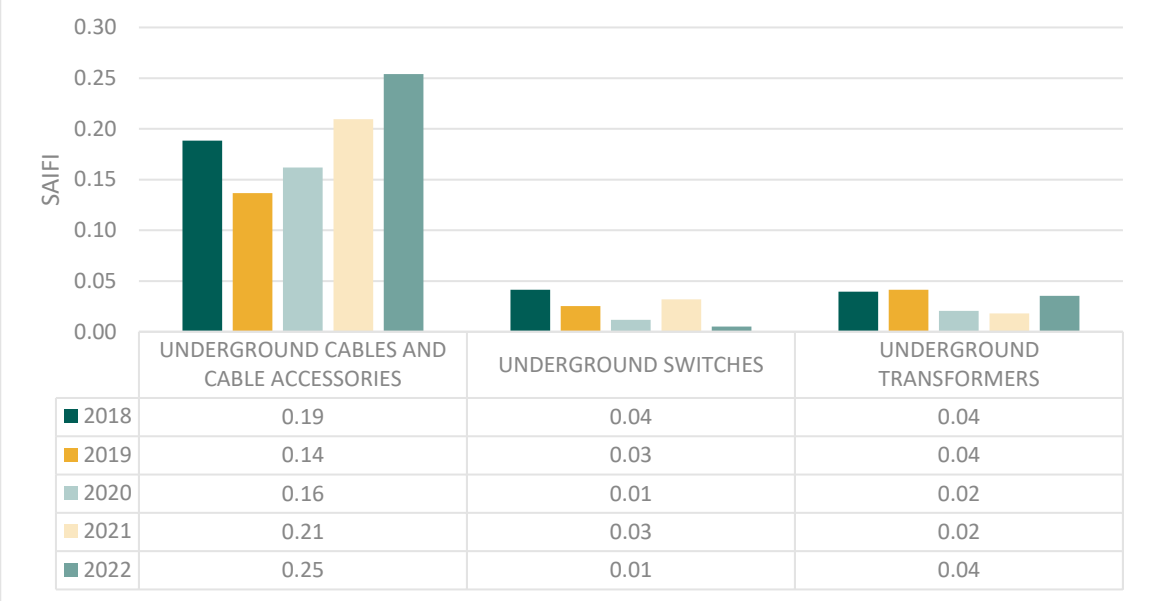
	OVERHEAD TRANSFORMERS	OVERHEAD SWITCHES	POLES AND POLE HARDWARE	OVERHEAD INSULATORS	OVERHEAD CONDUCTORS
2018	0.01	0.02	0.02	0.01	0.04
2019	0.00	0.01	0.03	0.02	0.03
2020	0.00	0.04	0.02	0.02	0.04
2021	0.00	0.03	0.04	0.03	0.04
2022	0.01	0.04	0.01	0.01	0.02

Figure 23: Defective Equipment SAIDI – Overhead (Excluding MEDs)

C2.10.2 Underground Defective Equipment

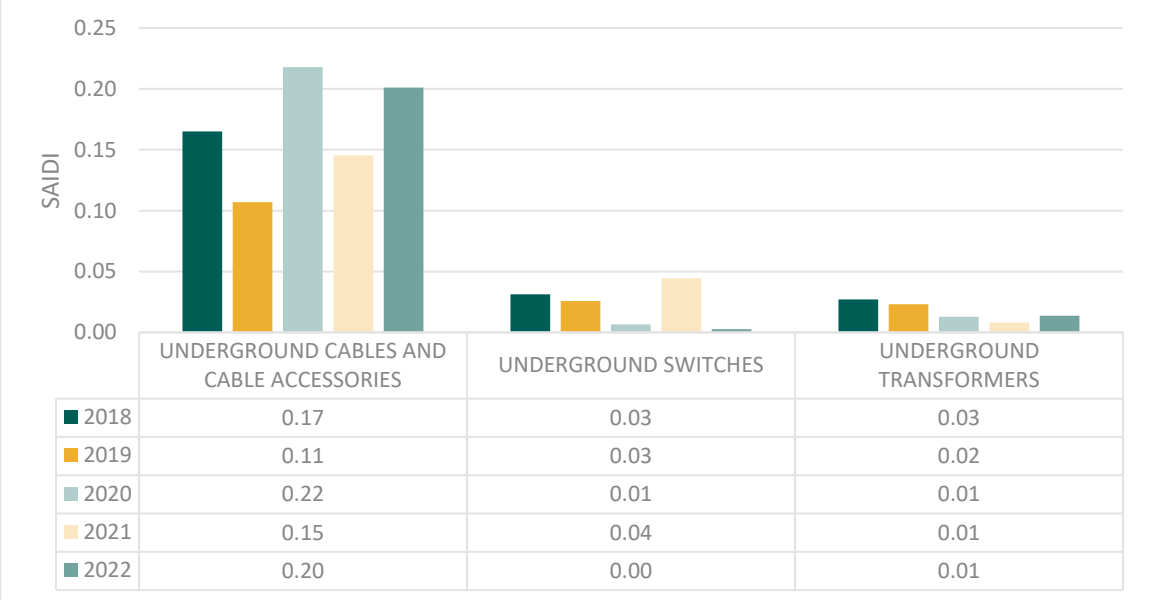
As shown by the underground defective equipment categories in Figures 24 and 25, below, underground cable and cable accessory failures dominate both the SAIFI and SAIDI indices and are the biggest equipment-related causes of interruptions in Toronto Hydro's system. Recently, Toronto Hydro has shifted focus away from rebuild projects to address urgent environmental risk associated with PCBs. However, the continued aging of direct-buried cables and of other types of cables that are reaching end of life are resulting in higher impacts for underground cable and cable accessory failures. This supports the need to refocus on investing in replacing cables that are past useful life, particularly high risk direct-buried cable, as detailed in the Underground System Renewal – Horseshoe program (see Exhibit 2B, Section E6.2), as well as performing cable diagnostic testing to improve the assessment of underground cables and cable accessories (see Exhibit 4, Tab 2, Schedule 2: Preventative and Predictive Underground Line Maintenance).

Despite the increasing trend of underground cable and cable accessory failures, the overall SAIDI trend for underground defective equipment remains relatively stable due to a decline in underground switch and transformer failures in recent years.



	UNDERGROUND CABLES AND CABLE ACCESSORIES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS
2018	0.19	0.04	0.04
2019	0.14	0.03	0.04
2020	0.16	0.01	0.02
2021	0.21	0.03	0.02
2022	0.25	0.01	0.04

Figure 24: Defective Equipment SAIFI – Underground (Excluding MEDs)



	UNDERGROUND CABLES AND CABLE ACCESSORIES	UNDERGROUND SWITCHES	UNDERGROUND TRANSFORMERS
2018	0.17	0.03	0.03
2019	0.11	0.03	0.02
2020	0.22	0.01	0.01
2021	0.15	0.04	0.01
2022	0.20	0.00	0.01

Figure 25: Defective Equipment SAIDI – Underground (Excluding MEDs)

D1 Asset Management Process Overview

Section D of the Distribution System Plan ("DSP") details Toronto Hydro's asset management process, which is the systematic approach the utility uses to:

- Collect, organize, and assess information on its physical assets and current and future operating conditions;
- Assess the utility's business priorities and customer focused goals and objectives in relation to its assets; and
- Plan, prioritize, and optimize expenditures on system-related modifications, renewal, operations, and maintenance, and on general plant facilities, systems and apparatus.

Toronto Hydro's primary asset management process is its Asset Management System, which addresses all distribution system assets and is referenced throughout the DSP as the "AM System", "AMS" or "AM Process". The utility's processes for non-system (i.e. general plant) assets are generally aligned with the AMS, relying on many of the same principles, inputs, and evaluative frameworks. However, as there are subtle but relevant differences between the distribution system and general plant processes, Toronto Hydro has included separate, supplemental sections dedicated to the particulars of the asset management processes for general plant assets. Overall, Toronto Hydro has the following major asset management areas:

1) Asset Management System ("AMS") for distribution assets;
2) Information and Operational Technology ("IT/OT") Asset Management; and
3) Facilities Asset Management.

The processes and details for each of these asset management areas are provided in the following sections:

- **Section D1** provides an overview of the asset management strategy and planning process for distribution assets, including the translation of corporate and stakeholder requirements into asset management objectives for the distribution system as well as for the AM system. This section also describes the asset management strategy, including continuous improvement initiatives that have been completed or commenced, with an emphasis on initiatives in the period since the OEB's December 19, 2019 decision on Toronto Hydro's 2020-2024 Custom IR application.

- **Section D2** describes the current state of the distribution system based on asset demographics, system configurations and various observable features of Toronto Hydro's distribution service area, including expectations for the continuing evolution of these features over the forecast period and beyond.
- **Section D3** describes Toronto Hydro's asset lifecycle optimization practices that aim to balance asset cost, risk and performance.
- **Section D4** describes the changing energy landscape, how Toronto Hydro developed its *Future Energy Scenarios*, and how that work has shaped its 2025-2029 load, generation, and Non-wires Solutions related capital investment.
- **Section D5** describes Toronto Hydro's Grid Modernization Roadmap that aims to adapt the distribution system and operations to the evolving needs of the energy landscape.
- **Section D6** describes the asset management approach for facilities assets.
- **Section D7** describes Toronto Hydro's plan to achieve Net Zero for direct greenhouse gas emissions from its operations by 2040.
- **Section D8** describes the asset management approach for IT/OT assets.

In addition to the major areas listed above, the utility also utilizes a robust approach to the management of its fleet assets, described within the Fleet and Equipment capital program in Section E8.3 of this DSP.

The various asset management processes provide the architecture for long-term, short-term, and maintenance planning functions. Toronto Hydro applied these processes in developing the 2025-2029 Capital Expenditure Plan, described in Section E of the DSP, and the system maintenance plans, described in Exhibit 4, Tab 2, Schedules 1-5.

Toronto Hydro's Commitment to Achieving ISO 55001 Certification

As highlighted in Section D1.3 below, Toronto Hydro has an extensive track record of continuous improvement in asset management. Toronto Hydro's steady adoption and refinement of standard practices in asset management has served customers well over the last two decades. Looking ahead, the utility recognizes that the coming acceleration in decarbonization, digitization (e.g. automation), and decentralization (i.e. two-way energy flows) within the energy economy will result in much greater asset management complexity and a more urgent need for adaptive flexibility within the utility's management systems. The utility believes that success in this more complex environment

will depend in large part on having a strong management foundation in the form of a rigorous and comprehensive AMS that consistently tracks toward industry best practices.

With this context in mind, Toronto Hydro is committing to aligning its AMS to the ISO 55001 standard for asset management, with the goal of achieving certification within the 2025-2029 rate period. ISO 55001 was developed by the International Organization for Standardization and is the most recognized standard for asset management globally. It provides terminology, requirements and guidance for establishing, implementing, maintaining and improving an effective asset management system, and represents a global consensus on asset management and how it can increase the value generated by organizations like Toronto Hydro.

Fundamental to the ISO 55001 framework are the concepts of strategic alignment, risk-based decision-making and continuous improvement. By pursuing certification, Toronto Hydro is volunteering to being held accountable through independent audits for the continuous improvement of its AMS and the maturation of its risk-based decision-making frameworks. The utility believes that the effort of pursuing certification will provide the additional rigor and discipline required to deliver greater value and performance, including greater cost-efficiency, as customer and stakeholder needs rapidly evolve and operating challenges become more intense (e.g. climate risk).

D1.1 Asset Management Objectives and Outcomes

Toronto Hydro's asset management objectives are to a large extent driven by relevant legislative and regulatory obligations and guidance such as the OEB's Distribution System Code ("DSC") and the *Electricity Act, 1998*, including:

- Following good utility practices for system planning to ensure reliability and quality of electricity service on both a short-term and long-term basis;[1]
- "[Ensuring] the adequacy, safety, sustainability and reliability of electricity supply in Ontario through responsible planning and management of electricity resources, supply and demand";[2] and

[1] Ontario Energy Board, Distribution System Code, Section 4.4.1

[2] Electricity Act, 1998, Section 1.

- "[Protecting] the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service".[3]

Additionally, Toronto Hydro aligns its AMS with other applicable legislative and regulatory requirements and principles, including the *Ontario Energy Board Act*, *1998*,[4] Toronto Hydro's Distribution Licence, the Standard Supply Service Code[5], and relevant City of Toronto by-laws.

Beyond its mandated service and compliance obligations, the broader objective of Toronto Hydro's AMS is to realize sustainable value from the organization's assets for the benefit of customers and stakeholders. This requires continuously balancing near-term customer preferences with the need to ensure predictable performance and costs over the long-term for both current and future customers.

Toronto Hydro's AM strategy is in line with corporate strategy and stakeholder needs and preferences. AM objectives are set in order to achieve the AM strategy. Toronto Hydro has aligned its AMS with the utility's strategy for the regulated business, as described in Exhibits 1B, Tab 1 and Exhibit 2B Section E2 of the DSP.

Toronto Hydro's corporate strategy and associated business planning processes, including the AMS, are guided by a set of principles that align with the utility's five corporate pillars. As represented in Figure 1 below, the utility maintains a constant focus on these five pillars – Customer, Environment, Operations, People, and Financial – in a balanced way that promotes customer value and a sustainable business. These principles are an essential element in the determination and prioritization of outcomes.

[3] Ibid.

[4] SO 1998, Ch 15, Sched. B

[5] Ontario Energy Board, Standard Supply Service Code (SSSC), "online", https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/standard-supply-service-code-sssc#:~:text=Sets%20out%20the%20rules%20that,connected%20to%20their%20distribution%20system.

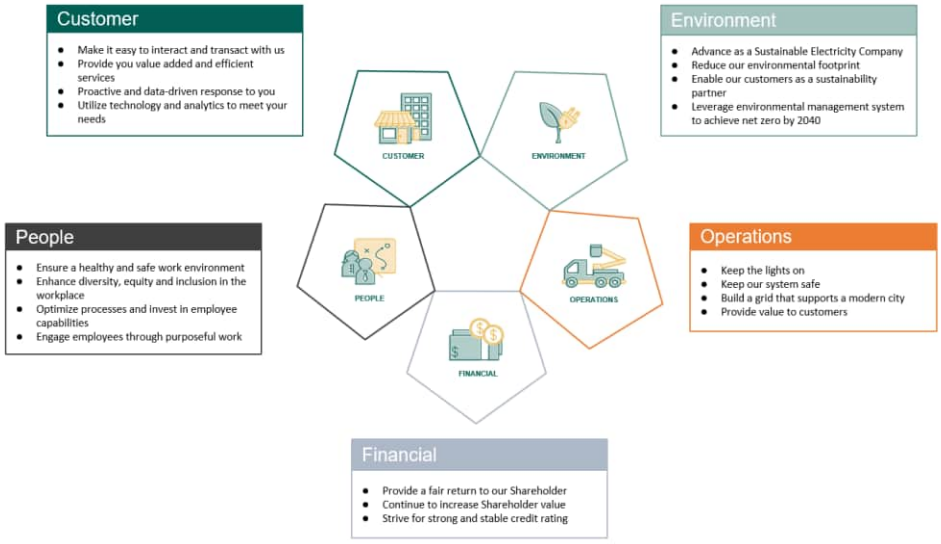


Figure 1: Toronto Hydro's Corporate Pillars

D1.2 Asset Management Process Overview

This section outlines the major elements of the AMS for distribution system assets, their inter-relationships, and the key inputs and outputs between each element.

The corporate direction outlined in the previous section determines the overall direction for decision-making throughout the AMS. At the same time, the information and performance results generated by the AMS inform the continuous refinement of corporate objectives, in balance with other considerations such as asset needs based on the current and future state of the system, customer engagement and benchmarking results.

Figure 2, below, illustrates the major planning and execution process elements of AMS, consisting of five main components:

- Investment Planning and Portfolio Reporting ("IPPR") Process;
- Scope and Project Development;
- Program Management and Execution;
- Performance Measurement; and
- Standards and Practice Review.

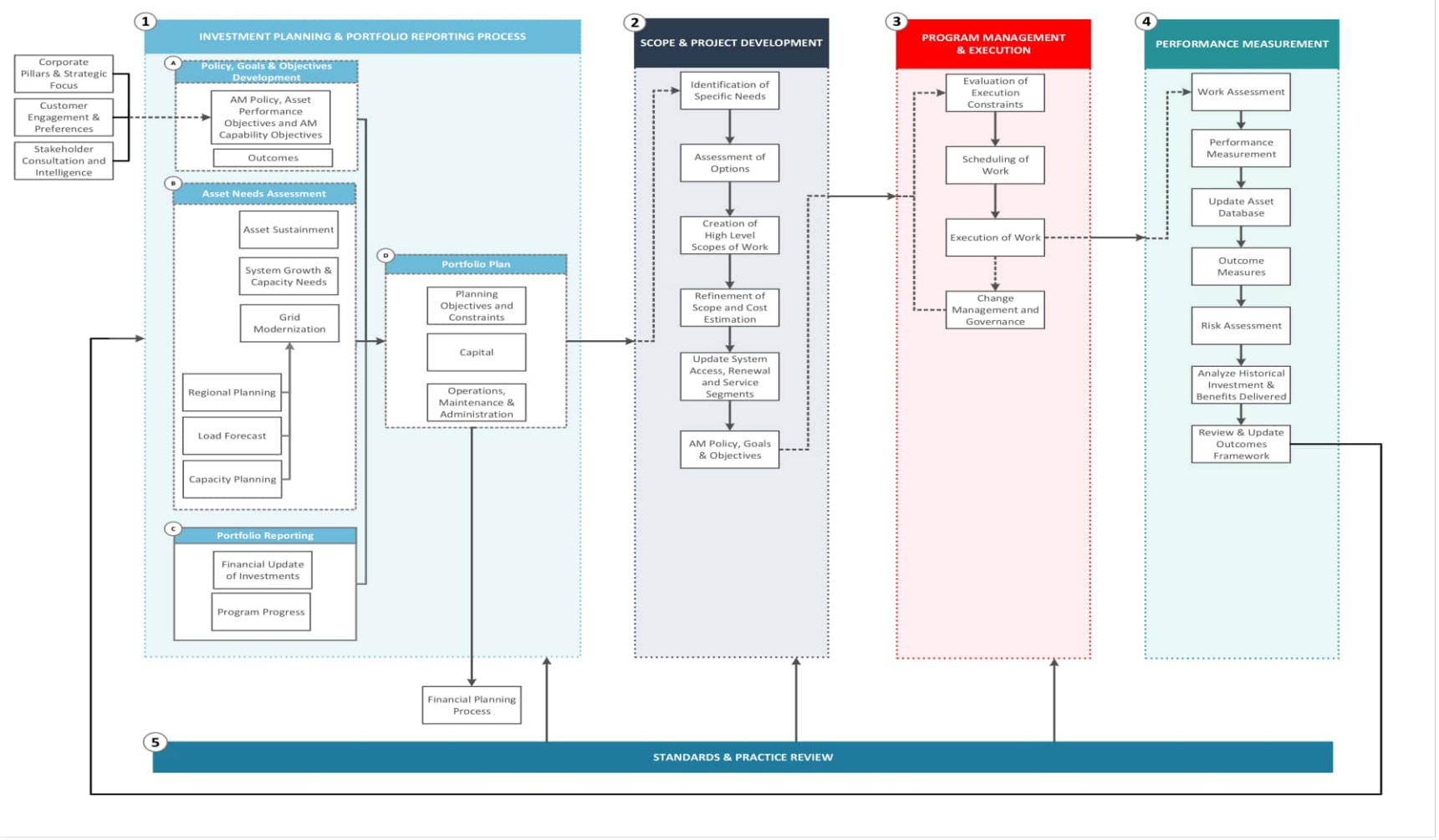


Figure 2: Asset Management Process Overview

The following sections outline each main component of the AM Process.

D1.2.1 Investment Planning and Portfolio Reporting ("IPPR") Process

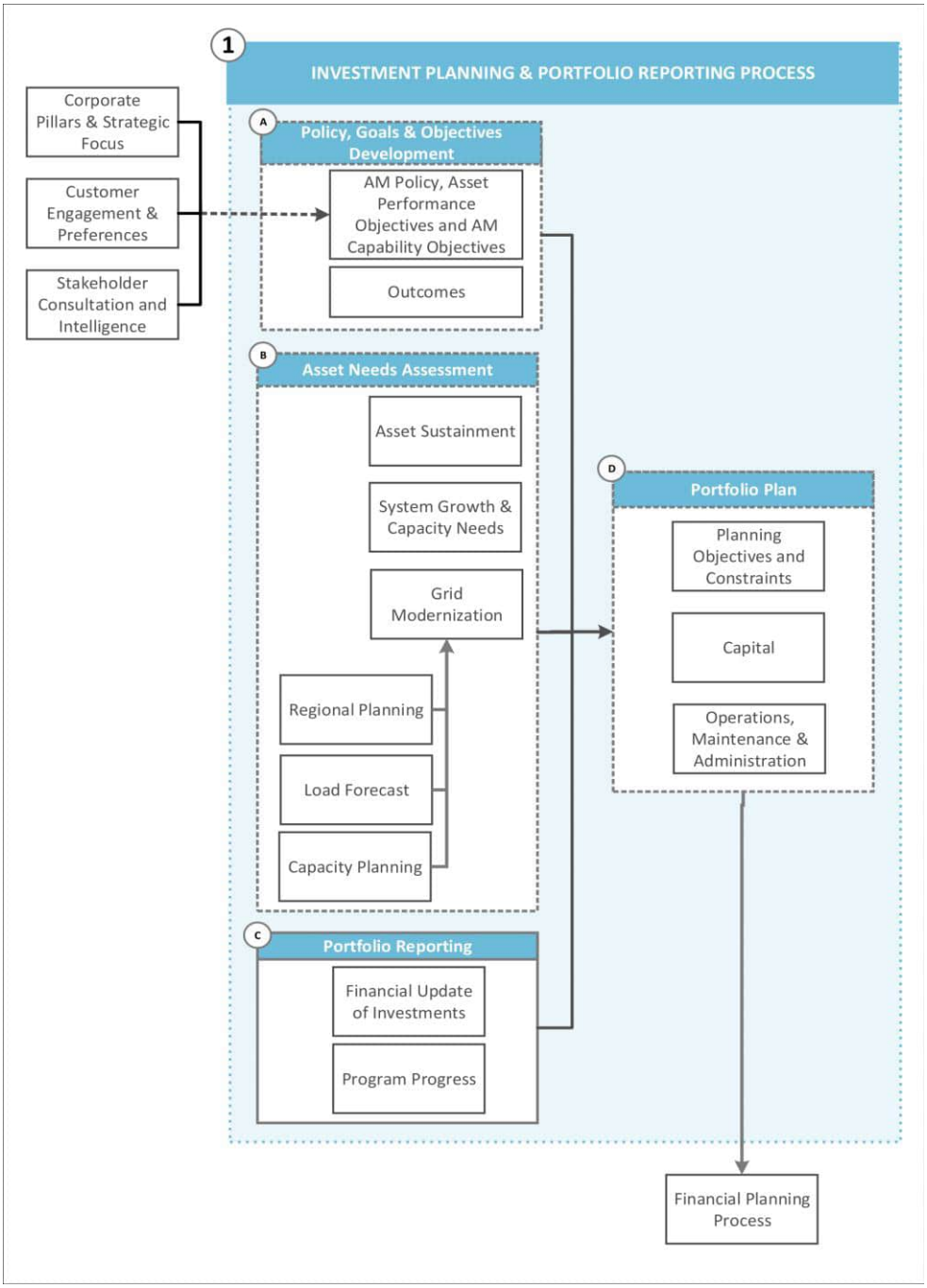


Figure 3: IPPR Process

The IPPR process is Toronto Hydro's system investment planning cycle, which includes both long-term and short-term planning horizons. The IPPR process aims to report on the current state of assets, forecast future states and associated risks, and assemble holistic investment plans. This integrated annual planning process involves:

- the analysis of current systematic needs and historic trends;
- the development of short-term and long-term plans – program forecasts, associated work volumes and performance objectives; and
- the optimization of different strategies by balancing financial constraints, risks, and outcomes.

It is composed of four sets of activities:

- **Policy, Goals and Objectives Development:** The IPPR process is guided by Toronto Hydro's asset management policy, goals and objectives. The utility periodically reviews and updates these elements to ensure continuous alignment of asset management decision-making with corporate strategy and customer and stakeholder needs and preferences. These activities are discussed in detail in section D1.2.1.1 below.
- **Asset Needs Assessment:** To determine the types and level of asset investment needed, Toronto Hydro tracks and analyzes the current state of its assets, their performance relative to a wide variety of risk indicators (e.g. environmental, reliability, and safety indicators), their ability to serve evolving demands from customers and external parties (e.g. bus-level load forecasts and evolving power quality needs), and grid enhancement and modernization roadmap. These activities are discussed in detail in section D1.2.1.2 below.
- **Portfolio Reporting:** Toronto Hydro monitors and assesses the progress of its system capital and maintenance programs against annual and longer-term budget, execution, and performance objectives. This helps ensure the utility is cost-effectively executing the DSP while making prudent adjustments in light of new information. These activities are discussed further in section D1.2.1.3 below.
- **Portfolio Planning**: Toronto Hydro uses the outputs of the above three activities to develop capital and maintenance investment plans for its portfolio of programs. These plans are the result of the utility's asset management goals and outcomes as applied to a combination of the current needs of the system and the current status of ongoing investment activities and accomplishments. Key aspects of the portfolio planning activity include the consideration of alternative investment strategies and the development of both short- and longer-term

expenditure plans for each capital program. These activities are described in detail in section D1.2.1.4 below.

Toronto Hydro executes all of the above activities annually, which ensures alignment between (i) the projects selected for execution within an annual capital plan and (ii) the utility's overall five-year expenditure plan and outcome objectives. The four major activities of the IPPR process are explained in further detail in the following sections.

D1.2.1.1 AM Policy, Asset Performance Objectives and AM Capability Objectives

Senior management direction for the AMS is provided through the Asset Management Policy and a set of strategic Asset Performance Objectives and AM Capability Objectives. The utility periodically reviews and, if necessary, adjusts these components of the AMS to ensure alignment with corporate strategy and evolving customer and stakeholder needs.

In 2022, as part of the utility's ongoing effort to align with the ISO 55001 standard for asset management, Toronto Hydro issued an updated corporate Asset Management Policy applicable to its distribution assets. This policy was developed in accordance with industry best practices and reflects Toronto Hydro's corporate strategy and organizational intent for managing its assets.

The substantive component of the Asset Management Policy is the following policy statement:

> *"Toronto Hydro's asset management policy is to ensure that it effectively manages its electricity distribution assets, across the complete asset lifecycle, in a safe, cost-effective, and sustainable manner, and that the management of those assets meets the needs of its customers and stakeholders, and provides a fair return to its shareholder. Toronto Hydro shall comply with all legal, regulatory and environmental requirements placed upon the organization and will prioritize the safety of its employees and the public.*
>
> *This Asset Management Policy shall be achieved through the management and continuous improvement of an efficient, coordinated, systematic, and embedded Asset Management System that:*
>
> - *develops and implements a Strategic Asset Management Plan;*
> - *balances costs, risks, opportunities and performance by applying a holistic approach to decision-making while:*

- *optimizing the distribution system's reliability performance in accordance with customer needs and preferences;*
- *enabling growth, fostering electrification, and accommodating evolving consumer and stakeholder needs; and striving for zero public and employee safety incidents.*

- *aligns with Toronto Hydro's corporate strategy as well as its safety and environmental management systems;*
- *collects and analyzes asset information to enable informed and holistic decision-making; and*
- *ensures the availability of the required resources to develop and implement Asset Management strategies and plans.*

All employees and contractors shall comply with this policy and contribute towards the continuous improvement of the Asset Management System."

Following the issuance of this policy in 2022, Toronto Hydro introduced a training module to foster company-wide awareness of the Asset Management Policy, the Asset Management System, and the benefits of continuous improvement in Asset Management. The utility also introduced formal Asset Management training programs to accelerate the onboarding and development of new employees, as well as a more intensive certification program for employees in key roles, to augment their understanding of the AMS, enable them to be stewards of the system, and foster a culture of continuous improvement.

As noted in the policy statement, the development of a Strategic Asset Management Plan ("SAMP") is an essential component of the AMS. Currently, the 2025-2029 Distribution System Plan (Exhibit 2B) serves as the utility's SAMP document. As Toronto Hydro continues its journey toward ISO 55001 certification, the intention is to develop a stand-alone SAMP document which will be updated more frequently and will form the basis for future DSPs.

Toronto Hydro's asset management strategy is encapsulated by two complimentary sets of objectives:

i. **Asset Performance Objectives**, which articulate Toronto Hydro's major customer- and stakeholder-focused performance objectives for its assets, i.e. "what" needs to be achieved with the assets; and

ii. **AM Capability Objectives**, which focus on the organization's capability to manage its assets, i.e. "how" the organization can manage its assets to achieve the performance objectives.

Toronto Hydro's Asset Performance Objectives for 2025-2029 are summarized in Tables 1 to 3 below. These objectives are aligned with the overall investment plan objectives and the utility's performance incentive framework and are a result of the detailed, iterative, and customer engagement-driven planning process summarized in Section E2 of the DSP.

Table 1: Asset Performance Objectives and Key Measures for Growth & City Electrification

OEB Performance Outcomes	Asset Performance Objectives (2025-2029)	Key Performance Measures
Customer Focus	• Connect customers efficiently and with consideration for an increase in connections volumes due to electrification • Accommodate relocations for committed third-party developments, including priority transit projects	1. New Services Connected on Time 2. Customer Satisfaction
Operational Effectiveness - Reliability	• Expand stations capacity to alleviate future load constraints, with consideration for increased electric vehicle uptake, decarbonization drivers, and other growth factors (digitalization and redevelopment) • Install control and monitoring capabilities for all generators > 50kW	1. System Capacity[6]
Public Policy Responsiveness	• Optimize near-term system capacity through load transfers, bus balancing, cable upgrades and the targeted use of non-wires solutions such as demand response and energy efficiency (i.e. flexibility services) • Alleviate constraints on restricted feeders to accommodate the proliferation of DER connections, including by supporting customers and third-parties to more easily identify optimal locations for DER projects	1. System Capacity 2. Restricted Feeders (DERs) 3. Distributed Generation Facilities Connected on Time

[6] System Capacity includes bus loading, heat restricted feeders, feeder position availability, etc.

1 **Table 2: Asset Performance Objectives and Key Measures for Sustainment & Stewardship**

OEB Performance Outcomes	Asset Performance Objectives (2025-2029)	Key Performance Measures
Operational Effectiveness - Safety	• Adhere to previous commitments for safety compliance activities (e.g. complete Box Conversion by 2026)	1. Total Recordable Injury Frequency 2. Serious Electrical Incident Index 3. Box Framed Poles Remaining on the System 4. Non-Energy Mitigating Cable Chamber Lids in High Risk Locations

Operational Effectiveness - Reliability	• Maintain recent historical system reliability, which includes:
	  ○ leveraging risk-based decision-making to ensure System Renewal investments are sufficient to maintain recent historical reliability for outages caused by Defective Equipment; and
	  ○ leveraging the Worst Performing Feeder program and other intervention tactics to improve reliability for customers experiencing service that is much worse than average
	• Manage asset risk by maintaining overall health demographics of the asset population in 2025-2029
	• Optimize the pace of renewal investment from year-to-year using risk-based decision-making tools
		1. Defective Equipment Outages (SAIDI, SAIFI)
		2. Worst Performing Feeders (e.g. FESI)
		3. Asset Health
		4. % Assets Past Useful Life
		5. Rear Lot Customers on System
		6. Direct-buried Cable on System (km)
		7. Network Modernization (% of submersible units)

Public Policy Responsiveness	• Adhere to previous commitments for environmental compliance activities (e.g. removal of at-risk PCBs by 2025)	1. PCB-contaminated Oil Spills 2. Lead Cable Remaining on System (km)
Financial Performance	• Ensure investment pacing contributes to stable long-term investment profiles for all assets (2030+)	1. Asset Health 2. % Assets Past Useful Life 3. Network Modernization (% of submersible units)

1 **Table 3: Asset Performance Objectives and Key Measures for Modernization**

OEB Performance Outcomes	Asset Performance Objectives (2025-2029)	Key Performance Measures
Customer Focus	• Prioritize technology investments that will deliver demonstrable benefits to customers, especially enhancements that will enhance value-for-money in the long-term (i.e. efficiency) • Leverage technology to improve customer experience (e.g. customer tools)	1. Customer Satisfaction 2. Bill Accuracy 3. Estimated Time of Restoration (ETOR) 4. Customer Escalations Resolution
Operational Effectiveness - Reliability	• Improve system reliability through greater system controllability (e.g. SCADA-enabled sectionalizing points) and enhanced fault management technologies, including advanced metering infrastructure (AMI 2.0) • Enhance resiliency and security of the system through advanced grids, targeted undergrounding of critical overhead assets, and enhancements to distribution schemes for critical loads downtown • Leverage technology to improve customer experience (e.g. reliability, power quality) • Enhance system observability, enabling better asset management and operational decision making and expanding the foundation for advanced distribution automation	1. Grid Automation Readiness 2. System Reliability (e.g. SAIFI, SAIDI) 3. Load Secured During Contingency Event (e.g. Loss of Supply)
Public Policy Responsiveness	• Leverage technology to improve customer experience (e.g. DER integration)	1. Restricted Feeders (DERs) 2. Distributed Generation Facilities Connected on Time
Financial Performance	• Prioritize technology investments that will deliver demonstrable benefits to customers, especially enhancements that will enhance value-for-money in the long-term (i.e. efficiency)	1. Grid Automation Readiness 2. System Capacity (Non-Wires) 3. Efficiency Achievements

As part of its effort to achieve ISO 55001 certification, Toronto Hydro is developing a detailed asset management roadmap which will lay out a series of longer-term AM Capability Objectives that the utility intends to pursue in the years ahead. Many of these capability building efforts fall into one of three strategic categories, which align with the utility's overall modernization and performance strategy for 2025-2029 and beyond:

1. **Enhancements to Risk-based Asset Management and Investment Portfolio Optimization Tools:** Toronto Hydro is currently executing a multi-year project to implement an industry-leading value framework within its new Engineering Asset Investment Planning ("EAIP") platform, Copperleaf C55. The EAIP platform is a powerful decision-support tool that facilitates consistent and objective value-based optimizations of the utility's substantial portfolio of capital projects.

   At the heart of this tool is a custom value framework that Toronto Hydro is currently developing which assigns relative value to investments based on their likely contribution to Toronto Hydro's key performance outcomes. For many of these investments, including a majority of the System Renewal programs, this value framework is built directly upon the utility's Condition Based Risk Management ("CBRM") framework, ensuring that projects will be consistently prioritized on the basis of their verifiable contributions to mitigating quantifiable condition-based asset risk. As discussed in D1.3.2.1 and in Section D3, Toronto Hydro is committed to continuously reviewing and enhancing its CBRM to ensure alignment with the observed reality of its assets in the field. The utility is also committed to researching and developing more sophisticated risk-based decision frameworks for assets that do not currently have condition-based models, including underground cable systems, in the 2025-2029 period.

   As for its EAIP tool, Toronto Hydro is currently on track to begin leveraging its optimization capabilities for the majority of its investment program by the beginning of the 2025-2029 period. Following EAIP implementation, Toronto Hydro plans to extend the use of its value framework upstream of the EAIP tool as part of a predictive/prescriptive analytics solution which will assist investment planners in identifying project candidates with the greatest potential value to customers.

2. **Asset Information Strategy and Governance:** As part of its journey toward ISO 55001 certification, the utility is in the process of developing an Asset Information Strategy that

outlines current and future asset information needs. This will be accompanied by a system agnostic Asset Information Standard document, which will help improve consistency in how mission-critical asset and customer information is classified, stored, and assessed for quality. Toronto Hydro also intends to develop a more comprehensive and rigorous data and analytics governance framework to support the development and adoption of decision-making tools and insights that can drive greater efficiency and performance. Toronto Hydro believes that greater use of data and analytics will be a significant driver of value in the 2025-2029 period and beyond. Furthermore, highly accurate and accessible asset and system data will be essential to the successful implementation of next-generation operational forecasting and automation tools such as the Advanced Distribution Management System and Distributed Energy Resource Management System. As part of the Grid Modernization Roadmap, the Asset Analytics & Decision-making portfolio covers Toronto Hydro's plans to fully and sustainably leverage the value of existing and new forms of distribution system data and intelligence. One of the domains of this portfolio involves integration of relevant enterprise systems into a fully harmonized asset data registry for asset planning. Some of the relevant enterprise systems are: the utility's Geographical Information System ("GIS"), Enterprise Resource Planning ("ERP") system, and Customer Care & Billing ("CC&B") system. The Asset Analytics & Decision-making portfolio is further described in Exhibit 2B, Section D5.

3. **Developing Enhanced Asset Analytics:** Toronto Hydro is currently ramping up its efforts to develop a more robust asset data analytics function. This effort involves three major elements: (i) recruiting and developing engineers and analysts with progressive data analytics and coding skillsets, (ii) researching, evaluating, and procuring advanced analytics solutions to meet specific asset management and operational needs and (iii) investing in the information technologies necessary to support efficient and effective use of data for analytics and machine learning applications. The utility has a rich trove of data which can be leveraged to create new insights to support better decision-making, and observability enhancing technologies such as AMI 2.0 promise to provide a step increase in the amount of data available to planners and system operators in the years to come. In the last several years, Toronto Hydro has made headway with respect to building out its analytics applications, for example by investing in the province's first long-term, distribution-level scenarios model for the energy transition, and developing

several pilot applications (not yet in production), including a homegrown electric vehicle detection model prototype, and a machine learning concept for predicting the cause of "Unknown" outages. Toronto Hydro plans to make accelerated investments in its asset analytics and machine learning capabilities over the next six years, including enhancing its use of simulation platforms to develop more robust insights into emerging challenges such as the capacity to host DERs on its system. As part of the development and evolution of Toronto Hydro's Asset Analytics & Decision-Making modernization strategy, the utility plans to enable predictive and prescriptive analytics in the utility's business processes through the use of advanced tools, such as artificial intelligence and machine learning (further described in Exhibit 2B, Section D5).

In addition to these three major categories of AM Capability Objectives, Toronto Hydro plans to pursue a variety of other enhancements to its AMS and AM capabilities, including planning process improvements, enhanced forecasting tools to support continuous improvement in areas such as supply chain management and construction labour balancing, and digital process automation to improve the efficiency and consistency of many elements of the AMS.

D1.2.1.2 Asset Needs Assessment

Toronto Hydro completes a needs assessment of its distribution system to determine the type of investments required. This includes determining the current state of assets, identifying system needs and challenges, and incorporating load forecasts and regional planning results. Further details on these focus areas and how they are used in developing the investment plans can be found in Section D3.2.

Toronto Hydro regularly performs a foundational analysis to understand the current state of the distribution system in terms of asset properties and quantities, asset performance risk (e.g. age, condition, and obsolescence), historical reliability, and asset utilization (e.g. capacity to connect customers and serve peak load). There are three areas Toronto Hydro focusses on to determine current and future asset needs: Asset Sustainment, System Growth and Capacity Needs, and Grid Modernization.

1. Asset Sustainment

Toronto Hydro aims to ensure stable long-term performance of its assets, maintain system reliability, and minimize asset failure risk. When an asset is assessed to be in poor condition, it is considered for

repair, upgrade or replacement under current standards (including regulatory and Toronto Hydro standards).

The typical planning process includes a review of:

- Condition Based Risk Framework;
- Assets Past Useful Life; and
- Potential Consequences of Failure.

Toronto Hydro's Asset Condition Assessment ("ACA") is the utility's Condition Based Risk Management ("CBRM") Framework. The ACA methodology assigns health index scores to assets based on an observable condition variable. These scores are categorized within five health index bands ("HI1" to "HI5") to support project planning. Asset condition demographics are a strong indicator of future asset performance and reliability. Toronto Hydro aims to keep assets within the HI3 ("moderate deterioration") to HI5 ("end of serviceable life") bands stable, with a particular emphasis on managing the shorter-term risks associated with HI4 and HI5 assets. The ACA allows Toronto Hydro to use data collected through inspections to establish a numerical representation of the condition of an asset by considering factors such as operation, degradation and lifecycle. The health score of an asset helps Toronto Hydro optimize asset replacement plans by indicating whether an asset has a higher or lower probability of failure than age alone would indicate. The ACA model also allows the utility to project future asset condition at an aggregate population level, which supports effective investment program pacing during the planning process.

Toronto Hydro is implementing probability of failure curves to derive a stronger and more objective relationship between condition and functional failures. Toronto Hydro's Probability of Failure methodology uses historical failure data in conjunction with the generated health scores from ACA.

In addition to ACA data and the development of probability of failure curves, asset age has a strong correlation with the likelihood of asset failure. Its simplicity and availability make it an informative source of data for system-wide analysis (e.g. reliability forecasting), particularly for longer time horizons. Toronto Hydro considers age by leveraging its Assets Past Useful Life ("APUL") analysis, which determines the proportion of assets currently past their useful life and expected to be without investment in the next five years. This analysis is done at the system level and for individual asset classes and is used to inform the pacing of renewal programs to ensure long-term stability/sustainability in combination with asset condition where available.

ACA, probability of failure and age are leading indicators of failure, and, by extension, the future reliability, safety, and environmental performance of Toronto Hydro's system. As noted above, Toronto Hydro also considers historical reliability – a lagging indicator of performance – in its asset needs assessment. Actual reliability helps to identify areas of poor or worsening performance and is a useful input in project prioritization. Historical reliability can also be a leading indicator of asset failure in specific circumstances.

Toronto Hydro also considers the potential consequences of failure when assessing asset needs. For example, an air-insulated pad-mount switch that is known to carry a higher risk of flashover compared to other pad-mount switches, posing employee and public safety risks, has a heightened consequence of failure and is therefore a higher priority for replacement.

2. System Growth & Capacity Needs

Toronto Hydro determines capacity and connection needs through the System Peak Demand Forecast, load connections forecasting, generation connections forecasting, and the Regional Planning process.

The 10-year weather-adjusted peak demand forecast ("System Peak Demand Forecast") is developed using a driver based, top-down forecasting methodology and is fundamental to the capacity planning process, including the stations capacity planning process which enables Toronto Hydro to identify capacity availability and anticipated constraints at substations in relation to future load growth. It forecasts the peak demand at all transformer station buses that supply Toronto Hydro's distribution grid. The System Peak Demand Forecast considers new load connections, increased distributed energy resources ("DERs"), electrification of transportation and fuel switching. Further information on the System Peak Demand Forecast can be found in Section D4.

To prepare for growth and electrification in the City of Toronto, Toronto Hydro has adopted additional growth and electrification drivers into its System Peak Demand Forecast. The inputs include (i) hyperscale data centers, (ii) electrification of transportation and (iii) Municipal Energy Plans which include large anticipated connections in different areas of the city.

Furthermore, in preparation for the 2025-2029 investment planning cycle and as a way of complementing and further contextualizing the capacity planning process, Toronto Hydro introduced the Future Energy Scenarios ("FES") model. FES is a bottom-up, consumer choice model that produced projections for peak load (kW), generation (kW), and energy consumption (kWh) under a

variety of potential energy system transformation scenarios. Toronto Hydro's goal for the FES project was to enrich its long-term strategic planning capabilities and provide its stakeholders with an understanding of the way in which electricity demand, consumption and generation may change in the future and the range of uncertainty involved. Further information on FES can be found in Section D4, including a detailed discussion in the associated Appendix A.

In addition to the System Peak Demand Forecast, there are load and generation connections forecasting processes, which result in forecasts of the amounts of expenditures required to accommodate anticipated load and generation customers.

The Customer Connections program captures system investments that Toronto Hydro is required to make to provide customers with access to its distribution system. This includes enabling new or modified load and distributed energy resources ("DER") connections to the distribution system following legal and regulatory obligations under various statutes and codes. The work also includes any expansion work necessary to address capacity constraints for the purpose of connecting customers. Toronto Hydro's primary objective in this program is to provide new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system. See Exhibit 2B, Section D2 for more details.

Toronto Hydro supports connecting DERs to the distribution system in alignment with the Distribution System Code, and in coordination with Hydro One Networks and the IESO. Toronto Hydro continues to see interest in solar generation, as customers seek to reduce bills (through the Net Metering program) and achieve ESG objectives.

Finally, the Regional Planning Process is a key element of distribution system planning and stations-level planning in particular. Toronto Hydro participates in infrastructure planning on a regional basis to ensure regional issues and requirements are effectively integrated into the utility's planning processes. Toronto Hydro participates in the Central Toronto Integrated Regional Resource Plan, led by the Independent Electricity System Operator, and in the Regional Infrastructure Plan for Metro Toronto Region and GTA North Region, led by Hydro One Networks Inc. Additional details on the Regional Planning process are discussed in Section B2.

3. Grid Modernization

Toronto Hydro is at an important turning point in its modernization journey. A confluence of external drivers – including accelerating climate change; emerging decarbonization and energy innovation

policy mandates; rapid digitalization of the economy; and potential decentralization of the energy system (i.e. DERs) – threatens to overwhelm grid capacities and capabilities in the long-term if not proactively addressed. To avoid both (i) long-term decline in system performance and (ii) becoming a barrier to the energy transition (in terms of both long-term costs to ratepayers and the grid's ability to serve and integrate customer loads and resources), Toronto Hydro has determined that it is necessary to accelerate strategic investment in specific field and information technologies that will deliver near-term benefits to customers while setting the utility on a path toward sustainable performance and improved efficiency as the pressures of climate change and the energy transition mount.

Toronto Hydro's overarching grid modernization plan is detailed in the Grid Modernization Strategy section found in Section D5. This strategy is the result of a cross-functional strategic planning effort undertaken in parallel with the typical business planning process over the course of 2021 and 2022. The focus and pacing of the investments featured in the Grid Modernization Strategy were informed by various strategic inputs, including customer and stakeholder engagement, government and regulatory policy, energy transition outlooks (including Toronto Hydro's own Future Energy Scenarios), engagement with industry groups and experts, publicly available literature regarding modernization efforts in leading jurisdictions (including examples of utilities and jurisdictions actively pursuing Distribution System Operator, or "DSO", capabilities), and an assessment of Toronto Hydro's existing grid modernization maturity versus the desired future state in 2030 and 2035. As detailed in the Grid Modernization Roadmap, Toronto Hydro has categorized these capability-building investments into three broad categories:

- **Intelligent Grid:** updating the existing distribution grid and introducing automation to deliver reliability and resiliency improvements, enhance system observability, and enable enhanced real-time decision-making;
- **Grid Readiness:** preparing the distribution system and operations to integrate DERs and leverage Non-Wires Solutions; and
- **Asset Analytics & Decision-making**: building on existing and future data sources and telemetry (sensors) to create value-added analytics and tools for enhanced planning, decision-making, and customer and stakeholder engagement

The Grid Modernization expenditure plans for 2025-2029 are integrated throughout Toronto Hydro's investments programs in Sections E5-E8. For a comprehensive guide to where specific modernization expenditures are found, please refer to Exhibit 2B, Section D5 and Section E2.

D1.2.1.3 Portfolio Reporting

As part of the IPPR process, Toronto Hydro monitors and reports on the progress of capital programs, which includes program level expenditures, project-specific execution status and project expenditures. The utility monitors changes in system-level outcomes (e.g. average reliability) and the effects of specific programs on specific outcomes (e.g. the reduction in the number of poles in end of serviceable life condition) during the Performance Measurement stage of the AM Process. This performance information is available to Toronto Hydro's planners to assess the benefits of the program to-date and identify necessary pacing and prioritization adjustments to meet objectives or emerging needs in future years.

D1.2.1.4 Portfolio Planning

The final piece of the annual IPPR Process is the development of the plan itself. Toronto Hydro planners use information from the Asset Needs Assessment and the Portfolio Reporting Process to develop capital investment and maintenance plans that support the achievement of the utility's asset management strategies and outcomes in alignment with customer needs and preferences.

1. Capital Programs

Toronto Hydro develops capital programs that address the needs and challenges of the system in alignment with strategic focus areas and customer preferences. The utility develops the programs to maintain and improve reliability and safety, meet service and compliance obligations, address load capacity and growth needs, tackle resiliency and business continuity risks, improve contingency constraints, and make necessary day-to-day operational investments. For the purpose of structuring the 2025-2029 business planning approach, these programs are categorized into the following four focus areas:

- Growth and City Electrification;
- Sustainment and Stewardship;
- Modernization; and
- General Plant.

On overview of these capital programs is provided in Section E2. A summary of how these programs map to the OEB's investment categories of System Access, System Renewal, System Service and General Plant can be found in Section E4 of the DSP.

2. *Maintenance Programs*

Toronto Hydro's maintenance planning process is designed to assess the condition, extend the life, and maintain the reliability of distribution assets. The utility designs its maintenance programs to extract the maximum value from existing assets. Maintenance typically occurs on set frequencies derived from Reliability Centered Maintenance ("RCM") standards and the OEB's minimum inspection requirements in Appendix B of the Distribution System Code ("DSC").

Toronto Hydro has four major categories of maintenance:

- **Preventative Maintenance:** Typically involves cyclical inspection and maintenance tasks, which emphasize assessing asset condition and preserving asset performance over the expected life of the asset, and maintaining public and employee safety.
- **Predictive Maintenance:** Involves testing or auditing equipment for a predetermined condition (or conditions) to anticipate failures, then undertaking the maintenance tasks necessary to prevent those failures.
- **Corrective Maintenance:** Involves repairing or replacing equipment after a deficiency has been reported, such as actions taken after emergency response crews have restored power following an outage. Corrective Maintenance actions may also result from deficiencies discovered during the execution of Preventive or Predictive Maintenance tasks or other planned work.
- **Emergency Maintenance:** Involves the urgent repair or replacement of equipment when the equipment fails, often causing power disruptions to Toronto Hydro customers.

The details of the maintenance programs in these categories can be found in Exhibit 4, Tab 2, Schedules 1-5.

Toronto Hydro ensures that capital and maintenance programs are coordinated by planning and reporting on both activities within the IPPR process. Maintenance programs account for changes associated with capital investment programs, such as new asset classes being introduced or existing asset classes being eliminated. For example, Toronto Hydro completed its planned replacement of Automatic Transfer Switches and Reverse Power Breakers as of 2022. With the elimination of these asset classes, maintenance plans were modified accordingly.

3. Pacing and Prioritization

Toronto Hydro paces its expenditure plans to support the achievement of multi-year outcome objectives (e.g. maintain or improve reliability over a number of years). Pacing decisions are informed by various leading and lagging indicators of risk and performance (e.g. asset condition demographics, reliability projections, reliability results), and an assessment of various risk mitigation alternatives, as discussed in Section D3.2.

Program expenditures are reprioritized annually based on actual accomplishments and measured performance relative to the multi-year plan, as well as ongoing analysis of evolving system, customer, and stakeholder needs. Toronto Hydro prioritizes projects within and across programs in accordance with anticipated project benefits, estimated costs, and an assessment of execution capabilities and constraints. On this basis, the lowest priority projects are deferred to future years, and the projects that offer the greatest value-for-money relative to the utility's customer-focused objectives are scheduled for execution.

D1.2.2 Scope and Project Development

The scope and project development component of the AM Process involves the development of discrete projects within each investment program. This process involves four components: identification of specific needs, assessment of options, development of high-level project scopes of work ("scopes"), and refinement of scopes and cost estimates.

The investment proposals from IPPR identify and prioritize the assets or issues that require intervention within each capital program. As part of the early stages of scope development, Toronto Hydro identifies the assets and issues in discrete geographical locations through the use of decision support tools. The utility considers alternatives while developing a scope, which include various engineering options available to address an issue. The utility then evaluates the options with consideration for risks, required performance, customer preferences, effects on third parties, adjacent investments, reconfiguration opportunities, and the overall costs versus benefits. Finally, the utility selects the preferred option for the specific area or issue being addressed, and collects and summarizes asset information for replacement or refurbishment along with high-level specifications for new assets to be installed as part of a conceptual design. This constitutes the initial scope of work.

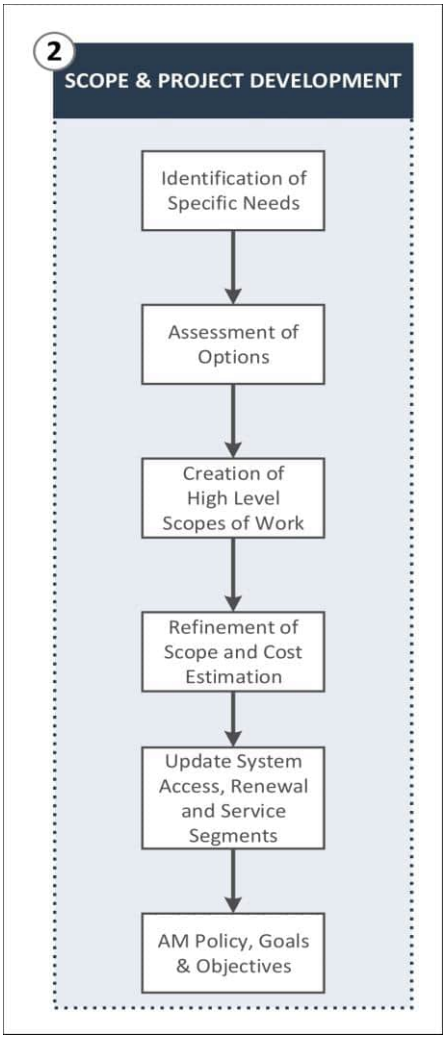


Figure 5: Scope and Development Stage

The next step is the project development stage, during which a cross-functional team of engineers, designers and field staff take the initial scope of work, assess feasibility and field conditions and execution risk. Project Development then produces refined scopes of work, preliminary designs and estimates, and aligns projects with execution work programs to allow for the most efficient use of resources. The project development team engages with internal and external stakeholders to ensure project timelines can be met, and to avoid conflicts and delays when a project is undergoing construction.

Where appropriate, the project development phase may break an original scope of work into smaller project phases for execution. This could be done for various reasons, including coordination with other work in the system, or to meet external constraints related to the location or the type of work. In the project development phase, the utility also undertakes initial project enabling tasks such as acquiring permits and coordinating with third parties prior to beginning final project design and construction. This helps to avoid design and scheduling uncertainty that can arise later in the process. As part of the project development process, Toronto Hydro also considers issues such as city road moratoriums, physical restrictions, or particular design related problems that may delay the project or require a redesign.

D1.2.3 Program Management and Execution

The program management and execution stage of the AM Process involves creating, delivering, and governing an executable work program. The major processes include evaluation of execution constraints, scheduling of work, execution of work, and the change management process that accounts for any required project changes.

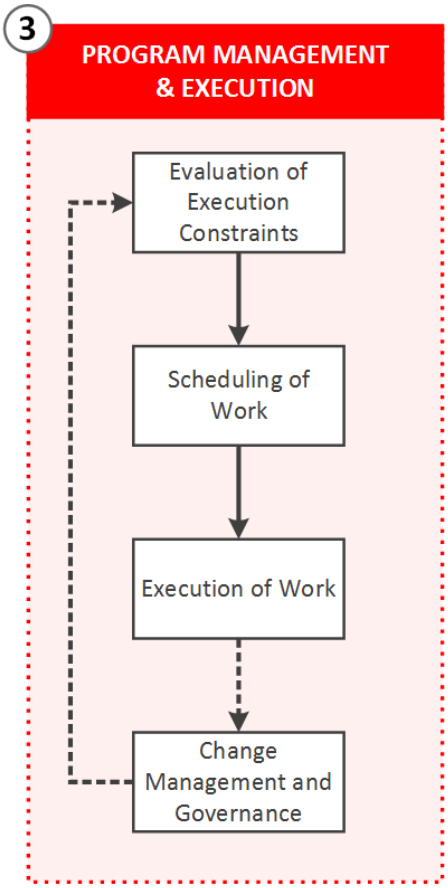


Figure 6: Program Management and Execution Stage

The "evaluation of execution constraints" stage considers multiple factors such as available resources, road moratoriums, switching restrictions, and coordination opportunities. Program managers, in coordination with system planners and in alignment with strategic objectives, select a prioritized mix of projects to be executed in a given year. Some of these projects involve assets to be replaced or issues to be resolved that are of the most urgent nature. Prioritization of work aims to balance renewal work with the emerging needs of the system. Toronto Hydro anticipates improvements in both the efficiency and effectiveness of this stage of the planning process as it continues to implement and integrate its new EAIP optimization tool.

Once Toronto Hydro develops an execution plan, the actual execution of work is monitored from the detailed design stage

through the construction stage. Projects are closely tracked to proactively identify and manage risks that may impact the successful delivery of the planned work.

Toronto Hydro monitors changes to projects through a change management and governance process. This process includes monthly executive performance reporting, key program status reporting, change request process management, project variance analysis, and numerous metrics to drive process adherence and continuous improvement. Depending on the magnitude of a required change to a project's cost, schedule, or scope of work, the change may require a detailed assessment of alternatives and formal approval from senior management and the executive team before proceeding.

Exhibit 4, Tab 2, Schedule 10, Section 8 provides further details about the processes utilized in the Program Management and Execution stage of the AM Process.

D1.2.4 Performance Measurement

The final stage of the AM Process is to monitor the performance of the investment program, and to determine to what extent projects have contributed to expected outcomes. These results feed back into the annual IPPR process so that Toronto Hydro can modify programs and refine objectives as appropriate.

Some key examples of outcome measures that Toronto Hydro tracks in relation to the capital and maintenance expenditure plans include:

- Asset Health Index;
- Reliability (e.g. SAIDI and SAIFI);
- Program Accomplishments (e.g. box poles removed)

Further details on Toronto Hydro's performance measures for the 2025-2029 DSP are provided in Section D1.2.1.1 and Section E2.

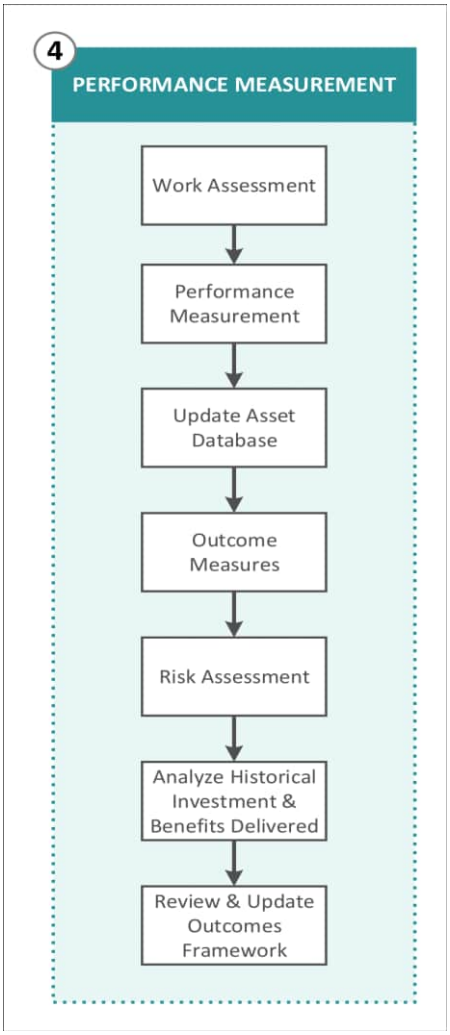


Figure 7: Performance Measurement Stage

D1.2.5 Standards and Practice Review

The Standards and Practice Review is driven by the need to evaluate particular standards and products to improve work execution and manage safety risks. This process influences three stages of the AM Process as planners, designers, and crews rely on this process to identify what equipment is available to them and its appropriate use. The review encompasses the necessary specifications and processes related to: (i) introducing standards and assets into the system; (ii) installation requirements; (iii) replacement considerations; (iv) identifying new assets to better meet system needs and customer preferences; (v) carrying out work in a consistent manner; and (vi) supporting improved safety.

1) **New and revised standards:** Toronto Hydro routinely introduces new standards and revises existing standards to ensure safe and effective work execution. New standards are created in response to a number of drivers, including but not limited to: (i) climate change risks; (ii) process or productivity improvements; (iii) equipment quality; and (iv) safety risks. When Toronto Hydro revises a standard, other documents, such as the Standard Design Practices followed by project designers, are updated to align with changes made.
2) **New products:** Introducing new products enables more efficient, safe, and reliable service to customers. Product requests are reviewed to ensure alignment with business needs, that the appropriate stakeholders are engaged, and that the product satisfies Electrical Safety Authority ("ESA") requirements for major and minor equipment approval. The need for a new product can be initiated for a number of reasons, including: (i) safety; (ii) productivity; and (iii) reliability. For example, Toronto Hydro plans to install reclosers on the trunk and laterals of feeders that will provide automated and remote controllability functions to address feeders experiencing numerous momentary and sustained interruptions, resulting in reduction in overall outage times and improvement in system resiliency.
3) **Refurbishment and replacement of equipment:** When major equipment, such as transformers, network protectors, and switches, is returned from the field, Toronto Hydro evaluates, inspects, and tests them to determine whether the asset can be reused (i.e. repaired or refurbished) or should be replaced (i.e. scrapped).
4) **Quality improvements:** When a product that is not near end-of-life is returned from the field because of failure, it is investigated to determine the root cause of the failure. Investigations are conducted in-house, by an expert third party, or by the original equipment manufacturer. If a manufacturing quality issue is discovered, the manufacturer is notified and requested to

make modifications to address the issue. If an installation quality issue is discovered, corrective and preventative actions include standards revisions, procedure changes, and additional training.

5) **Standard Design Practices:** The Standard Design Practices ("SDP") document provides guidance and instructions for the design of Toronto Hydro's distribution system. The SDP instills safety by design, enforces construction standards, and ensures alignment with business strategies and consistency between projects. The DSP set outs general guidelines with respect to technical matters, and refers to construction standards for specific details.
6) **Industry standards**: Toronto Hydro seeks to align with industry standards and best practices wherever possible. This avoids unnecessary custom-made products which can drive up costs and maintenance complexity. Toronto Hydro is part of an Inter-Utility Standards Forum ("IUSF"), through which utilities collaborate on solutions to common problems and develop common equipment specifications. Toronto Hydro is also a member of numerous standards committees of the Canadian Standards Association and the Institute of Electrical and Electronics Engineers.

D1.3 Asset Management Process Enhancements

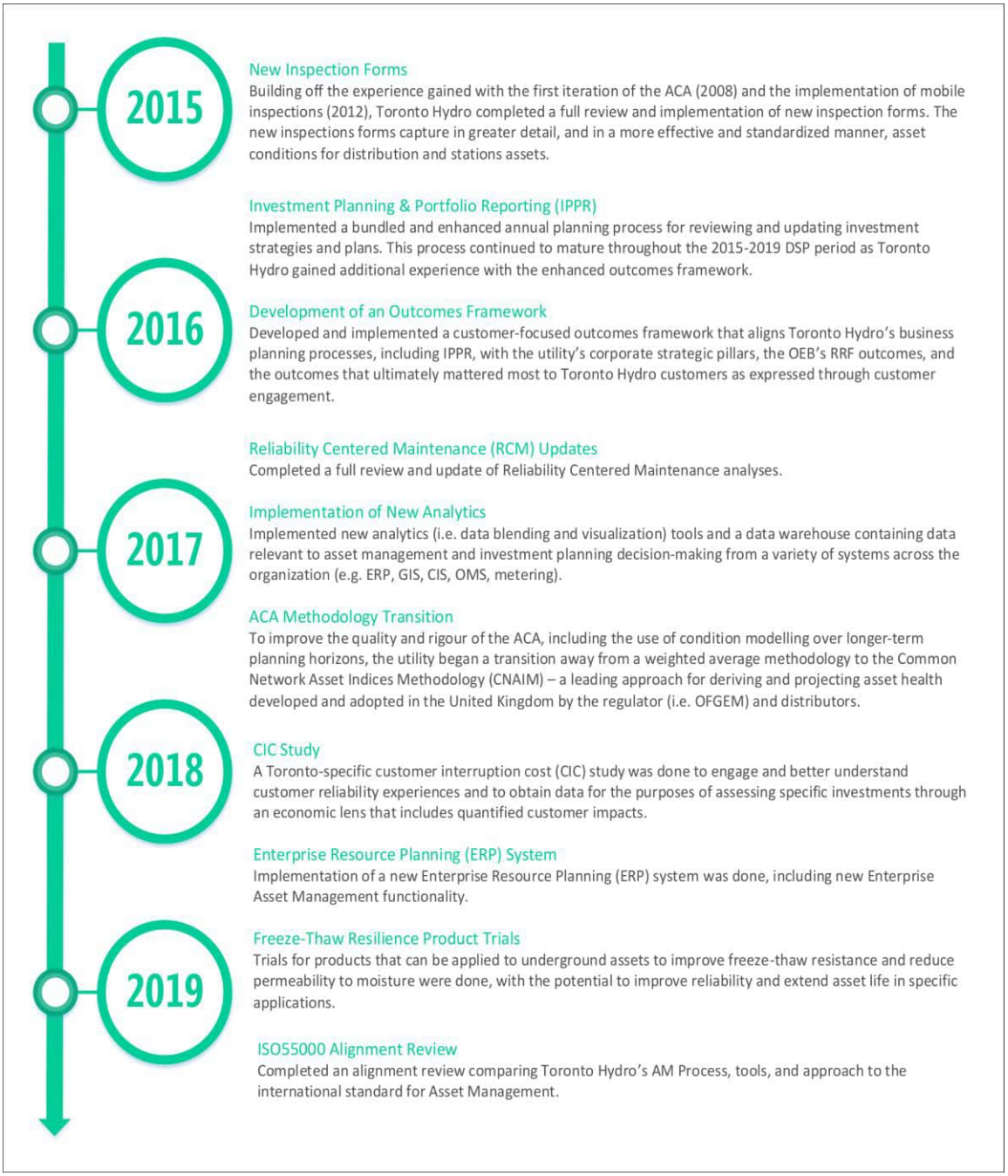
Toronto Hydro's AM process continues to evolve. The utility is continuously enhancing its approach to asset management to ensure the process and strategies remain aligned with the needs of its customers and the distribution system.

The recent progression of Toronto Hydro's AM process is described in the following two sections:

- D1.3.1 – Enhancements during previous filing period (2015-2019); and
- D1.3.2 – Enhancements during the current filing period (2020-2024).

D1.3.1 Past Enhancements (2015-2019)

Improvements to Toronto Hydro's AM Process over the 2015-2019 period are highlighted in Figure 8 below. The following section provides additional details on key process improvements.



1 **Figure 8: Past Enhancements of the AM Process (2015-2019)**

D1.3.2 Recent Enhancements (2020-2024)

Figure 9 outlines improvements to Toronto Hydro's AM Process over the 2020-2024 period.

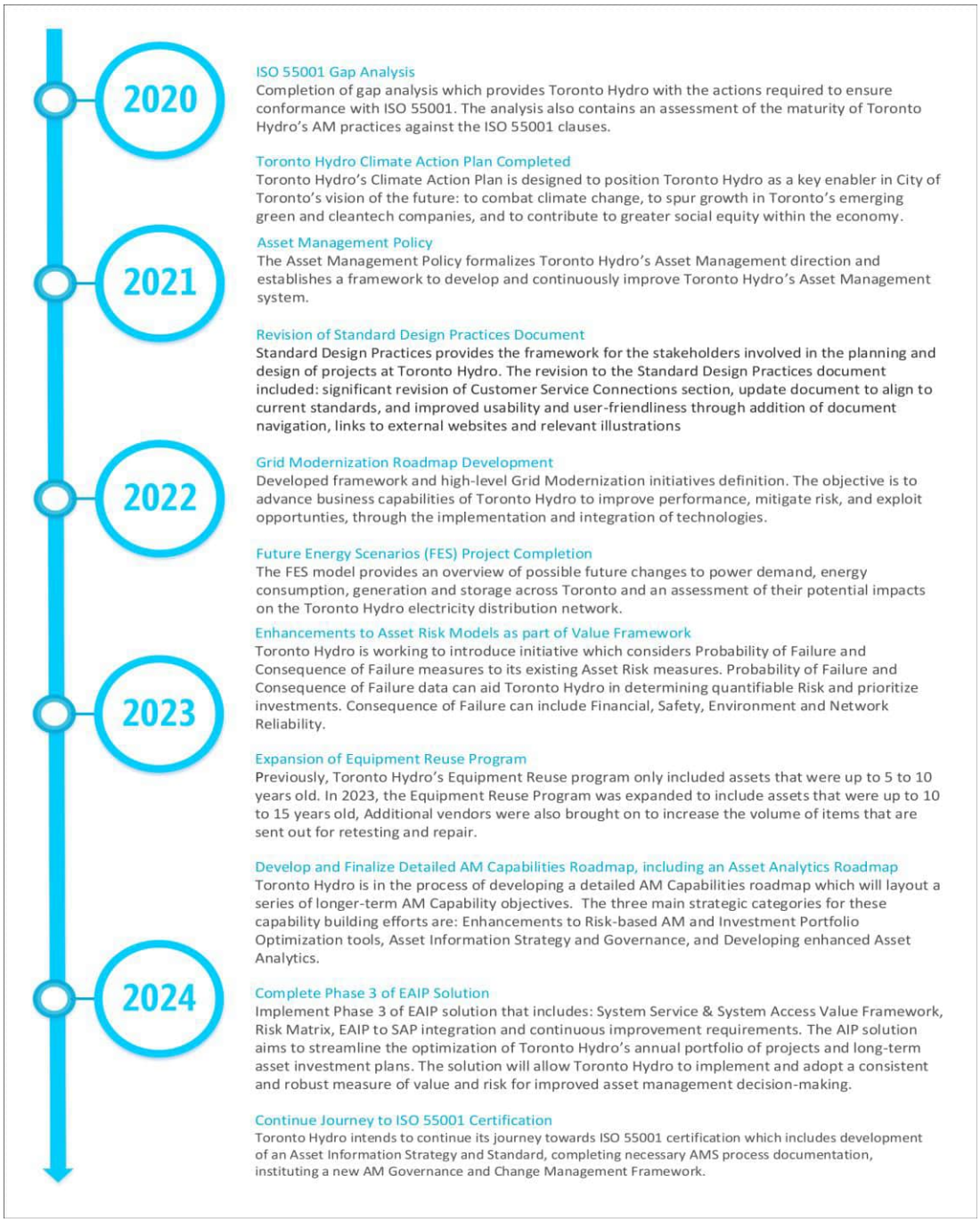


Figure 9: Recent Enhancements of the AM Process (2020-2024)

D1.3.2.1 Condition-based Risk Management Update

In 2017, Toronto Hydro transitioned from the ACA methodology originally adopted in 2008 to an ACA model that provides more accurate and comprehensive condition-based analytics, and that better supports expenditure planning over longer time horizons.

The model that Toronto Hydro has implemented is the Condition-Based Risk Management ("CBRM") methodology, known in the United Kingdom (where it originated) as the Common Network Asset Indices Methodology ("CNAIM"). This methodology was developed and adopted by the major utilities in the United Kingdom in collaboration with the regulator, Ofgem. In terms of the functional outputs of the model, the methodology provides a reliable and detailed calculation of condition score for every applicable asset based on the most recent inspection information and an asset class's unique requirements. The methodology further facilitates the ability to project and calculate future health scores for assets which provides information on asset demographics that can be used to evaluate proposed investment strategies over longer-term periods. Since the establishment of the methodology in 2017, the health score calculation and future forecasting methodology has remained largely consistent, with certain targeted adjustments to reflect inspection program changes and to ensure the model is producing results that are aligned with field observations.

This model provides incremental benefits at the strategic level by facilitating projections of asset condition demographics by asset class. This allows Toronto Hydro to assess the current and future condition profiles of an asset class to better calibrate the level of investment necessary to either maintain or improve the amount of failure risk associated with its aging, condition and deteriorating asset base over time.

Toronto Hydro is currently working to introduce a risk-based value framework into its EAIP tool. Under the umbrella of this initiative, Toronto Hydro is in the process of developing and implementing a fully quantified risk value for each unique asset based in part on the core principles and methodologies of the CBRM framework. Arriving at a quantified risk value involves multiplying the Probably of Failure for an asset – which is derived from its Asset Health Score (or age when condition is not available) – by a Consequence of Failure (also know as its "criticality") which can be expressed in dollars. Toronto Hydro is currently developing Consequence of Failure models that will include impacts such as financial, safety, environmental and reliability outcomes. Toronto Hydro is currently on track to implement this value framework in time for the beginning of the 2025-2029 period.

Appendix A to section D3 of the DSP provides a detailed discussion of recent and ongoing enhancements to the model, and condition results by major asset class.

D1.3.2.2 Data Consolidation: Data Warehousing for Engineering Analytics

Toronto Hydro is currently performing improvements to its engineering data warehouse to streamline data access, and perform "big data" calculations that can support planning and system investment strategies. In parallel, the utility is further leveraging data blending and analytics software, and has integrated software into business processes to improve productivity and drive new insights.

As part of this effort, Toronto Hydro is implementing an Engineering Asset Investment Planning ("EAIP") solution to streamline the optimization of Toronto Hydro's annual portfolio of projects and long-term asset investment plans. The solution will allow Toronto Hydro to implement and adopt a consistent and robust measure of value and risk for improved asset management decision-making.

The implementation of EAIP will provide an efficient interface for project creation and integrates components of both the scope and work package. Moreover, the EAIP solution provides a centralized and standardized repository for asset data, business cases, project outcomes, work packages and integrates with other information sources like the utility's ERP and GIS systems.

As part of the Asset Analytics & Decision-making portfolio within the Grid Modernization Roadmap, Toronto Hydro plans to integrate relevant enterprise systems into a fully harmonized asset data registry. Toronto Hydro also plans to accelerate the development and implementation of predictive and prescriptive analytics within asset management and grid operations. The portfolio is discussed in detail in Exhibit 2B, Section D5.

D2 Overview of Distribution Assets

D2.1 Distribution Service Area and Trends

Toronto Hydro is one of the largest municipal electrical distribution utilities in North America, serving the City of Toronto – Canada's largest city. The city is bounded by Lake Ontario to the South, Steeles Avenue to the North, Mississauga (mainly Highway 427) to the West, and Scarborough/Pickering Townline to the East. As shown in Figure 1 below, Toronto Hydro's service territory can be divided into two geographic areas: (i) an urban centre in downtown Toronto with a high customer density and a large financial and entertainment district; and (ii) a suburban area around downtown Toronto with a lower customer density, which is colloquially referred to as the "Horseshoe" area.



Figure 1: Areas of the Toronto Hydro Distribution System

The following subsections discuss the characteristics of Toronto Hydro's service territory, including its customers and load growth profiles, climate and weather, and economic profile. Section D2.2 provides a detailed description of the utility's asset demographics, system configurations, and asset condition, and Section D2.3 provides a summary of system utilization.

D2.1.1 Customer and Load Growth

Toronto Hydro's distribution system supplies approximately 790,000 customers with a peak load of 5,191 MVA as of 2022. Toronto Hydro has been experiencing steady customer growth for many years, as shown in Figure 2.

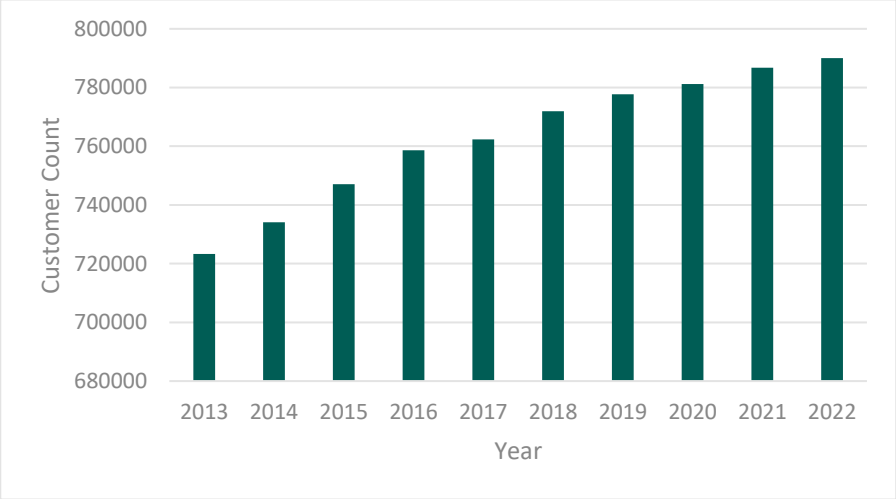


Figure 2: Historical Toronto Hydro Customer Counts

Despite steady customer and population growth, overall system peak load has remained relatively steady in recent years at approximately 5,000 MVA, as shown in Figure 3. It is important to note that system peak load varies with temperature.

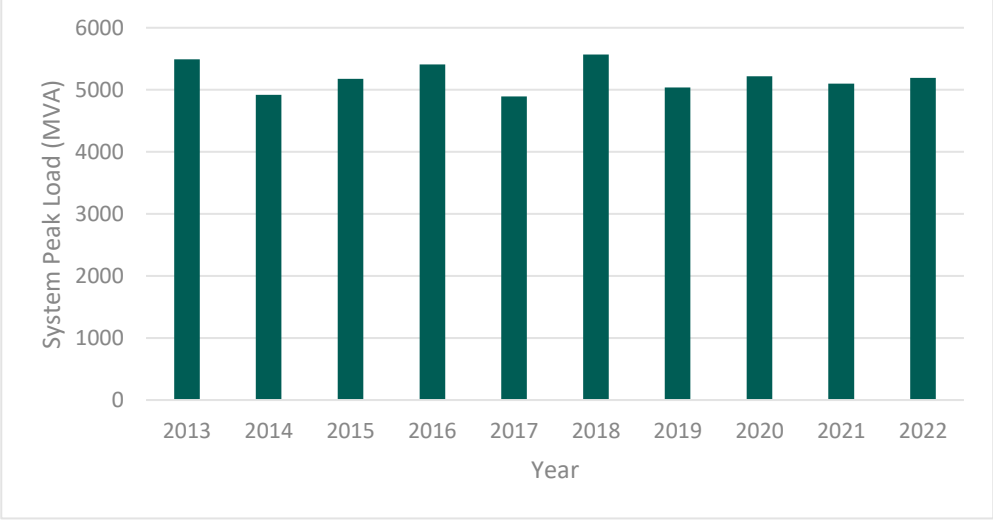


Figure 3: Historical Toronto Hydro System Peak Loading

Toronto is one of the fastest growing cities in North America with an additional 500,000 people expected by 2030.[1,2] Since 2015, the city of Toronto has led the crane count in the United States and Canada.[3] As of Q1 2023, Toronto has 238 cranes of which 58 percent are residential buildings and 29 percent are commercial/mixed use (see Figure 4 below).

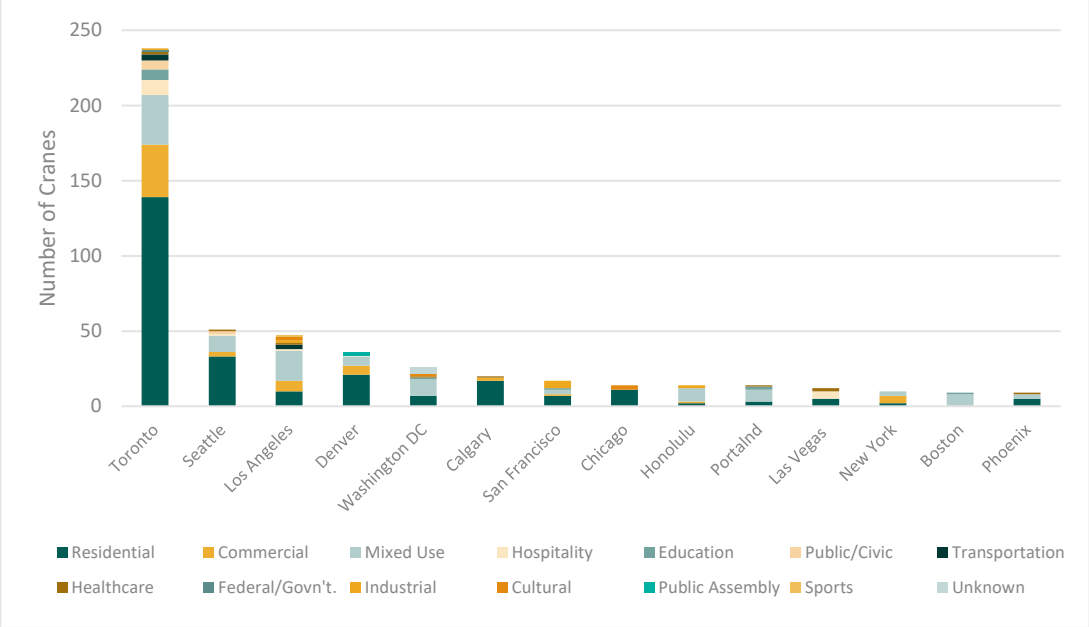


Figure 4: RLB Crane Index - Q1 2023

The city continues to experience highly concentrated load growth in certain pockets of the city due to a high number of large building developments. This concentrated growth occurs mainly in the downtown area, but also along major transit corridors such as Yonge Street and Sheppard Avenue as shown in Figure 5. Consequently, this growth is pushing certain distribution and station equipment

[1] Centre for Urban Research and Land Development, Toronto Second Fastest Growing Metropolitan Area, City of Toronto the Fastest Growing Central City, in the United States/Canada in 2022, https://www.torontomu.ca/centre-urban-research-land-development/blog/blogentry7311/, Research found City of Toronto to be the fastest growing central city in the United States and Canada.
[2] Toronto Public Health, Toronto's Population Health Profile: insight into the health of our city https://www.toronto.ca/wp-content/uploads/2023/02/940f-Torontos-Population-Health-Profile-2023.pdf, Toronto's population increased by 2.3 percent between 2016 and 2021. By 2031, Toronto's population is expected to exceed 3.4 million people. 2021: 2,794,356 2031 Projection: 3,460,604.
[3] Urbanize Toronto, RLB Crane Index Records 238 Cranes in Toronto During Q1 2023, https://toronto.urbanize.city/post/rlb-crane-index-records-238-cranes-toronto-during-q1-2023#:~:text=According%20to%20the%20latest%20report,%2C%20Chicago%20(14)%2C%20Honolulu

to capacity. Infrastructure renewal and upgrades are required in these areas to support growth while maintaining reliability and system resiliency.

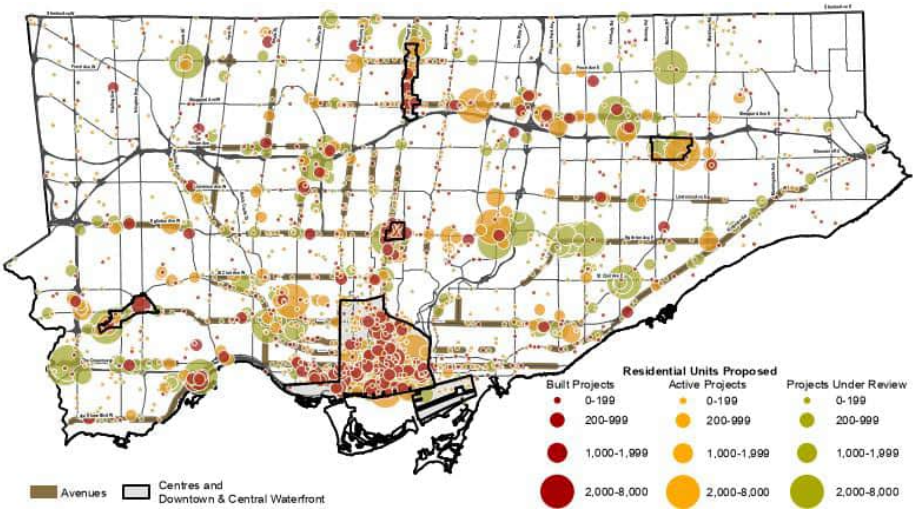


Figure 5:[4] Growth Nodes within the City of Toronto

Toronto is also Canada's largest data centre market.[5] With respect to data centre connections, Toronto Hydro connected approximately 102 MW of incremental demand load during the 2020-2024 period, and approximately 198 MW is forecasted to be connected during the 2025-2029 period.[6] According to Toronto Hydro's Peak Demand forecast, by 2031, data centres and EVs will contribute approximately 10 percent of the overall peak demand of the downtown region.[7]

Going forward, Toronto Hydro expects growing pressure on the distribution system, amplified by the accelerated adoption of Electric Vehicles ("EVs") and growth in electrified heating. The utility foresees these electrification drivers pushing the overall system peak higher in the future as well.

Growth in Electric Vehicles

Electric Vehicle ('EV') adoption is accelerating across the globe, driven in part by policies intended to reduce greenhouse gas emissions from the transportation sector. The Canadian government has

[4] City of Toronto, Development Pipeline 2022 Q2 (February 2023), https://www.toronto.ca/wp-content/uploads/2023/02/92b5-CityPlanning-Development-Pipeline-2022-Q2.pdf
[5] Cushman & Wakefield, 2022 Global Data Center Market Comparison, (2022), https://www.cushmanwakefield.com/en/insights/global-data-center-market-comparison
[6] Exhibit 2B, Section E5.1
[7] Exhibit 2B, Section D4.

announced a new light-duty vehicle sales goal targeting a 100 percent share for EVs by 2035, including interim targets of at least 20 percent by 2026 and 60 percent by 2030. To support its goals, the Government of Canada will invest $1.7 billion to extend incentives for light-duty vehicles, $400 million for charging stations, and $547.5 million for a purchase incentive program for medium-and heavy-duty vehicles.[8] The province of Ontario is the third largest vehicle-producing jurisdiction in North America.[9] Several automotive plants in Ontario are being prepared to build EVs and related components.[10]

Figure 6 shows that the number of new EV registrations in Ontario has been increasing over the last six years. For comparison, the total number of vehicle registration of all fuel types in Ontario have seen a steady decrease from 798,500 in 2018 to 594,500 in 2022. Toronto Hydro's Future Energy Scenarios ("FES") modelling results provide a range of plausible EV adoption rates in Toronto out to 2050 for three scenarios: Low, Medium and High EV adoption scenario. According to FES modelling, the number of Battery Electric Vehicles is projected to grow to approximately 1.8 million by 2050 in the Medium and High scenarios, and approximately 1.2 million by 2050 in the Low scenario. These results are discussed in the Future Energy Scenarios report.[11]

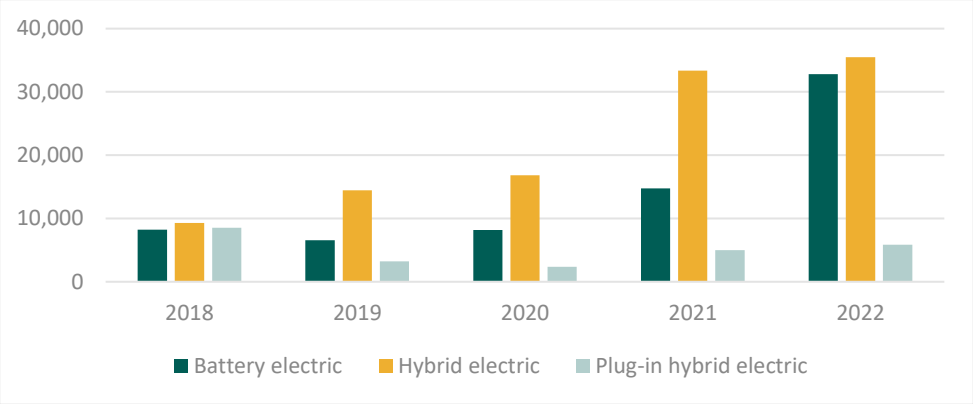


Figure 6: [12] Number of New Vehicle Registrations by Fuel Type in Ontario, as of Q4 2022

[8] Government of Canada, 2020 Emission Reduction Plan – Sector-by-sector overview (2022), https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030/sector-overview.html#sector6
[9] Invest Ontario, Automotive (2022), https://www.investontario.ca/automotive#intro
[10] Canadian Metalworking, Canada jumps into electric vehicle industry (2021) https://www.canadianmetalworking.com/canadianmetalworking/article/madeincanada/canada-jumps-into-electric-vehicle-industry.
[11] Exhibit 2B, Section D4, Appendix B.
[12] Statistics Canada, New Motor Vehicle Registrations (2023), https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2010002401

Growth in Electrified Heating

Heat pumps are an energy-efficient alternative to building heating and cooling systems. The adoption of heat pumps will transition gas and other home heating systems to use electricity. The transition of homes and buildings from natural gas furnaces to heat pumps is a key part of the City's TransformTO Net Zero Strategy.[13]

The Government of Canada has introduced incentives such as the Greener Home Grant, which grants up to $5,000 towards heat pumps and other energy-efficiency measures. In the City of Toronto Climate Change Perceptions Research, 44 percent of homeowners in Toronto say that they are likely to install an air-source heat pump. Figure 7 illustrates the market share of heat pumps in residential sector heating systems has been increasing in recent years. FES modelling explored uptake of electric heat pumps rates, which is discussed in the Future Energy Scenarios report.[14] According to the FES report, widespread uptake of heat pumps, along with technologies such as electric vehicles, are expected to be primary drivers of increases in peak demand and shifting of network peak from summer to winter in the 2030s.

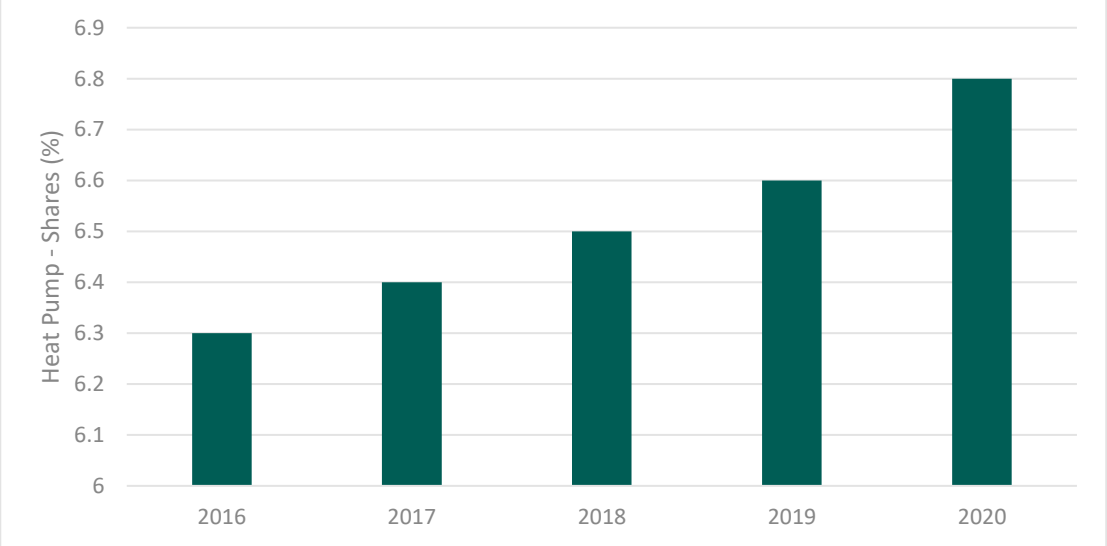


Figure 7: [15] Market Share of Heat Pumps in Residential Sector Heating System in Ontario

[13] City of Toronto, 2021 Net Zero Existing Building Strategy, (2022), https://www.toronto.ca/legdocs/mmis/2021/ie/bgrd/backgroundfile-168402.pdf
[14] *Supra* note 10, Section 4.2.
[15] Natural Resources Canada, Comprehensive Energy Use Database, (2023), Table 21, https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=on&rn=21&page=0

To keep pace with the growing city and ensure appropriate distribution system capacity, especially in order to support electrification, the utility plans to continue actively investing in capacity through the following programs, further described in Section E:

- Customer Connections (Section E5.1);
- Load Demand (Section E5.3);
- Generation Protection Monitoring & Control (Section E5.5);
- Non-Wires Alternatives (Section E7.2); and
- Stations Expansion (Section E7.4).

The utility's complimentary Grid Modernization Strategy is also central to cost-effectively maintaining reliability and improving resiliency in the face of accelerating growth in peak demand.[16]

D2.1.2 Climate and Weather

Climate change is a significant factor influencing Toronto Hydro's planning and operations. Scientists worldwide overwhelmingly agree that the planet is warming. By the year 2050, Toronto's climate is forecasted to be significantly different than the already changing climate seen today. For example, in Toronto, daily maximum temperatures of 25°C are expected to occur 110 times per year as opposed to 87 times per year currently.[17] A warmer climate will also allow the atmosphere to hold more moisture, which is expected to lead to more frequent and severe extreme weather events. These extreme events can cause major disruptions to Toronto Hydro's distribution system.

In addition to extreme weather events, Toronto experiences a wide range of weather conditions that may not be classified as extreme, but nevertheless have the potential to adversely affect the distribution system at various times during the year. Weather conditions of high heat, high winds, heavy rainfall, and heavy snowfall have the potential to cause major system damage and extensive outages. Not only are these weather conditions projected to occur more frequently and with greater severity in the future due to climate change, but trends from the past 25 years suggest that these changes are already affecting the system. Figure 8 below contains two charts depicting cumulative rainfall and the number of high wind days (i.e. with wind gusts exceeding 70 kilometres per hour) in Toronto over the past 25 years. In both cases it is observed that there is an increasing trendline over

[16] Exhibit 2B, Section D5.
[17] Toronto Hydro engaged Stantec to update its Climate Change Vulnerability Assessment, which is filed at Exhibit 2B, Section D2, Appendix A.

the period. With respect to high wind days, an even steeper increase has been observed, and seven of the 10 years with the greatest number of days of wind gusts above 70 kilometres per hour have occurred in the last 10 years (these years are highlighted in orange).

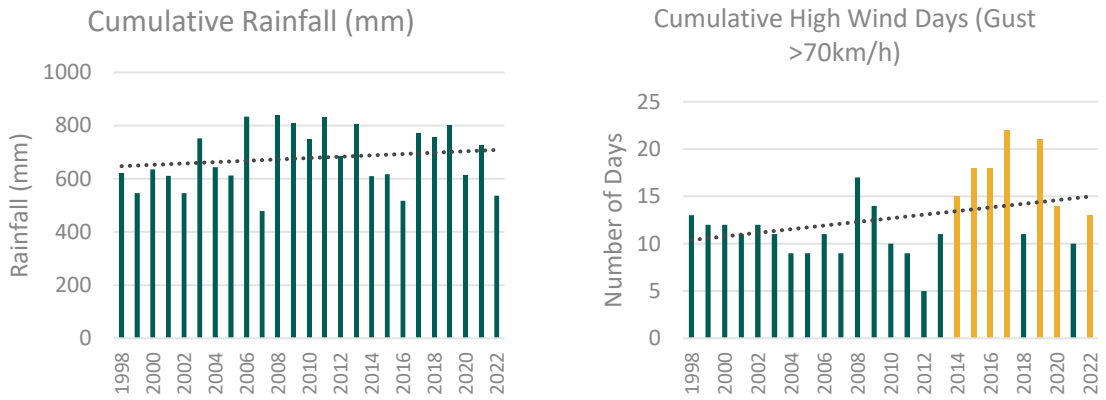


Figure 8: [18]Cumulative Rainfall (left) and Number of High Wind Days (right) in Toronto:

These trends are expected to continue through the 2030s and 2050s with the frequency of extreme rainfall events of 100 mm in less than 1-day antecedent increasing by 11 percent and 20 percent respectively. In terms of high winds, climate projections show that 10-year wind speeds are to increase by 0.7 percent and 2.7 percent in the 2030s and 2050s respectively.[19]

These weather trends have increased reliability risks for the distribution system. Toronto Hydro analyzed system reliability data to understand the correlation between wind speed above 70 kilometres per hour, the number of forced outages on the overhead system, and SAIDI performance. This revealed a high correlation between wind speed above 70 kilometres per hour and the number of forced outages on the overhead system. It was also determined that higher wind speeds were correlated with increased SAIDI.

Parts of the underground system are sensitive to significant rainfall, and in particular flooding, while the overhead system in general is sensitive to high winds, freezing rain and wet snow events resulting in damage and outages (e.g. from vegetation impact in proximity to overhead lines). In extreme

[18] Government of Canada, Weather, Climate and Hazard Historical Data http://climate.weather.gc.ca/historical_data/search_historic_data_e.html; Weather data compiled using Toronto Lester B. Pearson INTL A for January 1998 to June 2013 and Toronto INTL A for July 2013 to December 2022.
[19] *Supra* note 16.

cases, broken trees and the weight of ice accretions bring lines, poles and associated equipment to the ground.

The above-mentioned reliability risks are significant, as evidenced by an event that occurred on May 21, 2022. A major storm with wind gusts as high as 120 kilometres per hour swept through Toronto Hydro's service territory. These extreme winds caused substantial damage to vegetation, which in turn damaged overhead distribution wires and equipment. Approximately 142,000 customers (18 percent of Toronto Hydro's total customer base) were without power during this event. Similarly, four weather-related major events occurred during April to July of 2018 due to wind storms and freezing rain. The events caused 382,286 Customers Interrupted and 1,173,338 Customer Hours Interrupted (discussed in Exhibit 2B, Section C).

To better understand the risks related to increases in extreme and severe weather due to climate change, in June 2015, Toronto Hydro completed a vulnerability assessment following Engineers Canada's Public Infrastructure Engineering Vulnerability Committee ("PIEVC") protocol.[20] The assessment identified areas of vulnerability to Toronto Hydro's infrastructure as a result of climate change. Following this study, a climate change adaptation road map was developed, along with initiatives relating to climate data validation, review of equipment specifications, and review of the load forecasting model.

In 2022, Toronto Hydro updated the 2015 study to identify if any further work is required to update the adaptation measures.[21] The study utilized updated climate projection data from the 6th Coupled Model Intercomparison Project (CMIP6), along with IPCC's 6th Assessment Report (AR6) in 2021, to estimate climate parameter probabilities. These probabilities were then assessed to determine the materiality by recalculating risk scores over the study period (from 2022 to 2050) following the PIEVC protocol. The results of the study provided that two climate parameters had probability changes as follows:

Climate Parameter	**Threshold**	**Frequency** (2030s)	**Probability** (Study Period)	**Probability Score** (Study Period)	**Probability Score Change** (2022-2015)
Daily Maximum Temperatures	Days > 40°C	0.08 (0 - 0.1)	90%	6	Decrease (-1)
Ice Storm/ Freezing Rain	25 mm ≈ 12.5 mm radial	-2.2% in 1/20yr ice accretion	96%	6	Decrease (-1)

[20] EB-2018-0165, Exhibit 2B, Section D, Appendix D.
[21] *Supra* note 16.

For each of the above climate parameters, an assessment was completed to determine how these changes in probability impacted the infrastructure asset classes, similar to the 2015 report. The following table provides the results:

Climate Parameter	Threshold	Study Report Year	Number of Interactions by Risk Class		
			High	Medium	Low
Daily Maximum Temperature	40°C	2015	10	23	1
		2022	0	33	1
Ice Storm / Freezing Rain	25 mm ≈ 12.5 mm radial	2015	18	5	9
		2022	5	18	9

Each combination of infrastructure asset class and climate parameter is referred to as an 'interaction'. The updated probabilities resulted in material changes to the risk scores for 23 separate interactions (10 from daily maximum temperatures greater than 40°C and 13 from Ice Storms/Freezing Rain greater than 25 mm).

Although the results observed a decrease in risk scores for these 23 interactions, given the uncertain nature of the climate projection data, the recommendation was to not relax any adaptation measures associated with extreme heat or freezing rain events from the 2015 study.

Existing codes, standards, and regulations were developed with regard to historical weather data and do not always account for ongoing and future changes to the climate. In efforts to close this gap, Toronto Hydro now utilizes climate data projections for temperature, rainfall, and freezing rain in its equipment specifications and station load forecasting. Further, Toronto Hydro reviewed and updated major equipment specifications in 2016 to adapt to climate change, including:

- Revisions to submersible transformer specifications to require stainless steel construction and testing of the equipment's ability to withstand fully flooded conditions;
- Replacement of air-vented, padmounted switches with more robust designs; and
- Adoption of breakaway links in tree-covered areas for residential customers with overhead service connections, intended to facilitate faster restoration after extreme weather and prevent damage to customer-owned service masts.

In February 2023, CSA issued changes to it's Underground and Overhead Systems Standards related to Climate Change Adaptation. Toronto Hydro strives to meet and surpass these new requirements. Some impacts to Toronto Hydro design considerations include:

- Modification of standard pole loading analysis to accommodate extreme weather events in light of recent CSA updates; and
- Standardization of conversion of submersible transformers to padmounted transformers in residential rebuild projects, in order to mitigate the impacts of flooding.

The following 2025-2029 program activities will contribute to Toronto Hydro's ongoing efforts to renew and enhance its system to increase resiliency, thereby supporting the continued delivery of outcomes expected by existing and future customers:

- As assets are replaced in the Overhead System Renewal program (Exhibit 2B, Section E6.5), Toronto Hydro plans to reconfigure feeders and relocate assets away from the ravines and right of ways to improve accessibility for Toronto Hydro crew members and reduce vulnerability to outages in adverse weather conditions.
- Padmounted transformers will replace existing submersible units as the utility carries out its Underground System Renewal – Horseshoe program (Exhibit 2B, Section E6.2).
- Underground System Renewal – Horseshoe program will replace air-vented padmounted switches with more robust designs to mitigate risk of failure due to ingress of dirt and road contaminants on the live surface.
- The Network System Renewal program will replace end-of-life and deteriorated non-submersible protectors with submersible protectors to protect against flooding.
- The Network Circuit Reconfiguration segment under the Network System Renewal program (Exhibit 2B, Section E6.4) will help the utility improve system restoration capabilities in the event of outages.
- Installation of flood mitigation systems at stations identified as being vulnerable to flooding will occur under the Stations Renewal program (Exhibit 2B, Section E6.6).

In addition to these system hardening measures, Toronto Hydro's Grid Modernization Strategy for 2025-2029 has been developed in part to improve long-term system reliability and resiliency in the face of external pressures from both future increases in system utilization and evolving climate impacts. The strategy focuses on accelerating the deployment of digital field and operational technologies that will enhance the utility's ability to address developing fault conditions in real-time, improve outage restoration capabilities and operational flexibility, and lay the groundwork for widescale grid automation beginning in 2030. Key investments include the deployment of technologies that will enhance real-time system observability (e.g. next generation smart meters;

overhead and underground line sensors; network condition monitoring technologies), enhance system controllability (e.g. SCADA-enabled switches and reclosers); and enable integrated and increasingly predictive/automated control of the distribution system (e.g. Advanced Distribution Management System or "ADMS"). For more information on the Grid Modernization Strategy, please refer to Exhibit 2B, Section D5.

Toronto Hydro continues to be a partner of the City of Toronto in planning and preparing for the effects of climate change.

D2.1.3 Economic Profile

The City of Toronto is Canada's economic and financial hub. It is home to the Toronto Stock Exchange, as well as the headquarters of five of the nation's largest banks. Toronto accounts for approximately 20 percent of Canada's Gross Domestic Product ("GDP"). Its GDP growth has significantly outpaced the national average over the 2015 to 2019 period.[22] The city is the second largest financial service centre in North America.[23]

Toronto also has a diverse industrial and commercial base comprised of 14 key sectors including aerospace, design (e.g. fashion, interior), financial services, education, life sciences, technology, food, entertainment, and tourism.[24] The importance of Toronto's economy highlights the necessity of sufficient investments to ensure the delivery of value for distribution customers and to prepare for technology driven change.

Like many regions across the country and the world, Toronto's economy has recently faced significant inflationary pressures. Figure 9 shows the annual change in Consumer Price Index ("CPI") over the past ten years for the City of Toronto, Province of Ontario and Canada. CPI represents changes in prices as experienced by consumers. This figure illustrates the significant increases to CPI in recent years.

[22] Statistics Canada, Gross Domestic Product (GDP) at basic prices (2022), https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=3610046801
[23] City of Toronto, Business & Economy, Strong Economy, https://www.toronto.ca/business-economy/invest-in-toronto/strong-economy/
[24] City of Toronto, Business & Economy, https://www.toronto.ca/business-economy/industry-sector-support/

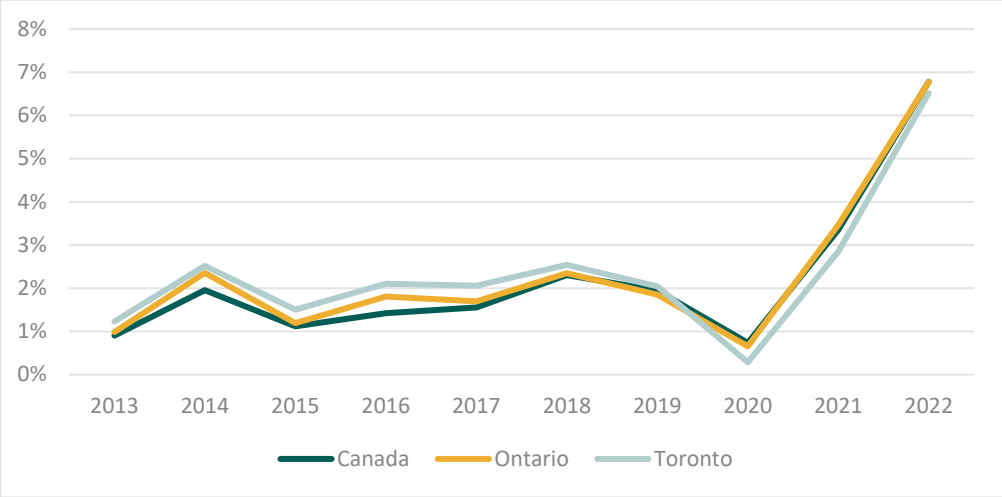


Figure 9: [25]Annual change in CPI over the past ten-year period

Similarly, Building Construction Price Indexes ("BCPI") provide change in prices over time that contractors charge to construct a range of new commercial, institutional, industrial and residential buildings. BCPI for non-residential buildings is relevant to Toronto Hydro's costs and has risen significantly in recent years. Figure 10 illustrates the average increase in BCPI for non-residential buildings for the City of Toronto.

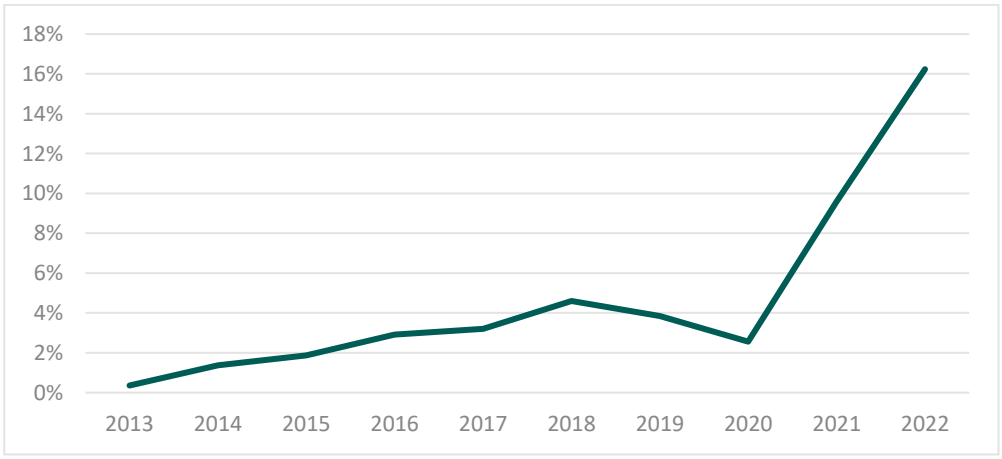


Figure 10: [26] Annual change in BCPI for non-residential buildings over the past ten-year period

[25] Statistics Canada, Table 18-10-0005-01 Consumer Price Index , annual average (2023), https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000501
[26] Statistics Canada, Table 18-10-0276-01 Building Contruction Price Indexes (2023), https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810027601

In addition to increases in CPI and BCPI for non-residential buildings, Toronto Hydro also faces increasing commodity prices. Figure 11 illustrates the average price for some top usage equipment in Toronto Hydro.

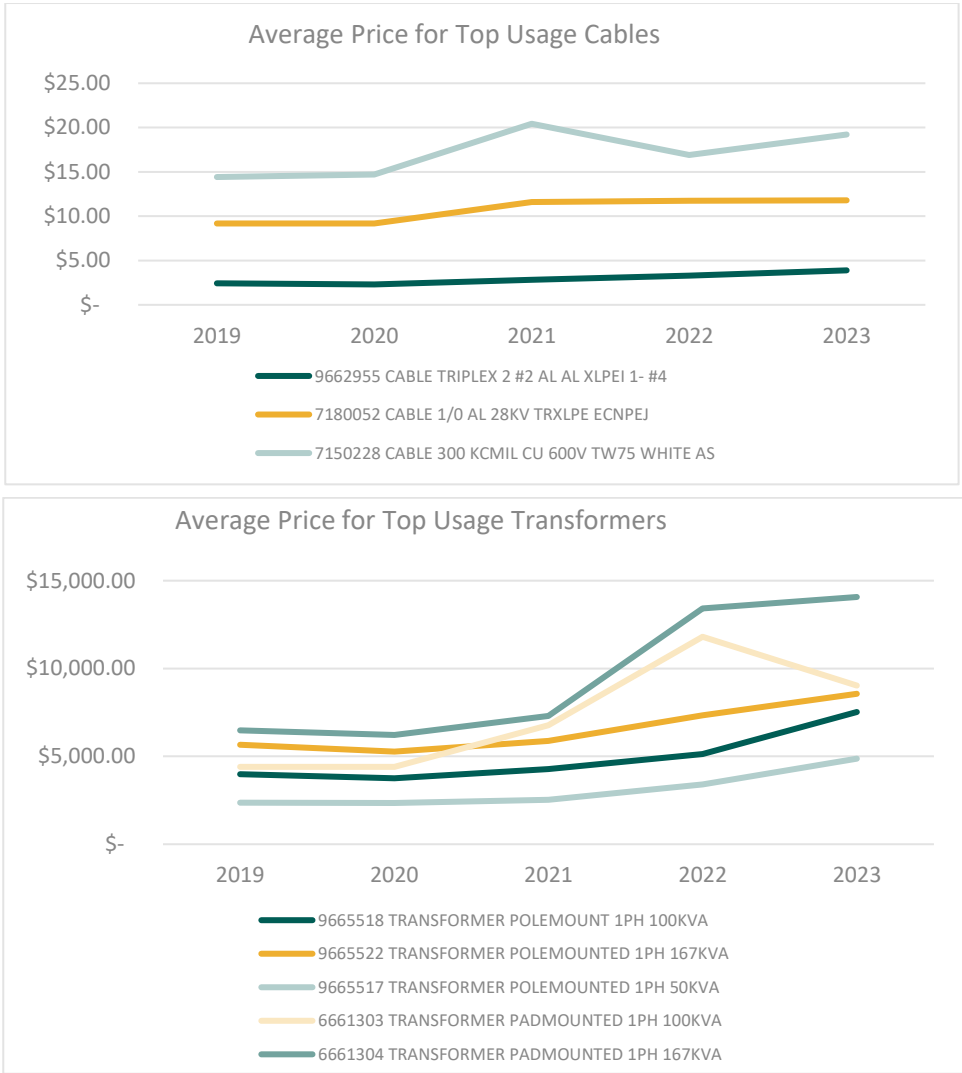


Figure 11: Average price for some top usage equipment in Toronto Hydro

D2.1.4 Toronto Hydro's Evolving Role in the City of Toronto

The role that Toronto Hydro plays in its service territory is evolving as new technologies emerge. In many cases, local and provincial policy imperatives aim to accelerate the uptake of new energy

related technologies such as distributed generation and energy resources, and power quality, reliability and resiliency solutions.

One example is the City of Toronto's climate change action plan and long-term vision. A key pillar of this plan is the *TransformTO* Net Zero Strategy,[27] which identifies how the City plans to reduce greenhouse gas emissions, improve health, grow the economy, and improve social equity. One of the major commitments of this plan is for 100 percent of vehicles in Toronto to use low-carbon energy by 2040. As part of achieving this goal, the City has made climate related investments for water, solid waste and parking. In addition, the City is making significant capital investments in the TTC, which includes vehicles such as buses, streetcars and subway cars.[28]

Toronto Hydro prepared a Climate Action Plan to support the City's objectives. The Climate Action Plan encompassed the areas of EV charging infrastructure, modernization of streetlighting, building electrification and energy efficiency, renewable energy, and energy storage.[29] Toronto Hydro has also established a target of achieving net zero for its own operations by 2040.

There are three climate action opportunities Toronto Hydro is pursuing to reach its objectives. Firstly, following the planning principles and forecasting approaches outlined in Section D4 of the DSP, Toronto Hydro plans to expand its existing electricity distribution business to build a grid that is capable of supporting the realization of the City's Net Zero Strategy. The second opportunity is for Toronto Hydro to create a new, non-rate-regulated Climate Advisory Services line of business to support the City's Net Zero Strategy by facilitating and stimulating the growth of emerging local cleantech markets. The third opportunity is pursuing modernization of outdoor lighting within the utility's existing unregulated streetlighting company.

Provincial and federal policy targeting greenhouse gas reductions is also a driver of technological change. Provincial energy policy, such as the Net Metering program, supports and incentivizes the connection of renewable energy projects to the local distribution system. As of the end of 2022, Toronto Hydro has connected 2,424 unique distributed energy resource ("DER") projects to its distribution grid, totaling approximately 305 MW of generation capacity.[30] As discussed in Section

[27] City of Toronto, TransformTO Net Zero Strategy, https://www.toronto.ca/legdocs/mmis/2021/ie/bgrd/backgroundfile-173758.pdf
[28] See Exhibit 2B, Section E.
[29] Toronto Hydro, Climate Action Plan, https://www.torontohydro.com/documents/20143/74105431/climate-action-plan.pdf/8fe4406c-7675-76a7-00c9-c0c4e58ae6df?t=1638298942821
[30] Exhibit 2B, Section E5.1.

E3, Toronto Hydro anticipates steady growth in generation connections going forward and is planning to invest in necessary renewable enabling improvements, including monitoring and control technologies, and energy storage systems to facilitate this growth during the 2025-2029 rate period.

D2.2 System Demographics and Characteristics

Toronto Hydro's distribution system consists of a mix of overhead, underground, network, and stations infrastructure. This infrastructure operates at voltages of 27.6 kV, 13.8 kV, and 4.16 kV, and includes approximately 61,000 distribution transformers, 17,000 primary switches, 15,600 kilometres of overhead conductors, and 13,800 kilometres of underground cables as of 2022. Unless otherwise mentioned, asset demographic information provided herein is as of 2022.

The following sections provide details on these sub-systems and how each sub-system relates to Toronto Hydro's major asset management objectives. As discussed in Exhibit 2B, Section D3, Toronto Hydro manages its distribution infrastructure and plans capital investments and maintenance to achieve asset performance objectives, specifically, the attainment of applicable outcomes summarized in Section D1, and further detailed in Sections C and E2 of the DSP.

The following table and accompanying explanations introduce Toronto Hydro's sub-systems through the lens of a core subset of risk related asset management performance measures, all of which relate directly or indirectly to Toronto Hydro's outcomes.

Table 1: Asset Management Performance Indicators by System Type

System	**Oil Deficiencies** (Number of assets)	**Priority Deficiencies** (Number assigned)	**Customer Hours of Interruption** due to Defective Equipment	**Customer Interruptions** due to Defective Equipment	**Condition** [31] (Percentage of Assets in HI4 or HI5)	**Oil Containing PCBs** (Number of assets with oil containing or at risk of containing PCB)	**Age** (Percentage of Assets past Useful Life)	**Legacy Assets**
	Lagging Indicator of Performance				**Leading Indicator of Performance**			
Overhead	11 (3%)	3,074 *(24%)*	68,312 *(27%)*	117,175 *(33%)*	8.8%	3,076 (57%)	16%	2756 Box Construction Poles 6832 Customers Served by Rear Lot 502 km of 4.16 kV conductor
Underground	298 (88%)	8,955 *(71%)*	170,290 *(68%)*	230,661 *(64%)*	3.3%	2,278 (42%)	23%	721 km of Direct-Buried Cable 140 Transclosures[32] 985 km of PILC[33] Cable 176 km AILC[34] Cables 202 km of 4.16 kV cable
Network	21 (6%)	0 (0%)	0 *(0%)*	0 *(0%)*	4.0%	66 (1%)	23%	533 Non-Submersible Network Units 651 vaults without communication
Stations	8 (2%)	560 (4%)	10,636 *(4%)*	9,652 *(3%)*	3.1%	-	43%	346 legacy breakers at TSs[35] 558 legacy breakers at MSs[36]
Total	**338 *(100%)***	**12,589 *(100%)***	**249,238 *(100%)***	**357,488 *(100%)***	**7.1%**	**5,420 (100%)**	**25.2%**	**-**

Notes: All figures are 2022 year-end actuals, unless otherwise noted.

[31] See Exhibit 2B, Section D3, Appendix A for summary of results and details on updates to Toronto Hydro's Asset Condition Assessment.
[32] As a result of data improvement efforts, the transclosure population was updated to 140.
[33] Paper Insulated Lead Covered ("PILC") cable.
[34] Asbestos Insulated Lead-Covered ("AILC") cable.
[35] Transformer Station ("TS").
[36] Municipal Station ("MS").

- **Oil Deficiencies:** An oil deficiency is any observation related to oil (e.g. dried oil, oil leak) made during planned asset inspections. These are reported by inspectors when inspecting equipment and components that are known to or intended to contain oil. Oil deficiencies are an indicator of the likelihood of oil spills. The primary driver for this metric is to protect the environment from oil spills and to adhere to federal, provincial, and municipal legislation, regulations, and by-laws pertaining to the release of oil into the environment. Toronto Hydro strives to achieve zero oil leaks into the environment. Programs that contribute to the management of this measure are Preventative and Predictive Maintenance programs for oil filled equipment,[37] and capital programs that replace deteriorating oil filled equipment, including Underground System Renewal,[38] and Reactive and Corrective Capital (Section E6.7).[39]

- **Priority Deficiencies**: Toronto Hydro defines "priority deficiencies" as the subset of all equipment deficiencies that require intervention on a reactive or corrective basis. Between 2020 to 2022, Toronto Hydro identified around 45,000 deficiencies each year through planned inspections, responding to equipment failures and power interruptions, or through the course of day-to-day work. The total number of deficiencies are higher compared to the last rate application partially due to the inclusion of deficiencies corrected on site, which were not counted in the previous DSP. Priority deficiencies are deficiencies that pose a high risk to reliability, safety, or the environment and are assigned as priority 1 (P1), priority 2 (P2), or priority 3 (P3) for the purposes of addressing the deficiency. Each category corresponds to a level of risk (with P1 being the highest risk) and a timeline for repairing the deficiency or replacing the asset. Toronto Hydro has various programs (including Reactive and Corrective Capital, Corrective Maintenance, and Emergency Response) to address asset deficiencies, some of which have already resulted in asset failure.[40] Given the risks, timely and effective responses to priority deficiencies are non-discretionary and must be taken over short time horizons (i.e. less than six months). Identifying and responding to priority deficiencies in a timely manner is critical to meeting the utility's performance objectives for key outcomes such as SAIDI and SAIFI, and the utility's safety and environmental objectives.

[37] Exhibit 4, Tab 2, Schedules 1, 2, and 3.
[38] Exhibit 2B, Sections E6.2 and E6.3.
[39] Exhibit 2B, Sections E6.7.
[40] Exhibit 2B, Section E6.7 and Exhibit 4, Tab 2, Schedule 4-5.

The volume of corrective work requests has been increasing in recent years which has resulted in a growing backlog of P3 deficiencies that need to be addressed. This increase can be attributed to deteriorating asset condition and asset-related safety risks to crews or the general public, in addition to enhanced inspection forms and the introduction of new inspections. This has resulted in approximately $20 million worth of backlog for lower priority work requests, which is expected to grow. To help manage this risk, the corrective work requests in the backlog have been further prioritized by level of risk within P3 priority, and by the primary and secondary impact of the deficiency.[41]

- **Customer Hours of Interruption ("CHI") and Customer Interruptions ("CI") (i.e. Outages)**: CHI and CI are measures of outage duration and frequency, scaled by the number of customers affected by each outage. Toronto Hydro uses this type of historical reliability data to identify priority project areas across all of its reliability-related programs, and to develop and pace investment program spending in order to improve key outcomes that the utility reports including SAIDI and SAIFI.

- **Assets with Material Deterioration or at End of Serviceable Life**: As described in detail in Section D3 and associated appendices, Toronto Hydro's asset condition assessment ("ACA") methodology assigns health scores to assets based on observable condition variables, and categorizes these scores within five health index bands ("HI1" to "HI5"). Asset condition demographics are a strong predictor of future asset performance. Over the long-term, Toronto Hydro is focused on managing the number of assets in the HI3 ("moderate deterioration") to HI5 ("end of serviceable life") bands, with a particular emphasis on preventing significant increases in the most critical HI4 and HI5 bands.

- **PCBs**: Toronto Hydro defines "PCB at-risk equipment" as an asset that: (i) is known to contain oil with greater than 2 ppm concentration of polychlorinated biphenyl ("PCB"); or (ii) has an unknown concentration of PCB and was manufactured in 1985 or earlier (and is therefore at a high risk of containing greater than 2 ppm PCB). This measure excludes cables. Due the toxic and persistent nature of PCBs, Environment Canada's *PCB Regulations*[42] prohibit the use of equipment that contains greater than 50 ppm PCBs, or the release of greater than one gram of PCBs, which could result from an oil leak with significantly less than 50 ppm. The City

[41] Exhibit 4, Tab 2, Schedule 4.
[42] PCB Regulations, SOR/2008-273, under the *Canadian Environmental Protection Act*, 1999.

of Toronto also enforces its own PCB-related bylaws with a near-zero tolerance for the discharge of PCBs into the storm and sanitary sewer systems.[43] Toronto Hydro plans to continue its efforts to address PCB at-risk equipment by 2025 through a combination of inspection and testing equipment under its maintenance programs,[44] and through targeted asset replacement in capital programs such as Overhead System Renewal,[45] Underground System Renewal,[46] Network System Renewal,[47] Stations Renewal,[48] and Reactive and Corrective Capital.[49]

- **Age**: Toronto Hydro monitors the percentage of its asset base that has passed useful life or will pass that milestone by the end of the next planning horizon. As a comprehensive indicator of failure risk across the system, this information is used for longer-term planning purposes. As of the end of 2022, Toronto Hydro's percentage of assets past useful life was 25 percent, with an additional 11 percent forecasted to reach expected useful life by the end of 2030, meaning that over a third of the utility's asset base is at or nearing the end of its typical useful life. By managing this measure over the long-term, the utility aims to provide predictability in the performance of key outcomes like reliability and safety for current and future customers, and to provide stability in costs, rates and labour resourcing by not allowing significant backlogs of asset replacement needs to accumulate.

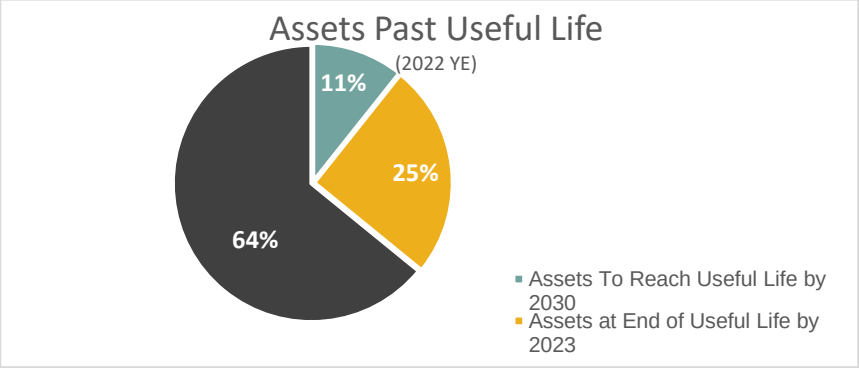


Figure 12: Assets Past Useful Life

[43] Toronto Municipal Code, Chapter 681 – Sewers.
[44] Exhibit 4, Tab 2, Schedules 1-4.
[45] Exhibit 2B Section E6.5.
[46] Exhibit 2B, Sections E6.2 and E6.3.
[47] Exhibit 2B Section 6.4.
[48] Exhibit 2B Section 6.6.
[49] *Supra* note 37.

- **Legacy Assets**: Legacy assets are specific asset types, configurations, or sub-systems that do not meet current Toronto Hydro standards. These assets often feature obsolete components with limited or no supplier or skilled labour support to maintain, repair or replace the assets, and carry elevated reliability, safety, or environmental risks. Additionally, lower voltage parts of Toronto Hydro's system are increasingly obsolete from a design perspective due to their inability to support the high levels of electrification and DER integration that the utility anticipates over the next 15-20 years. One of Toronto Hydro's asset management strategies is to eliminate all high-risk legacy assets within a specific and reasonable timeframe. The specific legacy assets are discussed further in the following sections as part of the overhead, underground, network, and stations systems descriptions. Table 2 above provides an estimate of the remaining volumes of certain key legacy assets across Toronto Hydro's different subsystems. For further details on specific legacy asset replacement and pacing, please see Exhibit 2B, Section E2.

The following sections provide a more detailed view of the overhead, underground, network, and stations sub-systems of Toronto Hydro's distribution system, including the age and condition demographics of the assets, and associated system challenges. Each section provides a further breakdown of how those sub-systems relate to Toronto Hydro's asset management indicators and measures discussed above.

D2.2.1 Overhead Grid System

The overhead system consists of poles, overhead conductors, overhead transformers, overhead switches, and other equipment including lightning arrestors, guying hardware, and wires. All of these assets are placed above ground in areas with sufficient space and clearance from overhead obstructions (e.g. trees and buildings). Advantages of using an overhead system are that it is cost effective and allows for more expeditious fault identification and outage restoration, given that all assets are out in the open and visible to crews. Disadvantages of this system are that it is prone to foreign interference from vehicles, trees, animals, and weather-related outages (i.e. caused by high winds or freezing rain), and requires adequate clearances to operate and maintain.



Figure 13: Overhead Distribution Transformer

The majority of Toronto Hydro's overhead system is operated at 27.6 kV and 13.8 kV, but a subset of the overhead system operates at 4.16 kV. The overhead system consists of approximately 166,500 poles, 7,400 overhead switches, 30,000 overhead transformers, 4,000 circuit-kilometres of overhead primary, and 11,300 circuit-kilometres of overhead secondary conductors as of 2022.

Asset management activities related to the overhead distribution system focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies, managing system performance with respect to reliability and power quality, and asset stewardship over the assets' lifespan.

Figure 14 provides the age demographic distribution of major overhead assets. As of 2022, approximately a quarter of poles are beyond their typical useful life of 45 years. Without any intervention, Toronto Hydro projects that the percentage of poles having reached or exceeded useful life will increase from 24 percent as of 2022 to approximately 30 percent by 2029. Similarly, overhead transformers having reached or exceeded useful life will increase from 14 percent as of 2022 to approximately 25 percent by 2029 and the percentage of overhead switches having reached or exceeded useful life will increase from 40 percent as of 2022 to approximately 68 percent by 2029.

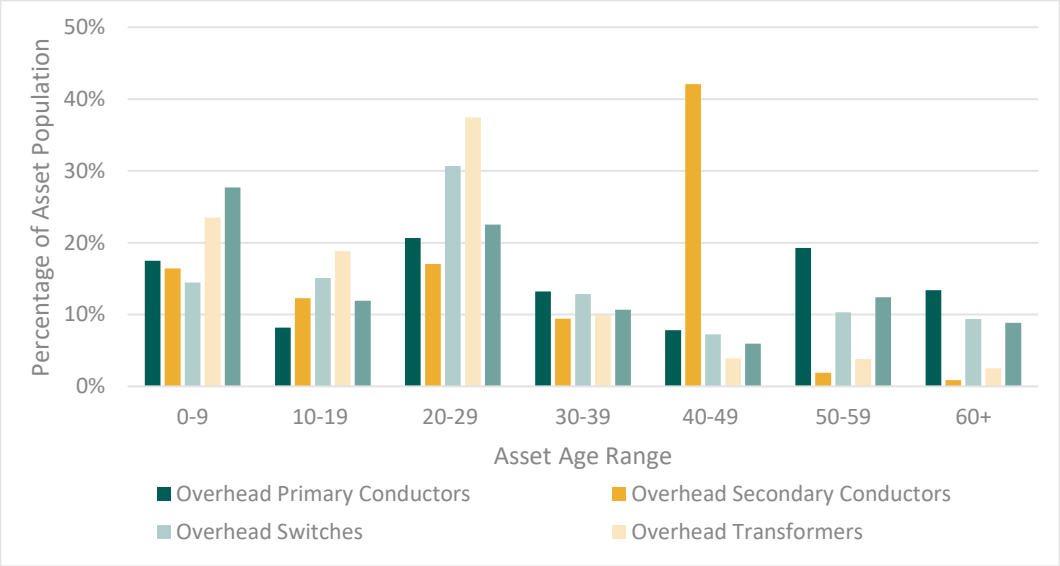


Figure 14: Overhead Assets Age Demographics as of 2022

Wood poles and overhead switches are the two major overhead asset classes for which Toronto Hydro performs an Asset Condition Assessment ("ACA"), as summarized in Figure 10. With respect to wood poles, the ACA showed that approximately 30 percent of Toronto Hydro's wood poles have at least moderate deterioration as of 2022. With over 21,000 wood poles in HI3 condition (i.e. "moderate deterioration"), 8,950 in HI4 condition (i.e. "material deterioration"), and approximately 509 in HI5 condition (i.e. "end of serviceable life"), pole replacement will continue to be a significant driver of both reactive and planned investment through 2029. The need for a continued pole replacement strategy and investment is underscored by the projected rate of deterioration across this asset class over the rate period.[50]

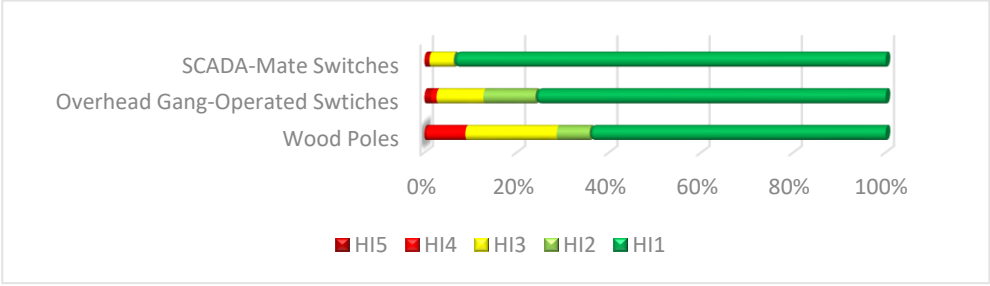


Figure 15: Asset Condition Assessment of Overhead Assets as of 2022

[50] *Supra* note 43.

Other key asset management performance measures that are relevant to the overhead system include:

- **Oil Deficiencies**: Pole top transformers are the only asset type in the overhead system that may exhibit oil deficiencies. During the 2020-2022 period, Toronto Hydro found on average six pole-top transformers with oil deficiencies annually. The Reactive and Corrective Capital program (Section E6.7) will continue to target pole top transformers exhibiting oil deficiencies.

- **Priority Deficiencies:** Overhead assets are susceptible to external interference from animals, insects, adverse weather, and vegetation contacts. These factors accelerate degradation processes and cause damage. From 2019 to 2022, Toronto Hydro issued more than 10,000 work requests to address deficiencies, predominantly for failing or failed overhead assets. In 2022 alone, Toronto Hydro classified 218 P1, 724 P2, and 2,132 P3 priority deficiencies on the overhead system.

- **PCBs**: Pole top transformers are the only asset type in the overhead system that are known to contain PCB contaminated oil. At of the end of 2024, there will be an estimated 500 PCB pole top transformers containing or at risk of containing PCBs remaining on the system. By replacing these assets, predominantly through the Overhead System Renewal program (Section E6.5), Toronto Hydro endeavours to eliminate the risk of PCB-contaminated oil spills by the end of 2025.

D2.2.1.1 Overhead Legacy Equipment

On the overhead system, a major challenge facing Toronto Hydro stems from legacy overhead assets such as porcelain insulators and arrestors, non-standard animal guards, and legacy construction types such as rear lot and box construction. These legacy assets contribute to poor reliability performance, safety risks, and other undesirable outcomes. Capital investment programs that are

planned to target and mitigate challenges within the overhead system include: Area Conversions,[51] Overhead System Renewal,[52] and Reactive and Corrective Capital.[53]

1. Obsolete and deteriorating overhead accessories

Overhead accessories include three major categories: insulator hardware, conductors, and animal guards. These assets are interconnected and integrated with transformers, poles, and switches and are vital components of the distribution system.

- **Legacy Insulator Hardware:** Toronto Hydro's legacy insulators are predominately porcelain, which is an insulation material that has been commonly used for switches, lightning arrestors, terminators, and line posts. The failure modes for assets with porcelain insulating material typically involve assets cracking and breaking apart. In some cases, discharge of fragments due to weakening structural integrity of the material could occur as a result of a failure. Porcelain hardware has the potential to fail in a catastrophic manner, releasing porcelain shards which can damage nearby equipment and public property. For example, one porcelain insulator failure incident in Toronto sent shards of porcelain into the balcony of a nearby home, shattering the window of the family room and causing damage to the windshield of a nearby police car. The effects of this porcelain pothead failure can be seen in Figure 16. In general, porcelain material tends to have a high risk of failure due to its tendency for contamination build-up that leads to electrical tracking (i.e. the breakdown of insulation materials, which can lead to faults), and as such, will be replaced with polymeric material.

[51] Exhibit 2B, Section E6.1.
[52] *Supra* note 43.
[53] *Supra* note 37.



Figure 16: Porcelain Pothead Failure

- **Animal Guards:** Existing legacy wildlife protection on Toronto Hydro's overhead distribution system consists of "Guthrie" guard animal protectors. Toronto Hydro is installing newer animal guards with a design that provides an improved physical non-conductive barrier. Figure 17 below shows the difference between "Guthrie" and the new animal guards used by Toronto Hydro to guard against wildlife.

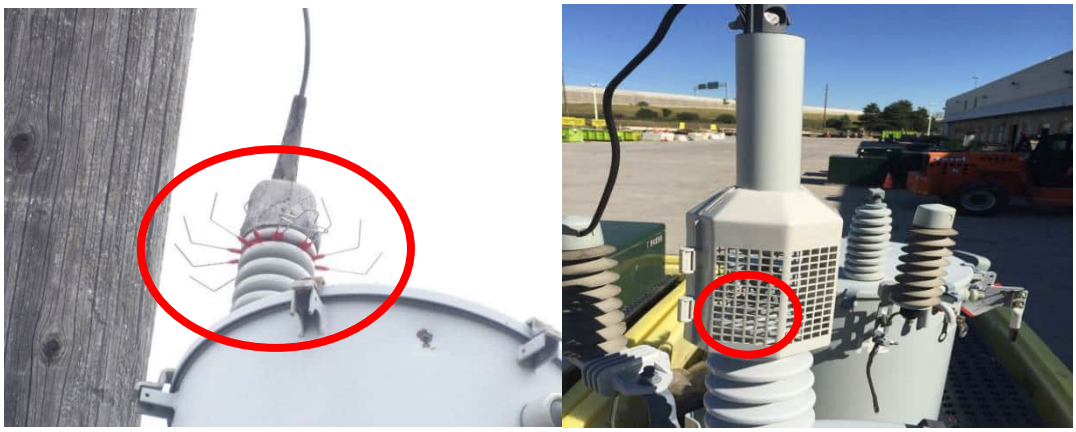


Figure 17: Animal Guards – Guthrie Guard (left), Newer Wildlife Guard (Right)

2. Legacy construction types

- **Rear Lot Construction:** This consists of overhead and underground assets that are installed in the backyard, or rear lot, and are generally operating near or beyond useful life. These assets were installed to serve residential customers in the Horseshoe region of Toronto. Due to accessibility limitations, outages on the rear lot plant tend to be longer in duration. The location of the plant also presents safety risks to customers and employees. Toronto Hydro

is continuing to replace rear lot plant with standard, front lot underground circuits as part of the Area Conversions program.[54]

- **Box Construction:** These overhead feeders are located along main streets in the downtown area and serve residential neighborhoods and small commercial customers. The congested, box-like framing of the circuits prevents crews from establishing safe limits of approach to live conductors, which in turn restricts operations and leads to longer power restoration times for customers when compared to modern overhead standards. Toronto Hydro plans to eliminate the remaining box framed poles by 2026 as part of the Area Conversions program (Section E6.1).

D2.2.1.2 Overhead Assets Failure Characteristics

Table 2 below highlights the failure modes and impacts of overhead asset failures.

Table 2: Overhead Asset Failure Modes

Asset	Failure Mode	Effects
Pole Top Transformer	a) Arc flash due to contamination of bushing. b) Corrosion of tank. c) Winding Failure.	a) Causes tracking and can lead to catastrophic failure (e.g. oil fire, spill). b) Causes oil leakage and potential environmental issues. c) Can lead to catastrophic failure (e.g. oil fire, spill).
Wood Poles & Accesssory Equipment	a) Rotted pole (below ground and at ground level). b) Contamination of insulators. c) Pest infestation.	a) Pole and equipment on it could fall causing an outage, safety issues and environmental issues associated with oil leakage. b) Pole can catch fire due to tracking. c) Compromises pole strength; equipment can fall and drop; safety and environmental risks.
Overhead Switches	a) Burnt disconnect contacts due to contamination. b) Corroded or loose connections.	a) Overheating of parts that can lead to malfunction and/or equipment falling. b) Device misoperation or overheating of parts that can lead to malfunction and/or equipment falling.

[54] *Supra* note 49.

D2.2.2 Underground Grid System

The underground system consists of cables, transformers, switches, and civil infrastructure. All of these assets are placed at grade, below grade, or inside building vaults. The underground system eliminates many non-asset risks that are present in the overhead system such as foreign interference and weather-related interruptions. However, this system also presents unique non-asset risks, such as flooding or faster deterioration due to moisture build-up. Although this system generally provides better reliability than the overhead system, the causes of outages are more difficult to identify and restoration may take longer because the assets are underground and not visible to crews.

The Horseshoe underground distribution system is operated at 27.6 kV, 13.8 kV, with a subset of the system operating at 4.16 kV. The downtown underground distribution system is operated at 13.8 kV, and 4.16 kV. The main underground configurations are either radial or looped, with radial being the predominant configuration in the downtown system.

System types and configurations are sometimes mixed to provide better reliability or flexibility when repairs are required, as is the case with Underground Residential Distribution ("URD"). URD is a distribution configuration in parts of the downtown area with primary cables, switches and distribution transformers placed underground while secondary voltage connections remain overhead. The primary feeders consist of a main-loop, sub-loop and branch circuits. Customers are supplied directly from either the sub-loops or branch circuits, which allow sectionalisation (i.e. the ability to use switching to segment a feeder into sections) within the feeder to minimize interruptions when work is required, or to allow partial restoration of the feeder under fault conditions. Figure 18 shows a picture of a typical installation.



Figure 18: Typical Layout of Underground Residential Distribution

Toronto Hydro's underground system consists of approximately 4,000 underground switches, 30,800 underground transformers, 10,300 cable chambers, and 6,100 circuit-kilometres of underground primary and 6,800 circuit-kilometres of underground secondary cables.

Asset management activities related to the underground distribution system focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies, managing system performance with respect to reliability and power quality, and asset stewardship over the assets' lifespan.

Figure 19 provides the age demographic distribution of major underground assets. The age of XLPE cables represents a significant risk to reliability in the 2025-2029 rate period and must be prioritized.[55] Moreover, as of 2022, over 20 percent of underground transformers are approaching their useful life of 30 years, over 20 percent of cable chambers are approaching their useful life of 65 years and approximately 80 percent of cable chamber roofs are at or approaching their useful life of 25 years. Without proactive intervention, Toronto Hydro projects that the percentage of

[55] Exhibit 2B, Section 6.2.

underground assets having reached or exceeded useful life will increase from approximately 20 percent to 40 percent by 2029 for underground transformers, from 20 percent to 31 percent by 2029 for cable chambers, from 80 percent to 87 percent for cable chamber roofs.

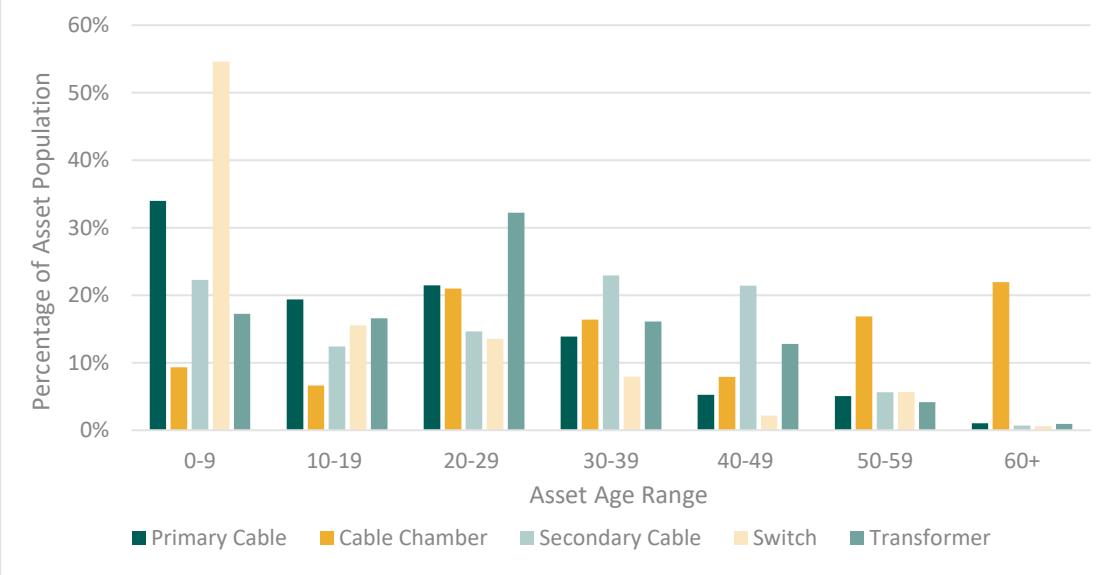


Figure 19: Underground Assets Age Demographic as of 2022

Underground switches, underground transformers and cable chambers are major underground asset classes for which Toronto Hydro performs an ACA. As shown in Figure 20, approximately 9 percent of Toronto Hydro's underground switches, 7 percent of underground transformers and 25 percent of cable chambers have at least moderate deterioration (i.e. HI3, HI4, and HI5) as of 2022. With over 2,000 cable chambers in HI3 condition, over 450 in HI4 condition, and 130 in HI5 condition (i.e. "end of serviceable life"), cable chamber replacement will continue to be a significant driver of both reactive and planned investment through 2029.

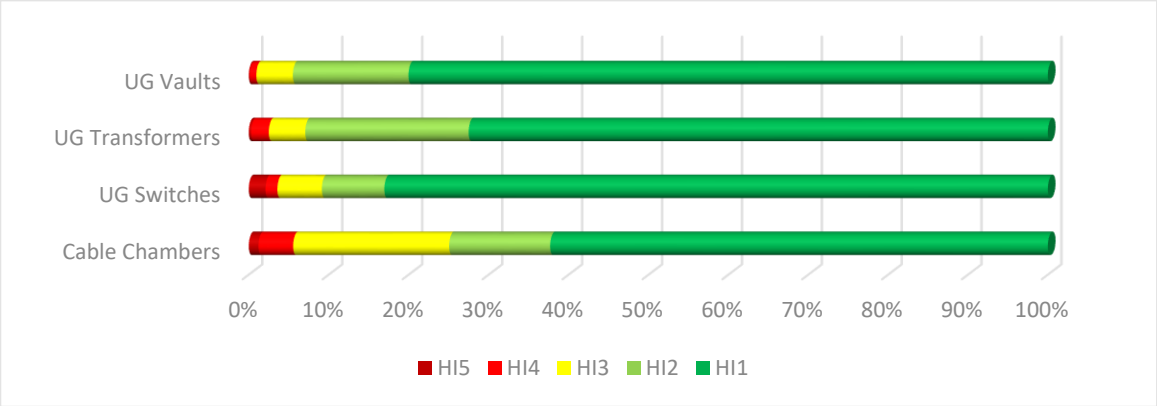


Figure 20: Asset Condition Assessment of Underground Assets as of 2022

Other key asset management performance measures that are relevant to the underground system include:

- **Oil Deficiencies:** Between 2020 to 2022, Toronto Hydro found, on average, 420 underground transformers with oil deficiencies per year. Assets replaced in the Underground System Renewal programs and Reactive Capital program will include assets exhibiting oil deficiencies found during inspections.

- **Priority Deficiencies:** The underground distribution system includes many below-grade vaults and cable chambers. The assets housed within them include cables, splices, joints, ducts, vents, hatchways, sump pumps, transformers, and switches. From 2019 to 2022, Toronto Hydro issued more than 25,000 work requests to address failing or failed underground assets. In 2022 alone, Toronto Hydro identified 496 P1, 1,677 P2, and 6,782 P3 priority deficiencies on the underground system.

- **PCBs:** Toronto Hydro has various types of underground transformers (e.g. submersible, padmounted, vault, and network), which can potentially contain PCB contaminated oil. Toronto Hydro plans to continue the replacement of the remaining underground transformers that are known to contain, or are at risk of containing, PCB-contaminated oil, by 2025, predominantly through the Underground System Renewal programs (Section E6.2 and E6.3). If sub-standard conditions are found during inspections, replacements may be done through the Reactive and Corrective Capital program as well.

D2.2.2.1 Underground Legacy Equipment

1. Direct-Buried XLPE Cable

Cables are the single greatest contributor to defective equipment caused outages on Toronto Hydro's system, contributing on average 146,000 CHIs annually from 2013 to 2022. The underground system in the Horseshoe area consists of 666 circuit-kilometres that are direct-buried cable and direct-buried cable in duct, of which 286 circuit-kilometres are direct-buried XLPE cable. Approximately 73 percent of direct-buried cable has reached or is past its useful life as of 2022. Toronto Hydro has already begun to see deterioration in underground system reliability performance in recent years, and the utility expects that a failure to proactively address this aging asset group will have worsening impacts on outages caused by defective equipment failures.

These cables are susceptible to outages due to direct exposure to environmental conditions. "Water treeing" is the most significant degradation process for XLPE cable, and starts with moisture penetration into the cable insulation in the presence of an electric field. These "trees" are microscopic tears within the dielectric. Over time, continuous seepage of moisture into the insulation combined with electrical stress allows ions from the conductor to migrate into the microscopic tears. These tears then become carbonized and form electrical trees. Once this final stage of water treeing is reached, the cable quickly fails due to internal short circuits that occur between the primary conductor and the neutral shield on the outside of the cable insulation. Figure 21 depicts the internal short circuit that occurs once electrical trees are formed in the dielectric insulation. Figure 22 illustrates field and laboratory samples of microscopic voids bubbles) and damage to the insulation.

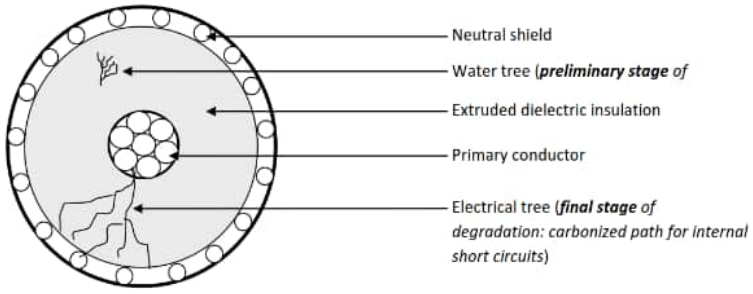


Figure 21: Cable Failure due to Electrical Treeing



Figure 22: Field and Laboratory Sample of Microscopic Voids and Damage XLPE Insulation

There is an immediate need to address the issues associated with direct-buried XLPE type cables so as to maintain system reliability for current and future customers in the Horseshoe area of Toronto. For further information, please see the Underground System Renewal – Horseshoe Program.[56]

2. Underground Lead Cable (PILC and AILC)

The majority of the cable in Toronto Hydro's downtown underground system is of two types: Paper-Insulated Lead-Covered ("PILC") and Asbestos-Insulated Lead-Covered ("AILC"). These cables are typically found at busy intersections beneath the sidewalks and roads of Toronto's downtown core. PILC cables are used as 13.8 kV primary cables, while AILC cables are used as secondary cables rated at 600 V. AILC cable is typically found on the secondary network 120/208 V and 240/416 V systems. Approximately 51 percent or 985 circuit-kilometres of Toronto Hydro's downtown primary system consists of PILC cable, whereas 49 percent or 176 circuit-kilometres of all secondary cable in the downtown network system consists of AILC cable.

Historically, utilities installed lead cable to take advantage of its reliability and compact design. However, over time, many utilities encountered environmental and health and safety issues with these cables. The industry has moved away from using these cables and for a number of years, there has been only one supplier remaining in the market for PILC (with none for AILC). Due to the supply risk (and the aforementioned environmental and safety risks), Toronto Hydro has avoided installing new lead cable for a number of years. Other utilities have taken a similar approach. As time passes,

[56] *Ibid.*

the number of individuals in the industry with the expert skillset required to work on lead cable in the field continues to diminish. Approximately 58 percent of all PILC cables and 93 percent of all AILC cables in the system are more than 30 years old. Toronto Hydro is continuing its proactive replacement of lead cables and plans to remove approximately 5.3 percent of 176 km AILC cable and 3.5 percent of 985 km PILC cable between 2025 to 2029. This is discussed further in the Cable Renewal segment of the Underground System Renewal – Downtown program.[57]

D2.2.2.2 Underground Assets Failure Characteristics

Table 3 provides a brief overview of the failure modes and impacts of underground asset failures.

Table 3: Underground Asset Failure Modes

Asset	Failure Mode	Effects
Underground Cable	a) Insulation degradation (eg. water trees). b) Carbon tracking in PILC cable paper insulation due to absence of oil medium (oil leak). c) Degradation due to age (cracked or degraded jacket).	a) Insulation breakdown and electrical fault. b) Impregnating oil dries up, cable overheats, degrading the insulation. c) Water ingress, corrosion of the metallic shield, penetration into the insulation (potentially causing water trees).
Submersible Transformers	a) Oil Leak. b) Corrosion of tank. c) Gasket deterioration due to age. d) Corroded secondary terminations (compression or bolted lugs).	a) Transformer cooling and insulating properties are diminished, electrical fault may occur. b) Oil leaks, transformer cooling and insulating properties are diminished; may result in internal components damage and electrical fault. c) Oil leaks, ingress of moisture may occur, transformer cooling and insulating properties are diminished. d) This failure mode can arise due to a flooding or contamination. Results in the secondary termination failure.

[57] Exhibit 2B, Section E6.3.

Asset	Failure Mode	Effects
Padmounted Transformers	a) Corroded enclosure. b) Enclosure has been exposed to moisture (ground water, moisture ingress). c) Contaminated or damaged insulating barriers. d) Degradation due to age/contamination. e) Gasket deterioration with age.	a) Public or animal access to the transformer. Transformer could be damaged or cause injury to the public. b) Improper ventilation, inadequate air flow, tracking, and flashover. Safety risks heighten as the transformer is located next to sidewalks. c) Tracking on the insulators, and eventual flashover. d) Insulation breakdown and electrical fault. e) Small traces of oil leaking. Ingress of moisture may occur; transformer cooling and insulating properties are diminished.
Underground Switches (Padmounted)	a) Loss of insulating properties due to contamination, moisture ingress, or humidity. b) Switch has been exposed to moisture (ground water, moisture ingress.	a) Flashover - presents a safety concern as the switch is located next to sidewalks. b) Improper ventilation and inadequate air flow create tracking and possible flashover and failure, presenting a safety concern as the switch is located next to sidewalks.
Cable Chambers	a) Collapsed duct. b) Excessive water leakage through ducts. c) Structural degradation at the neck. d) Cable racks and arms rust and deterioration. e) Cracks, spalling, delamination of concrete in walls or roof; corrosion in rebars.	a) Hotspot depending on the extent of damage, cable damage. Worst case can involve damage to connected equipment, posing a safety risk to the public. b) Degradation of walls, floor, corrosion to the racks. c) Access is restricted. If chamber is on roadway, a sinkhole may occur, posing a safety risk. d) Racks fall off the wall causing the cable or joint to be unsupported and possibly cause damage to other cables, posing a potential safety risk. e) Chunks of concrete falling down, structural collapse, wall or roof failure, and/or fire, posing a safety risk.

D2.2.3 Secondary Network System

The secondary network (or "network") system, which is predominantly found in the downtown Toronto area, was initially installed in the early-to-mid 1900s to improve reliability for critical loads. As the system evolved, it became recognized for its ability to efficiently serve medium sized loads in areas that have high density and small and narrow sidewalks. Such areas do not have sufficient space above grade for distribution infrastructure. The network system consists of interconnected low-voltage secondary cables, which are installed in a grid (also known as mesh) configuration. These grids are supplied by multiple network units housed in network vaults fed by different feeders, and offer additional redundancies that the typical overhead and underground distribution systems do not. Should a single primary feeder experience an outage, network connected customers will continue to be supplied from alternate primary circuits that continue to feed into the secondary grid. In this way, the secondary network system offers greater reliability than other underground or overhead systems.

At the heart of the network system are network units. The main difference between a network unit and a conventional radially-configured transformer is the addition of a network protector. The network protector prevents power from the secondary network grid from back feeding to the primary side. Should a fault occur on the primary side of the network unit, the network protector will automatically trip (i.e. open the switch to interrupt the current backfeeding into the fault). This protects the primary feeders from the fault, and allows the remaining network units to keep the secondary network grid up and running.

Though the network system is better at handling normal failure scenarios, in the case of a catastrophic failure such as a vault fire, the entire secondary network grid that is connected to the vault must be interrupted to allow emergency responders to extinguish the fire safely. In such a scenario, all connected customers are interrupted. To avoid these scenarios, network equipment must be kept in good condition to prevent vault fires or other failures from occurring. This is one of the reasons why Toronto Hydro takes a proactive approach to the maintenance and replacement of network units at risk of failure. Figure 23 below shows a typical submersible network unit.



Figure 23: Submersible Network Unit

The vaults that house network equipment are also an important component of the network system and must be maintained. If the integrity of a vault is compromised, the equipment inside the vault can be damaged, or the vault may become unsafe for employees. Unsafe conditions mean that crews are unable to complete any maintenance or repairs. Moreover, cracking and structural shifting of vault roof structures pose trip and fall hazards, and complete failure of roof elements can expose the public to energized electrical equipment. As of 2022, approximately 5.5 percent of network vaults and approximately 75 percent of network vault roofs past their useful life.

Figure 24 provides the age demographic distribution of major network assets. As of 2022, approximately 21 percent of network units and approximately 6 percent of network vaults are at or approaching their useful life of 35 years and 60 years, respectively. Without intervention, Toronto Hydro projects that the percentage of network units having reached or exceeded useful life will increase from 21 percent to 27 percent, and the percentage of network vaults will balloon from 6 percent to 26 percent by 2029. Non-submersible network units are one asset type that Toronto Hydro plans to target specifically. These units are susceptible to water ingress and elevated failure risks even when in good condition. As such, they need to be replaced to reduce the failure risks on

the network system. Replacements will occur on a prioritized basis considering factors such as condition, as discussed in Network System Renewal program.[58]

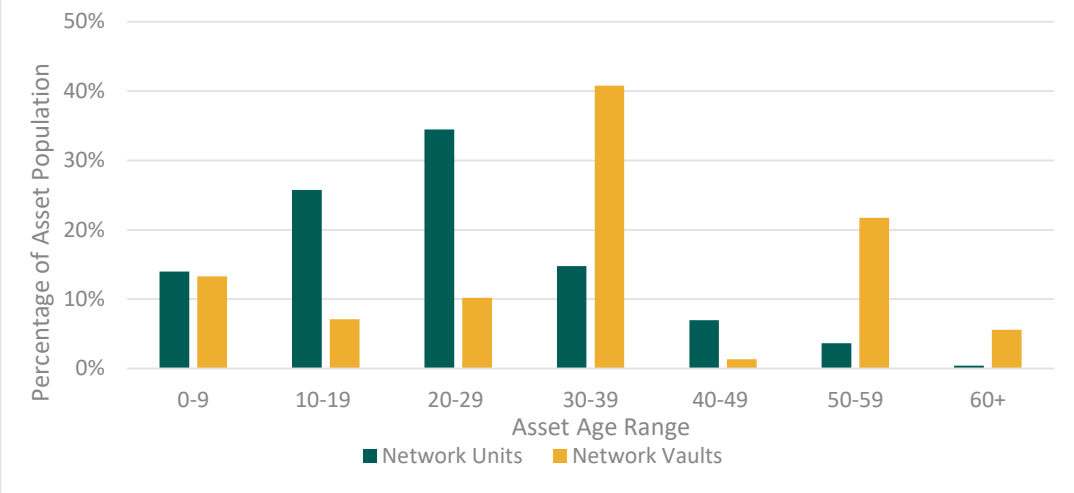


Figure 24: Network Assets Age Demographics as of 2022

Toronto Hydro performs an ACA for network transformers, network protectors, and network vault civil infrastructure. ACA results show that approximately 6 percent of network transformers, 29 percent of Toronto Hydro's network vaults and 15 percent of network protectors have at least moderate deterioration as of 2022.

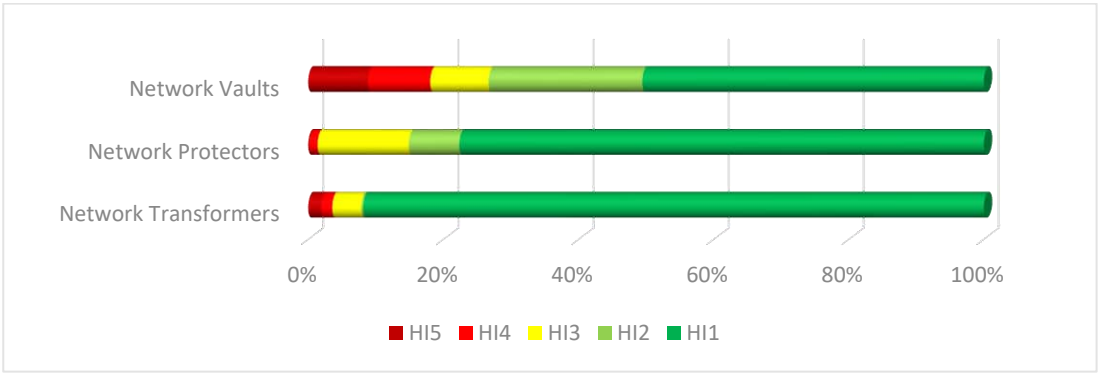


Figure 25: Asset Condition Assessment of Secondary Network Assets

Asset management activities related to the network focus on asset stewardship over asset life spans, mitigating environmental and safety risks, responding to system events and equipment deficiencies,

[58] Exhibit 2B, Section E6.4.

and managing system performance with respect to reliability and power quality. The following summarizes what this means relative to the measures set out in Table 2:

- **Oil Deficiencies**: Network transformers are the only asset group in the network system affected by this outcome. During the 2020-2022 period, Toronto Hydro found on average 47 oil deficiencies per year for network transformers. Assets replaced in the Network System Renewal Program and Reactive Capital Program will include assets exhibiting oil deficiencies found during inspections.
- **Priority Deficiencies**: Please see the discussion related to priority deficiencies under section D2.2.2 above as deficiencies related to the secondary network are generally tracked with all other underground deficiencies.

D2.2.3.1 Network Legacy Equipment

During the 2020-2024 rate period, Toronto Hydro has removed network legacy equipment, such as Automatic Transfer Switches ("ATS") and Reverse Power Breakers ("RPB"). Toronto Hydro continues to replace non-submersible network protectors as part of Network System Renewal program,[59] through 2029.

1. Eliminating Network Units with Non-Submersible Protectors

Although network units are replaced based on condition, another consideration that informs investment decisions is the presence of "non-submersible" designs which are characterized by ventilated or semi-dust-tight protectors. These units are susceptible to water ingress and elevated failure risks even when in good condition. The failure modes for network units are flooding and internal transformer failure. Flooding can damage the protector mechanism, causing the unit to short, or fail to operate, whereas transformer failure can result from overloading, low oil, moisture ingress, or age-related insulation deterioration. Toronto Hydro is continuing to replace non-submersible protectors with submersible protectors that feature watertight cases to help address flooding risks as part of the Network System Renewal program.[60] Figure 26 below shows the difference between a ventilated network unit and a submersible network unit, where the black protector identified is of a submersible design.

[59] *Ibid*.
[60] *Ibid*.



Figure 26: A ventilated Network Unit (Left) and a Submersible Network Unit (Right)

D2.2.3.2 Network Assets Failure Characteristics

Low voltage secondary distribution networks are susceptible to similar failure modes as other underground distribution systems; however, the consequences of failure to operate and network customer service reliability are often different, as outlined in Table 4 below.

Table 4: Network Asset Failure Modes

Asset	Failure Mode	Effects
Underground Primary Cable	a) Insulation degradation. b) Jacket damage. c) Mechanical stresses compromising geometry of cable. d) Multiple primary cable outages occur simultaneously.	a) Internal arc occurs; station circuit breaker trips causing feeder outage. b) Internal arc occurs; Network vaults continue to operate under contingency, with possible equipment overloads. c) Internal arc occurs; dual radial customers supplied by faulted feeder are interrupted until switched to alternate feeder. d) Equipment overloads may force the Control Room to drop the entire network, resulting in widespread customer interruptions.

Asset	Failure Mode	Effects
Underground Secondary Cable	a) Insulation degradation. b) Failed cable conductor contacts another conductor. c) Self-cleared secondary cable faults are not identified.	a) Arcing fault occurs. b) "Solid" fault occurs and may spread to adjacent cable junctions before self-clearing, resulting in interruptions to a small number of customers. c) Surrounding secondary cables may overload and eventually fault, resulting in interruptions to multiple customers.
Network Transformer	a) Insulation degradation due to age/contamination. b) Low or no oil level. c) Corrosion of the steel tank or gasket failure. d) Electric interlock stuck open and fails to prevent movement of the primary switch handle while transformer secondary is energized.	a) Internal insulation failure leading to an increased likelihood of catastrophics transformer failure due to the fact that the insulation characteristics are lost. b) Insulation fails to provide dielectric and mechanical insulation to the windings and may lead to major internal electrical fault in transformer or primary switch. c) Results in insulating oil leakage, which may cause contamination of the surrounding environment. d) Operator can move the handle without interference on an energized feeder; possibility of fatality.
Network Protector	a) Debris, salt, and moisture collect on the top of a network protector. b) Vault flooding allows water to enter the protector. c) Breaker mechanism gummed up, seized or broken. d) Motor fails (all possible causes), broken springs, broken close mechanism or motor fuse blown.	a) Causes an electrical short in protectors which typically result in vault fires, with the possible destruction of all electrical equipment in the vault. b) The mechanism fails and possibility of an electrical short; may result in permanent damage to the mechanism. c) Circuit breaker fails to close when instructed by relay. Motor fuse blows or motor may burn out, and excessive wears of moving parts. d) Motor assembly fails to provide mechanical force to charge springs that trip the circuit breaker open; moderate localized damage.

D2.2.4 Stations

Toronto Hydro's distribution system receives its transmission supply from Hydro One Networks Inc. ("Hydro One") at voltages of 230 kV, 115 kV at Transformer Stations ("TS"). In general, Toronto Hydro owns all of the medium voltage equipment up to the circuit breaker at a TS, subject to certain differences in ownership structures for each TS's equipment. Figure 27 below shows the ownership of station equipment and their associated demarcation point. In some areas, the voltage may be further stepped down to 13.8 kV or 4.16 kV at Municipal Stations ("MS") which are wholly-owned by Toronto Hydro.

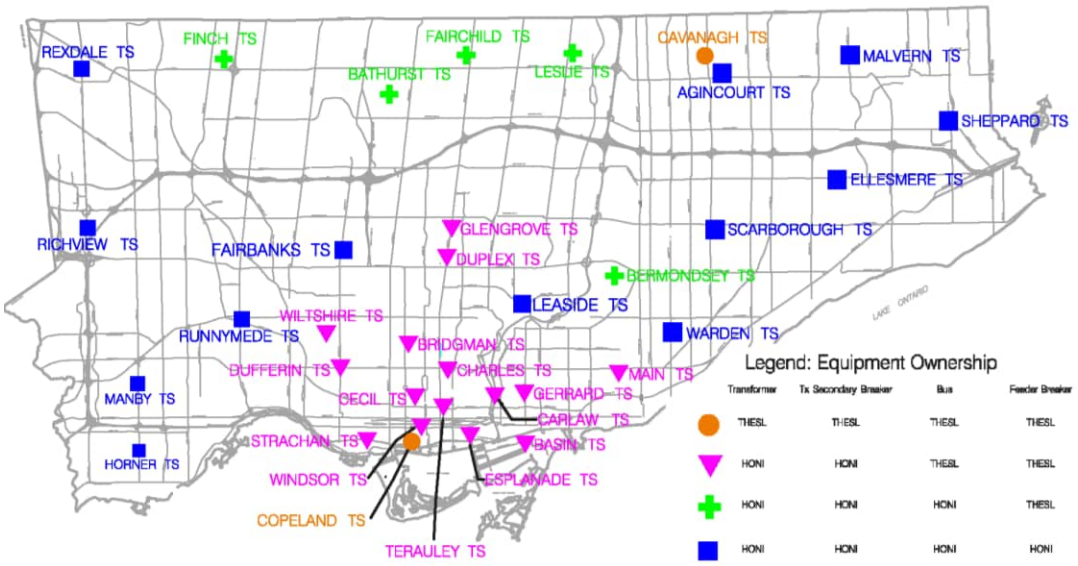


Figure 27: System Diagram of Station Components Ownership

Toronto Hydro is supplied by 37 TSs, including Copeland TS (as shown in Figure 27 above), and owns approximately 139 MSs. Within these stations, Toronto Hydro owns and operates approximately 200 switchgear, 175 power transformers, 40 outdoor circuit breakers, 80 remote terminal units ("RTUs"), and 170 direct-current ("DC") battery systems.

Feeders generally have at least one normally-open tie to another feeder to ensure there is a restoration option in case of an outage, or if planned work is required.[61] In the Horseshoe area, there are typically many normally open ties between feeders fed from the same bus or feeders fed from a

[61] Secondary network systems and pilot-wire/line-differential based systems operate with multiple supply points in parallel and do not require a normally open tie.

different bus or station. This allows for increased operational flexibility and the ability to restore some load in the event of a bus or station outage. Feeders in the downtown area rely on a radial configuration with normally open ties to feeders supplied from the same bus, but never have ties with feeders fed from other stations. This configuration limits the restoration options for these feeders in case of a station outage. Toronto Hydro does look for opportunities to build contingency ties between different downtown stations where economical. For example, Toronto Hydro invested $5.5 million to install interstation switchgear ties between Copeland TS and Windsor TS between 2020-2022. The Copeland to Windsor ties served three purposes: contingency support to prevent extended power outage in the downtown core, provide facilities to offload Windsor station switchgear to enable switchgear upgrade projects, and implement long-term downtown contingency ties between these two stations.

Asset management activities related to stations focus on mitigating environmental and safety risks, responding to system events and equipment deficiencies when they are identified, managing system performance with respect to reliability and power quality, and asset stewardship over the assets' life span.

Figure 28 provides the age demographic distribution of major station assets. Toronto Hydro's critical stations asset base is of an increasingly advanced age on average. As of 2022, 42 percent of Toronto Hydro's switchgear, 51 percent of power transformers, 42 percent of outdoor breakers, and 55 percent of DC battery systems are operating at or beyond their useful life. Without proactive intervention, the proportion of station assets operating beyond their useful life will continue to increase, contributing to already elevated asset failure risks for highly critical assets. Station asset renewal is complex and entails considerable operational constraints which limit the achievable level of renewal in a given year. Consistent investment and renewal work is needed to sustainably mitigate and control the failure risk presented by these assets.

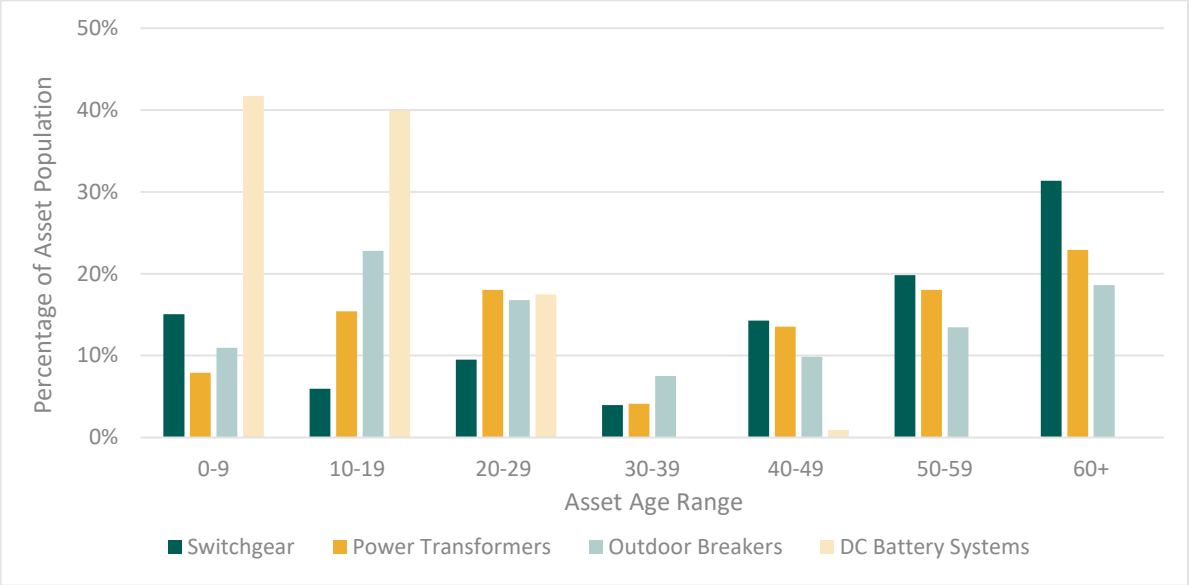


Figure 28: Stations Assets Demographics as of 2022

Within its stations asset classes, Toronto Hydro performs ACA analysis on its power transformers as well as various types of its circuit breakers. With the exception of standalone outdoor circuit breakers, circuit breakers are contained inside one of Toronto Hydro's switchgear and are considered components of their parent switchgear. Therefore, ACA performed on breakers helps serve as a proxy for switchgear condition.

Figure 29 shows that 98 percent of Toronto Hydro's air-blast circuit breakers, 93 percent of its oil circuit breakers, 39 percent of KSO oil circuit breakers, 12 percent of station power transformers, 78 percent of air-magnetic circuit breakers, 5 percent of SF_6 circuit breakers, and 1 percent of vacuum circuit breakers show signs of at least moderate deterioration. Accordingly, renewal of switchgear containing air-blast circuit breakers and oil circuit breakers are heavily targeted in the Stations Renewal Program.[62] Similarly, standalone outdoor KSO circuit breakers are prioritized for renewal in the proposed program.

[62] *Supra* note 46.

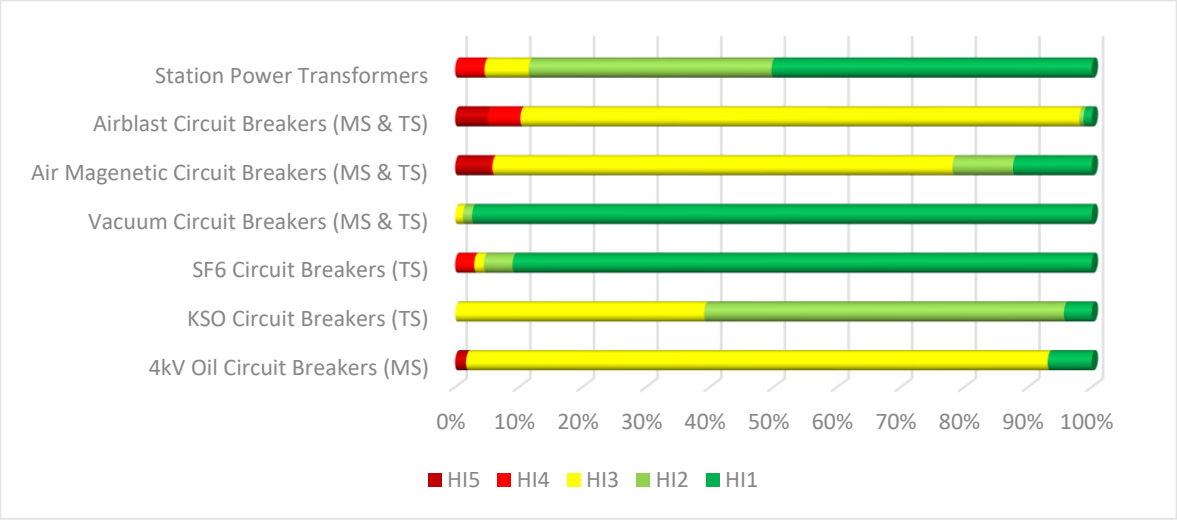


Figure 29: Asset Condition Assessment of Station Assets

Other key asset management performance measures that are relevant to the stations include:

- **Oil Deficiencies**: During the 2020-2022 period, Toronto Hydro found on average 12 station transformers with oil deficiencies per year. Assets replaced in the Station Renewal program,[63] and Reactive and Corrective Capital program will include assets exhibiting oil deficiencies found during inspections.[64]

- **Priority Deficiencies**: Station assets include power transformers, circuit breakers, switchgear, SCADA systems, relays, batteries and chargers, SCADA telemetry or control equipment, station alarms, DC panels, station heating, ventilation systems and sump pumps, which are installed across Toronto Hydro's 141 MSs and 37 TSs. From 2019 to 2022, Toronto Hydro issued more than 2,300 work requests to address failing or failed station assets.

D2.2.4.1 Stations Legacy Equipment

Toronto Hydro has many legacy station assets currently in operation, which are being phased out through capital renewal plans, as discussed in the Stations Renewal Program.[65]Legacy assets include: (i) non-arc-resistant brick and metalclad switchgear; (ii) air-blast, oil, KSO oil, and air magnetic circuit

[63] *Ibid*.
[64] *Supra* note 37.
[65] *Supra* note 46.

breakers; (iii) DACSCAN MDO-11, D20 ME, D20M++, and MOSCAD RTUs; electromechanical pilot-wire relays; and (iv) copper communications cable.

Oil and KSO oil circuit breakers are legacy assets which also present several risks including a safety risk to Toronto Hydro personnel, risk of collateral damage to adjacent station equipment, and in some cases a safety risk to the public or an environmental risk. Both oil and KSO oil circuit breakers contain oil, which may catch fire or even explode upon failure of the asset. KSO oil circuit breakers can also contain PCBs. By the end of 2029, Toronto Hydro plans to replace all remaining oil KSO circuit breakers with vacuum type breakers.

D2.2.4.2 Stations Major Assets Failure Characteristics

Table 5 below provides a brief overview of the failure modes and impacts of station asset failures. Typically, failure of these assets results in power outages to all customers supplied by the affected station bus, or even the entire station. In addition to power outages, station asset failures can lead to extensive and irreparable damage.

Table 5: Station Assets Failure Modes

Asset	Failure Mode	Effects
Switchgear	a) Control Cable lose connection due to breaker operation, auxillary socket broken or auxillary socket misalignment. b) Broken/cracked interphase barrier or insulators; dirt or debris on insulators. c) Total cable failure (all possible causes). d) Dirt or debris on busbar conductors.	a) Inability to monitor and operate the breaker via protection and control, and May result in an arc flash. b) Possible flashover, and safety issue involved with the failure due to the explosion if protection fails. c) Loss of power due to relay protection sensing the cable fault and tripping the breaker. d) May lead to overheating and melting of the busbar; flashovers might take out the whole bus and result in a major station shutdown.

Asset	Failure Mode	Effects
Power Transformer	a) Defective bushing gasket (Oil filled bushing). b) Paper insulation failure. c) Defective breather (all possible causes). d) Control circuit or motor failure of onload tap changer.	a) Oil leaks from the bushing may lead to loss of insulation, a short-circuit and eventually an outage. b) Power outage to entire station due to low or fluctuating voltage, or internal fault. c) Moisture enters through breather; moisture ingress will decrease insulation value of oil, eventually causing dielectric breakdown of oil. Flashover may occur. d) Failure to adjust output voltages to desired secondary voltages.
KSO Circuit Breaker	a) Worn latching mechanism or broken lifting rod. b) Breaker fails to open on a fault, no internal arcing occurs. c) Bushing failure causes flashover. d) Oil fails to insulate the live parts within the tank and also extinguishing the arc.	a) Operating mechanism fails to facilitate sequential movement of components to close the breaker; customers will be without power until transferred to alternate supply. b) Power outage to entire station switchgear. c) Power outage to entire station switchgear; flashover damages breaker. d) Breaker opens, but arc remains causing equipment damage and loss of bus. Breaker may rupture causing injury to workers in the vicinity, releasing fumes and oil into the environment and may cause damage to adjacent equipment.
DC Battery System	a) DC charger system fails. b) DC battery fails.	a) All station protection and control capability is lost after 8 hours when the battery has depleted. Station is then rendered inoperable. b) Station is noncompliant with Section 10.7.1 of the Transmission System Code. Should either the DC charger system or station service supply be out of service, then the station is rendered inoperable.

D2.2.5 Metering

Toronto Hydro utilizes several different meter types in order to ensure the reliable measurement of electricity acquired by the utility through the provincial transmission system and distributed to its customers. These include: (i) Residential, Small Commercial and Industrial; (ii) Interval; (iii) Suite Metering; and (iv) Wholesale.

- **Residential/Small Commercial & Industrial**: Toronto Hydro must continually upgrade its residential metering system to ensure that it continues to receive vendor support and is capable of enabling features on newer generation meters. The bulk of residential and small commercial and industrial meters have seals expiring between 2024 and 2026. As part of its AMI 2.0 initiative, Toronto Hydro plans to replace residential and small commercial and industrial meters with next generation meters.[66]

- **Interval**: Toronto Hydro plans to upgrade the Interval Metering system, ITRON Enterprise Edition ("IEE") to continue to successfully meter Toronto Hydro's interval metered customers (those with a demand of 50 kW or above). The upgrade is scheduled for completion by 2025. In 2017, Toronto Hydro had 7,000 Interval metered customers on IEE. In 2020, this increased to 14,000 customers due to the decommissioning of the 2G network in Toronto, and the subsequent conversion by Toronto Hydro of its 2G meters to newer 4G technology. By the end of 2022, Toronto Hydro's interval metered customers reached 17,000 customers due to conversion of various customer groups from manual reads and manual billing.

- **Suite Metering**: These meters represent the individually metered multi-residential buildings. The utility is legally obligated to provide suite meter installation services. Toronto Hydro offers this service in a competitive environment, and is also the provider of last resort in the event that the condominium chooses not to secure a third-party meter service provider. Currently, there are approximately 94,000 suites that are individually metered by Toronto Hydro and about 3,000 multi-residential buildings that are metered by one bulk meter. Toronto Hydro plans to continue to offer its suite metering services to new customers along with retrofit upgrades over the 2025-2029 rate period.

- **Wholesale**: Toronto Hydro plans to upgrade its wholesale revenue meters at all applicable wholesale metering points to comply with the metering standards mandated by the

[66] Exhibit 2B, Section E5.4.

Independent Electric System Operator ("IESO") Market Rules and Measurement Canada during the 2025-2029 period. These meters are installed at each of Toronto Hydro's transfer stations, and are used by Toronto Hydro to purchase power and to validate consumption with the IESO.

Toronto Hydro must maintain its fleet of meters in order to comply with both Measurement Canada and OEB mandates such as billing accuracy, estimated bills, and meter seals. In this regard, Toronto Hydro re-seals batches of meters to ensure accuracy and reactively replaces failed or non-communicating meters to ensure compliance. Toronto Hydro's meter population is aging with the majority of the residential and small C&I meter population reaching and exceeding 15 years of age during the 2025-2029 rate period. By 2025, approximately 90 percent of Toronto Hydro's residential and small commercial meters will surpass their useful life. To address this risk of failure, Toronto Hydro intends to replace its full population of first-generation residential and small C&I meters with next generation meters and supporting network infrastructure.

D2.2.5.1 Metering Major Assets Failure Characteristics

Table 6 below provides a brief overview of the failure modes and impacts of metering asset failures.

Table 6: Metering assets failure mode

Asset	Failure Mode	Effects
Energy Meter	a) Communications Failure	a) Bills must be estimated or meter manualy read
Instrument Transformer	b) Device Failure	b) Meter reads would be incorrect due to failed instrument transformers

D2.3 System Utilization

Toronto Hydro completes an annual System Peak Demand Forecast for station bus capacity to plan for short- and long-term load growth, additional capacity requirements to serve customers, and contingency scenarios such as planned work or loss of supply. This peak demand forecasting process is further explained in Section D4.1.1 and Section D3.3.1.1. To prevent system overloading which may lead to asset failures, the peak utilization of a bus should not reach or exceed 100 percent of its

rated capacity for extended periods of time.[67] Bus capacity rating is determined based on the ratings for all of its associated equipment and a Limited Time Rating for upstream equipment provided by Hydro One. [68] Forecasting is performed at the bus level.

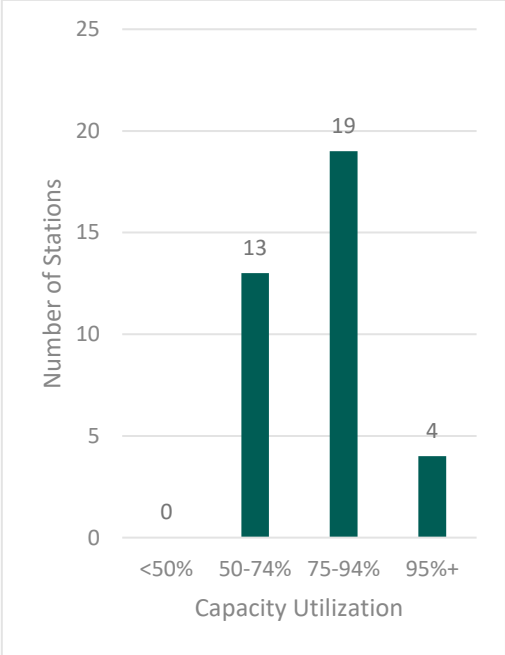


Figure 30: Forecasted Station Loading in 2025

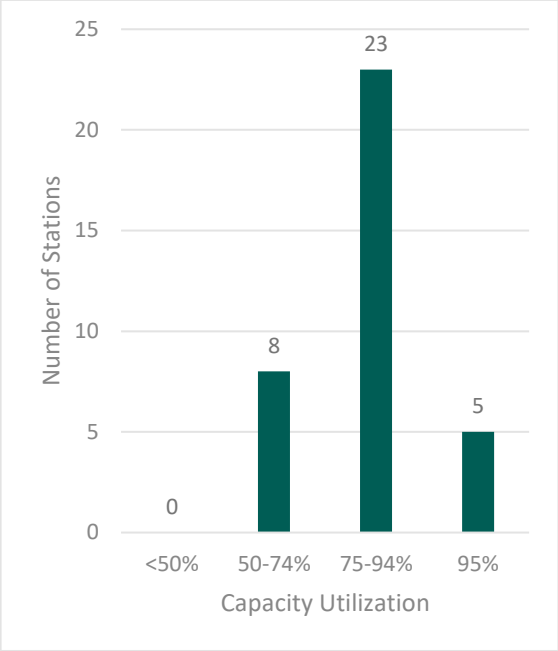


Figure 31: Forecasted Station Loading in 2030

From a station capacity standpoint, by 2025, 64 percent of Toronto Hydro stations will experience loading of 75 percent or higher, with four stations that are forecasted to be near capacity. By 2030, Toronto Hydro anticipates that the aforementioned percentage will increase to 78 percent, with five stations expected to exceed their capacity. Operating stations at 100 percent capacity would severely

[67] For planning purposes, a 95 percent loading threshold is used for the downtown region, while a 100 percent bus loading threshold is used for the Horseshoe. This difference in the threshold is due to the fact that there is more load transfer capabilities in the Horseshoe area than the downtown area so more time is required to make plans for downtown capacity constraints, than for Horseshoe capacity constraints. Further details of the load forecasting can be found in Section D3.1.2.1 Decision Support Systems as well as E7.7 Stations Expansion.

[68] Limited Time Rating ("LTR"): With respect to transformers, a limited time rating is a set of 15-minute, 2-hour, and 10-day MVA ratings determined by Hydro One in order to accommodate shorter time interval loading periods without causing equipment damage. All of Toronto Hydro's buses are supplied via at minimum two transformers operating in parallel. For bus capacity planning purposes, Toronto Hydro utilizes the 10-day LTR rating provided by Hydro One which is the maximum MVA the most limiting transformer can supply for a 10-day period with the other transformer out-of-service.

limit the utility's flexibility to manage abnormal system states (planned or unplanned). In a worst-case scenario, Toronto Hydro would be unable to maintain or replace a failing or failed asset.

More specifically, Toronto Hydro must also ensure that each of its stations has sufficient capacity to connect new or existing customers without sacrificing system reliability or operational flexibility for existing customers. Otherwise, extensive load transfers must be pursued through the Load Demand Program solely to free up the capacity needed to connect new customers without overloading a bus. Although this limit precedes station capacity, it is the primary driver for the need for extensive load transfers or station expansion projects so that new customer connections can be made.

To mitigate overloading at the stations and free up capacity to connect new large customers, Toronto Hydro analyzes each station's load forecast as well as available capacity in the area to resolve loading problems. Possible resolutions are to plan load transfers, upgrade existing components, or expand the station. A large number of limitations and considerations must be considered in implementing these solutions, including:

- incompatible system voltages (e.g. 27.6 kV vs. 13.8 kV);
- incompatible system types (e.g. radial versus looped, or overhead versus network);
- availability of civil infrastructure;
- availability of feeder positions;
- environmental or civil barriers (e.g. rivers, highways ravines); and
- relative cost between relief options.

Due to these various considerations, every station must be individually analyzed to determine an appropriate resolution.

On the feeder level, Toronto Hydro typically plans new customer connections or customer load increases by analyzing the area where the additional load requirements are emerging. Similar limitations and considerations at both the feeder level and station level must be accounted for in the planning process. This process is largely reactive given the significant uncertainty in forecasting feeder loading, because it is difficult to predict exactly where new loads will materialize and there are multiple feeders which can potentially connect new loads.

On the asset level, Toronto Hydro frequently reviews the system in areas of high capacity utilization or areas of poor reliability to determine what work can be undertaken to improve the system. It is difficult to monitor every asset in the system to ensure it is optimally utilized. Nonetheless, Toronto

Hydro has initiatives in place which will install new infrastructure and allow more assets to be closely monitored. Examples of such initiatives are network monitoring, stations control and monitoring replacements and new installations, and power transformer and switchgear replacements. These initiatives help prevent overloading which may cause premature equipment failure.

Stantec

CLIMATE CHANGE VULNERABILITY ASSESSMENT UPDATE

November 18, 2022

Prepared for:
Toronto Hydro-Electric System Limited

Prepared by:
Stantec

Project Number:
160925171

The conclusions in the Report titled Climate Change Vulnerability Assessment Update are Stantec's professional opinion, as of the time of the Report, and concerning the scope described in the Report. The opinions in the document are based on conditions and information existing at the time the scope of work was conducted and do not take into account any subsequent changes. The Report relates solely to the specific project for which Stantec was retained and the stated purpose for which the Report was prepared. The Report is not to be used or relied on for any variation or extension of the project, or for any other project or purpose, and any unauthorized use or reliance is at the recipient's own risk.

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Approved by:  — Digitally signed by Shippee, Norman Date: 2022.11.18 12:51:13 -05'00'

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Norman Shippee, Ph.D.

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Executive Summary

This Climate Change Vulnerability Assessment Update was conducted by Stantec to provide Toronto Hydro-Electric System Limited (Toronto Hydro) with updated climate parameters as described in the '2015 Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment', (AECOM and RSI, 2015: "the 2015 Study"). The main objective was to identify if any further work is required to update the adaptation actions recommended in the 2015 Study. The study uses updated climate projection data from the 6th Coupled Model Intercomparison Project (CMIP6), released along with the IPCC's 6th Assessment Report (AR6) in 2021, to estimate climate parameter probabilities. The two main tasks completed were to (1) update climate parameter probabilities and scores using CMIP6 data and scientific literature published since the 2015 Study; and (2) assess the materiality of the probability updates**,** by re-calculating the risk scores over the study period (from 2022 to 2050) following the PIEVC Protocol version 10 (Engineers Canada, 2011). Wherever possible, the same methods used in the 2015 Study were also used in this assessment.

To estimate the climate parameter probabilities, the complete ensemble of climate model outputs from the downscaled CanDCS-U6 dataset were used, and review of scientific literature, including the *Climate-Resilient Buildings and Core Public Infrastructure 2020* (Cannon et al., 2020) report was completed. A summary of the probability updates that resulted in a change to the probability scores is provided in the table below.

Climate Parameter	**Threshold**	**Frequency** (2030s)	**Probability** (Study Period)	**Probability Score** (Study Period)	**Probability Score Change** (2022-2015)
Daily Maximum Temperatures	Days > 40°C	0.08 (0 - 0.1)	90%	6	Decrease (-1)
Ice Storm/ Freezing Rain	25 mm ≈ 12.5 mm radial	-2.2% in 1/20yr ice accretion	96%	6	Decrease (-1)

Each combination of infrastructure asset class and climate parameter is referred to as an 'interaction'. The only climate parameters whose probability scores changed were 'days with maximum temperatures >40°C', and 'ice storms with >25mm of ice accretion', both of which decreased by 1. The updated probabilities resulted in material changes to the risk scores for 23 separate interactions (10 from daily maximum temperatures >40°C and 13 from Ice Storms >25mm), as summarized in the table below.

Climate Parameter	**Threshold**	**Study Report Year**	**Number of Interactions by Risk Class**		
			High	**Medium**	**Low**
Daily Maximum Temperature	40°C	2015	10	23	1
		2022	0	33	1
Ice Storm / Freezing Rain	25 mm ≈ 12.5 mm radial	2015	18	5	9
		2022	5	18	9

While the results show a slight decrease to the risk scores for these 23 interactions, the uncertainty in the climate projection data is high, therefore it is not recommended to relax the adaptation measures associated with extreme heat or freezing rain events from the 2015 Study.

Despite no change to the assigned probability scores, the annual frequency of high daily average temperatures >30°C (increase), heat waves (increase), and high nighttime temperatures (decrease) are all expected to change by >10% in the 2030s. The change is not material based on the approach applied. However, these climate parameters and their interactions with infrastructure asset classes may merit further study to identify whether the adaptation measures recommended in the 2015 Study report are sufficient to address the expected changes.



Acronyms / Abbreviations

AEP	Annual Exceedance Probability
AR5	5th Assessment Report
AR6	6th Assessment Report
BCCAQv2	Bias Correction/Constructed Analogues with Quantile delta mapping reordering
CanDCS-U6	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
CMIP5	Coupled Model Intercomparison Project 5
CMIP6	Coupled Model Intercomparison Project 6
ECCC	Environment and Climate Change Canada
EF	Enhanced Fujita Scale
GCM	Global Climate Model
IDF	Intensity-Duration Frequency
IPCC	Intergovernmental Panel on Climate Change
NTP	Northern Tornadoes Project
PCIC	Pacific Climate Impacts Consortium
PIEVC	Public Infrastructure Engineering Vulnerability Committee
RCP	Representative Concentration Pathway
RSI	Risk Sciences International
SSP	Shared Socioeconomic Pathway

1 Introduction

This study was conducted by Stantec Consulting Ltd. (Stantec) to provide Toronto Hydro-Electric System Limited (Toronto Hydro) with updated climate parameters as described in the '2015 Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment', (AECOM and RSI, 2015: "the 2015 Study"). The findings in this report are based on newly available global climate model (GCM) data from the 6th Coupled Model Intercomparison Project (CMIP6).

1.1 Background

A 2015 Study was conducted by AECOM and Risk Sciences International (RSI) using the latest climate projection information from the 5th Coupled Model Intercomparison Project (CMIP5) available at the time. The CMIP5 data was used to conduct a climate risk assessment using Engineers Canada's Public Infrastructure Engineering Vulnerability Committee's (PIEVC) assessment protocol (Engineers Canada, 2011) and estimate the vulnerability of Toronto Hydro's electrical distribution system to climate change and extreme weather events. The risk assessment included workshops, interviews, and an analysis of past climatic events to characterize the consequence of climate on Toronto Hydro's assets. Risk was evaluated by combining the climate hazard likelihood with the consequence information. The results of the 2015 Study were used to determine where infrastructure vulnerabilities to climate change were present and identify adaptation options to increase resilience.

In 2021, the IPCC released the 6th Assessment Report (AR6), as well as outputs from CMIP6, which represents an update to the latest climate change projection data from CMIP5. As one of the recommendations from the 2015 Study was to continue monitoring and evaluating climate change projection science, Toronto Hydro contracted Stantec to evaluate if the CMIP6 data will have a material change to the risk assessment set out in the 2015 Study.

1.2 Objective

The main objective of this assessment is to identify if any further study is required to update the adaptation actions recommended in the 2015 Study. This study uses updated climate projection data to estimate climate parameter probabilities and identifies whether these updates lead to materially different risk scores for Toronto Hydro's infrastructure asset classes over the study period.

1.3 Scope

The following scope of work has been completed as part of this assessment.

1. **Climate Parameter Probability Update:** Stantec collected downscaled CMIP6 global climate model data and reviewed scientific literature to estimate updated probability scores for the climate parameters found in the 2015 Study. This work aligns with Step 2, 'Data Gathering and Sufficiency' in version 10 of the PIEVC Protocol (Engineers Canada, 2011), as outlined in Section 1.2 of the 2015 Study.

2. **Materiality Assessment**: For those climate parameters where the probability score changed, Stantec re-calculated the study period risk score, to evaluate whether the change is material to each interaction. This aligns with Step 3, 'Risk Assessment', of the PIEVC Protocol, as outlined in Section 1.2 of the 2015 Study. We define a material change as one where the updated risk score fir an interaction crossed the risk tolerance thresholds from the 2015 Study.

Figure 1 outlines the work conducted in this study, and the nomenclature used to estimate climate-related risk to Toronto Hydro's assets. Beginning with a review of climate data and scientific literature, we estimated the relevant climate parameters and their probabilities over the study period, then translated them to probability scores. The updated probability scores were used to re-calculate and revise the risk scores for each of the infrastructure asset class and climate parameter interactions investigated in the 2015 Study. For consistency with the 2015 Study, the methods and thresholds used to estimate the probability and risk scores followed those outlined in version 10 of the PIEVC Protocol (Engineers Canada, 2011).

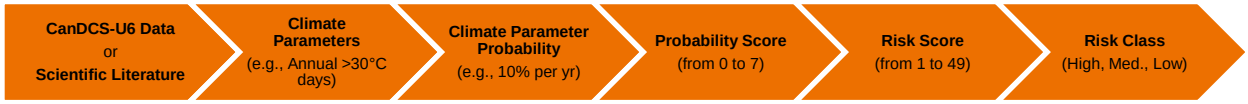

Figure 1: Project workflow

2 Climate Parameter Probability Update

This section describes the data and methods used to estimate updated climate parameter probabilities, and probability scores based on the updated climate data reviewed. The climate parameters investigated, and methods used to estimate probabilities align with the 2015 Study, except where noted otherwise.

2.1 Methodology

2.1.1 CLIMATE DATA

While the 2015 Study used coarse resolution (~200 km) climate projection information released along with the IPCC's 5th assessment report (AR5) – CMIP5, the Canadian Downscaled Climate Scenarios – Univariate (CMIP6), or CanDCS-U6, dataset produced by the Pacific Climate Impacts Consortium (PCIC) was used for this study. CanDCS-U6 is based on global climate model (GCM) outputs from the latest projections from the 6th Coupled Model Intercomparison Project (CMIP6), which were released in 2021. These represent a higher-resolution (~10 km grid) dataset that has been bias-corrected to align with a gridded historical weather reanalysis dataset (McKenney et al., 2011). The CanDCS-U6 dataset is delivered with daily resolution but is aggregated over 30-year time periods and across an ensemble of 26 models (Table 1) to estimate the range of climate parameter frequencies.

Table 1: Global Climate Models (GCMs) from CanDCS-U6 used in this study.

Model Name	Organization	Country	Organization Details
ACCESS-CM2	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
ACCESS-ESM1-5	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
BCC-CSM2-MR	BCC	China	Beijing Climate Center, China Meteorological Administration
CanESM5	CCCma	Canada	Canadian Centre for Climate Modelling and Analysis
CMCC-ESM2	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CNRM-CM6-1	CNRM-CERFACS	France	Centre National de Recherches Meteorologiques / Centre Europeen de Recherche et Formation Avancees en Calcul Scientifique
CNRM-ESM2-1	CNRM-CERFACS	France	Centre National de Recherches Meteorologiques / Centre Europeende Recherche et Formation Avancees en Calcul Scientifique
EC-Earth3	EC-Earth	Europe	EC-Earth Consortium
EC-Earth3-Veg	EC-Earth	Europe	EC-Earth Consortium
FGOALS-g3	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences

Model Name	Organization	Country	Organization Details
GFDL- ESM4	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
HadGEM3-GC31-LL	MOHC	UK	MetOffice Hadley Centre
INM-CM4-8	INM	Russia	Institute for Numerical Mathematics
INM-CM5-0	INM	Russia	Institute for Numerical Mathematics
IPSL-CM6A- LR	IPSL	France	Institut Pierre-Simon Laplace
KACE-1-0-G	NIMS-KMA	Korea	National Institute of Meteorological Sciences, Korea Meteorological Administration Republic of Korea
KIOST-ESM	KIOST	Korea	Korea Institute of Ocean Science & Technology Republic of Korea
MIROC-E2SL	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere
MIROC6	MIROC	Japan	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology
MPI-ESM1-2-HR	MPI-M	Germany	Max Planck Institute for Meteorology
MPI-ESM1-2-LR	MPI-M	Germany	Max Planck Institute for Meteorology
MRI-ESM2-0	MRI	Japan	Meteorological Research Institute
NorESM2-LM	NCC	Norway	Norwegian Climate Centre
NorESM2-MM	NCC	Norway	Norwegian Climate Centre
TaiESM1	AS-RCEC	China	Research Center for Environmental Changes, Academia Sinica
UKESM1-0-LL	Met Office - NERC	UK	Met Office Hadley Centre, Natural Environmental Research Council

Climate parameter probabilities from the 2015 Study relied on the Representative Concentration Pathway (RCP) 8.5 emissions scenario from CMIP5, which is largely consistent with the Shared Socioeconomic Pathway (SSP) 5-8.5 (from CMIP6) (Riahi et al., 2017). The RCP scenarios represent different levels of greenhouse gas (and other radiative forcings) that might occur by 2100 (e.g., RCP 8.5 represents an additional 8.5 Wm^{-2}). CMIP6 data is based on SSPs, which interpret how different levels of climate change mitigation (or lack thereof) could be achieved to reach specific greenhouse gas concentrations. While there is debate surrounding which pathway from CMIP6 is the most likely, the SSP5-8.5 pathway represents a high-emissions (more pessimistic) scenario (Riahi et al., 2017). Climate projection data from SSP5-8.5 was used for this analysis as a conservative estimate of future climatic conditions, and to maintain consistency with the 2015 Study.

The Toronto Hydro study area encompasses 21 grid cells from the CanDCS-U6 dataset (Figure 2). Stantec calculated applicable climate parameters across the entire 26-member ensemble of climate models, before calculating the mean, 10th and 90th percentiles over all models to produce most-likely, lower- and upper-end estimates for each parameter (see Appendix A). While recent studies (Hausfather et al., 2022) have shown that averaging the complete CMIP6 ensemble of models may overestimate future temperatures due to model bias, all model members of the CanDCS-U6 ensemble are bias-

corrected using the BCCAQv2 method (Cannon et al., 2015; Werner and Cannon, 2019), which corrects any potential biases to an observed historical dataset.

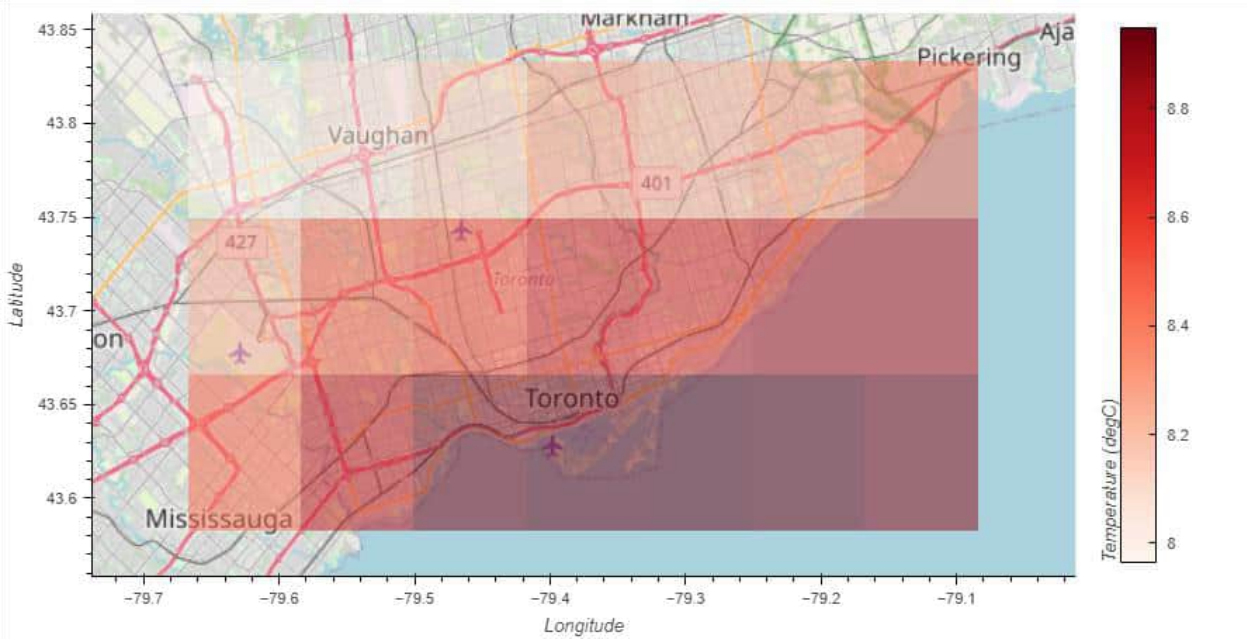

Figure 2: Mean air temperature over the baseline period (1981-2010), across the full CanDCS-U6 ensemble

Climate parameters that could not be calculated using the CanDCS-U6 data were investigated by conducting a literature review. The estimates of most of these parameters were derived using *Climate-resilient buildings and core public infrastructure (CRBCPI) 2020: An assessment of the impact of climate change on climatic design data in Canada* (Cannon et al., 2020). This document provides climatic design parameters based on the CanDCS-U5 dataset, which is a downscaled version of the CMIP5 data used in the 2015 Study. While the data are not based on the latest climate modelling (i.e., CMIP6), they do represent an update to the data used in the 2015 Study. Estimates of climate parameters that were not included in Cannon et al. (2020) relied upon other scientific publications identified by Stantec.

2.1.2 CLIMATE PARAMETER PROBABILITY

Some of the climate parameter probabilities were directly estimated from the CanDCS-U6 data (Table 2). Details on the methods used to calculate each parameter are provided in Section 2.2. To maintain consistency with the 2015 Study, the estimated frequencies/probabilities were adjusted to match the baseline values with those from the 2015 Study by applying the ‘delta’ approach as described in Appendix B, Section 3.3.1 of the 2015 Study report. The baseline probabilities from the 2015 Study are maintained in this study because their calculation relied on high-quality measurements obtained from weather stations, in contrast to the CanDCS-U6 baseline data, which rely on the less-precise NRCANmet dataset (Hopkinson et al., 2011).

Annual probabilities were estimated for the baseline period (1981-2010), the 2030s (2021-2050) and the 2050s (2041-2070), by dividing the number of event occurrences, by 30 years. The annual probabilities were then translated to study period probabilities by estimating the likelihood of occurrence over a 28-year period (from 2022 to 2050). Because seven years have passed since the 2015 Study (study period from 2015 to 2050), the length of the study period has changed, which influences the climate parameter probability of occurrence.

Table 2: Climate parameters and data sources used in the 2015 Study and the current (2022) study

Climate Parameter	Threshold(s)	2015 Data Source	2022 Data Source
Daily Maximum Temperatures	25°C, 30°C, 35°C, 40°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
High Daily Avg. Temperature	30°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
Heat Wave	3-days with max temp over 30°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
High Nighttime Temperatures	Nighttime low ≥23°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
Snowfall	5 cm, 10 cm daily	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
Frost-Free Days	0°C	CMIP5 Ensemble (IPCC AR5)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6)
Extreme Rainfall	100 mm in <1 day + antecedent	Kunkel et al. (2013)	Canadian Downscaled Climate Scenarios – Univariate (CMIP6); Cannon et al. (2020)
Ice Storm/Freezing Rain	15 mm, 25 mm, 60 mm	Cheng et al. (2011, 2014)	McCray et al (2022); Jeong et al (2018); Jarret et al (2019); Cannon et al. (2020)
High Winds	70 km/h, 90 km/h, 120 km/h	Cheng et al. (2012); Cheng (2014)	Cannon et al. (2020)
Tornado	EF1+, EF2+	Brooks et al. (2014)	Cheng et al. (2013); Gensini et al. (2018); Sills et al. (2020)
Lightning	Flash density per km km^2	Romps et al (2014)	Cheng et al. (2013); Gensini et al. (2018); Sills et al. (2020)

The updated climate parameter probabilities were categorized into one of the eight probability score classes used in the 2015 Study (Table 3). While more recent versions of the PIEVC protocol exist (e.g., the PIEVC High-Level Screening Guide – ICLR, 2022), Stantec applied the same scoring thresholds used in the 2015 Study to maintain consistency and comparability.

Table 3: Probability score classes applied in this study and the 2015 Study (from Engineers Canada, 2011)

Probability Score	Annual Probability	
0	<0.1 %	<1 in 1,000
1	1 %	1 in 100
2	5 %	1 in 20
3	10 %	1 in 10
4	20 %	1 in 5
5	40 %	1 in 2.5
6	70 %	1 in 1.4
7	>99 %	>1 in 1.01

2.2 Results

Updates to the projected annual frequency (2030s), study period probabilities, and probability score for each climate parameter are summarized in Table 4. For parameters derived from the CanDCS-U6 data, the mean, 10th, and 90th percentiles of the frequency (across 26 models) are provided. A more detailed comparison, including baseline probabilities and 2050s projections is included in Appendix A for reference. Specific methods applied and results obtained for each climate parameter are described in detail later in this section.

Table 4: Updates to climate parameter probabilities

Climate Parameter	Threshold	Frequency[1] (2030s)	Probability (Study Period)	Prob. Score (Study Period)	Score Change (2022 - 2015)
Daily Maximum Temperatures	Days > 25°C	86 (64 - 102)	>99%	7	None
Daily Maximum Temperatures	Days > 30°C	28 (10 - 41)	>99%	7	None
Daily Maximum Temperatures	Days > 35°C	2.8 (0 - 7)	>99%	7	None
Daily Maximum Temperatures	Days > 40°C	0.08 (0 - 0.1)	90%	6	Decrease (-1)
High Daily Avg. Temperature	Days > 30°C	0.75 (0 - 2.2)	>99%	7	None
Heat Wave	3+ consecutive days >30°C	2.6 (0.9 - 5.9)	>99%	7	None
High Nighttime Temperatures	Nighttime low ≥23°C	2.6 (0.1 - 5.9)	>99%	7	None

[1] Refers to annual frequency (days per year), unless otherwise noted in column 2. The values in parentheses indicate the 10th and 90th percentiles across 26 downscaled GCMs, from the CanDCS-U6 data.

Climate Parameter	Threshold	Frequency[1] (2030s)	Probability (Study Period)	Prob. Score (Study Period)	Score Change (2022 - 2015)
Snowfall	Days w/ >10 cm	1.2 (0 - 2.6)	100%	7	None
Snowfall	Days w/ > 5cm	4.4 (1.6 - 7.6)	100%	7	None
Frost-Free Days	Days > 0°C	249 (242 - 279)	100%	7	None
Extreme Rainfall	100 mm in <1 day + antecedent	+11% rainfall intensity	75%	6	None
Ice Storm/ Freezing Rain	Accretion 15 mm	-2.2% in 1/20yr ice accretion	99%	7	None
Ice Storm/ Freezing Rain	25 mm ≈ 12.5 mm radial	-2.2% in 1/20yr ice accretion	96%	6	Decrease (-1)
Ice Storm/ Freezing Rain	60 mm ≈ 30 mm radial	-2.2% in 1/20yr ice accretion	23%	4	None
High Winds	>70 km/h+	+0.7% in 10-yr wind speeds	>99%	7	None
High Winds	>90 km/h	+0.7% in 10-yr wind speeds	>99%	7	None
High Winds	>120 km/h	+0.8% in 25-yr wind speeds	76%	7	None
Tornado	EF1+	-	~0.6%	1	None
Tornado	EF2+	-	~0.3%	0	None
Lightning	Flash density per year per km^2	1.43	55% (Lg)	6	None

2.2.1 HEAT-RELATED PARAMETERS

Each of the heat-related parameters (Daily Maximum Temperature, High Daily Average Temperature, Heat Wave, and High Nighttime Temperature) were calculated directly from the CanDCS-U6 data. These parameters were shifted using an additive correction factor to match the baseline values to those provided in the 2015 Study. The heat-related climate parameters are defined as follows:

- Daily Maximum Temperatures above threshold temperature (25°C, 30°C, 35°C, and 40°C) – number of days per year when the maximum daily temperature exceeds a threshold.
- High Daily Average Temperature (above 30°C) – number of days per year when the average daily temperature exceeds 30°C.
- Heat Waves – number of times per year when the maximum daily temperature exceeds 30°C for three or more consecutive days.
- High Nighttime Temperatures (above 23°C) – number of days per year when minimum daily (nighttime) temperature exceeds 23°C.

There is an increase in the estimated number of days with maximum temperatures exceeding 25°C, 30°C, and 35°C in the 2030s and 2050s compared to the 2015 Study (see Appendix A). For each of these parameters, the probability of occurrence over the study period is almost certain (>99%). Because the 2015 Study already assigned the maximum probability score of 7 (>99%) over the study period, these values remain unchanged.

There is a decrease in the estimated number of days with maximum temperatures exceeding 40°C in the 2030s and 2050s, compared to the 2015 Study. As a result, the estimated probability of 40°C temperatures occurring over the study period is about 90% and is classified as a probability score of 6, a decrease from the 2015 Study score of 7.

The projected number of days with daily average temperature greater than 30°C is higher than that provided in the 2015 Study, increasing from 1.2 days per year to 4.3 days per year. The CanDCS-U6 data were also used to estimate the frequency in the 2030s, which was not previously provided. However, since the 2015 Study already assigned the maximum probability score of 7 (>99%) over the study period, the updated climate data do not justify a change to the probability score assigned.

The expected number of heat waves per year aligns with the values provided in the 2015 Study, however the CanDCS-U6 data allow for a more precise estimate of the annual frequency in the 2030s and 2050s. The 2015 Study projected more than 1 heat wave per year in the 2030s and 2050s, whereas the updated climate data indicate that 2.6 and 4.8 heat waves are expected per year, respectively. However, since the 2015 Study already assigned the maximum probability score of 7 (>99%) over the study period, the updated climate data do not justify a change to the probability score assigned.

The expected number of days with high nighttime temperatures is lower than the estimates provided in the 2015 Study, decreasing from 7 and 16 to 3 and 11 in the 2030s and 2050s, respectively. While this represents an almost 50% decrease, the probability of occurrence over the study period is still almost certain (>99%), and therefore the updated climate data do not justify a change to the probability score of 7 assigned in the 2015 Study.

2.2.2 FROST-FREE DAYS

Frost-free days were estimated using the CanDCS-U6 data. This parameter represents the number of days per year when the daily minimum temperature exceeded 0°C. The frequencies estimated from the CanDCS-U6 data were shifted using an additive correction factor to match the baseline value to that provided in the 2015 Study.

While there is a slight increase in the estimated number of frost-free days in the 2050s compared to the 2015 Study (increase 5 days), the differences are small in comparison to the annual number of frost-free days projected (278 days). Further, the 2015 Study assigned a probability score of 7 (>99%) over the study period. This score means that frost days (i.e., temperatures below 0°C) are effectively certain throughout the study period. These findings are supported by the updated climate data, and the probability scores remain unchanged.

2.2.3 EXTREME RAINFALL

While extreme rainfall events at the daily and higher resolution can be captured by the CanDCS-U6 dataset, the latest recommendations from Environment and Climate Change Canada (ECCC) suggest alternate methods to estimate future extreme rainfall. The approach uses the relationship between warming temperatures and precipitation extremes to update empirically based rainfall intensity-duration-frequency (IDF) curves for future climate projections (Canadian Standards Association, 2019). This method is described as 'temperature scaling', which is defined as $\boldsymbol{R_P = R_C \times 1.07^{\Delta T}}$, where R_P is future estimated rainfall intensity value, R_C is the current rainfall intensity value, and ΔT is long-term (30-years or more mean) annual mean temperature change for the study location. IDF change factors ($1.07^{\Delta T}$) based on CMIP5 data for cities across Canada are provided in Cannon et al (2020), accounting for site-specific projections in temperature change.

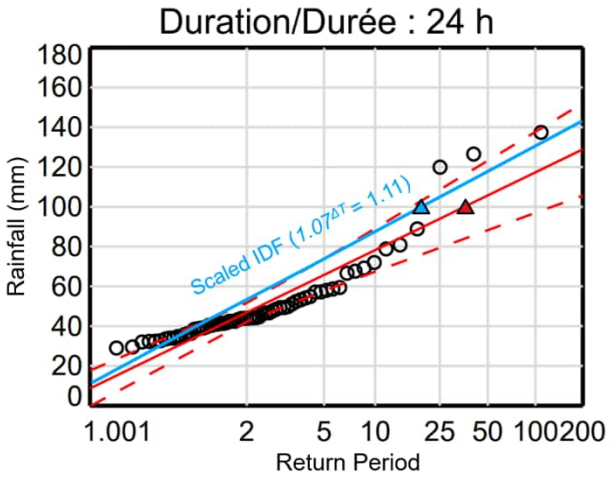

Figure 3: Scaled 24-hour rainfall probability curve for Toronto Pearson Airport, from ECCC. Triangles denote 100-mm rainfall probabilities for the baseline (red) and 2030s (blue).

For the Toronto area, the IDF change factor is given as 1.11, for the year 2035 (midpoint of the 2030s) for the RCP8.5 emissions scenario (Cannon et al., 2019 – Table 2.1). The 2015 study provides a baseline annual probability of 4% for 100 mm of rain in 24 hours, which generally agrees with the latest IDF curves for the Pearson Airport weather station, provided by ECCC (3%, or 33-year return period) (blue triangle, Figure 3). Applying the change factor to the latest IDF curve for Pearson Airport, gives an estimated annual probability of ~5% for a 100mm/24hr rainfall event in the 2030s (red triangle, Figure 3) and a study period probability of 75%. Using Table 3, this results in a probability score of 2 for the 2030s, and 6 for the study period, which is the same as that provided in the 2015 study.

While using downscaled climate model (e.g., CanDCS-U6) rainfall data is not the recommended approach for estimating future extreme rainfall probabilities from ECCC, the approach still merits investigation for this analysis. The mean probability of >100mm of rainfall in a 24-hour period across the CanDCS-U6 ensemble in the 2030s is ~0.02 (score of 2) resulting in a study period probability of 57% (score of 6), which agrees with the recommended approach discussed above.

2.2.4 SNOWFALL

The future probabilities of 5 and 10 cm snowfall events were estimated using the CanDCS-U6 data. Snowfall was approximated from temperature and precipitation data using the 'Brown' method presented in Verseghy (2009), which assumes the fraction of precipitation falling as snow decreases linearly between 0 °C (100% snow and 0% rain) and 2 °C (0% snow and 100% rain). The results were then

converted from mm of water equivalent to snow depth (in cm) using a density of 150 kg/m^3, which was selected to align with the number of 5 and 10 cm snowfall events provided in the 2015 Study (i.e., the snow density was used as a multiplicative correction factor). Cannon et al. (2020) notes that while there is medium confidence that snow loads will decrease over most of Southern Canada, there is low confidence in the magnitude of the decrease.

The results indicate the annual frequency of 5 cm snowfall events will decrease from 5.2 events per year in the baseline period to 4.4 in the 2030s, and 3.1 in the 2050s. Larger (10 cm) snowfall events are estimated to decrease in frequency from 1.4 events per year in the baseline to 1.2 and 0.9 events per year in the 2030s and 2050s, respectively. Despite the projected decrease in annual frequency of snowfall events, the probability of both 5 and 10 cm snowfall events occurring over the study period is almost certain (>99%), and therefore the probability scores from the 2015 Study remain unchanged (score of 7).

2.2.5 FREEZING RAIN

The future probabilities of freezing rain events were estimated based on a review of recent climate change literature applicable to the Toronto area, including McCray at al. (2022), Jeong et al. (2018), and Cannon et al (2020). The freezing rain events considered included 15, 25, and 60 mm of ice accretion, as defined in the 2015 Study.

While the studies do not explicitly provide estimates of the likelihood of the freezing rain events listed in the 2015 Study, McCray et al. (2022) and Jeong et al. (2018) found that the frequency, and magnitude, respectively, of freezing rain events are projected to decrease slightly in the Toronto area. Cannon et al. (2020) found 'with medium confidence' that while the magnitude of freezing rain events is expected to increase across Canada in general, there is a very small, expected decrease in the Toronto area (very low confidence). Specifically, they estimate reductions of 2.2% and 7.7% in ice thickness for the 1/20-year (5% annual exceedance probability) events based on 1°C and 1.75°C of global mean warming. These global mean warming estimates are consistent with the years 2035 (2030s) and 2055 (2050s) for the RCP8.5 emissions scenario (Cannon et al., 2019 – Table 2.1).

As a conservative approach, Cannon et al (2020) recommend using ice accretion loads established from recent historical data (i.e., no projected change in ice storm magnitude). In consideration of each of these sources, and the significant uncertainty expressed in each, the estimates probability score for each type of freezing rain event (10, 20, 30 mm) is likely to remain steady over the study period, as compared to the baseline. The updated study period probability scores are not changed for 10- and 30-mm events (7 and 4, respectively), but are decreased (from 7 to 6) for 20 mm events, compared to the 2015 Study.

2.2.6 WIND

The future probabilities of extreme wind events were estimated based on a review of recent climate change literature for the Toronto area (Cannon et al,2020). The extreme wind events considered include 70, 90 and 120 km/h wind thresholds, as defined in the 2015 Study.

Cannon et al. (2020) project a slight increase of extreme wind speeds in the Toronto area, with very low confidence. They estimate increases of 0.7% and 0.8% in hourly wind speeds for the 1/10-year (10% annual exceedance probability; AEP) and 1/25-year (4% AEP) events based on +1.0°C of global mean warming, which is consistent with the year 2035 (2030s) for the RCP8.5 emissions scenario (Cannon et al., 2019 – Table 2.1). The estimated increases for +1.75°C (equivalent to 2055/2050s for RCP8.5) are 2.7% and 3.4% for 1/10-year and 1/25-year events, respectively. These return periods were selected from the available data provided by Cannon et al (2019) to best align with the baseline probabilities from the 2015 Study (>100% AEP for 70 and 90 km/hr events, and 5% AEP for 120 km/hr events).

Cannon et al. (2019) emphasize that these wind speed projections are provided with very low confidence, because of (1) the limited amount of scientific literature, (2) a low signal-to-noise ratio in the projected changes, and (3) the general inability of climate models to simulate extreme winds associated with small-scale processes that influence wind speeds. Because the projected increases in wind speeds are small, and the confidence is very low, we have assigned probability scores that are consistent with the baseline for each threshold event (7, 7, and 2 for 70 km/hr, 90 km/hr and 120 km/hr events, respectively), which are also consistent with the scores from the 2015 Study.

2.2.7 TORNADOES

A review of recent climate change literature applicable to the Toronto area was conducted to identify whether any updates were required to the tornado probability estimate from the 2015 Study. The specific tornado events considered included those with strengths of EF1+ (wind speeds exceeding 138 km/h) and EF2+ (wind speeds exceeding 178 km/h) on the Enhanced Fujita (EF) scale.

Sills et al. (2020) used multiple methods (e.g., satellite imagery, drone and ground surveys) to identify tornadoes and assess their size and intensity in the Ontario region between 2017 and 2019 as part of the Northern Tornadoes Project (NTP). Using a systematic approach, they captured 78% to 283% more tornadoes annually than the 30-year Canadian national tornado dataset from 1980-2009, mainly due to their increased usage of satellite imagery, ground and drone surveys and an improved storm track identification. It is important to note that although there is a detected increase in tornado occurrence through NTP, it does not signify any relevant changes in the tornado frequency in Canada.

Figure 4 shows all NTP-documented tornadoes (from 2017-2019) in Southeastern Ontario, with selected contours from the tornado frequency modeling of Cheng et al (2013). Gensini and Brooks (2018) note that tornado environments have been shifting northeastward in the central United States, however Sills et al. (2020) emphasize that it would take numerous years before any trends could be confirmed in Canada. In

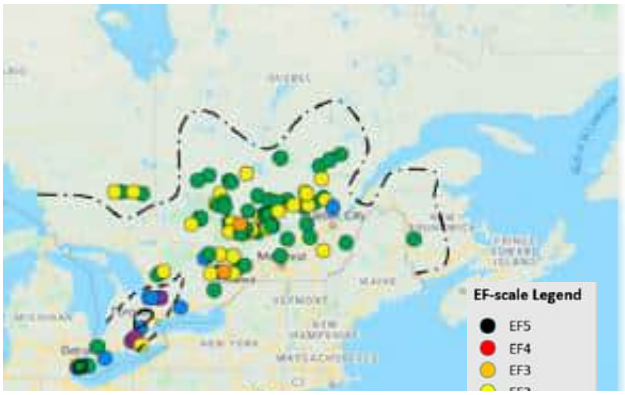

Figure 4: 2017-2019 tornadoes recorded by Sills et al. (2020), overlain with contours of annual tornado frequency in tornadoes per 10,000km2 per year from Cheng et al. (2013): dash-dotted = 0.1, dashed = 1.0, solid=2.0.

consideration of each of these sources, and the uncertainty expressed in each, the tornado probability scores from the 2015 Study remain unchanged (1 and 0 for EF-1 and EF-2 tornadoes, respectively).

2.2.8 LIGHTNING

The future probability of lightning was estimated based on a review of recent climate change literature and data applicable to the Toronto area (Romps et al (2014), Romps (2018) and Finney et al. (2018)). Lightning probability is quantified using the flash density per km^2.

The baseline probability of lightning events provided in the 2015 Study was estimated using data collected from the North American lightning detection network between 1999 and 2008. Environment Canada has since published mean annual lightning flash-density values for the Toronto Area over the period of 1999-2018. Because the time period of the updated data is twice as long as that from the data provided in the 2015 report, the new value provided by Environment Canada is used in this study. The updated value is 1.43 flashes per km^2 per year, which is consistent with the range provided in the 2015 Study (1.12-2.24 flashes per km^2 per year).

As noted in the 2015 Study, Romps et al. (2014) estimate that lightning strikes are projected to increase by 7-17% per degree Celsius of global warming. Similarly, Romps (2018) estimate increases of 8-16% per degree Celsius of warming, using two separate indices. Finney et al. (2018) however, applied a different approach to estimate changes in lightning frequency with climate change, and found that lightning frequency may decrease with warming global temperatures. Due to the general lack of literature linking lightning to climate change, the lack of consistency between projections, and the limited number of models applied in these studies, it is estimated the probability of lightning occurrence will not change significantly under a changing climate. As such, the probability score over the study period is 6, which represents no change from the 2015 Study.

3 Materiality Assessment

3.1 Materiality Methods

Each combination of climate parameter and infrastructure asset class is referred to as an interaction (e.g., the interaction between extreme heat and downtown core stations). To assess material changes in risk, Stantec calculated risk over the study period (2022-2050) for each interaction. Risk is calculated following the approach outlined in the 2015 Study, where ***Risk Score = Probability Score x Severity Score*** (Engineers Canada, 2011). Updated risk scores were only calculated for climate parameters for which the probability score differed from that assigned in the 2015 Study (freezing rain events (>25mm) and extreme heat events (>40°C)). Severity scores used to estimate risk in the 2015 Study were also used in this study.

Updated risk scores were calculated for 66 interactions (42 infrastructure asset classes and two climate parameters – note that some infrastructure asset classes are not exposed to extreme heat or ice storms). The results were then compared with the tolerance thresholds from the 2015 Study to classify the risks. Material changes (either positive or negative) were then identified based on whether the risk score crossed the threshold into a new class.

Table 5: Risk tolerance thresholds (classes) from the 2015 Study

Risk Score	Risk Class	Response
<12	Low Risk	Monitoring or no further action necessary
12 - 36	Medium Risk	Vulnerability may be present. Action may be required, to be determined through engineering analysis
>36	High Risk	Vulnerability present, action required

3.2 Materiality Results

Only two of the updated climate parameters probability scores were different from the 2015 Study: (1) daily maximum temperatures (>40°C) and (2) freezing rain/ice storms (>25 mm). Each of these probability scores, were reduced from a very high probability (7) to high probability (6). Based on these updated probability scores, the estimated risk for 23 of the interactions were calculated to be materially different from the 2015 Study. The materially different interactions, and their risk scores, are outlined below and in Table 6.

- Ten infrastructure asset classes at high risk to daily maximum temperatures >40°C changed to medium risk. All these material changes were for Transmission Step-down to Municipal and Municipal Stations.
- Thirteen infrastructure asset classes at high risk to freezing rain events >25 mm changed to medium risk. These material changes were for Transmission Step-down to Municipal and Municipal Stations as well as Overhead loops as part of the feeder configuration and emergency response.

Table 6: Summary of interactions with material changes to risk scores

Climate Parameter	Threshold	Study Report Year	Number of Interactions by Risk Class		
			High	Medium	Low
Daily Maximum Temperature	40°C	2015	10	23	1
		2022	0	33	1
Ice Storm / Freezing Rain	25 mm ≈ 12.5 mm radial	2015	18	5	9
		2022	5	18	9

Individual material risk classification changes are outlined in Table 7 with references to specific adaptation options from the 2015 Study and report.

Table 7: Material risk classification changes and adaptation option outcomes

Climate Parameter	Asset No.	Infrastructure Class or Category	2015 Risk Score	2022 Risk Score	Change to Risk Score	2015 Study Adaptation Recommendation[2]
High Temperature (40°C)	**1**	**Transmission Step-Down to Municipal**				• Further study required to address gaps in data availability and data quality
	1.1	**Former Toronto**				
	1.1.1	Downtown core stations	42	**36**	↓	
	1.1.2	Downtown outer stations without a station	42	**36**	↓	
	1.1.3	Station (13.8 kV)	42	**36**	↓	
	1.2	**Horseshoe Area**				
	1.2.1	Station	42	**36**	↓	
	1.2.4	Station	42	**36**	↓	
	1.2.5	Station (27.6 kV)	42	**36**	↓	
	1.2.8	2 Stations	42	**36**	↓	
	1.2.9	Southwest Stations	42	**36**	↓	
	2	**Municipal Stations (divided by Geography)**				
	2.1	**Toronto Hydro to Toronto Hydro & Private ownership**				
	2.1.1	Former Toronto (indoor/outdoor)	42	**36**	↓	
	2.1.3	Toronto Hydro to private ownership	42	**36**	↓	

[2] Adaptation recommendations are from Table 7-1 of the 2015 Study.

Climate Parameter	Asset No.	Infrastructure Class or Category	2015 Risk Score	2022 Risk Score	Change to Risk Score	2015 Study Adaptation Recommendation[2]
Freezing Rain /Ice Storm (>25 mm)	**1**	**Transmission Step-Down to Municipal**				• Management actions to account for changes in the infrastructure capacity • Further study required to address gaps in data availability and data quality
	1.1	**Former Toronto**				
	1.1.3	Station (13.8 kV)	42	**36**	↓	
	1.2	**Horseshoe Area**				
	1.2.1	Station	42	**36**	↓	
	1.2.2	Station (13.8 kV)	42	**36**	↓	
	1.2.3	East Stations	42	**36**	↓	
	1.2.4	Station	42	**36**	↓	
	1.2.5	Station (27.6 kV)	42	**36**	↓	
	1.2.6	Station	42	**36**	↓	
	1.2.7	Northwest Station	42	**36**	↓	
	1.2.8	2 Stations	42	**36**	↓	
	1.2.9	Southwest Stations	42	**36**	↓	
	2	**Municipal Stations**				
	2.1	**Toronto Hydro to Toronto Hydro & Private ownership**				
	2.1.2	Horseshoe Area (indoor/outdoor)	42	**36**	↓	
	3	**Feeder Configuration: Underground**				• Management actions to account for changes in the infrastructure capacity • Remedial engineering actions which aim to strengthen or upgrade the infrastructure
	3.5	**Overhead**				
		Loop				
	3.5.4	4.16 kV	42	**36**	↓	
	6	**Human Resources**				• Management actions to account for changes in the infrastructure capacity
	6.1	Emergency Response	42	**36**	↓	

4 Discussion

The results presented in the preceding sections show the updated climate projection information reviewed does not result in any material increases to the risk scores presented in the 2015 Study. However, there are a few differences between the climate parameter probabilities and risk scores that merit further discussion.

While many of the climate parameter probabilities/frequencies have increased (see Appendix A), the climate parameter probability score for the study period provided in the 2015 Study was already at the highest possible level (7, or greater than 99% annual probability). As a result, any notable increases in the frequency of these climatic events based on the updated data are not reflected in this risk assessment. To address this issue, the latest PIEVC guidance, released in the High-Level Screening Guide (ICLR, 2022) would dictate that some of these parameters should be evaluated using the 'middle-baseline' approach.

In the middle-baseline approach, the future probability score is dependent on the projected percent change in climate parameter frequency compared to the baseline (with a default baseline probability score of 3). More specifically, the middle baseline approach dictates that a >10% increase in climate parameter frequency, would result in an increase in the probability score from 3 to 4, and a >50% increase would result in a score of 5. Based on this approach, we have identified the climate parameters where probability scores of 7 from the 2015 Study could not be increased and where the projected 2030s frequency changed by more than 10% compared to that presented in the 2015 report.

- High Daily Average Temperature >30°C (increase from 0.6 to 0.8 days/year)
- Heat Waves (increase from >1 to 2.6 days/year)
- High Nighttime Temperatures >23°C (decrease from 7 to 3 days/year)

Although the probability scores (and hence the associated risk scores) for the above climate parameters are unchanged from the 2015 Study, their associated adaptation measures may merit further study to evaluate whether they are sufficient to address the differences in climate parameter frequencies.

While we found a slight decrease in the number of infrastructure asset classes at high risk due to extreme heat (>40°C) events, the range in climate parameter probabilities over the study period is broad across the CMIP6 model ensemble, and the probability score is very close to being a 7 over the study period (90% probability of occurrence). Therefore, although the change materially decreases based on this analysis, we do not recommend relaxing any of the adaptation measures proposed in the 2015 Study.

The 2015 Study estimated the probability score of freezing rain/ice storms events (>25 mm) would increase in the 2030s. Updated climate projection information suggests the probability will remain steady over the study period. Although we do not have an ensemble of models to consider for this climate parameter, the literature investigated expressed ‘very low confidence’ in the projections, and therefore the probability could range widely. Therefore, although the change materially decreases, based on this analysis, we do not recommend relaxing any of the measures associated with freezing rain events >25 mm.

5 Limitations

The findings in this report are subject to several limitations. Section 2 discusses specific uncertainties associated with each climate parameter. Some overarching limitations are noted below.

- Stantec did not review the 2015 Study adaptation recommendations to assess if they were sufficient to protect infrastructure assets against the relevant climate hazard, as this would have been beyond the scope of this study. The results from this study could be used to evaluate which of the adaptation recommendations merit further review.
- Climate data is inherently uncertain. The climate parameter probabilities provided should be considered as high-level estimates of future conditions. The primary source of uncertainty in climate projections is the estimate of greenhouse gas emissions that will be observed over the current century. Additional sources of uncertainty include (but are not limited to) climate model parameterization, bias, and resolution.
- Some of the climate parameters investigated are associated with very high degrees of uncertainty, because they are difficult to constrain using the outputs from climate models. Stantec has reviewed recently published scientific literature and guidance to provide an estimate of likely future conditions.
- The severity scores, as well as the thresholds used to define risk and climate parameter probability classes and scores were not reviewed as part of this analysis. The thresholds are consistent with those applied in the 2015 Study.

6 Closure

This study has provided an update to the climate parameters described in the 2015 Study, using newly available CMIP6 climate model data. By analyzing the CMIP6 data, as well as recent scientific literature and guidance documents, Stantec has updated the estimated risk scores for Toronto Hydro's infrastructure assets by applying the same risk assessment framework as was applied in the 2015 Study. Some parameters (heat waves, and daily average temperatures >30°C) are expected to occur more frequently than projected by the 2015 study, however, these events were already considered to be 'certain' over the study period in the 2015 Study. The only climate parameter probability scores that changed as a result of this analysis include extremely hot days (>40°C), and 25mm freezing rain events, both of which are projected to occur less frequently over the study period than was estimated in the 2015 Study. Though these decreases resulted in a downgrading from high to medium risk for multiple infrastructure asset classes, we do not recommend relaxing any of the adaptation measures provided in the 2015 Study.

7 References

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APPENDICES

Appendix A – 2022 Climate Parameter Probability Update

Climate Change Vulnerability Assessment Update
Appendix A – 2022 Climate Parameter Probability Update
November 18, 2022

Climate Parameter	Threshold	2015 Study								2022 Study								Study Period Probability Difference (2022-2015)
		Data Source	Annual Frequency			Probability Score			Study Period Probability (2015-2050)	Data Source	Annual Frequency - Corrected			Probability Score			Study Period Probability (2022-2050)	
			Baseline (1981-2010)	2030s (2021-2050)	2050s (2041-2070)	Baseline (1981-2010)	2030s & 2050s	Study Period (2015-2050)			Baseline (1981-2010)	2030s (2021-2050)	2050s (2041-2070)	Baseline (1981-2010)	2030s & 2050s	Study Period (2022-2050)		
Daily Maximum Temperatures	25°C	CMIP5 Ensemble (IPCC AR5)	66	84	106	7	7	7	100%	CanDCS-U6 Ensemble	66 (47 - 76)	86 (64 - 102)	110 (86 - 126)	7	7	7	>99%	No Change
Daily Maximum Temperatures	30°C	CMIP5 Ensemble (IPCC AR5)	16	26	47	7	7	7	100%	CanDCS-U6 Ensemble	16 (4 - 22)	28 (10 - 41)	50 (25 - 74)	7	7	7	>99%	No Change
Daily Maximum Temperatures	35°C	CMIP5 Ensemble (IPCC AR5)	0.75	3	8	6	7	7	100%	CanDCS-U6 Ensemble	0.8 (0 - 1.5)	2.8 (0 - 7)	9.2 (0.5 - 22.5)	6	7	7	>99%	No Change
Daily Maximum Temperatures	40°C	CMIP5 Ensemble (IPCC AR5)	0.01	0.3-2	1-7	1	4-7	7	~100%	CanDCS-U6 Ensemble	0.01 (0 - 0)	0.08 (0 - 0.1)	0.64 (0 - 1.98)	1	5	6	90%	Decrease
High Daily Avg. Temperature	30°C	CMIP5 Ensemble (IPCC AR5)	0.07	0.565	1.2	3	7	7	~100%	CanDCS-U6 Ensemble	0.07 (0 - 0.04)	0.75 (0 - 2.22)	4.31 (0 - 11.72)	3	7	7	>99%	No Change
Heat Wave	3-days with max temp over 30°C	CMIP5 Ensemble (IPCC AR5)	0.88	>1	>1	6	7	7	100%	CanDCS-U6 Ensemble	0.9 (0.2 - 3.3)	2.6 (0.9 - 5.9)	4.8 (2.9 - 8.3)	6	7	7	>99%	No Change
High Nighttime Temperatures	Nighttime low ≥23°C	CMIP5 Ensemble (IPCC AR5)	0.70	7	16	6	7	7	~100%	CanDCS-U6 Ensemble	0.7 (0 - 1.3)	2.6 (0.1 - 5.9)	10.7 (2.3 - 20.8)	6	7	7	>99%	No Change
Snowfall	Days w/ >10 cm	CMIP5 Ensemble (IPCC AR5)	1.5	Decreasing	Decreasing	7	7	7	100%	CanDCS-U6 Ensemble	1.4 (0.1 - 2.8)	1.2 (0 - 2.6)	0.9 (0 - 2.2)	7	7	7	>99%	No Change
Snowfall	Days w/ > 5cm	CMIP5 Ensemble (IPCC AR5)	5	Decreasing	Decreasing	7	7	7	100%	CanDCS-U6 Ensemble	5.2 (2.2 - 8.5)	4.4 (1.6 - 7.6)	3.1 (0.5 - 6)	7	7	7	>99%	No Change
Frost-Free Days	0°C	CMIP5 Ensemble (IPCC AR5)	229	249	273	7	7	7	100%	CanDCS-U6 Ensemble	229 (225 - 256)	249 (242 - 279)	278 (264 - 320)	7	7	7	>99%	No Change
Extreme Rainfall	100 mm in <1 day + antecedent	Kunkel et al. (2013)	0.04	Expected increase	Expected increase	2	3	6	~75%-85%	Cannon et al. (2020); CanDCS-U6 Ensemble	0.02	+11% rainfall intensity	+20% rainfall intensity	2	2	6	75%	No Change
Ice Storm/Freezing Rain	15 mm (tree branches)	Cheng et al. (2011, 2014)	0.11	0.13	0.16	3	3	7	>99%	McCray et al (2022); Jeong et al (2018); Jarret et al (2019); Cannon et al. (2020)	0.11	-2.2% in 1/20yr ice accretion	-7.7% in 1/20yr ice accretion	3	3	7	99%	No Change
Ice Storm/Freezing Rain	25 mm ≈ 12.5 mm radial	Cheng et al. (2011, 2014)	0.06	0.07	0.09	2	3	7	>95%	McCray et al (2022); Jeong et al (2018); Jarret et al (2019); Cannon et al. (2020)	0.06	-2.2% in 1/20yr ice accretion	-7.7% in 1/20yr ice accretion	2	2	6	96%	Decrease
Ice Storm/Freezing Rain	60 mm ≈ 30 mm radial	Cheng et al. (2011, 2014)	0.005	0.013	0.007	1	1	4	High: ~25% Low: ~8%	McCray et al (2022); Jeong et al (2018); Jarret et al (2019); Cannon et al. (2020)	0.005	-2.2% in 1/20yr ice accretion	-7.7% in 1/20yr ice accretion	1	1	4	23%	No Change
High Winds	70 km/h+ (tree branches)	Cheng et al. (2012); Cheng (2014)	21	N/A	25	7	7	7	100%	Cannon et al. (2020)	21	+0.7% in 10-yr wind speeds	+2.7% in 10-yr wind speeds	7	7	7	>99%	No Change
High Winds	90 km/h	Cheng et al. (2012), Cheng (2014)	2	N/A	>2.5	7	7	7	100%	Cannon et al. (2020)	2	+0.7% in 10-yr wind speeds	+2.7% in 10-yr wind speeds	7	7	7	>99%	No Change
High Winds	120 km/h	N/A	0.05	Likely Increase	Likely Increase	2	2	7	~85% or higher	Cannon et al. (2020)	0.05	+0.8% in 25-yr wind speeds	+3.4% in 25-yr wind speeds	2	2	7	76%	No Change
Tornado	EF1+	Brooks et al. (2014)	-	Unknown, no consensus	Unknown, no consensus	0	0	1	~0.6%	Cheng et al. (2013); Gensini et al. (2018); Sills et al. (2020)	-	Unknown, no consensus	Unknown, no consensus	0	0	1	~0.6%	No Change
Tornado	EF2+	Brooks et al. (2014)	-	Unknown, no consensus	Unknown, no consensus	0	0	0	~0.3%	Cheng et al. (2013); Gensini et al. (2018); Sills et al. (2020)	-	Unknown, no consensus	Unknown, no consensus	0	0	0	~0.3%	No Change
Lightning	Flash density per km km^2	Romps et al (2014)	1.12-2.24/yr/km^2	Expected increase, % unknown	Expected increase, % unknown	0-2	N/A	3-6	~50-70%(Lg); ~10-20% (Sm)	Romps et al (2014), Romps (2018), Finney et al. (2018)	1.43	1.43	1.43	1	1	6	55% (Lg)	No Change

Appendix B – 2022 Risk Scores for Interactions with Updated Climate Parameters

Climate Change Vulnerability Assessment Update
Appendix B – 2022 Risk Scores for Interactions with Updated Climate Parameters
November 18, 2022

Infrastructure Class or Category		4	High Temperature							10	Freezing Rain/Ice Storm						
			40°C								25 mm ≈ 12.5 mm radial						
		Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change	Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change
1	**Transmission Step-down to Municipal**																
1.1	**Former Toronto**																
1.1.1	Downtown core stations	Y	7	6	5+	6	42	**36**	↓	N							
1.1.2	Downtown outer stations without a station	Y	7	6	5+	6	42	**36**	↓	N							
1.1.3	Station (13.8 kV)	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2	**Horseshoe Area**																
1.2.1	Station	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2.2	Station (13.8 kV)	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
1.2.3	East Stations	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
1.2.4	Station	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2.5	Station (27.6 kV)	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2.6	Station	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
1.2.7	Northwest Station	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
1.2.8	2 Stations	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
1.2.9	Southwest Stations	Y	7	6	5+	6	42	**36**	↓	Y	7	6	6	6	42	**36**	↓
2	**Municipal Stations**																
2.1	**TO Hydro to TO Hydro & Private Ownership**																
2.1.1	Former Toronto (indoor/outdoor)	Y	7	6	5+	6	42	**36**	↓	N							
2.1.2	Horseshoe Area (indoor/outdoor)	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓
2.1.3	Toronto Hydro to private ownership	Y	7	6	5+	6	42	**36**	↓	N							
3	**Feeder Configuration: Underground**																
3.1	**Horseshoe Area: Dual Radial System**																
3.1.1	Submersible type	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.1.2	Vault type																
	Above ground	Y	7	6	3	3	21	**18**	↔	N							
	Below ground	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.1.3	Padmount Station	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.2	**Former Toronto: Dual Radial System**																

Climate Change Vulnerability Assessment Update
Appendix B – 2022 Risk Scores for Interactions with Updated Climate Parameters
November 18, 2022

Infrastructure Class or Category		4	High Temperature							10	Freezing Rain/Ice Storm						
			40°C								25 mm ≈ 12.5 mm radial						
		Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change	Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change
3.2.1	Submersible type	Y	7	6	3+	4	28	**24**	↔	Y	7	6	1+	2	14	**12**	↔
3.2.2	Vault Type																
	Above ground	Y	7	6	3+	4	28	**24**	↔	N							
	Below ground	Y	7	6	3+	4	28	**24**	↔	Y	7	6	1+	2	14	**12**	↔
3.2.3	Padmount Station	Y	7	6	3+	4	28	**24**	↔	Y	7	6	1+	2	14	**12**	↔
3.3	**Compact Loop Design**																
3.3.1	Former Toronto: Subway Type	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.4	**13.8 kV Network**																
3.4.1	Former Toronto	Y	7	6	3	3	21	**18**	↔	Y	7	6	1	1	7	**6**	↔
3.5	**Overhead**																
	Radial																
3.5.1	4.16 kV	Y	7	6	4+	5	35	**30**	↔	Y	7	6	6+	7	49	**42**	↔
3.5.2	13.8 kV Network	Y	7	6	4+	5	35	**30**	↔	Y	7	6	7	7	49	**42**	↔
3.5.3	27.6 kV	Y	7	6	4+	5	35	**30**	↔	Y	7	6	7	7	49	**42**	↔
	Loop																
3.5.4	4.16 kV	Y	7	6	4	4	28	**24**	↔	Y	7	6	6	6	42	**36**	↓
3.5.5	13.8 kV	Y	7	6	4	4	28	**24**	↔	Y	7	6	7	7	49	**42**	↔
3.5.6	27.6 kV	Y	7	6	4	4	28	**24**	↔	Y	7	6	7	7	49	**42**	↔
4	**Communications**																
4.1	Protection and control systems	Y	7	6	2	2	14	**12**	↔	N							
4.2	SCADA and Wireless Network	Y	7	6	1	1	7	**6**	↔	Y	7	6	1	1	7	**6**	↔
5	**Civil Structures**																
5.1	**Transmission and Municipal Stations**																
	Outdoor																
5.1.1	Equipment support	N								N							
5.1.2	Gantry	N								Y	7	6	1	1	7	**6**	↔
5.2	**Underground feeders: Former Toronto**																
5.2.1	Reinforced concrete cable chambers	N								Y	7	6	1+	2	14	**12**	↔

Infrastructure Class or Category		4	High Temperature							10	Freezing Rain/Ice Storm						
			40°C								25 mm ≈ 12.5 mm radial						
		Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change	Interaction (Y/N)	2015 Probability	2022 Probability	'S' Severity	'FS' Severity	2015 Risk	2022 Risk	Risk Change
5.2.2	Concrete vaults (reinforced)	N								Y	7	6	1+	2	14	**12**	↔
5.2.3	Underground cable ducts	N								N							
5.3	**Underground feeders: Horseshoe Area**																
5.3.1	Reinforced concrete cable chambers	N								Y	7	6	1	1	7	**6**	↔
5.3.2	Concrete vaults (reinforced)	N								Y	7	6	1	1	7	**6**	↔
5.3.3	Underground cable ducts	N								N							
6	**Human resources**																
6.1	Emergency Response	Y	7	6	5	5	35	**30**	↔	Y	7	6	6	6	42	**36**	↓

Appendix C – 2015 Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit 2B
Section D
Appendix D
ORIGINAL
(204 pages)

Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

June 2015



Image source: Toronto Hydro

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Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

Application of the Public Infrastructure Engineering Vulnerability Assessment Protocol to Electrical Distribution Infrastructure

Final Report - Public

6031-8907

June 2015

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Revisions List

Revision #	Revised by	Date	Description of the revisions
1	AECOM	8 May 2015	Response to Toronto Hydro comments on Preliminary Report
2	AECOM	29 May 2015	Response to Toronto Hydro comments on Final Report

Signatures

Report prepared by: Sophie Potvin-Champagne, Eng. 1 June 2015

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Executive Summary

The current study aims to evaluate the vulnerability of Toronto Hydro's electrical distribution system within the City of Toronto to a changing climate by employing Engineers Canada's Public Infrastructure Engineering Vulnerability Assessment Protocol (PIEVC Protocol). This study is a high level screening analysis designed to determine where infrastructure vulnerabilities to climate change may be present, to suggest avenues for adapting infrastructure to climate change, and to identify areas of further study.

Electrical Distribution System under Study

Toronto Hydro distributes electricity across the City of Toronto, Canada's largest city and home to approximately 2.8 million people in 2014. Toronto Hydro serves approximately 740,000 customers in the City of Toronto and owns approximately $3 billion dollars in assets, including over 170 transformer stations, approximately 29,000 km of overhead and underground wires, 20,000+ switches, 60,000+ transformers and 176,000+ poles.

The study period of this assessment was 2015 to 2050. A "system" level approach was employed to assess the impacts of climate change on the various parts of the electrical distribution system. This approach divided the distribution system into six major asset categories: stations, feeders, communications systems, civil structures, auxiliary mechanical systems and human resources. Asset categories were assessed based on their general characteristics (e.g. typical, representative or common electrical or mechanical configurations, standards, equipment). For example, this analysis focused on how systems designed to current (post 2000) CSA standards may interact with the climate parameters being considered. Changes to the electrical system considered in this assessment included the planned transition from rear lot to front lot power lines, the partial phase out of 4.16 kV system, some demand and supply projections[1], and replacement of non-submersible equipment. The streetlighting system and systems serving the Toronto Transit Commission (TTC) were not within the scope of this study.

Toronto Hydro documentation, electrical standards and consultations with Toronto Hydro staff (through ongoing communications and two workshops) were all used to help identify and describe asset categories, general characteristics and sensitivities to climate related stresses (climate parameters[2]).

Climate Parameters

20 climate parameters including high temperature, heavy rainfall, snowfall, freezing rain, high winds and lightning were considered in this assessment. Relevant climate parameters and threshold values at which infrastructure performance would be affected were identified through a literature review, consultations with Toronto Hydro staff and analysis of past outage events.

The probability of a climate parameter occurring during the study period was determined using global climate modelling (GCM) data obtained from the Intergovernmental Panel on Climate Change's 5th Assessment Report (IPCC AR5). In many cases, this information was validated or refined through the use of regional climate modelling data, statistical downscaling and climate analogues.

The probability of a climate parameter occurring is expressed both as a study period probability value (i.e. what is the probability of a climate parameter occurring sometime between 2015 – 2050) and an annual probability value centred around the 2030's and 2050's (i.e. what is the annual probability of a climate parameter occurring around

[1] It should be noted that city-wide land use changes (high rises, condo development and population growth) were not included in the analysis, due to the scope of such an undertaking and the complexity of information required. Vulnerabilities were determined based on the assumption that gradual population growth would generally be accommodated by corresponding growth of Toronto Hydro systems under business as usual practices without the added stress of climate change.

[2] A climate parameter is defined by the PIEVC Protocol as a specific set of weather conditions or climate trends deemed to be relevant to the infrastructure under consideration. The parameter may be a single variable, such as mean monthly temperature, or a combination of variables, such as low temperature combined with rainfall.

the 2030's and 2050's). Examining both annual and study period probability was useful for understanding vulnerabilities that may stem from events which could occur on an annual basis (e.g. high temperature) against those which could occur less than annually, but have the potential to cause significant damage to the system sometime during the 35 year study period (e.g. ice storms, high winds, tornadoes). The list of climate parameters considered in this study is shown in table ES-1.

Table ES-1 Climate Parameters and Probability of Occurrence

Climate Parameter		Annual Probability (Historical; **Projected 2030's and *2050's***)	Probability of Occurrence Study Period (2015-2050)
Daily Maximum Temperatures	25°C	66 per year; **84 per year**, ***106 per year***	100%
	30°C	16 per year; **26 per year**, ***47 per year***	100%
	35°C	0.75 per year; **3 per year**, ***8 per year***	100%
	40°C	~0.01 per year; **0.3 to 2 days per year, *1-7 days per year***	~100%
High Daily Avg. Temperature	30°C	0.07 per year; **N/A, *1.2 days per year***	~100%
Heat Wave	3 days max temp over 30°C	0.88 per year; **>1 for both**	100%
High Nighttime Temperatures	Nighttime low ≥23°C	0.70 per year; **7 per year, *16 per year***	~100%
Extreme Rainfall	100 mm in <1 day + antecedent	0.04 per year; ***extreme precipitation expected ↑, percentage unknown***	~75%-85%
Ice Storm/Freezing Rain	15 mm (tree branches)	0.11 per year; **>0.13 per year, *>0.16 per year***	>99%
	25 mm ≈ 12.5 mm radial	0.06 days per year; **>0.07 per year, *>0.09 per year***	>95%
	60 mm ≈ 30 mm radial	Upper bound of estimate: 0.007 events per year; **>0.008 per year; *>0.01 per year*** Lower bound of estimate: 0.002 events per year; **> 0.0023 per year; *0.003 per year***	High: ~25% Low: ~8%
High Winds	70 km/h+ (tree branches)	21 days per year***; N/A, *24 to 26 per year***	100%
	90 km/h	2 days per year; **N/A, *>2.5 per year***	100%
	120 km/h	~0.05 days per year; ***likely ↑, but % unknown***	~85% or higher
Tornado	EF1+	1-in-6,000; ***Unknown, no consensus***	~0.6%
	EF2+	1-in-12,000; ***Unknown, no consensus***	~0.3%
Lightning	Flash density per km km^2	1.12 to 2.24 per year per km^2; ***Expected increase, % change unknown***	~50-70%(Lg); ~10-20% (Sm)
Snowfall	Days w/ >10 cm	1.5 days per year; ***Trend decreasing but highly variable***	100%
	Days w/ > 5cm	5 days per year; ***Trend decreasing but highly variable***	100%
Frost		229 frost free days; **249 frost free days, *273 frost free days***	100%

Assessing Vulnerability

The vulnerability of the electrical system to climate parameters was determined using a risk based framework (probability of occurrence of a climate parameter coupled with the severity/consequence of the impact on the system). All high risk interactions were deemed as vulnerabilities for Toronto Hydro. Medium risk interactions were evaluated in further detail through an engineering analysis. Those which exhibited sensitivities or consequences similar to high risk interactions were also deemed as vulnerabilities for Toronto Hydro. Finally, interactions rated as low risk were generally judged as not being a significant issue or vulnerability for Toronto Hydro.

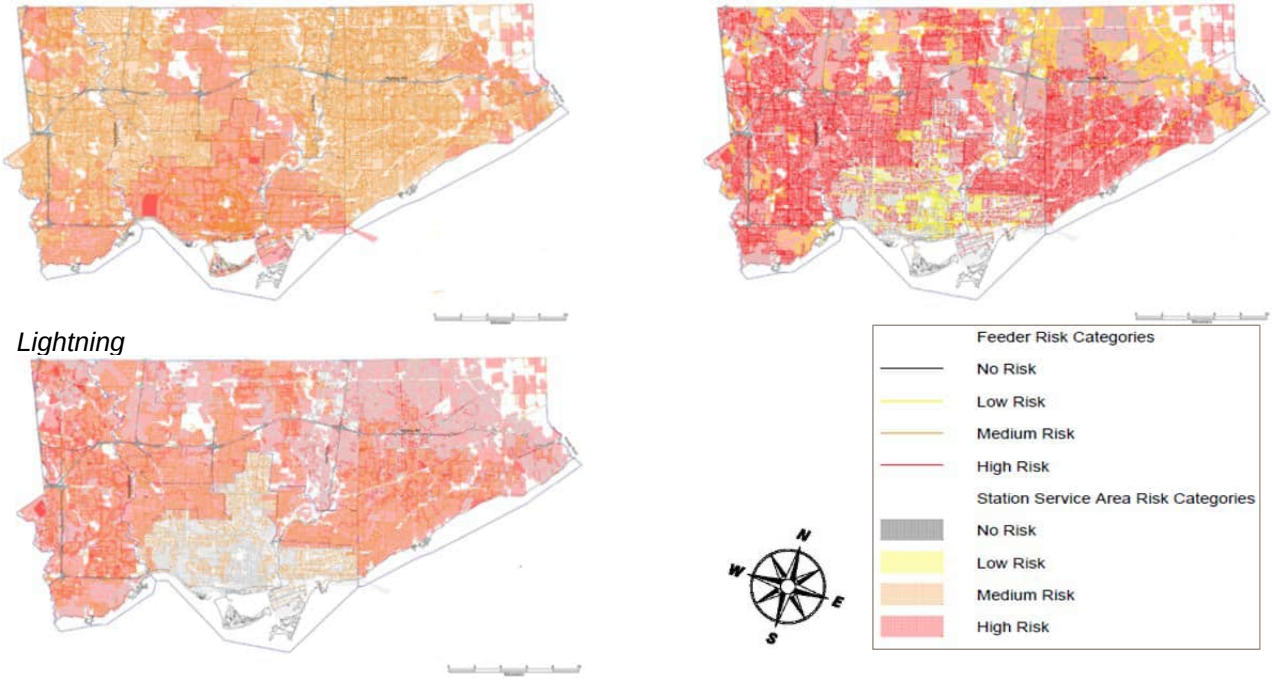
A mapping of the risk ratings was also completed as part of this study and represents a useful first approximation of spatial nature of climate change vulnerabilities to the electrical system. The mapping exercise provides additional information on how vulnerabilities stemming from stations can combine with vulnerabilities to feeder systems. In some cases, vulnerabilities stem primarily from station assets, while in other cases, both station and feeder vulnerabilities to weather events contribute to an area of greater vulnerability within the city. This mapping information can be easily combined with other layers of information such as technical hazard information (e.g. flood mapping), critical building and infrastructure locations (e.g. emergency resource centres, hospitals, transportation networks) and social vulnerability indices (e.g. age, income, population density, etc.) from other sources (e.g. TRCA, City of Toronto) to support further mapping studies and in depth analyses.

Figure ES-1 Example Maps Based on Risk Ratings for High Heat, Freezing Rain and Lightning

High Ambient Temperatures

Freezing Rain

Lightning



This study found that distribution system vulnerabilities to a changing climate were divided into five groups based on how climate parameters affect the system.

High Ambient Temperatures – Station and Feeder Assets

High ambient temperatures create problems for the distribution system because of the compounding effect of high demand (e.g. for cooling) and high ambient temperature affecting power transformer capacity and electrical transmission efficiency. Two climate parameters were of most significant concern, daily maximum temperatures exceeding 40°C (excluding humidity) and daily average temperatures exceeding 30°C. For these climate parameters, the analysis found that such extreme temperatures have occurred rarely in the past, but are projected to occur almost semi-annually by the 2030's, and annually by the 2050's. It is anticipated that vulnerability to high heat events will be concentrated in the Former Toronto area, although there are several horseshoe station service areas which would also be vulnerable.

Freezing Rain, Ice Storms, High Wind and Tornadoes – Overhead Station and Feeder Assets

Freezing rain, ice storms, high wind and tornado events can cause immediate structural issues for overhead station and feeder assets, as they have the capacity to exceed the design limits of equipment and their supports. Outages may result from damage to equipment arising from direct forces applied by climate parameters (e.g. wind, ice weight) or by other objects (e.g. tree branches, flying debris). Toronto Hydro has experienced problems related to freezing rain, ice storms (up to 25 mm) and high winds (up to 90 km/h) in the past. These events are projected to continue in the future, but continue to occur on a less than annual, or even decadal frequency. Nonetheless, the damages caused by these kinds of events can be severe, and mostly affect outdoor station and feeder assets, much of which is concentrated in the horseshoe service area.

Extreme Rainfall – Underground Feeder Assets

Extreme rainfall events may potentially flood underground feeder assets. These vulnerabilities are largely concentrated in the Former Toronto and northeastern horseshoe areas. Toronto Hydro is aware of these issues in relation to its assets and has programs to replace non-submersible equipment with submersible type equipment, to relocate equipment where possible. However, due to the large quantity of underground feeder assets across the city, replacement and reinforcement of underground assets will be a gradual and ongoing activity for Toronto Hydro over the study period. As such, some underground feeder assets may remain an area of vulnerability for Toronto Hydro.

Snowfall, Freezing Rain - Corrosion of Civil Structures

The degradation of civil structures (i.e. concrete and steel), which is accelerated by humidity and the presence of de-icing salts, was identified as a potential area of vulnerability to climate change. Corrosion is already an ongoing issue for Toronto Hydro. As such, current assets have a design lifespan which accounts to a great extent for corrosion issues. However, it is not clear from this study whether the climate change stresses will exacerbate this problem. While snowfall days are generally expected to decrease with a warming climate, they will continue to occur annually through to the 2050's. As a result, and in combination with freezing rain events, de-icing salts will also be applied annually through the study horizon, and corrosion will continue to be an ongoing preoccupation. Nonetheless, it should be emphasized that corrosion represents a long-term and on-going vulnerability for Toronto Hydro.

Lightning – Overhead Feeder Assets

Based on workshop feedback and an examination of Toronto Hydro's interruption tracking system's (ITIS) outage data, Toronto Hydro recognizes that lightning impacts are a significant source of outages on the distribution system today. While there have been advances in predicting lightning activity, there was insufficient data available on lightning strike intensity and arrester performance to suggest how future lighting activity may affect the electrical system. For these reasons, this study suggests that lightning strikes will continue to be an area of vulnerability.

Adaptation Options and Areas of Further Study

This study provides high level adaptation options under the themes of engineering actions, management actions, monitoring activities and further study. Generally, for high heat related climate parameters, Toronto Hydro could further investigate avenues to enhance the system's capacity to deal with higher demand under high temperature conditions, especially since extreme heat events are projected to occur on a semi-annual to annual basis by the 2030's and 2050's. On climate events causing structural damage issues (i.e. freezing rain, ice storms, high winds and tornadoes), adaptation options include optimizing emergency response and service restoration, as well as infrastructure hardening and burying infrastructure. While the latter engineering-type solutions are relatively capital intensive, asset renewal cycles provide excellent opportunities to consider these types of upgrades. This study also recommends that Toronto Hydro continue monitoring the occurrences and impacts of major freezing rain, high wind and tornado events on the system, as well as the science of climate change projections. This multi-faceted approach provides Toronto Hydro with greater flexibility in managing vulnerabilities related to these types of extreme climate events.

Other potential options to address identified vulnerabilities include continued monitoring and evaluation of climate change projection science, monitoring impacts of a changing climate on certain asset classes, evaluating the need to strengthen or defend certain infrastructure and equipment from climate parameters, and enhancing emergency response and service restoration practices.

Acknowledgements

This study was completed with support from Natural Resources Canada. It was produced through its Adaptation Platform Electrical Sector Working Group[3]. AECOM would also like to acknowledge Engineers Canada for the technical support, participation and for the use of its Public Infrastructure Engineering Vulnerability Committee (PIEVC) Protocol. The Toronto region's WeatherWise Partnership is also acknowledged for its work on bringing the issue of climate related threats on electrical infrastructure to the forefront, and for its support in bringing about this study. AECOM would like to thank the Clean Air Partnership for the opportunity to undertake this study.

AECOM would also like to acknowledge Toronto Hydro staff for their time and effort in providing information about their system, participating in workshops and meetings, providing insight into the functionality of their system, and reviewing documents and reports. Without their valuable contributions, this study could not have proceeded.

[3] For more information on climate change impacts and adaptation, please visit adaptation.nrcan.gc.ca" (or for French language publications/sites: "adaptation.rncan.gc.ca").

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List of Acronyms

CAP	Clean Air Partnership
GCM	Global climate model
GIS	Geographic Information Systems
HONI	Hydro One Networks Inc.
ITIS	Interruption Tracking System
NRCan	Natural Resources Canada
OPG	Ontario Power Generation
PIEVC	Public Infrastructure Engineering Vulnerability Committee
Protocol	The climate change based public infrastructure vulnerability assessment developed by the PIEVC and Engineers Canada
RCM	Regional climate model
RCP	Representative concentration pathway
RSI	Risk Sciences International
THESL	Toronto Hydro-Electric System Limited
TTC	Toronto Transit Commission

1 Study Context

1.1 Introduction and Mandate

In 2012, Engineers Canada partnered with the Clean Air Partnership (CAP) and Toronto Hydro to evaluate the risks of climate change on Toronto Hydro's electrical distribution infrastructure in the City of Toronto. At that time, CAP mandated AECOM and Risk Sciences International (RSI) to undertake a Public Infrastructure Engineering Vulnerability Assessment Protocol (PIEVC Protocol, or the Protocol)[4] based study on select components of Toronto Hydro's electrical distribution system to historical climate. That study, named the Toronto Hydro-Electric System PIEVC Pilot Case (pilot case study), was meant to demonstrate the applicability of the Protocol to electrical systems. The pilot case study was also envisioned as the first of a two-phase project to assess climate change related vulnerabilities to electrical systems. The pilot case study was completed at the end of summer 2012 (AECOM and RSI, 2012).

In summer 2013, CAP and Toronto Hydro elected to pursue the second phase of the climate change assessment with support from Natural Resources Canada's (NRCan) "Enhancing Competitiveness in a Changing Climate" program. NRCan's program is designed to facilitate the development and sharing of knowledge, tools and practices which assist decision-makers in the analysis and implementation of climate change related adaptation measures. CAP, once again mandated AECOM and RSI to carry out the Phase 2 climate change vulnerability assessment (Phase 2 study). The Phase 2 study is the subject of the current report.

1.2 Methodology and Approach

The Phase 2 study again employs the Protocol as the framework for the climate change analysis. The Protocol is composed of five steps:

- Step 1 – Project Definition;
- Step 2 – Data Gathering and Sufficiency;
- Step 3 – Risk Assessment;
- Step 4 – Engineering Analysis;
- Step 5 – Recommendations and Conclusions.

In contrast to the pilot case study, the scope of Phase 2 study was extended to include most of Toronto Hydro owned electrical distribution infrastructure and civil support structures across the City of Toronto. Toronto Hydro's streetlighting system and electrical systems for the Toronto Transit Commission were not within the scope of the present study. Anticipated climate changes and impacts at the 2030 and 2050 time horizons were evaluated. Most of the activities prescribed by the Protocol were completed as part of Phase 2 with the exception of a site visit. The triple-bottom line adaptation solutions development module, an optional undertaking in the PIEVC Protocol, was also not completed as part of Phase 2 of this study[5].

As part of the activities of Phase 2, two workshops were held with Toronto Hydro staff. The first workshop was held on July 3, 2014 in Toronto Hydro's offices in Toronto. At this workshop, an overview of the infrastructure and climate components (Steps 1 and 2 of the Protocol), were presented for discussion and validation with Toronto Hydro staff. On October 10, 2014, a second workshop was held to validate the risk assessment completed by AECOM and RSI (Step 3 of the Protocol).

[4] The Protocol is a structured and documented methodology for a screening level assessment of infrastructure vulnerability to a changing climate, and for developing adaptation solutions to identified vulnerabilities. The Protocol, currently in version 10, also allows users to evaluate the vulnerabilities stemming from current climate to the infrastructure as part of the overall assessment.

[5] The triple-bottom line adaptation solutions development module guides users in the development and screening of potential solutions to address the impacts of climate change identified in the preceding steps of the Protocol. It was not in the scope of the current study.

The components of the electrical distribution system (e.g. stations, power lines, transformers, switches, supports) under study are highly interdependent, and failures in one part of the system may result in interrelated structural, electrical or functional issues in other portions of the system (e.g. failures in poles may bring down power line and transformers, electrical faults may cause the system to lose protection, control or redundancy). For this reason, the study of electrical systems cannot be examined solely on the basis of its individual pieces or classes or equipment. This study adopts a *systems level approach*[6] to examining the climate change risks to the extensive, complex and interdependent components of Toronto Hydro's electrical distribution system. This approach divides the electrical distribution system into six major systems categories encompassing different individual components and classes of equipment. This generalization of electrical components into major systems categories facilitates an analysis that considers system dependencies and redundancies.

However, by generalizing the system into major systems categories, the granular detail of the system and its components (e.g. site specific characteristics, unique or individual pieces of equipment) may not be adequately captured. Therefore, to complete a reasonable study of the entire electrical distribution system, this study has made assumptions, informed by input from Toronto Hydro staff, about the types and classes of equipment and components typically found within each category. While the loss of granular detail may mask localized issues and vulnerabilities, it does allow this project to provide the first climate change based vulnerability assessment of electrical distribution infrastructure. This can help prioritize future investigations, resources and investment on vulnerable systems and their components in order to enhance the resilience of the electrical system.

1.3 Structure of this Report

This report is divided into seven chapters, including the present one. They are:

- Chapter 1: Study Context;
- Chapter 2: Description of the Infrastructure;
- Chapter 3: Assessment of Climate Changes;
- Chapter 4: Vulnerability Assessment Methodology;
- Chapter 5: Assessment Results;
- Chapter 6: Engineering Analysis; and,
- Chapter 7: Conclusions.

Note that Chapter 3, Assessment of Climate Changes and **Appendix B** and **C**, were authored by Risk Sciences International in consultation with AECOM study authors.

[6] This is in contrast to the component level analysis approach which was employed in the pilot case study.

2 Description of the Infrastructure

2.1 Study Area

The Phase 2 study covers Toronto Hydro's electrical distribution infrastructure and supporting civil infrastructure within the boundaries of the City of Toronto. Toronto Hydro distributes electricity across the City of Toronto, Canada's largest city, the provincial capital of Ontario, and home to approximately 2.8 million people (City of Toronto, 2014). The City of Toronto is bordered by the municipalities of Mississauga to the west (in Peel Region), Vaughan and Markham to the north (in York Region), and Pickering to the east (in Durham Region).

The City of Toronto covers approximately 641 km^2 on the northwestern shore of Lake Ontario (City of Toronto, 2014). The city's topography slopes gradually from the lakeshore, approximately 75 m above sea level to 200 m above sea level at its highest point along its northern border (City of Toronto, 2014). Three river systems cross the City of Toronto and flow into Lake Ontario. The Humber River lies on the west side of the City. The Don River essentially crosses the middle of the City of Toronto and flows into Lake Ontario just east of downtown. Finally, the Rouge River crosses the city's eastern edge. These rivers, their tributaries and creeks total about 307 km of water courses and punctuate the City's generally flat landscape with ravines.

The City lies at the eastern edge of the Carolinian Forest zone. The City contains approximately 10 million trees, approximately 4 million of which are publically owned. Of the latter, there are approximately 600,000 trees along streets and public right of ways, and another 3.5 million trees in parks, ravines and other natural areas of the city (City of Toronto, 2014).

2.1.1 Major Systems Categories Under Study

In 2014, Toronto Hydro's electrical distribution system served approximately 740,000 customers, of which around 658,000 were residential customers. The components of the Toronto Hydro's electrical distribution system are extensive, covering approximately $3 billion dollars in assets, including over 170 transformer stations of different classes, 29,000 km of overhead and underground wires, 20,000+ switches, 60,000+ transformers and 176,000+ poles (Toronto Hydro, 2014b). The present study covers most of Toronto Hydro's electrical distribution infrastructure and civil support structures, with the exclusion of its streetlighting system, and systems serving the Toronto Transit Commission (TTC). The electrical distribution system was divided into six *major systems categories* for the purposes of this study: transmission stations, feeder configurations, system communications, civil structures, mechanical auxiliaries and human resources. Figure 2-1 provides a schematic overview of the systems under study. The *major systems categories* are described hereafter, and hypotheses and generalizations that were made to facilitate the *system level analysis* approach are explained in this chapter. Supporting detail is included in Worksheet 1 of **Appendix H**.

This analysis divides the City of Toronto into two areas: the Former Toronto area and horseshoe area. This distinction is made because most of the legacy equipment is usually found in downtown Toronto and while equipment of newer design can usually be found in the horseshoe area. As such, the *major systems categories* (with the exception of human resources) are also separated between the Former Toronto area (which represents the downtown and inner city) and the horseshoe area (which covers the outlying suburbs). Figure 2-2 shows the division between the Former Toronto area (in green) and the horseshoe area (in blue).

Information about the *major systems categories* was drawn from three principal sources:

- *Overview of the Toronto Hydro Distribution Systems*. Toronto Hydro-Electric System Limited, 2014, Power point 203 p.
- *Overview of the Toronto Area Transmission Systems and Toronto Hydro Distribution Systems*. Toronto Hydro-Electric System Limited, 2014, Power point 121 p.

- System Expansion and Studies Section System Reliability Planning Department. *Toronto Hydro Distribution System Planning Guidelines.* Toronto Hydro-Electric System Limited, 2007, 22 p.

Figure 2-1 Major System Categories Under Study

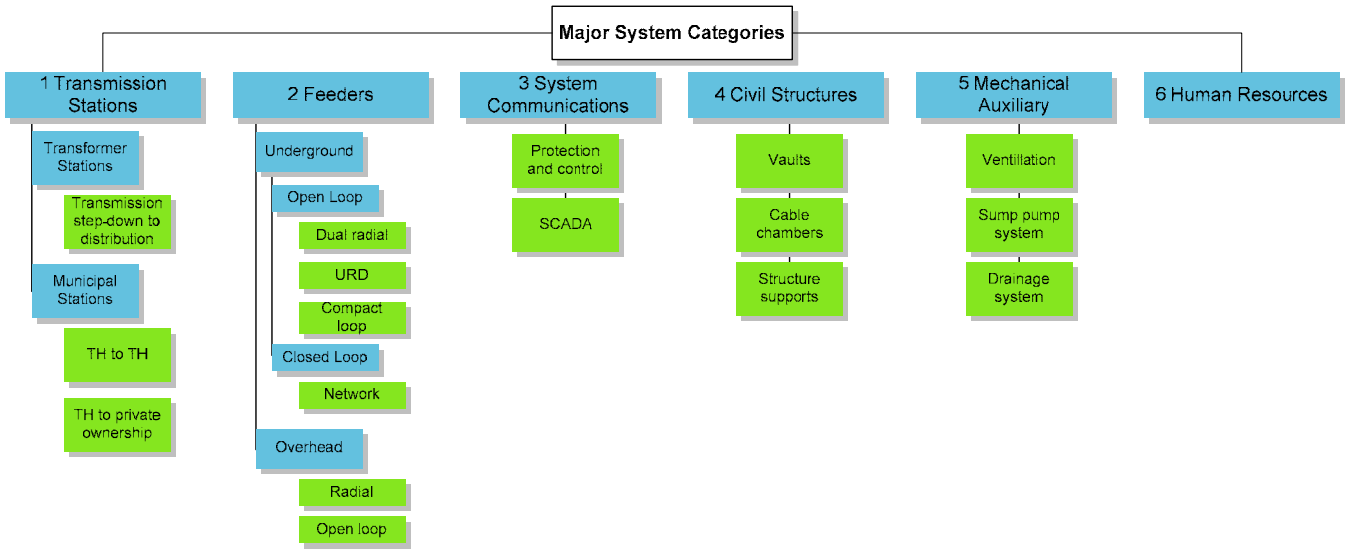
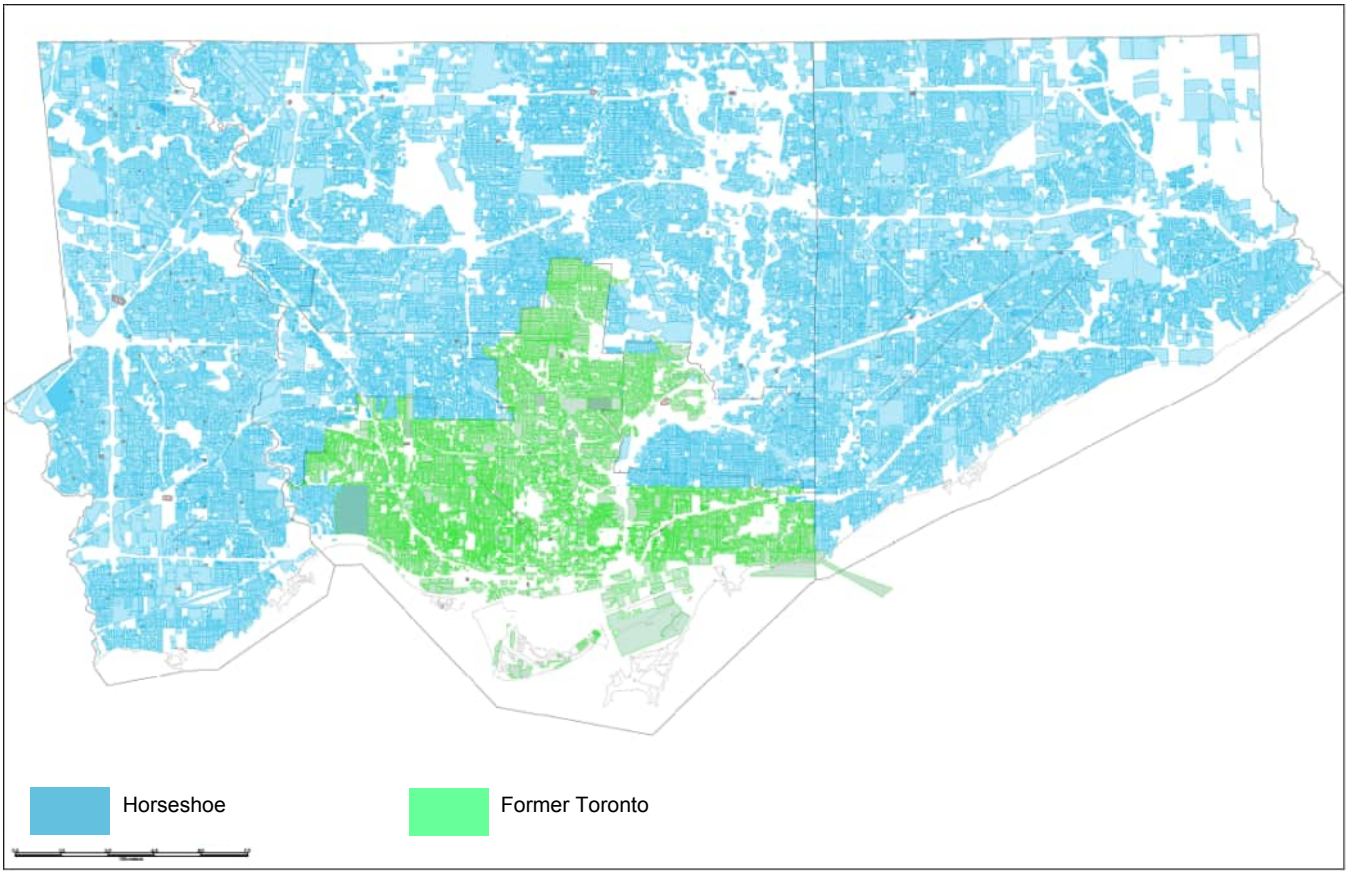


Figure 2-2 City of Toronto Study Area



2.2 General System Overview

The electric power system of the province of Ontario is a large interconnected electrical system of generating, transmission, and distribution infrastructure. Generating stations in Ontario are either privately or publicly owned. From the generation stations, the electricity is transmitted throughout the province over high voltage transmission lines, the majority of which is owned by Hydro One Networks Inc. (HONI). The electricity is then distributed to customers by local distribution companies like Toronto Hydro (Figure 2-3).

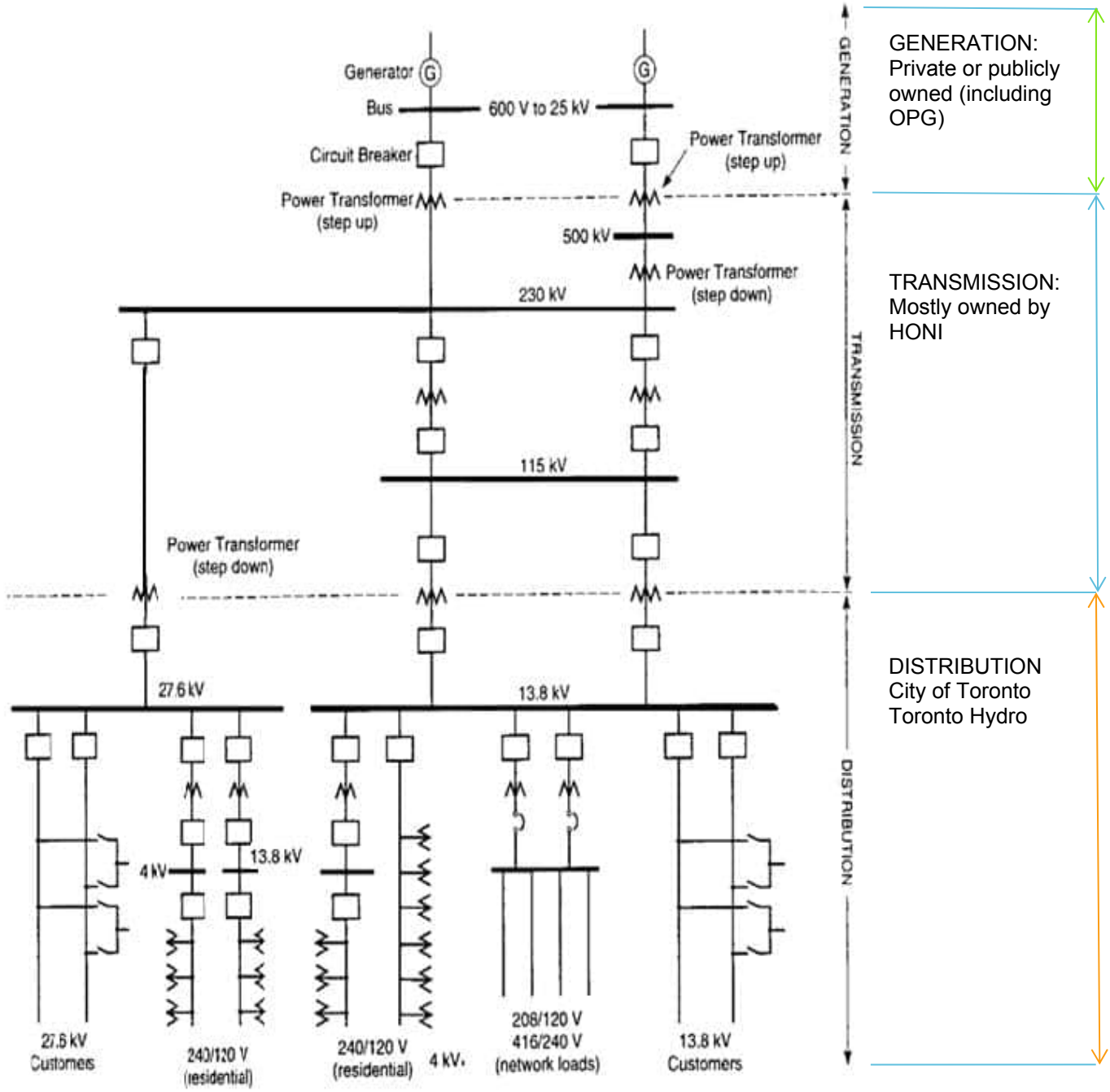
In the case of the City of Toronto, 230 kV and 115 kV transmission lines owned and operated by HONI bring power to the city. The 230 kV transmission lines mostly serve the horseshoe area, while the 115 kV lines serve most of the Former Toronto area. The 115 kV transmission lines are supplied from three major sources: Leaside station (230/115 kV step down) from the east, Manby station (230/115 kV step down) from the west, and by one generating station located within city limits, the Portlands Energy Centre (PEC) owned by Ontario Power Generation (OPG). PEC generates electricity through three natural gas turbine generators.

Presently, there are 35 transmission stations that step down high voltage currents (230 kV and 115 kV) to the distribution system voltages used by Toronto Hydro (i.e. 27.6 kV and 13.8 kV) (Figure 2-4). The equipment within these stations is owned by either Hydro One or Toronto Hydro, with the exception of Cavanagh station, where all equipment is owned by Toronto Hydro. The division of equipment ownership varies by station. However, since transmission stations are critical, first points of entry of electricity into the city's distribution network, this study considers all equipment within the transmission station, since equipment failure within the station, irrespective of ownership, may compromise its function.

From transmission stations, Toronto Hydro distributes electricity via a network of underground and overhead feeder systems at voltages of 27.6 kV and 13.8 kV. A third distribution voltage level of 4.16 kV, a legacy from historical distribution practices, also operates in the city. The 4.16 kV network is supplied by transformation of 27.6 kV or 13.8 kV feeds at Toronto Hydro owned municipal transformer stations. These three distribution voltages will remain in service for the duration of the Phase 2 study period, even though many of the 4.16 kV power lines are gradually being converted to 13.8 kV and 27.6 kV lines.

This electrical distribution infrastructure is connected via communications systems which afford control and protection of electrical equipment from damage or faults. This system is critical to the operation of the electrical system and is part of this study. In addition, this study considers all civil structures that support the electrical equipment and all mechanical equipment inside underground vaults (ventilation, sumps and pumps). A last category includes all human resources operating and managing Toronto Hydro distribution system.

Figure 2-3 Typical Electric Power System



Source: (Toronto Hydro, 2014d)

Figure 2-4 Transmission Stations

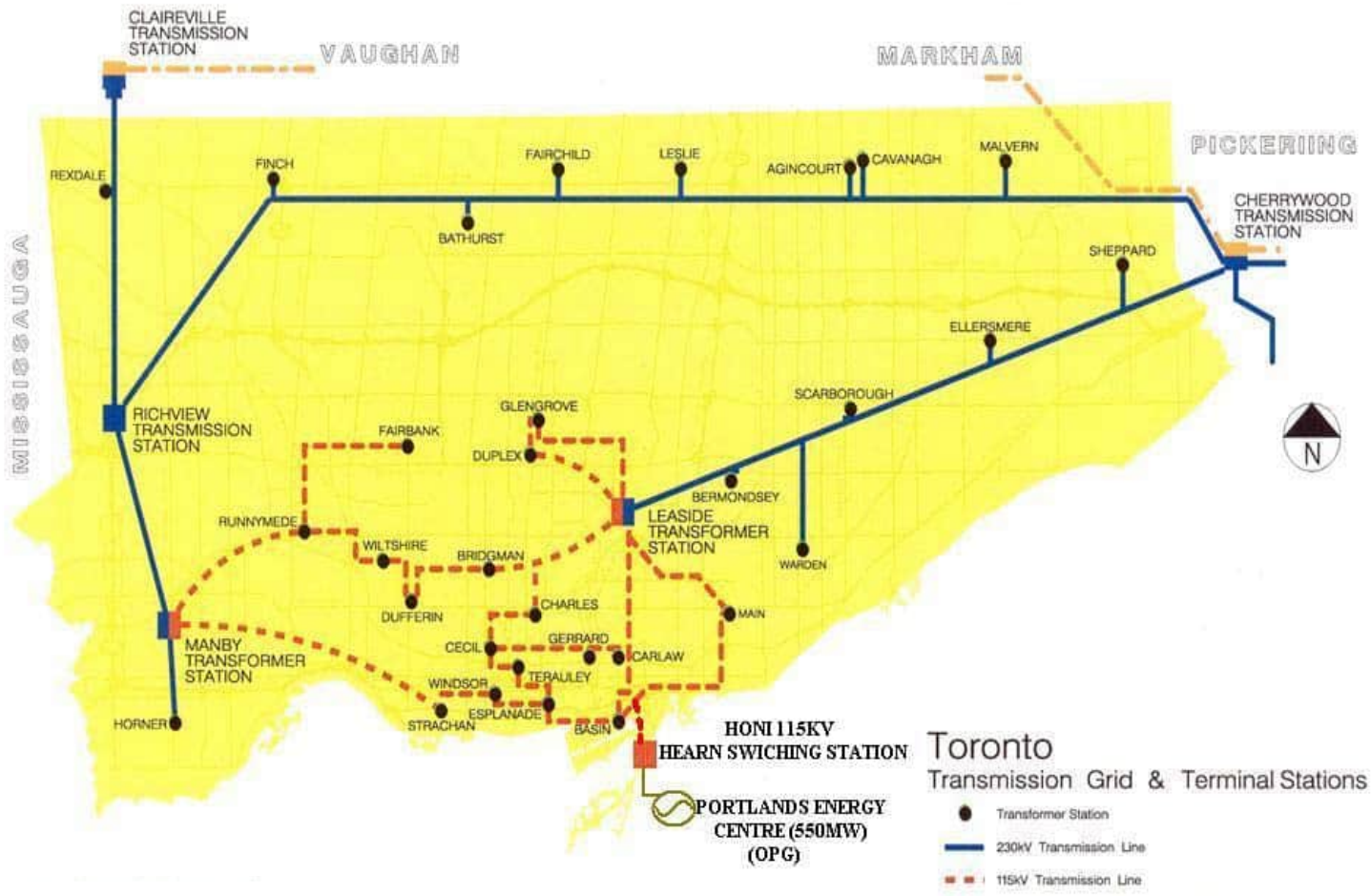


Figure source: (Toronto Hydro, 2014d)

2.3 Substations

2.3.1 Transmission Stations

At the moment, there are 35 transmission stations located in the City of Toronto. Most transmission stations located in the downtown and inner city have primary voltages at 115 kV and step-down to 13.8 kV. In the horseshoe area, the primary voltage is 230 kV and stepped-down to 27.6 kV (most) or 13.8 kV (some). The table below illustrates the list of stations that are divided into the two main service areas, and six sub-service areas[7] (Table 2-1).

[7] Stations have been grouped into these service areas by Toronto Hydro due to:
- Similarity of historical development and presumed potential for future development;
- Theoretical potential for permanently transferring load between neighbouring stations on an operational basis and/or through capital projects;
- Statistical correlation (coefficient of determination, R2) of the overall area growth rate to actual historical peak loads in the area (relative to potential alternative area groupings).

Table 2-1 Transmission Stations and Service Areas[8]

Service Area *(Voltage step down)*	Number of Stations
Former Toronto	
Downtown core *(115 kV/13.8 kV)*	6
Downtown outer *(115/13.8 kV, 230/115 kV, 115/27.6 kV)*	11
Horseshoe	
North Stations *(230/27.6 kV)*	2
East *(230 kV/27.6 kV, 230/115 kV)*	10
Northwest *(230 kV/27.6 kV)*	4
Southwest *(230/27.6 kV, 230/115 kV)*	2

In the Former Toronto area, there are no station ties between station service areas to allow for the transfer of some feeder loads from one station to another. In the horseshoe area, there are existing station ties available to allow the transfer some feeder loads from one station to another.

In the horseshoe area, the transmission stations are considered “outdoor”, as all equipment’s are exposed to the elements. A control building containing weather sensitive equipment and operators control room is located adjacent to the station. In the Former Toronto area, most stations are configured with equipment located indoors. The entire transmission station is surrounded by fences or walls for public safety.

All stations are essentially based on the Dual Element Spot Network (DESN) design configuration. Typically DESN has two power transformers with 230 kV or 115 kV primary windings, two 27.6 kV or 13.8 kV secondary windings and two buses.

By 2016, the Copeland Station (a gas insulated station) will be brought into service in the Former Toronto area. Gas Insulated Stations occupy less space than air insulated stations of comparable capacity. The gas used for insulation in the Copeland Station is Sulfur Hexafluoride (SF6).

Typical equipment – Transmission Stations

While each of the 35 transmission stations have site specific characteristics, representative and typical equipment found in all stations are:

[8] Station names have been excluded from this version of the report.

- Power transformers
- Lightning arresters
- Current and voltage transformers (instrument transformers)
- Disconnect-switches or interrupters (loadbreak switches)
- Circuit Breakers
- Medium voltage switchgears
- Bus bars
- Transmission station configurations: double bus - double breaker configuration, double bus - single breaker, double bus - double breaker or double bus and one and a half breakers.

A picture of a typical transmission station yard is shown in Figure 2-5.

Figure 2-5 The Station Yard at Cavanagh Transmission Station



Picture source: (Toronto Hydro, 2014a)

Note that this station *major systems category* does not include civil structures or protection and control systems. These other critical infrastructure components which form part of the transmission station are described under separate *major systems categories* below.

2.3.2 Municipal stations

The municipal stations are divided into two sub-categories. First, “Toronto Hydro to Toronto Hydro” municipal stations step down from 27.6 kV to 13.8 kV or to 4.16 kV in the Horseshoe Area, and in the Former Toronto area from 13.8 kV to 4.16 kV. There are also smaller transformer stations located on the sites of Toronto Hydro customers with high load demands. These stations are called “Toronto Hydro to Private ownership” stations in this study.

Toronto Hydro is converting its 4.16 kV voltage level over time to 13.8 kV and 27.6 kV because of age, loss minimization, equipment inventory reduction, and required or projected future load growth (Toronto Hydro, 2007). Toronto Hydro estimated that by 2030, 50% of the 4.16 kV equipment will be converted in the Horseshoe Area and all of it will be phased out in the Former Toronto area. By 2050, Toronto Hydro is expected to have replaced 70% of the 4.16 kV overhead power lines in the Horseshoe (Hypotheses issued in Workshop 1, 2014).

Toronto Hydro to Toronto Hydro

There are around 169 municipal stations (27.6 kV/ 13.8kV or 27.6 kV/13.8 kV / 4.16 kV) within the City of Toronto. Approximately 82 municipal stations are located entirely within a building, and these indoor stations are mostly located in the Former Toronto area. The remaining stations have some or all equipment located outdoors. These stations are classified as outdoor stations for the purposes of this study, and most are located in the horseshoe area. Figure 2-6 shows a picture of a typical outdoor station located in a residential area. For the purpose of this study, it is assumed that all Former Toronto area municipal stations are indoors, while horseshoe stations are outdoors. For those few outdoor stations in the Former Toronto area, their vulnerability will be identical to the outdoor stations in the horseshoe area.

Figure 2-6 Residential Area MS (front and rear views)



Figure source: (Toronto Hydro, 2014a)

Toronto Hydro to Private Ownership

Toronto Hydro to Private Ownership stations supply large loads at low voltages to private customers. The station is located on private property inside a closed room. Most of these stations are owned by Toronto Hydro, although some are owned by the customer.

Typical equipment – Municipal Stations

Typical equipment within municipal stations is similar to transmission stations, but are generally smaller in size because less capacity is required. In general, municipal stations include:

- Oil power transformers (ONAN/ONAF);
- Instrument transformers;
- Disconnect switches;
- Circuit Breakers;
- Cables;
- Fuses;
- Arresters.

2.4 Feeder Systems

Toronto Hydro employs feeder systems, or systems of power lines, transformers, switches and related equipment, to distribute electricity across the City of Toronto. The feeders are either installed on overhead poles (overhead systems) or travel through underground cables (underground systems). Overhead feeder systems can be located on the front side of a property (front lot) or at the back of the property (rear lot). However, rear lot systems will be phased out by the 2030s and are not considered in the scope of this study. They are progressively being replaced

by front lot overhead or underground infrastructure, which provides Toronto Hydro more convenient access. In total, Toronto Hydro customers are served by over 900 feeders[9] (Navigant Consulting Ltd. 2011).

Approximately 30 % of Toronto Hydro's distribution network is comprised of 27.6 kV feeders from 3 - 4 km (considered ''short'' lines) to 5 - 6 km (considered ''long'' lines) in length. These systems are mostly located in the horseshoe area. 70 % of Toronto Hydro's distribution feeders operate at 13.8kV, and vary in length between 2 – 3 km (short) to 3 - 4 km (long) (Navigant Consulting Ltd., 2011). The 13.8 kV systems serve both the downtown and horseshoe areas. A very small percentage of feeders still operate at 4.16 kV.

2.4.1 Electrical Configurations

The electrical configuration of a feeder determines the way electricity is delivered to customers. It is indicative of the feeder's ability to provide electrical service in the event of equipment damage and electrical faults. There are many different electrical configurations of feeders, and they include radial, dual radial, open loop and closed loop systems. Some of these systems may also be nested within one another (e.g. an open loop system with downstream radial feeders). Toronto Hydro's main underground and overhead feeders are arranged in an open loop type configuration, although there are also dual radial and radial feeder systems, some of which may be nested within the open loop configuration. Only one feeder type, the 13.8 kV network, is arranged in a closed loop type configuration. The various electrical configurations considered in this study are:

- Underground dual radial and underground residential distribution (URD) feeders;
- Underground closed loop network feeders;
- Overhead open loop and radial feeders.

In the open loop system, the feeder line runs out of the station through two separate feeder arms that eventually reconnect outside the station to form a loop. A load interrupting switch (tie switch) is located at the reconnection point and is normally kept open between the two feeder arms. If one feeder arm goes out, the load can be fed by the other feeder arm by closing the tie switch. In open loop systems under single contingency condition[10], the customer typically experiences an interruption when the feeder is switched from one feeder arm to the other.

In radial systems, the customer is supplied by only one feeder. It is the least expensive design but also offers the least flexibility in electrical service restoration in the event of a fault, as there is no other feeder that can supply electricity until the line is repaired. Radial feeder segments may be nested within open loop systems.

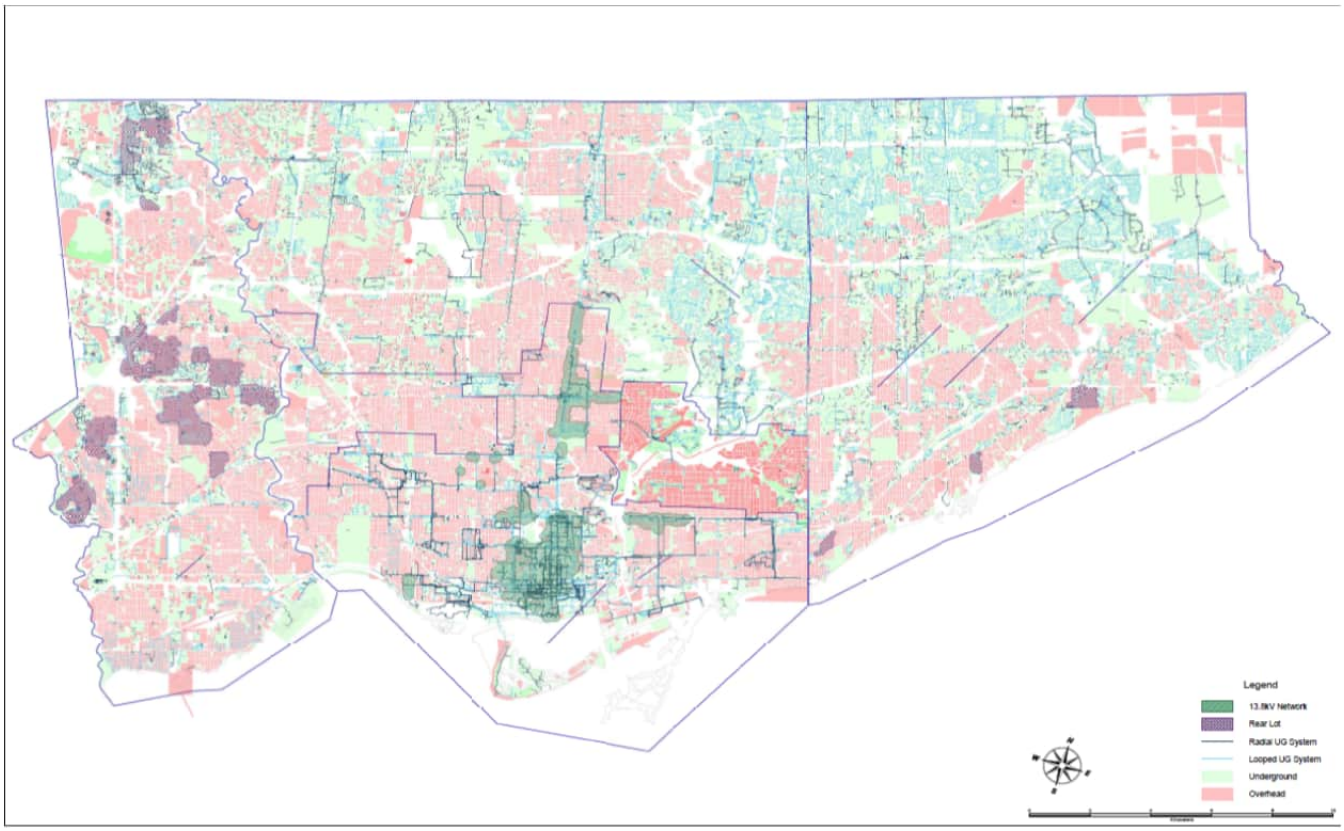
Dual radial systems are similar in design to radial feeders except that each customer is connected to two parallel radial feeders. The load is supplied by one of the radial feeders, as the other radial feeder remains on standby. In the case of a fault, the load is transferred from one feeder to the other by manipulating interrupter switches tying the two radial feeders together. Large commercial and industrial customers, as well as Toronto Hydro municipal stations and several older Toronto Transit Commission (TTC) stations are typically served by dual radial systems. A compact loop system is similar in configuration to a dual radial system, but is employed where space is more limited (e.g. in existing vaults).

In closed loop systems, customers are supplied by multiple feeders, and are fed via several redundant transformers and network protectors. If one feeder goes out, the customer can be supplied by another feeder. Closed loop systems are advantageous because under single contingency conditions, customers experience no power interruptions (Toronto Hydro, 2007). Only Toronto Hydro's 13.8 kV network system is a closed loop system.

[9] This total may vary depending on how feeder branches and sub-branches are counted.
[10] Single contingency condition or N-1 represents the condition where all electrical equipment is in service except one element. For example, if a substation has two power transformers, but one of them is out of service, the condition is called "N-1". The condition "N-1" generally occurs after a major disturbance causes equipment to trip and go-offline.

Figure 2-7**Error! Reference source not found.** shows the distribution of feeder types across the city. The 13.8 kV network, represented in dark green, is mostly concentrated in downtown Toronto (downtown core and the Yonge Street and Bloor Street corridors), while the other feeder types can be found across the city.

Figure 2-7 Location of Feeders, by Type



Source: Toronto Hydro

Typical equipment

For all underground feeders

The distribution transformer station of underground feeder systems can be classified according to one of three types:

- Vault type: The vault transformer can be small and located just below ground for single phase clients, or large and deeper underground for clients requiring larger, three-phase power supplies. Some vault type transformers can be located above ground inside a building. The equipment located in vault type enclosures cannot operate if the vault is flooded.
- Submersible type: They are designed similarly to the vault type transformer stations but the equipment is designed to operate when submersed. For example, submersible transformers are capable of continuous unattended operation while completely submerged under a head of 3 m of water over the top of the tank (IEEE Std C57.12.24, 2009, p. 3). They are currently the preferred design due to their submersibility.
- Padmount type: The padmount transformer is located on ground level in a metal-clad enclosure.

Underground feeder equipment typically consists of the following:

- Cables: The cables used in underground systems are generally insulated with cross-linked polyethylene (XLPE) or a paper insulated lead cover (PILC). The PILC cables also contain oil
- Pilot wire: For large and sensitive customers

- Fault circuit indicators
- Power transformers modules:
    - Load-break switch modules: Metal enclosed, air insulated, Vacuum or SF6 arc extinction, motorized or manual;
    - Fuse modules: Metal enclosed, air insulated, electronic fuses or SF6 power fuses or current limiting fused;
    - Power transformer : Oil type (most), dry type (in above grade vaults) or some used FR3 fluid (environmental friendly);
    - Elbows: cable connections to power transformers.
- Specifically for the network system, typical equipment consists of the following:Primary feeders;
- Network Units;
    - Primary Switch – Embedded in power transformer;
    - N/W Transformer: dry type;
    - N/W Protector: Breaker, back-up fuse, relays, current transformers, cable limiter.
- LV secondary network grid or spot networks;
- Except for the old network protectors, all network unit equipment are submersible.

For overhead, open loop and radial feeders:

- Poles: See civil categories below;
- Distribution transformers : ONAN (Oil Natural Air Natural) system;
- Gang-operated switches, single-phase switches or SCADA switches;
- Load interrupting switches;
- Fuse disconnecting switches;
- Conductors: “tree proof” protected aluminium (AL) conductors, steel reinforced aluminium conductors (ACSR), aluminium conductors (no tree proof protection), and copper (CU, legacy);
- Voltage Regulators;
- Circuit-breakers with reclosers;
- Capacitors;
- Insulators: made from porcelain (approximately half of all installed insulators) and polymer material (porcelain insulators are being progressively replaced by polymer insulators).

2.5 Communications Systems

The communications systems support the control and protection of electrical equipment. They are divided between protection and control systems, and the SCADA system.

For power lines, the distribution switch automation is generally limited to the 27.6 kV systems (Toronto Hydro, 2007).

Protection and control systems

The protection and control systems are located inside control buildings. Except for batteries, they are located in a temperature controlled room. Batteries at some stations in the Former Toronto area are currently located in the basement of buildings. However, Toronto Hydro expects to relocate these battery assets above grade by the 2030’s in order to help reduce flooding threats.

Typical electrical equipment

- Relays:
- Fuse, Load-break Switch, Circuit Breaker;
- Batteries;
- Auxiliary systems: cranes, fire alarm systems, air compressors, etc.

SCADA system

The supervisory control and data acquisition (SCADA) system is an automated system to remotely control equipment and gather operating information about electrical equipment.

Typical electrical equipment

- SCADA Switch;
- Battery;
- The remote terminal unit (RTU);
- Fault Detector;
- Fiber optic conductor;
- Motorized cell interrupter.

2.6 Civil Structures

The civil structures house or provide structural support for all electrical equipment. They are found in transmission and municipal stations, and all underground and overhead feeder systems.

As a general rule of thumb, civil structures are generally older in the Former Toronto than in the horseshoe area. Older structures (before 1970) may be more susceptible to climate impacts due to their degradation (wood rotting, corrosion of steel) and lack of reinforcement in concrete and design loads.

Typical equipment

For transmission and municipal stations:

- Gantry Towers;
- Exit lines;
- Equipment supports;
- Building: for indoor stations.

For underground feeders and transformer stations:

- Reinforced concrete cable chambers;
- Concrete vaults;
- Underground cable ducts.

For overhead feeders:

- In 2014, there were approximately 176,000 poles in Toronto Hydro's electrical distribution system. The types of poles by construction material are approximately distributed as follows :
    - Concrete : 36%;
    - Aluminum: 2%;
    - Steel: 4%;
    - Cedar Poles : 58%;
    - Fiber glass: Negligible.
    - Iron: Negligible.
- Conductors and hardware (e.g. supports, bolts, etc.);
- Concrete footings (for steel, aluminium, concrete and some wood poles).

2.7 Auxiliary mechanical

Ventilation

All vaults have passive ventilation i.e. natural ventilation through slot openings in cover grates.

Drainage system

Toronto Hydro drainage systems can generally be divided according to the two types of vaults in which they are found:

- Small, shallow single phase sub vaults: do not contain pumps. These vaults' drains are connected to the city's sewer or storm sewer system and drain naturally. These vaults are also being fitted with automatic Petro plugs which stop drainage when oil is detected in the flow (equipment or other pollutant source) in order to prevent oil leaks into the sewer.
- Big deep vaults for Network, URD feeders: most of these kinds of vaults are equipped with mechanical pumps as they are located at a significant depth below grade and often below city sewers. Drains are installed in the walls of the vault and pumps are used to force water into the city's sewer systems. Approximately 10 % of network, URD vaults have drains without pumps (i.e. gravity driven natural drainage).

Sump pump

In 2014, approximately 1600 vaults out of 14,937 vaults had sump pumps (11%) (Toronto Hydro, 2014e). Toronto Hydro estimates that by the 2030's, these sumps will have oil sensing traps that will close if oil (equipment or other pollutant source) is detected.

2.8 Human Resources

Toronto Hydro has approximately 1,500 employees comprised of certified tradespeople, engineers and management professionals (Toronto Hydro, 2012). Employees who are involved in the operation of the electrical distribution system include supervisors and field crews for overhead, underground and network systems, control room staff, call centre workers and dispatchers. Toronto Hydro staff also includes the management team, engineers, asset management specialists and electrical system designers.

Weather can generally affect human resources in two ways. Adverse weather events can affect travel conditions on the journey to and from work for all employees. Furthermore, adverse weather events can affect the working conditions for field crews and field supervisors who need to access, operate or work on equipment across the city. Toronto Hydro strives to ensure a safe working environment for its employees, and has occupational health and safety policies and procedures in place that conform with the international occupational health and safety management system specification OHSAS 18001. These policies and procedures are complemented by the professional judgement of its workers as to whether conditions are safe enough to access outdoor equipment.

2.9 Time Horizon

The evaluation was carried out for the study period (2015 to 2050), but with specific focus on the possible state of the electrical system at the 2030's and 2050's time horizons. For example, this study considered changes to infrastructure systems based on current practices, trends and policy directions (e.g. transition from rear lot to front lot power lines, the partial phase out of 4.16 kV system, some demand and supply projections[11], replacement of

[11] It should be noted that city-wide land use changes (high rises, condo development and population growth) were not included in the analysis, due to the scope of such an undertaking and the complexity of information required. However, system vulnerability was judged based on climate change stresses, as it was assumed that gradual population growth would be accommodated by corresponding growth of Toronto Hydro systems under business as usual practices without the added stress of climate change.

non-submersible equipment). Toronto Hydro documentation, electrical standards and consultations with Toronto Hydro staff were all used to help identify and describe the potential changes to assets at the 2030's and 2050's time horizon. The probability of a climate parameter occurring during the study period and on an annual basis for the 2030's and 2050's was also determined (see next chapter for further details).

2.10 Other Potential Changes that May Affect Infrastructure

2.10.1 Dependencies on Hydro One Infrastructure

Toronto Hydro is part of an interdependent electrical system that is reliant on infrastructure facilities that generate electricity, transmission systems that transport electricity over long distance, and transformer stations that convert voltages for transport and use. The electrical generation and transmission supply infrastructure on which Toronto Hydro relies upon can also be vulnerable to the impacts of a changing climate, and are owned by other electrical companies and organizations in Ontario. Therefore, it is important to note that the vulnerability of Toronto Hydro is therefore also tied to the vulnerability of these supply side infrastructure.

It should also be noted that in the event of a power outage, certain facilities and dependent infrastructure can be supplied by temporary, backup power generators (such as diesel or natural gas generators). In some cases, homeowners may be equipped with photo-voltaic cells that may be able to provide some power in the event of an outage. However, these forms of dispersed generation are specific to facilities and individuals, and not sufficient to meet the demands of larger portions of the population. Dispersed generation does not currently provide sufficient capacity to alleviate Toronto Hydro of its dependence on the large scale electrical generation and transmission supply infrastructure.

Most of the 230 kV, 115 kV and 27.6 kV station equipment that tie Hydro One transmission infrastructure to Toronto Hydro are owned by Hydro One, except for the 27.6 kV breakers at the transmission stations supplying the former North York area and the Cavanagh transmission station, which is totally owned by Toronto Hydro. In general, Toronto Hydro owns the 13.8 kV switchgear equipment. Toronto Hydro and Hydro One share a common Transmission Connection Agreement (Toronto Hydro, 2007).

2.10.2 Load Projections

Electrical load or demand is a significant factor in the operation of transmission stations. Demand is influenced by a variety of factors, including population size, types of uses (e.g. residential, commercial, industrial, institutional, infrastructure), time of day (e.g. peak, off-peak, night time), as well as daily temperature (e.g. heating, cooling).

For the present study, the projections of electrical load on each of the main transmission stations serving the City of Toronto were completed, and are shown in the next table. The methodology used by Toronto Hydro to calculate the projected load for the 2030's and 2050's is described in **Appendix F**. Major future load demand, added transmission station added capacity (i.e. growth), and proposed load transfers[12] were considered by Toronto Hydro.

[12] Load transfer represents the capability to discharge some load from one station to another transmission station. In case of an outage or a very high demand, the loss of supply, or requirement for additional electricity can be provided by another location. Some transmission stations have higher transfer capabilities than others due to higher installed capacity and/or lower demand. However, this capability changes with time: the increasing demand can lessen this flexibility, while investments in new additional capacity can increase the station capability.

Table 2-2 Load Projections by Transmission Station

Service Area *(Voltage step down)*	Number of Stations	Projected load (2030's)[13]	Projected load (2050's)
Former Toronto			
Downtown core *(115 kV/13.8 kV)*	6	86-95%	>95%
Downtown outer *(115/13.8 kV, 230/115 kV,115/27.6 kV)*	2	70-85%	>95%
	6	86-95%	
	3	>95%	
Horseshoe			
North Stations *(230/27.6 kV)*	1	86-95%	>100%
	1		86-95%
East *(230 kV/27.6 kV, 230/115 kV)*	1	<70%	70-85%
	2	<70%	86-95%
	3	70-85%	86-95%
	2	86-95%	86-95%
	1	86-95%	>100%
	1	>100%	>100%
Northwest *(230 kV/27.6 kV)*	2	70-85%	>100%
	1	86-95%	86-95%
	1	<70%	86-95%
Southwest *(230/27.6 kV,230/115 kV)*	2	86-95%	>100%

2.11 Data Sufficiency

The general characteristics of the systems under review were adequate for the purpose of this exercise, although it should be noted that no site visit was conducted in the project. Chapter 7 contains recommendations about further work that can be used to enhance the analysis of electrical system performance and sensitivities to climate related stresses.

[13] Note that Toronto Hydro considers 95 % as the max station load capacity in former Toronto area. This is because there are no station ties between station service areas to allow for the transfer of some feeder loads from one station to another. When a former Toronto area station achieves 95% of its capacity, it signals to Toronto Hydro that a station load relief project is required. In the horseshoe area, station max capacity is considered to be 100% max load capacity, as there are existing station ties available to allow the transfer of feeder loads from one station to another.

3 Assessment of Climate Changes

This chapter describes how the climate data used in this study was developed. This work involved three activities, the identification of climate parameters, the estimation of the historical and future probability of occurrence of climate parameters, and the conversion of probabilities into PIEVC scoring to support the risk assessment. The results of this work are summarized in a table at the end of this chapter (Table 3-2). **Appendix B** and **C** support this chapter, providing additional background information on the methods, information sources and assumptions. The climate work was principally conducted by Risk Sciences International in collaboration with AECOM.

3.1 Climate Data Development Methodology

The development of climate data to support this study involved three main activities.

- First, climate parameters (e.g. temperature, precipitation, wind) and threshold values at which infrastructure performance would be affected were identified (i.e. climate parameters);
- Next, the probability of occurrence of each climate parameter was estimated for future climates; and,
- Finally, the probability information of climate parameters was converted into the PIEVC seven point scoring scale to support the risk assessment.

3.1.1 Identification of Climate Parameters

The identification of relevant climate parameters and infrastructure impact thresholds was an iterative process involving a combination of three methods:

- Literature review of design loads in codes, standards and published literature;
- Practitioner consultation, including targeted interviews, email communications, and workshops; and,
- Forensic analyses of either system specific case studies or relevant cases in the published and grey literature.

While these methods were employed during Phase I, they were expanded significantly and updated for Phase 2. The list of climate parameters from Phase 1 of this study was revisited through practitioner consultations (i.e. workshops), and a more thorough forensic analysis process was conducted using newly available impacts data provided by Toronto Hydro. Literature, including the Institute of Electrical and Electronics Engineers (IEEE) and CSA standards, was reviewed by both RSI and AECOM research team members, yielding more specific design thresholds and criteria. Further information about these techniques can be found in **Appendix B.**

3.1.2 Estimating the Probability of Occurrence of Climate Parameters

To estimate the probability of occurrence of climate parameters over the study period, their probability of occurrence was first established for historical climates. Future conditions cannot be well understood until current and historical climate conditions are quantified, particularly with regards to already existing vulnerabilities and thresholds present within the distribution system. This historical information was combined with climate projections from an ensemble of global climate models through the application of the “Delta-method” (see description on next page) to obtain estimates of the probability of occurrence for climate parameters. Additional complementary estimation techniques (i.e. regional climate models, statistical downscaling, climate analogues) were also employed to evaluate several complex climate events (e.g. freezing rain, ice storms, high intensity rainfall, lightning, tornadoes), as well as to validate or refine the results obtained from the “Delta-method” approach. These tasks are summarized in the following section while more details can be found in **Appendix B**.

Establishing Historical Climate Baseline

The probability of occurrence of climate parameters under historical climate conditions was established in Phase I of this study. Phase 2 reviewed and further refined them in order to serve as a baseline for climate change projections.

Historical climate conditions were established based on Environment Canada's climate station network, the most reliable and highest quality long-term climate record in Canada. While there are numerous climate stations in and around the City of Toronto, detailed hourly weather data are usually only available from airport locations. Thus, the majority of historical climate information used in this analysis is based on records from Pearson International Airport, with further contributions from Buttonville and Toronto Island Airports. Toronto is also the location of the climate station with the longest period of record in Canada, located at its City Centre location, a separate site which provided further perspective on longer term historical climate.

In the case of extreme, very localized, or complex climate events (e.g. tornadoes, freezing rain, ice storms, lightning storms), authors employed alternative methods (e.g. using averaging periods greater than 30 years) or consulted alternative data sets (e.g. the historical tornado database) to establish a historical baseline because this information was not directly available from weather station data.

Future Projections

The climate projection data which serves as a basis for this study was sourced principally from global climate models (GCMs). The latest International Panel on Climate Change (IPCC) 5th Assessment Report (AR5) provided results from 40 GCMs, produced and operated by modeling centres from around the globe. These models provide many of the basic parameters used in developing projections, as well as providing the "boundary conditions" for more detailed assessments, such as downscaling studies. The availability of multiple models also allows for the use of climate model "ensembles," which use multiple models for the development of projections, rather than employing the results of a single model which may contain biases affecting the accuracy of results. The use of ensembles is considered by the IPCC as a best practice for climate analyses, and therefore has been the dominant method used for climate projections in Phase 2.

GCMs require "emissions scenarios" as inputs for the calculation of climate projections. The latest IPCC AR5 has introduced a new method of describing future changes in emissions. Representative Concentration Pathways, or RCPs, describe explicitly the expected increase in energy generated by increases in greenhouse gases. The most pessimistic emissions scenario, RCP 8.5, indicates an increase of 8.5 watts per square meter of additional energy under future climate conditions. It is referred to as the "business as usual" emissions scenario, provides the best fit based on historical trends in global emissions, and was the scenario used for Phase 2. Further details on IPCC findings, GCMs, RCPs, and other aspects of climate change projections, can be found in **Appendix B.**

Applying the "Delta-Method"

Individual GCMs contain inherent biases when attempting to recreate historical climate, for example being either too cool or warm compared to historical averages. To compensate for this effect, the "Delta-method" was employed. First, GCMs were evaluated to determine changes from their own respective baselines. This difference between model baseline and projected conditions is then applied to the observed historical climate baseline. For example, if the GCM ensemble indicated an average increase of 2 degrees between the baseline period and the 2050's, and a given station shows an average annual temperature of 3°C, then the projected annual average temperature for that location for the 2050's becomes 5°C. This represents the "delta", or the change in climate parameter based on the difference projected by the GCM ensemble applied to historical baseline data.

Treatment of Complex Climate Events

To validate the results obtained from the GCM – "Delta-Method" for some of the climate parameters, three other complementary estimation techniques were also used, regional climate modeling, statistical downscaling

techniques and climate analogues. Furthermore, some complex climate events tend to occur on much smaller spatial and temporal scales than are covered by GCMs (e.g. tornadoes, freezing rain, ice storms, lightning). Use of these three complementary estimation techniques was necessary to develop projections for these kinds of climate parameters.

It should be noted, however, that even with the availability of specialized methods, there remain highly localized atmospheric events which cannot be projected with confidence, and the effects of climate change on these types of events are still being researched by the climate research community. See **Appendix B** for further discussion of developing projections for complex climate events.

Estimating the Probability of Occurrence of Climate parameters

The methodology used for determining climate parameter probabilities for Phase 2 was somewhat modified from standard PIEVC Protocol based studies. The Protocol (Engineers Canada, 2012) indicates that the probability of a climate parameter occurring should be based on the probability of occurrence during the *full* time period of the study, which is typically the life cycle and long-term planning considerations of the infrastructure under study. For Phase 2, a period of 35 years between 2015 and 2050 was chosen. However, in recognition that response to these hazards can include both asset hardening/replacement cycles (long-term measures) as well as maintenance and management considerations (short term measures), a second set of probabilities based on annual occurrence was also determined. Examining both annual and study period probabilities was useful for understanding vulnerabilities based on climate parameters that would occur on an annual basis (e.g. high temperature) against those which would occur less than annually, but with the potential to cause significant impacts sometime during the 35 year study period (e.g. ice storms, high winds, tornadoes).

Annual probabilities are expressed as the number of occurrences per year for historical and (where available) projected estimates for the 2030's and 2050's, or more specifically for 30 year periods centred on those future decades. The so-called "study period" or "lifecycle" probability of occurrence is then expressed as a percentage (i.e. given those annual frequencies, what is the overall probability that an event will occur during the *entire 35 year time horizon*?).

The probability of occurrence of a climate parameter considered in this project is, in most cases, representative of a "point" probability (i.e. historical probability values based on measurements at a single location). However, the lightning and tornado climate parameters were also evaluated using different "target" sizes to illustrate the effects of changing this perspective, as well as to better correspond with field conditions and associated response. More detailed information about how the probabilities of individual climate parameters were determined can be found in **Appendix B**. The results of this work are listed in Table 3-2 at the end of this chapter.

3.1.3 Assigning a PIEVC Score to Climate parameter Probabilities

The probability of occurrence for climate parameters both annual and during the study period were converted into PIEVC probability scores (i.e. 0-7) for the risk assessment, following the quantitative "Method B" approach indicated in the Protocol (Engineers Canada, 2012) (see Table 3-1). For example, the annual probability of occurrence of high temperatures above 40°C was estimated to occur approximately 0.01 times per year in the historical period (last 100 years), or 1 % probability of occurring each year (PIEVC score 1). Similarly the annual probability for this parameter was 0.3 to 2 times per year for the 2030s, which signifies a 30 % to >100 % probability of occurring each year (PIEVC scores 4 to 7 respectively). This climate parameter is estimated to occur between 1 to 7 days per year by the 2050s, such the annual probability of occurrence is >100% (PIEVC score 7).

Table 3-1 PIEVC Version 10 Probability Scores based on Method B

Score	Probability	
0	< 0.1 %	< 1 in 1,000
1	1 %	1 in 100
2	5 %	1 in 20
3	10 %	1 in 10
4	20 %	1 in 5
5	40 %	1 in 2.5
6	70 %	1 in 1.4
7	> 99 %	> 1 in 1.01

3.2 Summary of Results

24 climate parameters covering temperature, precipitation, wind and lightning hazards were considered within the climate analysis. However, four of them were not carried forward in the vulnerability assessment due to data availability issues or relevance[14]. Table 3-2 provides a summary of the climate data results. Relevant climate parameters and infrastructure thresholds (climate parameters) to be used in this study are listed. For these climate parameters, historical and future probabilities of occurrence, as well as PIEVC probability scores for annual and study period probabilities are presented.

Table 3-2 Climate Parameters and Thresholds, Occurrence Probabilities and PIEVC Scoring

Climate Parameter	Threshold	Annual Probability (Historical; **Projected 2030 and *2050***)	Probability of Occurrence Study Period (2015-2050)	PIEVC Scoring		
				Historical	2030's & 2050's	Study Period
Daily Maximum Temperatures	25°C	66 per year; **84 per year**, ***106 per year***	100%	7	7	7
	30°C	16 per year; **26 per year**, ***47 per year***	100%	7	7	7
	35°C	0.75 per year; **3 per year**, ***8 per year***	100%	6	7	7
	40°C	~0.01 per year[15]; **0.3 to 2 days per year, *1-7 days per year***	~100%	1	4 - 7	7
High Daily Avg Temperature	30°C	0.07 per year[16]; **N/A, *1.2 days per year***	~100%	3	7	7
	35°C	*Zero* occurrences historically; ***zero occurrences projected***	0%	0	0	0
Heat Wave	3 days max temp over 30°C	0.88 per year; **>1 for both**	100%	6	7	7
High Night time Temperatures	Nighttime low ≥23°C	0.70 per year; **7 per year, *16 per year***	~100%	6	7	7
Extreme Rainfall	100 mm in <1 day + antecedent	0.04 per year; ***extreme precipitation expected ↑, percentage unknown***	~75%-85%	2	3	6

[14] The climate parameters not evaluated in the vulnerability assessment were high daily average temperature above 35°C (relevance), 6 hr+ freezing rain (relevance, as no ice accretion threshold was known), Minor ice accretion and deicing agents (complex interaction, no projection data available) and tree growth, pest and disease (complex interaction, no data available).
[15] Based on data from Toronto City Center station rather than Pearson Airport.
[16] Based on 4 occurrences since 1961 at Pearson Airport; see discussion in text for further details.

Climate Parameter	Threshold	Annual Probability (Historical; **Projected 2030 and *2050***)	Probability of Occurrence Study Period (2015-2050)	PIEVC Scoring		
				Historical	2030's & 2050's	Study Period
Ice Storm/Freezing Rain	15 mm (tree branches)	0.11 per year; **>0.13 per year, *>0.16 per year***	>99%	3	3	7
	25 mm ≈ 12.5 mm radial	0.06 days per year; **>0.07 per year, *>0.09 per year***	>95%	2	3	7
	60 mm ≈ 30 mm radial	High Risk: 0.007 events per year; **>0.008 per year; *>0.01 per year*** Low Risk: 0.002 events per year; **> 0.0023 per year; *0.003 per year***	High: ~25% Low: ~8%	0-1	0-1	2-4
	6 hours + freezing rain	0.65 days per year; **~0.75 per year, ~0.9*4 per year***	100%	5	6	7
High Winds	70 km/h+ (tree branches)	21 days per year***; N/A, *24 to 26 per year***	100%	7	7	7
	90 km/h	2 days per year; **N/A, *>2.5 per year***	100%	7	7	7
	120 km/h	~0.05 days per year; ***likely ↑, but % unknown***	~85% or higher	2	2	7
Tornado	EF1+	1-in-6,000; ***Unknown, no consensus***	~0.6%	0	0	1
	EF2+	1-in-12,000; ***Unknown, no consensus***	~0.3%	0	0	0
Lightning[17]	Flash density per km km^2	1.12 to 2.24 per year per km^2; ***Expected increase, % change unknown***	~50-70%(Lg); ~10-20% (Sm)	Lg - 2 Sm - 0	n/a	Lg – 6 Sm - 3
Snowfall	Days w/ >10 cm	1.5 days per year; ***Trend decreasing but highly variable***	100%	7	7	7
	Days w/ > 5cm	5 days per year; ***Trend decreasing but highly variable***	100%	7	7	7
Frost		229 frost free days; **249 frost free days, *273 frost free days***	100%	7	7	7
Complex Interactions	Minor ice accretion + deicing agents	***Projections unavailable***	N/A		N/A	
Complex Interactions	Changes in tree growth, disease conditions	***Projections unavailable***	N/A		N/A	

3.3 Data Sufficiency and Recommendations

The primary sources of information used in this climate data work were:

- Environment Canada Weather Station Data;
- IPCC AR5 quality controlled GCM output;
- TRCA environmental data and observations (TRCA 2014).

The climate data available for this study was judged to be sufficient to cover the majority of climate related stresses to electrical distribution systems (stemming from temperature, precipitation and wind). The study area of the City of Toronto also benefited from having good quality, long-term climate data that covered most areas of the city for these types of climate parameters. While further studies, in-depth analyses, and data quality improvements can be made (see Chapter 7), the climate data that was available was sufficient to support the risk assessment.

[17] Note that "Lg" and "Sm" refer to large and small transformer stations, see Appendix B for more details.

4 Vulnerability Assessment Methodology

The vulnerability of the electrical system to climate parameters was initially completed by employing a screening level risk based methodology (risk assessment) to identify low, medium and high risk interactions. The level of risk was evaluated based on the probability of occurrence of a climate parameter coupled with the severity (consequence) of the impact on the system and on electrical service provision. Low risk level interactions were generally judged as not being a significant issue for Toronto Hydro. Medium level risks were evaluated through a further engineering analysis to determine whether the interaction resulted in vulnerabilities (or part of a general pattern of vulnerability). Finally high risk level interactions were deemed as vulnerabilities for Toronto Hydro.

The general procedure for the risk assessment is described in Step 3 of the Protocol. However, study specific considerations (e.g. the *systems level approach*), adaptations and guidance for completing the risk assessment are described in the following chapter. Completion of the risk assessment follows the "Consultant Option" of the Protocol[18]. Notably in this option, AECOM completed the risk matrix through internal meetings with its own electrical engineers. This information was then validated with Toronto Hydro staff in a workshop held on October 10, 2014, at Toronto Hydro's offices.

4.1 Risk Tolerance Thresholds

The risk tolerance thresholds employed within this analysis conform with the proposed thresholds of the Protocol as given in the table below. These thresholds were validated with Toronto Hydro at the workshop.

Table 4-1 Risk Tolerance Thresholds

Risk Range	Threshold	Response
< 12	Low Risk	Monitoring or no further action necessary
12 – 36	Medium Risk	Vulnerability may be present. Action may be required, TBD through engineering analysis
> 36	High Risk	Vulnerability present, action required

4.2 Yes/No Analysis

The first consideration of the risk assessment is to identify whether a climate parameter will interact with the infrastructure system under consideration. A Yes/No analysis column for each of the 20 climate parameters is included in the risk assessment matrix presented in **Appendix D**. A "No (N)" result means that there is no interaction between the climate parameter and infrastructure system, while a "Yes (Y)" result means that there may be an interaction. The severity assessment is conducted only for "Yes" interactions.

4.3 Infrastructure Performance Responses - Systems Level Approach

As mentioned in the introduction, this study adopts a *systems level approach* to the analysis of climate change impacts on Toronto Hydro electrical distribution infrastructure due to the extensive, complex and interdependent nature of the electrical system. The severity of impact is evaluated based on the consequences of the interaction of different weather events with the systems and subsystems under study.

The relevant infrastructure performance responses remain the same as presented in the pilot case study. Notably, they are:

- Structural design - *Structural integrity, cracking, deformation, foundation anchoring, etc.*

[18] This approach, rather than the facilitated option, was adopted in this study because it was more efficient; the learnings gained from the pilot case study provided AECOM with the necessary insight to complete the risk assessment on its own prior to validation with Toronto Hydro.

- Functionality - *Effective load capacity, efficiency, etc.*
- Serviceability - *Ability to conduct maintenance or refurbishment, etc.*
- Operations, maintenance and materials performance - *Occupational safety, worksite access, operations and maintenance practices (frequency and type), etc.*
- Emergency Response - *Planning, access, response time*
- Insurance Considerations (Toronto Hydro perspective) - *claimable for repair, cause 3rd party payment, affect insurance rates*
- Policy and Procedure Considerations - *Planning, public sector, operations, maintenance policies and procedures, etc.*
- Health and Safety - *Injury, death, health and safety of Toronto Hydro employees, the public, etc.*
- Social Effects - *Use and enjoyment, access, commerce, damage to community assets (buildings), public perception, etc.*
- Environmental Effects - *Release or harm to natural systems (air, water, ground, flora, fauna)*

It is clear that within a *systems level approach*, weather interactions with infrastructure systems can solicit a range of different performance responses, as well as responses of differing degrees (i.e. intensity) from different components. In other words, some components within a system are more sensitive to certain types of weather events than others (e.g. heat affects the operation of transformers more than it affects the wooden pole on which the transformer is attached).

In order to conduct a logical, structured analysis, the proposed *systems level approach* identifies the infrastructure performance response stemming from the component (e.g. pole, transformer, power line, switch, etc.) which constitutes the weakest link in the system category for a given weather parameter. The component whose functionality, capacity, structural integrity or operation is affected or compromised the most, which in turn may cause other interdependent components or the entire system to cease to operate, fail, or lose capacity, constitutes the weakest link in the system. For example, the failure of a station power transformer due to high temperature and load may cut off electricity service, irrespective of what the heat may do to other equipment and structures. The station power transformer is thus considered to be the most sensitive and weakest link under high heat conditions.

As the primary role of Toronto Hydro's electrical distribution infrastructure is to provide electricity, one primary guiding criteria was used to determine which component(s) within the major systems categories constituted its weakest link: the component which, due to an interaction with a weather event, resulted in damage/failure of that component, which in turn compromised the ability of the system to deliver electricity to customers safely and securely. The risk assessment matrix presented in **Appendix D** contains a column named "consequence" which identifies the weakest link component and the anticipated infrastructure performance response.

4.3.1 Consideration of Redundancy and Station Capacity

While a component malfunction or failure may compromise the system's ability to provide electricity safely and securely, a *systems level approach* allows system design characteristics to mitigate this impact. Two notable characteristics of electrical systems are considered by this study: redundancy and station capacity.

Redundancy is the duplication of equipment and systems that afford an alternative way to deliver electrical services in the event of equipment damage or failure. In electrical systems, redundancy is provided through the presence of similar or identical equipment operating in parallel or kept on standby, and is a key component of essential infrastructure services such as electricity provision. Station capacity indicates that a station possesses capacity in excess of normal demand (i.e. under normal circumstances).

Redundancy and station capacity are characteristic of the different types of electrical systems under study. As redundancy and station capacity can mitigate component failures (i.e. allow systems to continue to provide electricity despite equipment failure in one area), they are used as mitigating factors which can attenuate severity

scores. The explanation of how redundancy and station capacity are evaluated for each of the major systems categories is in presented in the sections below.

Transmission Stations

A station's ability to mitigate the system's vulnerability to climate is most usefully considered with respect to high temperatures. During high temperatures, stations with greater excess capacity will be able to continue to supply electricity despite increased demand, while stations with less excess capacity may have to reduce demand (e.g. shed load through temporary forced outages) in order to operate station equipment acceptably (e.g. to avoid overheat and burnout).

Transmission station capacity is based on the load projection exercise completed by Toronto Hydro for this project. This study is briefly described in **Appendix F (**Also see Chapter 2, *Load projections*, for more information). Station capacity is rated as low or good based on the load cut-offs shown in the table below. If the station capacity is rated as low by the end of the study period (2050's), its severity evaluation for high temperature parameters is increased by ''+1''.

It is possible that excess station capacity can also be considered as a mitigating factor in the event of freezing rain, flooding, high winds, etc. For example, if a high wind event causes flying debris to damage an outdoor station, an adjacent station can help by picking up some of the load. In this case, it is the capacity of adjacent stations which helps determine the vulnerability of a service area. In the horseshoe area, station and feeder ties between service areas allow some of the load to be transferred[19]. However, this factor is not considered in the present study because adjacent stations can only take on a small portion of a faulted station's load (i.e. no station is designed to take the full load of an adjacent station, otherwise it would be overdesigned), nor are there sufficient feeder or station ties to allow the complete transfer of the load. Thus, large portions of a service area may still be susceptible to an outage at its transmission station in spite of the fact that an adjacent station has excess capacity.

Table 4-2 Severity Rating Based on Station Capacity by the 2050's

Severity Rating	Station Projected Load by the 2050's
Low (+1)	≥ 95 % (Toronto) and ≥100% Horseshoe Area
Good (no change)	< 95 %

Municipal Stations

The redundancy of the municipal stations is based on geography, and only considered for high temperature parameters for the same reasons as listed above under transmission stations. According to Toronto Hydro, if a municipal station is located in the Former Toronto area, it is generally considered that the station has less transfer capability than a station located in the horseshoe area. Severity ratings for all municipal stations in the Former Toronto area are increased by ''+1'' to reflect the low station transfer capacity in the event of a problem. This severity increase for former Toronto area municipal stations does not apply to other climate events such as freezing rain or wind because these stations are generally located indoors in the Former Toronto area.

The Toronto Hydro to Private ownership stations are dedicated to the owner. There are no transfer capacities to another station. A ''+1'' is added to the severity rating for high temperature parameters.

[19] Recall that at present, there are no station ties between station service areas in the Former Toronto area. The addition of station ties in this area is constrained by the fact that infrastructure is older, located in a dense built urban environment, and generally underground. At present, Toronto Hydro is considering the addition of station ties in the Former Toronto area, but this is not considered in this risk assessment due to its preliminary nature of this idea. In the horseshoe area, station ties allow stations to provide some load relief to adjacent service areas when required.

Underground Feeders

The redundancy of the underground feeders is based on the configuration of the feeder and its location in the city. Dual radial and residential feeders in the Former Toronto area are considered to have the lowest redundancy and capacity because structures are older, more stressed by higher loads, and are installed with less space between the conductors. The arrangement of the conductors is important because the ampacity of conductors are sensitive to the heat generated by nearby conductors. Severity ratings for these feeders are increased by ‘’+1’’ as a result (Table 4-3).

Table 4-3 Severity Rating Based on Feeder Configuration

Severity Rating	Increasing Levels of Feeder Redundancy
Low (+1)	Dual Radial & URD : Former Toronto
Moderate (no change)	Dual Radial & URD : Horseshoe
Good (no change)	Compact Loop Design
Best (no change)	Network

Overhead Feeders

The redundancy of the overhead feeders is considered between two configurations: radial or loop. Radial lines cannot be backed-up in the event of a fault, while loop configurations could allow electricity to be brought in through the “other side” of the loop. For this purpose, the severity ratings for radial feeder configurations are increased by ‘’+1’’.

Communications Systems

The redundancy evaluation is not considered for the communications systems, as they do not mitigate circumstances of loss of electrical service provision.

Civil Structures

Historically, infrastructure built for the distribution of electricity in the City of Toronto were concentrated in the downtown core and inner city and later extended to the horseshoe area. Part of the electrical equipment was replaced over time but much of the civil structures (e.g. underground vaults) remain in place due to their expected lifespan (35 - 60 years). It is thus assumed that the civil structures in the Former Toronto area are older and more degraded than the structures in the Horseshoe Area. A ‘’+1’’ severity scoring is added to the Former Toronto civil structures.

4.4 Scoring Severity

The severity scoring exercise is conducted using the scoring scale defined by the Protocol, method D. Examples of impacts on different equipment were developed in the course of this analysis. In addition to the guidance provided by the Protocol on severity scoring, this study provides a further, electrical system specific consideration in severity scoring. Two complementary, severity scoring scales were developed for this study to reflect the severity scoring differences between stations and feeder systems. As stations represent major nodes in the distribution of electricity, an affected or disabled station could result in a loss of service on all downstream feeder systems and customers. However, if a feeder branch or sub-branch is affected, only the customers on the branch or sub-branch may be affected. Thus, the impacts on station equipment are judged to be more severe than impacts on feeder systems. The severity scoring scale employed in this study, as presented below, reflects this general consideration.

Table 4-4 Severity Scoring Scale for Electrical Distribution Systems

Score	Stations			Feeders	
	Method D	**Descriptive**	**Examples**	**Descriptive**	**Example**
0	No Effect	Negligible or N/A		Negligible or N/A	
1	Measurable	Very Low - Some measurable change		Some loss of serviceability & capacity, no loss of function	*Arrestor failure, overheating cables, salt deterioration of civil/electrical equipment*
2	Minor	Low - Slight loss of serviceability	*Station battery – lifespan shortened*	Some loss of capacity & function	*Overheating transformer from high load*
3	Moderate	Moderate loss of serviceability, some loss of capacity, but no loss of function	*Station transformer heating up, but possibility of meeting demand from another station*	Moderate loss of function	*Broken spring in underground switchgear, distribution transformer out (must replace), cable*
4	Major	Major loss of serviceability, some loss of capacity & function	*Station transformer heating up, need to do load shedding*	Major loss of function of multiple equipment – localized	*Transformer and switchgear out (replace multiple equipment)*
5	Serious	More loss of capacity & function	*Station transformer heating up, need to do load shedding for longer duration*	Major loss of function of multiple equipment – wide area	*Transformer and Switchgear out Flooded vault that cannot be pumped*
6	Hazardous	Major - Loss of Function	*Loss of CT/VT transformer, battery assets*	Major loss of function of multiple equipment – wide area	*Leaning pole/downed line*
7	Catastrophic	Extreme – Loss of Asset	*Station trans. failure*	Major loss of function of multiple equipment – wide area	*Downed pole, line and transformer*

4.5 Mapping Risks

Due to the sheer number of similar assets and their distribution across the city, study authors and Toronto Hydro have elected to map climate change risks to the electrical distribution system in the City of Toronto. It was decided that two main asset classes would be included in the risk map: stations and feeders. The risks to supporting infrastructure, such as communication systems and civil structures, were difficult to represent on such a large scale. Furthermore, the risks to these systems are generally associated with, and can be adequately illustrated by, the risks to the stations and feeder systems.

The risk mapping exercise was completed using the geographic information systems (GIS) resources provided by Toronto Hydro. AECOM provided the final risk assessment matrix results to Toronto Hydro's GIS team. Each of the station and feeder assets in the risk assessment matrix were identified on GIS maps. Stations were illustrated as polygons representing the stations' service areas rather than as points where stations are located. This was done in order to illustrate the fact that faults at a station can affect an entire service area. Feeder systems were illustrated as line vectors on the map. Next, the low, medium or high classification of station or feeder risks were represented by colouring the assets class representations (polygons or lines) in yellow, orange or red to denote low, medium and high risks respectively. Where there were no interactions between climate and infrastructure, asset representations were coloured in grey. Finally, white spaces within the City of Toronto generally indicate where no electrical service is provided. Results of the risk mapping exercise are presented in Chapter 5 and in **Appendix E**.

5 Assessment Results

This chapter presents a summary of anticipated impacts from the interaction of climate events with electrical distribution system infrastructure resulting in low, medium and high risk interactions. In addition, special case risks are also presented.

5.1 Low Risk Interactions

High Temperature

SCADA systems may be affected by ambient air temperatures above 40°C. According to equipment design specifications (S&C manufacturer, 2011), such temperatures constitute unusual conditions for the interrupters within the SCADA system. At high temperatures over 40°C, the accuracy of power line current and voltage sensors, as well as the ability to provide DC voltages for the control of the switch, are not assured. SCADA system equipment are tested to operate between -40°C to +40°C. However, other components of the SCADA system like the communication and control unit can operate at temperatures up to +70°C. A low risk score was given considering that the SCADA switch is able to operate in temperatures above 40°C, but its performance (accuracy of sensors) may decrease.

Extreme Rainfall

Extreme rainfall poses a low risk to certain underground feeder systems in the horseshoe area. Underground feeder systems with some equipment located in above ground vaults or on padmounts may be affected by localized flooding due to extremely rainfall. This creates an issue in terms of accessing equipment.

Some transmission stations in the Former Toronto area currently have batteries and switchgear located below grade. This equipment could be damaged if flooding occurred. Toronto Hydro is currently moving its battery assets above grade when they reach the end of their lifecycle (typically 10 – 12 years). By the 2030's, it is expected that all station batteries will be moved above grade. Some of the switchgear equipment will also be moved above grade, although stations in the Former Toronto area may face space constraints to moving all equipment above grade. As such, it is likely that some switchgear will still be located below grade by the 2030s. However, stations are equipped with multiple sump pumps which can evacuate water that flows into the basements. According to a Toronto Hydro representative, there have been no flooding incidents to Toronto Hydro stations owing to heavy precipitation over the last several decades due to the pump and drainage systems found in stations. Based on expected work to relocate batteries and certain switchgear, and continued adequacy of sump pumps, the risk of flooding from extreme rainfall for transmission stations in the Former Toronto area was rated as a low risk.

Freezing Rain

For stations, 15 mm or less of freezing rain are not expected to create sufficient ice loads to cause structural problems. Freezing rain could cause some delays in accessing equipment (e.g. ground or equipment encrusted with a layer of ice), although this was judged to be of low risk by workshop participants

Snow

Snow accumulation and snow fall, especially for days with >10 cm of snow, can also cause visibility and access issues. Access to padmounted transformers and switches, as well as underground vaults may be hampered by snow pushed aside from road and sidewalk snow clearing equipment, thereby lengthening the time needed to access equipment. However, access issues from snow were judged to be of low risk by workshop participants.

Frost

Frost may cause the displacement of the ground (frost heave) and compromise the stability of the foundations of poles, vaults and cable chambers. Frost heave events are generally localized, and do not tend to disrupt electrical service. Furthermore, the number of frost free days are expected to increase by 2050 due to increases in annual temperatures. For these reasons, frost was judged to be of low risk. Civil structures located in the former Toronto area were given a slightly higher (+1) severity rating (and therefore risk rating) because the infrastructure is generally older than those found in the horseshoe area.

5.2 Medium Risk Interactions

High Temperature

High ambient air temperatures starting at 25°C and above are responsible for the majority of medium risks evaluated within this study. Unless stated, the temperatures presented below exclude consideration of humidity on felt temperature (i.e. humidex). From an electrical equipment point of view, it is the ambient air temperature, not humidity, which impacts the structural integrity or lifespan of equipment. Humidity, coupled with high ambient air temperatures may result in higher felt temperatures by people, which in turn can increase the demand for air-conditioning. However, risks posed by high temperatures to infrastructure are evaluated in terms of their design and performance characteristics (ability to shed heat or cool down), which are not affected by humidity levels. High humidity was considered when evaluating the risks to Toronto Hydro personnel.

High temperatures affect the lifespan of station batteries. Where the air temperature of rooms that house station batteries exceeds 25°C, the lifespan of the batteries will begin to degrade. This will result in the long-term in the replacement of batteries sooner than expected. The buildings containing the rooms where batteries are stored afford some protection from changes to external air temperatures. This means that an external air temperature of 25°C may not immediately trigger the premature degradation of batteries. However, rooms where batteries are stored are not temperature regulated, and the impacts to battery lifespan will increase as external air temperatures increase above 25°C. Heat impacts on station battery lifespan were judged to be of medium risk.

As maximum daily air temperatures exceed 35°C, station power transformers will be the most critical pieces of equipment to be affected. First, the use of air-conditioning will increase, thereby increasing the electrical load on transformers. Transformers will heat up, but warm ambient air temperatures also reduce the effectiveness of natural or mechanical cooling. Stations with low projected excess capacities by the 2030's and 2050's will be less able to meet additional demand during periods of high temperature because of higher existing base load. These include transmission stations located in downtown areas, as well as Bathurst station, Sheppard, Leaside, Rexdale, Woodbridge, Manby and Horner. These were judged to be slightly more at risk (+1 severity) as compared to other stations in the East and Northwest sub-service areas.

Heat waves, when the daily maximum temperature during three consecutive days exceeds 30°C, as well as warm nights (minimum temperatures ≥ 23°C) both constitute medium risks for station power transformers. High night time temperatures will result in continued electrical use for air-conditioning, and also decrease the potential for transformers to cool down overnight. However, overall electrical demand is lower at night than during the daytime, and Toronto Hydro staff did not consider high night time temperatures to be as significant a concern as high daytime temperatures or heat waves from an electrical system point of view (Workshop 2).

High temperatures above 40°C, average temperatures over 30°C on a 24h basis, heat waves and high night time temperatures were also judged to be a medium risk for underground and overhead feeder systems due to high electrical demand for cooling and high ambient temperatures. Cables and power transformers were the two most vulnerable parts of these feeder systems in terms of heat. Under high demand, underground conducting wires and their housing undergo thermal expansion. This affects the structural integrity of the housing by causing wear and potentially leading to microfractures that are susceptible to water infiltration. Underground cables laid in close proximity or side by side, as is the case for underground feeders in the denser Former Toronto area, are also

more susceptible to these expansion effects than underground feeders in the horseshoe area. Adjacent cables tend to heat one another up, and the increased heat reduces the cables' electrical transmission capacity. In overhead systems, cables under high demand will also lead to cable expansion and conductor sag. While this sag is generally accounted for in tree trimming and object clearance around power lines, excessive sag may be more prone to contacting objects and causing an electrical fault.

Feeder system power transformers are affected in a similar manner as their station counterparts. High ambient temperatures place additional demand from air-conditioning on transformers, while also affecting their ability to effectively cool. Overheating overhead transformers may fail or catch fire and will have to be replaced. In terms of relative risk, it should be noted that an overheating feeder line power transformer is less critical than an overheating station transformer, as the former serves fewer clients than the latter.

Underground dual radial, URD, compact loop and network systems afford increasing levels of redundancy for clients, due to their ability to supply electricity in the event of an outage through a different branch, loop or conduit of the feeder system. In this study, dual radial and URD feeders in the Former Toronto area were considered to be less able to cope with high electrical demand and mitigate outages than similar electrical feeder types in the horseshoe area. This is due to the fact that feeders in the Former Toronto area are already under high base load (denser environment), their equipment is generally older and cables running side by side increase the heat load and reduce their maximum capacity. Therefore, underground feeders in the Former Toronto area are considered to be slightly more at risk (+1 severity) to heat impacts as compared with similar feeder types in the horseshoe area.

Overhead feeder systems were judged to be slightly more at risk (+1 to +2 severity) than underground systems to temperatures above 40°C and to average temperatures above 30°C on a 24h basis. While electrical load demands may be similar for underground and overhead transformers, direct solar radiation and exposure to high ambient air temperatures can reduce the ability of overhead transformers to disperse heat. On the other hand, overhead transformers were judged to be less vulnerable to high night time temperatures than underground systems, due to increased circulation of cooler nighttime air around overhead transformers as compared to those located in underground vaults.

High ambient air temperatures were also judged to be medium-low risks for protection and control systems. Like station batteries, high temperatures will degrade the expected lifespan of batteries used to power the feeder protection and control systems in the event of a power failure.

Extreme Rainfall

The most significant medium risks from extreme rainfall events are related to the flooding of non-submersible vault-type electrical components kept below grade. Vaults below grade are usually equipped with either passive drainage systems or active pumping drainage systems to keep them from flooding. However, under extreme rainfall conditions, it is possible that the sewers to which these drainage systems are connected may themselves be at capacity, and without the ability to evacuate the water, some vaults may flood. In flooded vaults, non-submersible electrical equipment could be damaged, and an outage may occur. This is also a concern in some network type feeders in downtown Toronto, where old network protection equipment are not housed in submersible enclosures. Toronto Hydro is gradually installing submersible equipment in all below-grade vaults, but non-submersible equipment is still expected to be in present by the end of the study period. Furthermore, the equipment in flooded vaults cannot be accessed until the water is evacuated, creating a delay in responding to electrical incidents.

While not exclusively a problem related to heavy rainfall events, water infiltration into the ground and moisture around underground cables can lead to water treeing[20] and cracking of cable insulation. Deterioration of cable housing could lead to electrical faults if cracks become sufficiently large to allow ground moisture to serve as a pathway for electricity to ground.

[20] Tears in the cable's insulating layer caused by the presence of moisture and an alternating current's (AC) electric field.

It was noted in the workshop that extreme rainfall can be beneficial to overhead feeder systems. Salt residues from the wintertime and dust throughout the year can accumulate on electrical insulators. Moist conditions such as fog, mist or light rainfall can cause these accumulations to serve as conduits to ground, causing flashovers and potential pole fires and outages. Heavy rainfall events, especially in the early spring, are in fact beneficial for washing off the salt and dirt residues from insulators. Note that 27.6 kV and 13.8 kV lines are more prone to flashovers due to their higher voltages. It was noted in the workshop that 27.6 kV systems in particular may require more frequent cleaning than is currently the case in order to prevent flashovers, while flashovers do not tend to occur with 4.16 kV equipment.

High Winds

High winds over 70 km/h (but less than 90 km/h) were considered a medium risk to overhead power lines. While lines and poles are designed to withstand such wind speeds, it has been found that tree branches may begin to break at these thresholds and fall onto lines. Overhead conductors may also flail in the wind and contact branches. At the least, these tree contacts may cause momentary interruptions to electrical service. At the worst, tree branches and limbs may fall on and damage or sever power lines, potentially causing outages, fires and public safety hazards.

Lightning

Lightning strikes on overhead feeder systems was rated as a medium risk. Lightning arrestors installed on overhead power lines are designed to direct lightning surge currents to ground and protect pole mounted equipment such as transformers, switches and SCADA equipment. However, failure of the lightning arrestors can result in damaged equipment from lightning strikes and potentially lead to a localized outage.

Human Resources

Most of the human resource interactions with climate parameters (high heat, heavy precipitation, 15 mm of freezing rain, high wind, tornadoes, lightning and snowfall) were judged to be of medium risk. High heat conditions can make it dangerous to work on outdoor and overhead equipment for extended periods of time. For underground systems, high ambient temperatures can exacerbate hot conditions in vaults (heated by transformer operation), thereby also making it unsafe to work on equipment for extended periods of time. Workers tend to defer work under high heat conditions until temperatures above ground or within vaults cool sufficiently to allow safe continuous access. This may however cause a delay in the response to incidents on the electrical system.

Heavy precipitation, freezing rain and snowfall may make it difficult for all employees to travel to and from work, while also making it dangerous for field workers to get to equipment. During severe events such as high winds, tornadoes and lightning, workers apply their judgement and generally delay accessing equipment until the severe weather event has passed. Interestingly, the severity scoring of high winds at 70 km/h were slightly higher than scores for higher wind speeds (90 km/h, 120 km/h or tornadoes). This is because unsafe work conditions are very clear under extreme high wind events. However, at lower wind speeds, work conditions may appear to be acceptable, and workers may decide that the threat is reasonable given the need to restore electrical service. However, sudden, abrupt wind gusts could momentarily jeopardize worker safety.

As Toronto Hydro has occupational health and safety policies and procedures in place, the consequence of severe weather on workers tends to be delaying access and work on equipment until weather conditions, road access improves, and worksites are declared to be safe.

5.3 High Risk Interactions

The highest risks found in this study are related to structural damage and failure of electrical systems and components. In general, station equipment and overhead feeder systems were the two main system infrastructure categories susceptible to climate interactions that yield high risk interactions.

High Temperature

Days with peak temperatures above 40°C and days where average ambient temperatures exceed 30°C on a 24h basis are the two significant climate parameters rated as high risk for transmission and municipal stations. Days with peak temperatures above 40°C are currently a very rare occurrence, but are expected to occur on an almost annual basis by the 2030's and on an annual basis by the 2050's. Similarly, high ambient temperatures exceeding 30°C on a 24h basis are currently a rare occurrence, but may occur on an annual basis by the 2050's. In both cases, high electrical demand, coupled with loss of cooling efficiency, will cause station power transformers to overheat. In the most severe of cases, demand cannot be maintained without damaging station power transformers, which have an average replacement cost of around $500 K[21]. A coping mechanism employed by electrical utilities is to shed electrical load (load shedding), which entails instituting temporary outages in various sectors of the city in order to reduce load demand. For buildings and residents dependent on air-conditioning for cooling purposes, this represents a significant public health risk at a time of extreme heat events.

This high risk is especially relevant for transmission and municipal stations with low excess capacity by the 2030's and 2050's. As such, during periods of high demand, these stations have less excess capacity with which to meet electrical demand.

Freezing Rain and Ice Storms

There are three significant thresholds to consider for freezing rain and ice storm effects on the electrical distribution system. First, preliminary forensic analyses of outages from freezing rain indicate that 15+ mm of freezing rain is a trigger for the breaking of tree branches and limbs. These pose a threat to overhead feeder systems, and these freezing rain amounts have resulted in widespread outages in Toronto in the past due to tree contacts. The next threshold is 25 mm of freezing rain, which is the CSA design requirement for overhead electrical systems. Theoretically, overhead feeder systems, as well as the overhead exit lines at stations are supposed to withstand 25 mm of freezing rain (12.5 mm of radial ice accretion). However, such quantities of freezing rain and ice accretion on overhead infrastructure bring them to their structural design limits, which are further exacerbated by breaking tree branches and wind. Finally at 60 mm of freezing rain, the weight of ice accretion on overhead lines and station exit lines exceeds their design limit, and will likely cause them to collapse.

It should be noted that the high risk ratings for 15 mm and 25 mm of freezing rain on overhead feeder systems and station exit lines is based on probability of occurrence for the study period (probability scores of 7, event will occur during the study period)[22]. From an annual probability perspective, freezing rain events at 15mm and 25mm of freezing rain would actually result in medium risk ratings. As can be seen from Table 3-2 in Chapter 3, the current annual probability of occurrence of 15 mm of freezing rain is 0.11 days / year (1 in 9 year return period), and is projected to increase to 0.16 days / year (1 in 6 year return period) by the 2050's. The current annual probability of 25 mm of freezing rain is 0.06 days / year (1 in 17 year return period), and is projected to increase to 0.09 days per / year (1 in 11 year return period) by the 2050's.As the projected trend for 15 mm and 25 mm freezing rain events is increasing in the future, the interaction of these two climate parameters with overhead feeder systems and station exit lines are maintained as a high risk.

Similarly, it was found that 60 mm freezing rain events would actually fall into a medium risk category (study period probability of 4, annual probability of 1, severity score of 7). However, major ice storms are part of a pattern of risk that is similar to 25 mm freezing rain events. For this reason, it is maintained in the high risk category

High Winds

High winds and wind gusts at 90 km/h and 120 km/h were judged to be a high risk to overhead feeder systems. These wind speeds reach and exceed the design limits of conductor connections to support poles, and the poles

[21] Estimate provided through correspondence with Toronto Hydro staff.
[22] A comparison for freezing rain/ice storm lasting at least 6hr+ based on annual probability versus study period probability does not change the high risk rating.

themselves. Further compounding impacts is the potential for flying debris, such as broken tree branches and limbs, to further bring down overhead feeder systems.

The threats from high winds and gusts above 120 km/h were judged to be high risk due to wind forces on station overhead exit lines (exceeding design standard for poles). Furthermore, there is the potential for flying debris to damage station equipment at outdoor stations.

As is the case for freezing rain, it should be noted that the high risk ratings wind over 120 km/h were on overhead feeder systems and station exit lines is based on probability of occurrence for the study period (probability scores of 7, event will occur during the study period)[23]. However, from an annual probability perspective, events producing 120 km/h high winds would actual result in low and medium-low risk ratings for station and overhead feeder systems respectively. This is because the current annual probability of 120 km/h wind events is 0.05 days per year (1 in 20 year return period). This frequency is expected to increase during the study horizon, although the projected value is not known. These significant wind events are similar to the case of tornadoes, in that they are infrequent but can lead to significant damage to large areas of the distribution system if they occur (low probability, high severity events). As they are however expected to be more frequent than tornadoes, the 120 km/h wind – overhead systems interaction is maintained as high risk in this study.

Lightning

Lightning strikes on station equipment, notably power transformers, were rated as a high risk. Lightning arrestors at stations are designed to direct lightning surge currents to ground and protect electrical equipment. However, failure of the lightning arrestors can result in damaged equipment from lightning strikes and potentially causing an outage to an entire service area.

Human Resources

Heavy freezing rain events constitute a high risk for Toronto Hydro personnel. First, slippery surfaces make travel to and from work, and out to worksites dangerous for field crews. Second, field crews also have to contend with a layer of ice over electrical equipment, trees, and other overhead structures such as buildings. As such, the risk of injury to workers from freezing rain events remain even after the storm has passed due to the continuous ice loads on overhead power lines and trees, which may cause them to break without warning.

5.4 Special Cases – High Severity, Low Probability Events

Tornadoes

Tornadoes represent a high severity, low probability event. As mentioned in Chapter 3, while the likelihood of a tornado event touching down at a specific point or location is extremely small, the likelihood of a tornado occurring somewhere in the City of Toronto over study period (2015 – 2050) is in fact considerable. Furthermore, due to the lake breeze effect, northern portions of the city tend to have a high probability of seeing a tornado event, although it does not preclude an occurrence closer to the lakeshore. Tornadoes were judged to have catastrophic consequences on all above ground infrastructure, while underground infrastructure may become inaccessible due to windblown debris.

[23] A comparison for freezing rain/ice storm lasting at least 6hr+ based on annual probability versus study period probability does not change the high risk rating.

5.6 Special Cases – Low Severity, High Probability Events

Snowfall and freezing rain

The degradation of concrete and corrosion of steel materials (at grade and underground feeder systems) is a case of high probability, low severity events. These processes are accelerated by the application of de-icing salts during snowfall and freezing rain events. The application of salts can accelerate the corrosion of metal housing and enclosures of electrical equipment, resulting in shorter lifespans. It also affects the steel and concrete of vaults and cable chambers (civil equipment). Future warming associated with climate change is expected to decrease the number of days without snowfall, but the trend for freezing rain is expected to increase. Nonetheless, snowfall is expected to continue to be an annual event throughout the time horizon of this study. As such, degradation of civil structures will continue to be an issue for Toronto Hydro over the study period.

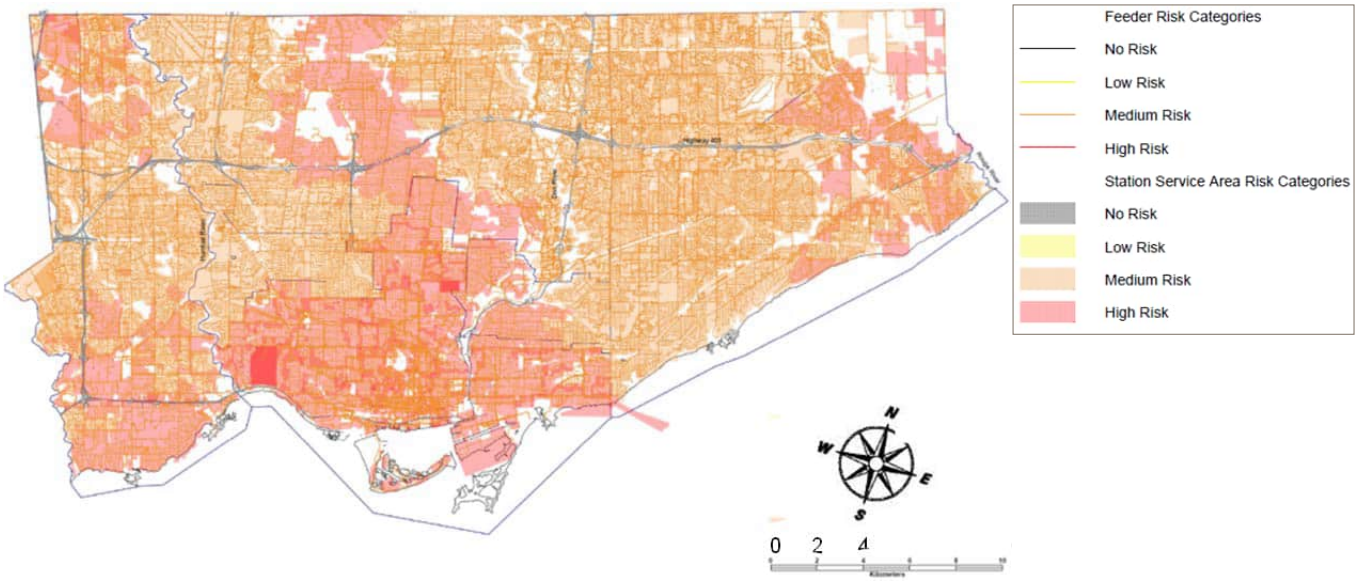
Underground electrical feeder equipment and civil structures located in the Former Toronto area received a slightly (+1) higher severity rating (and a medium-low risk rating) because the infrastructure is generally older than those found in the horseshoe area. It was found that older equipment and structures are more susceptible to degradation if corrosion had already begun (e.g. protective layers of paint may be worn off). Furthermore, older equipment may not be as resistant to corrosion as newer equipment due to the advancement of enclosure design and testing over time (Nema standard).

Some of this salt is dispersed by the moisture in the air, and can accumulate through the winter season on insulators on poles. These salt accumulations can cause electrical short circuits that could result in pole fires. Loop feeder systems are judged to be of lower risk than radial systems in the event of a short circuit or fire due to the potential to provide power temporarily through another loop of the feeder.

5.7 Mapping Risk Results

The mapping of risks provides complementary information to the risk assessment matrix, and facilitates a spatial understanding of low, medium and high risk interactions, and vulnerabilities (i.e. the medium and high risk interactions). For example, maps can provide an indication of the areas of vulnerability of overhead and underground infrastructure with respect to different kinds of weather events. Furthermore, the mapping exercise actually provides a new set of information on how vulnerabilities stemming from stations can combine with vulnerabilities to feeder systems. In some cases, vulnerabilities stem primarily from station assets (e.g. 120km/h wind and underground feeder assets), while in other cases, both station and feeder vulnerabilities to weather events contribute to an area of greater vulnerability within the city (i.e. freezing rain affecting both station and overhead feeder assets). The following section provides some spatial observations about the four climate parameters affecting electrical distribution infrastructure. All mapping results are provided in **Appendix E**.

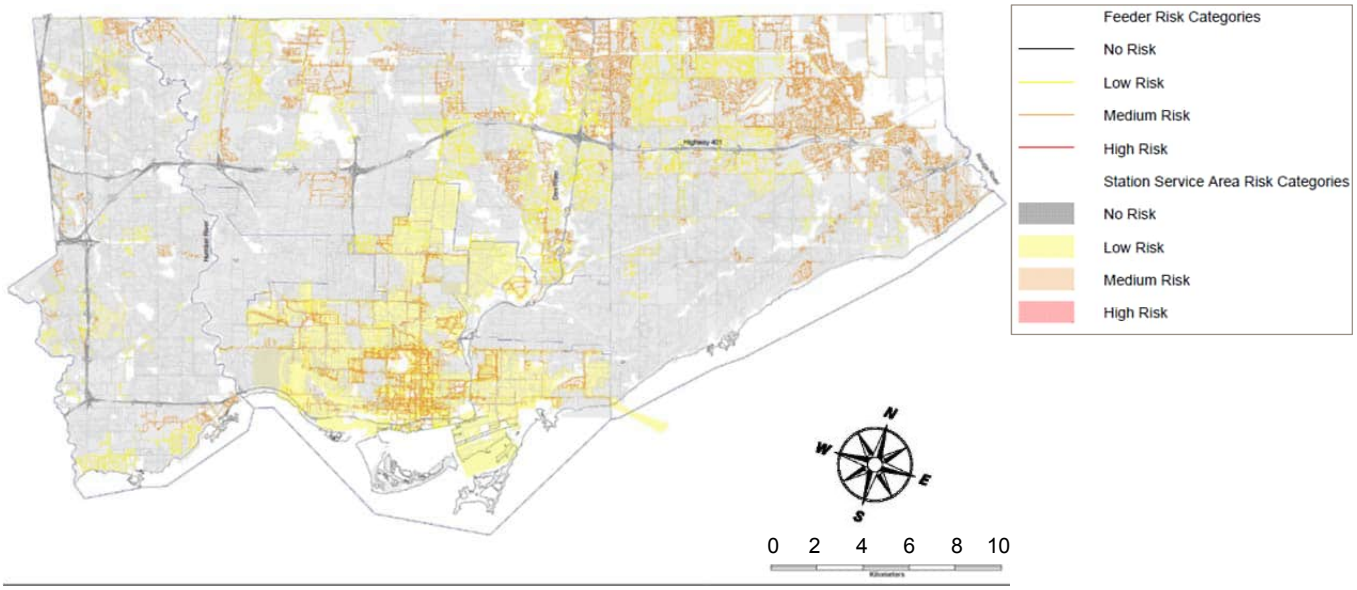
Figure 5-1 Risk Map, High Temperature Above 40°C, 2050's



Vulnerabilities from high heat events stem primarily from projected available station capacity by the 2050s, as this study did not find that vulnerabilities varied significantly (all rated medium risk) for feeder assets. Vulnerabilities to high heat events are more heavily concentrated in the Former Toronto area, although several horseshoe area stations would also be vulnerable during high heat events (Figure 5-1).

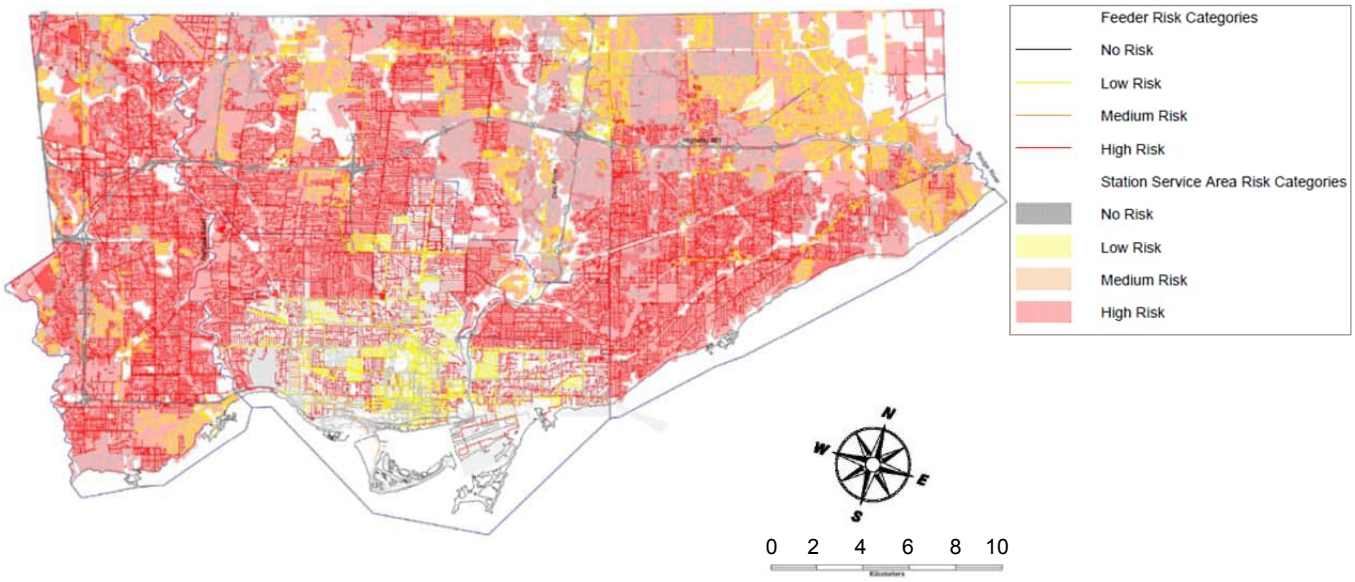
In terms of potential heavy rainfall risks to Toronto Hydro infrastructure, underground feeder systems that may be subject to flooding are located largely in the Former Toronto area and northeastern sections of the horseshoe (Figure 5-2). Some transmission station service areas in the Former Toronto area are marked as low risk due to the presence of some switchgear equipment that will likely remain in basements through the study period. Note however that sump pumps in stations make the probability of flood damage in stations from heavy precipitation less likely.

Figure 5-2 Risk Map, Extreme Rainfall, 100 mm in less than 24h, 2050's



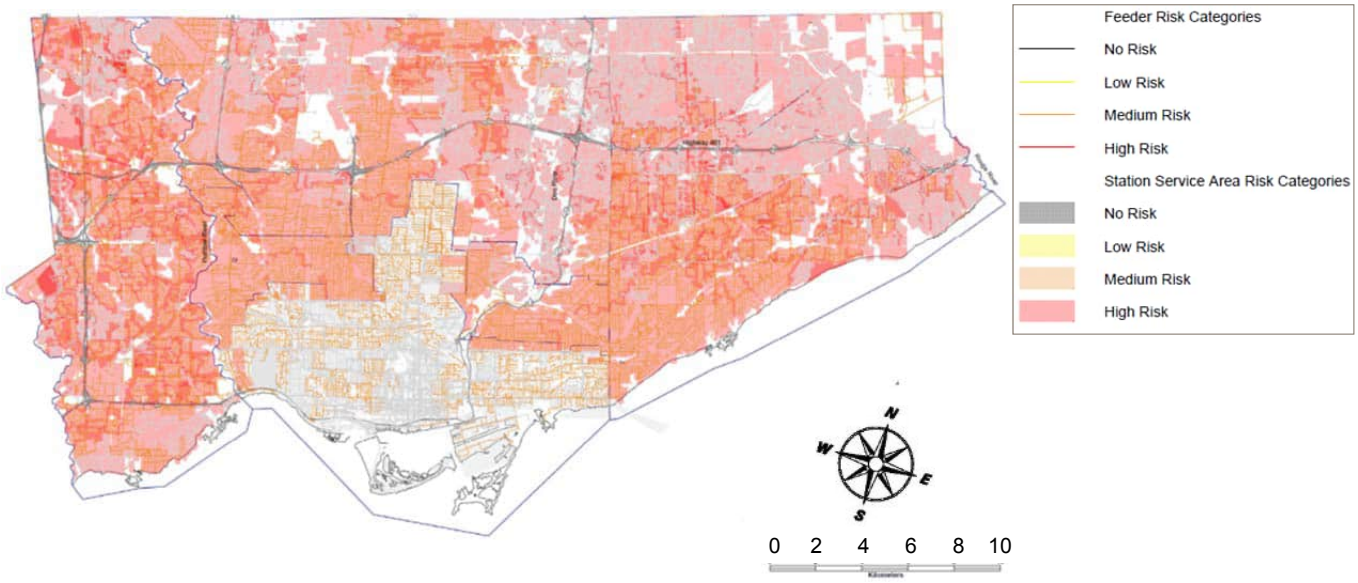
Toronto Hydro has a significant quantity of overhead distribution systems which are at vulnerable to extreme freezing rain, ice storms, high wind and tornado events. These feeder vulnerabilities combine with the fact that stations in the horseshoe area have station exit lines that are outdoors. This combination makes certain portions of the horseshoe particularly vulnerable to heavy freezing rain events and ice storm. Figure 5-3 shows the areas of vulnerability stemming from 25 mm of freezing rain, and is indicative of extreme precipitation/wind related vulnerabilities to overhead systems across Toronto.

Figure 5-3 Risk Map, 25 mm Freezing Rain, 2050's



Lightning strike vulnerabilities are largely concentrated in the horseshoe area, where both outdoor station equipment and overhead feeder systems are predominant. However, overhead feeder systems in the the Former Toronto area are also vulnerable (Figure 5-4).

Figure 5-4 Risk Map, Electrical Distribution Systems Potentially Affected by Lightning Strikes



There are several caveats that should be mentioned with respect to interpreting mapping results, due in large part to the fact that risk ratings were evaluated based on general system characteristics. Localized site characteristics that may mitigate or worsen risk ratings were not adequately captured in the mapping exercise. They include:

- Local geographic characteristics, assets and features. There may be local site characteristics such the tree canopy cover, types of trees, presence of buildings or other overhead structures, which may exacerbate weather events (e.g. wind) or shelter infrastructure from impacts. The presence of low lying areas (e.g. bowls, flood plains) was also not considered. This level of detail, provided by a full site inspection and digital terrain mapping, were not available for this project. Such information would be useful in refining the risk ratings and mapping for extreme rainfall, freezing rain and wind;

- Areas with lower drainage capacity due to configuration of city storm drainage infrastructure. This type of information requires a very detailed understanding of city infrastructure, which was not available for this study. Furthermore, this level of data is most useful when combined with digital terrain mapping in order to identify low lying areas with problematic drainage. Finally, future projections as to how city infrastructure might evolve over time were also not available for this project;

- The moderating effect of Lake Ontario. As noted in Chapter 3, the lake can play a significant role in influencing temperature and humidity along the lakeshore. For example, the lake effect can moderate temperatures during heat waves and can reduce the possibilities of freezing rain or snow falling on areas closer to the lakeshore. The extent and intensity of the lake effect can vary depending on the event and weather conditions. It was not possible to estimate the geographic extent of the lake effect, or by how much the probability scoring for certain climate parameters may be affected. As such, the lake effect's moderating influence was not taken into account sufficiently in the risk assessment and mapping exercise;

- Local electrical configurations and characteristics. There are likely cases where location specific electrical equipment may make certain feeder or station systems inherently more robust or redundant than would be the case of the general class of equipment. For example, additional feeder ties, loops or circuits could make certain feeders more redundant in the event of a downed power line. The age of equipment, their future replacement schedule will also have an effect on their risk rating. This level of detail is not captured at level of analysis undertaken in this study;

- For the extreme rainfall risk map, it should be noted that the mapping of transmission stations includes all stations. Information identifying the location of the stations whose batteries and switchgear are located below grade was not available. Further analysis is required to identify the precise locations of transmission with below grade assets in order to get a better mapping of flood related risks.

In spite of these shortcomings, the mapping exercise represents a useful first approximation of spatial nature of electrical system vulnerabilities to climate change. Furthermore, this mapping information can be more easily combined with other layers of information such as technical hazard information (e.g. flood mapping), physical locations (e.g. emergency resource centres, hospitals, transportation networks) and social vulnerability indices (e.g. age, income, population density, etc.) from other sources (e.g. TRCA, City of Toronto) to produce further mapping studies and in depth analyses to suit the needs of other policy makers.

6 Engineering Analysis

This chapter presents the results of the Step 4 of the Protocol, the Engineering Analysis. The purpose of Engineering Analysis is to conduct a further assessment of the system-climate interactions that were rated as a medium risk (interactions scoring between 14 and 35). For these interactions, the engineering analysis attempts to evaluate whether the infrastructure is vulnerable to a changing climate. To do so, the various factors that affect the load and the capacity of the infrastructure for the study time horizon are calculated. However, quantitative calculations of load and capacity were not always possible to make due to a lack of data to support such an analysis. For this reason, professional judgment is also applied in the engineering analysis. Infrastructure which is found to be vulnerable is passed to Step 5, while those which were not were discarded from further consideration.

In total, nineteen medium risk interactions were analyzed. Fifteen of them were deemed vulnerable and passed to Step 5, while 4 were discarded from further analysis. The following table summarizes the results of the engineering analysis. A brief description of the reasoning behind the results for each of the medium risk interactions is presented in this chapter, while the full engineering analysis can be found in **Appendix G.**

Table 6-1 Engineering Analysis Results

	Affected infrastructure	Climate Parameter	Further Action Recommended
	Municipal and Transmission Stations and Communications Systems		
1.	Transmission and municipal stations	High temperature above 25°C and above 30°C	Yes
	Protection and control systems	All temperatures	
2.	Transmission stations	High temperature above 35°C	Yes
3.	Transmission stations	High temperature above 40°C and average temperature > 30°C	Yes
4.	Transmission stations	Heat wave and high nighttime temperatures	Yes
5.	Transmission and municipal stations	Freezing rain, ice Storm 60 mm	Yes
6.	Municipal stations	High temperature	Yes
		Underground and Overhead Feeders	
7.	Underground feeders	High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime	Yes
8.	Underground feeders	Extreme rainfall	a. Feeders/water treeing: Yes b. Nun submersible vault: Yes c. Above ground stations: No d. N/W feeders: Yes
9.	Padmount stations	High winds 120 km/h	No
10.	Overhead feeders (radial and loop)	High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave	Yes
11.	Overhead feeders (radial)	High nighttime temperatures	No
12.	Overhead feeders (loop)	Freezing rain, ice Storm 15 mm	Yes
13.	Overhead feeders (radial and loop)	Freezing rain, ice Storm 60 mm	Yes
14.	Overhead feeders (radial and open loop) and SCADA system	Lightning	Yes
15.	Overhead feeders (radial)	Snow > 5 cm and snow > 10 cm	No
		Civil Structures	
16.	Civil structures: underground feeders (Former Toronto)	Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 6hrs+ (combination of events)	Yes
17.	Civil Structures: underground feeders (Former Toronto)	Snow > 5 cm and snow > 10 cm	No, but combinations of climates need additional study.
18.	Civil structures	Frost	Yes
19.	Human resources	All climate parameters	Yes

6.1 Municipal and Transmission Stations and Communications Systems

1. High temperature above 25°C and above 30°C / transmission and municipal stations and all Temperatures / protection and control systems

Further action recommended. Under higher temperatures, battery life expectancy (e.g. around 10 years) may decrease. Toronto Hydro has already encountered problems with some batteries failing prior to their expected lifespan..

2. High temperature above 35°C / transmission stations

Further action recommended, conclusions for high temperature and power transformers also apply (see Chapter 7). Transmission station designers will need to take into account the significant increase in days with maximum temperatures above 35°C, which reduces station capacity while, on the other hand, experiences an increased load demand. At the moment, no load growth rate for the period of this study was estimated. The recommendations given in Chapter 7 for transmission stations and maximum temperature above 40°C / average temp above 30°C also apply to this interaction.

3. High temperature above 40°C and average temperature > 30°C / transmission stations

Further action recommended. Most of the transmission stations considered in this study were judged to be vulnerable (high risk rating) to high temperatures. The stations in the Horseshoe received a medium-high risk score (35) due to the application of the concept of excess capacity, which is qualitative and notional (refer to the **Appendix F**). As such, it is recommended that transmission stations receiving a medium-high risk score be considered vulnerable to extreme high temperatures as part of a consistent pattern of risk. This will also help Toronto Hydro to adopt a consistent approach in the design, operations and maintenance of stations.

4. Heat wave (+30°C) and high nighttime temperatures (+23°C) / transmission stations

Further action recommended. Power transformers are vital equipment in the distribution of electricity and high temperatures have a significant impact on the capacity of the transformers. For these reasons, the conclusion of this report for temperature above 40°C and for high daily average temperature > 30°C are also relevant to the heat wave and high nighttime temperature parameters.

5. Freezing rain/ice storm 60 mm ≈ 30 mm radial (major outages) / transmission stations and municipal stations

Further action recommended. This interaction is part of a similar pattern of vulnerability as 25 mm freezing rain events. Therefore, solutions for 25 mm events are also relevant to mitigating heavy freezing rain events of ~ 60 mm.

6. High temperature (+35°C,+ 40°C, average temperature > 30°C, heat wave, high nighttime temperatures) / municipal stations

Further action recommended. High temperature and combinations of high temperature, high average temperature, high nighttime temperature and high load demand will have consequences on the capacity of the power transformers and cables.

6.2 Underground and Overhead Feeders

7. High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime / underground feeders

Further action recommended. Toronto Hydro replaces cables based on asset life replacement cycles or premature failures. However, it is projected that climate change related high temperatures could create higher

demand for cooling, and may place greater stress on cables and lead to increasing occurrences of cable failures. Therefore, high heat impacts on cable was deemed to be a vulnerability.

8. Extreme rainfall / underground feeders

a. Feeders: Water treeing of the cables, flooding

Further action recommended. Climate change related stresses (i.e. higher temperature, higher loading, flooding from extreme rainfall) will continue to stress underground cables and constitute a vulnerability for Toronto Hydro.

b. Non-submersible equipment failure in vault type stations below ground in the Horseshoe Area (Former Toronto has a high risk result)

Further action recommended. While Toronto Hydro is gradually replacing vault type non-submersible equipment with submersible versions, non-submersible vault type equipment is likely to remain in the system over the study period.

c. Above ground vault stations, access to the vault station and to the station equipment could be limited due to localized flooding of streets around the vault station, or at the station itself

No further action required. This impact does not relate to station load or capacity. The consequence is that the access to the vault stations or the stations equipment could be temporarily impeded. Impact is localized and temporary, and was not judged to warrant further action beyond current practices.

d. Network feeders: old N/W protectors are not submersible

Further action recommended. The old N/W protector may not operate properly if flooded. However, failure of the N/W protector will not automatically result in an interruption to the customer, since network systems are highly redundant. Toronto Hydro is installing new N/W protectors that are submersible, but there may still be older non-submersible N/W protectors in the systems, particularly in downtown over the study period. Further study could be undertaken to evaluate the cost of replacing old network protectors prior to the end of their expected lifecycle against the frequency and consequence of old N/W protectors being flooded.

9. High winds (120 km/h) / padmount stations on distribution network (Former Toronto)

No further action required. The damaged equipment will result in an overall or some loss of service capacity and function. However, it is judged that flying debris is too much of a random occurrence to warrant further action.

10. High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave / Overhead power lines (radial and loop)

Further action recommended. Higher temperatures will have impacts on the overall capacity of the power lines. In the downtown area, there are critical, constrained areas (i.e. built up zones) where added conductor/transformer capacity may be difficult to implement.

11. High nighttime temperatures / Overhead power lines (radial)

No further action required. Night time temperatures with minimum ≥ 23°C in and of itself is not a significant concern for Toronto Hydro in terms of electrical service provision as peak demand has subsided. However, it is important to note that high daily temperatures in combination with high night time temperatures are a concern. This has been considered under different climate-infrastructure interaction, average temperature over 30°C on a 24 h basis, so this particular interaction does not warrant further action.

12. Freezing rain - ice Storm 15 mm and high winds 70 km/h / Overhead feeders in loop configuration

Further action recommended. The risk assessment of radial systems resulted in a high risk rating for this interaction. In overhead loop systems, it was hypothesized that their more redundant configuration would reduce customer interruptions, affect fewer clients or cause outages of shorter durations, thus yielding a high-medium risk rating of 35. However, the frequency of freezing rain events are projected to increase slightly by the end of the study horizon compared to present day (see table 3-2). The tree canopy may also be weakened by increased disease threats. Finally, freezing rain events tend to be widespread, and there is no reason to believe that both branches of an overhead loop circuit might not be equally susceptible to damage. For all of these reasons, all overhead power lines, irrespective of electrical configuration, were deemed as vulnerable.

13. Freezing rain/ice storm 60 mm ≈ 30 mm radial (major outages) / overhead lines (radial and loop)

Further action recommended. See explanation for freezing rain and stations (item 5 above).

14. Lightning / overhead power lines (radial and open loop) and SCADA system

Further action recommended. It is difficult to predict the increase of lightning strikes for the study period; however it is interesting to note that the probability of a lightning strike in an area of 0,015 km^2 anywhere within the City of Toronto is very high for the study period. At the moment, lightning strike intensity, the number of lightning arrestors/km and arrestor performance are not monitored by Toronto Hydro. Given this uncertainty, and since lightning strikes are currently a frequent source of outages, lightning strikes were judged to be a continued vulnerability.

15. Snow > 5 cm and snow > 10 cm / overhead power lines (radial)

No further action required. The number of snow days is highly variable. The trend seems to be decreasing, but snow days will still occur annually. During the workshop, Toronto Hydro mentioned having problems regarding insulator tracking leading to pole fires especially at higher voltages (13.8 kV and 27.6 kV) and switch failures. However, Toronto Hydro is already monitoring and dealing with this issue.

6.3 Civil Structures

16. Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 6hrs+ (combination of events) / civil structures: underground feeders (Former Toronto)

Further action recommended. Vaults and chambers already suffering from degradation issues will deteriorate more rapidly over time. From THESL (Toronto Hydro, 2014a): *As below-grade structures age, the greatest concern becomes structural strength. Structural deficiencies affecting vaults include degradation of concrete and corrosion of supports such as beams and rebar. Once degradation and corrosion sets in, conditions can deteriorate rapidly and in many cases from one season to the next. Of particular concern is the winter season when moisture and water enter in below-*grade *structures, freezes and thaws, and carries with it salt that has been used at grade to melt ice and snow.*

While maintenance can reduce the rate of deterioration, incidence of extreme rainfall, snowfall, freezing rain and the application of road salt will persist throughout the study period and continue to contribute to the premature aging of civil structures. While, it could not be determined in the study whether premature aging of civil structures will be exacerbated by a changing climate, this issue will persist over the study period and is therefore judged as an on-going vulnerability

17. Snow > 5 cm and snow > 10 cm / civil structures: underground feeders (Former Toronto)

No further action required, but combinations of climates events require additional study. As days with snow will probably decrease, the snow days alone were not judge to be a significant vulnerability. However, snow days will still occur over the study period, and in combination with extreme rainfall, freezes and thaw, freezing rain, and the continued application of road salt, premature degradation of civil structures was judged to be an

ongoing vulnerability for Toronto Hydro.

18. Frost / civil structures (overhead and underground feeders)

Further action recommended. While the threat of frost is decreasing over the study period, it is noted that frost penetration will still occur with occasional extreme cold weather. Since Toronto Hydro already experiences problems with frost and its civil infrastructure, frost impacts are judged to be a vulnerability.

6.4 Human Resources

19. All climate parameters / human Resources

Further action recommended. While occupational health and safety procedures will continue to be in place in the future, human resources will continue to be vulnerable to climate change related weather events due to the need to travel, access, and work on equipment in spite of the weather.

7 Conclusions

The Phase 2 study presents a climate change based vulnerability assessment of electrical distribution infrastructure. It seeks to inform future investigations, planning and investment decisions on system and component vulnerabilities, and to support efforts to enhance the resilience of the electrical system. This chapter presents Step 5 of the Protocol and covers electrical distribution system vulnerabilities within the City of Toronto, adaptation options and areas of further study.

7.1 Vulnerabilities to a Changing Climate

The Phase 2 employed a high level risk based screening methodology to determine where infrastructure vulnerabilities to climate change may be present. All high risk infrastructure-climate parameter interactions, as well as medium risk interactions assessed as vulnerable through the engineering analysis comprise the vulnerabilities identified for Toronto Hydro's electrical distribution system to a changing climate. These vulnerabilities can be divided into five groups based on how climate parameters affect the system. The following paragraphs summarize these vulnerabilities, while table 7-1 provides more detailed information by infrastructure-climate parameter interactions.

High Ambient Temperatures – Station and Feeder Assets

High ambient temperatures create problems for the distribution system because of the compounding effect of high demand (e.g. for cooling) and high ambient temperature affecting equipment cooling and electrical transmission efficiency. Two specific climate parameters were of most significant concern, daily peak temperatures exceeding 40°C (excluding humidity) and daily average temperatures exceeding 30°C. In these cases, the climate analysis found that such extreme temperatures have occurred only rarely in the past, but are projected to occur on an almost semi-annual to annual basis by the 2030's and 2050's respectively. Through preliminary demand and supply growth projections completed for this study, these vulnerabilities were identified based on the notion that extreme heat will generate electrical demand for cooling in areas where station excess capacity is projected to be marginal. Furthermore, such temperature extremes may cause equipment, notably power transformers, to operate beyond their design specifications and increases the likelihood of failure. It is anticipated that vulnerability to high heat events will be concentrated in the Former Toronto area, although there are several horseshoe station service areas which would also be vulnerable.

Freezing Rain, Ice Storms, High Wind and Tornadoes – Overhead Station and Feeder Assets

Freezing rain, ice storms, high wind and tornado events cause immediate structural issues for overhead distribution assets, as they have the capacity to exceed the design limits of equipment and their supports. Outages may result from damage to equipment arising from direct forces applied by climate parameters (e.g. wind, weight of ice) or by other objects (e.g. tree branches, flying debris). These kinds of events affect outdoor station and feeder assets, which are largely concentrated in the horseshoe service area. It is important to emphasize that Toronto Hydro has experienced problems related to freezing rain, ice storms (up to 25 mm) and high winds (up to 90 km/h) in the past. These events are projected to continue in the future, but continue to occur on a less than annual or even decadal frequency. More severe ice storms (60 mm), high winds (over 120 km/h) and tornadoes (EF1+) have been extremely rare in the past, and while there is a lack of scientific consensus on projected future frequencies for these extreme events, they are likely to remain rare in the future. Nevertheless, the damages caused by these kinds of events can be severe. Therefore, they were judged as ongoing and future vulnerabilities for Toronto Hydro.

Extreme Rainfall – Underground Feeder Assets

Extreme rainfall events may potentially flood underground feeder assets, which are largely concentrated in the Former Toronto and northeastern horseshoe areas. Toronto Hydro is aware of these issues in relation to its

assets and has programs to replace non-submersible equipment with submersible type equipment, to relocate equipment where possible. However, due to the large quantity of underground feeder assets across the city, replacement and reinforcement of underground assets will be a gradual and ongoing activity for Toronto Hydro over the study period. As such, some underground feeder assets may remain an area of vulnerability for Toronto Hydro.

Snowfall, Freezing Rain - Corrosion of Civil Structures

The degradation of civil structures (i.e. concrete and steel), which is accelerated by humidity and the presence of de-icing salts, was identified as a potential area of vulnerability to climate change. Corrosion is already an ongoing issue for Toronto Hydro and current assets have a design lifespan which accounts to a great extent for corrosion issues. However, it is not clear from this study whether the climate change stresses will exacerbate the problem. While snowfall days are generally expected to decrease with a warming climate, they will continue to occur annually through to the 2050's. As a result, and in combination with freezing rain events, the application of de-icing salts will also be applied annually through the study horizon. Nonetheless, it should be emphasized that corrosion represents a long-term and on-going vulnerability for Toronto Hydro.

Lightning – Overhead Feeder Assets

Based on workshop feedback and an examination of Toronto Hydro's ITIS outage data, Toronto Hydro recognizes that lightning impacts are a significant source of outages on the distribution system today. While there have been advances in predicting lightning activity, there was insufficient data available on lightning strike intensity and arrester performance to suggest how future lighting activity may affect the electrical system. For these reasons, this study suggests that lightning activity will continue to be an area of vulnerability.

7.2 Adaptation Options

Adaptation options are suggested for all the infrastructure-climate parameter interactions identified as vulnerabilities. The Protocol classifies adaptation options in four possible categories:

- remedial engineering actions which aim to strengthen or upgrade the infrastructure;
- management actions to account for changes in the infrastructure capacity;
- continued monitoring of performance of the infrastructure and impacts; and
- further study required to address gaps in data availability and data quality.

Adaptation options by infrastructure-climate parameter interaction are presented in Table 7-1.

Table 7-1 Vulnerabilities and Adaptation Options by Infrastructure Asset, Climate Parameter

Affected infrastructure	Climate Parameter	Adaptation Option	Details
Stations, Communications and Protection Systems			
1. Transmission stations, municipal stations, protection and control systems Critical component: batteries	High temperature above 25°C	Further study required	Toronto Hydro has experienced problems with station batteries failing short of expected lifespans (i.e. approximately 10 years). Operating batteries in rooms where the ambient temperatures increases above 25°C is a contributing factor to premature battery failure (Toronto Hydro, 2014c). As battery rooms are not temperature controlled, Toronto Hydro could monitor how ambient temperatures of rooms within stations housing batteries fluctuate during the warmer summer months and evaluate whether additional measures are needed (e.g. review of battery technical specifications, including aging factor) to reduce battery degradation.

Affected infrastructure	Climate Parameter	Adaptation Option	Details
2. Transmission stations, municipal stations Critical component: power transformers	High temperature above 35°C, 40°C Average daily temperature > 30°C Heat wave High nighttime temperatures	Further study required	Given the increased frequency of high heat conditions in the future, coupled with continued demand growth, infrastructure owners (Toronto Hydro and Hydro One), could conduct a could conduct a further study evaluating the technical and financial feasibility of installing transformers with a higher capacity, or installing more transformers at stations (shared load) where space permits. Another possibility is to evaluate the technical and financial feasibility of increasing the design standard for current power transformer equipment, for example, by designing to a daily average ambient temperature higher than 30 °C (35 °C) and maximum temperature with a higher temperature than 40°C (45 °C). Finally, these measures should be complemented by continued demand side management /energy conservation programs.
3. Transmission stations: only outdoor stations 4. Municipal stations: Horseshoe area outdoor stations Critical component: Overhead exit lines (for freezing rain and high winds parameters)	Freezing rain/ice storm : 25 mm, 60 mm High winds : 120 km/h and tornadoes	Management actions and further study required .	Major freezing rain, ice storm, high wind and tornado events are not expected to be an annual occurrence in the future, but will still likely occur over the study period. Station exit lines, either overhead ones or where underground cables surface, are a particular point of vulnerability, as downed exit lines can sever power supply to the entire service area. Toronto Hydro could monitor the frequency of damage to station exit lines and poles across a range of potential weather threats (freezing rain, high winds) to evaluate whether this critical portion of the distribution network requires strengthening. Toronto Hydro could also consider a station by station study of surroundings to identify areas around stations susceptible to generating flying debris (e.g. trees, buildings). Emphasis should also be placed on optimizing the emergency response and restoration procedures to reduce system down time. Note that Toronto Hydro is already undertaking a review and enhancement where necessary of response planning, dispatching operations, prioritization of restoration activities, coordination with other utilities, response team training and preparation.
Arresters (for lightning parameter)	Lightning	Monitoring activities	Lightning events and strikes are difficult to predict, but are likely to increase in frequency and intensity. However, lightning strike intensity and arrester performance is not currently monitored. Given the importance of lightning strikes as a cause of outages, it is recommended that the lightning activities (e.g. frequency, intensity), soil resistivity (i.e. decreased soil moisture from longer and hotter summers) and impacts on the system could be more closely monitored to provide more information regarding the risks of lightning strikes. For example, where high voltage arresters are installed, counters (if not already present) could also be installed to check if a particular phase or transmission line suffers from an exceptionally high number of overvoltages leading to arrester operation. Lightning strikes on the building housing stations could be investigated to determine whether they resulted in any overvoltage impacts. If further studies on lightning activity result in a better definition of lightning characteristics and impacts, or if monitoring indicates a higher rate of failure, a review of actual design practices could be undertaken.

Affected infrastructure	Climate Parameter	Adaptation Option	Details
Feeders, Communication and Protection Systems			
5. Underground feeders Critical component: cables and power transformers	High temperature above 35°C, 40°C Average daily temperature > 30°C Heat wave High nighttime temperatures	Monitoring activities	For power transformers, see discussion above on station power transformers (see row 2). For cables, increased temperature operation tends to reduce the dielectric strength of the cables. Toronto Hydro is currently trialing cable diagnostic testing techniques as a method of detecting vulnerabilities in cables. If cable testing techniques prove reliable in detecting potential failures, Toronto Hydro could consider extending diagnostic techniques to all cables to monitor heat stress impacts on cables to evaluate whether high design standards or more frequent replacement is required.
6. Underground feeders : Submersible type Critical component: cables	Extreme rainfall: 100 mm <1 day + antecedent	Monitoring activities	The presence of water can lead to an electrical failure of the cables (water treeing) and/or reduce the dielectric strength of cables. Cable diagnostic testing can be employed to monitor the degradation of underground cables. This study also supports Toronto Hydro's program to replace and renew older cable assets with moisture and tree resistant underground conductors such as TRXLPE cables. The development of flood risk mapping, coupled with historical registry of flood related equipment failures could enhance the identification of areas for priority intervention.
7. Underground feeders: Vault type – Below ground Critical component: non-submersible equipment	Extreme rainfall: 100 mm <1 day + antecedent	Remedial engineering actions	Toronto Hydro is currently upgrading non-submersible equipment located in below grade vaults with submersible equipment, or relocating them above grade. The development of flood risk mapping, coupled with historical registry of flood related equipment failures could enhance the identification of areas for priority intervention.
8. Underground feeders: 13.8 kV Network systems	Extreme rainfall: 100 mm <1 day + antecedent	Remedial engineering actions	Many old network protectors are not submersible, particularly in the downtown area. The current Toronto Hydro standard is to use submersible network protectors when replacing old equipment. Further study could be undertaken to evaluate the benefit and cost of replacing old network protectors prior to their end of life versus replacement at their end of life (i.e. potential for flood damage and outages prior to replacement).
9. Overhead feeders (Radial and loop) Critical component: power transformers and conductors	High temperature above 35°C High temperature maximum above 40°C Average daily temperature > 30°C Heat wave	Monitoring activities	Climate change is projected to increase the frequency of high heat conditions in the future. Coupled with continued demand growth, this is projected to increase heat stresses on overhead distribution feeder assets. However, unlike the case with station transformers, where projected heat and capacity reveal a clear vulnerability in terms of supply capacity, it is not clear whether high temperatures will have the same impact across the distribution feeder system (i.e. are there bottlenecks to supplying electricity during periods of high heat at certain stations or across the grid?). Toronto Hydro should continue to monitor key grid operational indicators for distribution transformers, such as load currents, billing data, transformer oil and ambient temperatures. This information can be used to help evaluate whether distribution line capacities are sufficient to handle increased electrical loads.
10. Overhead feeders (Radial and loop) Critical component: conductors	Freezing Rain/Ice storm: 15 mm and high winds 70 km/h	Management actions and remedial engineering actions	Toronto Hydro is already experiencing outages caused by tree contacts and is planning to increase its vegetation management activities. This study supports the need for increased tree trimming practices around overhead power lines and use of tree proof conductors in areas where outages due to tree contacts have been frequent.
11. Overhead : Radial and Loop Critical component: poles	Freezing rain/ice storm: 25 mm High winds: 90 km/h and 120 km/h, tornadoes	Management actions and further study required	See recommendations for stations above on freezing rain and tornadoes (see row 3).

Affected infrastructure	Climate Parameter	Adaptation Option	Details
12. Overhead power lines (radial and open loop) and SCADA system	Lightning	Monitoring activities	See recommendations for stations above on lighting (see row 3).
Civil structures			
13. Civil structures: Underground feeders (Former Toronto)	Extreme rainfall, freezing rain/ice storm 15 mm & 25 mm & 60 mm (combination of events)	Further study required	While maintenance can mitigate the risks of civil structures deterioration, changing climate conditions (e.g. freezing rain, rainfall, freeze-thaw) may exacerbate premature degradation issues. However, it could not be determined in this study whether current design standards are sufficient to withstand future climate - salt and moisture related degradation. Further study could be undertaken to estimate salt/moisture corrosion effects in relation to climate change.
14. Civil structures: transmission and municipal stations, underground feeders	Frost	Further study required	The nature of the frost heave impacts to civil structures was not sufficiently evaluated within this study. Further study can be undertaken to identify whether there are any specific location, ground condition and structure combinations which contribute to frost heave impacts.
Human Resources			
15. Human Resources	Heat, freezing rain, wind and tornadoes	Management actions	Toronto Hydro applies an occupational health and safety manual. Toronto Hydro is already conducting a review of its procedures in light of future extreme events to determine whether modifications in procedure or training are needed.

7.3 Other Areas of Study

Additional climate and infrastructure related areas of further study that can be used to enhance the understanding of electrical system vulnerabilities to climate change are listed below.

Climate

- Increase monitoring of important climate parameters across the city. For both the climate assessments and forensic analyses, a lack of observational data made understanding climate risk challenging and introduced uncertainties, particularly for specific climate parameters such as wind gusts, hourly rainfall measurements, and freezing precipitation accumulations. New monitoring would provide important benefits, including:
    - Addressing gaps in historical data;
    - Facilitating comparisons between sites across the city;
    - Improving the spatial resolution of the climate monitoring network, increasing the likelihood of capturing important meteorological events; and,
    - Providing additional data to assist in detecting new and emerging trends sooner than would be possible using the current network.
- Enhance details about weather impacts contained in the ITIS database. Although information contained within the database was extremely useful and yielded important insights, there were still gaps in the details of weather related outages which limited the evaluation of impacts;
- Refine and expand forensic investigations (see **Appendix C**) completed in this Phase 2 study. Several climate parameters, individual climate events and impacts were not investigated thoroughly due to the scope of the present study. In particular, further analyses could be done on:
    - Lake modified air and lake breeze influences on atmospheric hazards, especially extreme temperatures, ice accretion events, and severe thunderstorms (including extreme rainfall, downbursts/microbursts, and tornadoes);
    - December 2013 ice storm and other ice accretion events, particularly to help refine understanding of apparent variations in impacts between different sections of the city.

  - Temperature gradients across the city during periods of extreme heat. For example, why do some days show greater temperature gradients across the city than others, and what impact does this have on the system?
- Monitor and study the complex interaction between changes in tree growth, pest and disease conditions and resultant changes in risk to overhead systems. This could include investigating
  - The extent to which accelerated tree growth affects tree strength, and specifically resistance to wind and ice accretion loading;
  - Emerging and/or worsening tree pest and disease conditions which could reasonably be expected within the City of Toronto in the coming decades, and what potential changes in risk these will pose to overhead systems.

Infrastructure

- Site specific electrical configuration and area characteristics were not collected due to the scope of this study and scale of infrastructure system being analyzed (e.g. land use changes, high rise and condo development, population growth, terrain elevation, sewers, storm sewers, roads, tree canopy and tree type, buildings). Specific site characteristics, equipment age, or unique or uncommon equipment can alter sensitivity and vulnerabilities. Further study approaches could adopt a smaller spatial scale (e.g. station service areas, neighbourhoods) to reduce these scope and level of effort challenges and identify more site specific vulnerabilities;
- The scope of study and level of effort did not permit a detailed analysis of system performance and outage management (i.e. simulations of power rerouting or contingencies under different outage scenarios to various parts of the system). Further study approaches could adopt a smaller spatial scale (e.g. station service areas, neighbourhoods) to reduce these scope and level of effort challenges and permit a more detailed study and understanding of system performance and outage management;
- Smart Grid Data: Toronto Hydro has recently begun collecting information about outages from its grid based on smart grid feedback. Data history was short and not reviewed in this analysis. Further study examining smart grid data can be used to identify problem areas due to high load demand.

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Workshop Presentations

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Background Information on Developing Climate Data

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Risk Assessment Matrix

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Engineering Analysis

Appendix H
PIEVC Worksheets

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Toronto Hydro-Electric System Limited Climate Change Vulnerability Assessment

Application of the Public Infrastructure Engineering Vulnerability Assessment Protocol to Electrical Distribution Infrastructure

Final Report Appendices - Public

6031-8907

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Appendix A
Workshop Presentations

This information has been removed from the public version of this report

Appendix B
Background Information on Developing Climate Data

Appendix B: Background Information for Developing Climate Data

B.1 Introduction

The following Appendix provides additional details about the methods used to develop the climate data used in the Toronto Hydro PIEVC Climate Change Risk Assessment. The development of climate data to support this study involved three main activities.

- Identify climate parameters (e.g. temperature, precipitation, wind) and threshold values at which infrastructure performance would be affected (i.e. climate hazards);
- Project the probability of occurrence of climate hazards for future climate; and,
- Convert projected probability of occurrence of future climate parameters into the seven point scoring scale employed by PIEVC studies to support the risk assessment.

This appendix provides more detailed information about the first two activities, namely the identification of relevant climate hazards and the estimation of their probability of occurrence in the future. The conversion of this probability information into PIEVC scores is not covered here, as it is already explained in the PIEVC Protocol V. 10.

B.2 Identification of Climate Parameters and Infrastructure Thresholds

In this study, the identification of relevant climate parameters and infrastructure impact thresholds (i.e. climate hazards) involved a combination of the three methods:

- Literature review;
- Practitioner consultation; and,
- Forensic analyses.

B.2.1 Literature Review

Design values in codes and standards generally provide an excellent “first guess” to determine infrastructure impact thresholds, providing information on not only baseline climatic design values, but on safety factors, load combinations, and so on. Codes and standards can also provide an understanding of changing thresholds depending on the age of infrastructure and therefore applicable code or standard. These values can also be used as a basis for discussion with practitioners, to determine if there are local modifications for in-field infrastructure. The occasional review and updating of codes and standards also tends to generate discussion and papers in the published literature, which can further provide background on why changes were made, how climatic data was processed, and when these changes became effective.

B.2.2 Practitioner Consultation

Discussion and consultation with practitioners is invaluable. Practitioners can describe important historical events and their impacts, relevant logistical and operational elements of the system, and new and emerging problems which may not be documented elsewhere. More generally, practitioners can provide guidance on where problematic interactions tend to arise and what can be done to reduce those impacts (i.e. adaptation measures).

This project included two workshops in which assumptions regarding climate elements and infrastructure breakdown were evaluated, discussed and modified. The first workshop played a significant role in re-evaluating climate elements which had been identified under Phase I. For example, in light of recent severe weather events **(see Appendix C)**, extreme rainfall and freezing rain were given somewhat higher priority under Phase II. Following a preliminary climate analysis, several thresholds were removed, modified, or refined at the second workshop, and the discussion of complex interactions confirmed findings from the forensic.

B.2.3 Forensic Analyses

Forensic analysis is the evaluation of past events through the application of scientific techniques and understanding to establish facts. It is meant to diagnose the causes of, and contributing factors to, a given infrastructure failure incident. These analyses can be used to refine our understanding of not only what caused a given failure, but also how to prevent or reduce the risks of similar failures in the future. In the context of extreme weather, we can evaluate the meteorological conditions associated with an incident and compare those to impacts produced (i.e. what was damaged, how was it damaged, etc.) and the supposed design capacity of that system (i.e. what was it designed for, do field conditions match design requirements).

Forensic analysis first requires the identification of important historical climatic events. In this case this was provided by Toronto Hydro's ITIS database, and further augmented by newspaper and press release searches. These events were then compared to all available observational data, including both Environment Canada's climate network and as well as data provided by TRCA (TRCA 2014) for several specific events. A full report containing analyses of several different events in the GTA is provided in **Appendix C**. These results were then compared to the literature and were also presented to practitioners for further scrutiny. Findings included the apparent impact of tree canopies on wind resistance of trees (resulting in subsequent secondary impacts on overhead systems), as well as regional differences in impacts from freezing rain, likely the result of a combination of local meteorological conditions (temperature regimes) and regional differences in canopy cover and tree health.

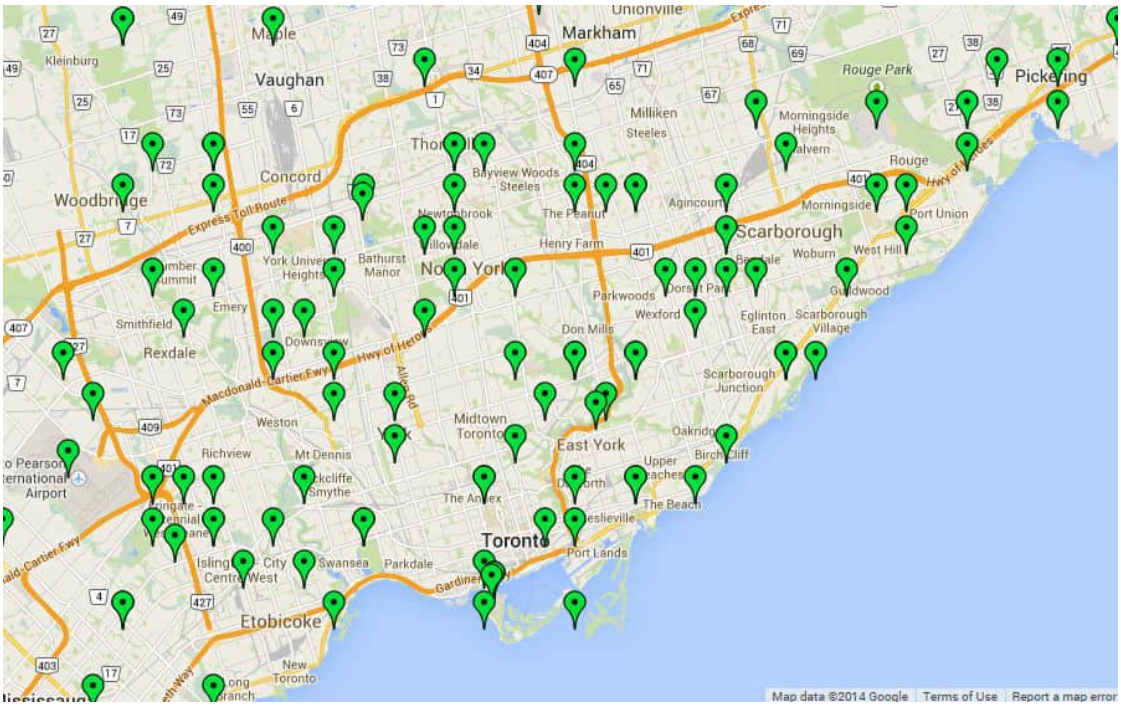
B.3 Establishing the Probability of Occurrence of Climate Hazards

The following section provides information necessary to project the future probability of occurrence of climate hazards. Information about the development of a historical climate baseline, the sourcing and use of future climate projection data, and the treatment of complex variables is presented.

B.3.1 Historical Climate Observations

Environment Canada is the authoritative source of climate information in Canada. In the Toronto region many observations stations have been in place and subsequently closed (see **Figure B.1**). In most cases stations only have observations for a few years – too short to establish a 'climatology'. The most recent normals period established by the World Meteorological Organization (WMO) was 1981-2010. Although 30 years is the accepted minimum, Environment Canada has calculated normals for stations which have at least 10 years of data within this period.

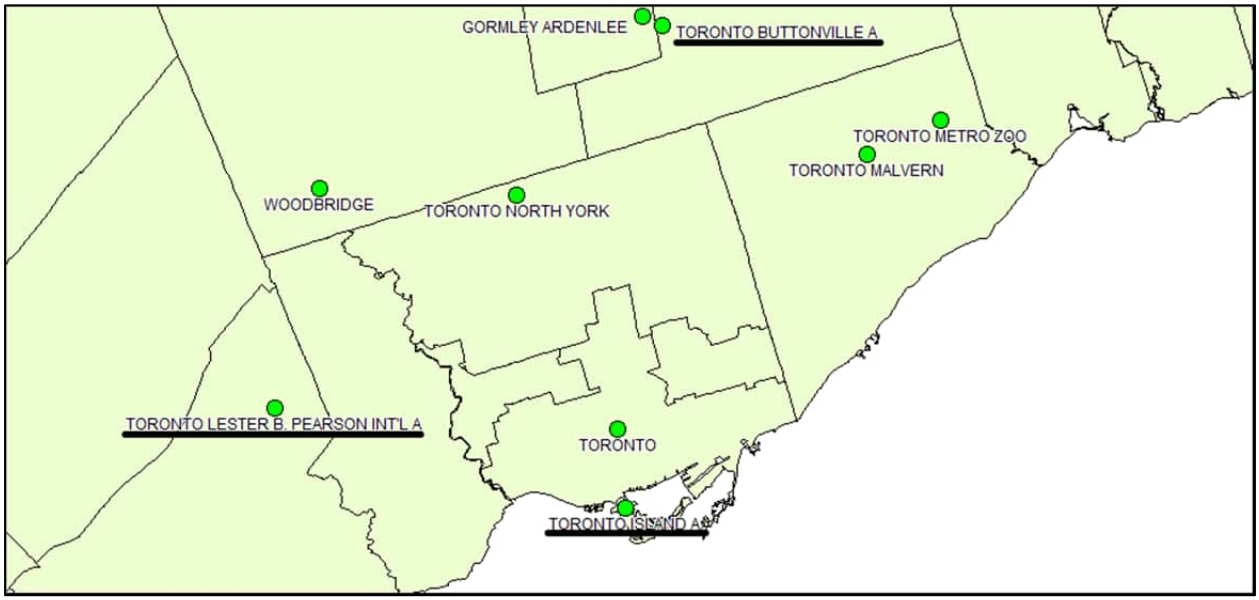
Figure B.1 All Historical Environment Canada Stations



Note: includes those not currently open

To establish reliable statistics on the frequency of events, long term records are preferred and with this area, there are some stations available. It is generally accepted that to establish a 'normal' climate, a minimum of 30 years of data as required. This supposedly ensures that short term natural variability is averaged out. Detailed hourly observations are usually only available at airport locations such as Toronto Pearson, Buttonville and Toronto Island. These airport locations are also typically the only source of variables other than temperature and precipitation (such as wind or weather observations). Of these, Toronto Pearson has the lengthiest reliable data record. Those regional stations for which normals data was calculated for 1981-2010 are shown in **Figure B.2**.

Figure B.2 Environment Canada 1981-2010 Normals Locations



Note: Stations with additional weather and wind data are underlined.

B.3.2 Future Projections

B.3.2.1 Global Climate Models

These variables will consider both the historical period frequencies observed in the region and the corresponding projections used in the most recent Intergovernmental Panel on Climate Change (IPCC)'s Fifth Assessment Report (AR5). The suite of models used in AR5 is from the Fifth Coupled Model Intercomparison Project (CMIP5), coordinated by the World Climate Research Program, and was retrieved from the following data portal:

http://cmip-pcmdi.llnl.gov/cmip5/guide_to_cmip5.html.

Since the second IPCC Assessment released in 1995, the number of contributing international climate modelling centres, models, and their complexity, have increased significantly – from 11 models to the current 40. With increased computing power, better refinement of atmospheric phenomena have been incorporated, and model spatial and temporal resolution has improved (Kharin et al. 2013). An important outcome of this increase in model availability is the ability to produce projections of future climate based upon an 'ensemble' of many models versus the use of single or only a few models. In this report, all available AR5 model runs (many models have more than a single projection available) were used. The use of multiple models to generate a 'best estimate' of climate change is preferred over a single model outcome. Research has indicated that the use of multi-model ensembles is preferable to the selection of a single or few individual models since each model can contain inherent biases and weaknesses (IPCC-TGICA, 2007, Tebaldi and Knutti, 2007). The use of the ensemble projection from the family of global modelling centers is likely the most reliable estimate of climate change projections on a large scale (Gleckler et al, 2008).

A full list of the climate models and their country of origin is presented in **Table B.1**.

Table B.1 List of CMIP5 Global Climate Models (GCMs) Used for this Study

Model Name	Organization	Country	Organization Details
ACCESS1-0	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
ACCESS1-3	CSIRO-BOM	Australia	CSIRO (Commonwealth Scientific and Industrial Research Organisation, Australia), and BOM (Bureau of Meteorology, Australia)
BCC-CSM1-1	BCC	China	Beijing Climate Center, China Meteorological Administration
BCC-CSM1-1-M	BCC	China	Beijing Climate Center, China Meteorological Administration
BNU-ESM	GCESS	China	College of Global Change and Earth System Science, Beijing Normal University
CanESM2	CCCma	Canada	Canadian Centre for Climate Modelling and Analysis
CCSM4	NCAR	US	National Center for Atmospheric Research
CESM1-BGC	NSF-DOE-NCAR	US	National Science Foundation, Department of Energy, National Center for Atmospheric Research
CESM1-CAM5	NSF-DOE-NCAR	US	National Science Foundation, Department of Energy, National Center for Atmospheric Research
CMCC-CESM	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CMCC-CM	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CMCC-CMS	CMCC	Italy	Centro Euro-Mediterraneo per I Cambiamenti Climatici
CNRM-CM5	CNRM-CERFACS	France	Centre National de Recherches Meteorologiques / Centre Europeen de Recherche et Formation Avancees en Calcul Scientifique
CSIRO-Mk3-6-0	CSIRO-QCCCE	Australia	Commonwealth Scientific and Industrial Research Organisation in collaboration with the Queensland Climate Change Centre of Excellence
FGOALS-g2	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences
FGOALS-s2	LASG-IAP	China	LASG, Institute of Atmospheric Physics, Chinese Academy of Sciences
FIO-ESM	FIO	China	The First Institute of Oceanography, SOA, China
GFDL-CM3	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GFDL-ESM2G	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GFDL-ESM2M	NOAA GFDL	US	Geophysical Fluid Dynamics Laboratory
GISS-E2-H	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-H-CC	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-R	NASA GISS	US	NASA Goddard Institute for Space Studies
GISS-E2-R-CC	NASA GISS	US	NASA Goddard Institute for Space Studies
HadCM3	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-AO	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-CC	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
HadGEM2-ES	MOHC	UK	MetOffice Hadley Centre (additional HadGEM2-ES realizations contributed by Instituto Nacional de Pesquisas Espaciais)
INMCM4	INM	Russia	Institute for Numerical Mathematics
IPSL-CM5A-LR	IPSL	France	Institut Pierre-Simon Laplace
IPSL-CM5A-MR	IPSL	France	Institut Pierre-Simon Laplace
IPSL-CM5B-LR	IPSL	France	Institut Pierre-Simon Laplace
MIROC-ESM	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere

Model Name	Organization	Country	Organization Details
			and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies
MIROC-ESM-CHEM	MIROC	Japan	Japan Agency for Marine-Earth Science and Technology, Atmosphere and Ocean Research Institute (The University of Tokyo), and National Institute for Environmental Studies
MIROC4h	MIROC	Japan	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology
MIROC5	MIROC	Japan	Atmosphere and Ocean Research Institute (The University of Tokyo), National Institute for Environmental Studies, and Japan Agency for Marine-Earth Science and Technology
MPI-ESM-LR	MPI-M	Germany	Max Planck Institute for Meteorology (MPI-M)
MPI-ESM-MR	MPI-M	Germany	Max Planck Institute for Meteorology (MPI-M)
MRI-CGCM3	MRI	Japan	Meteorological Research Institute
NorESM1-M	NCC	Norway	Norwegian Climate Centre
NorESM1-ME	NCC	Norway	Norwegian Climate Centre

B.3.2.2 Representative Concentration Pathways

A new initiative in the IPCC AR5 is the introduction of RCPs (Representative Concentration Pathways; see **Figures B.3** and **B.4**). They represent a range of possible projection outcomes which depend upon different degrees of atmospheric warming. The lowest RCP 2.6, represents an increase of 2.6 W/m^2 to the system, while the highest RCP 8.5 represents an increase of 8.5 W/m^2 of energy. This range encompasses the best estimate of what is possible under a small perturbation situation (2.6) and under a large increase in warming (8.5). It is unknown which of the RCPs will apply in the future. However, it is important to note that historically, the GHG emissions have followed the highest (8.5) pathway. In the absence of a global agreement on GHG reduction, this trend is expected to continue which would support this pathway going forward. Nevertheless, in this report, 4.5 (moderate) and 8.5 (high) projected change are presented. The number of models used for the ensemble varies with the RCP selected since not all international modelling centres generated model runs for all RCPs.

Figure B.3 Representative Concentration Pathways used for AR5

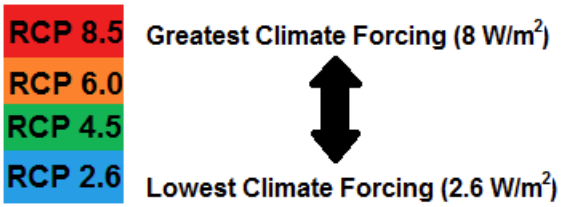
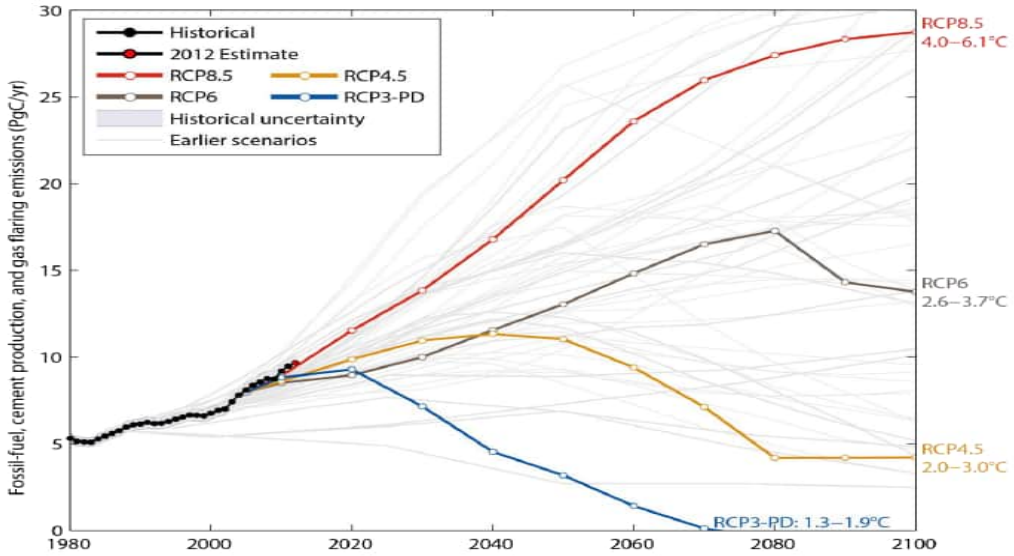


Figure B.4 Global GHG Emissions and their Relationship with Representative Concentration Pathway Assumptions



Source: Peters et al. 2012a

Factors influencing the RCP include population growth, economic growth, degree of urbanization, land use change, use of green versus carbon-based energy sources and any future international agreements on greenhouse gas (GHG) emissions, among others.

B.3.2.3 Important IPCC Findings

The full IPCC AR5 Working Group 1 Report was released in September 2013 and provides general details of the IPCC position on climate change. It can be found here: http://www.ipcc.ch/report/ar5/wg1/

Some of the main findings of this report are summarized in the Summary for Policymakers and are reproduced below:

- Warming of the climate system is **unequivocal**, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, sea level has risen, and the concentrations of greenhouse gases have increased.

- Each of the last three decades has been successively warmer at the Earth's surface than any preceding decade since 1850.

- Over the last two decades, the Greenland and Antarctic ice sheets have been losing mass, glaciers have continued to shrink almost worldwide, and Arctic sea ice and Northern Hemisphere spring snow cover have continued to decrease in extent.

- The atmospheric concentrations of carbon dioxide (CO2), methane, and nitrous oxide have increased to levels unprecedented in at least the last 800,000 years.

- Human influence on the climate system is clear. This is evident from the increasing greenhouse gas concentrations in the atmosphere, positive radiative forcing, observed warming, and understanding of the climate system.

- Human influence has been detected in warming of the atmosphere and the ocean, in changes in the global water cycle, in reductions in snow and ice, in global mean sea level rise, and in changes in some climate extremes. This evidence for human influence has grown since AR4. It is *extremely likely* that human influence has been the dominant cause of the observed warming since the mid-20th century.

- Observational and model studies of temperature change, climate feedbacks and changes in the Earth's energy budget together provide confidence in the magnitude of global warming in response to past and future forcing.

- Climate models have improved since the AR4. Models reproduce observed continental-scale surface temperature patterns and trends over many decades, including more rapid warming since the mid-20th century and cooling immediately following large volcanic eruptions.

- Global surface temperature change for the end of the 21st century is *likely* to exceed 1.5°C relative to 1850 to 1900 for all RCP scenarios except RCP2.6. It is *likely* to exceed 2°C for RCP6.0 and RCP8.5, and *more likely than not* to exceed 2°C for RCP4.5. Warming will continue beyond 2100 under all RCP scenarios except RCP2.6. Warming will continue to exhibit interannual-to-decadal variability and will not be regionally uniform.

- Changes in the global water cycle in response to the warming over the 21st century will not be uniform. The contrast in precipitation between wet and dry regions and between wet and dry seasons will increase, although there may be regional exceptions.

- Continued emissions of greenhouse gases will cause further warming and changes in all components of the climate system. Limiting climate change will require substantial and sustained reductions of greenhouse gas emissions.

With each subsequent report, the evidence of climate change builds and increasingly points towards greater confidence that human-kind is having and will continue to influence our future climate, from warming, to extreme events, to sea-level rise to melting sea-ice. Among the most recent IPCC reports was the addition of a separate document on climate extremes, the IPCC SREX document (SREX-IPCC, 2012). So in addition to changes in the mean climate, extreme climate events will also be impacted, and in many cases the changes in the extremes are expected to be greater than mean changes.

Of particular interest are some conclusions from the extremes report (SREX-IPCC, 2012):

- It is *virtually certain* that increases in the frequency and magnitude of warm daily temperature extremes and decreases in cold extremes will occur in the 21st century at the global scale.

- It is *very likely* that the length, frequency, and/or intensity of warm spells or heat waves will increase over most land areas

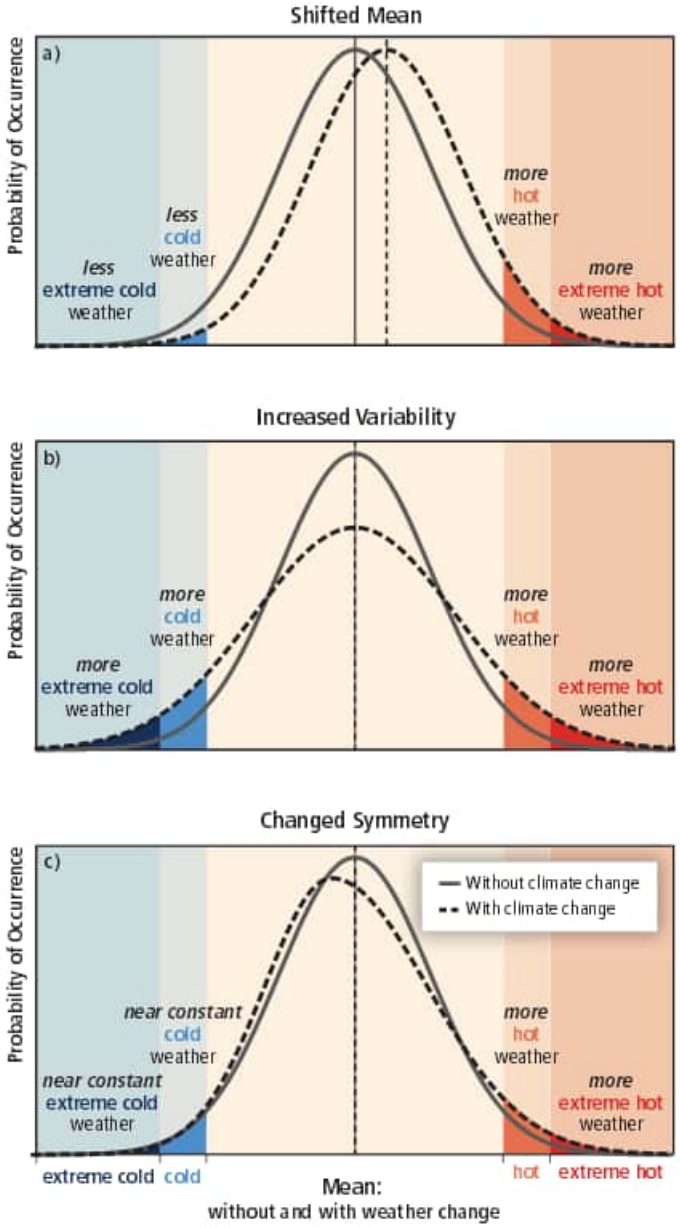
- It is likely that the frequency of heavy precipitation or the proportion of total rainfall from heavy falls will increase in the 21st century over many areas of the globe

- Extreme events will have greater impacts on sectors with closer links to climate, such as water, agriculture and food security, forestry, health, and tourism

- Attribution of single extreme events to anthropogenic climate change is challenging

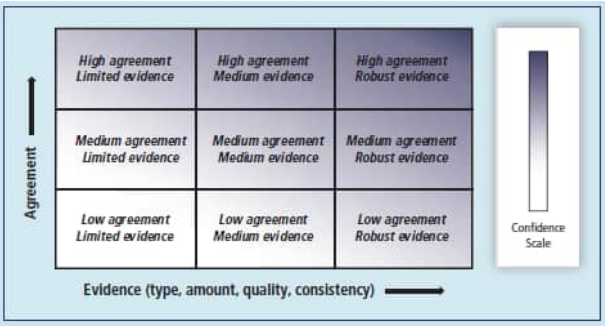
An example from the report is shown below for changes in temperature, which demonstrate how greater likelihood of extremes is possible through changes in mean, variability and symmetry.

Figure B.5 How Changes in Temperature Distributions can affect Extremes (IPCC, 2012)



Confidence wording in the IPCC documents are characterized by the use of specific terms such as ‘very likely’ or ‘virtually certain’, where in previous reports changes may have been referred to as ‘likely’. There has been a gradual increase in confidence of the projections from climate models over time. A summary of the confidence terminology used in the official reports is shown below (SREX-IPCC, 2012):

Figure B.6 IPCC Confidence Terminology



A depiction of evidence and agreement statements and their relationship to confidence. Confidence increases toward the top-right corner as suggested by the increasing strength of shading. Generally, evidence is most robust when there are multiple, consistent independent lines of high-quality evidence.

The following terms indicate the assessed likelihood:

Term*	Likelihood of the Outcome
Virtually certain	99–100% probability
Very likely	90–100% probability
Likely	66–100% probability
About as likely as not	33–66% probability
Unlikely	0–33% probability
Very unlikely	0–10% probability
Exceptionally unlikely	0–1% probability

* Additional terms that were used in limited circumstances in the Fourth Assessment Report (*extremely likely:* 95–100% probability, *more likely than not:* >50–100% probability, and *extremely unlikely:* 0–5% probability) may also be used when appropriate.

With each report there are more and higher quality observations of the changing climate and improvements in the models equations/parameterizations, and their spatial and temporal detail. The IPCC reports continue to provide the best science-based information on projected climate change assembled from the best climate researchers worldwide. Climate change projections for this report are based upon the same new models used for guidance in the IPCC AR5 report recently released.

B.3.3 Climate Projection Methodology

B.3.3.1 The Delta-Method Applied to the Ensemble

The use of the CMIP5 ensemble not only allows for the calculation of an average projection of future climate which represents the consensus of all independent models, but it also allows for the estimation of projection uncertainty and statistical distributions which could not be determined from a single model. The projections for the variables in this report represent the 'best estimate' available – and are more indicative of the general expectations of climate change over any single model.

The ability of the CMIP5 ensemble to reproduce the historical temperature gives us confidence that the newest models used in this report are reliable and when grouped can provide accurate estimates. This would imply that reliable historical climatology should lead to reliable future projections.

This study uses a so-called 'delta' approach (sometimes also called 'climate change factor approach'), to obtain future estimates of climate variables. It is generally comprised of the following tasks.

1. Obtain a baseline climate condition (or 'average' climate).

2. Using an ensemble of all available CMIP5 models ('CMIP5 ensemble'), we obtain the model average climate for this same period – the average of all models for the grid covering Peel region. However, each modeling center does not use the same grid alignment and resolution, so a first step before obtaining the average of all the models is to regrid them all to a common resolution. This regridding typically uses a scale representative of the resolution of the models, in this case approximately 200 by 200 km.

3. The CMIP5 ensemble future climate is obtained for this same cell for each of the required future periods. In this case, every 10 years starting in the year 2011 and ending in the year 2100. From this we will have average future conditions of all the models for ten 10 year periods.

4. The difference (or 'delta') between the CMIP5 baseline and CMIP5 future periods are obtained – this represents the change in climate condition. Ten climate deltas are produced, for example, the delta between the baseline (1981-2010) and the 2051-2060 period is one of the deltas.

5. The final step is to then apply this delta value to the baseline period.

B.3.3.2 Complex Climate Events: Regional Climate Models and other projection techniques

The delta method applied to an ensemble of GCMs is not the only method available for climate change studies. Instead of using a delta ensemble approach, the delta approach could also be applied to single model, but the projection estimates would therefore only rely on ones assumption that the single model employed was the ideal choice. In climate science there are tradeoffs between model complexity and expediency.

It should be noted that many high impact atmospheric events tend to occur on much smaller spatial and temporal scales than are covered by GCMs (e.g. lightning, freezing rain, ice storms, tornadoes). Two main strategies have been developed to help address this, the use of regional climate models (RCM's) [1] and statistical downscaling studies. Both strategies were used in Phase 2 for several of the more localized and shorter duration climate elements analyzed. For one set of climate hazards (e.g extreme temperatures), the technique of employing a climate analogue was also used to validate the "delta-method" for determining these climate hazard probabilities.

Regional Climate Models

Another approach for obtaining specific climate projection information is to run a very high resolution model once over the area of interest (so called 'dynamical downscaling'). In the simplest of terms one can either have 'many model runs at a coarse resolution' or 'few model runs at high resolution'. These high resolution models are called 'Regional Climate Models' (RCMs). There are RCMs available, but this data can be difficult to obtain and they still require a coarser resolution CMIP5 or earlier model to act as a precursor. Over North America, the North American Regional Climate Change Assessment Program (NARCCAP) has assembled less than a dozen RCMs for various time periods (http://www.narccap.ucar.edu/). As these models have a high temporal and spatial resolution (i.e. hours and tens of kilometers), there are fewer RCMs available than the CMIP5 Global Climate Model collection. In addition there are far fewer model runs from which to obtain an average climate change value. For this study, the decision was to use many coarser models from which to obtain the climate change signal rather than fewer higher resolution models. However, some of the probability results for one set of climate hazards in Phase 2 (extreme temperatures) were generated using the CANRCM4 model, and a discussion of associated uncertainties can be found under the specific descriptions for those climate hazards found below.

Statistical Downscaling

Statistical downscaling studies attempt to solve the spatial challenges by developing statistical links between GCM scale climate conditions and localized, short duration events (e.g. freezing rain/ice accretion and wind gusts). Historical, point location climate data is compared with conditions on the scale of GCM grids. Statistical links, so called "transfer functions", are then developed based on these relationships. After GCM projections are developed for a given future period, these transfer functions are then used to "downscale" GCM projection back down to local scales. Although much less computationally intensive than RCMs, individual statistical downscaling studies still require significant expertise and time for proper execution.

[1] These are sometimes referred to as "dynamical downscaling" methods, to provide an analogous term to alternative "statistical downscaling" methods.

The main drawback of this technique is that climate projections can then only be obtained from specific observation station locations which have sufficiently long data records. This method calibrates historical climate observed at an observation station (for example Toronto Pearson Airport), with historical model data at a coarse scale (called 'predictors'), to obtain a statistical relationship. For example, perhaps the daily temperature observed is related to the modeled upper atmosphere wind direction. If one provides the future upper atmosphere wind direction from a climate change model, it could then be used as one of the variables to predict the future temperature. The difficulty with this process even with pre-constructed software is that spurious associations based on pure statistics and not climatology can be applied which would produce unrealistic future conditions. Certainly some expertise in the statistical software is required. Additionally, this method requires specially formatted input statistical climate model data which is only available for a few models – and for few model runs and RCPs. This procedure would have to be repeated for all station locations for which there was long term reliable station observation data to produce estimates of climate change for only those specific locations.

An IPCC document entitled "Guidelines for Use of Climate Scenarios Developed from Statistical Downscaling Methods" (Wilby et al, 2004) further discusses these procedures.

Phase 2 made use of previously published statistical downscaling studies to support future climate change projections (Cheng, Li and Auld 2011, Cheng 2014).

Climate Analogues

In the case of extreme temperatures (i.e. average temperature over 30 and 35 C, extreme over 40C) climate change projections were also compared to a "climate analogue." Climate analogues refer to locations in other geographical areas which possess historical climates which resemble in many respects the future climate of the study area. The future temperature regime for the 2050's for the City of Toronto is very similar to the current and historical climate of northern Kentucky. While not an exact comparison – there are significant differences in regional geographical characteristics, for example – rough, "order of magnitude" comparisons can be made to help further determine if climate change projections are in fact realistic and represent potentially "real" climates.

B.4 Determining the Probability of Occurrence of Specific Climate Hazards

Based on the general methodology presented above, the probability of individual climate hazards were determined. The following sections describe in detail how they were estimated.

Extreme Temperatures

Temperatures and temperatures related indices are the most basic and reliable of climate elements, and therefore associated trends and projected changes to temperatures have the greatest confidence. Thresholds are based on previous consultation work from Phase I, IEEE standards for switching and transformer equipment, with some additional consideration from impact studies found in the literature - for example, see (McEvoy, Ahmed et Mullett 2012). The lowest thresholds generally address load forecasting and related factors, while higher temperatures begin to consider direct impacts to equipment.

Historical values were assessed using observations for Pearson Airport for the 1981-2010 normals period. Climate projections were then developed using the AR5 ensemble and RCP 8.5 emissions scenario. For temperature related thresholds which require information of *daily* temperature information, such as heat waves, 40°C maximum daily temperature, or the 35°C average daily threshold, required special treatment and were developed using projections from the CanRCM4 regional climate model (RCM), again using the RCP 8.5 scenario. The "Delta method" was then used to apply the modeled changes in frequency of those days applied to historical averages. It should also be noted that the range indicated for the 40°C threshold is the result of applying two methods, RCM and GCM based estimates,

since RCMs are again potentially prone to overestimates due to numerical instability[2], while the GCM method may under-estimate the frequency of extremes due to averaging from large spatial scales. These results were further checked against climate analogues in northern Kentucky, again to serve as a consistency check against model projections to determine if these projected increases were realistic.

Extreme Daily Averaged and Maximum Temperatures

Manufacturers of electrical distribution equipment specify both maximum *one day average* and *peak ambient* temperatures for the operation of transformers and other components. With global warming, it is unsurprising that all thresholds show an increase in event frequency. High temperatures which already occur several times per year increase further in frequency, and a few extreme temperatures which are currently less than annual occurrences (e.g. daily average temperature of 30°C) are projected to become annual events.

The most striking results were noted with some of the highest temperature thresholds. For example, days with peak temperatures of 40°C or greater are extremely rare, with only one incident on record for Toronto's Downtown station[3], and *no* events reported at Pearson Airport during its entire period of record. However, indications are that these extreme heat days may become an annual or near-annual occurrence by the 2050's. Similarly, days with 24 hour *average* temperatures of 30°C or higher are also extremely rare but may become, on average, annual occurrences. However, as with the historical behaviour of lower threshold values, there will likely be some years with several days over the "new" threshold, while other years will have none.

Multi-Day Heat Events and "Warm" Nights

Other measures of extreme heat have been proposed as having a potential impact on electrical infrastructure.

While heat waves, defined as three or more days with maximum temperatures above 30°C, are currently slightly less than annual events, these are expected to increase in frequency to just over 1 per year, on average, into the 2030's and 2050's. The length of a given heat wave may also increase into the future. Regional climate model results suggest that for the 2030's, an average of approximately four (4) consecutive days over 30°C will occur every year, and by the 2050's the estimate is as high as *six* (6) consecutive days over 30°C per year.

So-called "warm nights" have also been implicated in excessive stress on electrical infrastructure (McEvoy, Ahmed et Mullett 2012) through increases in nighttime electrical customer use (i.e. need for continuous use of air conditioning systems), combined with an inability for equipment to sufficiently cool under warm nighttime ambient temperatures. These have increased substantially in recent years, with average of greater than one event per year in the most recent 15 year period of record at Pearson Airport. This includes a record of five (5) warm nights in 2005, as well as the warmest overnight temperature ever recorded in 2006 at 26.3°C. However, while the literature has indicated that the latter element may be important for combined impacts and stress to the electrical system, most workshop participants were indeed quite skeptical that warm nights were an important measure for electrical system impacts, indicating they considered extreme *daytime* temperatures and electrical use as the dominant cause for impacts to distribution systems, rather than warm nights.

[2] Estimated increases in frequency from CanRCM4 were indeed so striking that they were checked against GCM based estimates for consistency. However, even when considering spatial and temporal averaging which will occur with the larger grid spacing and time steps inherent in GCMs, the ensemble still indicated significant increases in extreme heat days well beyond anything within historical experience.

[3] Three (3) consecutive days in July 1936 showed maximum temperatures reaching 40.6°C.

Spatial Geographical Variability

Mapping of extreme temperature days (**Appendix C**) indicate important temperature differences across the city, with temperature differences of 3-5 degrees between the shores of Lake Ontario and northern portions of the city. This is a direct result of the presence of Lake Ontario and its lake breeze, with cooler air from the lake keeping the shoreline and nearby areas cooler than parts of the city further north.

Extreme Short Duration Rainfall

The July 8, 2013 flash flood event in the GTA provided an example of the vulnerability of underground infrastructure to atmospheric events. While this particular case impacted Hydro One infrastructure, it is indicative of possible impacts to similar infrastructure owned and operated by Toronto Hydro. It was also an example of the importance and potential impacts generated by the loss of 3rd party infrastructure on which Toronto Hydro relies, emphasizing the interconnectedness of the electrical grid.

The threshold of "100 mm + antecedent" is based on rainfall accumulations estimated near the failure sites from the July 8th, 2013 event as well as other cases **(see Appendix C)**, although workshop participants felt this threshold might indeed be as low as 60 mm of rainfall. This threshold is in specific reference to high-intensity, localized rainfall events, characteristic of severe thunderstorms during the warm season. These generally last only a few hours in total, with the majority of that rain (over 50%) falling within a 1 hour time period. However, in every case, there was also antecedent rainfall in the preceding week which likely contributed to the overland flooding.

While these events are very difficult to predict even in short term forecasts, historical analyses on global precipitation extremes indicate that, in general, they will increase in intensity with climate change. However, the magnitude of this change, particularly for specific geographical regions, is not well understood (Kunkel, et al. 2013). Extreme, localized rainfall events represent an event type which cannot be modeled directly by GCM or even RCM output, and unfortunately no statistical downscaling studies for extreme thunderstorm rainfall exists for the GTA or nearby regions. However, global trends of historical increases in extreme rainfall are so significant that the climate team chose to increase annual probability score by one to account for this clear increase in thunderstorm extreme rainfall risk

Ice Storms and Freezing Rain Ice Accretions

Damage thresholds were also based on previous forensic work on freezing rain impacts, most notably Klaassen et al. (2003), as well as design requirements in codes and standards (CSA 2010a). These include thresholds for tree damage (15 mm) and for minimum CSA design (25 mm totals ≈ 0.5 inch radial). Freezing rain events represent an example of meteorologically complex events which require special treatment, and hence future projections presented here are based on tailored statistically downscaled results from published studies. Customized data specifically developed for Pearson International Airport were provided courtesy of C. Cheng (2011), using the same methodology employed in Cheng et al. (2011, 2014). Downscaled projections are expressed in *duration* rather than *accumulation amounts* due to the nature of the analysis methods used for downscaling. Climate projections of the parent large scale weather patterns (so-called "synoptic map typing") are based on the patterns and conditions which produce ice storms. For the downscaling work, these weather patterns were linked to the *duration* of freezing precipitation and not *amounts*, since total precipitation accumulation can vary significantly depending on available moisture. The duration threshold is also quite low (6 hours+) due to sample size, since storms of this magnitude or greater are infrequent.

However, these projections can be applied to other measures of ice storm severity given the following considerations:

1. Storms producing amounts on the order of 15 and 25 mm are of part of this "6 hour+" population, and we can therefore use results for the 6 hour+ storms as guidance for what will happen with 15 and 25 mm events; and,

2. Cheng et al. (2011, 2014) consistently showed greater increases in frequency for higher thresholds, hence storms with higher thresholds are expected to increase in frequency as much as or more than storms at lower thresholds;

Hence, changes in 6 hour+ event frequency are expressed as particular values, whereas the greater accumulation events are expressed as "greater than" some value.

Regional Differences in Severity

The severity of freezing rain events, specifically in terms of total ice accretion, tend to be lower for areas closest to Lake Ontario. In contrast to the summer, the lake acts to keep temperatures warmer during the early winter, an effect that appears to have been a factor during the December 2013 ice storm (see **Appendix C**). However, there are also indications from the forensic analyses that older portions of the city, particularly areas with a combination of significant, mature tree canopy cover and older overhead electrical distribution equipment, may be more sensitive to ice storms and are therefore more susceptible to smaller ice accretions.

It is very difficult to determine the return period or annual frequency of the extreme cases, since no events producing greater than 40 mm of total ice accretion have been reported in the GTA. The CSA standard for transmission line design (CSA 2010b) contains return period estimates for radial ice accretion for various locations[4]. Depending ones location within the City of Toronto, estimates for 30 mm ice accretion event (roughly 60 mm of total ice) indicate anywhere from a 1-in-150 to a 1-in-500 year return period event, termed "high" and "low" risk values, respectively, in table 3-2 in the main report. When increases in frequency of large ice storms is taken into account, these produce 35 year study period/"lifecycle" probability estimates of ~25% and ~8%, respectively[5]. However, these values are based on estimated return periods for extremely rare events, and the period of record on which they are based is far shorter than the return periods assigned to these ice accretion values.

Complexity of Freezing Rain Accretion versus Impacts

A myriad of measurements are given for freezing rain ice accretion due its complexity. Accumulations from airports, for example, represent *total* freezing rain amounts and not the thickness of accretions on overhead lines and structures, and hence certain freezing rain amounts can result in very different levels of ice accretion on infrastructure depending on numerous other factors (e.g. time, wind speeds, ambient temperatures). We also note that a significant majority of damage from the December 2013 ice storm was due to tree contacts at accretion thresholds lower than design requirements **(Appendix C)**, hence the inclusion of the 15 mm threshold.

High Winds

High winds can be produced by a variety of storm types and vary greatly in scale, intensity and duration. Design wind speeds found in codes and standards are based on large scale (synoptic) storms, while cases of extreme localized damage tend to occur with thunderstorm winds, including microbursts and tornadoes. This complexity introduces significant challenges when attempting to determine wind speed return periods for engineering design using historical data (Lombardo, Main et Simiu 2009), let alone the challenge of understanding how these might change under future climate conditions. Much like ice storms, wind gusts tend to also be affected by highly localized meteorological and geographical factors, and so meaningful projections cannot be directly extracted from GCMs or even RCMs.

[4] The values provided in the CSA standard (CSA 2010b) are themselves based on the Chaîné ice accretion model. These were felt to be accurate enough to provide estimates of extreme ice storms in the GTA for this study.

[5] Based on climate design table, highest risk locations are Etobicoke and North York, with the lowest risk is in Scarborough (CSA 2010a), the former not surprisingly representing areas which are slightly further away from the lake.

The 70 and 90 km/h thresholds are based on practitioner consultation from Phase I as well as forensic analyses conducted for Phase II (**Appendix C**). The highest threshold, 120 km/h, is based on IEEE design standards for switch gear and transformers, as well as other impact thresholds work, for example the EF-scale and McDonald and Mehta (2006). Climate change projections for the 70 and 90 km/h thresholds were obtained from statistically downscaled results in the published literature (Cheng, Li et Li, et al. 2012, Cheng 2014) using statistical downscaling methods similar to those used for freezing rain, while projections for 120 km/h threshold were not available.

The statistically downscaled results indicate increases for both thresholds analyzed here. Cheng et al. (2012, 2014) also indicated that increases in frequency of wind gusts were consistently greater as thresholds also increased (e.g. 80 km/h gusts increased more than 70 km/h gusts), but did not conduct analyses for thresholds greater than the 90 km/h due to small sample size.

Tornadoes

Tornadoes are small scale, isolated events, and hence the only available historical data are records of observations of their occurrence and/or resulting damage. Probability scores for EF1 and EF2 tornadoes were calculated based on historical records of occurrence within the City of Toronto from the most recently available 70 years of observational data. Historical data prior to this was deemed too unreliable to contribute to statistics in a meaningful fashion. This inconsistency also renders historical trend detection nearly impossible[6]. Their localized and complex nature also prevents the development of meaningful climate projections through any of the methods described here, including GCM or RCM output as well as statistical downscaling.

As with extreme temperatures, lightning and ice accretion, the northern portions of the city such as the North York and Rexdale (northern Etobicoke) areas exhibit a higher risk of tornadoes historically, again mainly due to the effects of the Lake Ontario lake breeze, but this does not exclude the occurrence of tornadoes in and around the downtown core.

Two different intensity levels were chosen due to important differences in their impacts. Research on historical events indicated that concrete utility poles and other more resilient infrastructure only fail in EF2 or stronger tornadoes, and hence these were investigated separately to determine relative risk.

High Impact/Low Probability Events: Probability Estimates and Their Interpretation

Tornado probabilities were subject to further analyses beyond those used for most other climate elements. Probability scores in Table 3-2 of the main report reflect the probability of occurrence for a *single point*; however, since these values are extremely small, a different statistical perspective was needed to better represent the type of risk posed by tornadoes. The City of Toronto has recorded five (5) F-2[7] tornadoes on two separate days since 1900, with a possible sixth case in 1976 in North York. Hence, over the 35 year life cycle study period, there is a 46% to 61% chance that a weather event producing one or more EF-2 tornadoes will strike somewhere within the City of Toronto. While the probability of a direct impact to a specific point or location is extremely small, the likelihood of a significant event *somewhere* in the city between 2015 and 2050 is in fact considerable, and could entail catastrophic impacts to a portion of the city's infrastructure.

Lightning

As with all other climate elements, lightning can vary significantly in intensity, with the same storm producing different lightning strikes with amperage values varying by several orders of magnitude. Even

[6] However, some very recent work in the United States may finally be revealing changes in tornado climatology potentially associated with climate change in the form of increased *variability* in occurrence[6] (Brooks, Carbin et Marsh 2014).

[7] The so-called "Enhanced" Fujita, or EF-Scale, has only been used in Canada as the official replacement to the F-scale since 2013; however, the EF-scale is intended to be compatible with F-scale ratings in the historical record, and so references to tornadoes using the F-scale can, for the purposes of this report, simply be considered as storms of equivalent intensity.

for a single thunderstorm event, there now exists a great deal of data currently available for use in analyses and even forecasting of lightning occurrence, particularly following the establishment of the North American lightning detection network in the late 1990's, and more recent "total lightning" detection networks being installed in the GTA for meteorological monitoring for the upcoming 2015 PanAm games. It is suggested that Toronto Hydro investigate this data to better understand how lightning interacts with the electrical distribution system, such as investigation of significant lightning events (e.g. July 21 & 22, 2002) to determine why and how they generated so many impacts.

Investigation of New Probability Scoring Methodology

Lightning probability scores differ from Phase I due the changes in the method used to calculate probability values. The annual average frequency of cloud-to-ground lightning strikes varies across the city from under 1.12 to over 2.24 lightning strikes per square kilometer. The highest frequencies are seen in the northwest portions of the city, while the lowest are seen in southern Etobicoke (see Figure B-7). However, each individual strike will only affect a very small area. Hence, the probability of impact was estimated using representative "target sizes" (i.e. areas which represent the usual footprint of a given piece of infrastructure). A further assumption was tested assuming that lightning strikes would need to be within 25 meters of a piece of overhead infrastructure to produce negative impacts. The resulting probability scores were felt to be more representative of field conditions, particularly when considering the frequency of lightning impacts reported by Toronto Hydro (**see Appendix C**). These were also weighed against mounting evidence that lightning occurrence will increase in frequency with climate change, for example (Romps, et al. 2014), but by an uncertain amount[8].

Using two different "target" sizes provided by AECOM representing large (0.015 km^2) and small municipal (0.0001 km^2) transformer stations, probability of impact were calculated and compared, with and without the assumption of a 25 meter radius of impact. The results are provided in Table B-2 below.

Figure B-7 Lighting Distribution in Greater Toronto Area for 1999 – 2008 period, Lightning Strikes / /km^2•yr)

[8] Romps et al. (2014) indicated a potential increase of ~50% in total lightning strikes in the continental United States by the end of the century. However, while their methodology proved to be quite robust when compared to observational data, there was no assessment of GCM error in recreating the indices which drove this increase. Their index and model also appear to have difficulty with lake breeze related convection, which is of great importance for Toronto's lightning climatology. Hence, the RSI climate team chose to not apply these percentages as there remains too much uncertainty in how global climate change will impact lightning frequency in the Toronto area specifically.

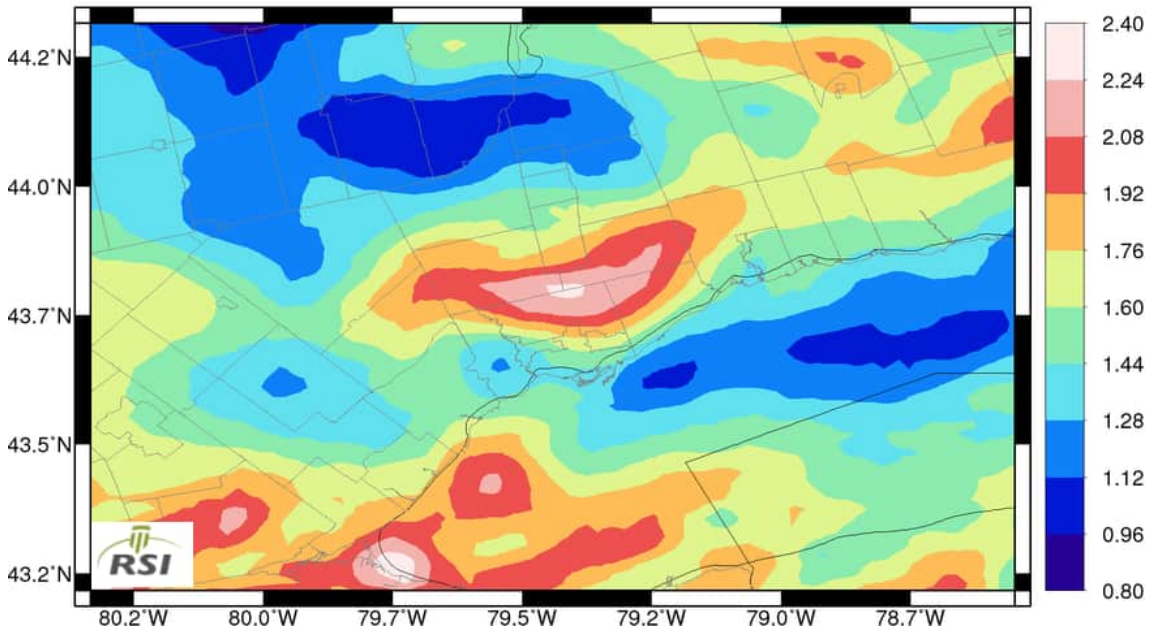

44.2°N
44.0°N
43.7°N
43.5°N
43.2°N
80.2°W
80.0°W
79.7°W
79.5°W
79.2°W
79.0°W
78.7°W
RSI
2.40
2.24
2.08
1.92
1.76
1.60
1.44
1.28
1.12
0.96
0.80

Table B.2 Lightning Strike Probabilities Transformer Stations

Target Type	Annual Lightning Frequency (km^{-2})	Annual Probability Score (2050's)	Study/"Lifecycle" Period Probability Score (2015-2050)
Large Transformer Station	1.12	1	5
Large Transformer Station	2.24	2	6
Municipal Transformer Station	1.12	0	2
Municipal Transformer Station	2.24	0	3

Snow

Snowfall thresholds were chosen following the second workshop and are intended to address "nuisance" events, such as those which require the application of deicing agents (5 cm+) and those leading to restricted to site access (10 cm+). The group chose to focus upon nuisance events at the "lower end" of the snowfall accumulation spectrum, rather than extreme snowfall events, since overhead systems were not considered by workshop participants as being sensitive to direct snow loading. Historical data indicate that the total number of days exceeding these thresholds are decreasing, as expected with global warming, but not at all rapidly enough to consider snow a "disappearing" hazard. In addition to this, and in contrast to days with small snowfall totals, days with extreme snowfall will continue to occur well into the future, and may in fact *increase* in intensity with further warming (Kunkel, et al. 2013). Hence, days in which snow will pose a hazard to infrastructure will continue well into the coming decades, even with continued warming.

Frost

Participants at the second workshop also indicated frost depth as being a concern for civil infrastructure, particularly following the extreme cold experienced during the 2013-14 winter season. As with other cool season hazards, the frost free period is expected to increase in length, which will result in less frost penetration on average, although occasional extremely cold winters will continue to occur well into the future. Frost depth calculations were not conducted for this project due to time and resource constraints, as well as significant variability associated with frost depth under the same atmospheric conditions. The latter is impacted by soil moisture, thermal conductivity, snow cover, and several other factors which vary greatly across the city. However, if frost heave is considered an important risk, further study could be conducted, using the 2013-2014 winter season as an example case study.

Complex Interactions

Complex interactions are generally defined as interactions which generate negative or unwanted impacts to infrastructure but which are the result of a *sequence* of events involving both climate and human factors. For the sake of simplicity, we have considered most climate elements in isolation. As the forensic analyses indicate, however, most real-world climate impacts are often attributed to one dominant element but with additional impacts from other simultaneously occurring hazards.

High Humidity Near-Zero Winter Environments

This complex interaction type was identified through both workshops and forensics work, and their occurrence appears to result from a *sequence* of events involving a combination of minor ice accretions followed by the application of de-icing agents. These are characterized by multi-day periods in which temperatures are near zero degrees, often "crossing" the zero degree line multiple times, and include

multiple periods of freezing or frozen precipitation. Ice accretion may be from a combination of freezing rain, wet snow or rain-on-snow “re-freezing”, with possible *additional* accretion from fog which is often present between periods of precipitation. These very moist conditions are then coupled with de-icing agents to cause short circuits, resulting in pole top fires and other incidents associated with short circuiting of insulators and switch gear.

Such a complex events entail the sequential occurrence of several meteorological factors coupled with human factors and are therefore impossible to project using the current set of climate change projection techniques. However, having identified these conditions, their occurrence could be monitored and even anticipated several days in advance using a combination of current conditions and short term weather forecasts, allowing for the mobilization of operational resources. The January 31st to February 3rd, 2003 event described in **Appendix C**, and a similar event which was identified for the transmission sector “sister” PIEVC study (January 2000) can be used to form the basis of pattern recognition for future events of a similar nature.

Tree Growth, Disease and Pests: Implications for Overhead Infrastructure

The second important complex interaction identified by our analysis entails the impacts of environmental changes affecting tree growth and health, affecting their resiliency to climatic loading. Higher average temperatures are expected to extend the growing season. This will likely result in faster tree growth and necessitate more spending on right-of-way maintenance, as well as possibly increasing tree vulnerability to wind and ice loading. The impacts of new and/or exacerbated disease and pest conditions can also increase tree vulnerability to damage, with the December 2013 ice storm and impacts on emerald ash borer infested trees being an example of this increased vulnerability. The complex interaction between accelerated growth rates, disease and pest regimes, and the resulting changes in vulnerability to adjacent infrastructure have only recently been identified and are not well understood, but should be subject to further study.

Appendix C
Forensic Analysis of Weather Related Power Outage Events

Brief Forensic Analyses of Weather Related Power Outage Events

C.1 Introduction

To better understand the nature and magnitude of climatic and meteorological events responsible for impacts to Toronto Hydro's electrical distribution system, as well as neighboring LDCs, RSI staff conducted forensic analyses of events generating significant impacts to the system. Information on the nature and extent of those impacts was compared to meteorological data to understand the nature and magnitude of atmospheric loads and conditions associated with these impacts. The analyses below consist of what can be termed either "single incident" or "cross-incident analyses," the former consisting of a "deep dive" into an individual events (listed in **Table C.1**), while the latter consists of the inter-comparison of numerous similar events to help determine commonalities.

In particular, events that were deemed meteorologically complex or multi-causal in nature, as well as meteorological events representing instances of impact thresholds, were selected for further assessment under "single incident" analysis to help refined our understanding of the thresholds at which impacts begin to occur, and what the causes and drivers of those impacts might be. Winter storms (including freezing rain events), summer thunderstorms, and a high heat case were evaluated for more detailed analyses. Other cases, such as fall season high winds, were evaluated under "cross-incident" analyses, for the purpose of evaluating and cross-checking thresholds determined from other sources (e.g. literature and practitioner interviews).

Several data sources were consulted for both meteorological and infrastructure impacts information. The former included data from Environment Canada's national climate data archive, Toronto Region Conservation Authority (2014) precipitation data, consultant reports (Cole Engineering 2013), as well as remote sensing data where appropriate. Impacts data were provided directly by Toronto Hydro, as well as outage incident press releases, newspaper accounts, and internal report (where available). Events which underwent detailed analyses are listed below in **Table C.1**.

C.1.1 Event Types and Relation to Impacts

Any number of climate and weather related events are capable of producing unwanted interactions with power distribution infrastructure. Direct impacts from severe winds, ice accretion, heavy/wet snow, extreme heat and lightning can directly overload support structures and conductors, as well as adjacent vegetation, which is also prone to failure, causing secondary impacts. Underground infrastructure is sensitive to flooding and longer term processes, such as enhanced corrosion through seepage and penetration of deicing agents. For each hazard, there are generally a small sub-set of mechanisms which can produce them. High winds during the warm season are associated with severe thunderstorms (including downbursts, microbursts and tornadoes), which tend to be intense but localized, whereas should season and winter severe winds are associated with large scale low pressure systems (so-called "synoptic lows"). Winds associated with these events are more widespread and can last for several

hours to more than a day. Similarly, precipitation events are generally associated with thunderstorms during the warm season and low pressure systems in the cool season (snow storms, ice storms, etc.). It should become quickly apparent that several event types can occur simultaneously, resulting in multiple cause power outage events.

Identification of event type is critical in understanding what types of impacts to expect at different times of year, including duration of the event, potential challenges for response and maintenance, presence of simultaneously occurring hazards, and for some event types what antecedent conditions to monitor to help anticipate or forecast weather related impacts. During the late spring and summer, for example, a number of significant thunderstorm events tend to be proceeded by high temperature and humidity combinations which themselves may have generated impacts on the system. While individual events are indeed complex, infrastructure operators can begin to understand the antecedent conditions to help increase readiness for such events.

Event type identification is also critical to climatological analyses and the development of adaptation responses. More localized, short duration events present significant challenges for assessing future climate vulnerability and risk, but less complex climate elements, such as temperature, are far less difficult to analyze, and confidence in both the consistency of historical data as well as certainty in projected trends are much greater.

Adaptation responses, particularly those regarding maintenance and operations, must take into account the nature of the events generating impacts. How much lead time can one expect for storm warnings, if any? What hazards may be posed to repair crews, or restrict access to damage locations? For example, a number of recent press releases indicated that full repair efforts have been postponed based on the timing of high winds, with crews waiting for the "worst to pass" before executing major restoration efforts (see "Superstorm Sandy" analysis below). More sophisticated operations and management actions such as these are critical to optimizing response to severe weather events.

C.1.2 Brief Note on Impacts Data

Staff at Toronto Hydro kindly provided outage incident data for this analysis, which proved invaluable for determining the types and magnitude of events which were responsible for significant power outage events. However, this type of cross-disciplinary forensic analysis was not the original intent of the failure database, and as such there were a number of challenges which presented themselves when using the data.

Most notably, it became clear that data collection was inconsistent throughout the period of record. While the database contains events from the years 2000 to 2013 inclusive, earlier events have dozens of reports per date, while more recent major outage events do not. In 2013, the July 8th flood and December 21st-22nd ice storm, which Toronto Hydro staff indicated were among the worst in their history, have very few listings in the database. This is likely due to changes in reporting practices, which apparently began in 2007 judging from the frequency of weather events with 20+ reports each, but this requires confirmation Toronto Hydro staff.

This emphasizes the need for the standard forensic practice of consulting and comparing multiple sources of data. For example, impacts data can be used to indicate if event intensity, such as high winds, could have been significantly higher than meteorological measurements may indicate. Conversely, meteorological data can be used to either guide and/or refine the search for impacts data, or even correct coding or other errors in impacts data.

C.2 Toronto Hydro Outage Data

As indicated above, outage data from Toronto Hydro were interrogated to identify significant outage events which could be used for further study. Days with 20 or more reports were identified, and these were further refined by checking for potentially related reports on days before and after identified event dates. While it is fairly clear that data from 2007 to 2013 were collected under different reporting requirements, 2000-2006 appear to be consistent, and so data for this period will be evaluated here.

A total of 46 weather events were identified with this methodology. Just over half (54%) of these events occurred over fairly extended periods of 12 to 48 hours; this has implications for maintenance and repair response measures. For fall wind storms and winter precipitation events, this quite literally meant several consecutive hours of either high winds or precipitation generating impacts, while for summer events this likely represents two or more episodes of thunderstorm activity within a one to two day period.

C.2.1 "Worst" Years

In terms of the "worst" years, we have two measures; total number of events, total number of damage reports for these events, and number of damage reports per event. The years 2000 and 2005 are tied for the most events in a given year (9). In terms of total reports for all events combined, 2000 has the highest at 6—followed by 2003. In terms of average event severity, the total number of reports was divided by the number of events in a given year as a rough measure of "average" severity for a given year. The year 2003 had the highest average, with an average of just over 84 reports per event. Even though 2000 and 2005 contain single major events, their averages fall well below those seen in 2003, 69 and 56 reports per event respectively.

The year 2000 followed two main themes. A series of severe winter storms in February were responsible for multiple reports and were characterized by either freezing rain or heavy wet snow and rainfall combinations, both characteristic of "warm" winter storms producing heavy precipitation at temperatures near or at 0°C[1]. This was followed by late spring to summer severe thunderstorm events, including the May 12-13, 2000 event, as well as a thunderstorm event on July 14, 2000, which generated over 100 reports through mainly lightning related damage.

The year 2005 was characterized by high heat and humidity during the summer months, which either directly contributed to infrastructure underperformance as well as severe thunderstorm events, most

[1] At temperatures at or just below freezing, atmospheric water content is at its highest while still being able to support ice formation; hence temperatures near zero are associated with either freezing rain or high density, wet snow capable of physically coating and loading overhead lines and trees.

notably the August 19th, 2005 storm. This was followed in the fall by a series of wind storms which produced scattered outages throughout the GTA, which was among several areas across Ontario which were impacted by intense fall windstorms (e.g. over 100,000 Hydro One customers lost power during the November 6, 2005 synoptic storm; Hydro One 2005).

Finally, in 2003, Toronto Hydro was impacted by a similar combination of event types, with two winter storms in rapid succession in February, followed by severe thunderstorm activity during the late spring and summer, followed by large scale wind events from late September to mid-November.

All of the so-called "worst" years identified here have the following in common:

- Repeated events, often with only days between similar types of incidents
- Two or three "modes" of high impact weather events in the same year, specifically:
    - "warm" winter storms, meaning they were associated with temperatures at or just below 0°C with some combination of heavy snow, freezing rain or even rainfall mid-winter;
    - Severe thunderstorms and high heat and humidity during the summer;
    - Multiple fall season large scale (synoptic) wind storms;
- One major event which produced over 150 damage reports

These findings can help with better planning and anticipation of particularly high impact years. For example, periods of very high heat and humidity should be watched closely, as they are occasionally followed by severe thunderstorm events when the heat "breaks" with the passage of a cold front or other air mass change. Fall and spring large scale wind storms will occasionally occur in series, as occurred between September 29th and November 13th 2005[2], repeatedly impacting the same area. These findings appear to be consistent with recent experiences; in 2013, Toronto Hydro suffered two major weather related outage events, one in the summer from a severe thunderstorm event producing extreme rainfall, followed in the winter by a freezing rain event.

It may also be possible to anticipate a particularly severe damage year since the "major" events producing over 150 reports tend not to occur in isolation but usually occur in years with a number of less severe but still significant events, although the consistency of this pattern requires further research.

C.2.2 "Worst" Events for 2000 to 2006 Period

The two events with the greatest number of reports, May 12-13, 2000 and August 19, 2005, were both subject to detailed analyses. Another three events (Jan 31-February 4, 2003; July 14, 2000 and July 21-22, 2002) produced over 100 reports, with September 19, 2003 coming very close at 99 reports.

What is of particular interest is the number of severe thunderstorm related reports which were accompanied by mainly lightning related outages. Even for storms which included extreme rainfall and high winds related impacts, lightning appeared to be the dominant factor in producing outages. The July

[2] A fourth synoptic storm occurred on November 15 to 16, 2005 but did not cause significant impacts to Toronto Hydro's infrastructure, instead tracking to the north east and affecting Georgian Bay and the "Nickel Belt," causing over 50,000 Hydro One customers to lose power.

21-22, 2002 event is particularly noteworthy. Although we do not have detailed lightning information, such information is available from the national lightning detection network, and the frequency and amperage of lightning experienced during this thunderstorm series could be investigated to determine what made this particular lightning storm so damaging to the system in comparison to any number of other events. A summary of all events identified through this method is provided in **Table C.2**.

C.3 Fall and Winter Storms

C.3.1 December 20-22, 2013 Ice Storm

The December 2013 ice storm in south central Ontario has been deemed the worst ice storm in Toronto Hydro's history in terms of impacts to the city's distribution system. It is estimated that at the peak of event during the overnight hours between December 21st and 22nd, ~300,000 customers were without power. The most recent estimates of total damage incurred by Toronto Hydro's distribution system has been placed at nearly $15 million, specifically for restoration and repair (Toronto Star: March 31, 2014).

The storm also impacted several other adjacent LDC's, including:

- Enersource (Mississauga), 91,000 customers affected (Mississauga.ca 2014);
- Hydro One Brampton, 15,500 customers (Brampton Guardian, Dec 30, 2013);
- PowerStream (York Region[3]) 92,000 customers (Markham Economist and Sun, December 31, 2013);
- Veridian (Pickering/Ajax/Port Hope) 40,000 (Veridan Connections Press Release, Dec 22, 2013);
- Whitby 13,000 (Oshawa This Week, Dec 22, 2013)
- Oshawa Public Utilities Company ~30,000; and,
- Rural areas of Clarington (Hydro One) ~46,000 (Ajax News Adviser, Dec 23, 2013)

Meteorological data from both Environment Canada and Toronto Region Conservation Authority stations were analyzed to estimated ice accretion totals and rates in and around the GTA, which were then compared to impacts on electrical distribution infrastructure in the area.

C.3.1.1 Impacts and Meteorological Conditions: City of Toronto

Figure C.1 compares estimated ice accretion values at Pearson and Buttonville Airports with the total number of customers affected reported by Toronto Hydro. While ice accretion values were not directly reported by any of the stations evaluated, they can be estimated by combining hourly observations of precipitation type with daily rainfall totals. Freezing rainfall and drizzle totals were estimated by first determining the fraction of precipitation falling as freezing rain or drizzle (since liquid rainfall and snow were also reported on some days). Accretion rates were then weighted by precipitation type (1 for rain, 0.5 for moderate rain, and 0.1 for drizzle, based relative accretion rates from Klaassen et al. 2003), which were then further developed into estimated hourly average accretion rates. These were then summed for each day between December 20th and December 23rd for both Pearson Airport and

[3] PowerStream also suffered the complete outage of their website, which had not been designed to receive the traffic volumes which it encountered during the event (Markham Economist and Sun, December 31, 2013).

Buttonville Airports, the only locations near the City of Toronto for which hourly observations of precipitation type were available. Given that several locations experienced both above zero temperatures and liquid precipitation during the multi-day period under analysis, and that ice accretion on overhead structures, lines and trees is further affected by wire or branch diameter and surface characteristic, it is likely that estimated multi-day ice accretion estimates are *over*-estimates of true accretion values. This will be taken into account during the discussion of impacts.

Ice accretion totals for the 3 day period are over 30 mm for Pearson Airport and nearly 35 mm at Buttonville. A review of hourly temperatures at both airport for the same time period (not shown) also indicate that Pearson Airport was above zero for several hours longer than Buttonville, implying that less freezing precipitation accretions may have been retained there than at Buttonville. A comparison of photographs taken following the storm, both of ice accretions on different objects, as well as the apparent severity of tree damage to areas near the two airports provide evidence that ice accretions immediately north of the City of Toronto incurred ice accretion amounts several millimeters greater than those experiences in northern portions of the city (**Figure C.2**).

The relative impacts of temperature regimes become readily apparent, however, when ice accretion estimates are isolated to include only freezing rain totals beginning late morning on December 21st, excluding accretion contributions from the December 20th to 21st overnight precipitation episode. Ice accretion values become only 13 mm for Buttonville and *25* mm for Pearson. This implies to important elements for understanding how ice accretion values evolved in different portions of the GTA, particularly:

- Higher than 13mm ice accretion values for municipalities north of Toronto cannot be explained without including precipitation amounts from the earlier December 20th-21st episode;
- Lower than 25 mm ice accretion values near Pearson Airport likely cannot be explained without considering periods of >0°C temperatures, combined with the effects of liquid (non-freezing) rain and drizzle

Estimate ice accretion values on the order of ~20 mm were present when outages began, with amounts of 18 and 23 mm at Pearson and Buttonville respectively just prior to first report of 8,500 outages. Press releases indicate that this initial damage was indeed focused in northern and northeastern portions of the city (Toronto Hydro Press Release; December 21, 11:58 PM); accretion values estimated from these airports are likely representative of those experienced in the first areas suffering from widespread power outages. Rounding down to allow for some ice accretion losses due previously discussed factors, a range of 15-20 mm are likely responsible.

To better understand conditions in and near the downtown core versus surrounding portions of the city, hourly temperatures at the Downtown meteorological station (located at the University of Toronto campus on Bloor Street) and Toronto Island's Billy Bishop airport, were compared to those at Pearson Airport (**Figure C.3**). Radar imagery (**Figure C.4**) indicates that precipitation elements were moving very rapidly (over 100 km/h) during the freezing rain event, hence hourly precipitation reports at Pearson Airport are likely representative of the occurrence or non-occurrence of precipitation conditions at

stations located less than 20 km to the ESE, where manned observations of precipitation type are not available. Precipitation reports from Pearson Airport were therefore superimposed on temperature plots to indicate when precipitation was occurring, and more importantly to imply whether or not precipitation was falling as liquid rain or freezing rain for downtown locations for a given hour.

Figure C.4 shows hourly temperatures at the three Toronto locations, implying that the city's downtown core likely received much less freezing rain than surrounding areas (the so-called "horseshoe" of former suburbs), and that accretions from December 20th and most of December 21st would have been unable to remain on exposed surfaces. However, a period of particularly heavy precipitation overnight between December 21st and 22nd correspond with temperatures below freezing, with both downtown stations falling below 0°C between 10 and 11 PM on the night of the 21st.

Toronto Island Airport reported 17.7 mm on December 21st and 13.9 mm on December 22 and the Downtown station reported 17.0 mm and 14.3 mm, respectively. Assuming the majority of precipitation on December 22nd fell as freezing rain, with some additional contributions from precipitation late in the evening on December 21st, ice accretion values in the downtown core were likely on the order of ~15 mm, compared to estimated values in excess of 25-30 mm or more estimated for northern portions of the city and adjacent municipalities. The implication, however, is that severely impacted portions of the city of Toronto near the downtown core may have seen significantly smaller ice accretion values than other parts of the city but still suffered from multi-day power outages.

Estimates of ice accretion rates at Pearson and Buttonville airports, along with the severity of impacts in the downtown core, which likely only saw ~15 mm, suggest that the final hours of the freezing rain event produced much more rapid ice accretion rates than earlier phases. Between 11 PM December 21st (when downtown stations were below 0°C) and 9AM the following morning, only 7 hours of freezing rain was observed at Pearson Airport. Even with significant averaging inherent in ice accretion rate estimates calculated in **Figure C.1** for Pearson and Buttonville airports, freezing rain ice accretion rates peaked during the early morning hours of December 22nd, estimated at 2.13 mm/h at Pearson and 1.25 mm/h at Buttonville, compared to estimated hourly rates on preceding days (0.79 and 0.95 mm/h for Pearson; 0.92 and 1.19 mm/h for Buttonville). A review of radar imagery for that time period (**Figure C.3**) indicates that a particularly heavy area of precipitation, associated with a small scale meteorological feature, tracked over the GTA and surrounding areas in the early morning hours of December 22nd. This corresponded with the rapid increase and peak in reported outages, and was likely responsible for a large portion, if not the majority, of ice accretions experienced in and around the downtown core.

Immediately following the ice storm, one spokesperson for Toronto Hydro indicated the worst damage appeared to be following highway 401, but this was prior to knowing full extent of damage in Scarborough (Toronto Star; December 23, 2013). Outage maps of the city the following day showed a clear delineation of much less severe impacts south of Bloor Street versus areas north and east of the downtown core, however a lack of both detailed impacts data and/or meteorological observations, particularly for Scarborough and East York, complicate better diagnoses of the reasons for these differences. At these scales, there could be a complex interplay between local topography, infrastructure characteristics, tree canopy extent and/or health, as well as small scale meteorological

elements (e.g. there may have been marked small scale differences in temperature gradients or locally enhanced precipitation). Without higher resolution data, all potential causes for these boundaries remain speculative.

C.3.1.2 Impacts and Atmospheric Conditions: Durham Region LDCs

Analyses of impacts to LDC's east of the city of Toronto are complicated by a lack of both detailed impacts information as well as aforementioned meteorological observation data. Only daily precipitation totals and hourly temperature data are available for Oshawa Airport, and only a small number of TRCA stations were available to provide temperature data for the Ajax and Pickering areas, but did feature high sampling rates (5 and 15 minute intervals). However, given the characteristics of damage reported by the press, it can be easily surmised that a significant amount of ice accretion occurred in the region.

A review of hourly temperature data for Oshawa Airport indicate that for the 72 hour period beginning at 4 PM on December 20th, there were only ~4 hours in which temperatures were at or just slightly above 0°C, specifically between 11 PM December 22nd and 2 AM December 23rd. This suggests that the majority of the precipitation on December 21st and 22nd, with daily totals of 17.6 mm and 10.3 mm, respectively, was likely freezing rain. Accretions could have also included some of the 8.1 mm reported on December 20th, where temperatures remained below 0°C after 4 PM. Similarly, temperature data from a TRCA weather station at Bayly and Church in Ajax (**Figure C.6**) indicate ~3.5 hours mid-day on December 21st, for which temperatures were above 0°C for the same time period, as do temperature data for the Brock West Landfill site, north of Pickering, for ~3.3 hours (TRCA 2014). The overnight temperature spike indicated at Oshawa Airport on December 21st and 22nd also shows up clearly for these two stations, but remains *below* freezing. Temperatures remained below 0.5°C for all three sites, even with sampling rates of 15 and 5 minutes for the two TRCA sites. Hence, when considering temperature conditions associated with the event, freezing rainfall totals in the ~25-35 mm range are likely for portions of southern Durham region.

Restoration times were checked in local newspapers and available press releases from LDCs (mainly Veridian) to ascertain how quickly Durham region LDCs recovered from the event when compared to Toronto Hydro. A rough benchmark of 90% restoration was used to compare the LDCs and using the morning of December 22nd as a start time for full restoration efforts:

- Veridian (Ajax, Bowmanville, Newcastle, Port Hope), restored by 8 PM December 24th, 2.5 days;
- Oshawa PUC, restored mid-day December 23rd, ~1 day;
- Whitby Hydro, fully restored by December 24th, 1-2 days;

These are compared to Toronto Hydro, which required more than **5** days to restore power to 90% of customers affected by the event. The effects of scale on Toronto Hydro's distribution system, as well as increased vulnerability from aged infrastructure, aged trees adjacent to overhead lines, and difficulty servicing and accessing equipment cannot be underestimated. There are also likely differences in the ratio of response capacity (e.g. number of personnel versus number of customers) as well as shear geographical area to be covered. Significant differences in recovery time appear to be an excellent

example of how logistical challenges for larger metropolitan LDCs can result in marked difference in vulnerability when compared to much smaller LDCs servicing small cities and rural areas, in spite of the fact that Durham Region appears to have, on average, been impacted by similar to possibly higher ice accretions than large portions of the City of Toronto. Overall, at least in the case of the December 2013 ice storm, larger LDCs appear to be more susceptible to ice storms than smaller ones, likely due to a combination of factors.

Veridian indicated that by noon on December 26th, only ~1,700 of the original 40,000 customers who had lost power remained without service (DurhamRegion.com, Dec 27, 2013), and that these mainly consisted of particularly difficult to repair elements, such as backyard supply lines. Similar comments were made by Toronto Hydro staff regarding back-lots which needed to be serviced and which were quite common in some parts of the city, although indications are that these will be eventually phased out.

Tree impacts were again named explicitly as the cause of much of the damage in Durham Region (Ajax News Adviser; December 23, 2013). On December 26th, Oshawa PUC continued to report problems with tree branches falling on lines generating new damage, and on the same day a statement by utilities officials in Whitby indicated that recent snowfalls had added more weight to ice covered tree limbs, and warned of an increasing the risk of breakage and the potential for new damage (Durham Region.com, December 26, 2013). These concerns are again similar to those expressed by Toronto Hydro and indicate an aspect of ice storm damage which should be considered in response and recovery methods.

C.3.1.3 Case Specific Findings December '13 Ice Storm:

While ice accretion values likely approached or even slightly exceeded minimum CSA design requirements (CSA 2010) for overhead systems for small portions of the city of Toronto, Durham Region, and other areas, it appears that the vast majority of damage inflicted on overhead distribution lines during the ice storm was due to the impacts from falling tree limbs. Immediately following the ice storm, tree damage was indicated as "worse than originally anticipated" (TH Press Release, Dec 23, 2014, 3 PM) in spite of what has since been termed aggressive tree trimming programs in place prior to this event. At least two municipalities, Brampton and Whitby, also indicated concerns that emerald ash borer (EAB) affected trees posed particular risks due to their weakened state. Tree impact damage continued for several hours to several days after significant ice accretion ceased. One line worker described how falling tree limbs continued to damage lines even during maintenance, and that repairs had to be redone at some locations (Toronto Star: December 23, 2013). This is also consistent with continued tree fall observed by one of the authors (S. Eng) during the mid and late-afternoon of December 22nd in central Etobicoke area, again several hours after significant ice accretions had ceased.

It is hypothesized that continued damage may have been due to both continued light freezing and frozen precipitation which continued periodically at various locations through December 22nd and 23rd, and gradual loss of fiber strength from prolonged loading.

During the recovery effort, there were notable. increases in estimated restoration times as efforts progressed. Estimates in earlier press releases indicated restoration times of 12-16 hours were

expected, while *eventual* restoration times, particularly for the remaining 10% of customers to be restored, were in excess of 5 days.

Total ice accretion amounts for areas surrounding the City of Toronto were likely much higher than those experienced in the downtown core and surrounding areas. In areas within Durham and York Regions, temperatures generally remained cold enough to maintain freezing rain ice accretions which began as early as the afternoon of December 20th. As one approached the downtown core of the City of Toronto, the event transitioned to one better characterized as a relatively short duration but fairly intense period of freezing rain, the majority of ice accretions and impacts occurring during the overnight and early morning hours between December 21st and 22nd, rather than multi-day ice accretions apparent in areas surrounding the city. These characteristics of the freezing rain event need to be understood when considering differences in both impacts and vulnerability of Toronto Hydro's distribution network when compared to LDCs in adjacent municipalities.

Press releases in the days following the event placed a clear emphasis on electrical stand pipe damage to individual homes in Toronto Hydro press releases. It is hypothesized that, as ice accretion amounts increase, more and more elements of the electrical system are damaged, hence repairs become exponentially more difficult to execute, as impacts progress from isolated large branches on lines to entire trees, and as a higher percentage of individual residences suffer damage, as indicated by the widespread damage to individual residential standpipes suffered in the Toronto Area. Similar impacts were noted during the January 1998 ice storm in Quebec, where all not only transmission corridors were severely damaged, but also individual residential lines, making recovery especially challenging due to numerous repairs on the individual customer level.

A lack of manned observations of precipitation type south and east of Pearson Airport was found to be frustrating to the investigation, particularly for **Toronto City Center** and **Island Airport** stations as well as **Oshawa Airport**. While useful findings were developed based on precipitation estimates and proxy analyses (e.g. use of temperatures to imply precipitation type), manned observations confirming precipitation type and accumulation rates would greatly assist with diagnoses of conditions in downtown Toronto as well as for Durham Region LDCs. Impacts data in the form of outage timelines and descriptions of damage could then be combined with more representative meteorological data to compare relative sensitivities of adjacent LDCs to ice storm conditions. A lack of any meteorological observations for East York and Scarborough were particularly frustrating, given apparent (and as of yet unexplained) boundaries in impact severity for these portions of the city.

Similar problems were encountered with TRCA data. While some locations provide precipitation data during the winter, all were well north and west of both Toronto's downtown core, as well as populations centers in Durham Region impacted by the storm. This indicates the need for improved monitoring of winter precipitation in populated areas of the GTA, since differences in impact severity between different municipalities is difficult without detailed observational data on precipitation characteristics.

A significant meteorological component of the event, especially for areas in and around Toronto's downtown core, appears to have been a particularly heavy episode of precipitation during the early

morning hours of December 22nd associated with a small scale meteorological feature. This implies that for high impact winter events, even those associated with large scale processes, difficult to forecast smaller scale[4] meteorological phenomenon, perhaps only a few dozen kilometers in physical extent and affecting a given location for only a few hours, may still play an important role in generating impacts. This emphasizes the need for continued monitoring of weather forecasts and meteorological remote sensing data such as radar, since the onset of impacts from these types of phenomenon can be quite rapid and are akin to severe thunderstorm events during the warm season.

In addition to Toronto Hydro, several other LDCs also indicated marked differences in the severity and extent of impacts within individual municipalities. Enersource outage maps, for example, showed particularly severe impacts in the northwestern portion of Mississauga. Veridian indicated that southeastern portions of Ajax suffered more damage and were more difficult to restore, mainly due to aged trees characteristic of the area (Ajax News Adviser; Dec 23, 2013), and similar reports of particularly heavily affected areas were also noted for Pickering (DurhamRegion.com; Dec 24, 2014), although a specific cause for these difficulties was not given. More detailed studies of these localized disparities in impacts would be extremely informative. These would likely consist of surveys and could include a review of individual incident reports and the collection of visual materials, as well as an assessment of contributing factors such as tree species and canopy cover maps, infrastructure age and characteristics, and so on.

C.3.2 Other Winter Storms

For comparison to the December 2013 event, other ice storms were reviewed to determine if thresholds from previous research (Klaassen et al. 2003) were directly applicable to the City of Toronto and to also determine the severity of impacts from less severe and widespread storms. Klaassen et al. (2003) indicated that ice storms with as little as 15 mm of total ice accumulation have resulted in widespread power outages, mainly due to tree limb impacts, and while this agrees well with analyses from the December 2013 storm, other events should also be interrogated.

C.3.2.1 January 31st to February 4th, 2003: Complex Winter Event

The period between January 31st and February 4th, 2003 saw multiple types of precipitation and a variety of conditions impacting the Toronto Hydro distribution system, and resulted in over 50,000 customers being affected at various time by power outages (ITIS data). Some 160 incidents were reported in the ITIS database beginning on the evening of January 31st through to February 4th, including blown transformers and current limiting fuses, tracking problems, and some instances of galloping and tree contacts. On the night of February 3, 2003, “hundreds” of car accidents and numerous power outages were blamed on a combination of freezing rain and high winds, mainly across Scarborough and North York (Toronto Star, February 4, 2003). These impacts were the result of a complex weather event which involved two large scale low-pressure systems, several different types of precipitation, and significant associated temperature variations over the course of 5 days.

[4] In meteorology, these are termed “meso-scale” weather phenomenon, which tend to occur on spatial scales smaller than distances between important surface observation stations, and on sub-daily (less than 24 hour) temporal scales.

A low pressure system which had originated in Alberta impacted southern Ontario on January 31st and February 1st, followed by a second low pressure system which had originally formed over Texas and Oklahoma, impacting Toronto on February 3rd and 4th. In addition to impacts to Toronto Hydro's system, power outages were also reported in Richmond Hill and Markham (Toronto Star Feb 4, 2003).

Impacts on February 1st were almost exclusively restricted to 27.6 kV equipment (except for one report), and, save for a few downed wired and tree contacts, were generally characterized generally consisted of tracking, electrical shorts and blown fuses associated with ice accretions. Beginning at around 10:30 am on February 1st through to the morning of February 3rd, several reports of electrical shorts and salt covering equipment were received, likely associated with attempts at deicing following the January 31st-February 1st storm. On February 3rd, freezing rain related reports began anew at ~5 PM and continued until 6 AM one February 4th. For this episode of severe weather, winds had been forecast to reach 70 km/h on February 3rd; maximum gusts would eventually be measured at 78 km/h (Pearson Airport) and 85 km/h at (Toronto Island Airport) the following day.

Conditions at Pearson Airport indicate that for the entire period between January 31st and February 4th the atmosphere was near or at saturation, with fog and haze being reported in conjunction with and between bouts of freezing rain, drizzle or light snow, however a total of only four hours of freezing rain were reported at Pearson Airport during that period. Temperatures crossed the 0°C boundary no less than *eight* times during this time period (**Figure C.7**).

The types of impacts, where descriptions were available, were quite different than those indicated for the December 2013 ice storm. Reports during the first portion of the event, mainly on February 1st, involved blown current limiting fuses and tracking problems. During the "break" in precipitation between February 1st and 3rd, 14 instances of *salt* related problems were addressed. Following this, a second round of precipitation, including the only reported freezing rain at Pearson Airport, combined with increasingly strong winds into February 4th, brought the first reports of galloping (mainly in Etobicoke) and only 4 reported instances of tree contacts, in addition to more blown fuses and pole top fires from icing related electrical shorts.

A *separate* storm over the Atlantic coast during the same time period, impacting the Maritimes on February 2nd and 3rd and producing 40-60 mm of ice accretion knocking out power to over 63,000 customers and causing other *very* significant damage, including roof collapses of barns and other storage buildings (EC 2003). By February 5th, 27,000 customers remained without power in New Brunswick (Toronto Star, Feb 5, 2003). The majority of repairs to the electrical system lasted for 5 days, and several locations had to be repaired twice or three times due to continued falling of ice laden trees, which was further exasperated by winds of ~75 km/h following the freezing rain (EC 2003). Massive ice accretions associated with this storm were at least partially due to the proximity of the storm to its source of moisture. Hence, while it produced similar wind speeds to the February 3rd and 4th low pressure system that affected southern Ontario, ice accretion amounts were *far* greater.

C.3.2.2 Case Study Specific Findings for January 31st-Febraury 4th

Galloping was indicated during the second storm, mainly in Toronto's west end, from what were likely a combination of ice accretions of on the order of 10 mm or less, but with winds gusting to the 70 to 80 km/h range. This is fairly close to the "15mm + 70 km/h" wind threshold indicated in previous work (CSA 2010), but may have been associated with lower ice accretion values but higher wind speeds. Additional cases would be needed to understand if galloping due to combined ice-wind loads occur in a range of wind speed and ice accretion combinations, but this case does indicate the potential for forecasting such problems when combined with monitoring of ice accretion.

Additional ice accretion, from either drizzle or light snow, coupled with several hours of reported fog or haze, is also highly likely for this event, but additional date related to this event is needed to diagnose actual accretion amounts and their causes. One should also consider that heavier precipitation may have occurred further east in North York and Scarborough, where the majority of ice accretion related impacts were reported. Indeed, several ITIS damage reports from those locations indicated ongoing snow and/or freezing rain for times when conditions at Pearson did not indicate *any* ongoing precipitation (e.g. two reports of snow in North York on the night of January 31st correspond with reports of "haze" at Toronto Pearson for the same time period). High wind and galloping conditions are likely better captured by records at Pearson Airport, since many of those incidents were reported much closer in Etobicoke.

When considering the types of impacts reported for this even, it is suggested that fog ice accretion may have slightly different characteristics than freezing rain ice accretion, which may result in slightly different impacts; i.e. when ice accretes due to fog and light drizzle in a humid environment, does it coat equipment differently than more rapidly accreting freezing rain? Did this lead to more localized problems associated with shorts and arching, in contrast to failures associated with direct physical impacts from ice loading and tree contacts? The role temperature fluctuations during and following periods of precipitation should also be investigated further. The degree of temperature variability for this event was much greater for this even when compared to the December 2013 ice storm, which again may have affected the type and degree of impacts (see **Table C.3**).

C.3.3 Large Scale Wind Storms

Large scale wind storms were identified through the Toronto Hydro Outage data for the 2000-2006 period. The maximum wind gusts reported during these storms were then compared to the number of outage events reported in the ITIS database and were also compared to the cause description, mainly identifying whether or not tree contacts were mentioned. The results of this comparison are described in **Table C.4** and illustrated in **Figure C.8**. Large scale, long duration wind events associated with low pressure systems were chosen instead of summer severe wind events associated with severe thunderstorms, since wind measurements at Pearson and Island airports were more likely to be representative of wind conditions at the damage sites for the large scale storms.

For the majority of events, a threshold wind speed of around 90 km/h emerges. A recent event on November 1, 2013, described in Toronto Hydro press releases but not well captured in ITIS, bears this

out, in which 3,500 customers lost power during a wind storm which produce gusts up to 91 km/h at Pearson Airport.

It is notable that one of the most significant events, September 19, 2003 with 99 damage reports, also had the lowest reported gust at 72 km/h and is a pronounced outlier on the graph (bottom bar in **Figure C.8**), and the only other event which occurred in September shows the 2nd lowest wind speed value at 78 km/h.

To further investigate this wind speed relationship, the month of November 2005 was "back checked" to see how well a threshold of ~90 km/h was able to predict impacts to the Toronto Hydro system (**Table C.5** and **Figure C.9**). A total of 53 outage incidents were reported in ITIS for this month, with the largest number reported on November 6th and into the early morning hours of November 7th (35 reports). As indicated in **Table C.4**, these correspond with gusts of up to 89 km/h. Incidents were reported on 6 other days, with the second greatest number occurring on November 9th (9 reports). That day saw snow during the morning hours, followed by severe thunderstorm activity which resulted in one tornado in the City of Hamilton. Damage from thunderstorms is expected to be localized and therefore low wind speeds measured at Pearson airport are not surprising. The day with the third greatest number of reports also shows the second highest gust reported that month.

There are a number of potential reasons for this apparent seasonal difference between wind speed thresholds, most likely the effects of deciduous trees being still in full leaf, but, other considerations, such ground softness due temperatures remaining above freezing, must be considered given the very small sample size present here. However, data do appear indicate that threshold winds for damage increased from ~70 km/h during early fall up to ~90 km/h for late fall and winter windstorm events, and the causes listed for these impacts hint at a relationship to tree contacts.

We should mention that spring low pressure systems are also capable of producing high winds, but these do not seem to be as significant as fall season large scale wind storms. Spring severe wind storms also tend to have embedded thunderstorms, which act to further localize winds and complicate efforts to determine the representativeness of measurements. Examples of this event type include the April 20 to 21, 2000 and April 12, 2001 storms. March 9-10, 2002 is the only significant spring wind storm in the 2000-2006 period, but this event was also accompanied by severe thunderstorm activity which produced much more significant impacts in other parts of Ontario, including the loss of multiple Hydro One electrical transmission towers.

C.3.3.1 Superstorm Sandy: October 29-30, 2012

So-called "Superstorm" Sandy, responsible for major devastation in several major east coast cities in the United States, also produced impacts in Canada, including one fatality from windblown debris. Toronto Hydro estimated about 60,000 customers had lost power during the storm (T.H. Press Releases, Toronto Star 2012). Adjacent LDE Enersource reported approximately 6,000 customers lost power during the event, with 6 crews beginning restoration efforts at around 6PM on October 29th (Mississauga News 2012). Causes for these outages included the loss of three hydro poles. ORNGE air crews had also been grounded at 2 pm October 29th due to high winds (Toronto Star 2012).

Toronto Hydro had been initially criticized for not immediately declaring Level 3 status for this event and beginning repairs; however, the vice president of grid management indicated attempting repairs during the storm would have been futile and dangerous for repair crews (Toronto Star 2012). “There’s nothing we could have done between 2 am and 6 am.” Press releases issued as early as 6 PM on October 29th warned customers that repairs may be impossible during high winds.

A map depicting impacts and rainfall measurements for the event is provided in **Figure C.10**. Unfortunately, outage incident data appears to be incomplete for this time period (the event having occurred after 2006), and media reports for the city of Toronto lack specific damage and failure location descriptions. This is in sharp contrast to media reports from the City of Mississauga (Mississauga News 2012), the source of all media damage reports indicated in **Figure C.10**.

With the exception of one incident, wind damage reports from ITIS all appear in the southern half of the City of Toronto, and these also correspond very well with media reports of wind damage in Mississauga, as well as the difference in measured severity between Pearson (80 km/h max gust) and Toronto Island (91 km/h). There are simply too few available rain related damage reports to determine if important thresholds were reached for direct overland flooding related damage, and a comparison between Buttonville and Pearson to determine if antecedent rainfall played an important role appears to be negative. Both areas experienced similar amounts of antecedent rainfall on October 28th, followed by wind gusts of similar magnitudes on October 29th; however, only areas located southwest and southeast of Pearson reported any notable wind damage.

Toronto Hydro press releases, including those issued as early as 9:30 PM on October 29th, before the peak of the storm, in indicated trees and tree limb contact with overhead wires as the main cause of the outages (T.H. 2012). The October 30th 10:39 PM press release specifically indicated, “Toronto Hydro estimates that more than 85 per cent of outages were caused by tree contacts with power line[s]” Further indicating that repairs are expected to exceed $1 million and that other jurisdictions, which have far less tree cover, were not expected to be as heavily impacted. On the evening of October 30th, the worst affected area was roughly bounded by “Talwood Drive (north), Eglinton Ave E (south), Bayview Ave (west) and Don Mills Rd (east)”

The preponderance of tree and tree related damage in the southern portions of Toronto and Peel, coupled with the transition from wind gust regimes from 80 km/h to 90 km/h, further supports the findings from the analysis of large scale wind storms indicating wind speed thresholds of 90 km/h, again likely related to tree contacts. Budget and time limitations prevent further analysis of this event (e.g. search for impacts in Durham region) for the time being, but further research is strongly indicated.

C.4 Severe Summer Thunderstorm Events

C.4.1 July 8, 2013 Extreme Rainfall Event

“Little India resident Kurt Krausewipz, said the ‘thick heavy sheets of rain,’ reminded him of monsoon season in Southeast Asia.” (Toronto Star, July 9, 2013)

The flash flood event on July 8th, 2013 was responsible for the largest 24 hour rainfall amount ever reported at Pearson Airport. The event was notable for a number of important impacts, including the stranding hundreds of GO transit commuters for 5 hours on a flooded train in the Don Valley (Toronto

Star, July 9, 2013), as well as an eventual tally of nearly $1 billion in insured damages (CBC.ca 2014), mainly resulting from basement flooding. It also resulted in a significant power outage event for Toronto Hydro, with approximately 300,000 customers losing power for several hours[5] (Toronto Hydro Press Release, July 9, 2013). The outage event was mainly triggered by the failure of critical infrastructure located below grade[6] at two transformer stations linking Toronto's distribution system with Ontario's electrical transmission system.

To understand the magnitude of the event, and to assist with developing a threshold for this type of failure, maps depicting rainfall amounts across the city (Cole Engineering Group, 2013) were compared with media reports of damage, as well as the locations of the two transmission stations which suffered failures during the event (Hydro One, 2014). See **Figure C.11** for station locations relative to rainfall accumulation amounts.

The extreme rainfall event began around 4 PM and produced eventual failures at Manby and Richview transformer stations, with Hydro One declaring a "Level 2 Transmission Emergency" (Hydro One 2014). Both are located within and near the area of greatest rainfall accumulations recorded for the event, located roughly along and on either side of the Etobicoke-Mississauga border (Cole Engineering Group, 2013). A rainfall total of 126 mm was reported at Pearson International Airport, with a maximum 1 hour total of 74 mm (EC 2014); however, this was roughly within the western edge of what municipal rain gauge networks indicate as a "bull's-eye" centered slightly E of Pearson International, which contained accumulations of over *130 mm* of rain (Cole Engineering Group, 2013). Richview TS is located in the *immediate center* of this area of extreme precipitation. Manby TS is located several kilometers to the south and was subject to far less rainfall in its immediate vicinity, located nearly on and just north of the 80 mm rainfall contour. It is not clear how much additional flooding at Manby TS was the result of runoff from areas further north, or if the design and characteristics of Manby TS may have made it more vulnerable to flooding than other stations. Hydro One's system officially returned to "normal" status at 2:44 PM July 15th (Hydro One 2014).

"Level 2 remained in effect until 5:34 p.m. on July 12th as Hydro One worked to reinforce the system with restored transmission connections between Richview TS and its remote terminal stations: Trafalgar TS, Cherrywood TS, Parkway TS and Claireville TS. This provided redundant supplies and vastly improved network security." (Hydro One, 2014)

It is notable that stations located near a secondary maximum over downtown Toronto (particularly Leaside TS), did not suffer the same impacts as Richview and Manby. Rainfall in the core of the downtown maximum approaching 100 mm. Toronto's climate station at the U of T campus reported 96.8 mm of rain (EC 2014), but Leaside TS is located approximately 3-4 km to the NW of the core of this

[5] In contrast to the Dec 2013 ice storm, however, the nature of the failures allowed for ~90% restoration for distribution customers by the early hours of the following morning (TH Press Release, July 9, 2013).

[6] Interviews by RSI with practitioners at the OPA for the "sister" transmission case study indicated that placement of critical infrastructure in below grade locations may have also played a critical role in the failures experienced in this case.

much smaller maximum subject to an estimated 65-70 mm rainfall, and was also not "down-stream" from another maximum as was the case for Manby TS.

Rainfall data from Pearson International also indicate possible antecedent rainfall conditions, since 26.6 mm of rain were recorded on July 7th, the day prior to the event, and a total of 31.4 mm of rain was recorded in the full week prior to the rainfall event (EC 2014). Similarly, Toronto's downtown climate station reported 38.1 mm of rainfall on July 7th and a total of 48 mm during the week preceding the July 8th flood.

"Since June 1, downtown has seen 165 mm of rain, about double the average of 87 mm." (Toronto Star July 9, 2013)

As with the Superstorm Sandy case, outage data appeared to also be lacking in the ITIS data, with only one listing indicated for this event. However, the clear cause in this case was the direct impact to transmission infrastructure, reducing the need for similar analyses conducted for other cases in which outage causes were more local and directly related to physical impacts to the distribution system.

C.4.1.1 Case Specific Findings July 8th Flood

Rainfall in excess of 100 mm in less than 24 hours, and indeed within the span of only a few hours, appears to have been required to cause the types of failures experienced at the two western Toronto stations. Antecedent rainfall may have also played a role in the flooding, generating more runoff than would have otherwise occurred. Topography and associated runoff patterns may have also played a role, particularly for Manby TS, but conclusive evidence of this would require further investigation.

This may also be a case of extreme rainfall rates under the "sub-daily" category, given that both this case and August 19, 2005 saw the majority of rainfall occur within a few hours, with a majority of the total 24 hour rainfall occurring within approximately *one* (1) hour. Extreme rainfall rates should be directly correlated with runoff efficiency and design requirements (e.g. pumping rates for mitigation, flash flood peaks, etc.) and may be important in determining how such events generate severe impacts to these systems.

While the main infrastructure that failed was indeed owned by Hydro One, these findings have direct implications of great importance to Toronto Hydro Infrastructure. Toronto Hydro was still directly and severely impacted by the failure of 3rd party infrastructure. The PIEVC process includes 3rd party infrastructure among the needed elements for review and consideration, and this is particularly relevant for the highly interconnected electrical grid as a whole. While this was not the case in this particular event, similar infrastructure owned by Toronto Hydro may be susceptible to extreme rainfall conditions. These locations and infrastructure elements should be explicitly identified and evaluated for their vulnerability.

C.4.2 August 19, 2005 Finch Washout Event

A large "supercell" thunderstorm produced significant impacts across a swath of south-central Ontario on August 19, 2005. Perhaps the most well-known and publicized impacts from the event consisted of the complete washout of a section of Finch Avenue at Black Creek in North York. In addition to this,

however, there were numerous reports of basement flooding in Toronto and York region, several vehicles being swept off of roads or submerged, in addition to several thousand homes in Toronto suffering power outages, mainly in Etobicoke and Scarborough areas (Toronto Star, August 20th, 2005). The specific causes for these outages were not provided by media reports, however ITIS incident reports, coupled with the location of reported damage, indicate that outages were mainly related to flooding. Preceding the impacts in the GTA, the supercell storm produced two large, F2 tornadoes west of the city in the Listowel and Fergus areas, severely impacting farming and cottage communities.

A map of reported impacts is provided in **Figure C.12**, combining ITIS and media damage reports with meteorological measurements for comparison. A fairly clear pattern emerges in which a corridor of extreme rainfall with embedded amounts in excess of 100 mm corresponds quite well with the majority of extreme rainfall related outage incidents, indicated by red and orange circles superimposed with an "X" in a band extending from central North York ESE to Scarborough. Extreme rainfall amounts to the immediate north of Toronto were also associated with significant basement flooding in York region. A second more isolated patch of extreme rainfall may be indicated in north Etobicoke, but could also be illusory due to the suspect reading (only 24.7 mm) located north of the Finch Washout.

Interestingly enough, tree contact and wind related damage reports are generally located south of the corridor of extreme precipitation; this is consistent with the storm type. While impacting Toronto and the GTA, the storm produced a swath flooding rainfall and large hail under as a core of heavy precipitation tracked across the city, while winds gusting to ~70 km/h or more were present *south* of this core and were responsible for several minor tree contact related damage reports[7]. A comparison between wind measurements at different locations, however, could not be conducted, as wind gust data are not available for this date for Toronto's Island airport.

C.5 Extreme Heat Days

While it is generally common knowledge that during hot and humid days during the summer, air temperatures are much cooler along the shores of Lake Ontario than they are in other parts of the city, the potential impact this temperature difference may have on electrical system response is not often considered.

Table C.6 provides a comparison between three stations to determine temperature differences across the City of Toronto on days in which high heat impacts on the distribution system were indicated (see **Table C.2** for greater details). These stations are located on or very near the western, southern and northern boundaries of the City of Toronto and provide an excellent measure of the temperature differences experienced across the city. Temperature differences of between 2.6 and 5.7 degrees are evident, while the locations of impacts strongly indicate a preference for impacts to infrastructure in Etobicoke. The number of incident reports appear to be correlated to the maximum temperature, although sample size is extremely small. The average temperature difference between Pearson Airport

[7] Had the storm produced a tornado while over the city, it would have been located at the southern edge of the heavy precipitation core. Luckily, the storm changed characteristics when approaching the GTA and appears to have been no longer tornadic when impacting the area.

and Toronto Island Airport is 4.1 degrees for the four high heat days, and the difference between North York Climate Station and Toronto Island is slightly less at 3.1 degrees.

Figure C. 13 shows an example of a high heat day (July 16, 2006) in which impacts began to be reported in North York at two different transformer stations. Interestingly enough, two of the four reports are listed as "Adverse Weather/Tree Contacts", and we are unsure of the nature of these reported causes. Either they have been mistakenly coded, or tree contacts may have occurred due to line sag, but details on the specific impact characteristics are lacking. The small number of reports indicated in North York for this date and the inter-comparison in **Table C.6**, coupled with results from the literature review and discussions with practitioners, provide additional evidence that negative impacts to the distribution system begin to appear as temperatures approach ~35°C.

This case, however, provides an excellent example of the temperature gradient often present across the City of Toronto during extreme heat days, with slightly higher temperatures occurring further from the lake. During the summer, the temperature difference between land and lake often result in the production of a lake breeze, in which cooler, heavier air over the lake flows inland, the leading edge of that air often acting as a miniature cold front. This can result in notable temperature gradients across the city, and can also trigger and/or enhance thunderstorm activity at the boundary between lake air and air further inland.

Although time and resources did not allow for more detailed assessment, a greater number of days in which extreme heat impacted the Toronto Hydro distribution system should be further investigated to help refine this threshold further. Further analysis is also needed to ensure that the impacts of other air mass boundaries (i.e. large scale fronts) are not skewing the results presented here, as similar temperature gradients can be produced through other mechanisms unrelated to the effects of the lake.

C.6 Final Conclusions

In summary, the forensic analyses resulted in the following conclusions:

- Although data sufficiency and time allotted to the project prevented the thorough investigation of many of the events identified through this forensic analysis, several avenues of future research were identified which could lead directly to improved operational maintenance and management measures, including improved forecasting of climatic impacts to assist in anticipation and preparation for significant events.
- In some cases, it was clear that Toronto Hydro operations and maintenance crews were making effective use of forecasts to help plan and optimize repair and response, such as allowing severe weather conditions to pass before full repair operations were initiated.
- In most cases, and particularly for those in which localized differences in impact severity were evident, further analysis was stymied by a lack of observational data. Even with the inclusion of additional observational data provided by TRCA (2014), spatial gaps in observations prevented the assessment and diagnosis of conditions in certain locations (e.g. December, 2013 ice storm

damage in Scarborough lacking ice accretion or temperature measures; August 19, 2005 severe thunderstorm wind speed measurements in southern portions of the city).

- The majority of power outage events identified in the 2000-2006 period were extended events lasting up to 48 hours, representing the need for sustained operational response, but the characteristics of these events differed depending on season:
    - Extended warm season events consisted of 2 or more acute weather events in quick succession, and were a combination of related hazards producing impacts (e.g. extreme heat followed by thunderstorm activity)
    - Cool season and shoulder season events tended to last several hours; when storms occurred in succession, they tended to be separated by periods of one or more days
    - The years with the greatest reported impacts to the distribution system were characterized by multiple moderate to major outage events occurring in different seasons (e.g. significant severe thunderstorm event during the summer followed by one or more wind storms during the fall season)
- Thresholds determined for wind speed and ice storm damage agree well with previous work and research, and these also appear to be *directly* related to tree contact related impacts rather than direct climatic loading of infrastructure through wind or ice accretion.
    - The 70 km/h threshold for wind gusts, originally provided by Toronto Hydro staff during Phase I, appears to be correlated with tree damage, particularly during the warm portions of the year when deciduous trees are in full leaf, resulting in secondary impacts to the distribution system; further research is needed to confirm this relationship
    - The 90 km/h threshold appears to be both related to the baseline climatic loading used in design of civil infrastructure components (see CSA 2010) as well as tree damage after deciduous trees have shed their leaves
    - The lower bound of 15 mm for freezing rain totals resulting in tree contacts with overhead systems agree well with the findings from Klaassen et al. (2003)
    - Freezing rain totals of less than 15 mm, however, may cause impacts when combined with high humidity environments near the 0°C boundary. This can specifically result in flashovers and other related impacts. While not as severe as direct damage to overhead lines and other equipment, these types of impacts can be numerous, widespread, and localized, presenting particular challenges for restoration efforts
- Overall, larger metropolitan LDCs appear to be more vulnerable to climatic events than smaller LDCs, particularly when considering overall restoration times; this is likely due a culmination of factors, not the least of which include the state and age of equipment, difficulty of access for system repair in an urban environment, and the relative proportion of staff available with respect to total number of customers and the size of a geographical area of responsibility.
- Certain regions within the city appear to be more susceptible to weather related power outages; potential regional differences in vulnerability should be investigated further. It is not clear at this time if these vulnerabilities are due to aging infrastructure, proximity to aged canopies, difficult to access infrastructure (e.g. back-lots) or some other combination of factors.

- There were several cases in which events tended to follow one-another in series, with either the restoration following a major event being hampered by subsequent smaller events, or several moderate events resulting in prolonged, multi-day outage cases where new damage occurred immediately following recovery from previous events
- Extreme rainfall impacts are worst with warm season severe thunderstorms. These were characterized by highly localized events impacting only a portion of the City, generating rainfall accumulations of over 100 mm, the majority of which (>50%) falling on during a period of *one hour*. Rainfall impacts with longer the longer duration, larger scale events investigated here (e.g. "Superstorm Sandy") appeared to be minor.
- Changes in tree health conditions such as disease and pests may also be playing a role in increasing sensitivity to damage, as suggested by analyses of the December 2013 ice storm. These represent very complex interactions, since the extent of certain disease and pests will also be affected by changing climate regimes, and their interaction with the structural integrity of trees and limbs is still unknown.
- Even for winter events, which are ostensibly much less localized in nature than warm season storms, localized differences in infrastructure impacts were evident, and without additional data, the causes for these disparities were not entirely clear. In one case (December 21-22, 2013) a small scale weather feature was explicitly identified as having very likely been a major contributor to the case overall, and similar findings are expected if similarly in-depth analyses are conducted of other high impact winter storms.
- Differences in impacts due to storm structure and other localized meteorological factors were evident in some cases (e.g. separation of precipitation and wind related impacts Aug 19, 2005). While these are to be expected, they may also assist in response to events when combined with remote sensing data, such that response crews may be better informed as to the type of impacts they may encounter following a severe storm.
- Events were not only characterized by impacts to the distribution system, but tended to consist of multiple, often severe impacts to other buildings and infrastructure, including transportation, and communication infrastructure. These impacts compounded effects on the distribution system by further complicating operational response.
- Smaller events which barely generated more than 20 damage reports, such as July 1, 2001 (lightning and rainfall) or April 28, 2002 (high winds), should be studied to understand where the lower damage thresholds may lie and/or which areas within the city or infrastructure types/categories are the *most* vulnerable
- The presence of Lake Ontario directly impacts the behaviour of certain weather hazards, generating differences in risk across the city; it generally moderates temperatures, warming areas adjacent to the lake during the cool season and cooling areas near the lake during the summer. This effect either mitigates or exacerbates the severity of hazards depending on the type of hazard (e.g. areas downtown are kept cooler during extreme heat days, but the leading edge of the lake breeze also plays a role in enhancing severe thunderstorm hazards for other portions of the city).

- The interconnectivity of Ontario's electrical grid is vital to understanding the potential impacts from atmospheric hazards; coordination between transmission providers and LDCs in risk assessment analyses may be *pivotal* in understanding and addressing these risks.

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Table C.1: Events subject to detailed investigation.

Date(s)	**Event Hazard Type(s)**
January 31st to February 4th, 2003	Multi-day ice accretion event; complex interactions
August 19, 2005	Flash flooding; lightning, some winds (tree contacts)
July 16, 2006	Extreme Heat; threshold/borderline event
October 29-30, 2012	Superstorm Sandy; winds, possible rainfall impacts
July 8, 2013	Flash Flooding; failure of 3rd party underground infrastructure
December 21-22, 2013	Ice Storm; mainly tree contacts

Table C.2: Toronto Hydro Events Outage Events 2000-2006 with *20 or more* incident reports.

Medium to High Impact Events T.H. Failure Database	Event Type	Number of Reports
February 23 to 25, 2000	rain and snow	49
February 3 to 4, 2000	freezing rain	37
February 16, 2000	snow and freezing rain	72
4/20/2000 and 4/21/2000	high winds and rainfall	42
May 12 to 13, 2000	wind, rain and lightning	157
6/14/2000 and 6/15/2000	lightning and "adverse weather"	58
14-Jul-00	lightning	121
7/17/2000 and 7/18/2000	lightning, some high winds, extreme heat	88
5-Jan-01	snow	28
12-Apr-01	high winds	33
1-Jul-01	rain and high wind	21
4-Jul-01	rain, lightning, and wind	21
7/22/2001 and 7/23/2001 and 7/24/2001	lightning	53
8/7/2001 to 8/9/2001	heat and humidity	72
25-Oct-01	high winds	20
1-Feb-02	high winds	29
March 9 to 10, 2002	"adverse weather"	78
28-Apr-02	high winds, rain	21
7/21/2002 to 7/22/2002	lightning, some heat and humidity	107
9/20/2002 to 9/21/2002	rain and lightning	23
1/31/2003 to 2/1/2003	snow and freezing rain	155
2/3/2003 to 2/4/2003	freezing rain	71
5/5/2003 and May 6, 2003	lightning	45
8/21/2003 and 8/22/2003	lightning, high winds and rain	58

19-Sep-03	high winds	**99**
10/15/2003 and 10/16/2003	high winds	**81**
11/12/2003 and 11/13/2003	high Winds	**80**
4-Jul-04	lightning, rain	**43**
23-Dec-04	Freezing rain	**27**
2/6/2005 and 02/07/2005	fog	**25**
6/13/2005 and 6/14/2005	lightning, some "tree contacts"	**42**
28-Jun-05	lightning	**30**
4-Jul-05	lightning, some wind and rain	**68**
July 11 to 12, 2005	heat and humidity	**39**
8/19/2005 and 8/20/2005	extreme rainfall, high winds and lightning; DETAILED ANALYSIS	**162**
29-Sep-05	high winds	**42**
6 to 7-Nov-05	high winds	**35**
2/17/2006 and 2/16/2006	high winds	**49**
31-May-06	lightning	**24**
6/28/2006 and 6/29/2006	lightning, rain extremes	**88**
10-Jul-06	rain, lightning	**24**
7/17/2006 & 7/18/2006	lightning, heat and humidity, some wind	**66**
8-Sep-06	rain, lightning	**24**
10/4/2006 and 10/3/2006	lightning and high winds	**30**
29-Oct-06	high winds	**28**

Table C.3: Comparison of ice accretion events with reported impacts.

Dates	Estimated Total Ice Accretion	Total # Hours **Freezing Rain** and Drizzle	Impacts
January 31-February 4, 2003	Est. ~10-12 mm (difficult given complex temperature regime and multiple	**Pearson: 4 hours (Feb 3rd);** no freezing drizzle reported, but snow, drizzle, fog and haze reported at various times	Most damage from shorted and blown fuses, tracking, few downed lines, galloping during high winds following 2nd period of precipitation; high humidity and multiple

	precipitation types)		temperature changes about 0°C
December 20-22, 2013	Est. <15 mm Downtown Toronto to 25-35 mm York and Durham Regions	**Pearson: 4, 16 and 6**, and 2, 5 and 10; **Buttonville: 8, 13 and 8**,and 1, 5 and 10; Total hours for December 20th, 21st, and 22nd, respectively	Mainly due to tree impacts, greater periods of temperatures above 0C and liquid precipitation for locations closer to downtown Toronto, significantly reducing ice accretion totals for full 3 day period

Table C.4: Comparison of highest wind gusts with large scale outage events.

Date	**Peak Measured Gusts (km/h)**	**Cause Description**[8]
25-Oct-01	Pearson: 91; Toronto Island: 82	Tree contacts 8/20
19-Sep-03	Pearson: 72; Toronto Island: 80	Tree contacts 32/99; other causes included "driving rain", "auto reclose" of breaker due to high winds
15 to 16-Oct-03	Pearson: 91; Toronto Island: 89	Tree contacts 30/81; remainder mainly "high wind/adverse weather", one report of "fuse fell open in high wind"
12 to 13-Nov-03	Pearson: 93; Toronto Island: 96	Tree contacts 16/64; remainder simply indicated as "high wind/adverse weather", some lightning
29-Sep-05	Pearson: 78	Tree contacts 28/42, rest related to high winds, including broken insulator
6 to 7-Nov-05	Pearson: 89	Tree contacts 13/35
16 to 17-Feb-06	Pearson: 91	Tree contact: 8/13 (16th) & 12/34 (17th); also some freezing rain reported on both dates, remaining[9] were generally listed as high winds, incl. one broken insulator
29-Oct-06	Pearson: 96	Tree contact: 12/28 reports
1-Nov-13	Pearson: 91	Tree contacts: 3/7 reports

Table C.5: Comparison of *all* impact reports for November 2005 to maximum gust speed.

Date	Gust Speed (Pearson Airport)	**Number of Reports**; Notes
Nov 6th	89	**35**; 2 early morning Nov 7th, considered same event
Nov 9th	59	**9**; same day F1 Tornado, Hamilton, ON; morn report include

[8] Tree contacts were counted both when coded as cause, as well as cases where cause was coded as "adverse weather" but description of impacts indicated tree contacts were responsible.

[9] One report of a "temperature extreme" causing a failure at -3°C ambient temperatures appears to be a coding error.

		snow, thunderstorms mid-day and evening, wind caused limbs on wires 3 reports, lightning related outages 3 others
Nov 11th	35	**1**; rain indicated as cause
Nov 16th	83	**4**; three high wind reports, one "no cause", "switch fell open"
Nov 17th	59	**1**; large tree on line, rain indicated
Nov 24th	78	**2**; winds indicated as cause, possible duplicate report of one incident
Nov 25th	48	**1**; conditions indicated as "clear" no specific cause given

Table C.6: Comparison of maximum temperatures (°C) for high and extreme heat days.

Date	**Impacts (# heat related reports)**	**Pearson Airport**	**Toronto Island Airport**	**North York Climate Station**
July 17, 2000	Minor; only 2 in Etobicoke	28.6	24.4	27.0
Aug 8, 2001	33 total; 18 in Scarborough, 10 Etobicoke	37.9	34.7	37.5
July 11, 2005	19 total; 10 Etobicoke, 7 North York	35.5	29.8	34.0
July 12, 2005	18 total; 7 Etobicoke, 7 North York	34.7	31.4	34.5

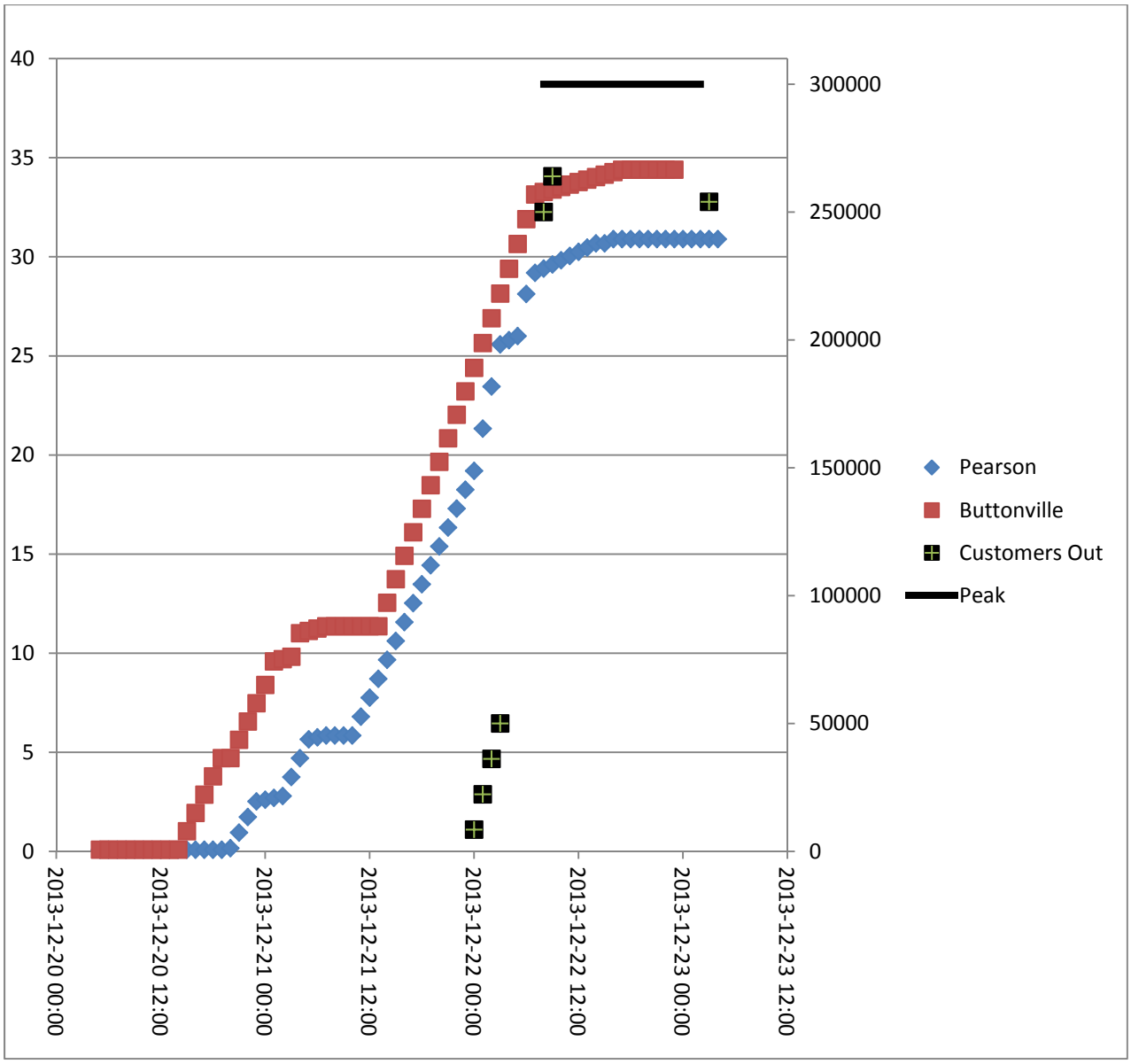


Figure C.1: Estimated ice accretion rates using observations at Pearson and Buttonville Airports. Peak outages (300,000 customers) is represented a long black bar since the exact time period in which this number of customers were without electrical service was not given and indeed may not be known.

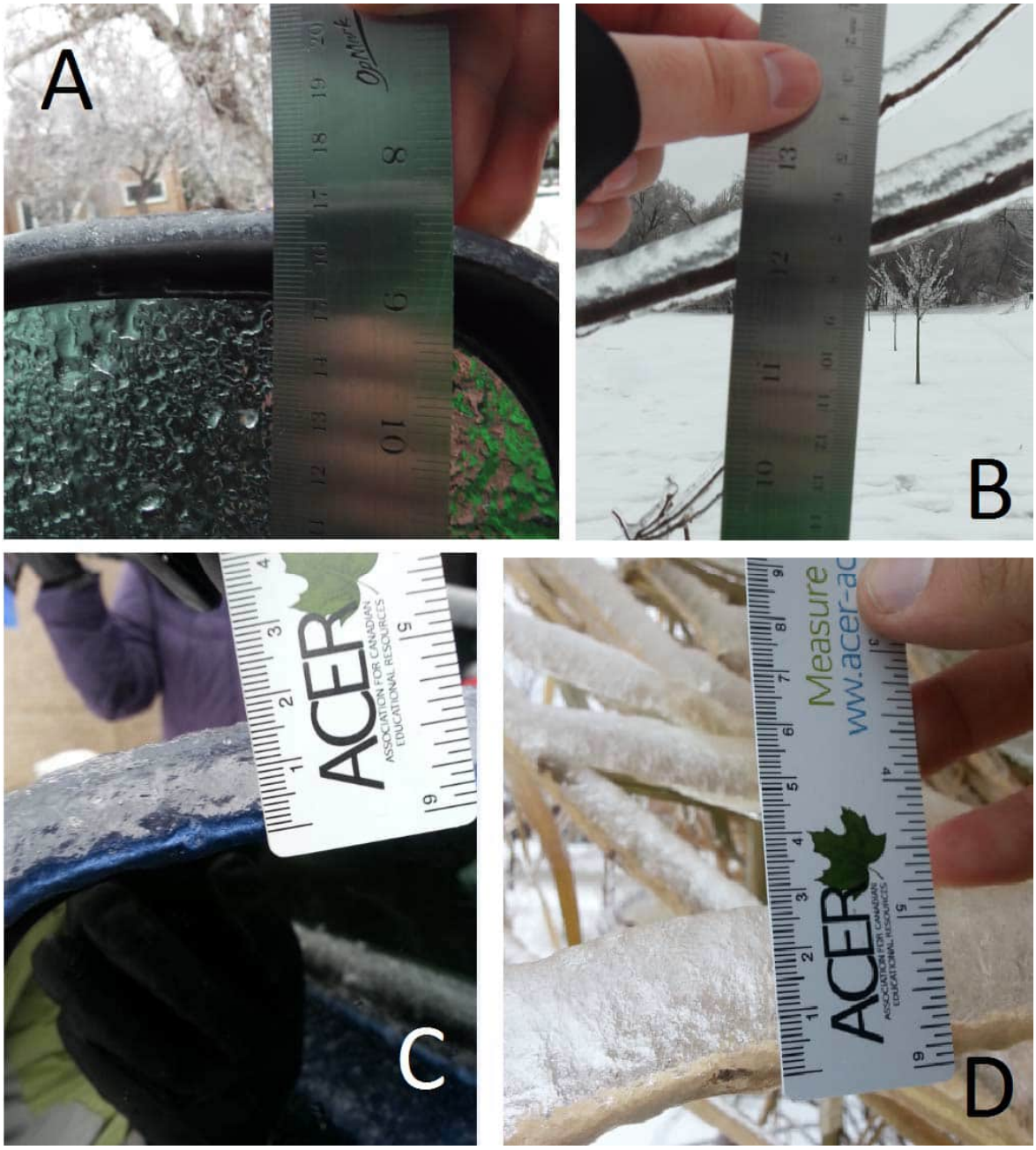


Figure C.2: Ice accretion measurements on similar objects are compared between locations in central Etobicoke (A and B), located ~5 km SE of Pearson airport, and Richmond Hill (C and D), ~9 km NW Buttonville Airport. Ice accretions on car side mirrors are measured at 6 and 15 mm and for branches of similar diameter at 10 and 23 mm, for Etobicoke and Richmond Hill locations, respectively. While measurements are not exactly equivalent in terms of exposure and accretion surface and shape characteristics, they do provide evidence that ice accretion amounts were appreciably higher for municipalities north of the City of Toronto in comparison to locations near Pearson Airport. Photos by RSI team members H. Auld (Thornhill) and S. Eng (Etobicoke).

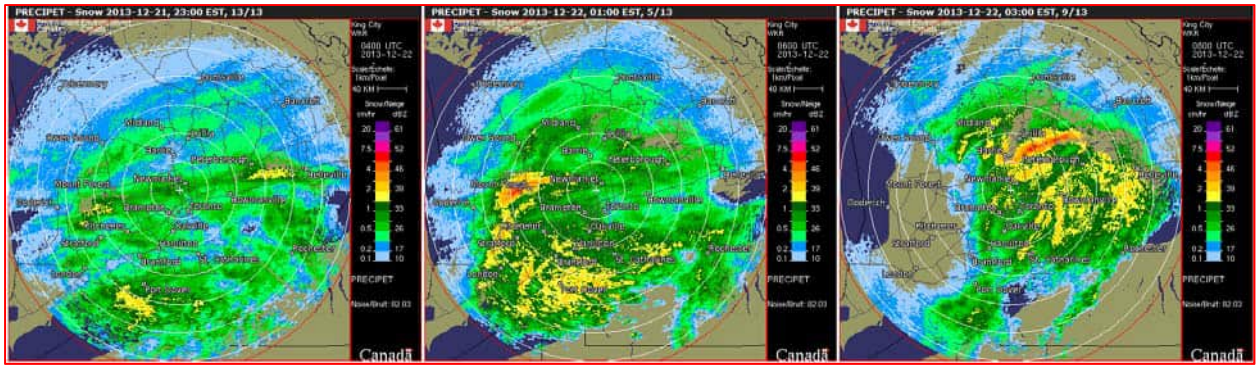


Figure C.3: King City radar imagery; panel times (left to right)correspond to 11 PM December 21st, 1 AM December 22nd and 3 AM, December 22nd, 2013. A small scale meteorological feature appears to have been responsible for an area of particularly heavy precipitation which tracked across the GTA in early morning hours, corresponding with the highest ice accretion rate estimates for the entire event.

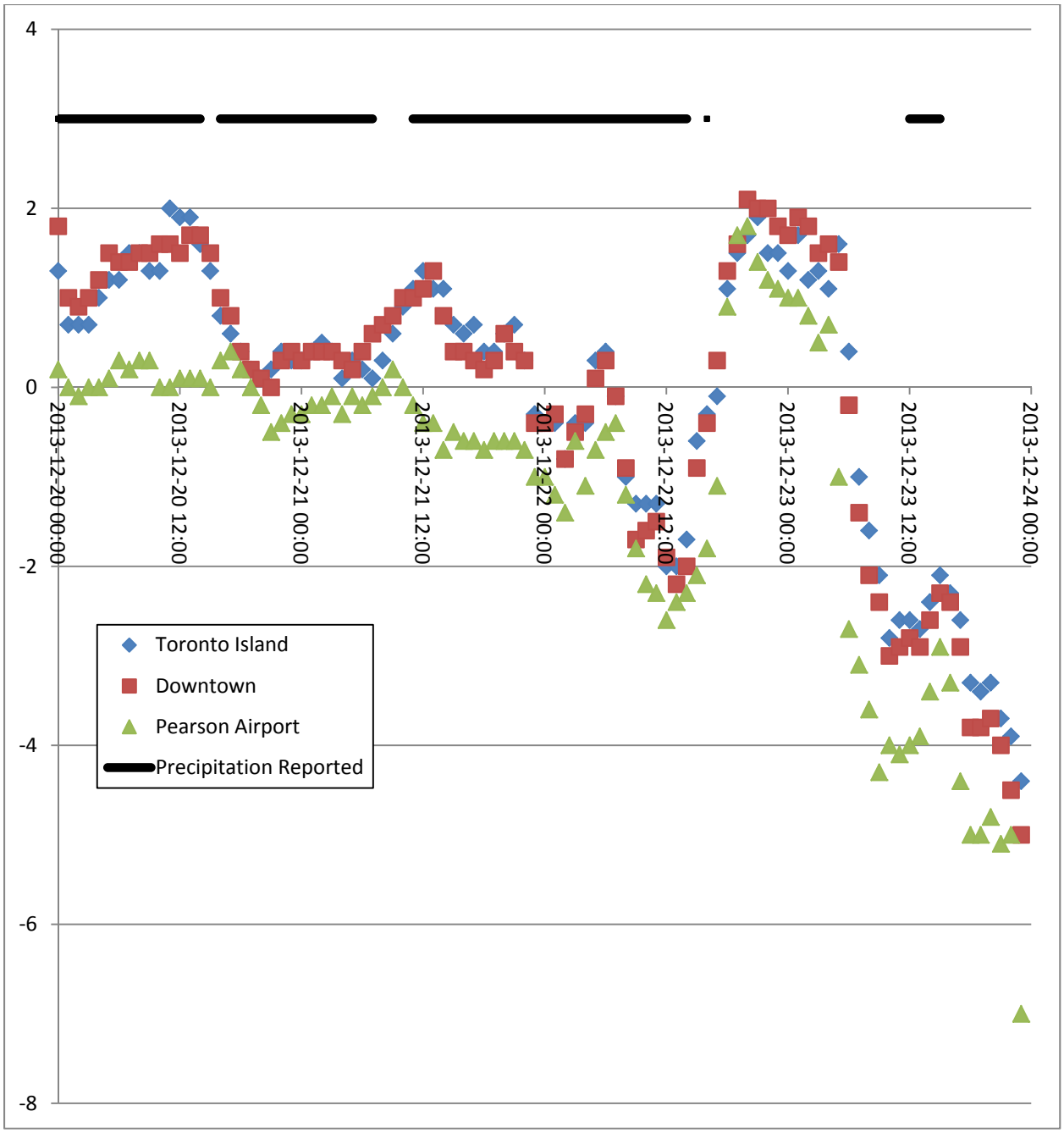


Figure C.4: Comparison of hourly temperatures between Pearson International Airport and stations located in downtown, accompanied by hours with reported precipitation. It is likely that precipitation occuring before 11 PM on December 21st did not contribute to any important ice accretion, but still resulted in significant impacts to many neighbourhoods in and around the downtown core.

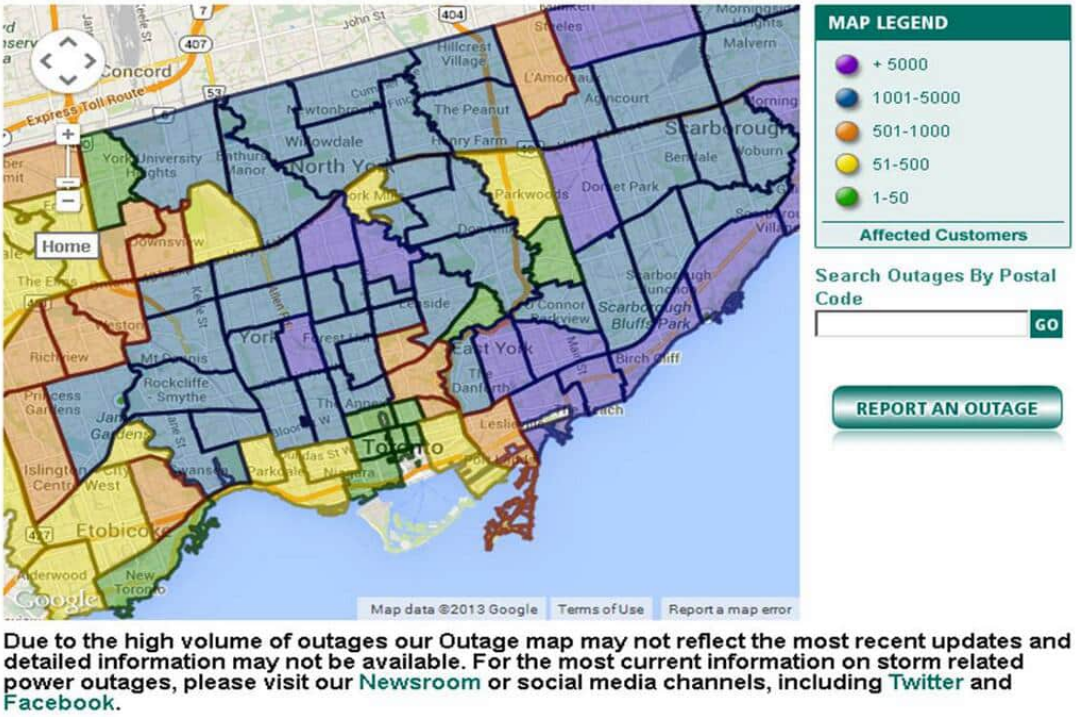


Figure C.5: Toronto Hydro outages map valid for 11 AM December 23rd. Note clear boundaries to north of Bloor and east of Woodbine/Don Valley. Unfortunately, both detailed impacts data and meteorological observations prevent better diagnoses of causes for these differences in system response to the event for areas like East York and Scarborough. Image retreived 11:50 AM December 23rd, 2013.

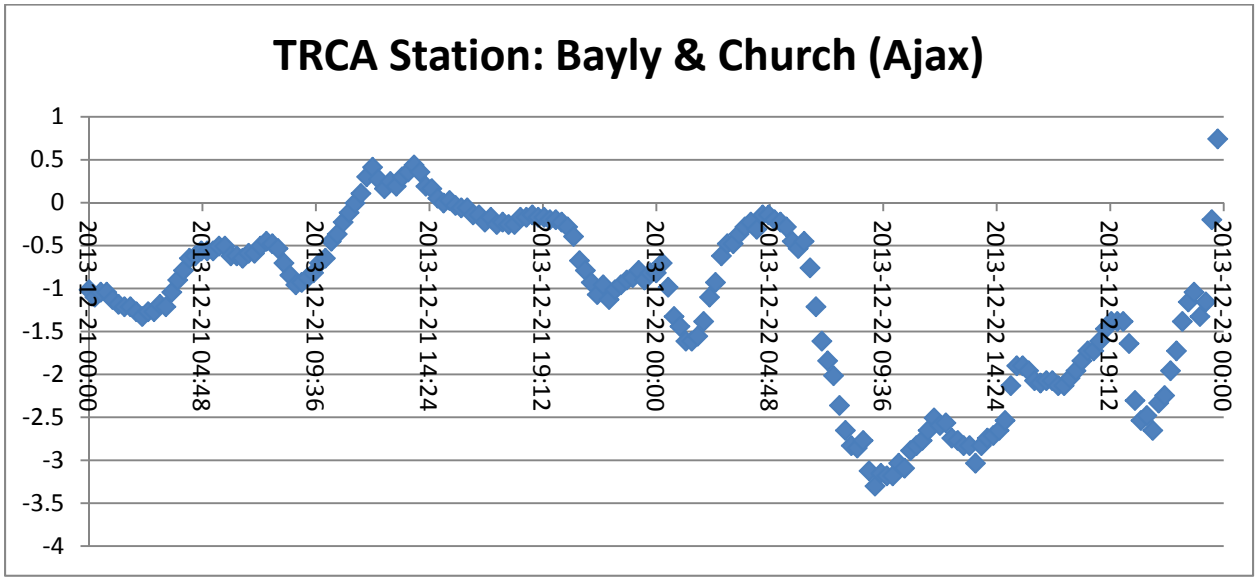


Figure C.6: Temperature Data from Bayly and Church in Ajax. When considered in conjunction with temperature and precipitation measurements from Oshawa Airport, these temerpatures indicate likelyhood that the majority of precipitation experienced between December 21st and December 23rd

was in the form of freezing rain, suggesting ice accretions in Ajax were likely similar to other portions of Durham Region. Data courtesy of Toronto Region Conservation Authority.

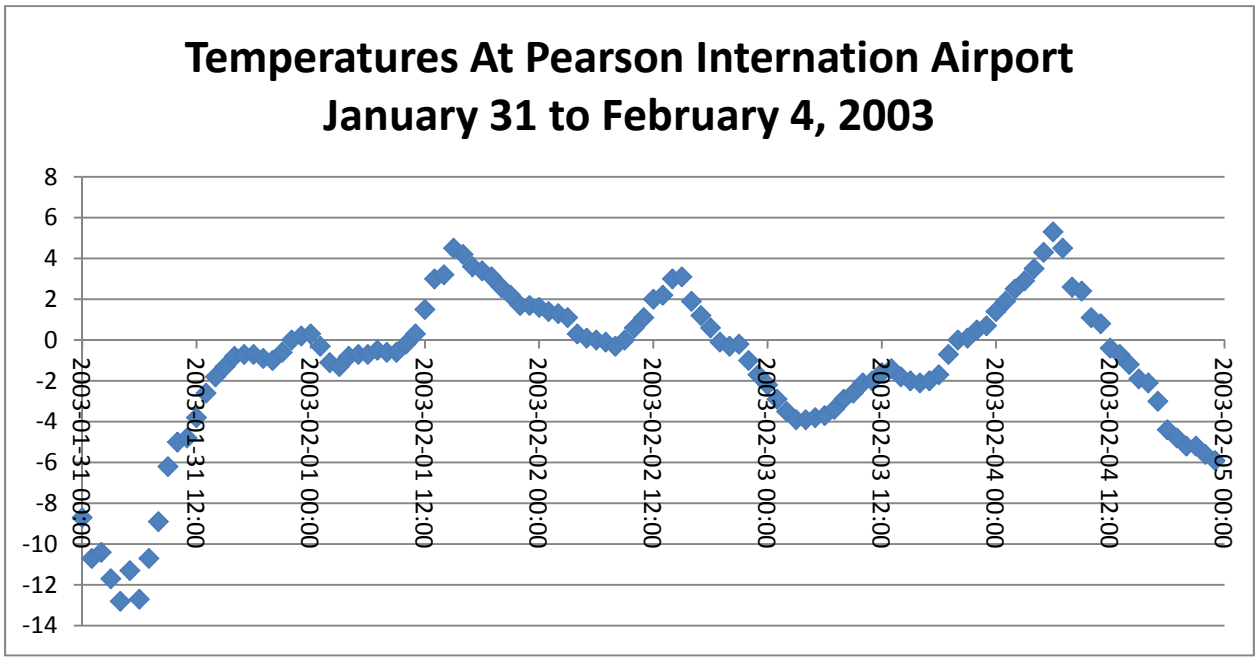


Figure C.7: Hourly temperatures at Pearson Airport between January 31st and Febraury 4th, 2003, corresponding with a complex winter event that produced a total of 160 incident reports as well as outages for over 50,000 Toronto Hydro customers. Temperatures "crossed" the 0°C line no less than 8 times during the 5 day period of unsettled weather.

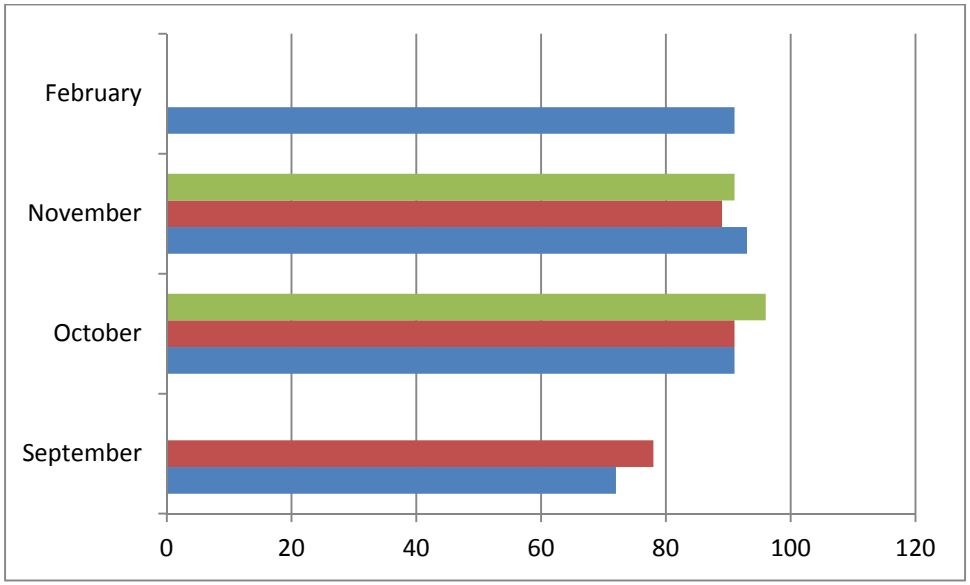


Figure C.8: Max gusts for outage events plotted by month indicate a potential relationship which deserves further study.

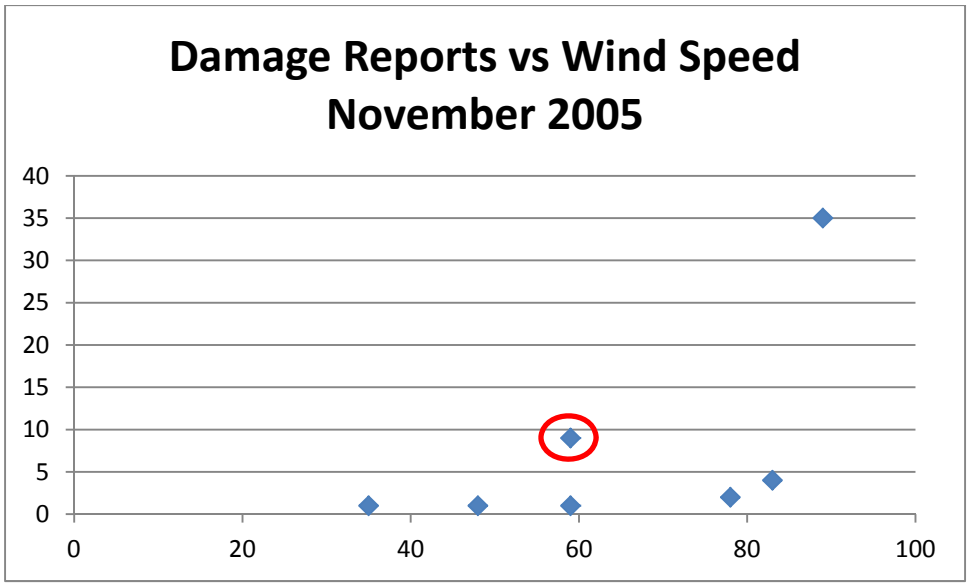


Figure C.9: Number of reports versus max gust reported for November 2005. Note the one apparent outlier, circled in **red**, is November 9th, in which localized impacts are expected and conditions at Pearson Airport are expected to be less representative of conditions producing impacts at a given site.

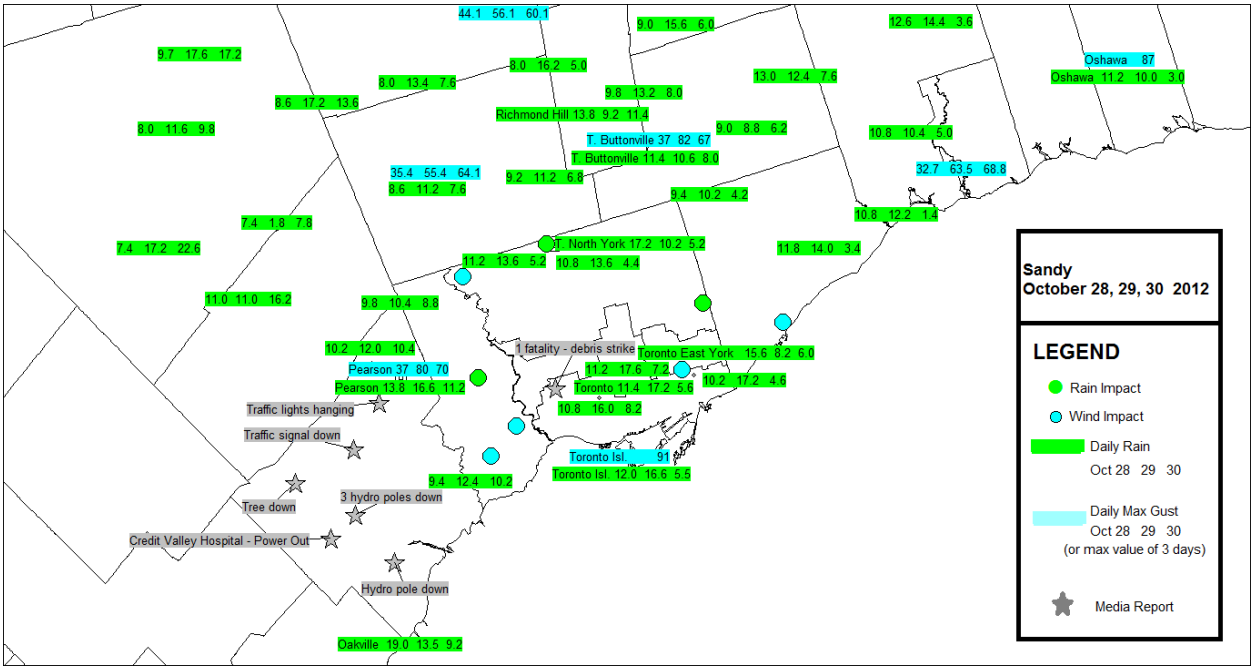


Figure C.10: Map comparing reported impacts with meteorological data for "Superstorm" Sandy. Meteorological data are for October 28th, 29th and 30th and help illustrate the progression of events. Precipitation and wind values are a combination of both EC and TRCA (2014) observational data.

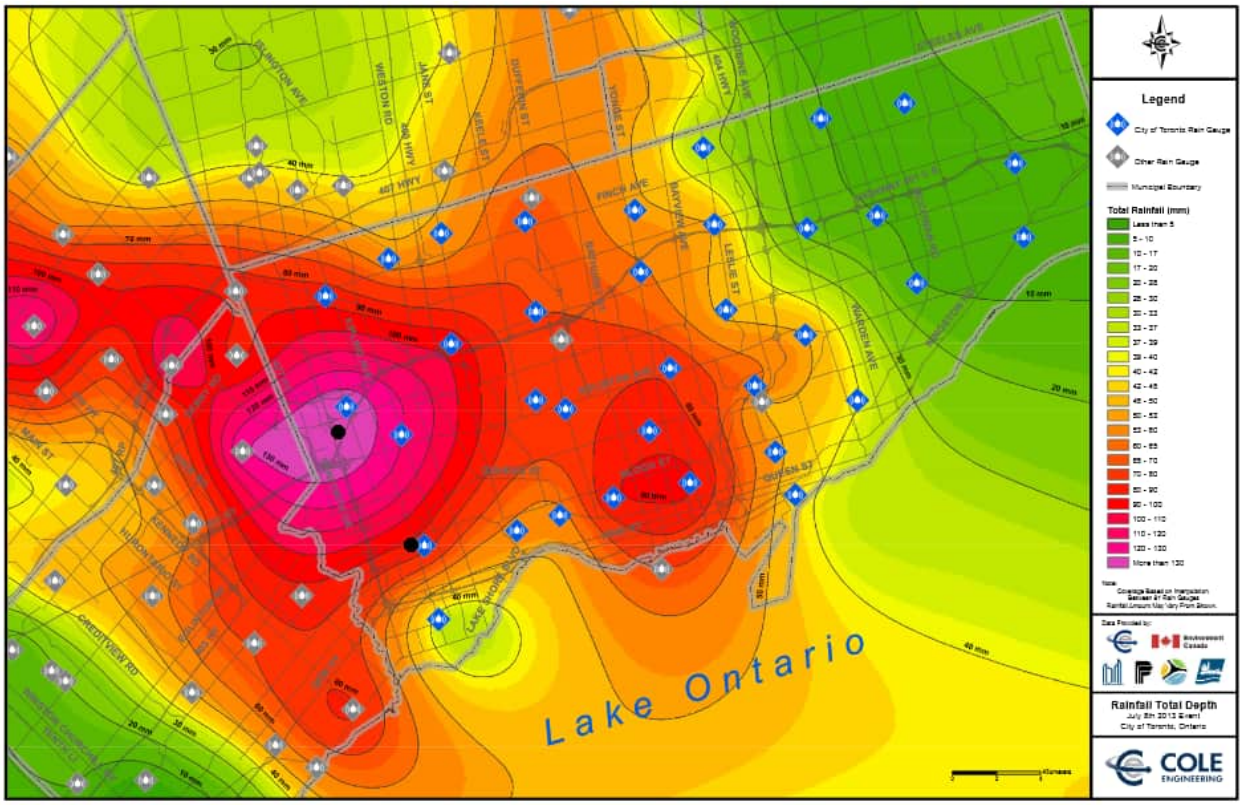


Figure C.11: Contoured 24 hour rainfall totals for the City of Toronto with the locations of Richview and Manby TS superimposed (black dots) added. High resolution PDF map of rainfall totals is available online: http://coleengineering.ca/wordpress/wp-content/themes/Evolution/pdf/2013-articles/rainfall-map.pdf (Cole Engineering Group, 2013)

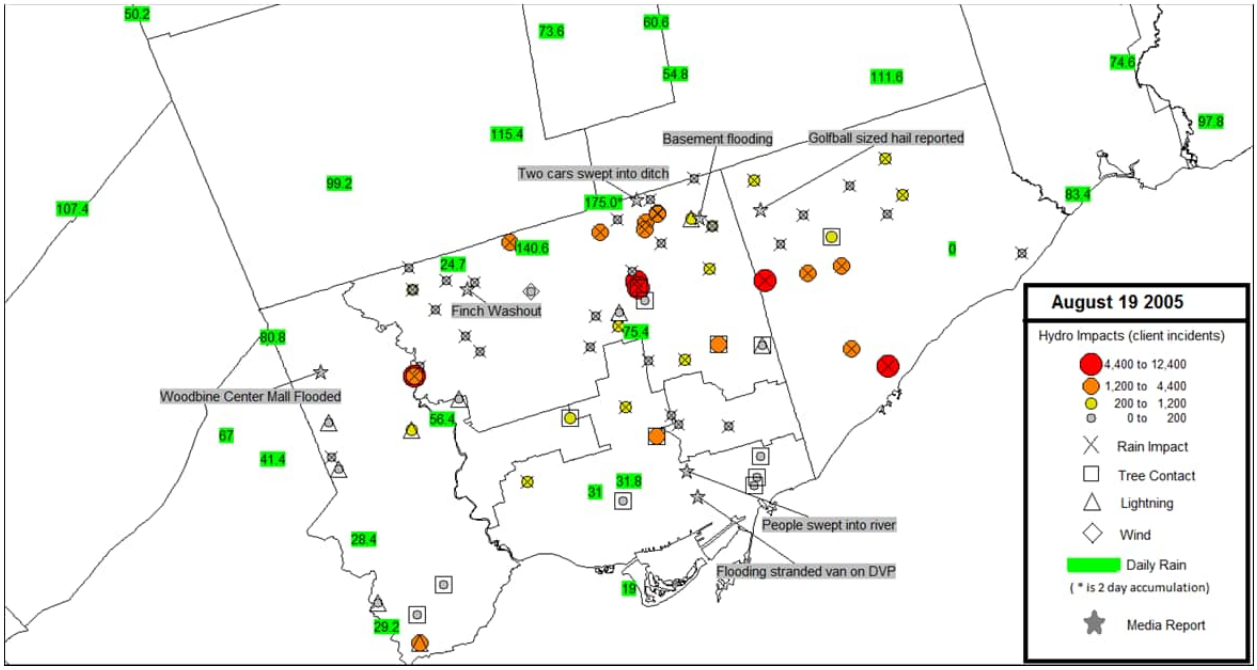


Figure C.12: August 19, 2005 severe thunderstorm event. Map of impacts combining impact types from ITIS and media reports with meteorological data.

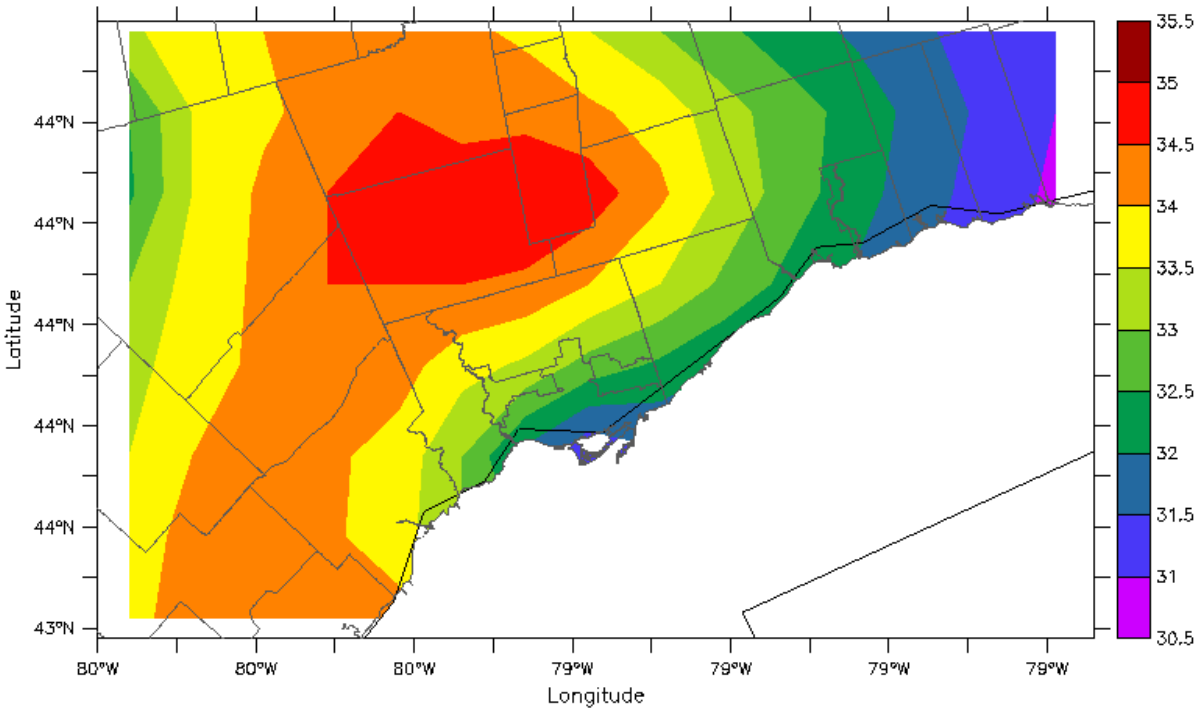


Figure C.13: July 16, 2006, maximum surface temperature (°C) for Toronto and surrounding areas. Data from Cangrd gridded data set.

Appendix D
Risk Assessment Matrix

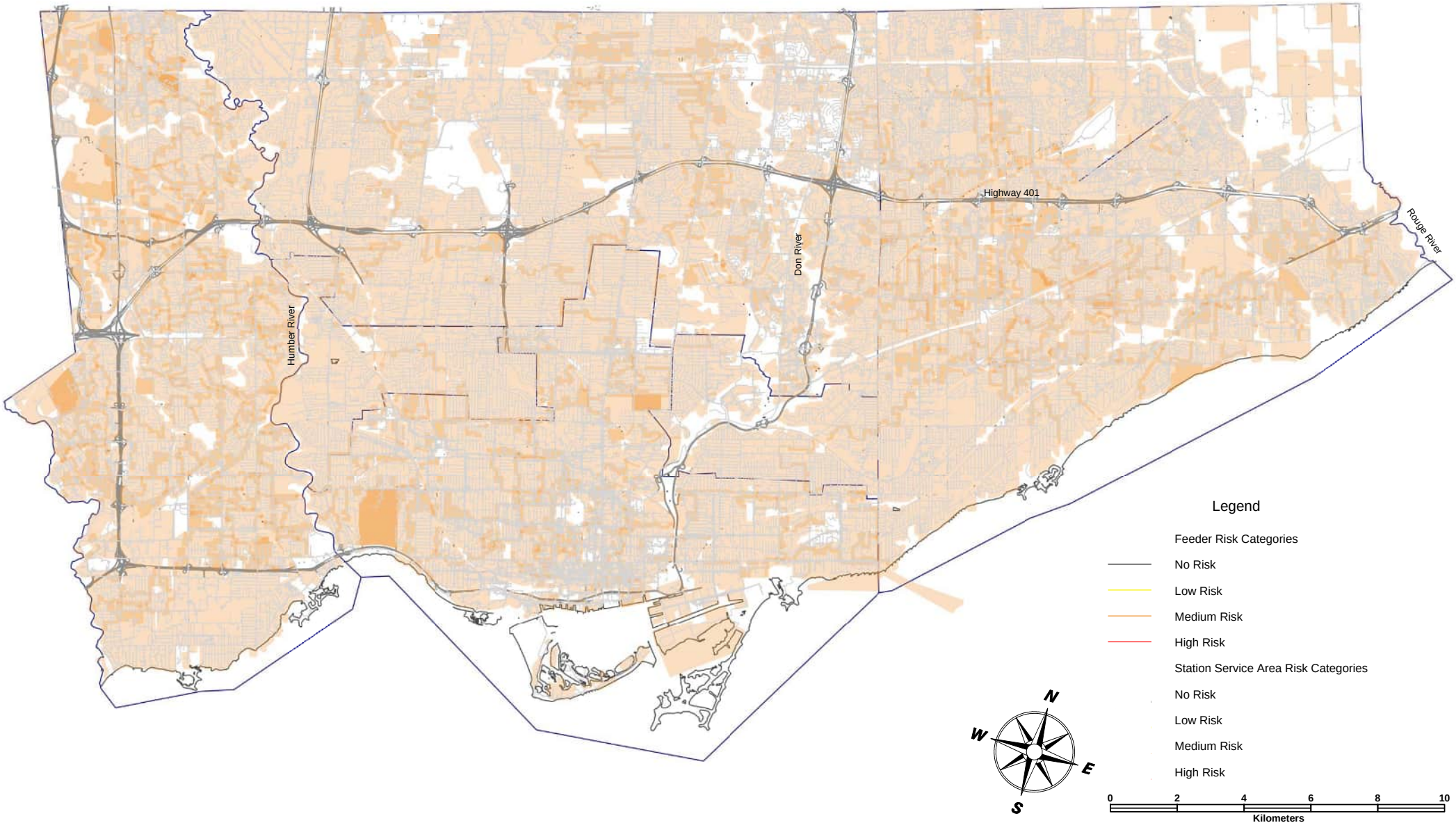
| Study Period | Evaluation | Other Comment | 1 High Temperature | | | | | | | 2 High Temperature | | | | | | | 3 High Temperature | | | | | | | 4 High Temperature | | | | | | | 5 Average temperature >30°C | | | | | | | 6 Heat Wave | | | | | | | 7 High Nighttime Temperatures | | | | | | | 8 Extreme Rainfall | | | | | | | 9 Freezing Rain/Ice Storm | | | | | | |
|---|---|---

10	Freezing Rain/Ice Storm				11	Freezing Rain/Ice Storm				12	High Winds				13	High Winds				14	High Winds				15	Tornadoes				16	Tornadoes				17	Lightning				18	Snow				19	Snow				20	Frost (ground)			
25 mm (design threshold)					60 mm(major outages)					70 km/h+ (tree branches)					90 km/h (min design value; TH higher??)					120 km/h					EF1+					EF2+ (concrete poles, permanent structures)					Days with > 5 cm					Days with > 10 cm					Extreme cold weather			
Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R	Y/N	P	Consequence (qual.)	S	FS	R
N	7					N	4					N	7					N	7					N	7					Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0	N	6					N	7					N	7					N	7			
N	7					N	4					N	7					N	7					N	7					Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0	N	6					N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
Y	7	Gantry + exit lines	6	6	42	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	7	7	49	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
N	7					N	4					N	7					N	7					N	7					Y	1	Debris could impact the building	7	7	7	Y	0	Building and equipment can be damaged	7	7	0	N	6					N	7					N	7			
Y	7	Exit lines	6	6	42	Y	4	Exit lines: overhead	7	7	28	N	7					N	7					Y	7	Exit lines, and flying debris could impact the equipement	6	6	42	Y	1	All equipment can be damaged	7	7	7	Y	0	All equipment can be damaged	7	7	0	Y	6	If arresters don't work , failure of the transf.	6	6	36	N	7					N	7			
N	7					N	4					N	7					N	7					N	7					N	1					N	0					Y	6					N	7					N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7			
N	7					N	4				0	N	7					N	7					N	7					N	1					N	0					N	6					N	7					N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7				0	N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7					Y	7	Debris could impact the equipement	1	1	7	Y	1	Pad mount equipment can be damaged	2	2	2	Y	0	Pad mount equipment can be damaged	2	2	0	N	6					Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7			
N	7					N	4					N	7					N	7					N	7					N	1					N	0					N	6					N	7					N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1+	2	14	Y	4	Salt corrosion - electrical metal enclosures, access	1+	2	8	N	7					Y	7	Debris could impact the equipement	1+	2	14	Y	1	Pad mount equipment can be damaged	2+	3	3	Y	0	Pad mount equipment can be damaged	2+	3	0	N	6					Y	7	Salt corrosion - electrical metal enclosures	1+	2	14	Y	7	Salt corrosion - electrical metal enclosures, Access	1+	2	14	N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7			
Y	7	Salt corrosion - electrical metal enclosures, access	1	1	7	Y	4	Salt corrosion - electrical metal enclosures, access	1	1	4	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - electrical metal enclosures	1	1	7	Y	7	Salt corrosion - electrical metal enclosures, Access	1	1	7	N	7			
Y																		Y																																						
Y	7	Poles & conductors downed, Salt+Contamination	6+	7	49	Y	4	Poles & conductors downed, Salt+Contamination	6+	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49	Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4+	5	30	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49	Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4+	5	30	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4+	5	35	Y	7	Poles & conductors	6+	7	49	Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4+	5	30	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	deposit of salt on insulator can create a failure	1+	2	14	Y	7	Foundations for concrete, steel poles, frost heave	1+	2	14
Y	7	Poles & conductors downed, Salt+Contamination	6	6	42	Y	4	Poles & conductors downed, Salt+Contamination	6	6	24	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42	Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4	4	24	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42	Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4	4	24	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
Y	7	Poles & conductors downed, Salt+Contamination	7	7	49	Y	4	Poles & conductors downed, Salt+Contamination	7	7	28	Y	7	Conductors (tree contacts)	4	4	28	Y	7	Poles & conductors	6	6	42	Y	7	Poles	7	7	49	Y	1	All structures	7	7	7	Y	0	All structures	7	7	0	Y	6	If arresters don't work, a localize outage can occur	4	4	24	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	deposit of salt on insulator can create a failure	1	1	7	Y	7	Foundations for concrete, steel poles, frost heave	1	1	7
N	7					N	4					N	7					N	7					N	7					N	1					N	0					N	6					N	7					N	7			
Y	7	Access	1	1	7	Y	4	Access	1	1	4	N	7					N	7					N	7					N	1					N	0					Y	6	Equipment could fail if protection won't work	3	3	18	N	7					N	7					N	7			
N	7					N	4					N	7					N	7					Y	7	TC & CVT structures			0	Y	1	All supports	7	7	7	Y	0	All supports	7	7	0	N	6					N	7					N	7					Y	7	Foundations, frost heave	2	2	14
Y	7	Gantry + exit lines	1	1	7	Y	4	Gantry + exit lines	7	7	28	N	7					N	7					N	7					Y	1	Gantry	7	7	7	Y	0	Gantry	7	7	0	N	6					N	7					N	7					Y	7	Foundations, frost heave	2	2	14
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	8	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - concrete and steel	1+	2	14	Y	7	Salt corrosion - concrete and steel, access	1+	2	14	Y	7	Foundations, frost heave	1+	2	14
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	14	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1+	2	8	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - concrete and steel	1+	2	14	Y	7	Salt corrosion - concrete and steel, access	1+	2	14	Y	7	Foundations, frost heave	1+	2	14
N	7					N	4					N	7					N	7					N	7					N	1					N	0					N	6					N	7					N	7					Y	7	Foundations, frost heave	1+	2	14
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	4	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - concrete and steel	1	1	7	Y	7	Salt corrosion - concrete and steel, access	1	1	7	Y	7	Foundations, frost heave	1	1	7
Y	7	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	7	Y	4	Accelerated corrosion of reinforcing bars and degradation of concrete	1	1	4	N	7					N	7					N	7					N	1					N	0					N	6					Y	7	Salt corrosion - concrete and steel	1	1	7	Y	7	Salt corrosion - concrete and steel, access	1	1	7	Y	7	Foundations, frost heave	1	1	7
N	7					N	4					N	7					N	7					N	7					N	1					N	0					N	6					N	7					N	7					Y	7	Foundations, frost heave	1	1	7
Y	7	safe access to site	6	6	42	Y	4	safe access to site	6	6	24	Y	7	access, location has to be declare safe	2	2	14	Y	7	access, location has to be declare safe	2	2	14	Y	7	access, location has to be declare safe	2	2	14	Y	1	access, location has to be declare safe	2	2	2	Y	0	access, location has to be declare safe	2	2	0	Y	6	staff security	3-4	4	24	Y	7	Access, staff security	1-2	2	14	Y	7	Access, staff security	3	3	21	N	7									

Appendix E
Risk Maps

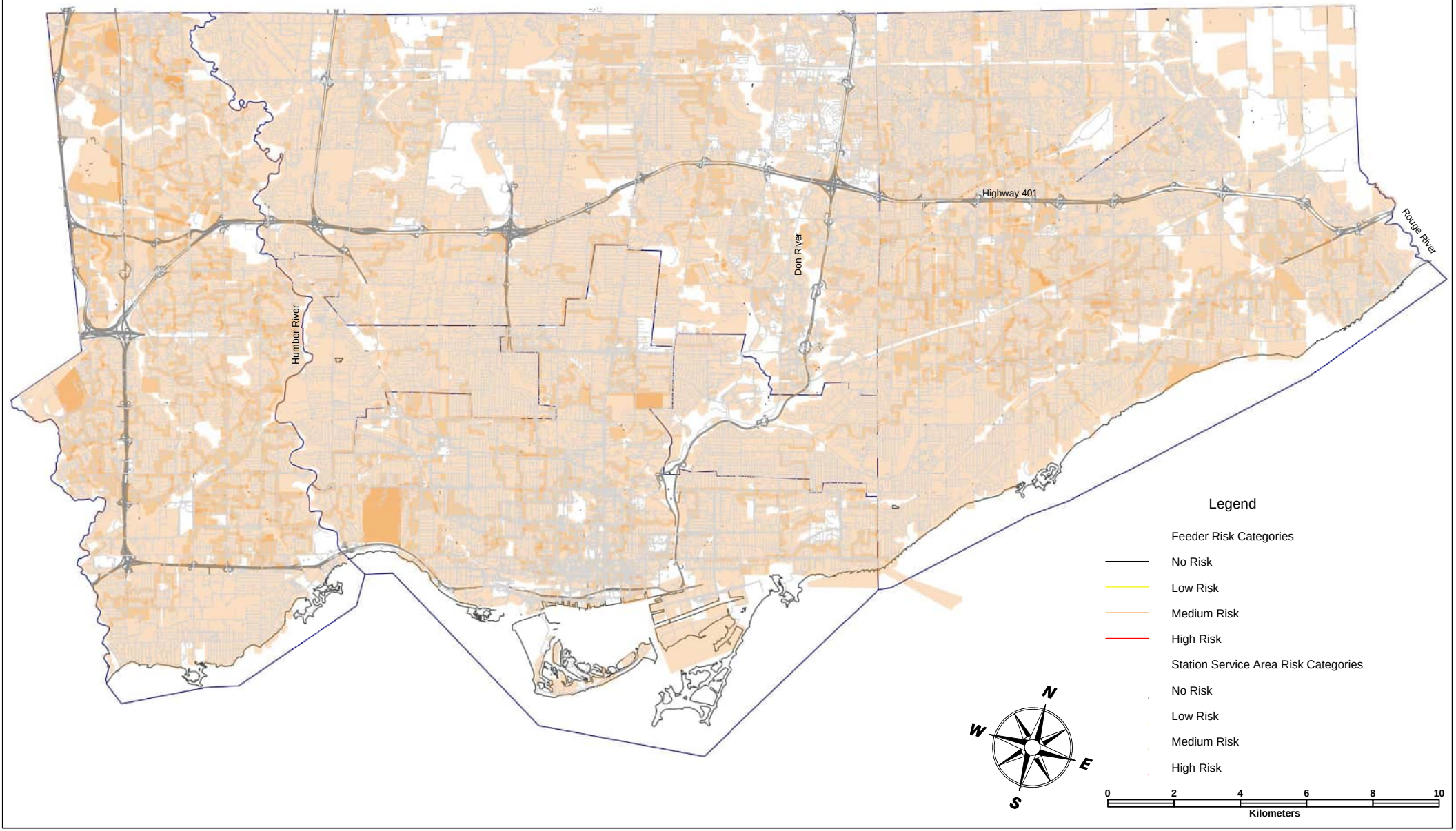
PIEVC Phase 2 Climate Change Risk Map by 2050

1. High Temperature Maximum Above 25 C



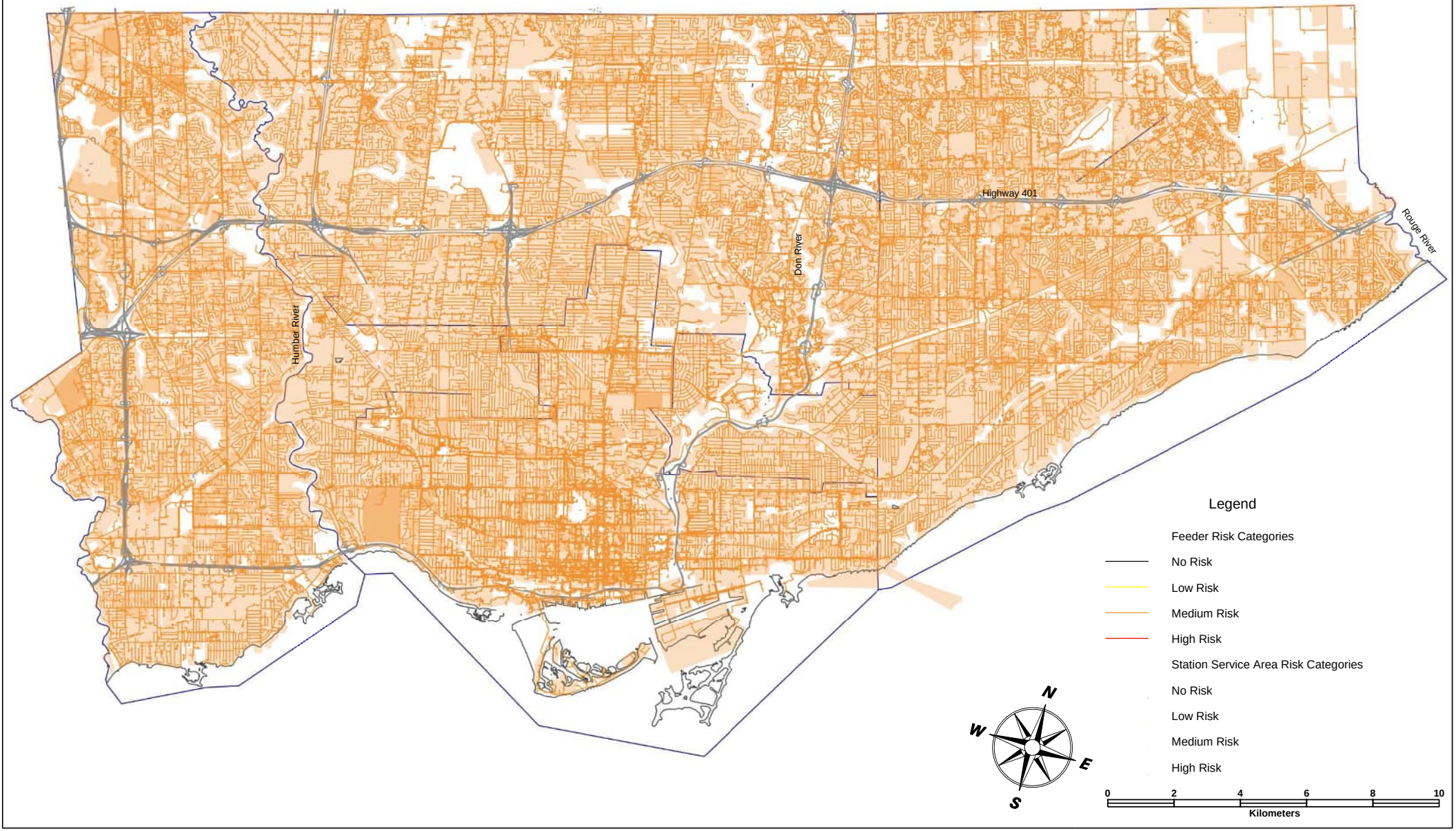
PIEVC Phase 2 Climate Change Risk Map by 2050

2. High Temperature Maximum Above 30 C



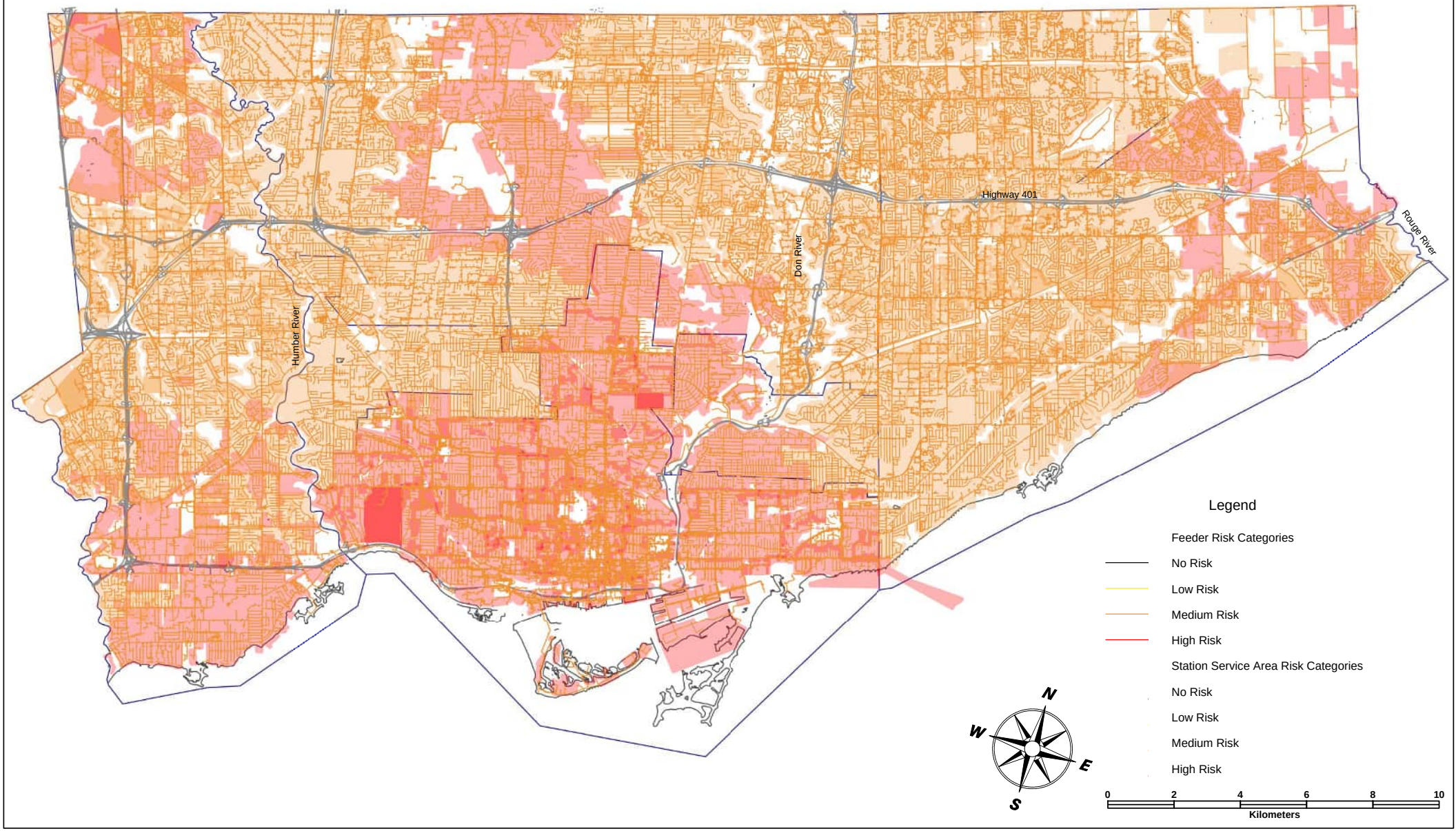
PIEVC Phase 2 Climate Change Risk Map by 2050

3. High Temperature Maximum Above 35 C



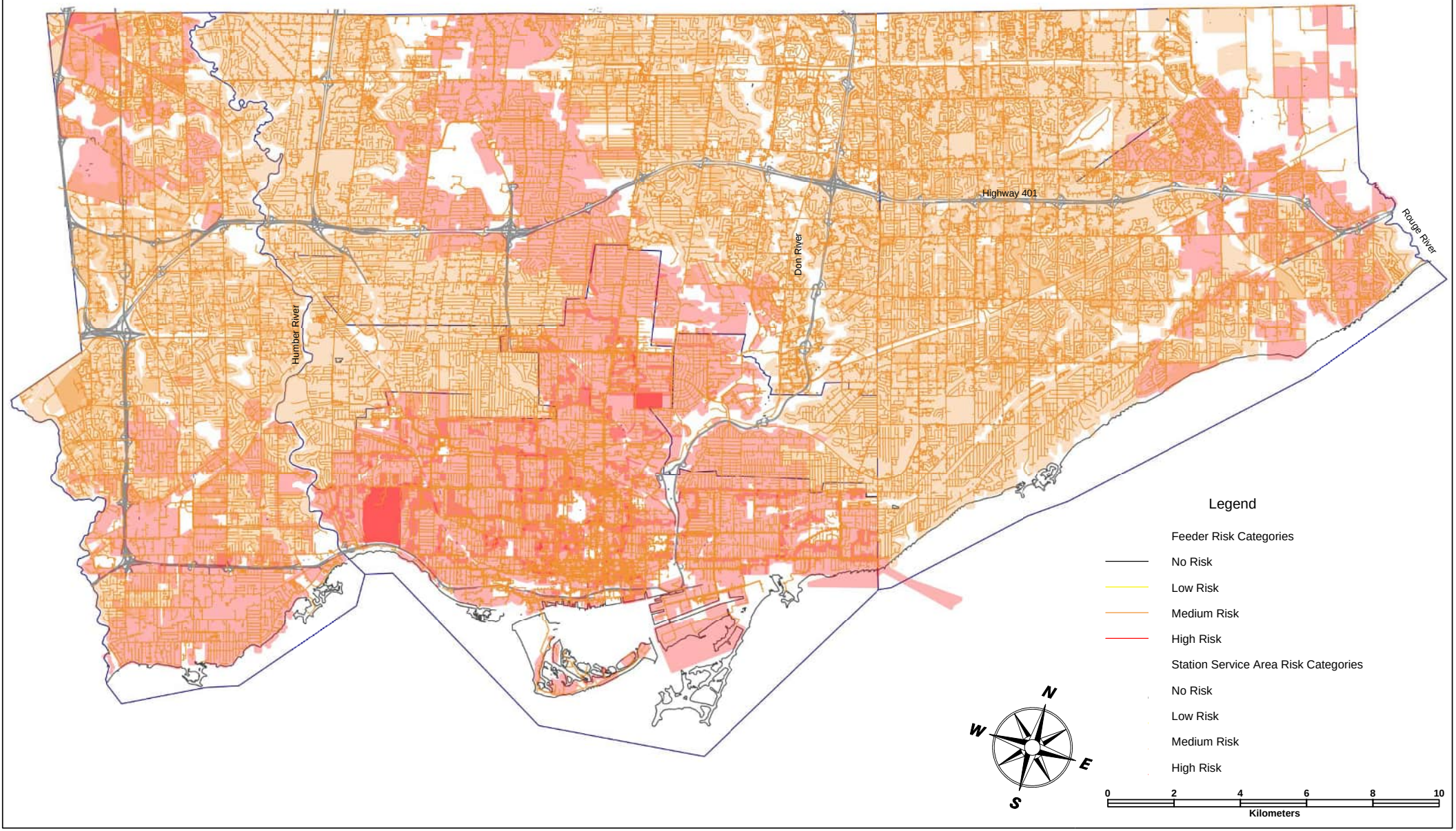
PIEVC Phase 2 Climate Change Risk Map by 2050

4. High Temperature Maximum Above 40 C



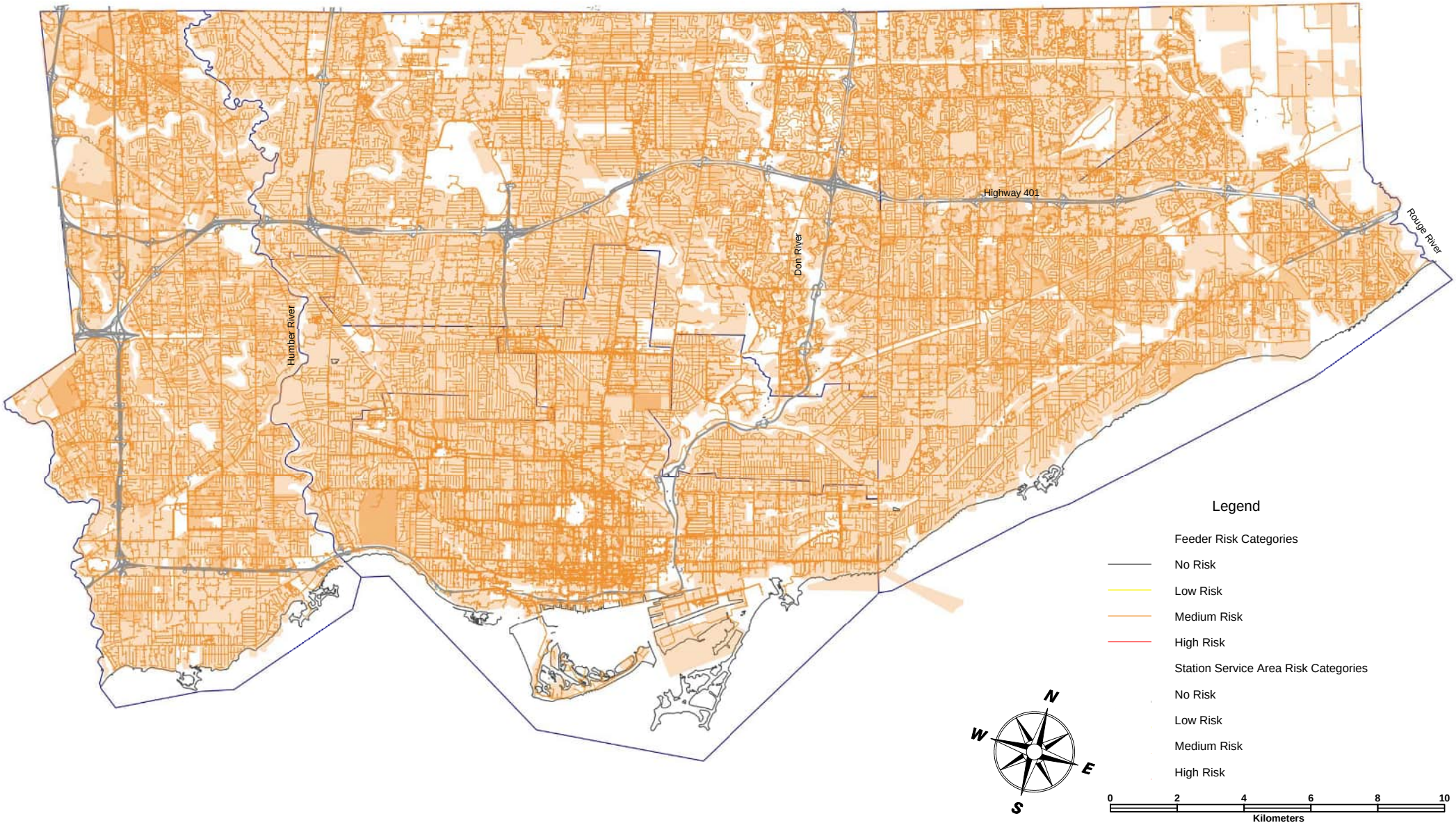
PIEVC Phase 2 Climate Change Risk Map by 2050

5. Average Temperature Above 30 C for 24 Hours



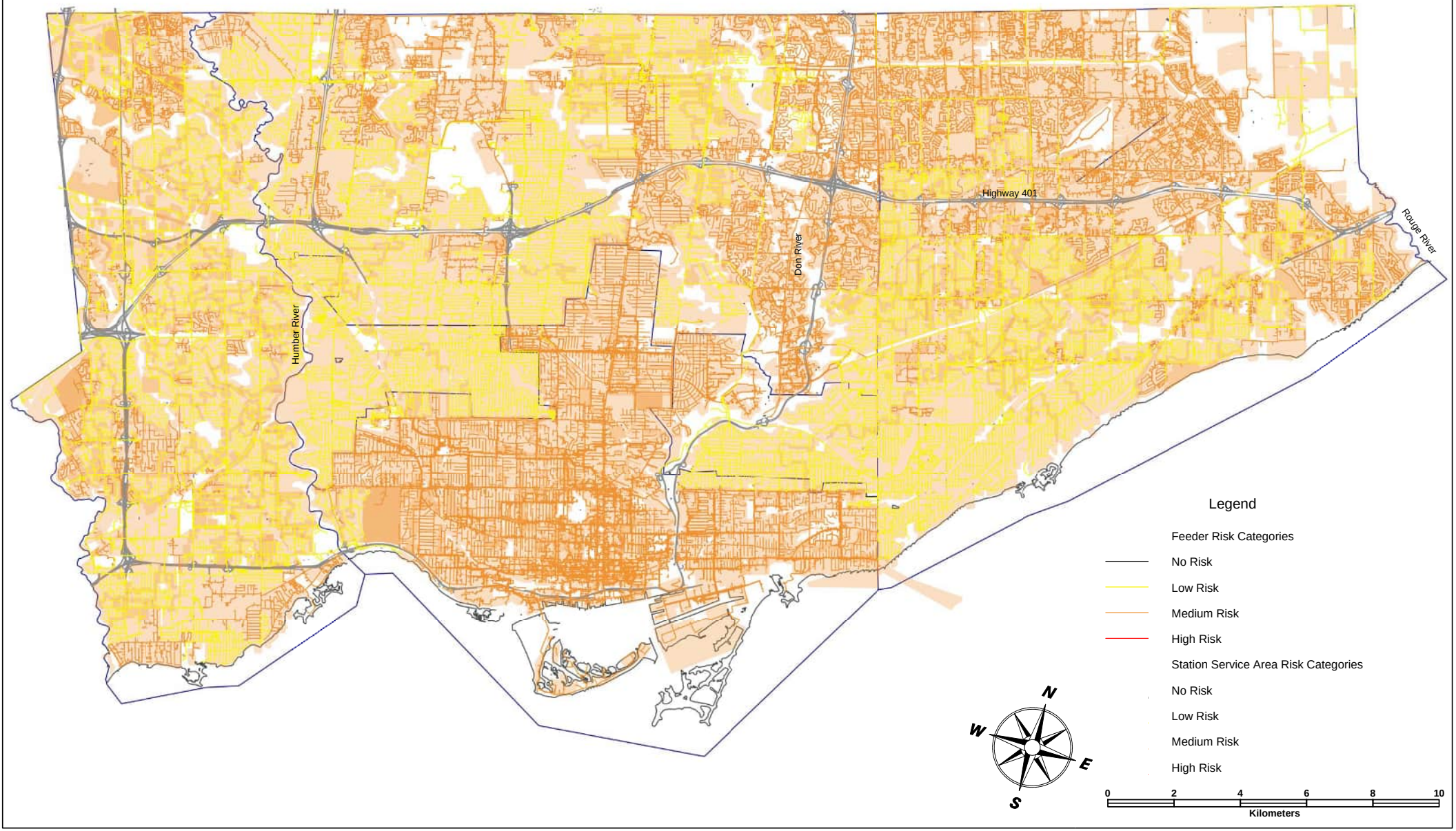
PIEVC Phase 2 Climate Change Risk Map by 2050

6. Heat Wave 3 Day with Maximum Temperature Above 30 C



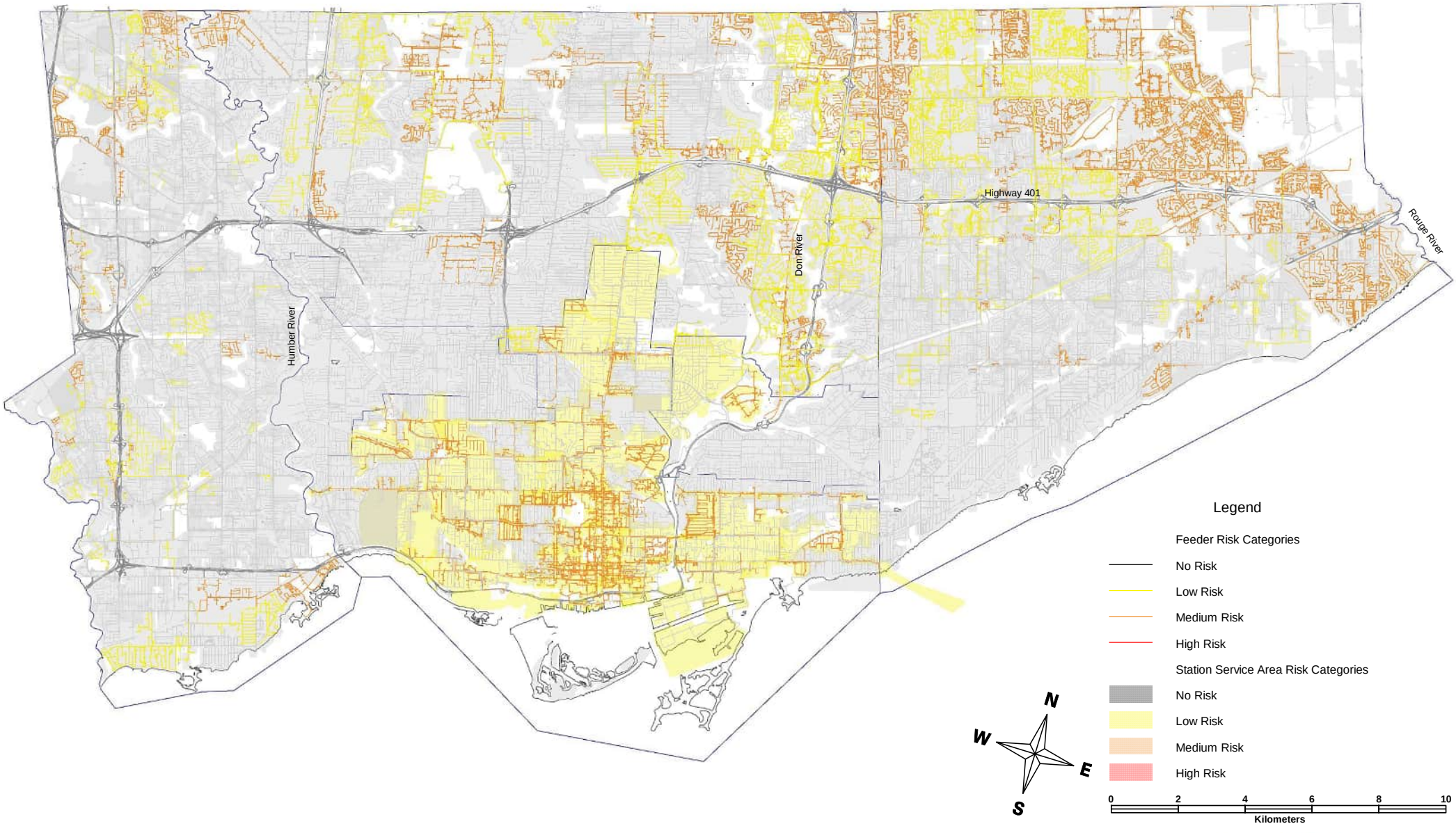
PIEVC Phase 2 Climate Change Risk Map by 2050

7. High Night Time Temperature Minimum Above 23 C



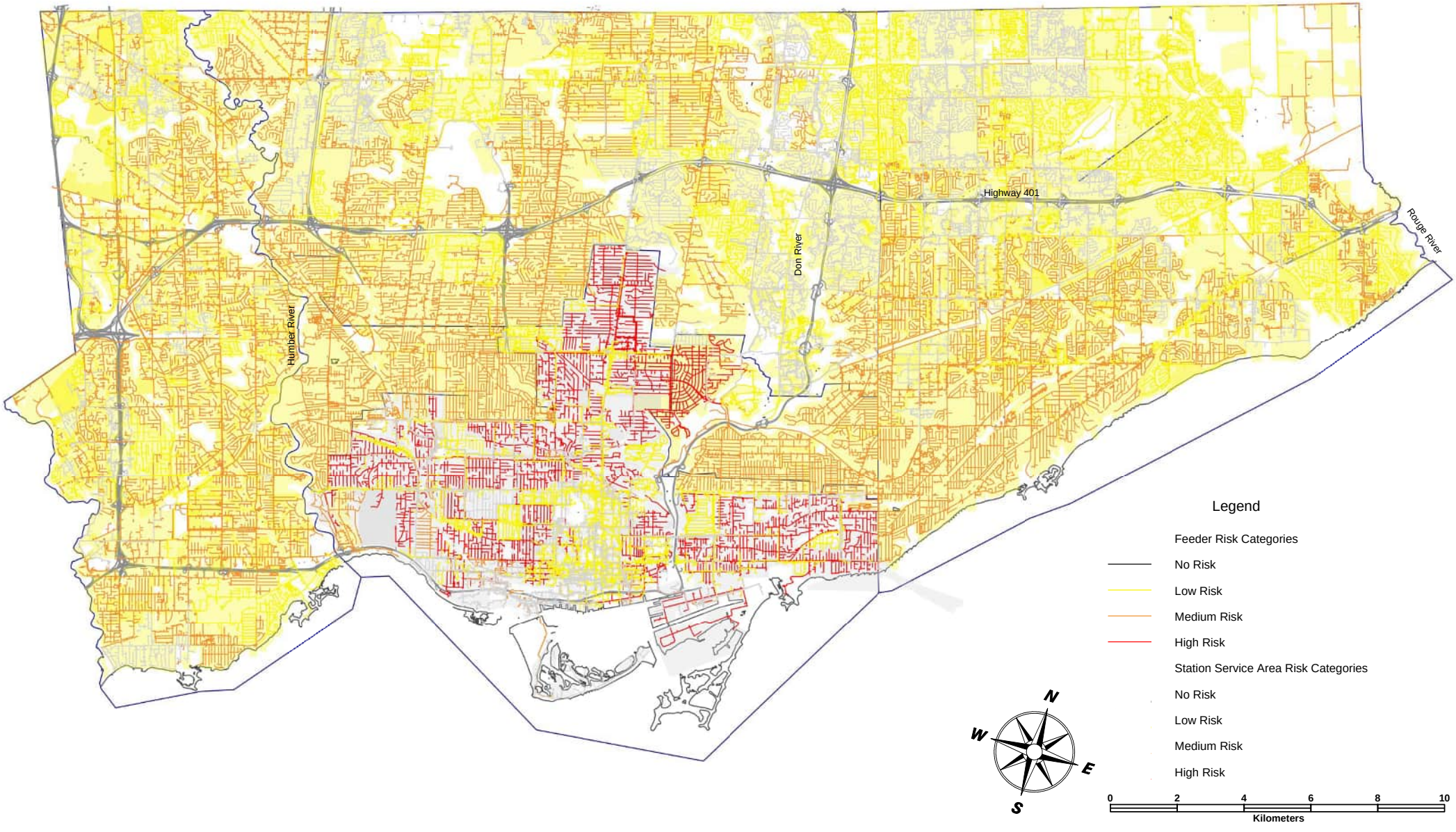
PIEVC Phase 2 Climate Change Risk Map by 2050

8. Extreme Rainfall 100mm in Less than 24 Hours



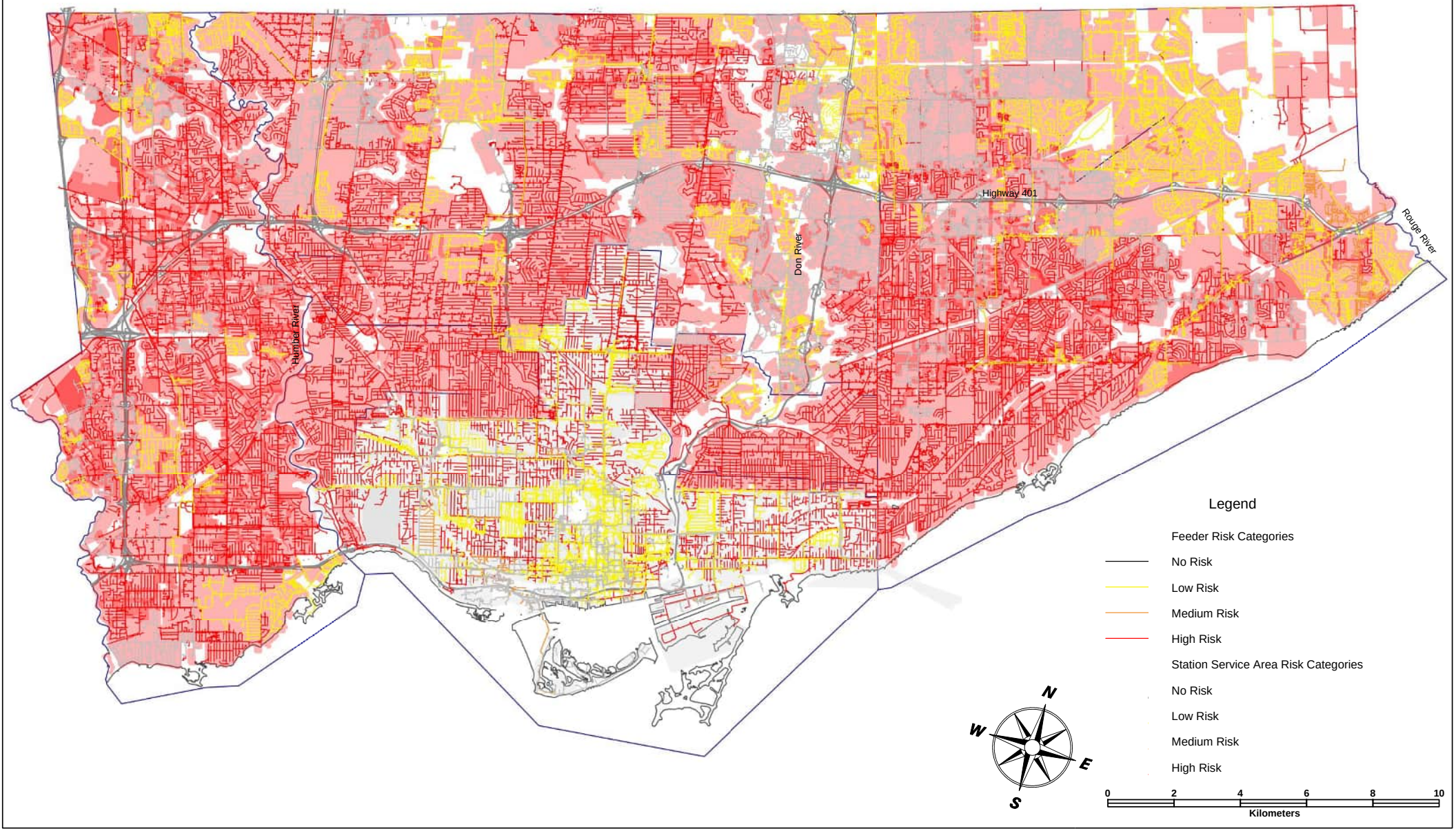
PIEVC Phase 2 Climate Change Risk Map by 2050

9. 15mm Freezing Rain/Ice Storm



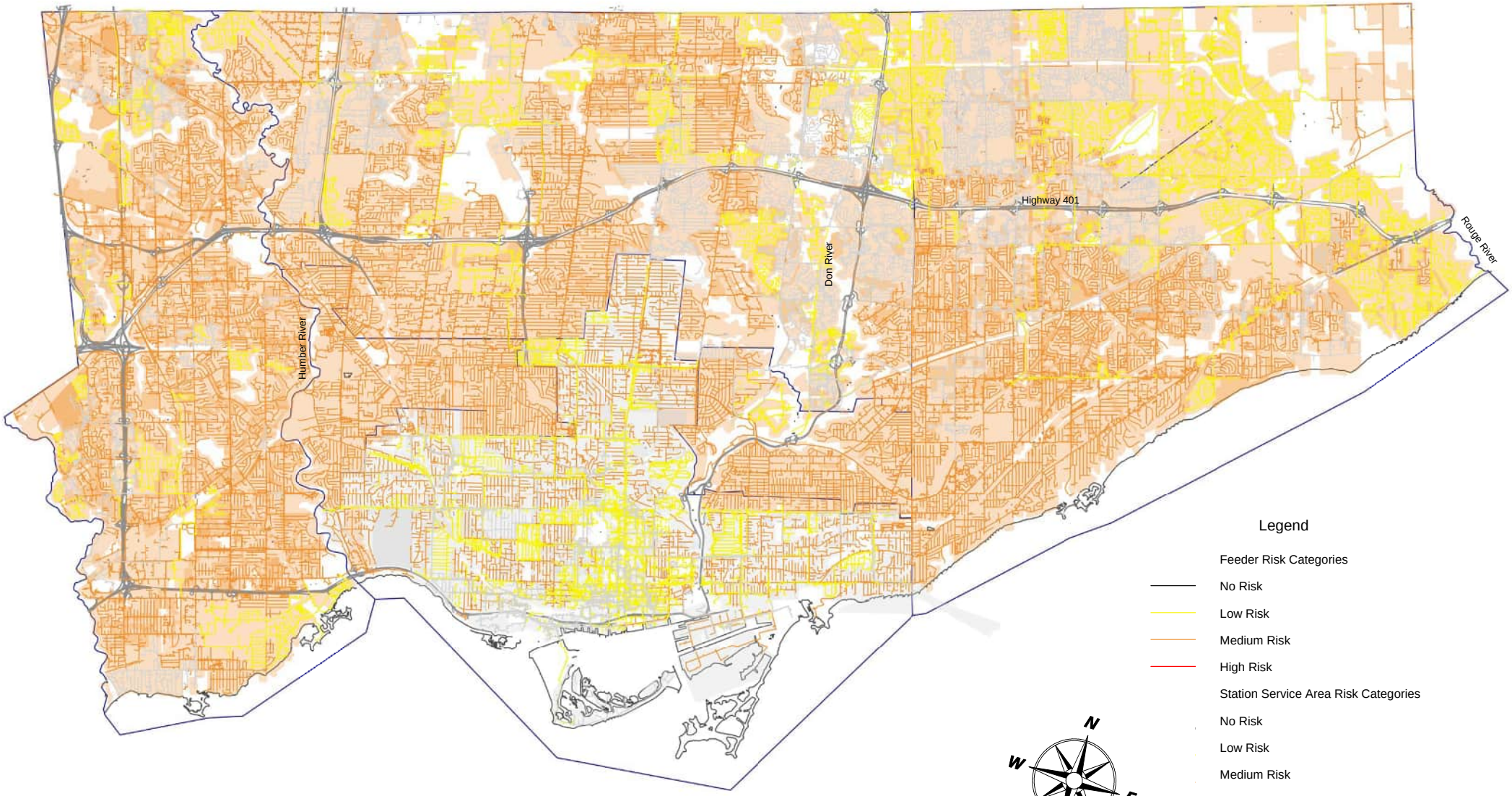
PIEVC Phase 2 Climate Change Risk Map by 2050

10. 25mm Freezing Rain/Ice Storm



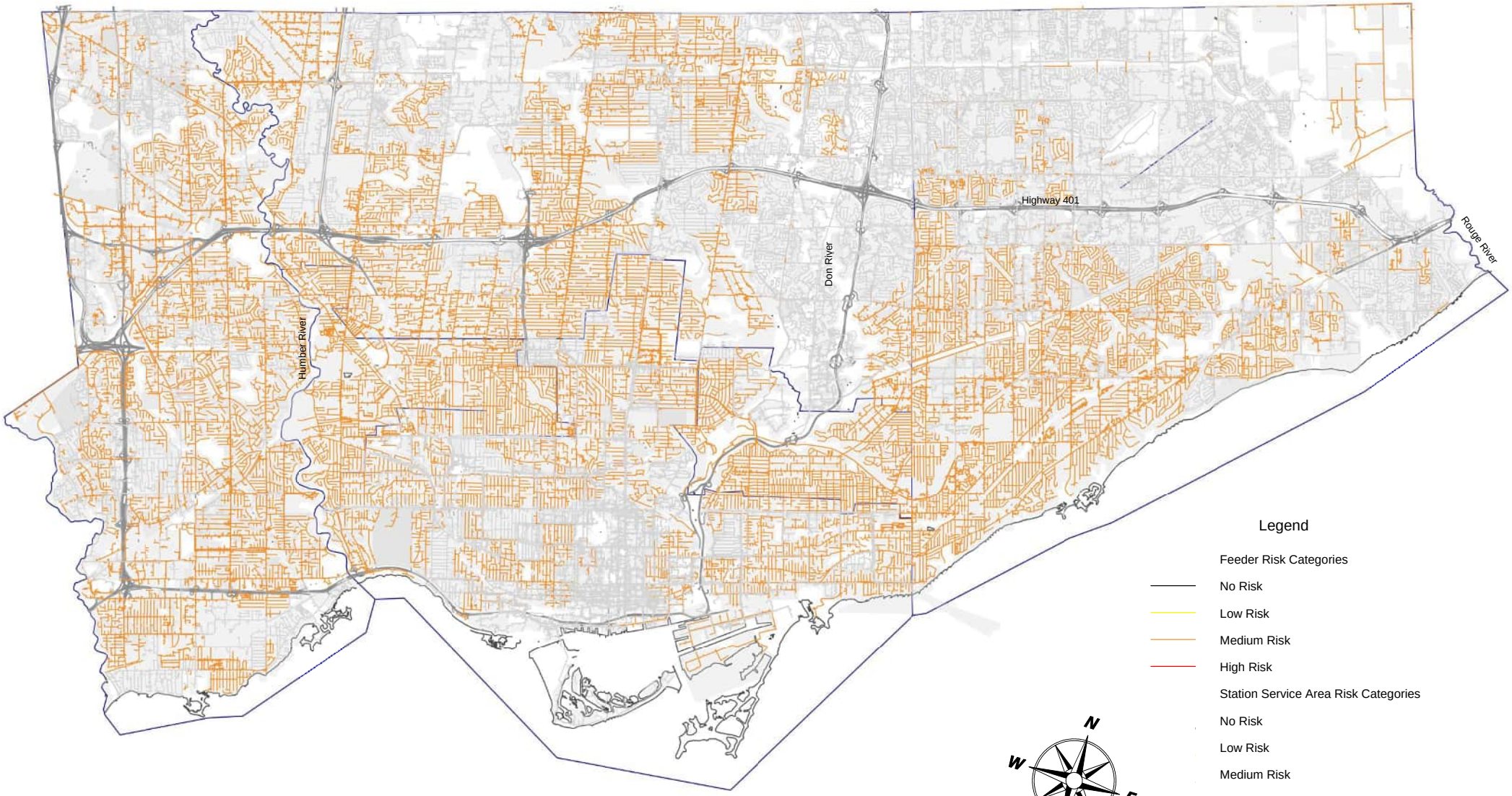
PIEVC Phase 2 Climate Change Risk Map by 2050

11. 60mm Freezing Rain/Ice Storm



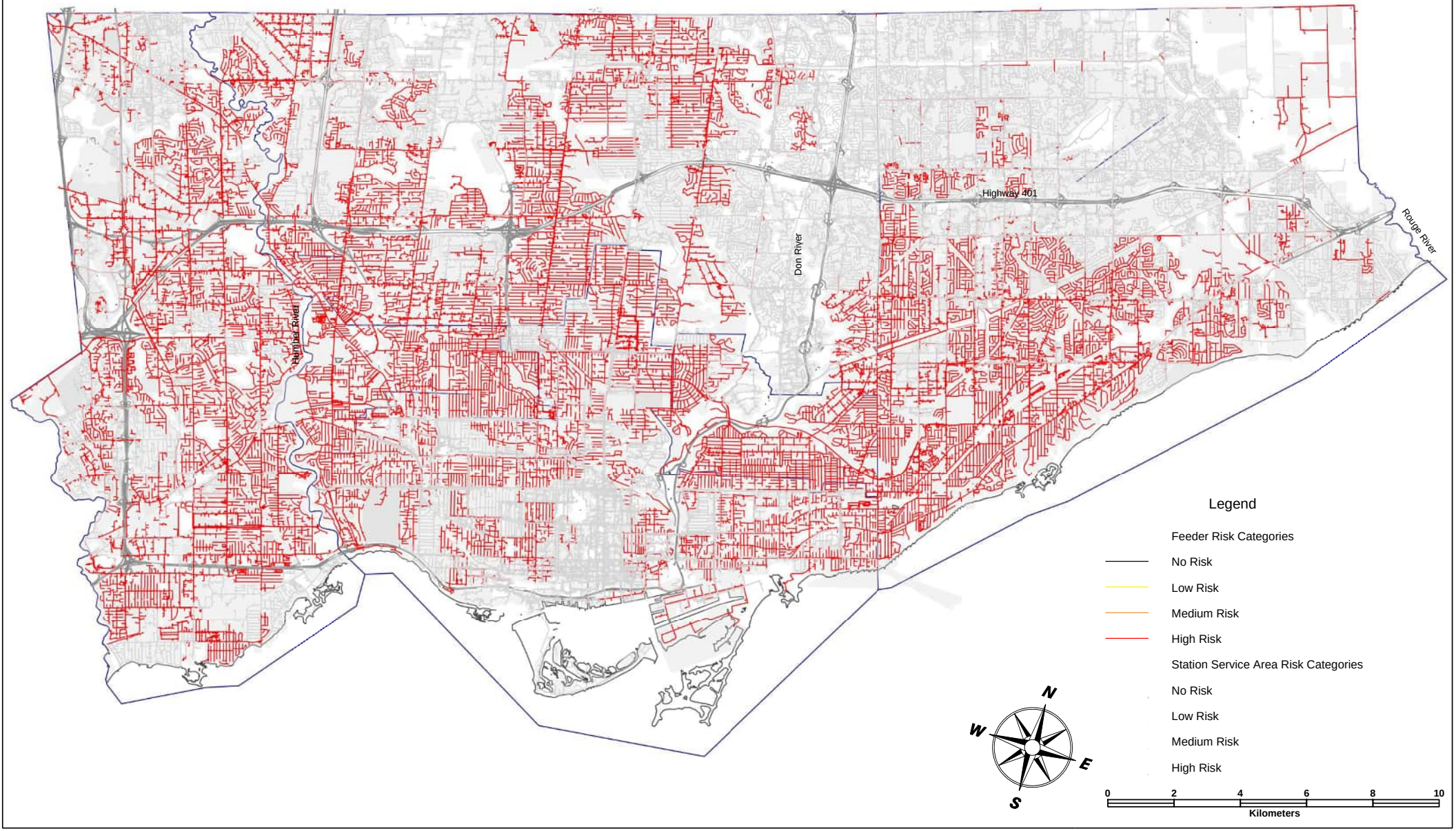
PIEVC Phase 2 Climate Change Risk Map by 2050

12. High Winds Greater Than 70km/h



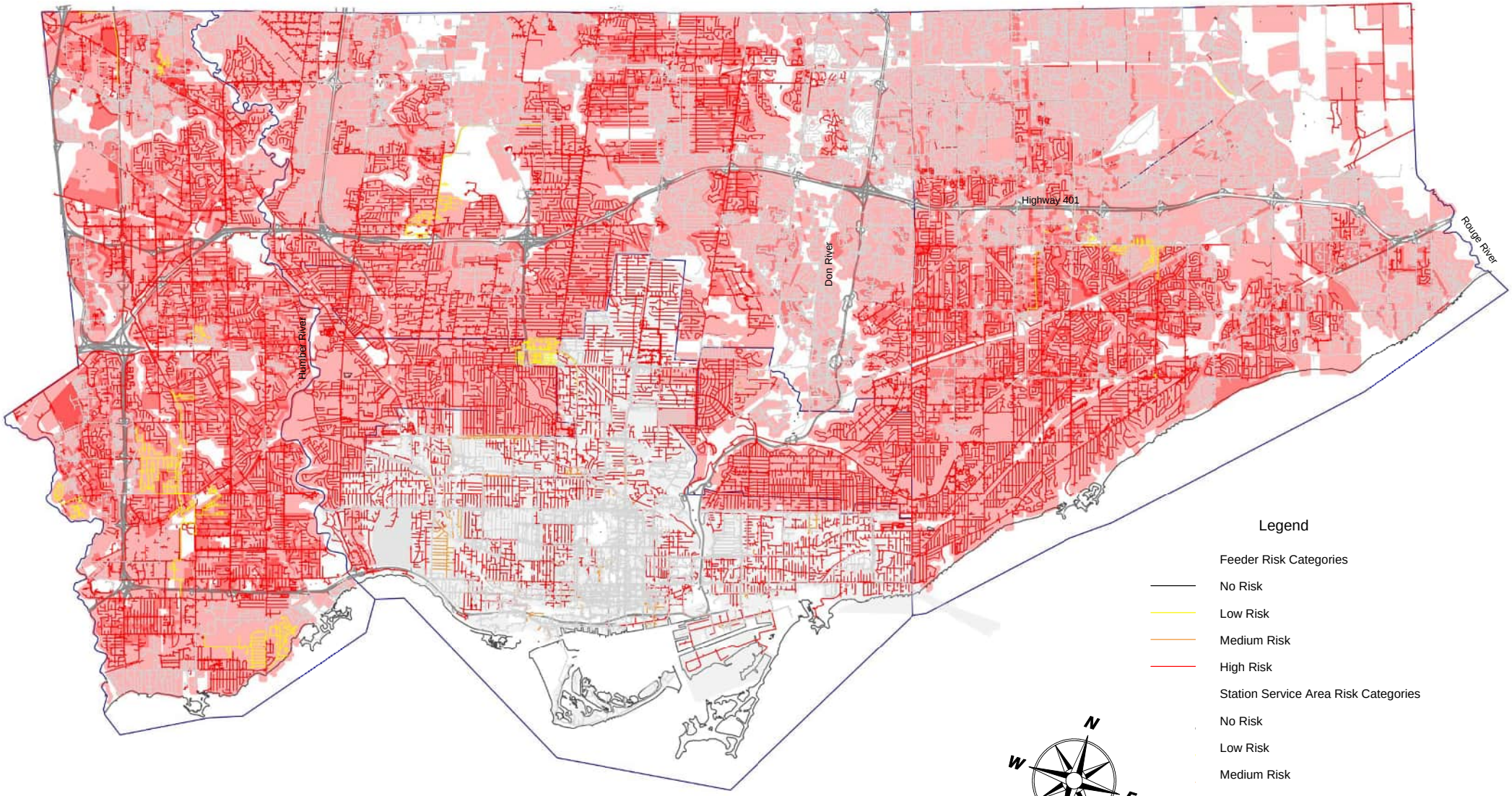
PIEVC Phase 2 Climate Change Risk Map by 2050

13. High Winds Greater Than 90km/h



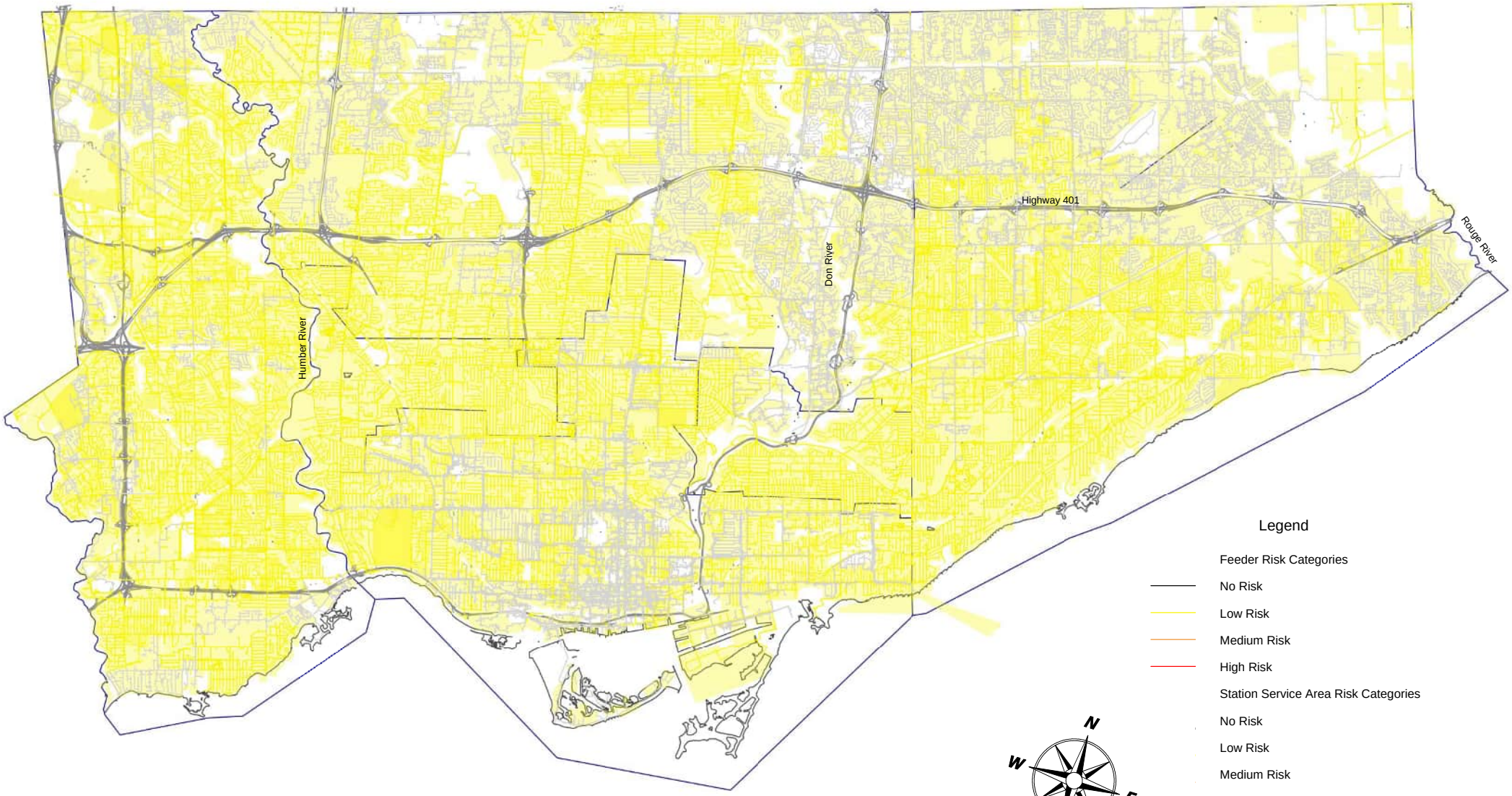
PIEVC Phase 2 Climate Change Risk Map by 2050

14. High Winds Greater Than 120km/h



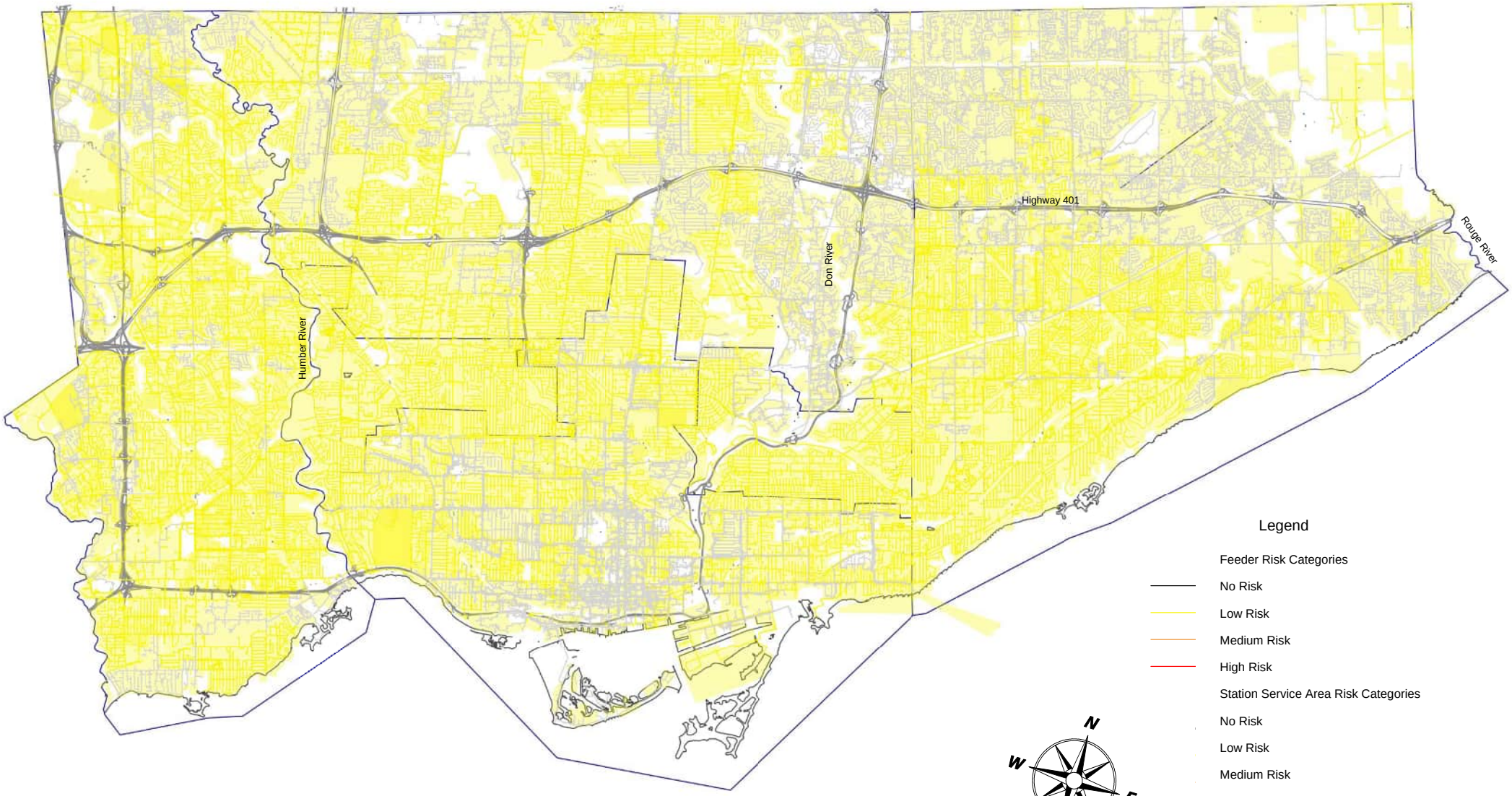
PIEVC Phase 2 Climate Change Risk Map by 2050

15. Tornadoes EF1+



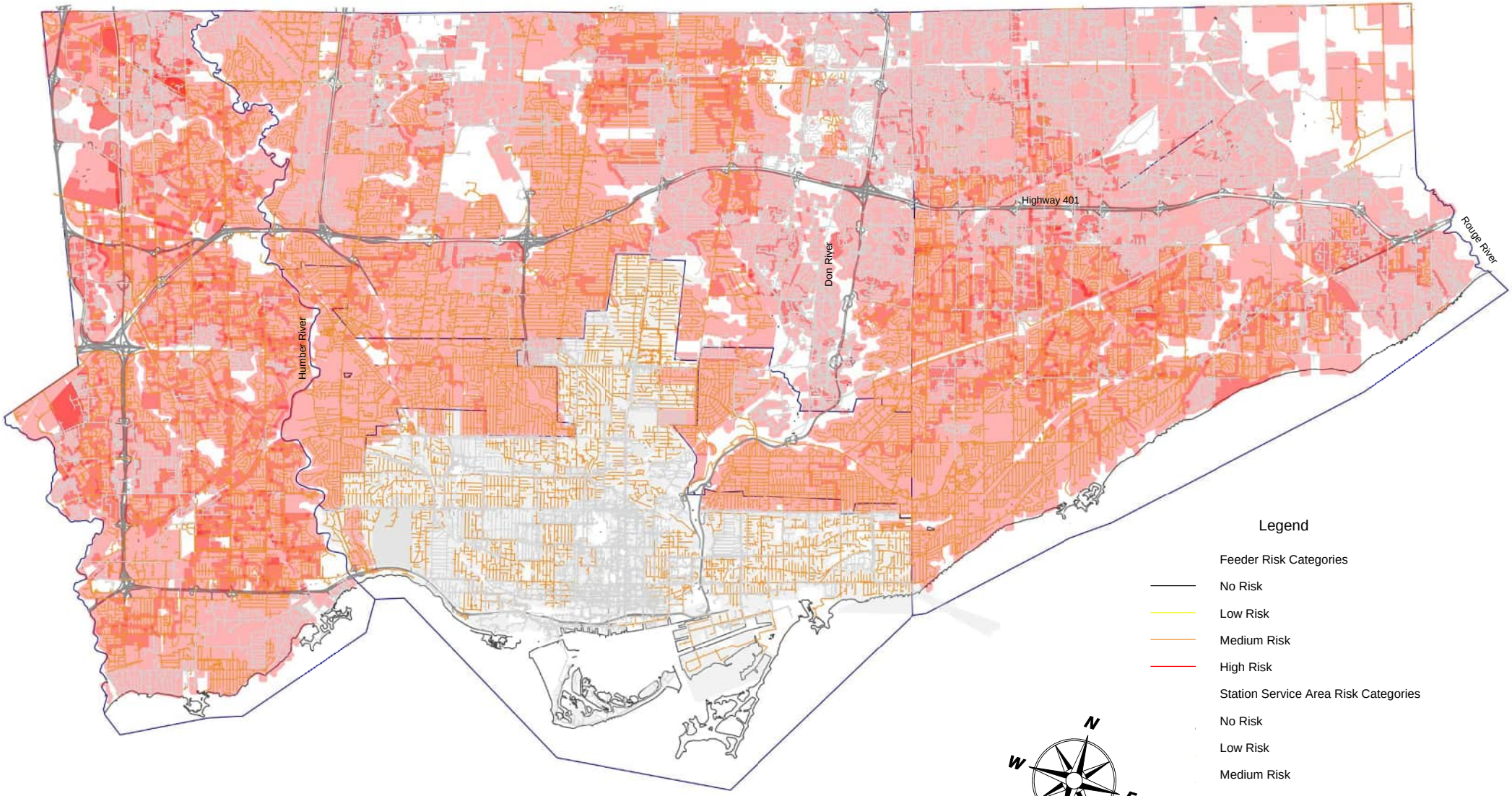
PIEVC Phase 2 Climate Change Risk Map by 2050

16. Tornadoes EF2+



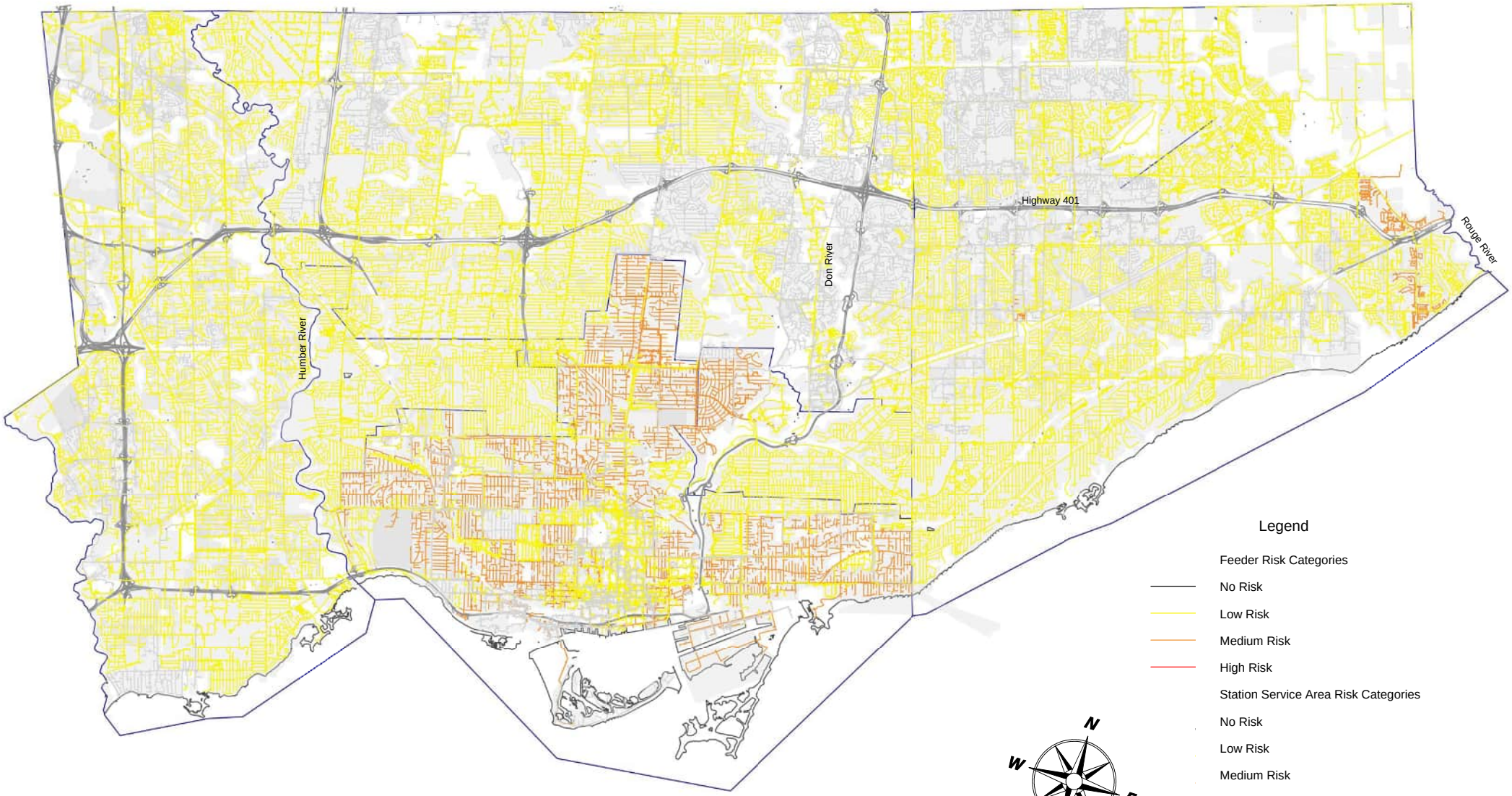
PIEVC Phase 2 Climate Change Risk Map by 2050

17. Lightning



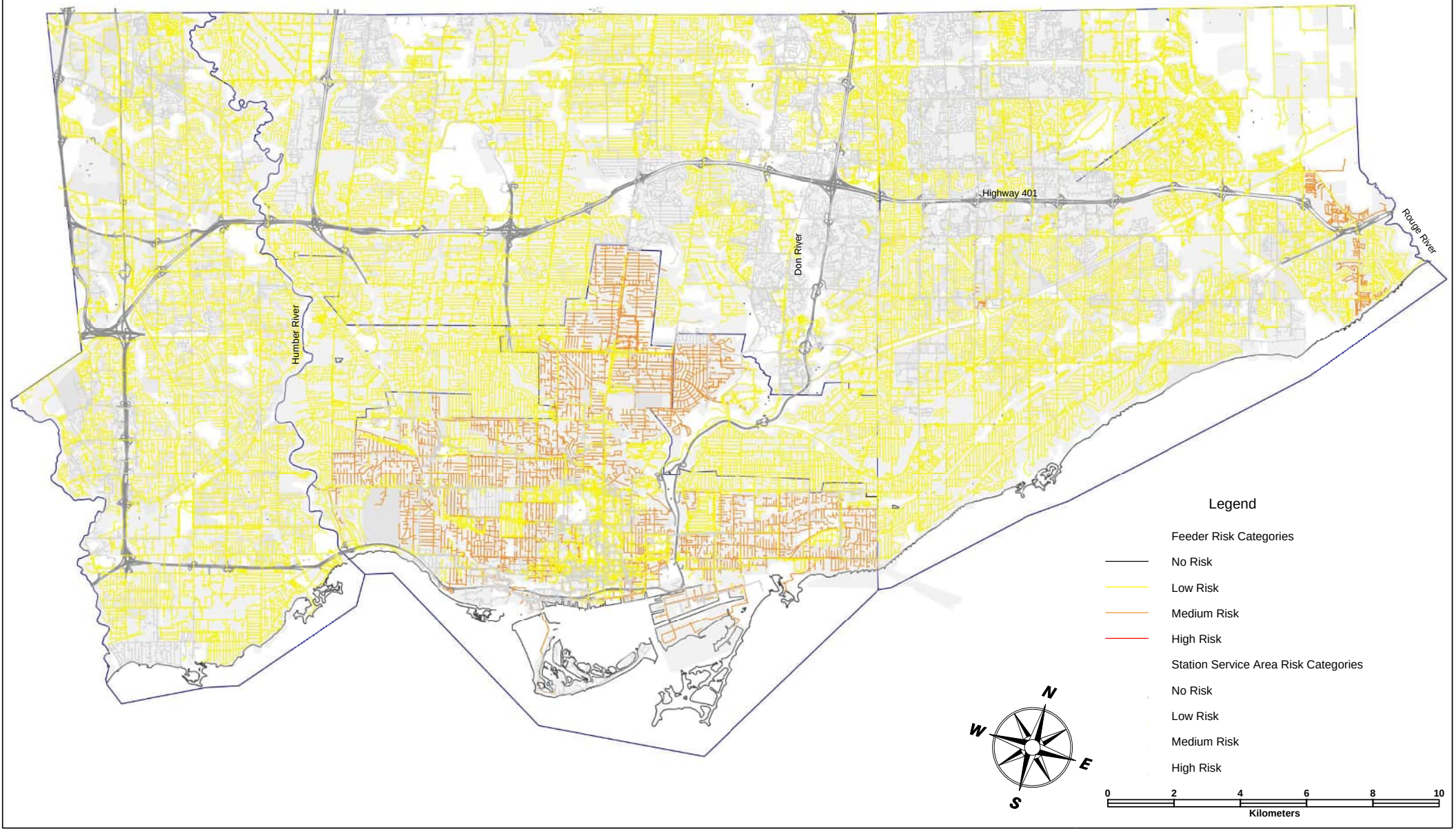
PIEVC Phase 2 Climate Change Risk Map by 2050

18. Snow >5cm



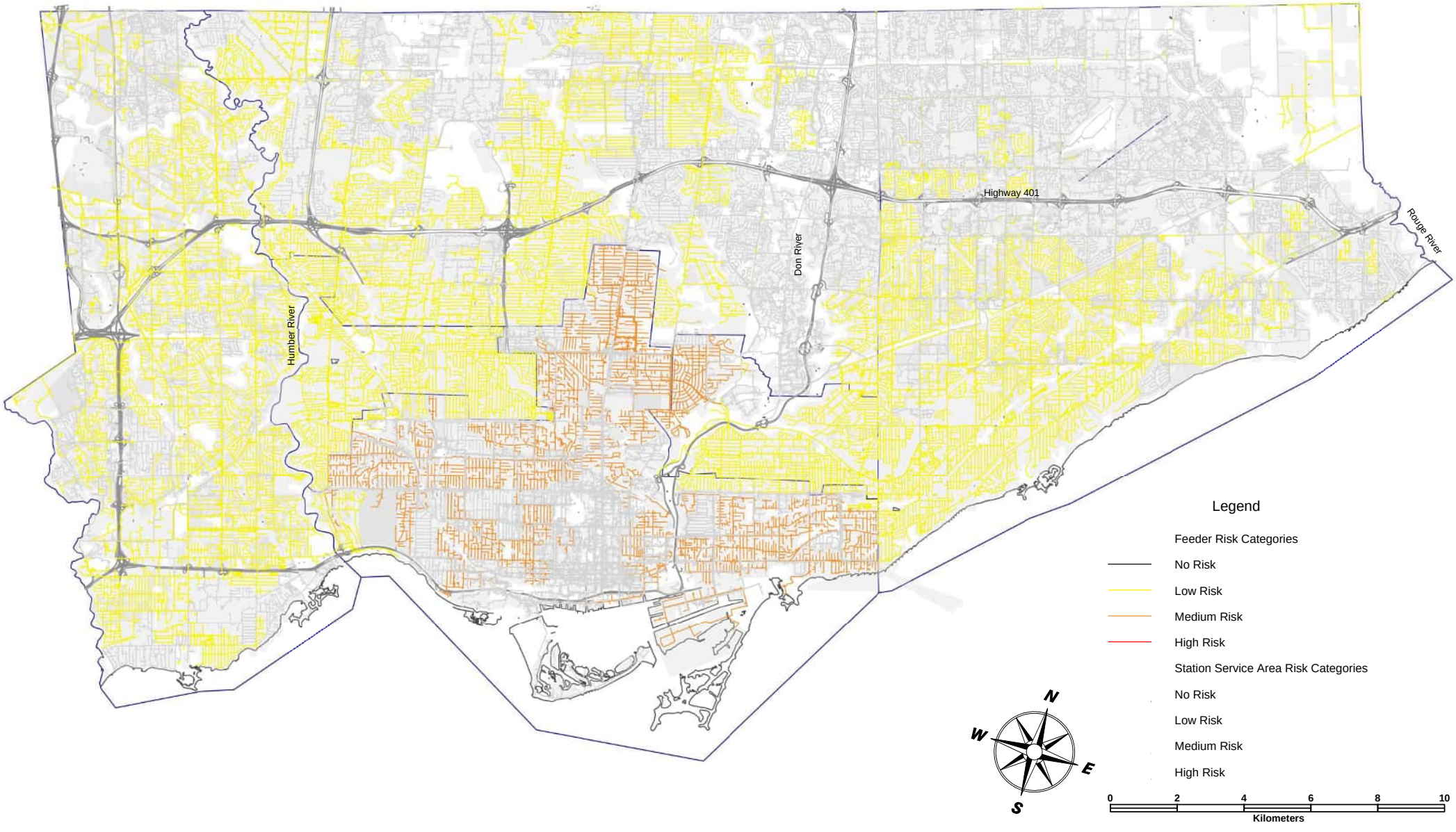
PIEVC Phase 2 Climate Change Risk Map by 2050

19. Snow >10cm



PIEVC Phase 2 Climate Change Risk Map by 2050

20. Extreme Cold Weather



Appendix F
Load Projection Methodology – Toronto Hydro

This information has been removed from the public version of this report

Appendix G
Engineering Analysis

Worksheet 4

The following appendix provides details about the estimation and calculation of the various load and capacity factors used in the Engineering Assessment of medium risk climate/infrastructure interactions. AECOM has elected to present this material in the following section in lieu of worksheet 4 template of the PIEVC Protocol.

1.1 Engineering Analysis Method

The engineering analysis is presented according to the following structure:

1. # Climate parameter / infrastructure system or component

Results and consequences: a recapitulation of the risk scoring results (scores range from 1 to 49) and consequences from Protocol Step 3, risk assessment activity

Task 1: Total Load: The total projected load, L_T, is the sum of three load parameters, $L_E + L_C + L_O$
- L_E = Existing load.
- L_C = Changing climate load placed on the infrastructure components for the project time horizon (2030 – 2050).
- L_o = Other projected change loads.

Task 2: Capacity: The total projected capacity, C_T is the sum of three parameters, $C_E - C_{\Delta E} + C_A$
- C_E = Existing capacity.
- $C_{\Delta E}$ = Projected change (loss) in capacity arising from aging and normal wear and tear of the infrastructure components
- C_A = Other projected additional capacity

Task 3: Vulnerability ratio: When possible, the vulnerability ratio is calculated

$$V_R = \frac{L_T}{C_T}$$

→ When $V_R > 1$, the infrastructure component is vulnerable

→ When $V_R < 1$, the infrastructure component has adaptive capacity

Task 4: Capacity Deficit: When the infrastructure is considered vulnerable, the projected capacity deficit, C_D is calculated, where possible. $C_D = L_T – C_T = L_T – (C_E + C_{\Delta E} + C_A)$

Task 5: Conclusions from the Engineering Analysis: A statement is made as to whether the climate parameter-infrastructure interaction should be passed to Step 5 of the Protocol (i.e. making a recommendation to mitigate a vulnerability) or need not be considered further due to resilience to climate change.

When the engineering analysis cannot be completed, data gaps and possible types of additional studies are described that would facilitate the assessment of infrastructure vulnerability.

1.2 Resiliency or Vulnerability Evaluation

1. High temperature above 25°C and above 30°C / Transmission and Municipal stations and all Temperatures / Protection and Control systems

- **Results and consequences**: Risk scores of 14 and 21 depending on station excess capacity rating. Batteries lifespan is reduced. They are vital components because they are used as back-up power in case of power outages and emergencies and supplied DC current to many equipment in the stations.

- **Load**

L_E = Continuous loads (e.g. lighting) + Noncontinuous loads (e.g. fire protection systems) + Momentary loads (e.g. switchgear operations). A margin of 10-15% can be applied by the designer. Also the battery's rated capacity should be at least 125% (1.25 aging factor) of the load expected of its service life (IEEE-Std-485, 1997).

L_C: Same loads will apply. Ventilation may be a little bit higher because of higher temperatures but the load will not change drastically.

L_o: No other load to consider

$L_T = L_E + L_C + L_O = L_E + xL_E + 0$, where x is very small. Approximation: $L_T = L_E$

- **Capacity**

C_E: The batteries are designed to operate at a temperature of 25°C. They are not installed in a temperature controlled room.

C_E capacity at 25°C = 100%. Expected service life = 25 years
The end of life of a battery is considered to be at 80% of its capacity (IEEE 485).

$C_{\Delta E}$: Battery capacity at higher temperatures will actually increase if the cells are designed for a capacity of 100% at 25°C. From IEEE (IEEE-Std-485, 1997), "If the lowest expected electrolyte temperature is above 25 °C (77 °F), it is a conservative practice to select a cell size to match the required capacity at the standard temperature and to recognize the resulting increase in available capacity as part of the overall design margin". However, sustained high ambient temperatures result in reduced battery lifetimes.

$C_{\Delta E}$ capacity over 25°C: more than 100%. Expected Service life will be less than 25 years. From Toronto Hydro's experience, some batteries have only lasted 10 years when they were expected to last 25 years.

C_A: Battery designs are maintained at 100% capacity at 25°C.

$C_T = C_E - C_{\Delta E} + C_A = C_E – (-xC_E) + 0 = (1+ x)\ C_E$, but expected lifetime decrease.

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{Le}{(1+x)Ce} < 1\ but\ life\ expenctancy\ decrease$$

- **Conclusion: Yes. Further action recommended.** Under higher temperatures, batteries will continue to be able to supply the necessary power to operate equipment (e.g. lighting, fire protection systems, switchgears). However, battery life may continue to be shorter than expected. Toronto Hydro has already encountered this problem, as batteries with a lifespan of 25 years are being replaced after 10 years.

2. High temperature above 35°C / Transmission stations

- **Results and consequences**: Risk scores of 21 and 28 depending of station excess capacity rating. Power transformers may be overloaded.

- **Load**

L_E = Maximum coincident load (year of design) + % of contingency at ambient temperature of 30°C
The actual peak load of the area is around 5 000 MVA.

L_C = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

L_o = Load will increase caused to higher consumption of clients = bL_E

$L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E$

- **Capacity**

C_E: Horseshoe area station power transformer capacity is considered maximum with 100% of its total capacity at 30°C average ambient, and hottest point within power transformers not exceeding 110 °C. For Former Toronto area, the station capacity is restricted to no more than 95% of its total capacity because there are no station ties among transformer stations.
Expected service life = 20.55 years (180 000 hours).
Toronto Area transmission stations installed capacity is around 7 550 MVA.

$C_{\Delta E}$: x%, where x is less than 100. According to IEEE (IEEE-Std_C57.91, 2012) the associated maximum air temperature should not be more than 10°C above the average ambient air temperature for air-cooled transformers (40°C). Station capacity at higher temperatures (e.g. 35°C) will be lower than at design temperature (30°C ambient) because the hottest point within power transformers has to be maintained below 110°C. Same expected service life if the load is adjusted (i.e. decreased) to meet these temperature restrictions. There x% at maximum temperatures above 35°C will not be large.

C_A: Additional capacity will depend on the station. Some transmission stations will have added capacity by the end of the study period due to planned or anticipated upgrades, while others will not. The added capacity was evaluated within the risk assessment. “Good” rating mean that the transmission stations will have a greater future capacity margin, while “moderate” and “low” ratings mean stations will have less of a future capacity margin. From an overall systems standpoint, the worst case scenario is equivalent to no additional capacity added.

$C_T = C_E - C_{\Delta E} + C_A = C_E – (xC_E) + 0 = (1 - x)\ C_E$ = Approximation $C_T \approx C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1 + a + b)Le}{Ce} = \frac{Load\ growth\ rate\ \times 5000\ MVA}{7550\ MVA}$$

Value of (1+ a + b) = Toronto Hydro could estimate a mean load growth rate for the study period.

- **Capacity deficit**

$C_D = L_T – C_T = (1 + a + b)\ L_E – (1-x)\ C_E$.

The capacity deficit can’t be calculated because the load growth rate for the study period is not known.

- **Conclusion: Additional study recommended, conclusions for high temperature and power transformers also apply (see Chapter 7).** Transmission station designers will need to take into account the significant increase in days with maximum temperatures above 35°C, which reduces station capacity while, on the other hand, experiences an increased load demand. At the moment, no load growth rate for the period of this study was estimated. This could be calculated in further studies. The recommendations given in Chapter 7 for transmission stations and maximum temperature above 40°C / average temp above 30°C apply to this interaction.

3. High temperature above 40°C and Average temperature > 30°C / Transmission stations

- **Results and consequences**: risk score of 35 for transmission stations which have good future capacity (excess capacity) in the Horseshoe Area. Transmission stations with low future capacity ratings scored a high risk. Power transformers will be overloaded.

- **Vulnerability Ratio:** Refer to parameter #2.

- **Conclusion: Further action recommended**. Most of the transmission stations considered in this study were judged to be vulnerable (high risk rating) to high temperatures. The stations in the Horseshoe received a medium-high risk score (35) due to the application of the concept of excess capacity, which is qualitative and notional (refer to the **Appendix F**). As such, it is recommended that transmission stations receiving a medium-high risk score be considered vulnerable to extreme high temperatures as part of a consistent pattern of risk. This will also help Toronto Hydro to adopt a consistent approach in the design, operations and maintenance of stations.

4. Heat wave (+30°C) and High nighttime temperatures (+23°C) / Transmission stations

- **Results and consequences**: risk rating of 21, 28 and 35 depending of station capacity rating by 2050. Power transformers may be overloaded.

- **Load**

L_E = Maximum coincident Load (year of design) + % of contingency at ambient temperature of 30°C

L_C = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

L_o = Load will increase caused to higher consumption of clients = bL_E

$L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E$

- **Capacity**

C_E: Horseshoe area station power transformer capacity is considered maximum with 100% of its total capacity. For Former Toronto area, the station capacity is restricted to no more than 95% of its total capacity because there are no station ties among transformer stations.
Expected service life = 20.55 years (180 000 hours).

$C_{\Delta E}$: x%, where x is lower than 100. Power transformers can operate at temperature above 30°C, but long periods of high temperature can affect the equipment, such as when night time temperatures are high. The power transformer has no time to cool.

C_A: Additional capacity will depend on the station. Some transmission stations will have added capacity by the end of the study period due to planned or anticipated upgrades, while others will not. The future capacity was evaluated within the risk assessment. “Good” rating mean that the transmission stations will have a greater future capacity margin, while “low” rating means stations will have less of a future capacity margin. From an overall systems standpoint, the worst case scenario is equivalent to no additional capacity added.

$C_T = C_E - C_{\Delta E} + C_A = C_E – (xC_E) + 0 = (1 - x)\ C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1 + a + b)Le}{(1 - x)Ce} = \frac{Load\ growth\ rate\ \times 5000\ MVA}{(1 - x)7550\ MVA}$$

Value of (1+ a + b) = Toronto Hydro could estimate a mean load growth rate for the study period.

Value of (1-x) = The loss of capacity is highly variable. It will not only depend of the maximum temperatures but also of the minimum temperatures. If the minimum temperature stays high during many days the power transformers will have no time to cool and its capacity will have to be reduced. High nighttime is important in that sense.

- **Capacity deficit**

$C_D = L_T – C_T = (1 + a + b) L_E – (1-x) C_E$.

The capacity deficit cannot be calculated because the load growth and the loss of capacity are not known.

- **Conclusion: Additional study recommended, conclusions for high temperature and power transformers also apply (see Chapter 7).** Consecutive days with high temperatures and high night time will increase over the study period. For example, high nighttime temperatures will go from 0.7 day/year to 7 days/year in 2030 to 16 days/year in 2050. Power transformers are vital equipment in the distribution of electricity and high temperatures have a significant impact on the capacity of the transformers. For these reasons, the conclusion of this report for temperature above 40°C and for high daily average temperature>30°C are also relevant to the heat wave and high nighttime temperature parameters. A load growth rate could be calculated for a better evaluation of impacts.

5. Freezing Rain/Ice Storm 60 mm ≈ 30 mm radial (major outages) / Transmission stations and Municipal stations

- **Results and consequences**: risk rating 28
  Outgoing lines (overhead) could fall down

- **Load**

L_E = Actual load is equal to the actual number of days of freezing rain

L_C = The load due to the freezing rain will slightly increase, **$L_C = aL_E$,** where ''a'' is a % of increase (small)

L_o = N/A

$L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E \rightarrow L_T > L_E$

- **Capacity**

C_E: The overhead power lines in the Toronto area are designed based on the CSA standard 22.3. Loads and load combinations correspond to so-called "Heavy Loading" specified in Table 30 of the CSA standard: wind of 400 Pa, 12.5 mm ice, -20°C temperatures.

$C_{\Delta E}$: It is assumed that the capacity will remain the same if the design criteria are not changing. **$C_{\Delta E} = 0$**

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A = C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{Ce} > 1$$, the infrastructure is vulnerable

- **Capacity deficit**

$C_D = L_T – C_T = (1 + a) L_E – C_E$.

- **Conclusion: Further action recommended.** The probability of occurrence of a heavy freezing rain event of 60 mm is relatively low in the future (8 – 25% probability of occurrence over the 35 year study period). However, this this interaction is part of a similar pattern of vulnerability as 25 mm freezing rain events (design capacity). Therefore, solutions for 25 mm events also relevant to mitigating heavy freezing rain events of ~ 60 mm.

6. High temperature (+35°C,+ 40°C, average temperature > 30°C, heat wave, high nighttime temperatures) / Municipal stations

- **Results and consequences**: 21, 28, 35. Medium to high medium risks.
  Consequences: Power transformers may overload.

- **Load & Capacity:** Same assumptions as for the power transformers in the transmission stations.
  The load will increase because of warmer temperatures. The capacity will decrease because of power transformers low ability to withstand hot temperatures for extended periods.
  Added capacity: Many Toronto Hydro to Toronto Hydro stations which interconnect the 4.16 kV power lines, will progressively be replaced by converted lines at 13.8 kV. Most of the municipal stations will then be to interconnect voltage levels from 27.6 kV to 13.8 kV. It is assumed that added capacity during the study period will be low for the 27.6-13.8 kV / 4.16 kV stations. More capacity can be added to the 27.6 kV/13.8 kV stations and will be variable depending on the stations need.
  For Toronto Hydro to Private owner ship, added capacity is possible and will be very variable depending on Client's need.

  $L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E$
  $C_T = C_E - C_{\Delta E} + C_A = C_E – (xC_E) + yC_A$ where x is variable and y is small and variable$\rightarrow C_T < C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a+b)Le}{\mathrm{CE} - (\mathrm{xCE}) + \mathrm{yCA}} < 1$$

- **Conclusion: Further action recommended**. High temperature and combinations of high temperature, high average temperature, high nighttime temperature and high load demand will have consequences on the capacity of the power transformers and the cables. For Toronto Hydro to Private ownership stations, a case by case evaluation is recommended.

1.2.1 Underground and Overhead feeders

7. High temperature maximum above 35°C & above 40°C, average temp >30°C, heat wave and high nighttime / Underground feeders

- **Results and consequences**: risk ratings 14, 21 and 28. The high demand stresses cables and power transformers. More capacity was available in the horseshoe area giving slightly lower results.

- **Load**

L_E = Actual demand + % of contingency

L_C = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

L_o = Load will increase because of higher electrical consumption of clients (more electronic devices) = bL_E

$L_T = L_E + L_C + L_O$

- **Capacity**

C_E: Actual design of cables and power transformers is based on the actual load plus a margin. For underground feeders in the dual radial system, feeder capacity equals 50% of load for two parallel feeders. IEC 60287 base maximum ambient temperature at 35°C and maximum ground temperature at 20°C (IEC-60287))

$C_{\Delta E}$: XLPE cables have an expected life of 40 years (for concrete duct installations) and for PILC cables 75 years. These cables are today reaching their expected life because they were installed during the early 1900s (for PILC)

and 1950s (for XLPE). They will be changed through testing or from failure, because even if the cables are old they could be still being in good conditions (Toronto Hydro - OM&A, 2014). However, with climate changes (higher temperature), these cables will be stressed more often. Aging processes will accelerate and reduce capacity. This is a highly variable factor and cannot easily be calculated.

C_A: Added capacity will be done by Toronto Hydro. Underground planning group could estimate the projected capacity for the study period.

$C_T = C_E - C_{\Delta E}$? + C_A

- **Conclusion: Further action recommended.** The vulnerability ratio and the capacity deficit cannot be calculated because the projected load on cables is not known. However, it is projected that climate change related high temperatures could create higher demand for cooling, and may place greater stress on cables and lead to increasing occurrences of cable failures. Therefore, high heat impacts on cable was deemed to be a vulnerability.

8. Extreme rainfall / Underground feeders

- **Results and consequences**: risk rating of 12, 18, 24, 30
    a. Feeders: Water treeing of the cables, flooding (18-24);
    b. Nun-submersible equipment failure in vault type stations below ground (30 Horseshoe Area, 36 Former Toronto);
    c. Above ground stations, access could be limited (12);
    d. Network feeders: old N/W protectors are not submersible (30).

a. Feeders: Water treeing of the cables, flooding (18 Horseshoe Area, 24 Former Toronto)

Water treeing refers to a partially conductive structure that may form, in the presence of water, within the polyethylene dielectric used in buried high voltage cables. […] Water trees begin as a microscopic region near a defect. They then grow under the continued presence of a high electrical field and water. Water trees may eventually grow to the point where they bridge the outer ground layer to the center high voltage conductor, leading to complete electrical failure at that point (Wikipedia).

- **Load**

L_E = Actual demand + % of contingency

L_C = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

L_o = Load will increase due to higher electrical consumption by clients (more electronic devices)= bL_E

$L_T = L_E + L_C + L_O$

- **Capacity**

C_E: Actual design of cables is based on the actual load plus margin. For the underground feeders in the dual radial systems, each feeder capacity is equal to the load x 2.

$C_{\Delta E}$: Flooding and heavy soil moisture tends to reduce the dielectric strength of cables. This cannot be calculated as it is highly variable. *The aging mechanism of underground cables depends on factors that involve the cable characteristics, accessory characteristics, and operating conditions, different power cable systems will age in different ways. In fact, aging degradation, and failure mechanisms are statistical in nature.* (NEETRAC, 2010)

C_A: Toronto Hydro shall have a planning procedure for increasing the capacity of their underground system in line with load growth.

- **Conclusion: Further action recommended.** The load can be calculated by Toronto Hydro's estimates. However, the capacity is very hard to define, as aging degradation depends on many factors. Nonetheless, in combination with high heat events, extreme rainfall impacts on underground cables was deemed a vulnerability.

b. Non-submersible equipment failure in vault type stations below ground in the Horseshoe Area (30) (Former Toronto has a high risk result)

- **Load**

$\mathbf{L_E}$ = 0.04 flood per year (over 100 mm + short duration).

$\mathbf{L_C}$ = 0, flood intensity is considered to be the same for a given event (100 mm rainfall), but it will occur with greater frequency. Another complicating factor is how local drainage conditions (area topography, sewer system changes, land use changes) may or may not change flood characteristics in below ground vaults. At the scale of the current study, site specific flooding characteristics are not considered.

$\mathbf{L_o}$ = N/A

$\mathbf{L_T = L_E + L_C + L_O} = L_E$.

- **Capacity**

$\mathbf{C_E}$: Cannot work when flooded. Most of the vaults have pumps when they are deeper than the city sewers. Small shallow single phase vaults drain naturally to the sewers. Pumps usually work well. There is no specific information available on the capacity of the pumps, but they are assumed to function correctly, as there are no indications that pump capacity needs to increase.

$\mathbf{C_{\Delta E}}$: same as today. $C_{\Delta E} = C_{E1} - C_{E2} = 0$.

$\mathbf{C_A}$: No additional capacity required.

$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E}$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{Le}{Ce} = 1$$

Conclusion: Further action recommended. Without replacement of non-submersible equipment by submersible equipment, the performance of electrical equipment in below grade vaults will not change over time (i.e. non-functional when flooded) The planned conversion of non-submersible equipment to submersible types in flood prone areas will help reduce vulnerability. While Toronto Hydro is gradually replacing vault type non-submersible equipment with submersible versions, non-submersible vault type equipment is likely to remain in the system over the study period, and hence remain a vulnerability for Toronto Hydro.

c. Above ground stations, access to the station and to the station equipment could be limited due to localized flooding of streets around the station, or at the station itself

- **Results and consequences** Low –medium risk.

- **Conclusion: No further action required.** This impact does not relate to station load or capacity. The consequence is that the access to the vault stations or the stations equipment could be temporarily impeded. Impact is localized and temporary, and was not judged to warrant further action beyond current practices.

d. Network feeders: old N/W protectors are not submersible (30)

- **Conclusion: Additional Study Recommended.** The old N/W protector may not operate properly if flooded. A network protector automatically connects and disconnects its power transformer from the network when the protector relay detects that power starts flowing in a reverse direction, preventing back feed, which is a potential safety hazard. However a failure of the N/W protector will not mean an interruption to the customer, since network systems are highly redundant. Network protectors are overhauled on a three-year cycle.

  Installations of new N/W protectors are submersible but there are still many old N/W protectors in the systems, particularly in downtown. Further study could be undertaken to evaluate the cost of replacing old network protectors prior to the end of their expected lifecycle against the frequency and impact of old N/W protectors being flooded.

9. High winds (120 km/h) / Padmount stations on distribution network (Former Toronto)

- **Results and consequences**: risk rating 14. Flying debris could impact the equipment.

- **Vulnerability Ratio:** The consequence of high winds and structural loads from flying debris are difficult to establish in terms of the load and the capacity of padmount stations. It's an independent impact based on a statistical probability.

- **Conclusion: No further action required.** The damaged equipment will result in an overall or some loss of service capacity and function. However, it is judged that flying debris is too much of a random occurrence to warrant further action.

10. High temperature maximum above 35°C & above 40°C, average temp >30°C and heat wave / Overhead power lines (radial and loop)

- **Results and consequences**: risk ratings of 14, 21, 28, 35
  These 4 climate parameters have the same consequences: Overload of the ONAN power transformers and the overhead conductors.

- **Load**

$\mathbf{L_E}$ = Max load + % of contingency

$\mathbf{L_C}$ = Load will increase because temperature is higher, demand will be higher (air conditioning) = aL_E

$\mathbf{L_o}$ = Load will increase because of load growth due to population growth = bL_E

$\mathbf{L_T = L_E + L_C + L_O = L_E + aL_E + bL_E = (1+a+b)L_E \rightarrow L_T > L_E}$

- **Capacity (ONAN power transformers)**

$\mathbf{C_E}$: 100% at 30°C average ambient + hottest point within transformer not exceeding 110 °C.

$\mathbf{C_{\Delta E}}$: x%, where x is lower than 100. Capacity at higher temperature will decrease, because the hottest point has to be kept under 110°C.[1]

$\mathbf{C_A}$: Additional capacity can be added by adding more power transformers on the lines.

$\mathbf{C_T = C_E - C_{\Delta E} + C_A = C_E – (xC_E) + C_A = (1 - x)\ C_E + C_A}$

- **Capacity (overhead conductors)**

[1] For example: temperature of 40°C during 10 hours, the average load should not excess 80-85% of the nominal kVA.

C_E: 100% at 75°C for ACSR conductors and 25°C ambient (manufacturers' limits).
Effects of high temperature can results in the annealing[2] of aluminum used within ACSR and AAC conductors. This effect begins at 93°C for these types of conductors, and is a function of the magnitude of the temperature and the duration of the application (electrical power flow).

$C_{\Delta E}$: x%, where x is lower than 100. The added combination of high temperature and higher current flow will significantly reduce the capacity of the conductors.
Other impacts: loss of strength due to annealing, increase in sag.

C_A: Capacity can be added by using other or larger types of conductors. However, in some place it could be difficult to do so as it would means to redesign the existing lines and may result, for example, in the replacement of existing poles by stronger ones generating high costs.

$C_T = C_E - C_{\Delta E} + C_A = C_E – (xC_E) + C_A = (1 - x)\, C_E + C_A$.

The reduction of the capacity is difficult to calculate because of the great diversity of operating circumstances and loading of the entire system. However, calculations for critical areas, where added capacity can be difficult to do, should be done.

- **Vulnerability Ratio:** Cannot be calculated because too many variables are not known.

- **Conclusion: Further action recommended.** Higher temperatures will have impacts on the overall capacity of the power lines. In the downtown area, there are critical, constrained areas (i.e. built up zone) where added conductor/transformer capacity may be difficult to implement.

11. High nighttime temperatures / Overhead power lines (radial)

- **Results and consequences:** risk rating 14
  Overload of the ONAN power transformers

- **Load and Capacity:**
  Refer to the previous evaluation. However, the capacity of the power transformers will not be reduced as much as for higher daily maximum temperature. Therefore, $C_E = xC_E$, with x as a small value.

  High nighttime temperatures have consequences on the capacity of the power transformer to cool enough before being loaded the next day. Climate projections show a significant increase in the number of days with low night time temperatures ≥ 23°C. The actual design of power transformers can support this temperature limit. As such, this impact was judged as low.

- **Conclusion: No further action required.** Night time temperatures with minimum ≥ 23°C will not have big impacts on the delivery of electricity. However, it is important to note that combination events of high daily temperature and high night time temperature are a concern. This is taken into account under the parameter, average temperature over 30°C on a 24 h basis.

12. Freezing Rain - Ice Storm 15 mm and high winds 70 km/h / Overhead Feeders in Loop Configuration

- **Results and consequences**: risk ratings of 28, 35 Conductors (tree contacts).

- **Load:**

[2] Annealing is the metallurgical process where applied temperature softens hardened metal resulting in loss of strength. For overhead conductors, annealing can degrade the strength of aluminum wires used in ACSR and AAC conductors (PJM Overhead conductor Ad Hoc Committee, 2010)

L_E = the actual load is based on tree branches that usually start to break with a 15 mm of freezing rain.

L_C = freezing rain of 15 mm will happen a little bit more often for the study period (from 0.11/year to 0.12/year to 0.16/year). Hypothesis $L_C = L_E$

L_o = N/A

$L_T = L_E + L_C + L_O = L_E$.

- **Capacity :**

C_E: Actual overall ''capacity'' of the tree canopy in Toronto.

$C_{\Delta E}$: $C_{\Delta E} = C_{future} < C_E$. The future overall ''capacity'' will decrease (or vulnerability to damage will increase) because of new or exacerbated disease and pest conditions and possibly, because of the tree faster growth (extended growing season, more branches).

C_A: N/A

$C_T = C_E - C_{\Delta E}$

- **Vulnerability Ratio**
  - $VR = \frac{Lt}{Ct} = \frac{Le}{Ce - C\Delta E}, where\ \frac{Le}{Ce} = 1, as\ Ce - C\Delta E$ is smaller, V_R will be >1

- **Capacity deficit**

$C_D = L_T – C_T$ = It cannot be calculated because the future capacity of the trees is not known.

- **Conclusion: Further action recommended.** The risk assessment completed in step 3 for radial systems resulted in a high risk rating for this interaction. In overhead loop systems, it was hypothesized that their more redundant configuration would reduce customer interruptions, affect fewer clients or cause outages of shorter durations, thus yielding a high-medium risk rating of 35. However, freezing rain events are expected to occur slightly more often than it does currently by the end of the study horizon. The tree canopy may also be affected by new or increased disease threats and extended growing season. Conductors will also sag more due to more extreme weather (ice, warm weather, etc.) leading to more contacts with the tree branches. According to THESL (Toronto Hydro - OM&A 2014): "*Vegetation interference is one of the most common causes of power interruption"*. Finally, freezing rain events tend to be widespread, and there is no reason to believe that both branches of an overhead loop circuit might not be equally susceptible to damage. For all of these reasons, all overhead power lines, irrespective of electrical configuration, were deemed as vulnerable.

13. Freezing Rain/Ice Storm 60 mm ≈ 30 mm radial (major outages) / Overhead lines (radial and loop)

- **Results and consequences**: risk rating 24, 28
  Overhead lines could fall down, salt contamination

- **Load**

L_E = Actual load is equal to the actual number of days of freezing rain

L_C = The load due to the freezing rain will slightly increase, **$L_C = aL_E$,** where ''a'' is a % of increase (small)

L_o = N/A

$L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E \rightarrow L_T > L_E$

- **Capacity**

C_E: The overhead power lines in the Toronto area are designed based on the CSA standard 22.3. Loads and load combinations correspond to so-called "Heavy Loading" specified in Table 30 of the CSA standard: wind of 400 Pa, 12.5 mm ice, -20°C temperatures.

$C_{\Delta E}$: It is assumed that the capacity will remain the same if the design criteria are not changing. $C_{\Delta E} = 0$

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A = C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{Ce} > 1$$, the infrastructure is vulnerable

- **Capacity deficit**

$C_D = L_T - C_T = (1 + a)\, L_E - C_E$.

- **Conclusion: Further action recommended.** See explanation for freezing rain and stations (item 5 above).

14. Lightning / Overhead power lines (radial and open loop) and SCADA system

- **Results and consequences**: risk rating of 18, 24, 30, failure of equipment (localized).

- **Vulnerability Ratio:** In this case, the impact comes from a direct or indirect strikes and has no consequences on the load and capacity of the infrastructure.

- **Conclusion: Further action recommended.** It is difficult to predict the increase of lightning strikes for the study period; however it is interesting to note that the probability of a lightning strike in an area of 0,015 km^2 anywhere within the City of Toronto is very high for the study period. At the moment, the number of arrestors/km, lightning strike intensity and arrestor performance are not monitored by Toronto Hydro. In the absence of this information, and since lightning strikes are currently a frequent source of outages, lightning strikes were judged to be a continued vulnerability. Further studies could evaluate if the actual protection of overhead power lines is sufficient, or if investments for more protection needs to be made. Direct strike impacts can be studied with software (e.g EMTP), while indirect strikes can be calculated numerically.

15. Snow > 5 cm and Snow > 10 cm / Overhead power lines (radial)

- **Results and consequences**: risk ratings of 14, salt deposited on the roads can also accumulate on insulators from water evaporation and transport through the air, and can create a failure (reduce the effective insulation levels and can lead to insulator tracking, flashover and potential pole fires or switch with porcelain insulator failure).

- **Vulnerability Ratio:** In that case, the impact is indirect and has no consequences on the load and capacity of the infrastructure.

- **Conclusion: No further action required.** The number of snow days is highly variable. The trend seems to be decreasing, but snow days will still occur annually. During the workshop, Toronto Hydro mentioned having problems regarding insulator tracking leading to pole fires especially at higher voltages (13.8 kV and 27.6 kV) and switch failures. However, Toronto Hydro is already monitoring and dealing with this issue. From THESL's report (Toronto Hydro - OM&A 2014): *to mitigate the risk of contamination and insulator tracking, insulators at the highest risk locations are washed twice a year.* Furthermore, recall that porcelain insulators are being

progressively replaced by polymer insulators. *Polymer insulators are hydrophobic, and are not susceptible to the same failure mode due to contamination. […] Regular maintenance enables the detection and prediction of common failure modes. One such mode is the failure of switch's porcelain insulators. […] Porcelain switches pose high safety risks due to their susceptibility to contamination build-up and electrical tracking, which can lead to cracking […] posing a safety risk to employees or members of the public below.* As older porcelain insulators are being replaced by polymer insulators, it was judged that no further action than what is currently underway is required.

1.2.2 Civil structures

16. Extreme Rainfall, Freezing rain/Ice storm 15 mm & 25 mm & 60 mm (Combination of events) / Civil structures: Underground feeders (Former Toronto)

- **Results and consequences**: risk rating of 12, 14
  Accelerated corrosion of reinforcing bars and degradation of concrete in cable chambers and vaults.

- **Load**

L_E = Currently, civil structures (cable chambers, vaults) degrade at a pace related to the actual load (salt and moisture) related to current weather: Extreme Rainfall (100 mm) 0.04/year + Ice Storm (15 mm) 0.11/year + Ice Storm (25 mm) 0.06/year + Ice Storm (6hrs+) 0.65/year.

L_C = In the future, the structures will degrade more rapidly due to the more severe weather:
2030: Extreme Rainfall (100 mm) unknown but increase + Ice Storm (15 mm) 0.12/year + Ice Storm (25 mm) 0.07/year + Ice Storm (6hrs+) 0.73/year.
2050: Extreme Rainfall (100 mm) unknown but increase + Ice Storm (15 mm) 0.16/year + Ice Storm (25 mm) 0.09/year + Ice Storm (6hrs+) 0.94/year.

L_o: No other load.

$L_T = L_E + L_C + L_O = L_E + aL_E = (1+a)L_E$

- **Capacity**

C_E: actual capacity based on design criteria

$C_{\Delta E}$: As vaults are getting older, the capacity of the structures will decrease (approximately 60% of all network vaults will reach their expected life within the next ten years and 80% of network vault roofs and 60% of all cable chamber roofs are already beyond their useful life (Toronto Hydro - OM&A, 2014).

For the purpose of the study, we can then assume that $C_{\Delta E} = aC_E$, where ''a'' equal a percentage of diminution of capacity versus actual capacity

C_A: N/A

$C_T = C_E - C_{\Delta E} + C_A$ = $(1-a)C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1+a)Le}{(1-a)Ce} > 1$$, the infrastructure component is vulnerable

- **Conclusion: Further action recommended.** Vaults and chambers already suffering from degradation issues will deteriorate more rapidly over time. From THESL (Toronto Hydro - OM&A 2014): *As below-grade structures age, the greatest concern becomes structural strength. Structural deficiencies affecting vaults include degradation of concrete and corrosion of supports such as beams and rebar. Once degradation and*

*corrosion sets in, conditions can deteriorate rapidly and in many cases from one season to the next. Of particular concern is the winter season when moisture and water enter in below-*grade *structures, freezes and thaws, and carries with it salt that has been used at grade to melt ice and snow.*

While maintenance can reduce the rate of deterioration, incidence of extreme rainfall, snowfall, freezing rain and the application of road salt will persist throughout the study period and continue to contribute to the premature aging of civil structures. While, it could not be determined in the study whether premature aging of civil structures will be exacerbated by a changing climate, this issue will persist over the study period and is therefore judged as an on-going vulnerability.

17. Snow > 5 cm and Snow > 10 cm / Civil structures: Underground feeders (Former Toronto)

- **Results and consequences**: risk ratings of 14, 21, Degradation of concrete in cable chambers and vaults.
- **Load**

$\mathbf{L_E}$ = Actually the civil structures (cable chambers, vaults) degrade at a rhythm caused by current climate.

$\mathbf{L_C}$ = The ''load'' will probably decrease. $-aL_E$

$\mathbf{L_o}$ = No other load.

$\mathbf{L_T = L_E + L_C + L_O = L_E - aL_E = (1-a)L_E}$

- **Capacity**

$\mathbf{C_E}$: actual capacity based on design criteria

$\mathbf{C_{\Delta E}}$: As vaults age, the capacity of the structures will decrease (approximately 60% of all network vaults will reach their expected life within the next ten years and 80% of network vault roofs and 60% of all cable chamber roofs are already beyond their useful life, (Toronto Hydro - OM&A, 2014)).

For the purpose of the study, we can then assume that $C_{\Delta E} = bC_E$, where ''a'' equal a percentage of diminution of capacity versus actual capacity

$\mathbf{C_A}$: N/A

$\mathbf{C_T = C_E - C_{\Delta E} + C_A} = (1-b)C_E$

- **Vulnerability Ratio**

$$VR = \frac{Lt}{Ct} = \frac{(1-a)Le}{(1-b)Ce}$$, it is not possible to know if a will be < or > b

- **Conclusion: No further action required, but combinations of climates events require additional study.** As days with snow will probably decrease, the snow days alone were not judge to be a significant vulnerability. However, snow days will still occur over the study period, and in combination with extreme rainfall, freezes and thaw, freezing rain, and the continued application of road salt, premature degradation of civil structures was judged to be an ongoing vulnerability for Toronto Hydro.

18. Frost / Civil structures (overhead and underground feeders)

- **Results and consequences**: risk rating of 14, frost heave of civil structures

- **Vulnerability Ratio:** In the future, the ‘’load’’ will reduced as less frost days are expected. However, as vaults and as the foundations for concrete or steel poles age, the capacity of the structures will decrease.

  Conclusion: Further action recommended. Even if the frost threat is decreasing, it is noted that frost penetration will still occur during the study period with occasionally extreme weather. Since, Toronto Hydro already experiences problems with frost and its civil infrastructure, frost impacts were judged to be a vulnerability.

19. All Climate Parameters / Human Resources

- **Results and consequences:** risk ratings of 14 to 28, weather related impacts on safe site access, work conditions and travel

- **Conclusion: Further action recommended.** While occupational health and safety procedures will continue to be in place in the future, human resources will continue to be vulnerable to climate change related weather events due to the need to travel, access, and work on equipment in spite of the weather.

Appendix H
PIEVC Worksheets

Worksheet 1 and 2 have been removed from the public version of this report.

However, information on infrastructure can be found in summary form in Chapter 2 of this report. Climate information can be found in Chapter 3, and in Appendix B and Appendix C of this report.

Worksheet 3 information can be found in Appendix D.

Worksheet 4 information can be found in Appendix G.

Worksheet 5 information is contained within Chapter 7 of this report.

D3 Asset Lifecycle Optimization

Exhibit 2B, Section D1 provided an end-to-end overview of Toronto Hydro's distribution system Asset Management System ("AMS"), from strategic planning, to execution and reporting, including the translation of corporate and stakeholder requirements into asset performance and asset management capability objectives. Section D2 provided an overview of the current state of the major distribution assets that the utility manages based on asset demographics, system configurations and various observable features of Toronto Hydro's distribution service area. Section D3 focuses on key factors that guide and influence investment pacing and prioritization decisions within the AM Process.

- **Section D3.1** provides an overview of the replacement, refurbishment, and maintenance approaches that Toronto Hydro applies to major asset classes to optimize the value derived from individual assets over their lifecycles. These asset lifecycle optimization practices are the fundamental building blocks for asset management and investment planning at Toronto Hydro;
- **Section D3.2** describes the ways in which the utility considers and manages failure risk in its AMS. Risk management takes various qualitative and quantitative forms and is fundamental to deriving expenditure plans that support the optimization of future outcomes within a constrained budget;
- **Section D3.3** describes the ways in which the utility considers and manages capacity risk in its AMS; and
- **Section D3.4** describes the expenditure program planning process that Toronto Hydro uses to derive a capital expenditure plan from its AMS.

For an overview of how the practices discussed in this section informed Toronto Hydro's 2025-2029 Capital Expenditure Plan for system-related investments, see Exhibit 2B, Section E2.2.

D3.1 Asset Lifecycle Optimization Practices

As noted in Exhibit 2B, Section D1, the broad objective of Toronto Hydro's AMS is to realize sustainable value from the organization's assets for the benefit of customers and stakeholders. At the most fundamental level, this value is realized by consistently implementing prudent lifecycle optimization practices tailored to specific asset classes. These practices serve as guidelines for when

and how to inspect and intervene on a specific asset, where intervention includes asset maintenance, refurbishment, and replacement.

Toronto Hydro's lifecycle optimization practices are the result of decades of experience managing major distribution assets across a dense, mature, and congested major city that is served by various system designs and configurations. These practices consider the various attributes of an asset class, including, but not limited to: (i) the intended functionality of the asset in the distribution system and the various modes of deterioration and failure over the asset's typical lifespan; (ii) the potential impact of various failure modes on distribution service; and (iii) the typical costs and customer impacts of intervention.

As discussed in Section D1, Toronto Hydro is committed to continuous improvement in asset management, and is pursuing certification under the internationally recognized ISO 55001 standard for Asset Management in the 2025-2029 period. The utility expects that the journey toward certification will involve additional improvements and refinements to its asset lifecycle optimization practices, including more comprehensive documentation and governance of said practices and associated processes and decision-making tools.

The following two sub-sections describe Toronto Hydro's asset lifecycle optimization practices, beginning with the utility's foundational maintenance and refurbishment practices, followed by a description of the utility's typical asset replacement practices for major asset classes.

D3.1.1 Maintenance and Refurbishment Practices

As part of its overall asset management process, Toronto Hydro aims to ensure the continuous serviceability (i.e. usefulness) of assets over their typical or expected useful lives, and to extend an asset's serviceability when it is feasible and economical to do so. Asset maintenance and refurbishment practices are the methods by which Toronto Hydro supports these objectives.

D3.1.1.1 Reliability Centered Maintenance

Toronto Hydro typically conducts inspection and maintenance tasks on a fixed cycle, however some tasks are performed on a variable cycle. These activities are focused on preserving and maximizing an asset's performance over its expected useful life while mitigating a wide variety of system risks. Maintenance activities support the minimization of overall lifecycle costs and account for factors such as the safety of Toronto Hydro employees and the public, responsible environmental stewardship and associated obligations, and compliance with statutory and regulatory requirements.

Toronto Hydro's foundation for maintenance planning is Reliability Centered Maintenance ("RCM"), an established engineering framework for the maintenance of assets throughout their lifecycles. The RCM framework determines failure management policies for any physical asset in its present operating context to maximize useful life and reliability based on the assets function, and the consequences of functional failure, including the asset's criticality to the distribution system. The output of an RCM analysis includes a failure mode analysis, which is used to identify proactive tasks (with associated time intervals) that help to predict or prevent failures from occurring. It also focuses on preventing failures where consequences are most severe. Toronto Hydro initially adopted an RCM framework in 2003 and subsequently reviewed and updated its outputs in 2011 and over the 2016 and 2017 period, ensuring compliance with the Society of Automotive Engineers ("SAE") standards SAE JA-1011 and SAE JA-1012 which sets outs the minimum characteristics that a process must have in order to be an RCM process and provides guidance on how to meet the requirements of SAE JA-1011, respectively.[1] The resulting analysis produces failure management policies forming part of the maintenance program that are deemed to be the most cost and risk effective at sustaining asset performance in accordance with the company's risk tolerance level.

RCM is a comprehensive approach to the lifecycle maintenance of distribution system assets. Initially developed in the airline industry to manage high maintenance costs and high failure rates, RCM has allowed Toronto Hydro to increase its analytical capabilities in determining the optimal level of maintenance expenditures and the appropriate time of intervention for a specific asset class. The RCM framework incorporates a thorough analysis of assets going beyond manufacturers' requirements to evaluate functional failures under utility-specific operating conditions. The analysis identifies and categorizes consequences of failure (i.e. safety, cost, reliability). Maintenance programs are subsequently set to mitigate these consequences by establishing recommended optimal asset intervention timelines.

The benefits of RCM include:

1) A structured and data-driven targeted maintenance program;
2) Reduced efforts and costs expended on maintenance programs with little resultant value; and
3) Increased reliability due to the effectiveness of the failure prevention program.

[1] Society of Automotive Engineers, SAE JA-1011 (August 2009) and SAE JA-1012 (August 2011).

Toronto Hydro leverages the RCM framework, in combination with the Ontario Energy Board's ("OEB")'s Minimum Inspection Requirements, and the continuous monitoring and assessment of asset performance, to derive its maintenance programs and associated expenditure plans.

As part of developing RCM-based maintenance program expenditure plans, Toronto Hydro continues to seek opportunities for incremental productivity. For example, the utility has standardized the maintenance cycles of overhead switches to align with station maintenance cycles whenever possible to minimize the need for multiple equipment outages and significant switching resources.

The expenditure plans for all planned maintenance programs can be found in Exhibit 4, Tab 2, Schedules 1-3. Table 1 below provides a summary of maintenance practices for the major asset types on each part of Toronto Hydro's distribution system.

Table 1: System Maintenance Practices

System	Asset Class/Type	Planned Maintenance Activities	Current Cycle	Proposed 25-29 Changes
Overhead	*Pole-top Transformer*	Line Patrols	3 Years Visual, 1 Year Infrared	
	Distribution Poles	Line Patrols	3 Years Visual	
		Wood Pole Inspection & Treatment	10 Years	8 Years
		Concrete & Steel Poles	-	10 Years
	Primary Conductors	Line Patrols	3 Years Visual, 1 Year Infrared	
		Tree Trimming	2-5 Years, with the majority being 3 Years	
	Secondary Conductors	Line Patrols	3 Years Visual	
	Switches	Line Patrols	3 Years Visual, 1 Year Infrared	
		Maintenance (SCADA-Mate & Gang-Operated)	Variable Cycle Greater than 6 Years	6 Years

System	Asset Class/Type	Planned Maintenance Activities	Current Cycle	Proposed 25-29 Changes
		Battery Replacement for Switches (SCADA-Mate & Gang-Operated) and Repeater Radio	3 Years	
	Insulators	Insulator Washing (for Porcelain)	6 Months	
Underground	*Padmounted Transformer*	Inspection (Civil + Electrical)	3 Years	
	Submersible Transformer	Vault Inspection (Civil + Electrical)	3 Years	
	CRD Transformer		1 Year	
	URD Transformer			
	Building Vault Transformer	Inspection (Civil + Electrical)	3 Years	
	Padmounted Switch	Inspection (Civil + Electrical)	1 Year	
		Battery Replacement	3 Years	
	Cable Chamber	Cable Chamber	10 Years	
	Cables	Cable Diagnostic Testing	Risk Based	
		Contact Voltage Scanning	1-3 Years	
Network	*Network Transformer*	Network Vault Inspection – Electrical	1 Year	
		Network Vault Inspection – Civil	6 Months	1 Year
		Reverse Power Breaker Overhaul	3 Years	
		Protector Top Cleaning	1 Year	
		Network Protector Overhaul - HV[2]	4 Years	

[2] High Voltage ("HV")

System	Asset Class/Type	Planned Maintenance Activities	Current Cycle	Proposed 25-29 Changes
		Network Protector Overhaul - LV[3]	5 Years	
Station	*Station TS & MS (Maintenance & Facilities)*	Monthly Inspections	1 Month	
		Seasonal Detailed Inspection	6 Months	
	Circuit Breaker (All Types) & Switch	Maintenance	4 Years	
	Bus Disconnect Switches			
	B-Bus	B-Bus Cleaning	4 Years	
	Power Transformer	Equipment Maintenance	4 Years	
	DC Battery & Charger	Seasonal Detailed Inspection	6 Months	
	Compressed Air System	Station Compressed Air System Maintenance	6 Months	
	Station Alarms in Downtown	Alarm Testing	1 Year	
	Pilot Wire	Pilot Wire Protection	6 Years	

The proposed changes in cycles for certain asset types are explained below:

- Starting in 2025, Toronto Hydro will be adjusting the inspection cycle for wood poles from ten to eight years in order to better manage the growing volume of wood poles past their useful life, and in HI4 and HI5 condition based on the ACA. This adjustment will also allow Toronto Hydro to better inform its wood pole ACA and support planning of system renewal investments with more timely inspection data of poles in poor condition.

- In 2025, Toronto Hydro will begin to inspect concrete and steel poles as part of its dedicated pole inspection program on a ten-year cycle. Inspections of these poles are supported by the

[3] Low Voltage ("LV")

CSA Standard C22.3, are expected to reduce burden on reactive capital, and will allow Toronto Hydro to improve decisions on planned renewal investments for these assets.

- Due to resourcing and operational constraints, Toronto Hydro has historically found achieving the four-year maintenance cycle of overhead switches noted in its 2020-2024 DSP to be challenging, instead attaining variable cycles generally greater than six years. Beginning in 2025, Toronto Hydro will be maintaining overhead switches on a six-year inspection cycle at a minimum, an approach that is supported by an independent study of Toronto Hydro's overhead switch maintenance practices.

- As of 2027, Toronto Hydro's network vaults will have sensors providing remote monitoring and control, which will allow the utility to reduce the number of on- site inspections, yielding cost savings from the adjustments of maintenance cycles from six months to one year.

D3.1.1.2 Summary of Maintenance Programs and Activities

Asset maintenance programs (Exhibit 4, Tab 2, Schedules 1-5) are grouped into four major categories based on their functionality, as shown below:

- Preventative Maintenance;
- Predictive Maintenance;
- Emergency Maintenance; and
- Corrective Maintenance.

The framework of preventative and predictive maintenance programs is driven primarily by regulatory requirements, as mandated by the OEB's Distribution System Code Minimum Inspection Requirements.[4]

Capturing Asset Deficiencies

The details of how the asset inspections and capital and maintenance programs are related are summarized below as part of the deficiency capturing process in Figure 1.

[4] Ontario Energy Board, Distribution System Code, (August 2, 2023), Appendix C.

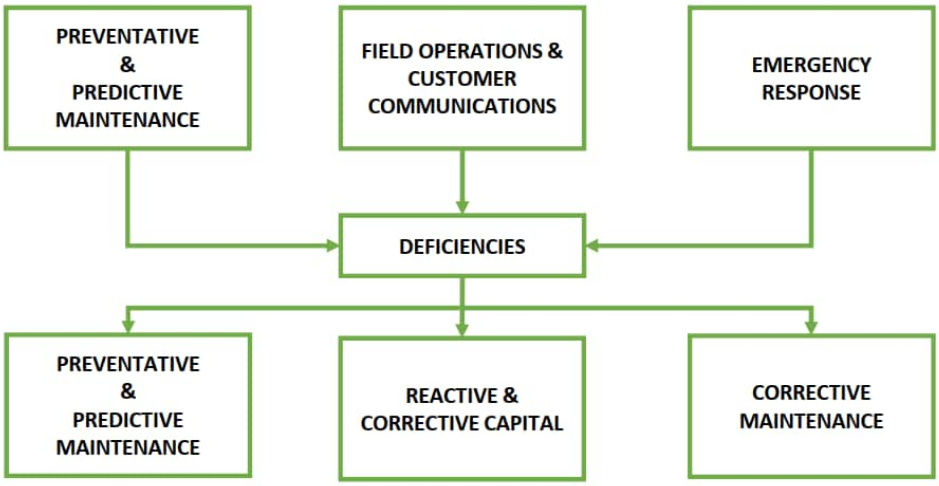


Figure 1: Deficiency Capturing Process

Distribution system events such as power outages are initially addressed through the Emergency Response program.[5] The cost of any capital work (e.g. major asset replacement) carried-out during an Emergency Response event is captured in the Reactive Capital program.[6] An Emergency Response event can also result in follow-up work to be carried out via the Reactive Capital segment.

The more substantial source of Reactive and Corrective Capital work is the identification of asset failures and deficiencies through maintenance activities and daily utility operations.

- Toronto Hydro's Preventative and Predictive Maintenance programs systematically identify asset failures and prioritize deficiencies through regularly scheduled system maintenance activities. Through the "find it and fix it" practice, on-site repair of minor deficiencies is carried out.[7]

- Failures and deficiencies are also identified through daily field operations and customer contact. These include observations by field crews and system operators during the normal course of operations, external emails, customer inquiries requiring field assessment and follow up including phone calls received from the customer service team, and meter errors captured through internal data collection systems.

[5] Exhibit 4, Tab 2, Schedule 5.
[6] Exhibit 2B, Section E6.7.
[7] Exhibit 4, Tab 2, Schedules 1-3.

These processes and activities can result in both capital and operating expenditures (e.g. corrective tree trimming). The Corrective Maintenance program,[8] is the operational counterpart to the Reactive Capital segment.[9]

Toronto Hydro has a rigorous process for reviewing all work inquiries from these sources to validate the need for reactive intervention, assess the nature of reactive intervention required (i.e. capital versus maintenance), and the level of urgency/priority to be assigned to each item. Prioritization of the asset deficiencies identified as part of the work request process is based on the urgency of the work and how quickly it needs to be resolved. The work requests are classified into three categories (P1, P2, and P3) as discussed in Section D3.2.1.3 and illustrated in Figure 2. Toronto Hydro also identifies a P4 category of deficiencies, which require monitoring, but for which no work requests are issued.

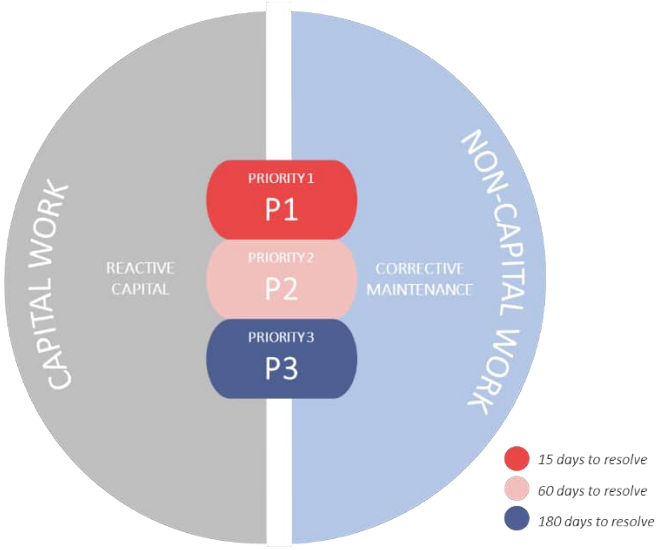


Figure 2: Work Request Prioritization

1. Preventative Maintenance

This type of maintenance involves inspections and maintenance tasks on a fixed or variable cycle, which emphasizes preserving asset performance over its expected life, and maintaining public and employee safety. Maintenance cycles are typically defined based on the average time between

[8] Exhibit 4, Tab 2, Schedule 4.
[9] *Supra* note 6.

failures of a given asset class, and are intended to maintain the asset before it is statistically likely to fail. An example of a preventative maintenance task is the inspection of wooden utility poles, which Toronto Hydro currently carries out on a ten-year cycle and intends to shift to an eight-year cycle in the next rate period.[10]

2. Predictive Maintenance

Predictive maintenance involves the testing and inspection of equipment for predetermined conditions that are indicative of a potential failure. The results of this process feed into asset investment decision-making frameworks such as Toronto Hydro's Asset Condition Assessment, and will trigger corrective tasks to prevent failures when necessary. Predictive maintenance is the most effective maintenance approach for assets that exhibit conditions that can be identified, practically monitored, and corrected prior to failure. An example of a predictive maintenance task is the Dissolved Gas Analysis of power transformer mineral oil, which identifies the presence of dissolved gases and other chemical compounds in the oil as an indication of potential failure modes (e.g. overheating, excessive moisture, or breakdown of the insulating paper). Corrective maintenance tasks can then be undertaken to correct the deficiencies to avoid equipment failure. For additional information.[11]

3. Emergency Maintenance

Emergency maintenance involves the urgent repair or replacement of equipment that has failed or is in imminent danger of failure, in order to restore or maintain power in Toronto Hydro's distribution system. This type of maintenance may also involve an immediate response to a safety or environmental hazard. Emergency Maintenance can arise from: response to requests for support from Toronto Emergency Management Services and the public, equipment failure, events related to severe weather, motor vehicle accidents, power quality issues, and reactive equipment isolations. It emphasizes safe and prompt response to restore service or prevent a service disruption. An example of emergency maintenance would be restoration of service to customers that have lost power due to a broken tree branch on the overhead lines.[12]

[10] *Supra* note 7.
[11] *Ibid.*
[12] Exhibit 4, Tab 2, Schedule 5.

4. Corrective Maintenance

Corrective Maintenance involves repairing equipment after a deficiency has been reported via preventative and predictive maintenance tasks or other sources, such as inquiries from customers, feeder patrols, and deficiencies identified by crews during day-to-day operations. Corrective work activities contribute to maintaining safety, environmental integrity, and overall system reliability. These tasks typically involve a short planning horizon since a portion of the distribution system is faulted, isolated, or in otherwise in an unacceptable condition.

Corrective Maintenance contributes to public and employee safety by ensuring prompt repair or replacement of high-risk assets or asset components approaching imminent failure; eliminating safety risks such as trip hazards caused by sink holes on sidewalks and the absence of adequate pole guying, washing insulators located in high contamination areas to prevent flashover, and detection and elimination of energized contact voltage on surfaces and structures within Toronto Hydro's distribution system. Corrective work also contributes to Toronto Hydro's environmental objectives, for example by repairing cables and splices exhibiting signs of oil deficiency to prevent oil spills into the environment, and prevention of excessive corrosion by cleaning oil-filled equipment and applying corrosion inhibiting coatings. Other examples of Corrective Maintenance tasks include: (i) the replacement of a cracked porcelain insulator; (ii) the repair of a broken guy wires; (iii) the removal of vegetation growing on a pole and into an overhead line; or (iv) the replacement of a conductor splice.

Corrective maintenance can also be required as a result of an unplanned system events or emergencies. For example, a faulted section of underground cable that had been isolated from the system during an emergency response can be unearthed and repaired or replaced as a Corrective Maintenance action. For additional information, please refer to the Corrective Maintenance program.[13]

D3.1.1.3 Impact of Capital Investments on Maintenance

Toronto Hydro routinely assesses the impact of its capital investments on distribution system maintenance needs and planning. A significant portion of maintenance program expenditures is directed toward activities that are independent of capital investments, including: (i) routine maintenance to preserve asset performance over its expected life; (ii) vegetation management to

[13] *Supra* note 8.

maintain minimum clearance requirements for overhead conductors and equipment; (iii) and cyclical patrols and inspections undertaken to comply with minimum requirements under the Distribution System Code; and (v) emergency maintenance following severe weather and storm damage. Maintenance programs also provide the asset condition information necessary to plan sustainment programs. Where there is an impact, the directional relationship between capital investments and maintenance depends on a number of factors, including the type of investment (e.g. Growth and City Electrification, Sustainment and Stewardship, or Modernization), mandated requirements (e.g. OEB minimum inspection cycles), and the specific characteristics of the assets involved.

Growth investments are generally expected to put upward pressure on maintenance requirements as the number of assets on the distribution system increase to accommodate new customers. For example, the addition of Copeland TS (Phase 1) has increased the number of TSs (and station assets) that the utility has to regularly inspect and maintain, with some of these inspections occurring on a monthly basis. The expansion of Copeland TS (Phase 2) will similarly increase the number of station assets requiring maintenance, once complete. While these types of large, discrete S=stations expansion projects are fairly infrequent, more routine growth investments also tend to increase the total number of assets that must be incorporated into Toronto Hydro's existing preventative and predictive maintenance cycles. For example, from 2017 to 2022 the number of distribution transformers on Toronto Hydro's system increased by over 750 and the number of poles increased by over 4,500. In addition, Toronto Hydro may introduce new assets, which require the introduction (and over time, expansion) of new maintenance and inspection activities. For example, in 2022 Toronto Hydro began annual inspections, testing, and cleaning of its Bulwer Battery Energy Storage System ("BESS") assets under the Preventative and Predictive Station Maintenance program,[14] and expects to expand this to additional Toronto Hydro-owned energy storage systems as they are added under the Non-Wires Solutions capital program.[15]

Within the Sustainment and Stewardship investment category, typical like-for-like asset replacement is generally expected to have no impact on routine maintenance and inspection requirements, especially where, as is most common, these investments are aimed at maintaining rather than improving overall asset condition. In certain cases, where Toronto Hydro conducts condition-based maintenance (increased frequency of maintenance activities for higher-risk assets within a population based on condition assessments), the utility could potentially reduce the number of

[14] Exhibit 4, Tab 2, Schedule 3.
[15] Exhibit 2B, Section E7.2.

assets requiring the higher maintenance frequency through capital investments aimed at improving condition demographics. As an example of condition-based maintenance, Toronto Hydro increased the frequency of inspections for Submersible Transformer during the period of 2019-2020 to manage the incremental risk posed by oil deficiencies within the submersible transformer population at that time prior to returning to a three-year cycle once the risk has been adequately managed. Typically, the impact would be minimal and this approach is not consistent with Toronto Hydro's general sustainment strategy to maintain asset condition. Similarly, like-for-like replacement activities will only reduce aggregate Corrective Maintenance expenditures if replacements are done at a high enough pace to materially improve asset health demographics, which could in turn reduce the expected volume of deficiencies requiring corrective intervention (e.g. repair). However, even this dynamic can be complicated by the fact that a younger and healthier asset base may require relatively higher levels of Corrective Maintenance for subsets of assets, due to the fact that younger equipment with defects may be better suited to repair (i.e. maintenance) as opposed to full replacement (i.e. reactive capital). In reality, Toronto Hydro has seen a rise in the volume of corrective work requests. This has resulted in approximately $20 million worth of backlog for lower priority work requests, which the utility expects will continue to grow.

Where Sustainment and Stewardship investments are removing legacy and functionally obsolete assets or configurations from the system, this can eliminate the need for maintenance activities or higher maintenance frequencies that are specific to the legacy asset type. Toronto Hydro anticipates that Sustainment and Stewardship programs targeting legacy assets such as air-blast circuit breakers, non-submersible network protectors, porcelain insulators, box construction, and rear lot construction will contribute to a gradual and modest reduction in costs related to legacy equipment maintenance as the population declines and the assets are replaced with equipment that typically requires lower maintenance costs, or are maintenance free. For example, unlike newer types of circuit breakers, air-blast circuit breakers require air compressors to function, and Toronto Hydro inspects and maintains these air compressors twice a year. As Toronto Hydro removes air-blast circuit breakers from the system through its Stations Renewal program,[16] it will aim to reduce and eventually eliminate the volume of these inspections under the Preventative and Predictive Station Maintenance program.[17] Sustainment and Stewardship programs, including Area Conversions, Underground System Renewal – Horseshoe, and Overhead System Renewal, also contribute to the gradual removal of the legacy 4.16 kV system, which enables the decommissioning of Municipal

[16] Exhibit 2B, Section E6.6.
[17] Exhibit 4, Tab 2, Schedule 3.

Stations, reducing the overall volume of station maintenance and inspection activities. At the same time, new equipment, and new standards and practices may introduce incremental maintenance requirements. The utility considers maintenance requirements when evaluating new products and developing new standards as part of its continuous Standards and Practices Review activities.

Replacement of legacy systems can also help to reduce emergency and corrective maintenance. Legacy designs in poor condition may require more frequent corrective or emergency repair as more components are expected to fail, and there is an increased risk to reliability, safety, and environment outcomes. In addition, obsolete assets and configurations can have access, capacity, and procurement issues that may increase costs during corrective or emergency work. For example, both the Rear Lot and Box Construction configurations addressed by the Area Conversions program are targeted, in part, because of the challenges crews face in accessing them for repairs and the corresponding tendency towards longer outages.[18] Rear Lot feeder outages are on average 2.5 hours longer than outages on the rest of the system and these feeders can be particularly vulnerable to outages during adverse weather contributing to higher emergency maintenance costs. In May of 2022 there was a derecho wind storm which interrupted power to approximately 142,000 Toronto Hydro customers including customers on three Rear Lot feeders, which were out for more than two days, with the longest lasting 53.1 hours.

Modernization investments often have the greatest potential to reduce maintenance costs, although like growth investments, they tend to include the installation of new assets, such as SCADA-mate switches and reclosers under the System Enhancements program,[19] which contribute to increasing volumes of routine maintenance and inspection activities. The Network Condition Monitoring and Control ("NCMC") program is one modernization investment that has a clear benefit in terms of reducing expected maintenance costs.[20] As a result of the implementation of NCMC, which installs sensors in network vaults providing remote monitoring and control, Toronto Hydro expects to reduce the number of planned vault inspections required for each network vault per year, reducing maintenance costs by approximately $275,000 each year in the Preventative and Predictive Underground Line Maintenance program once all vaults are commissioned.[21]

[18] Exhibit 2B, Section E6.1.
[19] Exhibit 2B, Section E7.1.
[20] Exhibit 2B, Section E7.3.
[21] Exhibit 4, Tab 2, Schedule 2.

D3.1.1.4 Overview of Toronto Hydro's Refurbishment Practices

Both maintenance and refurbishment involve intervening on an asset to maintain or maximize its serviceability. Maintenance consists of activities that are necessary to ensure the reliable operation of an asset over its expected useful life. Refurbishment differs from maintenance in that it involves renovating an asset to extend its serviceable life. For example, tree trimming is a form of maintenance, while rebuilding a vault roof is a form of refurbishment.

Toronto Hydro's refurbishment efforts are mainly focused on assets that have been taken out of service (e.g. through a renewal project or as a result of failure). An asset may be considered for refurbishment if it meets specific criteria and is in good enough condition to be reintroduced into the system after appropriate testing. This is done for major asset types like transformers, network protectors, switchgears, and switches. Toronto Hydro evaluates major equipment returned from the field, and categorizes it based on the following criteria:

1) **Decommissioned equipment that remains operational:** Should a major asset such as a station power transformer be removed from the system as part of a system renewal project, or due to station decommissioning, Toronto Hydro will inspect and test the equipment to determine if it is still fit for service. If the equipment is still operational, the utility will keep it as a spare in case of reactive replacements.
2) **Repair of failed or defective equipment:** Equipment will be repaired or refurbished if it meets the following criteria: (i) it is under warranty; (ii) it is a critical spare (e.g. 4 kV assets); (iii) transformers less than 15 years old; (iv) network protectors less than 10 years old; (v) overhead switches less than five years old; or (vi) underground switches less than 15 years old. An example would be load conversion, where 4 kV equipment is removed from the system and replaced with the current standard. The removed assets are typically refurbished and kept as spares due to the scarcity of these obsolete asset types and in the event that other 4 kV assets on the system need to be replaced reactively.

Equipment that does not meet the specific criteria for re-use listed above will be scrapped.

Where appropriate, Toronto Hydro undertakes targeted refurbishments in the field to maximize the serviceable life of existing assets. For example, as mentioned above, the utility will rebuild a deteriorated vault roof, extending the useful life of the entire vault.

D3.1.2 Asset Replacement Practices

The decision to replace an asset can result from many drivers, including asset failure, deterioration and failure risk, functional obsolescence, historical performance, standards alignment, planning and execution efficiencies, capacity requirements, and third-party requests.

Failure, failure risk, and functional obsolescence are the three most significant trigger drivers for asset replacement for Sustainment and Stewardship investments. Renewal-driven replacement practices for specific asset classes can range from primarily reactive replacement, where replacement largely occurs when the asset has failed (i.e. it can no longer serve its intended function), to primarily proactive replacement, where the consequence of failure for an asset class (i.e. the asset's criticality) is high, making it unacceptable to run the asset to failure under most circumstances.

While a few asset classes are situated at the far ends of the reactive-proactive spectrum, Toronto Hydro manages most major asset classes using a blend of reactive and proactive replacement strategies. This approach reflects how the risk profile and specific performance challenges within and across asset classes evolves over time, particularly in a large, dense, and congested city served by a variety of highly utilized systems inherited from several predecessor smaller utilities. It also reflects variability in the location-specific criticality of individual assets across the system. The proportion of assets the utility replaces proactively is related to the utility's performance objectives and the risk assessments underlying projected performance.

The overall pace of asset replacement over time is also determined by long-term system stewardship objectives in accordance with good utility practice. As a steward of the grid, if Toronto Hydro expects a large demographic "wall" or "wave" of end-of-life assets approaching within a 10-15-year period, it has a responsibility to assess the impact and reasonability of smoothing out the investment profile. Practically this entails replacing a subset of the assets sooner, rather than waiting until the wave hits and being forced to replace all assets within a tighter window. This approach is preferred because it creates a more stable investment profile, leading to more realistic and efficient project resourcing and execution. It also has the benefit of yielding more predictable and stable rate impacts for customers. Increasingly, customers support investments that provide longer-term benefits. When specifically asked to make trade-offs between price and other outcomes (system health, reliability and efficiency) regarding these type of stewardship investments, the majority of customers surveyed

agreed that Toronto Hydro's draft plan struck the right balance, with many customers expressing a preference for Toronto Hydro to spend more.[22]

The reverse of this dynamic is also relevant: if Toronto Hydro sees longer-term needs for an asset class easing-up over time, the utility may choose to slightly delay a proportion of necessary short-term investments, effectively accepting some short-term incremental asset failure risk in favour of a smoother investment profile and the related benefits. Note that with the emerging drive toward electrifying consumer loads (e.g. electric vehicles; heat pumps), Toronto Hydro anticipates that opportunities to defer asset replacement may be fewer in the future, since the utility is likely to face a higher rate of urgent low-voltage expansion needs (e.g. upsizing pole-top transformers to accommodate greater peak demand at the neighbourhood level).

Tables 2 to 6 below provide an overview of Toronto Hydro's current replacement practices for assets on each part of the distribution system.

[22] Exhibit 1B, Tab 3, Schedule 1

Table 2: Summary of Overhead System Asset Replacement Practices

Asset	Asset Replacement Practices
Poles	Toronto Hydro manages the risk profile of its pole population by proactively replacing poles in alignment with condition demographics and other risk factors (e.g. legacy asset replacement needs). Poles are replaced on an individual basis or as part of area rebuilds. Poles are prioritized for replacement based on condition, age, criticality, and relationship (e.g. proximity) to other high-risk assets. In the event poles fail while in service, Toronto Hydro replaces them reactively. Due to the urban environment in which Toronto Hydro operates, the utility has a very low risk appetite for catastrophic pole failure (i.e. collapse of pole) and designs its pole testing, inspection and reactive replacement programs to substantially mitigate this risk. During pole replacements, deteriorated and obsolete accessories such as porcelain insulators are also replaced because they are susceptible to contamination build-up, which can lead to asset failure and pole fires.
Pole-top Transformers	Toronto Hydro manages the risk profile of its pole-top transformer population through proactive and reactive replacement. The utility prioritizes transformers that present heightened failure risks based on inspection results, age, area reliability, and environmental risks (e.g. oil leaks containing polychlorinated biphenyls ("PCBs")). Due to the low individual criticality of a typical, PCB-free pole-top transformer, Toronto Hydro will generally replace these assets reactively or as part of a larger proactive area rebuild project when there are economies of scale. Toronto Hydro plans to replace the remaining "PCB at-risk" transformers in the distribution system to minimize failures and environmental risk. Toronto Hydro also expects that, due to the emerging pressures of electrification, space and capacity constraints will increasingly be a factor in the decision to schedule a pole-top transformer for proactive replacement.
Overhead Switches	Overhead switches are constantly exposed to harsh environmental conditions, and their failure often leads to prolonged outages and can pose significant safety risks to utility workers if an arc flash happens during the switch failure. Where appropriate, switches are replaced as part of a planned area rebuild, or else reactively upon failure due to age, condition, or external factors. Where safety risks are identified for a type or class of switches, the utility executes planned replacements of these assets to mitigate the risks.

Asset	Asset Replacement Practices
Overhead Conductors (primary and secondary)	Toronto Hydro does not have a dedicated proactive renewal strategy for overhead conductors. Where appropriate, conductors are replaced as part of a planned area rebuild (e.g. upgrade to tree-proof conductor in heavily treed areas) or reactively upon failure due to age, condition, or external factors. Toronto Hydro expects that, due to the emerging pressures of electrification, capacity constraints on the secondary conductor buses which supply low-voltage electricity at the neighbourhood level will increasingly be a factor in the decision to schedule renewal projects.

1 **Table 3: Summary of Underground System Asset Replacement Practices**

Asset	Asset Replacement Practices
Underground Cables (Polyethylene)	Toronto Hydro manages the risk profile of its underground cable population by both proactively and reactively replacing polyethylene (e.g. cross-linked polyethylene ("XLPE")) cables. The utility proactively replaces aged or poor performing cables through neighbourhood rebuild projects to manage significant reliability risks associated with these assets, mainly targeting poor performing direct-buried cables in the Horseshoe area. Otherwise, if these cables fail while in service, they are repaired or replaced reactively. With the introduction of a new Cable Diagnostic Testing program, Toronto Hydro is leveraging new forms of asset condition information to prioritize cable and cable accessory replacements both reactively and on a planned basis.
Underground Cables (Lead)	Underground lead cables have traditionally been replaced reactively on the downtown underground distribution system. However, with increasing reliability, safety, and operational risks associated with lead cables (i.e. leaking cables, congested cable chambers, increasing numbers of splices, dwindling supply and expertise), Toronto Hydro started to proactively replace paper-insulated lead-covered cables and asbestos-insulated lead-covered cables in 2020 and will continue to do so until the population is fully removed. The utility uses risk-based prioritization, which considers historical failures, age, feeder uniformity based on cable type, and the magnitude and criticality of the load served by each feeder to direct expenditures to the projects with the greatest customer value. Aside from the modest proactive investments that are planned for the 2025-2029 period, these cables are repaired or replaced reactively when they fail while in service.

Asset	Asset Replacement Practices
Underground switches	Toronto Hydro manages the risk profile of underground switches by proactively replacing them, taking into consideration age, condition, and failure impact. Toronto Hydro also plans to replace switches as part of area rebuild projects. Otherwise, switches that fail while in service are replaced reactively.
Underground Transformers	Toronto Hydro manages the risk profile of its underground transformer population through proactive and reactive replacement. Underground transformers are replaced as part of planned area rebuilds or on an individual basis if they pose an environmental risk due to the risk of leaking oil containing PCBs and are at or past their useful life and/or in deteriorating condition. Otherwise, transformers that fail while in service are replaced reactively. Toronto Hydro expects that, due to the emerging pressures of electrification, constraints on the secondary distribution system which supplies low-voltage electricity at the neighbourhood level will increasingly be a factor in the decision to schedule renewal projects.
Underground Legacy Switchgear	Historically, Toronto Hydro has replaced underground legacy switchgear in customer-owned vaults reactively. However, due to the growing number of deficiencies where repairs are not an option and require replacement due to obsolescence, the utility is introducing proactive replacement of these legacy assets starting in 2025. Toronto Hydro plans to target the worst condition and most critical assets to maintain reliability performance and reduce safety risks, prioritizing them according to condition, inspection and maintenance history, and past reliability.
Cable Chamber	Toronto Hydro manages the risk profile of its underground cable chambers by proactively replacing cable chambers in HI5 and HI4 condition due to the growing number of deteriorating chambers and the complexity of chamber reconstruction work. Cable chambers are also prioritized based on the types of customers and thermal loading of feeders. Otherwise, cable chambers that fail while in service are addressed reactively. The utility plans to proactively replace cable chamber lids to address public safety risks in high traffic areas.

Asset	Asset Replacement Practices
Underground Residential Distribution ("URD")	Toronto Hydro manages the reliability performance for customers served by the unique URD system by proactively replacing URD assets. Toronto Hydro targets critical and obsolete URD assets in deteriorating and poor condition or past their useful life such as switching and non-switching vaults, switches, and transformers that contribute to the deterioration of system reliability. The utility prioritizes URD replacement projects based on the condition of civil roofs as deficient roofs pose an immediate risk to the public. Otherwise, assets that fail while in-service are replaced reactively.

1 **Table 4: Summary of Network System Asset Replacement Practices**

Asset	Asset Replacement Practices
Network Units	Toronto Hydro manages the risk profile of its network unit population by proactively replacing units in alignment with condition demographics and other risk factors (e.g. safety and environmental risks). The utility proactively replaces network units with a higher risk of failure due to age, condition, obsolescence, or location (i.e. prone to flooding). Older units with obsolete "non-submersible" protectors, which make them susceptible to water ingress causing failure, are generally beyond their useful life and are at risk of leaking oil containing PCBs. The utility is aiming to reduce and eventually eliminate the population of non-submersible units due to increasing risks of flooding. Otherwise, units that fail while in service are replaced reactively. Toronto Hydro continues to install new network units that are submersible and equipped with sensors to monitor transformer, protector, and vault conditions, resulting in the cost-effective reduction of reliability, environmental, and safety risks associated with network assets.
Network Vaults	Toronto Hydro manages the risk profile of its network vault population by proactively replacing vaults or vault roofs in alignment with condition demographics and other risk factors (e.g. safety risks). Due to the complexity of vault rebuild projects, Toronto Hydro must maintain a steady pace of renewal targeting the worst condition locations. Vaults are prioritized primarily based on condition and the associated safety risks of structural deterioration, customers served, and external factors (i.e. road moratoriums). If a deteriorated vault is no longer needed due to load displacement, then the utility will decommission it. Otherwise, vaults that fail while in service are addressed reactively.
Network Cables	See Underground cables – polyethylene and lead.

1 **Table 5: Summary of Stations Asset Replacement Practices**

Asset	Asset Replacement Practices
Transformer Station ("TS") Switchgear	Toronto Hydro manages the risk profile of its TS switchgear population by proactively replacing assets to manage overall switchgear demographic risk and system reliability. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Existing units are often difficult and infeasible to safely maintain due to their design, and therefore, proactive replacement is preferred to resolve maintenance issues. Asset replacements need to be done proactively, as they have long lead times to procure (e.g. 12-18 months), and design and construct (e.g. 3-4 years). Replacement prioritization is dependent on various factors, including: age, enclosure construction, load, arc flash rating, breaker condition, obsolescence, and safety. These assets can fail while in service, and in such situations, customers may experience long outages while Toronto Hydro restores power and subsequently repairs or replaces the failed switchgear reactively.
TS Oil Circuit Breakers (KSO)	Toronto Hydro manages the risk profile of its TS oil circuit breaker population by proactively replacing assets. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Asset replacements need to be done proactively as they have long lead times. Toronto Hydro replaces TS KSO oil circuit breakers based on age, condition, load, obsolescence, and safety and environmental risks (i.e. oil containing PCBs). Otherwise, assets are replaced reactively when they fail while in service.[23] Given the above risks, Toronto Hydro plans to remove all remaining KSO Oil circuit breakers from the system in the 2025-2029 period.
Municipal Station ("MS") Switchgear	Toronto Hydro manages the risk profile of its MS switchgear population by proactively replacing them. Given the high criticality of these assets, the utility has a low risk appetite for reactive replacement. Asset replacements need to be done proactively due to long lead times. Existing units are often difficult and infeasible to safely maintain due to their design, and therefore, proactive replacement is preferred to resolve maintenance issues. Toronto Hydro replaces MS switchgear based on age, breaker condition assessment results, type of circuit breaker, load, the obsolescence of the asset, resiliency of the surrounding distribution system to withstand switchgear failures, and the safety and reliability risks they present. New MS switchgears are arc-resistant. When these assets fail while in service, Toronto Hydro will first attempt to repair the unit, but depending on the severity of the fault, may replace it reactively.

[23] *Supra* note 16.

Asset	Asset Replacement Practices
MS Primary Supply	MS primary supply assets (disconnect switches, cables, and circuit breakers) are proactively replaced to maintain overall condition demographics and reliability. MS primary supply assets are replaced proactively as part of MS power transformer replacement projects and may be included as part of switchgear replacement projects. Prior to 2019, power transformer replacements were typically completed without replacing their MS primary supply. Toronto Hydro proposes to continue to replace the primary supply at MSs where power transformers were previously replaced, but only where the primary cable is direct buried or in direct buried duct since this comprises the majority of the failure risk. MSs targeted for primary supply replacement are prioritized based on failure risk as determined by age and configuration (e.g. direct-buried cable). It takes three months to reactively replace a failed primary supply.
Power Transformers	Toronto Hydro manages the risk profile of its power transformers by proactively replacing them to manage overall demographic risk and system reliability. Power transformers require long lead times (e.g. 12 months) to procure, design and construct and therefore need to be replaced as part of a steady proactive renewal program. These assets are prioritized based on condition assessment, age, dissolved gas analysis, load, and resiliency of the surrounding distribution system to withstand transformer failures. Toronto Hydro plans to increase pace of power transformer replacement to address an increasing power transformer failure rate.
Station Service Transformers ("SSTs")	Toronto Hydro replaces SSTs proactively to manage age demographics and maintain reliability on the system. Asset replacement also requires long lead times and as a result, needs to be done proactively. Units are prioritized based on their age and associated environmental risk (i.e. risk of oil containing PCBs). Once these assets fail in service, the station service supply cannot afford to experience a subsequent failure as that failure would render the station inoperable. Moreover, any planned renewal or maintenance work of ancillary systems may be delayed.
Remote Terminal Units ("RTUs")	Toronto Hydro replaces functionally obsolete RTUs proactively as they are beyond their useful life, and no longer supported by their manufacturers. These assets can be repaired within a two-week period; however, repairs cannot be maintained over the long term due to the scarcity of spare parts. These assets also have a long replacement time (e.g. six months) and are therefore difficult to replace reactively. These assets are prioritized based on age, number of customers connected, load and failure rate.

Asset	Asset Replacement Practices
Relays & Copper Communication Cable	Toronto Hydro replaces relays proactively, mainly driven by obsolescence and the need to support grid modernization, but also driven by failure risk due to age. Copper communications cables are replaced proactively with fiber to mitigate the failure risk associated with older cables and to allow Toronto Hydro to have complete control, since many of the copper communication cables in the system are owned by third-parties. Assets are prioritized according to the number of customers and load connected, and failure rate of the station.
Direct Current ("DC") Battery Systems	Toronto Hydro replaces and maintains DC battery systems to ensure they can supply power to the station for eight hours (as mandated by the Transmission System Code). Replacement of the assets is prioritised based on functional obsolescence, age, and condition of the asset.
AC Panels	Toronto Hydro proactively replaces AC panels to mitigate failure risk of obsolete and end-of-life assets. An AC panel failure has a large impact because they supply all the station loads such as heating, cooling, lighting, ancillary equipment and DC charging systems with no backup supply in case of failure. AC panel replacements are prioritized based on age and the number of customers connected to the station.

1 **Table 6: Summary of Metering Asset Replacement Practices**

Asset	Asset Replacement Practices
Meters	Toronto Hydro replaces meters proactively at or beyond the end of their useful life to manage risk of failure and customer billing interruptions. Meters are replaced reactively if they fail to read or communicate or suffer complete failure. Reactive meter replacement consists of the replacement of defective metering equipment in the field including: smart meters, suite meters, interval meters and primary meters.

D3.2 Asset Lifecycle Risk Management Policies and Practices

Customer-focused outcome measures such as system reliability, safety incidents, connections efficiency, and oil spills are lagging indicators of system performance. These measures are essential to understanding the actual experience of customers, stakeholders, employees, and the general public in relation to the distribution system. However, certain lagging measures, by their nature, can be difficult to directly influence through actions taken in the near-term. This is especially true for measures that are influenced by asset failure. Toronto Hydro manages hundreds of thousands of distribution assets that are typically in service for decades. These assets can fail in a variety of ways at any point in their lifespan, and it is impossible to know with precision exactly when failure will occur. Therefore, in the daily effort to direct expenditures toward cost-effective interventions that will drive performance outcomes, Toronto Hydro must rely on risk – a leading indicator of performance – to make informed investment decisions.

As a large urban utility with a highly utilized system and a significant asset renewal need, risk assessment is essential to ensuring that system reliability and other outcomes can be maintained within a constrained expenditure plan. Risk assessments are also used to determine areas of the system that would benefit the most from investments in grid modernization.

This section outlines Toronto Hydro's lifecycle risk management methods and practices for its distribution assets, detailing the utility's risk assessment frameworks, including key considerations in risk evaluation, and typical risk mitigation approaches. Capacity related risk is discussed separately in Section D3.3.

D3.2.1 Overview of Risk Assessment Methods

Toronto Hydro's risk assessment framework consists of the following key elements:

- Probability of Failure;
- Consequence of Failure; and
- Risk Analysis.

Details of each key element follows.

D3.2.1.1 Probability of Failure

Probability (i.e. likelihood) of failure ("PoF") is an important consideration in determining whether asset intervention is necessary. This section focuses upon three key forms of analytics that Toronto Hydro uses to enable PoF evaluation: (i) Asset Condition Assessment ("ACA"); (ii) predictive failure modelling; and (iii) Historical Reliability Analysis.

1. Asset Condition Assessment ("ACA")

As explained in Section D1 and in Appendix A to this Section, Toronto Hydro employs an ACA methodology to monitor the condition of various key asset classes within its system and produce a Health Score to support project planning. The ACA allows Toronto Hydro to use data collected through inspections to produce a relative numerical representation of an asset's condition, considering key factors that affect its operation, degradation, and lifecycle.

Toronto Hydro uses ACA to support tactical and strategic investment planning decisions. Planners use inspection data and health scores – in combination with other information and professional judgement – to prioritize assets for tactical intervention in the short- to medium term. This includes identifying priority deficiencies that require reactive or corrective action, and prioritizing assets for planned renewal projects in a given budget period. At a strategic level, Toronto Hydro uses ACA results to examine condition demographics and trends within major asset classes to support the development of longer-term investment plans within the annual Investment Planning & Portfolio Reporting ("IPPR") Process.

The ACA model that Toronto Hydro has implemented is the Condition-Based Risk Management ("CBRM") methodology. This methodology was developed and adopted by the major utilities in the United Kingdom in collaboration with the regulator, the Office of Gas and Electricity Markets ("Ofgem").[24] The methodology provides a health score for every applicable asset based on the most recent inspection information. The methodology also projects Future Health Scores for assets, which provides intelligence on asset demographics that the utility leverages to evaluate proposed investment strategies over longer periods. Since the adoption of CBRM in 2017, Toronto Hydro's Health Score calculations and projection methodologies have remained largely consistent, with the

[24] The specific implementation of CBRM used by Ofgem for regulatory purposes is called the Common Network Asset Indices Methodology, or "CNAIM".

exception of certain targeted adjustments to reflect inspection program changes and to ensure the model is producing results that are aligned with field observations.

The general approach used to produce the health score for each asset is illustrated in Figure 3.

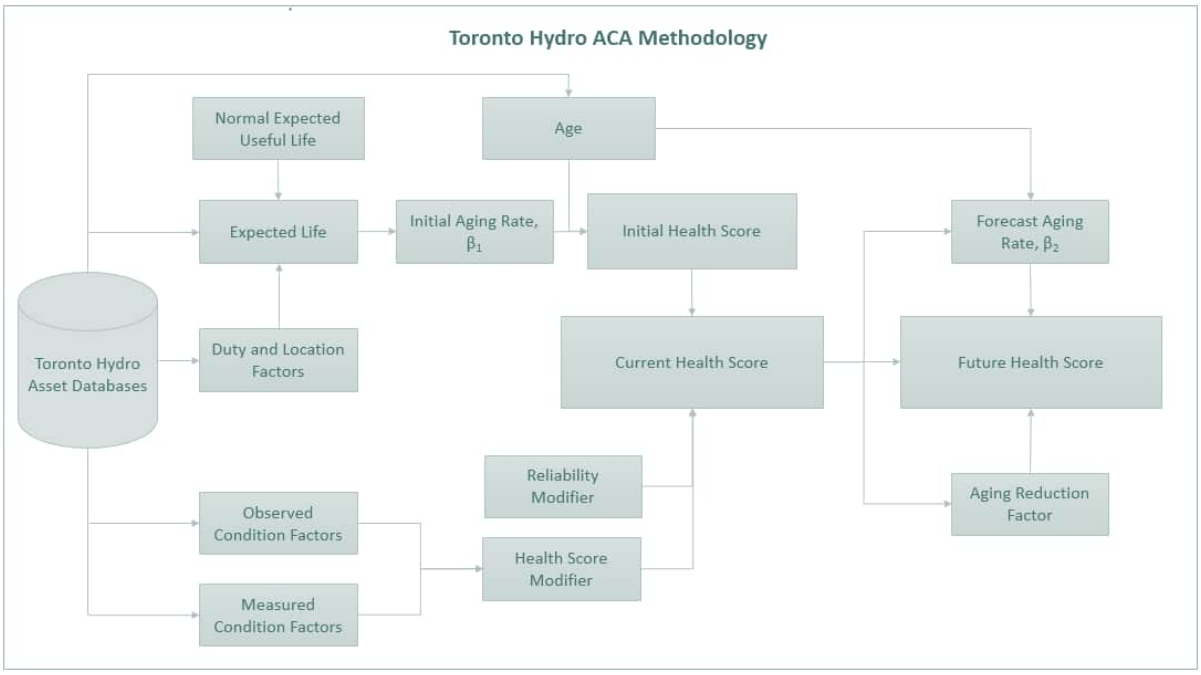


Figure 3: Asset Condition Assessment Process as Part of ACA

ACA results (i.e. Health Scores) for a particular asset class are grouped into five Health Index ("HI") bands that represent key stages of an asset's lifecycle, ranging from new or like new condition to the stage where asset degradation is significant enough to warrant urgent attention. Toronto Hydro uses asset health demographics and the underlying inspection details during the project scope development phase of IPPR, as outlined in Section D1. This enables planners to assess the relative probability of failure of their assets in the short and mid-term timeframe based on the HI band. The bands are defined as per Table 7 below.

Table 7: Health Index bands and definitions

HI Band	Lower Limit of Health Score	Upper Limit of Health Score	Definition
HI1	≥ 0.5	< 4	New or good condition
HI2	≥ 4	< 5.5	Minor deterioration; in serviceable condition
HI3	≥ 5.5	< 6.5	Moderate deterioration; requires assessment and monitoring
HI4	≥ 6.5	< 8	Material deterioration; consider intervention
HI5 (Current Health)	≥ 8	≤ 10	End of serviceable life; intervention required
HI5 (Future Health)	≥ 8	≤ 15	

Asset classes with HI scores are shown in Table 8 below.

Table 8: Assets Evaluated in the ACA

Switches	Breakers	Vaults	Transformers	Other
• Overhead Gang-Operated • SCADA-Mate • Air-Insulated Padmount • SF_6-Insulated Padmount • SF_6-Insulated Submersible • Air-Insulated Submersible	• 4 kV Oil Circuit (MS) • KSO Oil Circuit (TS) • SF6 Circuit (TS) • Vacuum Circuit (MS & TS) • Air Magnetic Circuit (MS & TS) • Airblast Circuit (MS & TS)	• ATS • CLD • CRD • Network • Submersible Switch • URD	• Station Power • Network • Submersible • Vault • Padmount	• Wood Poles • Network Protectors • Cable Chambers

The ACA output is essential in two respects. First, the ACA produces a relative outlook of the population's condition for each individual asset class within the program. Second, the ACA highlights trends in the condition of asset populations. For system planners, these insights provide an indication of the relative probability of failure for an asset and how failure risk within an asset population is evolving over time. Being aware of these issues and trends allows Toronto Hydro to balance capital investments against continuing maintenance. More generally, the ability to compare current and

future HI results for an asset class can support decision-making when developing expenditure plan envelopes for longer-term investment programs. In its 2025-2029 Distribution System Plan ("DSP"), Toronto Hydro has used this information to compare proposed investment levels against current and projected volumes of assets in the two worst health bands ("HI4") and ("HI5").

As highlighted in Section D1.3.2.1, and as a next step in the evolution of the utility's ACA approach, Toronto Hydro is in the process of implementing the Probability of Failure component of the broader CBRM methodology. This extension of the methodology will allow the utility to convert an asset Health Score (which serves as an indirect indicator of relative PoF) into an absolute PoF value which can then be applied in quantitative risk-based decision-making frameworks, including the utility's value framework for capital investments. The role of PoF in these frameworks is discussed further in the following section.

2. Predictive Failure Modelling

Predictive failure modelling is another essential component of Toronto Hydro's approach to risk-based asset management. Predictive failure modelling involves the derivation of hazard rate functions for each asset class and the application of said functions to existing and future asset population demographics to produce a predicted number of failures per year. The utility leverages these failure models to support risk-based investment decision-making and system performance projections.

A hazard rate, commonly used in reliability engineering, represents the instantaneous likelihood of failure given that an asset has survived up to a particular time. To the extent that North American distribution utilities like Toronto Hydro have pursued quantitative risk-based asset management tools in recent decades, they have typically relied upon age-based hazard rate functions to produce quantified PoF values. In Toronto Hydro's case, while age-based PoF is currently the more mature mode of analysis for analytics such as reliability projections, the utility is in the process of introducing condition-based PoF as an enhancement to its decision-making tools and analytics. As noted above, this condition-based PoF is an extension of the Health Score concept within the CBRM framework.

As discussed in Section D1.2.1.1, as part of its ongoing multi-year effort to implement an industry leading Engineering Asset Investment Planning ("EAIP") platform, Toronto Hydro is developing a custom value framework which assigns relative value to investments based on their likely contribution to Toronto Hydro's key performance outcomes. For many of these investments, including a majority of the System Renewal programs, this value framework is built directly upon the

utility's CBRM framework, ensuring that projects will be consistently prioritized on the basis of their verifiable contributions to mitigating quantifiable condition-based asset risk. The condition-based PoF values will serve as an important input to this framework.

The role of predictive failure modelling in reliability projection procedures is discussed in Section D3.2.1.3.

3. Historical Reliability Analysis

The third component of Toronto Hydro's probability of failure analysis involves the analysis of historical reliability data in order to identify failure trends for asset populations and areas of the system.

Toronto Hydro's reliability analytics system stores historical outage information which the utility uses as a tool in developing capital spending. By continuously analyzing the reliability performance of its circuits and substation assets, Toronto Hydro can identify areas experiencing reliability issues, which may be caused by asset deterioration or legacy design related issues. Toronto Hydro utilizes the following ten major cause codes to classify historical outages:

- Adverse Environment;
- Adverse Weather;
- Defective Equipment;
- Foreign Interference;
- Human Element;
- Lightning;
- Loss of Supply;
- Scheduled Outages;
- Tree Contacts; and
- Unknown.

From a probability of failure perspective, this data can be used to identify those asset classes and sub-classes, as well as parts of the system that experience a high frequency of failure. In specific scenarios, historical reliability performance can be a strong indicator of future issues. As an example, reliability data has been utilized as part of Toronto Hydro's planning procedures to identify feeders containing the most problematic direct-buried underground cables.

D3.2.1.2 Consequences of Failure

When determining the risk of asset failure, there are two components considered; the probability of failure (explained in Section D3.2.1.1) and the consequences of failure. Consequences are generally broken down into major categories (e.g. safety consequences) that align with Toronto Hydro's corporate pillars and outcomes framework.

1. Reliability

Toronto Hydro evaluates reliability consequences associated with its assets using a mix of quantitative and qualitative information:

- Reliability performance analysis;
- Customer engagement and consultation activities;
- Key account customer program and responses to customer calls and complaints;
- Reliability analysis identifying long-duration impacts; and
- Application of customer interruption costs.

Table 9 provides additional information related to each of the aforementioned tools and approaches.

1 **Table 9: Summary information used to establish Reliability Consequences**

Tool or Approach	Summary
Reliability Performance Analysis	As explained above in Section D3.2.1.1, Toronto Hydro's reliability analytics system keeps detailed records on outage events. The utility mines this data to gather insights into the frequency and consequences of different kinds of events, including various modes of asset failure for the different types of assets on the distribution system. This analysis is useful for developing statistical averages and ranges that are applicable in risk modelling (e.g. average number of customers interrupted and average duration of an outage for a pole-top transformer failure on the 27.6 kV system). It is also useful in determining which asset sub-types and specific parts of the distribution system are exhibiting higher than average reliability consequences (e.g. quantifying the higher average outage duration consequences for events on the rear lot system). Toronto Hydro leverages these reliability analytics both directly and in combination with other leading and lagging indicators to establish the relative consequence of failure for different assets, and to establish investment priorities. Reliability analytics are also important for more dynamic, "in year" management of customer reliability impacts. For example, a distribution feeder that is experiencing a rash of outages in the short-term will be monitored more closely and intervened upon more urgently as a potential "worst performing feeder." Flagging a feeder as a worst performer effectively elevates the consequence of failure of each subsequent outage, since further deterioration in performance would violate management's standards for acceptable reliability.

Tool or Approach	Summary
Network/Reliability Consequence of Failure ("CoF")	As part of its ongoing efforts to implement an EAIP system, Toronto Hydro is developing a custom Value Framework that is aligned with its corporate pillars and outcomes framework. Network/Reliability CoF is one component of the framework. The Network/Reliability CoF models the customers interrupted and duration impact of asset failure, leveraging Customer Interruption Costs ("CIC") to quantify the cost of failure to customers. CICs represent a measure of monetary losses for customers due to an interruption of electric service. CIC values are calculated in two parts: Event cost and Duration cost. The Event cost represents the impact to customers due to the occurrence of the outage. Within the Value Framework, the event cost is calculated by multiplying customer interruption costs with total customers impacted for an asset failure. The duration cost represents the costs incurred as the length of the outage increases, calculated by multiplying the duration cost by the average time to restore power after an asset failure, considering time required for switching operations and repair or replacement. This component of the value framework, when combined with the PoF, will supersede the utility's legacy Feeder Investment Model as the primary means of assessing the impact of asset failure through a fully quantified and probabilistic risk lens.

Tool or Approach	Summary
Customer Engagement	Toronto Hydro executes a variety of customer engagement programs designed to establish interactions with customers that provide the utility with qualitative and quantitative insight into the customer's experience, needs, preferences, and priorities. This information can come through various channels, ranging from ad hoc customer interactions, to periodic engagements with larger customers, to infrequent but highly comprehensive investment planning-related engagements and surveys. Key examples include: • **Key Account Customer Program:** Toronto Hydro's Key Account Customers are those customers who have critical loads, including: customers who have electricity use greater than one MW at a single site or combined across a number of sites, priority loads such as hospitals and financial institutions, essential public services including the Toronto Transit Commission, schools, and developers. Toronto Hydro manages a key account customer program for these customers to address specific concerns and issues in a timely manner. The utility proactively engages with these customers on a wide range of topics including resolving issues related to reliability and power quality. These engagements help Toronto Hydro to calibrate its decision-making to ensure it is aligned appropriately with the customer's experience of outage and power quality events. • **Rate Application Customer Engagement:** Every five years, in preparation for its rate-setting application cycle, Toronto Hydro undertakes extensive Customer Engagement as part of business planning. This process produces a detailed and comprehensive view of high-level customer preferences when it comes to key outcomes including reliability and resiliency. Toronto Hydro uses this information to calibrate its investment strategy and ensure general investment pacing and prioritization is reflective of the customer's willingness to pay to avoid the reliability consequences of system faults.

2. Environmental

Toronto Hydro takes all reasonable actions to reduce the risk of asset failures resulting in adverse effects to the environment. Beyond the potential environmental impacts that can result from certain asset failure modes, Toronto Hydro can face associated consequences such as potential non-compliance or breach of regulatory obligations, which in turn can have severe reputational and financial implications.

Toronto Hydro's major environmental concerns include: (i) oil or SF_6 gas leaks of all types; (ii) reducing greenhouse gas emissions ("GHG"); and (iii) mitigating the use of substances like asbestos, lead, and PCBs in its equipment. Through planned asset inspections, oil deficiencies in the system are identified and necessary corrective action is taken. Toronto Hydro is continuously striving to mitigate environmental risks such as the risk of oil spills, while simultaneously ensuring compliance with federal, provincial, and municipal regulations pertaining to the release of oil into the environment. Similarly, through inspection and renewal programs, assets containing lead, asbestos, and PCBs are identified and included for replacement with standardized and less harmful equipment. Toronto Hydro will mitigate the risk of oil spills containing PCBs on its overhead, underground and network systems by 2025 by replacing at-risk assets. Toronto Hydro is also acting to reduce SF_6 gas leakage into the environment. For example, the latest generation of SF_6-insulated switches Toronto Hydro installs have welded viewing windows that mitigate SF_6 gas leakage into the environment. Moreover, the utility is trialing Solid Dielectric ("SD") switchgear as an alternative to SF_6 insulated gear.

Toronto Hydro is including Environmental CoF as another component within its custom value framework as part of its EAIP implementation. The Environment CoF will reflect the above considerations, quantifying the impacts of oil and SF_6 gas leaks or contamination, GHG emissions, and equipment disposal. In addition, considerations for increased consequence due to the presence of substances such as PCBs will also be made in determining the overall environmental consequence of asset failure.

3. Safety

Mitigating safety risks to Toronto Hydro employees and the general public is the highest priority objective of Toronto Hydro's Asset Management process. As highlighted in Section E2.3, customers consider the safety of the system to be a default priority for the utility. Public and employee safety is the overarching priority of Toronto Hydro and is built into its culture, operations, and decision-making frameworks. Toronto Hydro continues to strive for zero public and employee safety incidents each year. Moreover, one of Toronto Hydro's objectives is to comply with all safety regulations and standards over the 2025-2029 period.

Toronto Hydro is implementing Safety CoF within its custom value framework. Safety CoF will quantify impacts to both public and crew safety, including direct and indirect costs associated with death or serious injuries, lost time injuries, and third- party damages resulting from asset failure.

Factors that impact the severity or probability of an injury, such as an asset's proximity to high traffic areas or the size of an asset, will also be considered within the overall Safety CoF.

Nearly all of the utility's asset renewal, service, and maintenance activities are driven in part (and sometimes entirely) by safety considerations. For example, Toronto Hydro's programs to reduce and eliminate obsolete legacy equipment and configurations are driven in large part by known safety risks and related operational restrictions. Examples of these activities include:

- Eliminating safety risks related to Electrical Utility Safety Rules ("EUSR") compliance issues associated with legacy box construction configurations;
- Reducing public and employee exposure to safety risks as a result of outages in rear lot configurations;
- Addressing emerging safety risks identified by the Electrical Safety Association ("ESA") such as potential fire risks at "Delta-Wye" locations; and
- Reducing public safety risk due to cable chamber lid ejections

Toronto Hydro's Environmental, Health and Safety ("EHS") and Standards functions, funded by the Human Resources and Safety program (Exhibit 4, Tab 2, Schedule 15) and the Asset and Program Management program (Exhibit 4, Tab 2, Schedule 9), have important roles in maintaining safe work practices, implementing engineering controls, and adhering to requirements related to environmental protection and occupational health and safety. In the event of an incident relating to asset failure(s) where there is an environmental or safety risk, staff responsible for the aforementioned functions (i.e. EHS and Standards) will investigate to determine the defect in the equipment. EHS bulletins will be released for immediate notification of potential workplace hazards, accidents, injuries, near misses, environmental issues, and important information regarding accident prevention. If applicable, a new standard for a replacement product will be developed.

If the defective equipment poses a significant risk to the system, a capital or maintenance program would be proposed to replace the asset with new standardized equipment. For example, delta-wye corrective work under the Corrective Maintenance program,[25] addresses the potential hazard of fire and shock posed by three-phase grounded wye-connected secondary transformation with no grounded neutral conductor between the transformer's secondary neutral terminal and the

[25] *Supra* note 8.

customer's service entrance equipment. This issue was flagged by the ESA and this work enables compliance to ESA requirements.

4. Public Policy

In addition to addressing customer reliability, environmental, and safety concerns, Toronto Hydro must remain compliant with public policies and regulations. Certain circumstances or asset failures carry with them the risk of putting Toronto Hydro in violation of public policies. Some relevant public policies include:

- Managing asbestos as per the *Ontario Occupational Health and Safety Act* as well as the *Canadian Environmental Protection Act* to eliminate and phase out asbestos;[26]
- Reducing the risk of PCB leakage into the environment and eliminating all PCB containing equipment greater than 50 ppm to comply with PCB Regulations as defined in the *Canadian Environmental Protection Act*, SOR/2008-273,[27] and in the City of Toronto *Municipal Code,* Chapter 681 – Sewers;[28] and
- Ensuring compliance with *Ontario Regulation* 22/4,[29] and safety performance as measured through the Serious Electrical Incidents Index.

5. Financial

Some of the consequences of asset failure discussed above can also have significant financial impacts for Toronto Hydro. Financial CoF will be integrated within Toronto Hydro's value framework in order to reflect the direct financial costs of failure required to replace or repair an asset. Asset failure can also cause outages disrupting the normal operations of businesses, damage the surrounding area (e.g. through oil spills), and create safety risks. These can increase the risk of Toronto Hydro incurring additional costs for environmental remediation, fines, and legal costs in the form of claims and any resulting litigation, in addition to asset replacement or repair costs. The potential financial impacts of failure differ depending on the nature of the failure and from asset to asset because assets operate under varying conditions and loadings.

[26] *Occupational Health and Safety Act* , R.S.O. 1990, c. O.1 and *Canadian Environmental Protection Act,* 1999.
[27] PCB Regulations (SOR/2008-273), under the *Canadian Environmental Protection Act,* 1999.
[28] Toronto Municipal code, Chapter 681 Sewers (July 27, 2023).
[29] O. Reg. 22/04: Electrical Distribution Safety, under Electricity Act, 1998, S.O. 1998, c. 15, Schedule. A.

D3.2.1.3 Risk Analysis

The probability and consequence inputs, as identified in Sections D3.2.1.1 and D3.2.1.2 respectively, are used either individually, or in combination as part of analyses prior to arriving at risk-based decisions related to long-term and short-term asset management plans and investments. The risk of failure may be determined by using a combination of qualitative and quantitative methods. Various risk-based tools are utilized to provide multi-faceted perspectives that support and ultimately justify investment decisions. The following subsections provide insight into the various risk-based decision-making tools that are used at Toronto Hydro.

1. Quantified Risk-Based Analysis

As mentioned in Section D3.2.1.1, Toronto Hydro is taking the next step in the advanced implementation of its risk frameworks by developing a custom value framework to inform its EAIP platform. The value framework will allow a quantitative assessment of the relative value for projects based on their alignment to key outcomes. It integrates risk assessments in quantifying the value for projects along with other value drivers, allowing the utility to consider the overall value of investments in decision-making and produce an optimized set of projects to achieve key performance outcomes.

Toronto Hydro's value framework, especially as it relates to Sustainment and Stewardship investments, is rooted in the CBRM methodology and is informed by both the probability and consequence of failure inputs discussed in Section D3.2.1.1 and D3.2.1.2 above. The value framework integrates incremental development within its ACA methodology (such as condition based PoF curves) along with quantified consequence of asset failure (CoF) as detailed in Section D3.2.1.2 above, specifically:

- Network/Reliability Consequences;
- Environmental Consequences;
- Safety Consequences; and
- Financial Consequences

The custom Value Framework embedded within its EAIP platform will allow Toronto Hydro to assess and understand the risk profile of its assets in order to support decision-making as it relates to its short- and long-term investments, including assessments of value for alternative approaches for intervention. Comparing the change in risk mitigation (value of investment), along with other value

drivers, over multiple years allows Toronto Hydro to evaluate trade-offs between outcomes, resource requirements, and budgetary pressures year over year. Subsequently, Toronto Hydro can leverage the capabilities of its EAIP tool to establish an optimized set of projects to achieve performance outcomes in each year that is aligned with its outcomes framework.

2. Reliability Projections

In order to conceptualize the impact of investment programs, Toronto Hydro performs an analysis of historical system reliability and produces a reliability projection ("RP"). The RP provides a risk-based view utilizing the major reliability indices (e.g. SAIFI, SAIDI) and enables informed decision making for capital investments. The RP is based upon:

a) asset demographics data and associated failure projections;
b) historical reliability performance; and
c) planned program investments.

The system historical reliability category is broken into individual cause codes and in some cases (e.g. defective equipment) down to the asset level. For Defective Equipment, Toronto Hydro projected failure and outage impacts at an asset class level based on associated demographics, historical reliability, and the expected benefits of it's 2025-2029 planned Sustainment and Stewardship investments. The utility applied a historical five-year average to project other cause codes. It also included projections for the reliability related benefits of Grid Modernization investments.

As part of the RP process, a reactive replacement scenario is produced, to estimate the performance of the current system without proactive intervention. The scenario depicts what is expected if assets remain in service and naturally reach end-of-life. Asset failures increase as they are operated beyond useful life and in deteriorated conditions, contributing to worsening reliability. This provides a reliability centric risk view for Toronto Hydro.

In addition to the reactive replacement approach, Toronto Hydro produces a scenario to project the reliability impact of the Sustainment and Stewardship programs and reliability related benefits of grid modernization programs on the system. This is determined by reviewing each planned program for reliability benefits, improved operational flexibility, and influences on asset demographics. The program benefits are applied to the individual outage cause codes (listed above in section D3.2.1.1) based on their level of impact on reliability. The results are then aggregated to the system level to

obtain the final system-wide reliability projections. RP analysis and results used in the development of the capital expenditure plan are discussed in Section E2.2.2.3.

In general, this conceptual analysis is used by Toronto Hydro to evaluate the reliability impact of the proposed capital expenditure plan. This analysis also supports Toronto Hydro in setting targets for reliability performance as part of its Custom Performance Measures for SAIDI (excluding Loss of Supply, Major Event Days, and Scheduled Outages) and SAIFI (Defective Equipment).[30]

3. Worst Performing Feeder ("WPF")

Toronto Hydro assesses the overall performance of the system in order to improve service reliability for customers supplied by poorly performing feeders. The utility identifies feeders performing poorly over a rolling 12-month period and performs work to mitigate further interruptions. Toronto Hydro defines a feeder as performing poorly when it meets, or is trending towards meeting criteria below:

- Non-key account feeders that are at risk of experiencing seven or more sustained interruptions (referred to as Feeders Experiencing Sustained Interruptions of seven or more, or "FESI-7").[31]
- Key Account feeders at risk of experiencing six or more sustained interruptions (referred to as Feeders Experiencing Sustained Interruptions of 6 or more, or "KAWPF-6").
- Key Account feeders that contain large critical customers with Ion meters installed at their service entrance that have their operations negatively impacted by multiple sustained or momentary interruptions and/or power quality issues. These customers are typically large manufacturing facilities or hospitals, which are sensitive to voltage sags and momentary outages.
- Feeders that are experiencing systemic issues in a localized area that are resulting in, or at risk of resulting in multiple sustained or momentary interruptions.

The WPFs in the system are typically addressed through a combination of short-term intervention (both capital and maintenance) and complementary planned renewal work. Additional details

[30] Exhibit 1B, Tab 3, Schedule 2.
[31] Note that, with recent upgrades to the Network Management System and the ongoing transition to Oracle Utility Analytics for reliability analysis, Toronto Hydro is now capturing a greater number of very small outages. The utility is currently assessing the impact of this change on its FESI-7 measure (which counts individual outages equally, regardless of size) and may choose to redesign this feeder-based reliability the measure to more accurately reflect the experience of customers who are truly experiencing an unacceptable frequency of interruptions.

related to programs targeting worst performing feeders, which are in place to improve reliability and meet the needs of customers, may be found in Reactive and Corrective Capital program.[32] As a result of investments to improve the reliability of these feeders, sustained improvements have been achieved as illustrated in Exhibit 2B, Section C.

4. Enterprise Risk Management

Toronto Hydro considers a broad range of risks that the corporation faces through the Enterprise Risk Management ("ERM") process. Toronto Hydro's ERM framework has been designed to manage risks at the corporate level, and considers the risks facing individual asset classes and risks relevant to investment programs.

Toronto Hydro continuously works to identify and manage corporate risks that emerge from the asset base, and create new programs to manage these risks when prudent to do so. For example, various risks have been analyzed and managed using the ERM framework including risks posed by direct-buried cables, porcelain insulators, cable chamber lids, and secondary cables. The ERM framework groups such risk under categories such as "asset management risk" or "public safety risk". The ERM framework and the analytical results derived from the ERM process serve as another input into Toronto Hydro's overall risk assessment and management procedure. This input is available and updated regularly for monthly and annual tracking of risk mitigation measures while providing visibility into broader corporate risks.

5. Priority Deficiencies

When defective equipment is found, either through a planned inspection or following emergency response, the appropriate follow up actions are assigned based on the nature of the work. Toronto Hydro applies a risk framework to help prioritize repairs and corrective actions. In addition, the framework is useful for assessing risk trends related to both particular asset classes and system overall.

Toronto Hydro reviews all deficiencies to determine appropriate actions and the level of priority to be assigned to each deficiency. Prioritization of the asset deficiencies as part of the work request process is based on the urgency of the work and the risk it poses. The work requests are classified into three categories:

[32] *Supra* note 6.

- **P1**, requiring a resolution within 15 days;
- **P2**, requiring a resolution within 60 days; and
- **P3**, requiring a resolution within 180 days.

Toronto Hydro also identifies a P4 category of low priority deficiencies largely for the purposes of monitoring a deficiency, but no corrective work is issued. For additional details related to deficiencies, defective equipment, and prioritized reactive and corrective actions, please see the Reactive and Corrective Capital,[33] Corrective Maintenance,[34] and Emergency Response programs.[35]

6. Legacy Assets

Toronto Hydro's risk assessment frameworks include inventories of legacy assets and configurations that have been identified based on various factors (e.g. their likelihood of failure and resulting impact on system reliability, safety, or the environment). These assets and configurations are also typically functionally obsolete with limited or no support from manufacturers or third-party service providers. Toronto Hydro monitors these legacy assets to manage and minimize their associated risks to customers, employees, and the public. The utility evaluates legacy asset risk and performance over time, adjusting investment plans over the short, medium, and long-term to ensure the risks are being addressed at an appropriate and feasible pace. The reduction or elimination of these assets and the associated risks was a major contributing factor when developing the investment plans outlined in Section E of the DSP. For more information on Toronto Hydro's legacy assets, please refer to Section D2.

D3.2.2 Overview of Risk Mitigation Methods

Through its capital and maintenance investment plans, Toronto Hydro mitigates both the quantitative and qualitative risks identified above. Toronto Hydro manages risks by prudently investing in its assets while deriving value for customers. As such, the risk-based models and approaches described above are key inputs into the decision-making process for investment planning. Assets that pose a risk to the system are identified based on their contribution to the various risk factors discussed above as part of the IPPR process and grouped into investments categories.

[33] *Supra* note 6.
[34] *Supra* note 8.
[35] *Supra* note 5.

D3.2.2.1 Sustainment and Stewardship Investments

As part of Toronto Hydro's risk mitigation efforts, Sustainment and Stewardship investments form a significant portion of the utility's capital investments. These investments are geared towards maintaining the foundations of a safe and reliable system and standardizing outdated equipment. They aim to ensure long-term performance of Toronto Hydro's assets, maintain system reliability, and minimize asset failure risk. The Sustainment and Stewardship investment category also contains programs aimed at addressing the other risk areas identified in Section D3.2.1.2 and D3.2.1.3 above. Programs such as Area Conversions (Exhibit 2B, Section E6.1) are aimed at eliminating legacy designs along with their reliability and safety consequences. In addition, Sustainment and Stewardship programs inherently target assets that pose environmental risks, such as oil leaks, especially for equipment containing PCBs. They also include more specialized programs that address areas with high historical failures or failed assets, through programs such as the Reactive and Corrective Capital program.[36]

D3.2.2.2 Growth and City Electrification Investments

Growth and City Electrification investments allow Toronto Hydro to connect and serve growing demand for electricity as Toronto continues to grow, digitize and decarbonize key sectors of the economy. These investments ensure Toronto Hydro meets capacity and connection needs and is able to provide new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system. Toronto Hydro determines capacity and connection needs through the Stations Load Forecast, load connections forecasting, generations connections forecasting, and the Regional Planning process.[37] The Customer Connections program captures system investments that Toronto Hydro is required to make to provide customers with access to its distribution system, including enabling new or modified load and distributed generation connections to the distribution system.[38] Section D3.3 further discusses Toronto Hydro's policies and practices in regards to capacity planning and the connection of both load and generation customers.

D3.2.2.3 Modernization Investments

Modernization investments allow Toronto Hydro to adopt new technology to improve system performance and reduce costs over time, and to protect the system against intensifying threats.

[36] *Supra* note 6.
[37] Exhibit 2B, Section D4.
[38] Exhibit 2B, Section E5.1

Toronto Hydro invests in programs that allow for other cost-effective forms to mitigate the risks discussed in Section D3.2.1. For example, Toronto Hydro is investing in improving operational flexibility and observability through the System Enhancements program.[39] Installation of SCADA-Mate switches or reclosers allows Toronto Hydro to address reliability related risks, in a manner that compliments renewal activities in delivering the utility's overall reliability objectives.

Toronto Hydro is also investing in grid enhancement and modernization efforts to adapt to the changing needs of customers, environment, safety considerations, and stakeholders. The distribution grid faces pressure to support the energy transition and electrification such as the need to integrate increasing number of DERs and EVs in a safe and efficient manner. Toronto Hydro's Grid Readiness initiative aims to address the risk of increasing DERs and EVs proliferation. Moreover, Toronto Hydro's investments in Intelligent Grid initiative enhances observability and controllability of the grid, and mitigate risks around climate change and cybersecurity threats. For more information on the initiatives related to Grid Modernization, please refer to Exhibit 2B, Section D5.

D3.2.2.4 Maintenance and Refurbishment Activities

Toronto Hydro uses maintenance programs, as detailed in Exhibit 4, to both identify and mitigate risks in the system. Inspections are key in providing data inputs for risk analyses, including assessment of asset condition and identifying priority deficiencies that require intervention. This data provides Toronto Hydro with information on assets that is critical to decision making, such as the presence of oil leaks or other forms of equipment deterioration. In addition, maintenance programs can help maximize the life of assets, thereby managing the overall need for capital intervention. For example, treatment of wood poles helps protect against infestation and rot, reducing the probability of failure.

D3.2.2.5 Other Investments

Toronto Hydro must also invest to ensure it manages risks in terms of meeting the needs of its customers and stakeholders. For example, it must meet the expectations of regulatory bodies and governments with respect to policies. This includes proactive metering investments that ensure Toronto Hydro remains in compliance with the requirements set by Measurement Canada.

[39] *Supra* note 19.

D3.3 Asset Utilization Policies and Practices

This section highlights Toronto Hydro's policies and practices in regards to capacity planning and the connection of both load and generation customers. It details Toronto Hydro's process to assess capacity requirements, connections, and steps to mitigate risks.

D3.3.1 Capacity and Connections Capability Assessments

Toronto Hydro continues to monitor capacity related risks within its system from both a short- and long-term view point. This includes working with third parties such as the Transmitter (i.e. Hydro One Networks) and the Independent Electricity System Operator ("IESO") as required for planning purposes, for both load connections and generation connections.

D3.3.1.1 Distribution Capacity & Capability Assessments

1. Peak Demand Forecasting

Toronto Hydro uses a peak demand forecasting process to identify capacity constraints at substations within the system ("System Peak Demand Forecast"). This allows Toronto Hydro to maintain awareness of bus capacity as new connections are made and natural load growth (or reductions) occur. The System Peak Demand Forecast provides a near-to-medium term view of the station bus capacity so that appropriate plans can be made to accommodate varying growth within the system.[40]

In order to complete a ten-year System Peak Demand Forecast at the substation level, as shown in Figure 5, Toronto Hydro identifies the annual non-coincident peak loads (both summer and winter peaks) for each individual bus at its substations. These peak loads are then normalized based on historical temperatures at which they occur.

Following this, additional load growth is added to each bus considering economic variables. Toronto Hydro considered three new specific drivers in the development of the System Peak Demand Forecast: (i) hyperscale data centres, (ii) electrification of transportation, including EVs, and (iii) Municipal Energy Plans which include large anticipated connections in different areas of the city. In addition, all customer connection requests and planned permanent work such as load transfers and voltage conversions are added to each bus.

[40] See Exhibit 2B, Section D4.1.1 for a detailed description of Toronto Hydro's Peak Demand Forecast methodology.

Lastly, probabilistic simulations are performed to produce the final peak demand forecast of non-coincident bus peaks. For the System Peak Demand Forecast, Toronto Hydro modeled the variability of temperature to consider the impact of climate change on econometric indicators and simultaneously included drivers for data centers, electric vehicles, conservation and demand management, and distributed energy resources forecasts and applied a probability to determine the most likely outcome.

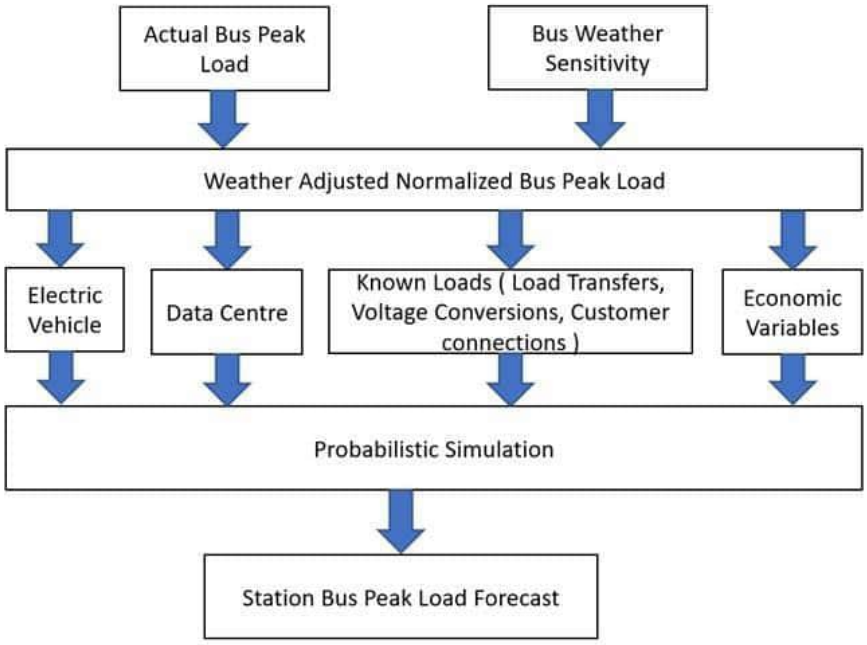


Figure 5: Process to Forecast Peak Demand at Substations

Recognizing the unprecedented energy transition set to unfold over the coming years, Toronto Hydro augmented its capacity planning and decision-making process with the results of long-term scenario modelling tool known as Future Energy Scenarios. The Future Energy Scenarios model is distinct from the Peak Demand Forecast in that it does not attempt to determine the most likely demand based on historical trends and other probabilistic sources of information. Rather, the Future Energy Scenarios model projects what the demand would be under various policy, technology and consumer behaviour assumptions that are linked to the varying aspirations, goals, targets, and constraints of decarbonizing the economy by 2040 or 2050.[41]

[41] Future Energy Scenarios model is described in more detail in Exhibit 2B, Section D4, Appendix A and Appendix B.

2. Connection Capability

In order to connect new customers, both capacity and spare feeder positions are needed. As existing feeders reach their capacity, new feeders must be pulled from a station into the distribution system to connect new customers. Although a station may have the capacity to supply this demand, if there are no feeder positions to connect new feeders to the station, then the station would be unable to support new connections. To this end, Toronto Hydro also monitors the number of spare feeder positions at its stations. When new feeders are needed and no spare feeder positions are available, Toronto Hydro engages in capital work under the Load Demand program to transfer feeder loads and free up feeder positions so that new customer connections can be made.[42]

D3.3.1.2 Generation Capacity & Capability Assessment

Increased demand for power from consumers and the interconnection of distributed energy resources ("DER") have placed limitations on certain areas of the system. Toronto Hydro supports connecting DERs to the distribution system in alignment with the Distribution System Code and in coordination with Hydro One Networks and the IESO. Toronto Hydro has identified a number of constraints within its system that impact DER connections and interconnection-related decisions, including the following:

1) Short circuit capacity constraints;
2) Anti-islanding conditions for DER;
3) System thermal limits and load transfer capability; and
4) Protection and power quality challenges from high DER penetration.

To determine the impact of DER penetration on a station feeder, sophisticated fault and power flow simulation models are employed. These models provide visibility on different variables, such as fault current, and the contribution of those variables to the limiting constraints listed above.

Studies are performed for each new DER application enabling Toronto Hydro to continually evaluate the available existing short circuit capacity of the system.

[42] Exhibit 2B, Section E5.3.

D3.3.2 Capacity Risk Mitigation Methods

Based on the risk assessments above, Toronto Hydro invests in a number of programs to mitigate the risk of capacity shortfalls or the inability to connect new customers. These methods include expansion to increase capacity, enhancements to better utilize existing equipment, and load transfers as detailed below.

D3.3.2.1 Expansion Investments

Expansion investments provide one approach to manage the risk of capacity shortfalls within the system. By increasing capacity at substations, Toronto Hydro is able to address the need in localized areas of the system that experience load growth. Investments for expansion are primarily funded through the Stations Expansion program.[43] Expansion investments often require involvement from the transmitter, and Toronto Hydro may need to provide capital contributions for upgrades to transmission equipment at substations to enable an increase in capacity. Expansion may also be embedded as part of renewal activities for power transformers and switchgear units if deemed necessary, either to increase capacity or to increase the number of feeder positions available at a substation to provide new feeders to connect customers.

D3.3.2.2 Load Transfers

Prior to investing in expansion projects, Toronto Hydro assesses the feasibility to alleviate capacity shortfalls by transferring load to adjacent feeders, buses, or substations. If feasible, transfers are typically more cost effective than expansion. This approach allows Toronto Hydro to ensure efficient utilization of its existing infrastructure prior to investments in expansion.

D3.3.2.3 Enhancement Investments

Toronto Hydro also considers investments that allows it to enhance the system in order to alleviate capacity shortfalls or connection limitations, in a cost-effective manner. To manage load restrictions, especially due to peaks, Toronto Hydro has worked extensively with its customers to implement a Local Demand Response program to manage peak demand effectively and developed an Energy Storage Systems program.[44] For generation connections, investments in monitoring and control equipment are made through capital programs, including Generation Protection, Monitoring, and

[43] Exhibit 2B, Section E7.4.
[44] *Supra* note 15.

Control, to actively manage DER sources to ensure safe connections.[45] These investments allow Toronto Hydro to effectively manage capacity and connection limitations, without the need for extensive renewal activities, thereby deferring large capital investments. These investments form part of Toronto Hydro's Grid Modernization Strategy for 2025-2029.[46]

D3.4 Program Planning Approach and Project Development

This section details the framework and process that Toronto Hydro relies on to develop its capital and maintenance programs. It highlights the key components of the IPPR process that drives the development of investment programs, as shown in Figure 6.

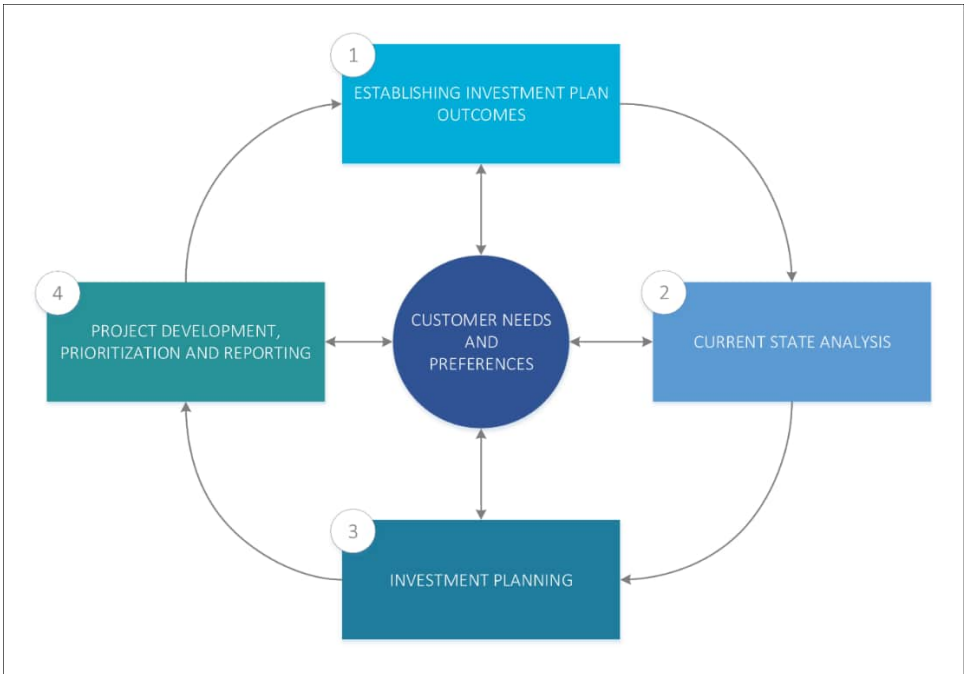


Figure 6: The IPPR Program Development Framework

The process can be divided into four key components:

1) **Asset Management Policy, Goals, and Objectives:** The process begins by establishing the asset management policy, goals, and objectives, and is informed by both the broader corporate strategy as well as customer needs, expectations, and feedback.

[45] Exhibit 2B, Section E5.5.
[46] Exhibit 2B, Section D5.

2) **Asset Needs Assessment:** This part of the process establishes an understanding of the current state of assets based on asset demographics and condition results. This information provides the base data required for planners to analyze the risk that the asset poses to the system.
3) **Portfolio Planning:** Based on the information output from the first two steps and the various risks discussed above, Toronto Hydro analyzes assets to identify the required level of spend to manage risk and in turn achieve the intended outcomes. Based on the driver of the work, investment programs are established as part of this step.
4) **Portfolio Reporting:** Once investment programs have been executed in the field through individual projects, the IPPR process includes a feedback loop where the project-specific execution status and project expenditures are reported to inform projects proposed in upcoming years.

D3.4.1 Asset Management Policy, Goals and Objectives

As discussed in Section D1, Toronto Hydro's Asset Management System ("AMS") is guided by its AM policy, goals, and related outcome objectives that the utility sets in alignment with its corporate pillars, objectives, and customer engagements. Figure 4 in Section D1 provides a summary of the AM policy, goals, and objectives, and Section E2 provides an overview of how Toronto Hydro established its AM outcome objectives for the 2025-2029 DSP.

Toronto Hydro uses outcome measures in each focus area to quantify the impact of investments towards each outcome. This framework is integral in enabling decision-making for asset management in both the long-term and short-term. For more details on Toronto Hydro's proposed Performance Measures for the 2025-2029 period, see Exhibit 1B, Tab 3, Schedule 1.

D3.4.2 Asset Needs Assessment

In order to create an optimized program, Toronto Hydro completes a needs assessment. In this regard, an important process is the current state analysis ("CSA") which provides Toronto Hydro with an assessment of the major assets that are currently installed in the system.

Key parameters that are collected from and integrated into the CSA include:

- Asset registry data (e.g. nomenclature, asset class/sub-class, installation type);
- Asset quantity data;

- Asset condition assessment and demographic data; and
- Asset-class and system-wide replacement value based upon useful life criteria.

The CSA utilizes information from Toronto Hydro's various enterprise systems, including the Geographic Information System ("GIS") and Enterprise Resource Planning ("ERP") system to establish the core asset registry data and asset demographics. Through the development of the CSA, Toronto Hydro can quickly establish key information on major assets including condition, age, useful life, and replacement value.

There are two key outputs from the CSA process:

- **Asset demographic data:** Provides a yearly break down for the number of asset units installed along with their respective costs. This data set allows Toronto Hydro to establish the percentage of assets past useful life.
- **Condition demographic data:** Indicates Health Scores (and subsequent Health Index bands) for applicable asset classes and sub-classes, helping to flag higher risk assets within the system from a condition perspective.

This process establishes foundational data that is used in the long-term and short-term planning processes for distribution assets. Figure 7 illustrates the inputs, elements, and outputs associated with the CSA.

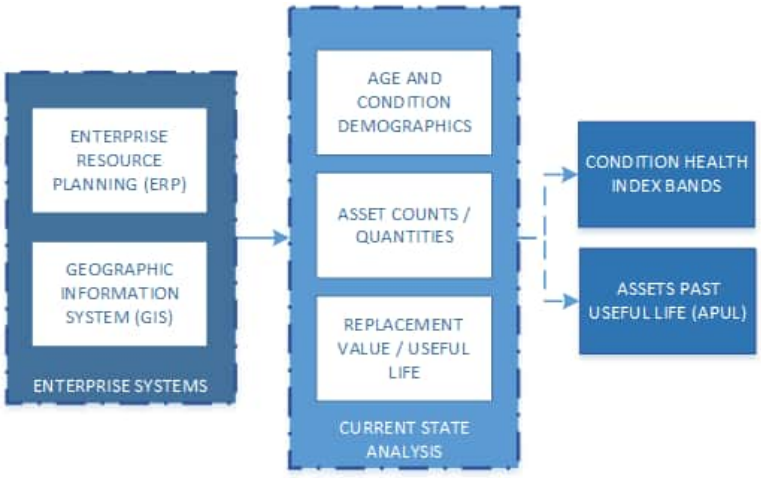


Figure 7: CSA Process

In addition to asset specific data, Toronto Hydro assesses emerging needs and challenges of the system by evaluating additional risk factors. For example, Toronto Hydro evaluates the available and forecasted capacity of the system to identify capacity-related risks. As discussed in Section D1.2.1.2 as well as D3.3 above, this is done through load forecasting, reviewing scenarios such as the Future Energy Scenarios ("FES"), load and generation connections forecasting, as well as the Regional Planning Process. These processes enable Toronto Hydro to identify spare capacity and anticipate areas of potential constraints as a result of developments and load growth or reductions in different areas of the City. The Regional Planning Process is an important input for distribution system planning (specifically, station plans), as a result of infrastructure planning on a regional basis to better predict system challenges. Capacity Planning is discussed in more detail in Exhibit 2B, Section D4.

Toronto Hydro accounts for emerging needs as they arise in the system. This could be as a result of asset specific information (legacy assets and configurations, safety and environmental concerns relating to a specific type of asset), climate and weather impacts, technological advances, or available capacity to connect customers. The processes identified in this section are used to assist system planners with developing well informed plans that consider the various risks and challenges mentioned above in order to meet the needs of the system.

The results of the Asset Needs Assessment that formed the basis of Toronto Hydro's system investment plan for 2025-2029 are discussed in Exhibit 2B, Section E2.2.

D3.4.3 Portfolio Planning

The Portfolio Planning process produces program-level expenditure plans in alignment with the utility's asset management objectives. As part of Portfolio Planning, asset-related data from the CSA is combined with system-wide information regarding known challenges facing the distribution system in order to assess asset and system needs. Toronto Hydro relies on the analyses and decision support tools (as discussed in Section D3.2 and Section D3.3) to identify assets or areas with high levels of risk requiring intervention. When identifying and proposing portfolios, the utility also accounts for customer feedback resulting from regular customer engagement activities. Customers' needs and preferences are a key input for determining the investments needed to meet customers' expectations on service.

During the Portfolio Planning process, Toronto Hydro develops investment requirements for managing system assets and challenges, based on the condition of assets, age of assets, risks of asset failure, legacy assets within the system, load growth, and opportunities for modernization. The

analysis of assets from both a risk and outcomes perspective during the investment planning process ultimately drives the development (and management) of capital programs, which are detailed in Exhibit 2B, Sections E5 to E7 of the DSP.

The various risk analyses presented in Section D3.2 and Section D3.3 drive the overall investment required to manage the distribution system. Toronto Hydro assesses its entire asset base in light of the risks discussed above. Assets that are past their useful life or in HI4 ("material deterioration") or HI5 ("end of serviceable life") condition are identified, as defined earlier in Section D2.2. Information regarding historical failures is combined with asset level information to better understand not just the probability of failure but the cause of failure as well. The configuration of the system is also analyzed in these cases to see if inherent design limitations are contributing to increased risk for specific assets or types of configurations in the system. For example, the presence of legacy assets, such as paper-insulated lead-covered ("PILC") cable and asbestos-insulated lead-covered ("AILC") cable, can often result in safety or environmental consequences. The severity of the risk posed by these assets is considered when deciding whether to invest in replacing these assets proactively and also in determining the correct pace of replacement. Ultimately, similar types of interventions with the same driver are aggregated into capital programs. The expected probability of failure and historical reliability information also drives the requirement for Reactive and Corrective capital in order to address the level of failures observed.

In addition, Toronto Hydro must consider work that must be accomplished as part of its mandate (e.g. pursuant to the Distribution System Code), and responsibility as a Local Distribution Company ("LDC"). These investments may be demand driven or initiated by a third-party, and are categorized as System Access programs, such as Customer Connections or Externally Initiated Plant Relocations.

Program expenditures are then aggregated to create a total investment plan for any given year. The impact of the cumulative investment plan on outcomes is considered to ensure that investments are made in a prudent manner that manages the various risks discussed in this section while providing value for the customer.

Toronto Hydro considers, on an aggregate level, the impact of various investment levels on outcome measures (for example, SAIFI, SAIDI, and System Capacity). By forecasting the performance of key outcome measures over the long-term under proposed investment levels, Toronto Hydro is able to understand trade-offs in investing in different programs and at different investment levels. This initial

investment requirement represents a bottom-up needs assessment by system planners for the optimal expenditure levels required.

Various investment strategies are reviewed and deliberated internally before selecting a proposed approach. Once investment plans are reviewed, the information becomes a foundational input as part of other corporate business planning activities.

For more details on how these activities unfolded for the 2025-2029 Capital Expenditure Plan, see Exhibit 2B, Section E2.

D3.4.4 Portfolio Reporting

The IPPR process also creates a feedback loop that provides information about program level completion and historical work executed in each program.

Information is reported on an individual project basis and includes the project's total spending and assets replaced or installed in any particular program. This data is broadly used within Toronto Hydro in assessing the status of capital programs as a result of the completed projects. This was first outlined in Section D1.2.1.3 under the discussions regarding the IPPR process. The aggregate of project-specific expenditures and asset units installed indicates how much of the capital investment program has been executed relative to the target for the program. Reporting is an important component in the process as it provides feedback on Toronto Hydro's ability to execute proposed investments as well as an opportunity to revisit and adjust plans for the upcoming years if needed.

D3.4.5 Project Development and Prioritization

As part of short-term planning activities, once capital investment programs are established, as explained in Section D3.4.3, assets and issues identified for each program are addressed as part of discrete capital projects. As explained within Section D1.2.2, the scope and project development process includes four phases: (i) identification of specific needs; (ii) assessment of options; (iii) high level scope creation; and (iv) refinement of scope and cost estimation.

During the first two phases, investment planners analyze discrete portions of the distribution system, such as a neighbourhood or street, in order to identify projects that align with the investment program criteria and drivers. Depending on the investment program driver and program type (i.e. core renewal, critical issues, or other necessary day-to-day operational investments), enterprise data is used to identify assets at a discrete level so that investment opportunities are identified, risk is

managed, and outcome objectives are achieved. For example, with respect to a program driven by failure risk, enterprise systems and the analyses discussed in Section D3.2 can be utilized to identify the program-level prioritized assets that align with this driver.

In addition, ACA results can be used to identify those assets in HI4 and HI5 bands. Reliability analytics can be used to cross-reference studied locations against historical reliability events and performance issues. Finally, enterprise systems including the GIS are used to further support the study process, by providing supplementary details such as age, asset type and sub-type information.

For safety or capacity constraint-driven programs, nameplate information or localized data (as per the load forecasting process, discussed in Section D3.3) may be used to identify specific investment needs.

When an investment need for a project within a particular investment program has been confirmed and verified, phase three of the Scope and Project Development is carried out. A project draft, also known as scope of work, is produced which confirms the assets to be replaced, and establishes the high-level design for the new assets to be installed. While some projects may involve assets replaced in-kind, other projects may result in the installation of new assets in a new configuration. Examples include the conversion of overhead plant rear lot to underground plant in order to minimize outages caused by external factors, or the re-configuration of radial circuits to looped circuits and redistribution of load in order to reduce outage duration and impacts. Ultimately, the high-level forecasts produced via the long-term planning process will be further refined into an annual capital budget, as more rigorous project estimates are produced.

In tandem with producing the high-level design, Toronto Hydro documents the scope of work to be performed and produces a high-level cost estimate to execute the project. Efficiency savings can be realized by addressing the prioritized assets and issues along with adjacent assets that also require intervention as a single project, as opposed to replacing these assets individually on a reactive basis. Toronto Hydro is undertaking a multi-year project to implement its EAIP system. Projection information will be stored within this system, along with key supporting data points and impacted assets, to enable value calculations by applying Toronto Hydro's custom Value Framework. A project study may also be divided into multiple project drafts where necessary to allow construction to be executed in manageable pieces that are minimally intrusive to both the general public as well as customers. As part of the project development process, Toronto Hydro also considers issues such as city road moratoriums, physical restrictions, or particular design related problems that may delay

the project or require a redesign. The project draft then undergoes a quality control assessment, before proceeding into the project finalization stage through the planning supervisor.

Once approved, the project is further refined both in terms of the scope of work as well as the cost estimate. As part of this process, field visits are conducted to ensure accuracy of the data that is used, obtain additional information and measurements, and to understand other potential risks for construction. Permitting requirements are also dealt with at this stage. This process results in a more refined project draft and cost estimate.

Ultimately, a series of projects are produced for each investment program, which results in further refinement to the capital investment spending levels for the associated program. Once the projects are finalized, they will be scheduled for execution based upon the Project Management and Execution process outlined in D1.2.3. Each project is scheduled based upon relative priority, resource availability, and system constraints (e.g. contingency issues or summer switching restrictions). Factors that impact project scheduling and execution include:

- Project scope and requirements, for example, asset delivery to locations and complexity of the site;
- External constraints such as coordination with external groups;
- Permitting and moratoriums;
- Supply chain;
- Coordination between other projects; and
- Resource balancing.

As part of scheduling, investment planners and program managers meet to discuss the relative priority of the various projects to establish the capital work program for execution in a given year. Toronto Hydro is currently on track to begin leveraging the optimization capabilities of its EAIP tool for the vast majority of its investment programs by the beginning of the 2025-2029 period. The implementation of EAIP will allow Toronto Hydro to implement and adopt a consistent and robust measure of value (and risk) for improved asset management decision making.

As part of the execution process, the detailed project design and estimate are produced to finalize capital investment spending levels. To address any required change to the project cost, schedule, or scope of work, Toronto Hydro maintains a change management and governance process. This process provides visibility across all relevant stakeholders on major project changes, requiring

approval so that the change is appropriately processed and documented for awareness regarding lessons learned for future projects.

Asset Condition Assessment

Methodology Update and 2022 Results Analysis

1. Introduction

Asset Condition Assessment ("ACA") involves the use of condition inspection data to estimate the remaining serviceable life of physical assets. Utilities periodically inspect physical assets to monitor signs of degradation (e.g. visible corrosion) that can lead to asset failure. Inspection data on its own is useful in identifying and prioritizing assets for maintenance, refurbishment, or replacement. An ACA augments inspection data for assets by processing such data to arrive at a health score that represents an asset's condition and proximity to end of serviceable life.

This report highlights changes to Toronto Hydro's approach to ACA since implementing the Condition Based Risk Management framework ("CBRM") in 2017[1] and summarizes the ACA results for 2022 year-end ("YE"), including projections to 2029YE.[2] For convenience, the 2017YE results are also produced. Section 2 summarizes the key changes Toronto Hydro implemented to its ACA methodology, including continuous improvement efforts to implement additional components of the CBRM.

Section 3 highlights the ACA results for 2017YE, 2022YE, and projections for 2029YE, which are also summarized in Exhibit 2B, Section D3, Appendix B. Planners use inspection data and individual HI scores – in combination with other information and professional judgement – to prioritize assets for tactical intervention in the short- to medium-term. This includes identifying priority deficiencies that require reactive or corrective action and prioritizing assets for planned renewal projects in a given budget period. At a strategic level, Toronto Hydro uses ACA results to examine condition demographics and trends within major asset classes. ACA results (i.e. Health Scores) for a particular asset class are grouped into five Health Index ("HI") bands that represent key stages of an asset's lifecycle, ranging from new or like-new condition to the stage where asset degradation is significant enough to warrant urgent attention. This information supports the development of longer-term investment plans and serves as an important input into Toronto Hydro's 2025-2029 DSP. For more details on how Toronto Hydro leverages ACA within its Asset Management framework, please refer to Section D3.

2. Summary of Enhancement to ACA Methodology

Within CBRM there are three main aspects: Asset Health, Asset Criticality, and Asset Risk, with the latter being a combination of the first two. Each of these can be expressed as an index, which indicates relative value, or a specific value (probability or monetary). As part of its initial implementation in 2017, Toronto Hydro focussed on Asset Health expressed through the Health Index, which fully replaced and improved upon its previous asset health methodology. Since then, Toronto Hydro continues to review and refine the existing methodology, as well as build on it by adopting incremental components of CBRM, including condition-driven Probability of Failure ("PoF") on the Asset Health side and Consequence of Failure ("CoF") on the Asset Criticality side. Toronto Hydro retained EA Technology to help guide this process and to review the improvements as well as identify opportunities for continuous improvement. EA

[1] See EB-2018-0165, Exhibit 2B, Section D, Appendix C for details.

[2] The specific implementation of CBRM used by Ofgem for regulatory purposes is called the Common Network Asset Indices Methodology, or "CNAIM".

Technology's review of Toronto Hydro's current ACA models and results is included in Exhibit 2B, Section D3, Appendix C.

Table 1 below summarizes the material refinements introduced to the Asset Condition Assessment Methodology.

Table 1: Material Refinements to ACA Asset Models

Refinement	Description	Impacted Asset Models
Normal Expected Life	Toronto Hydro implemented changes to the normal expected life within the ACA models of impacted asset classes to reflect revisions to useful life values in light of its updated Depreciation Study completed by Concentric Inc.[3]	• Underground Transformer (Submersible, Padmount, & Vault) • Air Insulated Pad-mount Switches • Network Protectors • SCADAMATE switches • Circuit Breaker (Air Blast, Air Magnetic) • Station Power Transformer
Wood Pole Asset Model Refinement	The condition factor for the Wood Pole model was refined based on Toronto Hydro's field experience to better reflect specific condition parameters. Specifically, the level of granularity was increased within the models for the following condition parameters: Pole Base Rot was separated into: • Pole Base Rot (At/Below Ground Level) • Pole Base Rot (Above/ Level) Pole Void was separated into: • Pole Void (Wood Loss) • Pole Void (Hollow Heart/Pockets Present) Bird/Animal Damage: • Calibrated factor for "Extensive" condition observation Pole Separation was separated into: • Pole Separation (Cracks) • Pole Separation (Pole Top Feathering)	• Wood Pole

[3] Available at Exhibit 2A, Tab 2, Schedule 1, Appendix D. While the Depreciation Study was intended primarily to determine useful lives for financial purposes, Toronto Hydro leveraged insights gained from that exercise to review and revise as appropriate its 'engineering' or 'planning' useful lives.

Continuous Improvement:

In addition to the refinements and enhancements above, Toronto Hydro is in the process of implementing condition-driven PoF curves for applicable asset classes. For a given asset, the PoF per annum can be calculated with the following cubic relationship:

$$PoF = k \cdot \left(1 + (H \cdot C) + \frac{(H \cdot C)^2}{2!} + \frac{(H \cdot C)^3}{3!}\right)$$

Where:

- k, C – Asset class specific constants
- H – Asset health score unless $H \geq 4$, 4 otherwise

Historical failure data in conjunction with the calculated health scores are used to determine PoF parameters on an asset class basis.

In addition to the PoF, Toronto Hydro intends to implement the Consequence of Failure ("CoF") and Criticality aspects of CBRM, co-ordinating and aligning with Value Framework developments for System Renewal investments as part of its implementation of an Asset Investment Planning ("EAIP") system. For details on Toronto Hydro's Value Framework developments, please see Section D1.2.1.1 and D3.2.1.1.

3. Health Score Results

Tables 3-5 and Figures 1-3 provide a summary of the health index distribution for each asset class by count and percentage:

- Historical, as of the end of 2017;
- Current, as of the end of 2022
- Future, projected for year end 2029

The health bands are defined as per table 2 below:

Table 2: Health Index bands and definitions

HI Band	Lower Limit of Health Score	Upper Limit of Health Score	Definition
HI1	≥ 0.5	< 4	New or good condition
HI2	≥ 4	< 5.5	Minor deterioration; in serviceable condition
HI3	≥ 5.5	< 6.5	Moderate deterioration; requires assessment and monitoring
HI4	≥ 6.5	< 8	Material deterioration; consider intervention
HI5 (Current Health)	≥ 8	≤ 10	End of serviceable life; intervention required
HI5 (Future Health)	≥ 8	≤ 15	

Table 3: Summary of Health Index Distribution as of year end 2017.

Asset Class	Health Score				
	HI1	HI2	HI3	HI4	HI5
Cable Chambers	8,112	1,162	1,350	398	89
4kV Oil Circuit Breaker	36	4	123	24	
AirBlast Circuit Breaker	15	9	206	1	3
Air Magnetic Circuit Breaker	145	90	247	21	53
Oil KSO Circuit Breaker	10	7	11	11	1
SF6 Circuit Breaker	130	6	18	3	3
Vacuum Circuit Breaker	578	46	13	2	29
Network Protectors	1,086	185	319	74	26
Overhead Gang operated Switches	854	27	76	3	9
Air Insulated Padmount Switch	404	20	73	30	45
SF6 Insulated Padmount Switch	402	-	2	-	6
SCADAMATE Switches	1,084	1	26	-	8
Air Insulated Submersible Switch	755	79	27	7	-
SF6 Insulated Submersible Switch	353	14	7	3	19
Station Power Transformers	83	77	61	13	8
Network Transformers	1,334	255	166	60	7
Padmount Transformers	5,547	656	283	113	18
Submersible Transformers	7,816	588	271	172	55
Vault Transformers	6,807	4,315	450	214	45
Underground Vaults (Combined)	1,017	186	72	12	29
ATS Vaults	8	-	-	-	-
CLD Vaults	21	-	-	-	-
CRD Vaults	9	-	1	-	-
Network Vaults	322	120	63	11	29
Submersible Switch Vaults	115	5	-	-	-
URD Vaults	542	61	8	1	-
Wood Poles*	63,526	7,354	29,779	5,687	722

*Please note that Wood Pole results are re-calculated based on the refinement to the Wood Pole asset model highlighted in Table 1 above.

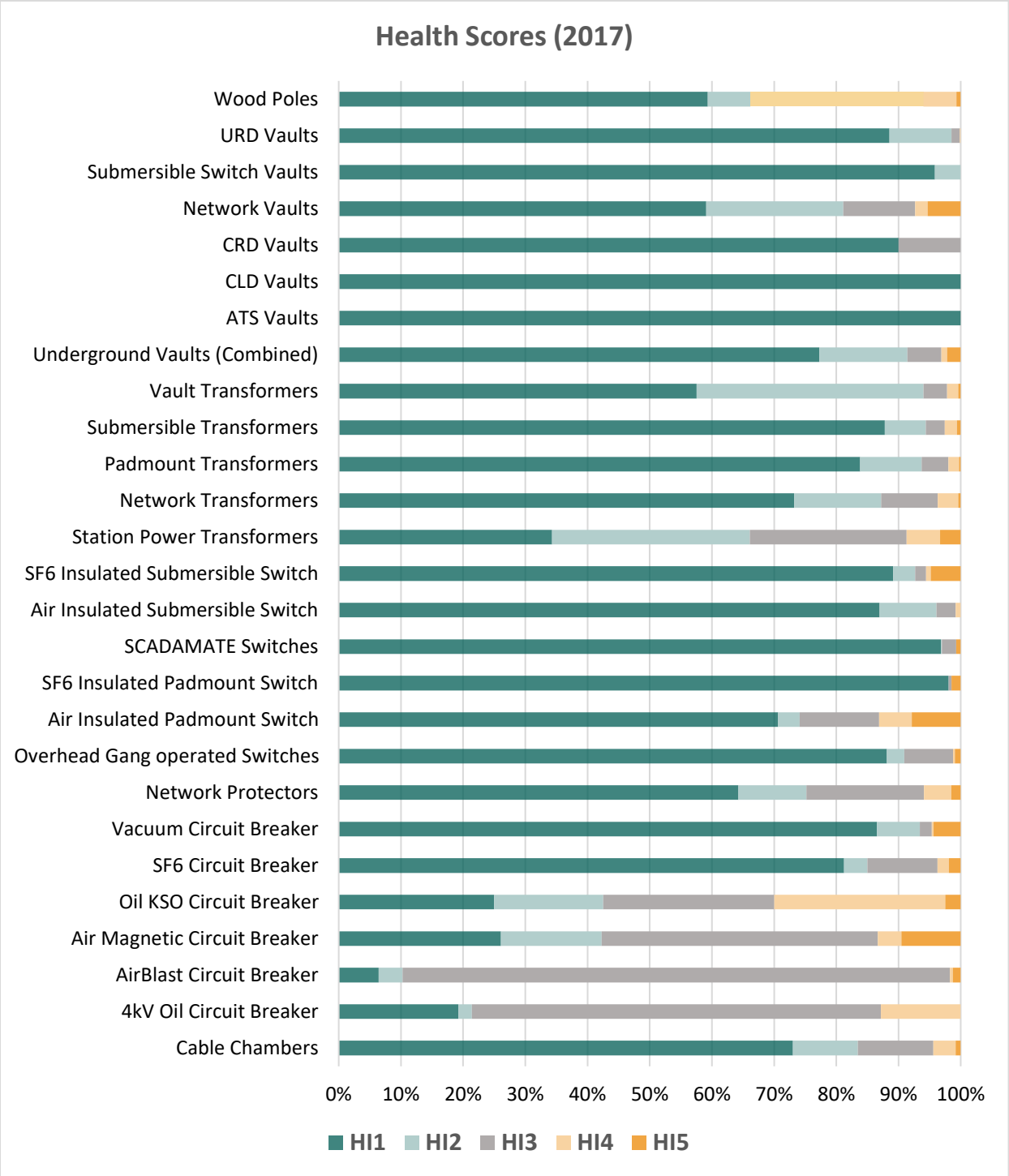
Table 4: Summary of Current Health Index Distribution as of year end 2022.

Asset Class	Health Score				
	HI1	HI2	HI3	HI4	HI5
Cable Chambers	6,640	1,346	2,079	462	130
4kV Oil Circuit Breaker	4	-	53	-	1
AirBlast Circuit Breaker	2	1	137	8	8
Air Magnetic Circuit Breaker	61	47	357	2	27
Oil KSO Circuit Breaker	1	13	9	-	-
SF6 Circuit Breaker	121	6	2	4	-
Vacuum Circuit Breaker	803	12	10	-	-
Network Protectors	1,342	129	233	21	3
Overhead Gang operated Switches	659	98	88	10	13
Air Insulated Padmount Switch	359	4	64	24	29
SF6 Insulated Padmount Switch	663	-	-	1	16
SCADAMATE Switches	1,078	9	66	4	13
Air Insulated Submersible Switch	720	183	67	7	-
SF6 Insulated Submersible Switch	437	18	15	7	10
Station Power Transformers	87	66	12	8	-
Network Transformers	1,370	244	61	40	3
Padmount Transformers	5,142	1,085	527	233	24
Submersible Transformers	8,120	699	162	133	47
Vault Transformers	6,799	3,869	571	247	11
Underground Vaults (Combined)	870	164	49	53	47
ATS Vaults	5	1	-	1	-
CLD Vaults	20	2	-	-	-
CRD Vaults	8	3	-	-	-
Network Vaults	225	110	44	46	45
Submersible Switch Vaults	70	3	-	-	-
URD Vaults	542	45	5	6	2
Wood Poles*	68,288	7,566	21,073	8,950	509

Table 5: Summary of Future Health Index projected for year end 2029.

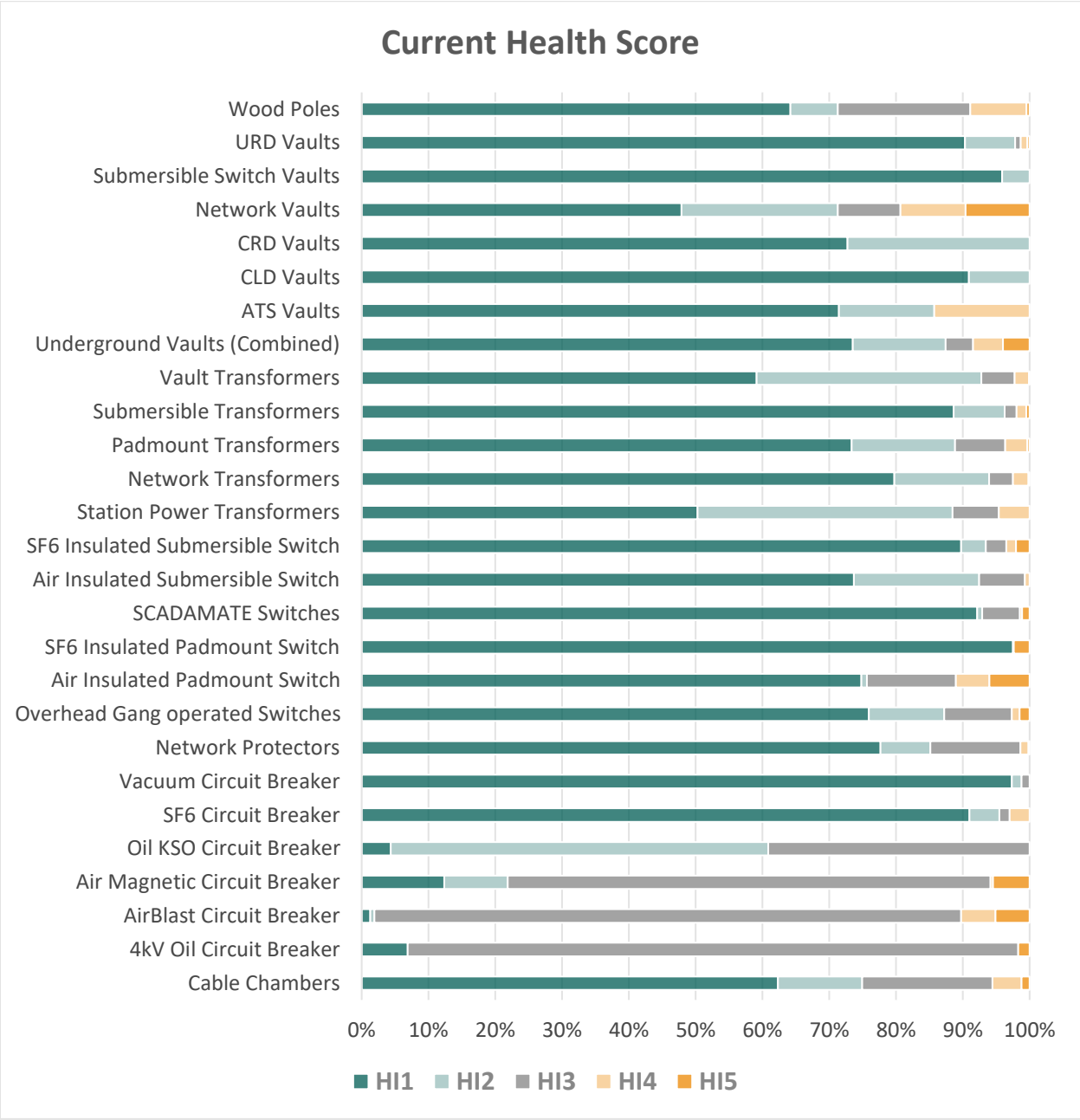
Asset Class	Health Score;				
	HI1	HI2	HI3	HI4	HI5
Cable Chambers	6,015	1,026	2,503	535	578
4kV Oil Circuit Breaker	4	-	29	24	1
AirBlast Circuit Breaker	2	-	97	43	14
Air Magnetic Circuit Breaker	11	50	41	361	31
Oil KSO Circuit Breaker	1	-	8	14	-
SF6 Circuit Breaker	93	28	4	2	6
Vacuum Circuit Breaker	786	17	10	12	-
Network Protectors	1,298	40	56	187	147
Overhead Gang operated Switches	517	106	111	91	43
Air Insulated Padmount Switch	320	18	13	16	113
SF6 Insulated Padmount Switch	663	-	-	-	17
SCADAMATE Switches	724	65	69	149	163
Air Insulated Submersible Switch	667	53	152	90	15
SF6 Insulated Submersible Switch	419	26	9	6	27
Station Power Transformers	82	11	60	12	8
Network Transformers	1,243	111	215	87	62
Padmount Transformers	4,451	542	887	595	536
Submersible Transformers	7,330	642	635	240	314
Vault Transformers	5,220	1,668	3,595	587	427
Underground Vaults (Combined)	848	101	83	52	99
ATS Vaults	4	1	1	-	1
CLD Vaults	20	-	2	-	-
CRD Vaults	8	3	-	-	-
Network Vaults	207	92	34	47	90
Submersible Switch Vaults	68	4	1	-	-
URD Vaults	541	1	45	5	8
Wood Poles*	60,308	8,350	5,570	24,464	7,694

Figure 1: Health Score Distribution by Asset Class as of year end 2017



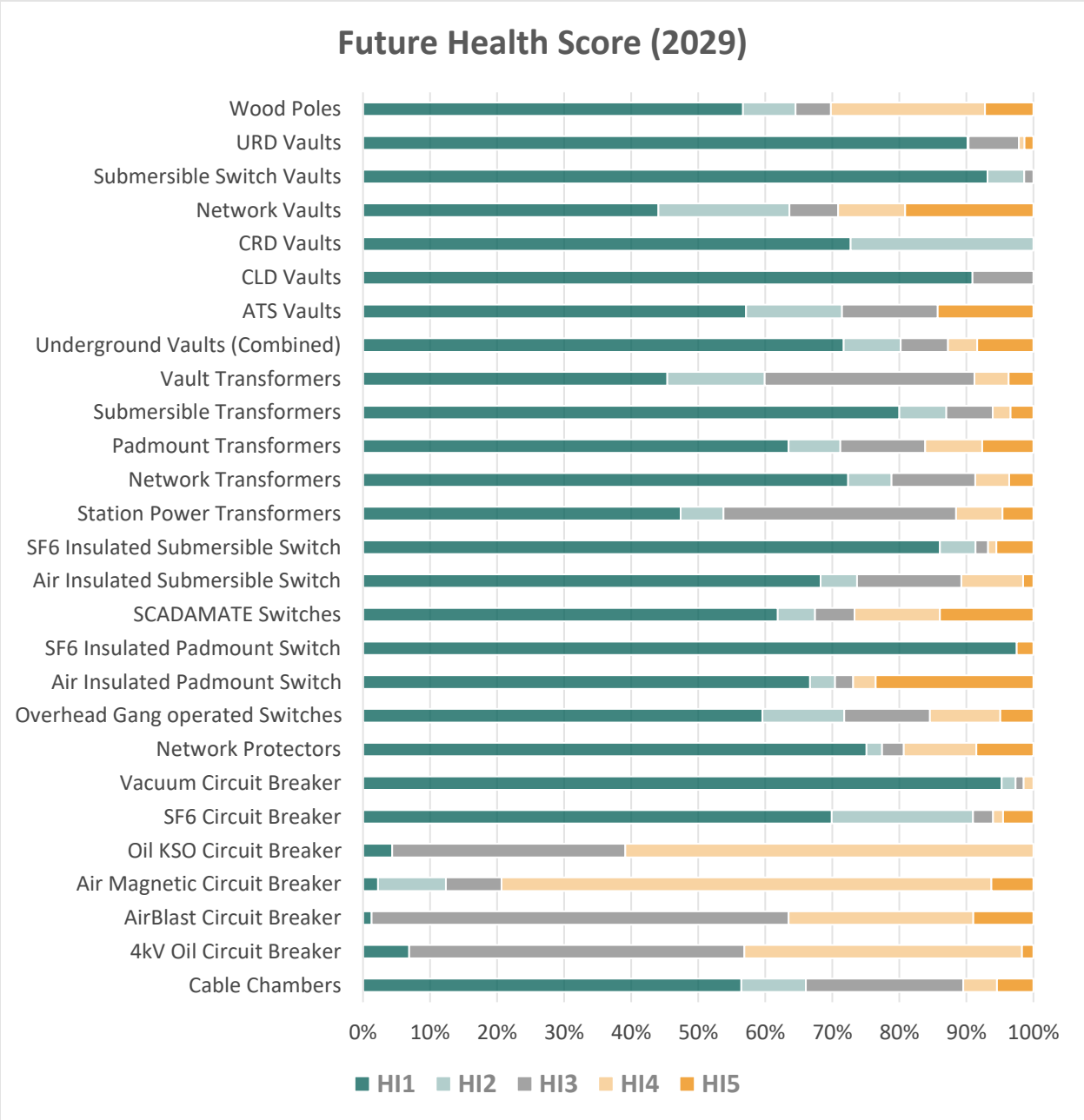
HI1 - New or good condition; HI2 - Minor deterioration, in serviceable condition; HI3 - Moderate deterioration, requires assessment and monitoring; HI4 - Material deterioration, consider intervention; HI5 - End of serviceable life, intervention required;

Figure 2: Current Health Score Distribution by Asset Class as of year end 2022

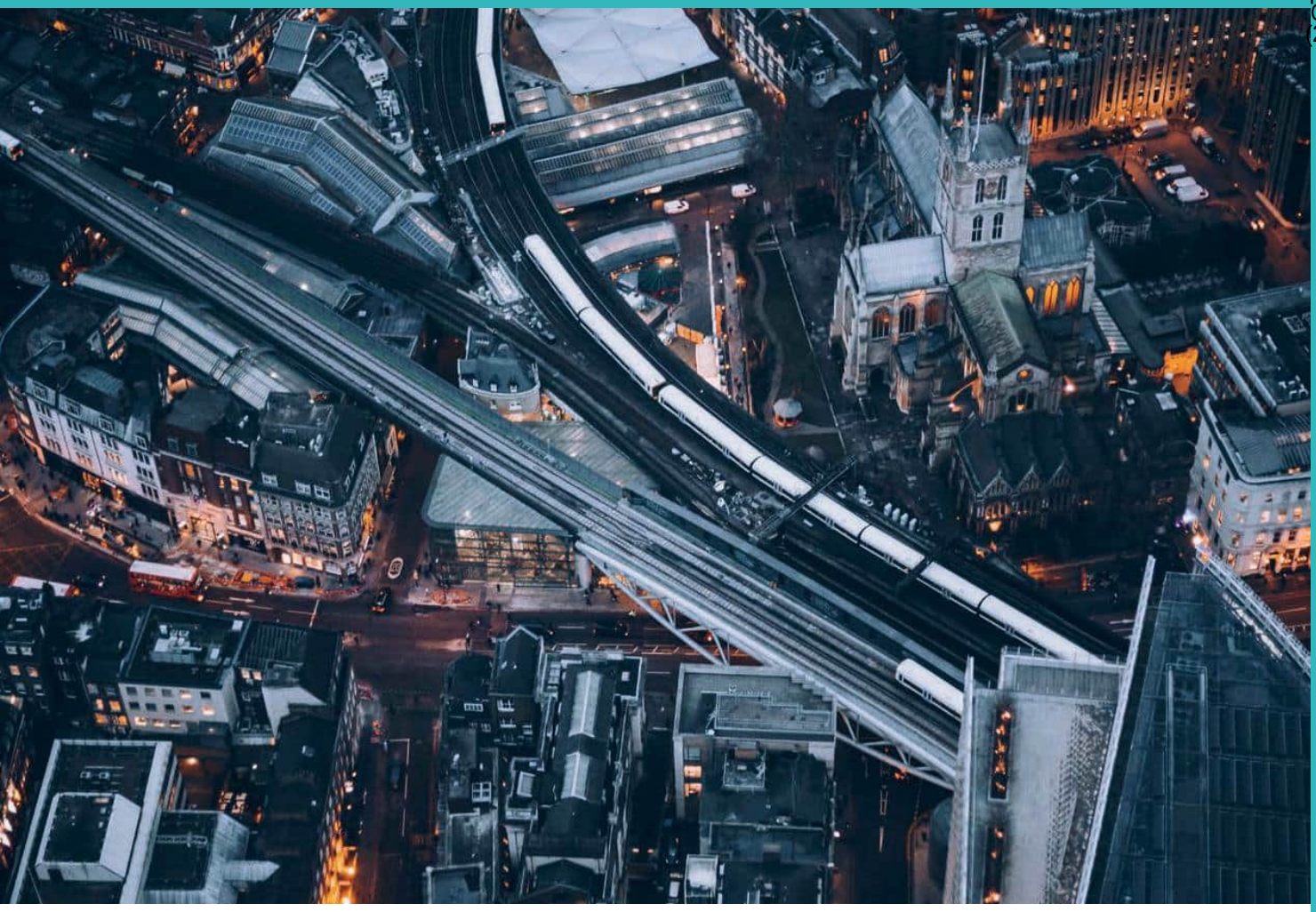


HI1 - New or good condition; HI2 - Minor deterioration, in serviceable condition; HI3 - Moderate deterioration, requires assessment and monitoring; HI4 - Material deterioration, consider intervention; HI5 - End of serviceable life, intervention required;

Figure 3: Future Health Score Distribution by Asset Class for year end 2029



HI1 - New or good condition; HI2 - Minor deterioration, in serviceable condition; HI3 - Moderate deterioration, requires assessment and monitoring; HI4 - Material deterioration, consider intervention; HI5 - End of serviceable life, intervention required;



REPORT

Review of ACA Modelling Enhancements and Customisations

Private and Confidential

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1. Introduction

Toronto Hydro-Electric System Limited (THESL), is a wholly owned subsidiary of Toronto Hydro Corporation, and is the largest municipal electricity company in Canada. Its electrical distribution network comprises of over 13,500km of underground cables and 15,000km of overhead lines that distribute around 19% of the electricity consumed in the province of Ontario to approximately 790,000 customers located within the city of Toronto and its surrounding area.

THESL is recognised within the region as a sustainable electricity company and is committed to develop its in-house capabilities through continuous improvement. Within the discipline of asset management, this has included an undertaking to implement a series of Asset Condition Assessment (ACA) models based on the Common Network Asset Indices Methodology (CNAIM).

CNAIM, or the Common Methodology as it is often referred to, is the approach used by Distribution Network Operators (DNOs) in Great Britain to report asset health and criticality as part of their regulatory reporting requirements. EA Technology has supported the GB Distribution Network Operators through the development of CNAIM and has worked with the majority of the GB DNOs to implement the methodology and embed it within their organisations.

In 2017/8, THESL, supported by EA Technology, successfully completed a project to develop, build and commission a suite of enhanced CNAIM-based ACA models to support their endeavours pertaining to the adoption of an advanced condition-based approach for electrical system planning, the strategic evaluation of both capital investments and day-to-day maintenance activities.

Since 2021 THESL has embarked on the process of enhancing its implementation of the ACA methodology, including implementation of probability of failure (PoF) and consequences of failure (CoF). EA Technology was engaged to provide guidance and feedback on the derivation of appropriate inputs to the PoF and CoF calculations.

This latest engagement involves an independent review of the ACA implementation, enhancements and customisations made by THESL since 2018. Consideration has been given to the general outputs of the enhanced THESL ACA models, alignment with the core principles of the CNAIM methodology, and the generally accepted industry practices for condition and risk-based asset management within an electrical distribution arena.

1.1 Scope and Objectives

The agreed scope of work to be undertaken by EA Technology comprises of three main activities:

- Task 1: a review of the changes and enhancements THESL has made to its health score methodologies since 2018.
- Task2: a review of the current and future health score outputs for three asset classes selected by THESL.
- Task 3: a review of THESL's implementation of probability of failure, consequence of failure, asset criticality and risk.

The objective of this undertaking is to provide assurance to THESL that the enhancements and customisations introduced into the ACA models since 2018 align with the core principles of the CNAIM methodology.

This piece of review work has been undertaken remotely and is limited to the materials supplied by THESL which, where necessary, have been supported by clarifications made via video conference meetings.

2. Definitions

The following terms and abbreviations are contained within this document:

ACA	Asset Condition Assessment
BOSCEM	Basic Oil Spill Cost Estimation Model
CAD	Canadian Dollar
CBRM	Condition Based Risk Management
CI	Customer Interruption
CMI	Customer Minutes of Interruption
CNAIM	Common Network Asset Indices Methodology
CoF	Consequence of Failure
DNO	Distribution Network Operator
GB	Great Britain
HI	Health Index
HS	Health Score
ITIS	Interruption Tracking Information System
kV	Kilovolt
PoF	Probability of Failure
PCB	Polychlorinated Biphenyl
SF_6	Sulphur Hexafluoride
THESL	Toronto Hydro-Electric System Ltd.
UG	Underground
WSIB	Workplace Safety and Insurance Board

3. THESL ACA Model Portfolio

Following completion of the initial ACA model development project in 2018, THESL currently operate and maintain a total of 21 asset condition assessment models. These models are listed in Table 1 below.

Table 1 Breakdown of THESL ACA models by Asset Type

Asset Type	THESL ACA Model / Asset Class
Switchgear	Air Insulated Pad-mounted Switches Air Insulated Submersible Switches Air Magnetic Circuit Breakers Air Blast Circuit Breakers Network Protectors Oil Circuit Breakers Oil KSO Circuit Breakers Overhead Gang Operated Switches SCADAMATE Switches SF_6 Circuit Breakers SF_6 Insulated Pad-mounted Switches SF_6 Insulated Submersible Switches Vacuum Circuit Breakers
Transformer	Network Transformers Pad-mount Transformers Station Power Transformers Submersible Transformers Vault Transformers
Overhead Line	Wood Poles
Civils	Cable Chambers UG Vaults

The initial ACA model development project was immediately followed by an independent review which was completed by specialist asset management consultants from EA Technology with expert asset condition modelling knowledge. This review recommended that changes to the ACA model calibration and its associated processes were made in order to disassociate the ACA model outputs from established THESL tactical asset management practice, which would allow the core CNAIM methodology to provide a more strategic view of the asset portfolio.

Following a short series of specialist asset management training sessions, and with the support provided by EA Technology, THESL successfully revised the calibrations such that the ACA models were less reliant upon computational caps and collars designed to 'force' health score calculations subject to the identification of user-specified asset deficiencies obtained through programmes of inspection. It is understood that the ACA models were internally reviewed by THESL to ensure real-world alignment before the models were 'frozen' prior to the start of preparations for the 2018/2019 regulatory filing.

4. ACA Asset Health Score Review

4.1 Introduction

Task 1 has involved a review of THESL's ACA model inputs and calibrations to identify any changes that have been made to the ACA Health Score derivation methodology since the models were previously frozen in 2018.

The review has considered:

- the full range of ACA models contained within Table 1 above;
- variation(s) in information sources, data validation, and input data fields which feed the ACA models' computational algorithms;
- changes to data processing approach, algorithm format, and calculation sequence;
- the process of ACA Health Score calibration employed by THESL;
- any revisions to calibration values (including condition caps and collars) and, where appropriate;
- THESL's rationale and justification for change.

4.2 Review of Findings

The independent desktop review has considered the information provided by THESL, from which it appears that THESL's asset management function remains comfortable with the vast majority of the previously frozen 2018 ACA models.

Information exchanged between THESL and EA Technology has confirmed that THESL have explored the possibilities for further ACA model development behind the scenes. Consideration has been given to potential solutions pertaining to geographic, situational and locational influences thought to directly affect asset health. However, difficulties have been experienced with a number of potential avenues explored in terms of data quality, availability, and ease of data maintenance. These issues are considered to affect the repeatability of ACA modelling over time, and therefore THESL have elected not to include this data enhancement until such time that a more enduring solution can be found. A summary table of ACA model modifications is provided in Table 2 below.

THESL have confirmed that there have been no notable changes in asset inspection and maintenance programmes since the last review, and that input data sourcing, processing and validation approaches remain unchanged since 2018, and therefore no changes to the number of model input data fields have been made.

Table 2 Summary of ACA Methodology Changes 2018 to Present

	Changes to ACA Model							
THESL ACA Model / Asset Class	Information Source?	Source Data Validation?	Model Input Data Fields?	Computational Algorithm Format?	Calculation Sequence?	Calibration Process?	Calibration Value?	Caps or Collars?
Air Insulated Pad-mounted Switches	No	No	No	No	No	No	No	No
Air Insulated Submersible Switches	No	No	No	No	No	No	No	No
Air Magnetic Circuit Breakers	No	No	No	No	No	No	No	No
Air-Blast Circuit Breakers	No	No	No	No	No	No	No	No
Cable Chambers	No	No	No	No	No	No	No	No
Network Protectors	No	No	No	No	No	No	No	No
Network Transformers	No	No	No	No	No	No	No	No
Oil Circuit Breakers	No	No	No	No	No	No	No	No
Oil KSO Circuit Breakers	No	No	No	No	No	No	No	No
Overhead Gang operated Switches	No	No	No	No	No	No	No	No
Pad-mounted Transformers	No	No	No	No	No	No	No	No
SCADAMATE Switches	No	No	No	No	No	No	No	No
SF_6 Circuit Breakers	No	No	No	No	No	No	No	No
SF_6 Insulated Pad-mounted Switches	No	No	No	No	No	No	No	No
SF_6 Insulated Submersible Switches	No	No	No	No	No	No	No	No
Station Power Transformers	No	No	No	No	No	No	No	No
Submersible Transformers	No	No	No	No	No	No	No	No
UG Vaults	No	No	No	No	No	No	No	No
Vacuum Circuit Breakers	No	No	No	No	No	No	No	No
Vault Transformers	No	No	No	No	No	No	No	No
Wood Poles	No	No	No	Yes	No	No	Yes	No

From a computational perspective, the high-level desktop review has found that modification to the THESL ACA Health Score methodology has only taken place within a single asset class, namely wood poles. For all other asset classes, the previously established input information sources, data validation techniques, computational algorithms and calculation sequences are understood to remain unchanged. THESL stand by the results produced by these models and have stated that their approach to ACA model verification, review and calibration continues to be directly aligned with earlier guidance and direction provided by EA Technology and continues to remain effective. Therefore modification of these ongoing ACA models and their associated maintenance processes has been deemed unnecessary.

Within the Wood Pole ACA model, the identified changes are considered to represent a significant indication of asset management maturity development and evidence of THESL's adoption and engagement with advanced asset management techniques. The modifications made to the wood pole ACA model are considered to be comparatively minor in nature, as they relate specifically to the observed condition point factor derivation. However, this act of refinement demonstrates the existence of functioning closed loop feedback channels within the organisation's asset management system, and proof that they are being effectively used.

Wood pole structures owned and operated by THESL are understood to be subject to a lengthy, 10 year inspection cycle, of which only a proportion of the asset population are condition assessed in any one year. This approach to asset inspection is commonplace as, if implemented correctly, the condition of other assets within the wider population can be either implied or inferred, reducing resource requirements and operational costs. However, this inspection approach also has a significance during ACA methodology and model development, as traditionally asset managers raise concerns about the ability of field data to accurately reflect the condition of physical assets which have not been inspected for a long period of time. Hence, the development of ACA models in such circumstances often takes place using only a proportion of the wood pole asset population and/or inspection information – which is neither unusual nor unexpected during asset modelling solution development.

Following the completion and commissioning of ACA models for asset classes with long inspection periods, over a period of time updated asset inspection data is collected, processed, and used to inform health score calculation. Gradually inference and implied condition are replaced with real condition data which enables the generation of more accurate asset health profiles.

ACA model outputs need to be subjected to regular review in order to reduce the risk of model drift – where the results produced by condition assessment modelling systems start to vary such that they gradually no longer accurately reflect the "real-world" physical asset condition. The key control to protect against drift being either re-calibration or model refinement.

As an organisation, THESL have acquired vital essential modelling experience with their updated ACA methodology and solution and are understood to have conducted a series of regular ACA model output reviews and tests. It is through this analysis that THESL have identified the early signs of conservative model drift, in which the health score profiles generated by the ACA system relating to wood poles are being recognised as being too pessimistic. i.e. are being represented by a higher health score than would be expected.

Evaluation of the ACA results has identified examples of field inspectors discovering multiple minor pole defects, small pole voids or low levels of pole rot at a wood pole structure being interpreted by ACA models as causing potential for an unacceptable increase in probability of failure, thereby directing intervention. THESL recognise such identified attributes as potential concerns; however, within the existing wood pole management framework, they would not provide a sufficient justification for significant capital intervention.

In part, this situation has been caused by inexperience and unfamiliarity pertaining to health score definition and interpretation and is likely to have been as a result of an overstatement of specific observed condition point influence during the model's initial development and calibration. The resulting effect being a natural misalignment of health score values during a period of bedding in and condition data refreshment.

EA Technology understand that the condition data input 'Pole Rot' was initially a combination of three data fields (Surface Rot Below Ground Level, Surface Rot at Ground Level, and Surface Rot Above Ground Level) collected during routine inspection. The data input into the ACA model was the worst of the recorded inspection results, with a commonly applied calibration. Following a review of the model outputs, THESL identified that the resultant condition factor was providing an excessive influence within the health score derivation. By separating these originally combined input data fields and using individual calibration tables, a higher degree of influence control can be obtained. THESL's ACA model refinement now treats the observed condition points 'Pole Base Rot (At/Below Ground Level)' and 'Pole Base Rot (Above Ground Level)' separately.

In the 2018 wood pole model, the observed condition points 'Pole Void' and 'Pole Separation' were treated in a similar way to 'Pole Rot'. The worst of two recorded inspection results formed the input into the ACA model, again, with a commonly applied calibration. Following the review of the results from the model outputs, THESL have separated the inputs as shown in Table 3 and included individual calibration tables to increase the modelling effect of moderate hollow hearts/pockets presence and reduce the modelled effect of pole structures found to possess slight cracks when compared to structures suffering with slight pole top feathering.

Table 3 Observed Condition Inputs for Pole Voids and Pole Separation in 2018 and 2022 Models

ACA Model 2018	ACA Model 2022
Pole Void	Pole Void (Wood Loss) Pole Void (Hollow Heart/Pockets Present)
Pole Separation	Pole Separation (Cracks) Pole Separation (Pole Top Feathering)

As part of the review process, the calibration associated with 'Extensive Animal damage' has also been revised (increased slightly) to align with the identified deficiencies outlined above.

In order to facilitate the changes outlined above, the computational data processing algorithms used to determine the Pole Rot, Pole Void and Pole Separation condition factors must have been modified to accept the additional data fields and calibration inputs. However, algorithms associated with the calculation of the Observed Condition Factor retain the standard MMI (Maximum and Modified Increment) technique used in CNAIM and is therefore considered to remain consistent with the underlying principles of the Common Methodology.

EA Technology consider that this type of ACA model refinement is only to be expected and would form part of the natural organic asset condition modelling process as organisations such as THESL adopt and embrace more modern, advanced asset management approaches. As in the case outlined above, any such model or methodology revision would be expected to include detailed internal evaluation, review and, where necessary, aspects of model re-calibration. Evidence of this having taken place exists in the fact that the observed condition factor 'Animal Damage' has been adjusted to ensure result consistency.

5. Review of Current and Future ACA Health Score Outputs

Task 2 has involved a desktop review of the ACA model outputs for the following asset classes as selected by THESL: Wood Poles, Network Transformers and Submersible Transformers. The data extract files have been provided in MS Excel format and include all data inputs, intermediate calculations (e.g. initial health score, condition modifiers, health score caps and collars), current health score values and predicted health scores for future years.

Observations on the implementation of the CNAIM methodology, the calibration settings and the current and future health index profiles for wood poles, network transformers and submersible transformers are provided in Sections 5.1 to 5.3. As part of the review, the intermediate calculations, including derivation of observed and measured condition modifiers and ageing rates have been verified as being consistent with the CNAIM methodology.

5.1 Wood Poles

The wood pole model comprises 106,386 assets ranging in age from new to more than 45 years old. The initial health score of each asset is derived from its age and the normal expected life of the asset class (45 years). More than 25% of the population (29,469 poles) have an initial health score of 5.5 driven by the age of the asset. This seems to be quite high and is likely to be due to the calibration of the Normal Expected Life (see Section 7.1).

The model includes both observed and measured condition modifiers as indicated in Table 4.

Table 4 Wood Pole Model: Observed and Measured Condition Modifiers

Observed Condition			Measured Condition	
Modifier	Worst Condition of:	HS Collar(s)	Modifier	HS Collar(s)
Pole Leaning	-	Yes	Pole Strength	Yes
Bird/Animal Damage	-	Yes	Shell Thickness	Yes
Pole Based Rot	At/below ground level Above ground level	Yes		
Pole Separation	Cracks Pole top feathering	Yes		
Pole Void	Wood loss Hollow heart/pockets present	Yes		

Health score collars have been applied to all of the modifiers such that poor results from a condition inspection or measurement give a health score that is at least the specified value of the collar. The setting of the condition factors and the corresponding health score collars are considered to be reasonable and aligned with both THESL's established practices and the principles of the CNAIM methodology.

The current and future (year 5) health index profile* for wood poles as calculated using the ACA methodology is shown in Figure 1.

* The Health Index banding criteria are those in CNAIM v1.1 where HI has an upper limit of a health score of 4.

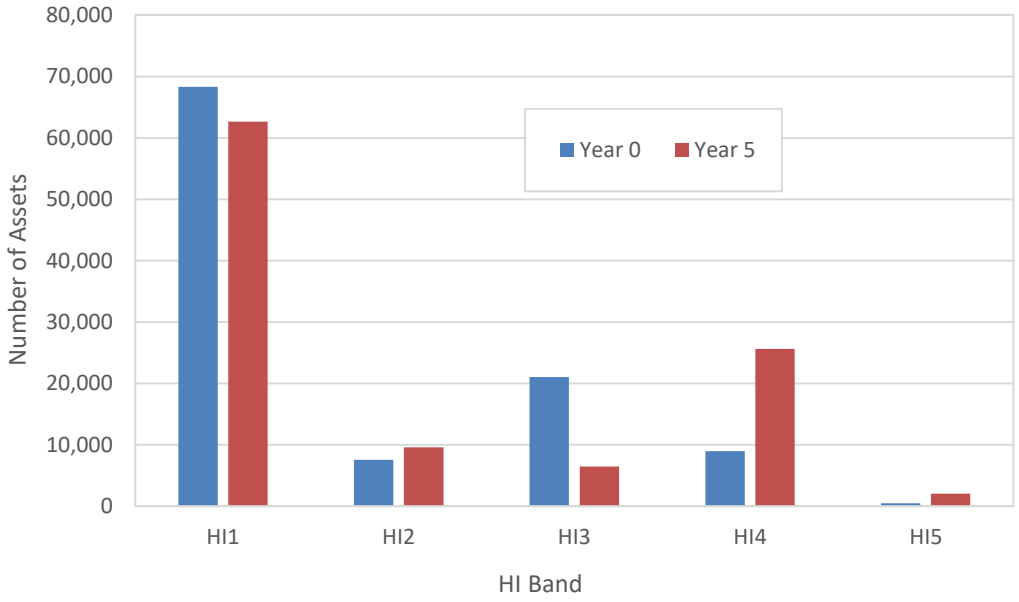

Figure 1 Wood Poles: Current and Future (Year 5) Health Index Profile

The current health index profile seems reasonable given the age profile and condition of the asset population. The 'spike' in the number of wood poles in the HI3 band is driven by assets that have ages beyond the expected life of 45 years.

Just over 2% of the asset population have health score values set through condition collars, mainly due to moderate pole separation (cracks and pole top feathering). This shows a considered approach to the setting of condition collars to identify assets with issues requiring intervention.

The CNAIM methodology includes an additional (reliability) modifier to reflect any issues or observations that are not reflected in the observed and measured condition modifiers. THESL have used this methodology feature in the wood pole model and applied a collar of 7.25 to assets that have been confirmed to be in a poor condition by inspectors in the field. This is considered to be an appropriate use of the reliability modifier mechanism to directly impact asset health where information is available.

Figure 1 shows a slow movement of assets from HI1 to HI2 and HI3 over the next 5 years, with a more rapid progression from HI3. This seems reasonable given the age profile and underlying condition of the asset portfolio and indicates that the health score modifiers have been set appropriately, resulting in a realistic ageing rate for the prediction of health scores into the future.

5.2 Network Transformers

The network transformer model comprises 1,718 assets ranging in age from new to more than 40 years old. The initial health score of each asset is derived from its age, the normal expected life of the asset class (35 years) and a measure of how hard the asset is working (the ratio of peak loading to transformer rating). THESL recognise that there are inaccuracies in the transformer loading data and it is understood that a default is applied to any transformers with a calculated utilisation of more than 200%. This is a valid approach where known inaccuracies and inconsistencies exist in the data sources.

There are 229 assets with an initial health score of 5.5 driven by either the age of the transformer and / or a reduced normal expected asset life due to the high duty that the asset is experiencing. This proportion of assets

with a maximum initial score of 5.5 is reasonable given the age profile and high utilisation of some of the transformers.

The model includes both observed and measured condition modifiers as indicated in Table 5. .

Table 5 Network Transformer Model: Observed and Measured Condition Modifiers

Observed Condition			Measured Condition	
Modifier	HS Collar(s)	Comments	Modifier	HS Collar(s)
External Condition of Tank	Yes	Stronger factors and collars for corrosion of the lid and base than for corrosion of the transformer body	Partial Discharge	Yes
Oil Leaks	Yes	Stronger factors and collars for leaks from the base than for leaks not from the base	Temperature Readings	Yes
Connection Condition	No	-		
Primary Switch Condition	Yes	-		

A number of health score collars have been applied such that poor results from a condition inspection or measurement give a health score that is at least the specified value of the collar. The setting of the condition factors and the corresponding health score collars are considered to be reasonable and aligned with both THESL's existing practices and the principles of the CNAIM methodology.

The current and future (year 5) health index profile* for network transformers as calculated using the ACA methodology is shown in Figure 2.

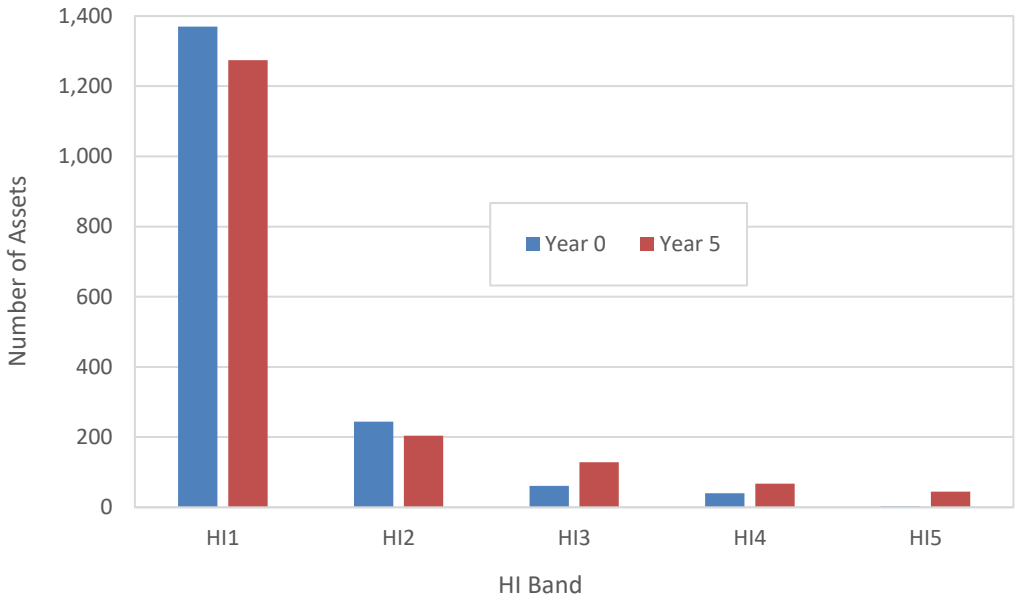

Figure 2 Network Transformers: Current and Future (Year 5) Health Index Profile

* The Health Index banding criteria are those in CNAIM v1.1 where HI has an upper limit of a health score of 4

The current health index profile looks reasonable given the age and condition of the asset population. A small number of assets (44) have health score values set through condition collars, mainly due to corrosion issues and / or significant oil leaks. This shows a considered approach to the setting of health score collars to identify assets with issues requiring intervention.

Figure 2 shows the assets moving slowly through the health index bands over the next 5 years. This seems reasonable given the age profile and underlying condition of the asset portfolio and indicates that the health score modifiers have been set appropriately, resulting in a realistic ageing rate for the prediction of health scores into the future.

5.3 Submersible Transformers

The submersible transformer model comprises 9,161 assets ranging in age from new to more than 40 years old. The initial health score of each asset is derived from its age, the expected life of the asset class (30 years) and a measure of how hard the asset is working (the ratio peak loading to transformer rating). THESL recognise that there are inaccuracies in the transformer loading data and have applied a default to any transformers with a calculated utilisation of more than 150%. This is a valid approach where data inaccuracies exist.

There are 568 assets with an initial health score of 5.5 driven by either the age of the transformer and / or a reduced expected asset life due to the high duty that the asset is experiencing. This proportion of assets with a maximum initial score of 5.5 is reasonable given the age profile and utilisation of some of the transformers.

The submersible transformer model includes three observed condition modifiers as follows:

- External condition of tank (with stronger factors and collars for corrosion of the lid and base than for corrosion of the transformer body).
- Oil leaks (with stronger factors and collars applied to leaks from the base than to leaks not from the base).
- Connection condition. No condition collars are applied.

The setting of the condition factors and the corresponding health score collars are considered to be reasonable and aligned to the principles of the CNAIM methodology.

The current and future (year 5) health index profile* for submersible transformers as calculated using the ACA methodology is shown in Figure 3.

* The Health Index banding criteria are those in CNAIM v1.1 where HI has an upper limit of a health score of 4

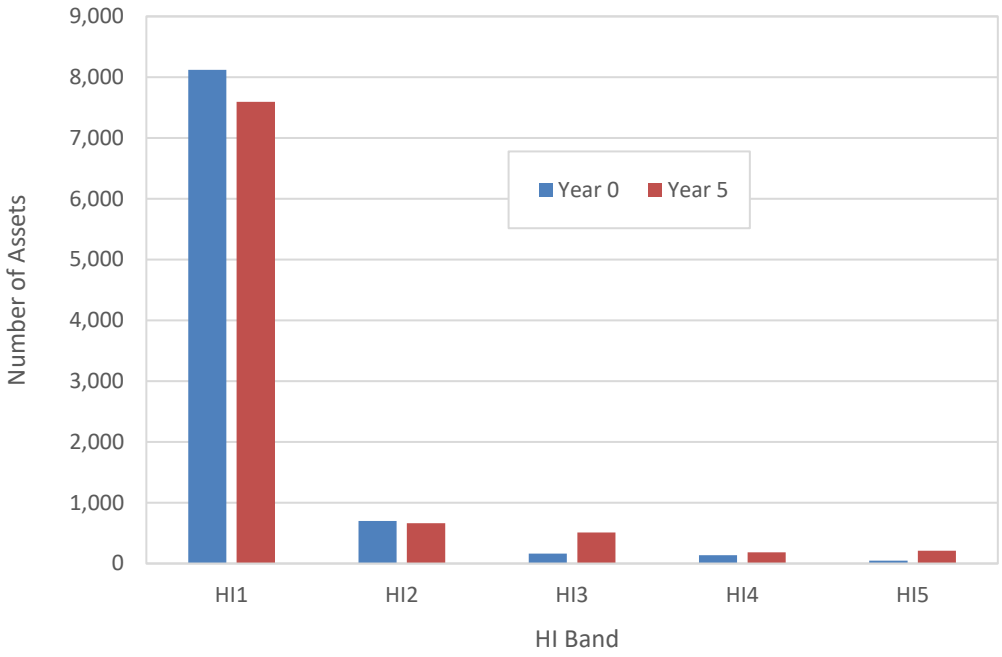

Figure 3 Submersible Transformers: Current and Future (Year 5) Health Index Profile

The current health index profile would appear to be reasonable given the age and condition of the asset population. A small proportion of assets (around 3%) have health score values set through condition collars, mainly due to oil leaks and corrosion issues. This shows a considered approach to the setting of health score collars to identify assets with issues requiring intervention.

Figure 3 shows the assets moving slowly through the health index bands over the next 5 years. Again, this seems reasonable given the age profile and underlying condition of the asset portfolio and indicates that the health score modifiers have been set appropriately, resulting in a realistic ageing rate for the prediction of health scores into the future.

5.4 General Comments

The high-level assessment of THESL's ACA models for wood poles, network transformers and submersible transformers has found the logic, factor evaluation and calculation sequence to align with the principles of the CNAIM methodology. In particular, the results show:

- heath index profiles indicative of an asset population that appears to be maintained and generally in a good condition;
- the proportion of health score results that have been 'forced' by health score collars seems reasonable for the asset populations; and
- acceleration of assets to the HI4 band appears reasonable and aligns with established THESL asset management thinking and existing business processes.

EA Technology understand that THESL are continuing to work on improving data quality. This review has highlighted the following data anomalies:

- The network transformer and submersible transformer models include some unrealistically high utilisation values. THESL have recognised the potential for data inaccuracies and applied default duty factors above threshold transformer utilisations (understood to be 200% in the network transformer

model and 150% in the submersible transformer model). This is a valid approach and provides a straightforward way of eliminating questionable data and potentially overstating the heath score and ageing rate for the affected assets.

- It is understood that more than one data source is being used for network transformer utilisation and operating temperature. Some of this data looks suspect, with a number of units apparently delivering 3 times name plate rating having reported maximum operating temperatures in the region of 40°C. This is clearly a data discrepancy and may possibly understate the measured condition modifier and hence the health score of affected assets.
- Wood pole inspection frequency is understood to be conducted on a rolling 10 year cycle. However, the data extract file provided contains condition data collected either in or before 2012. The review has also found that for a small proportion of structures within the population, the nature of the structure material is either unknown, unclear, or 'wood'. Such data gaps and discrepancies are not unusual in asset populations of this size and should reduce over time as more data is collected, resulting in more granular health index profiles.

6. Review of THESL's Probability of Failure, Consequence of Failure, Asset Criticality, and Risk Implementation

Task 3 has involved a review of THESL's ACA derivation of asset probabilities of failure, the determination of consequence of failure values from their broader Value Framework, and the approach to the application of criticality factors in order to calculate risk. Due to the recognised differences in operating and regulatory environment between Ontario and Great Britain, this review has not focused on establishing whether THESL have been able to duplicate the CNAIM methodology's calculation sequence. Instead, it has determined whether the implementation is reasonable and aligned with generally accepted industry practices and the underlying principles of the Common Methodology.

6.1 THESL Failure Mode Definitions

The CNAIM methodology considers functional failures* in the derivation of probability of failure (PoF) and consequences of failure (CoF). These relate to the inability of an asset to adequately perform its intended function and are therefore not solely limited to failures that result in an interruption to supply. Three failure types are included within the CNAIM methodology (incipient, degraded, and catastrophic) and these are used in the evaluation of both PoF and CoF.

THESL have defined three failure modes depending on the asset deterioration stage and corresponding remedial action as listed in Table 6. These failure modes have been applied in the ACA methodology for the derivation of probability of failure and consequence of failure values. The three failure modes align with both THESL's established practices and the principles of the CNAIM methodology and are considered to be appropriate for the evaluation of asset PoF and CoF.

Table 6 THESL Failure Mode Definitions

Failure Mode	Description
Incipient	A failure associated with early-stage asset degradation. Such failures can be resolved through the undertaking of planned corrective action which may require an outage.
Degraded	A failure associated with advanced asset degradation, for which reactive repair would be expected to only have a limited effect. Such failures are likely to result in planned asset replacement.
Outage	A failure associated with advanced asset degradation, which will often result in a sustained outage until unplanned reactive works have been completed.

* Functional failures considered in Common Methodology relate only to those failures directly resulting from the condition of the asset itself; failures of function due to third party activities are not included.

6.2 Probability of Failure

The CNAIM methodology uses a standard relationship between health score and PoF based on a modified cubic relationship as follows:

$$PoF = k \cdot \left(1 + (H \cdot c) + \frac{(H \cdot c)^2}{2!} + \frac{(H \cdot c)^3}{3!}\right)$$

where:

PoF = probability of failure per annum

H = a variable equal to health score, unless health score ≤ 4 and then H = 4

k & c = constants (for a given asset category)

The value of c fixes the relative values of the probability of failure for different health scores (i.e. the slope of the curve) and k determines the absolute value.

Within CNAIM, c has been set to the same value (1.087) for all asset categories and has been selected such that the PoF for an asset with a health score of 10 is ten times higher than the PoF of a new asset.

The value of k has been set for each asset category covered by the CNIAM methodology by considering the number of functional failures in the different failure modes recorded in Great Britain over a five year period.

As the values of k are averaged across the DNOs within Great Britain, it is appropriate for THESL to derive representative values of k for each asset class from the asset populations and known failures in each of the failure mode categories defined in Table 6. During the engagement on THESL's continued CNAIM/CBRM implementation in 2021/22, EA Technology explained the approach to determining k and provided THESL with an Excel spreadsheet* showing a worked example of how to derive a 'composite' value of k from multiple failure modes.

THESL have comprehensive records of historic failures and have been able to derive k values for each of the asset classes covered by the ACA methodology. During the initial review of the probability of failure curves it was found that the calculated PoF values were excessively high for some asset classes. Following a trouble-shooting session with EA Technology asset management specialists, THESL revisited the definition of incipient failures to exclude failures that could be classed as operational defects.

The k values provided by THESL for each of their asset classes have been reviewed as part of Task 3 and the revised definition of incipient failures gives PoF curves that seem credible across all asset classes. It is not meaningful to compare THESL's k values with those in CNAIM given the proportions of each failure type comprising a 'composite' failure, the asset populations and differences in asset management practices; however, the process undertaken to derive representative values of k is considered to be robust and the corresponding PoF curves appear reasonable.

6.3 Consequences of Failure

All of the ACA models developed by THESL include the four consequence categories associated with asset failure that are included within CNAIM: Network Performance, Safety, Financial, and Environmental. Sections 6.3.1 to 6.3.4 below consider each of the defined consequence categories in turn.

* *Derivation of k.xlsx*. Excel spreadsheet provided to THESL by email on 15 April 2021.

The Consequences of Failure methodology in CNAIM is based on the production of a Reference Cost of Failure in each consequence category which represents the 'typical' effects of a failure based on an organisation's experience. Asset-specific modifying factors are then applied to these reference costs in order to reflect the costs associated with a condition-based failure of the specific asset. These factors are generally referred to as criticality factors and are discussed further in Section 6.4.

6.3.1 Network Performance Consequences

In the CNAIM methodology, the Network Performance Consequences of Failure take into account the way in which electrical system operators restore customer supplies following unplanned events and asset failures. THESL's ACA approach to Network Performance CoF appears to directly align with CNAIM with the consideration of three distinct phases of supply restoration that reflect a staged restoration process:

- Phase 1 makes allowance for system redundancy, auto-change-over schemes, intelligent networks, and SMART grid technologies which either prevent reportable supply interruptions or those that act independently and automatically to restore healthy electrical system components before any interruption (duration) is required to be recorded as part of the governing regulatory system.
- Phase 2 is associated with system re-configuration via switching operations in an effort to firstly minimise, and secondly provide a means of isolation for non-serviceable network sections whilst reconnecting more connected customer supplies.
- Phase 3 typically involves activities designed to either repair or replace failed power system assets thereby enabling the integrity of the original system to be restored.

Quantification of Network Performance Consequences of Failure usually involves analysing the number of customer supplies affected by supply interruptions caused by asset failure along with their associated outage durations. Alternatively, system operators need to establish a robust mechanism through which reductions in available system capacity and capability can be determined. For convenience, this quantification often works in terms of domestic supply equivalence and is generally more easily understood.

THESL's ACA quantification of Network Performance CoF is formed using two component parts reflecting the costs of customer interruptions (CIs), and the on-going cost of electrical supply outage duration (CMI). The sum of the blended CI and CMI costs is then multiplied by the probability of interruption before the application of any criticality factors.

THESL have carried out an in-depth evaluation of the information held within their Interruption Tracking Information System (ITIS) relating to historical asset failure, unplanned outage, and emergency response activities. Following the completion of a statistical analysis of the data, THESL have been able to both identify and quantify network performance consequences for each of the failure modes under consideration.

This review has found that in terms of secondary transformers, the Network Performance CoF (outage duration) determinations for fuse replacements, component repairs, and the restoration of supplies through the adoption of alternative 'temporary solutions' straightforward to understand and apply. Transformer replacement is not as intuitive, as the relationship between transformer location and assignment of the closest resource (yard) availability is not as immediately obvious for those unfamiliar with the nuances of the organisation.

Quantification of asset failures are presented in terms of the number of connected customers supplies affected and takes account of the likelihood of electrical protection system success through a statistical determination of the number of multiple supply interruption occurrences on a per failure mode basis. Consideration should be given to extending this form of evaluation into network configurations that possess higher security of supply standards such as n-1 where asset failures do not necessarily result in unplanned outages.

Both CoF calculation stages employ THESL system performance data and financial values which provide a solid basis for defence if challenged. Although highly dependent upon system control data processes, THESL's implementation of this aspect of the ACA modelling process appears to align with the underlying philosophy of CNAIM where asset failures result in unplanned outages.

6.3.2 Safety Consequences

THESL's ACA models have been designed to generate consequence of failure values for events that have the potential to result in loss of life, cause reportable lost time accidents, or inflict damage to a third party's property. It is understood that the approach taken is universally applied across the entire suite of THESL's ACA models.

When considering asset failures which result in fatality, the ACA models calculate the safety consequences of failure differently depending upon whether or not the deceased is a direct employee of the utility. In the instance that direct employees are fatally wounded, the consequence values are based upon figures associated with the Ontario Workplace Safety and Insurance Board (WSIB). The consequence values used to represent fatalities involving members of the general public are also based on WSIB figures and are further supplemented by financial values outlined in the WorkSafe BC Incident Cost Calculator.

Safety consequences of failure associated with lost time incidents are derived using an Exposure Hour Methodology based upon THESL data, with WSIB costs for direct employees of the utility and Government of Canada figures for events not involving employees.

At the present time, safety consequences associated with damage to third party property are not included within the total safety consequence value determination.

The consequence values used within the ACA models are summarised in Table 7 below.

Table 7 ACA Safety Consequences of Failure Inputs

Safety Consequence Category	Probability of Consequence Occurrence	Consequence Value
Fatality	Values set as per CNAIM	Direct Employee $1.6m CAD Member of the Public $1.784m CAD
Lost Time Accident	0.00815%	Direct Employee $15k CAD Member of the Public $6k CAD
Damage to Third Party Property	No data available	Defaulted to $0 CAD

The approach taken to determine the Safety Consequence of Failure values is considered to directly align with the principles outlined within the CNAIM methodology. They appear to be based upon sensible information sources, and as they comprise of recognised industry and government standard figures, would be considered both reasonable and defendable if challenged.

6.3.3 Financial Consequences

The Financial Consequences of Failure in THESL's ACA models are determined by defined asset failure modes as outlined in Section 6.1:

- *Incipient failures*. Financial consequences are based upon the financial figures used to determine the regulatory Rate Case Filing and real-world OPEX expenditures obtained from THESL's historical data.
- *Degraded failure* financial consequences are based upon THESL's standardised unit cost information combined with THESL's previous experience of managing and undertaking capital works.
- *Outage failures*. Financial consequences have been derived from analysis of THESL's historical emergency response figures.

The inclusion of standardised unit costing information is considered to be an appropriate route to determine the Financial Consequences of Failure within the ACA methodology as the values incorporated are both recognisable and defendable in equal measure.

6.3.4 Environmental Consequences

THESL's ACA models consider four different aspects of environmental impact when calculating the Environmental Consequences of Failure. These relate to loss of oil containment, the release of SF_6 insulant gas, the potential effects of asset failures resulting in fire, and the generation of waste.

The environmental consequences for oil and SF_6 releases are treated in the same way. For each failure mode under consideration, an evaluation has been made to determine the likelihood of insulant release; this is currently supported by a worst-case scenario assumption that a total loss of insulant occurs. The product of these values is then multiplied by an environmental contamination/release cost which is used to derive individual environmental consequences.

The environmental consequences associated with fire centre around the potential to ignite oil and are again calculated by first determining a likelihood of fire event occurrence, a representative means of quantifying the impact of any fire event (typically via the conversion to equivalent volume of CO_2 emitted), and the identification of a per unit emission cost.

Fire event probability has been sourced from THESL's Interruption Tracking Information System to identify the number of asset failures that involved fire events as a proportion of the total number of asset failures experienced for each asset class. THESL have then used asset records to determine how much oil assets contain, before using standardised government figures to calculate a financial value for the environmental consequences.

It is understood that THESL are, at the time of writing, not able to accurately determine a satisfactory mechanism through which waste disposal costs can be accurately identified. This is thought to be due in part to the variability of scrap materials on the open market which offsets the total cost of asset decommissioning and disposal. Within the ACA models, therefore, the financial value pertaining to the environmental consequences from generation of waste have been set to a default value such that they do not contribute to the overall Environmental Consequences of Failure calculation.

A summary of the Environmental Consequences of Failure inputs is shown in Table 8 below.

Table 8 ACA Environmental Consequences of Failure Inputs

Category	Calculation Input	Information Source
Oil	Probability of release occurrence	THESL ITIS and Oil Spill Incident Records
	Assumed Volume released (per event)	Assumed complete loss of all asset oil. Source THESL asset records.
	Unit cost (per litre)	Basic Oil Spill Cost Estimation Model (BOSCEM) by the US Environmental Protection Agency
SF_6	Probability of release occurrence	THESL ITIS and EHS data
	Assumed Volume released (per event)	Assumed that all asset SF_6 is lost. Source THESL asset records.
	Unit cost (per kg)	Government of Canada CO_2 emission cost scaled to SF_6 equivalent $1,195/kg CAD
Fire	Probability of failure causing fire	Derived from THESL's ITIS data
	Volume of fire (CO_2 emission)	Total oil volume taken from THESL asset records converted to CO_2 emission value.
	Unit Cost (CO_2 emission)	Government of Canada $50/ton CAD
Waste	Waste disposal costs	Not currently used. Defaulted to $0 CAD

The ACA approach to environmental CoF quantification is regarded as being aligned with CNAIM, and is considered to employ sensible, defendable unit costs and probabilities against each relevant consequence category. The difficulties THESL are experiencing in relation to determining average asset disposal costs are understood, as is the intention to continue to search for a workable solution.

6.4 Asset Criticality

The CoF methodology within CNAIM is based on the production of a Reference Cost of Failure in each consequence category which represents the 'typical' effects of a failure based on DNO experience. Asset-specific modifying factors are then applied to these reference costs in order to reflect the costs associated with a condition-based failure of each asset. These factors are generally referred to as criticality factors.

THESL have followed a similar approach to the CNAIM methodology and considered the application of criticality factors in each of the four consequence categories as discussed in Sections 6.4.1 to 6.4.4 below.

6.4.1 Network Performance Criticality

THESL's ACA models contain a Customer Sensitivity Factor that can be employed to reflect circumstances where the impact of unplanned power outages is increased due to customer reliance on electricity (e.g. customers with health issues such as a dependency on dialysis machines). This criticality factor is currently defaulted to unity, and therefore does not influence the Network Performance Consequences of Failure. THESL are understood to be considering the most appropriate approach to applying the Customer Sensitivity Factor and may introduce it in the future.

For a small number of asset classes, THESL are understood to have introduced an additional criticality factor which considers the accrued labour hours recorded against asset intervention.

Statistical analysis performed by THESL during evaluation of consequences of failure has identified differences in response times depending on where assets are located. For example, there are increased logistical challenges in the downtown area which can lead to increased intervention costs as well as potentially extending the duration of supply interruptions.

The exact way in which this modifying factor has been implemented remains unclear, and care must be taken to avoid double counting when determining financial failure costs. However, if proven internally by THESL to be credible, robust, reliable and statistically significant, it is a clever use of the criticality factor facility and would be considered to be completely aligned with the principles which underpin CNAIM.

6.4.2 Safety Criticality

THESL's ACA models make provision for two inputs to the Safety Criticality Factor: a Traffic Factor and a Size Factor. The Size Factor is currently defaulted to unity as THESL do not believe that the severity of any interaction with a failed asset is influenced by its operating voltage, rating, or physical size.

The Traffic Factor has been introduced to reflect how busy the immediate vicinity around the asset is perceived to be. This factor is set using individual asset risk ratings, which have been derived directly from CNAIM guidance. Therefore, ACA models should increase the safety consequences of assets in densely populated areas such as main throughfares, within close proximity to stadiums etc. The magnitude of the Traffic Factor in the ACA models is not known; however, factors in the range from 0.7 to 2.0 would be regarded as reasonable and aligned to CNAIM principles.

6.4.3 Financial Criticality

THESL have identified that significant differences exist in the cost of undertaking asset replacement depending upon the geographic region in which work is required. Two regions, referred to anecdotally as "Downtown" and "the Horseshoe" have been defined, and a Location Factor has been derived from analysis of THESL's historical material and labour costs.

It is understood that the Location Factor is intended to represent some of the challenges associated with resourcing within THESL, and the availability of specific skillsets in particular areas; e.g. lines teams within the city centre region. If set by individual asset class, such an approach can be made to reflect the additional time required for appropriate resources to make their way to asset failures. However, care must be taken not to overinflate the effects of this phenomenon by double counting. It is considered that if a Location Factor is applied globally (i.e. across all ACA models) then there is a possibility that the calculation of financial risk will be distorted.

For those asset classes where the Financial Consequences of Failure are directly linked to the ratings or capacity of the replacement unit, THESL's ACA models include a Size Factor. This enables the costs associated with asset replacement to be scaled to the size of the failed unit. However, as the ACA calculated costs are currently determined using unit costs this feature is set to apply a default value that does not affect the overall Financial Criticality Factor.

6.4.4 Environmental Criticality

The transformer and switchgear ACA models make provision for two inputs to the Environmental Criticality Factor to account for the location of the asset and the presence of polychlorinated biphenyls (PCBs). THESL have identified that oil filled assets that are contaminated with PCBs are more expensive to dispose of when

compared to non-contaminated units and have included a PCB Factor. This has been determined from the ratio of the decontamination cost for a metric ton of soil with PCB oil to the decontamination cost for a metric ton of soil with regular (no PCB) soil and is considered to be reasonable and defendable if challenged.

The second input to the Environmental Criticality Factor is the Location Factor which accounts for the additional clean-up costs associated with assets close to water. It has been determined using the BOSCEM method by dividing the environmental cost of asset failure close to water by the environmental cost of asset failure on dry land. This approach is consistent with the principles of the CNAIM methodology and is considered to be reasonable and defendable if challenged.

6.5 General Comments

The review of THESL's derivation of asset probabilities of failure and the determination of consequence of failure values from their broader Value Framework has found the implementation to be logical and to align with the principles and framework of the CNAIM methodology. In summary:

- THESL have incorporated three failure modes into the ACA methodology which have been defined to align with the company's asset management practices. This approach allows THESL to make use of historical data to evaluate failure rates and costs of remedial action in each of the failure modes.
- THESL have comprehensive records of historic failures and have been able to derive k values for each of the asset classes covered by the ACA methodology. The analysis undertaken is considered to be robust and the corresponding PoF curves appear reasonable.
- The Consequence of Failure categories used by THESL align with those in CNAIM. These capture the key issues affecting electricity network businesses and can be quantified in terms that allow for monetisation within each consequence category, thus enabling the assessment of risk on a comparable basis across all asset categories.
- Reference Costs of Failure and criticality factors have been derived from recognised data sources and are considered to be relevant to THESL's operating environment.
- The approach to determining reference costs of failure and criticality factors is logical and transparent and, where asset failures result in unplanned customer outages, would be considered robust and defendable if challenged.

7. Discussion and Opportunities for Future Enhancements

THESL have made significant progress in the implementation of their ACA methodology since EA Technology's initial engagement in 2017. They have demonstrated a clear understanding of the concepts behind the GB's Common Methodology and have developed probability of failure curves and consequence of failure values that are appropriate to their operating and regulatory environment whilst retaining alignment with the objectives and principles of CNAIM.

THESL's ACA methodology continues to evolve and it is therefore likely that there will be modifications and enhancements as it 'beds-in' (matures) within the company and more inspection data becomes available to inform the models. This is considered to be a natural process in which the models will improve incrementally over time as the benefits of the approach are realised across the organisation.

Sections 7.1 to 7.4 below summarise the key observations from EA Technology's review of THESL's enhancements and customisations to the ACA methodology. In addition, suggestions for future ACA model developments and/or refinements are provided.

7.1 Health Score Derivation

The principles and philosophy upon which the THESL ACA methodology is based make allowance for asset managers and system operators to draw upon their experience to not only identify, but actually define, sub-groups within asset populations where there are known differences in service lives, asset performance, etc. Examples include:

- *Normal Expected Lives*. Variation in service life by user-identified and defined sub-populations would be expected. This offers the opportunity to enhance the granularity of the health score outputs by setting different Normal Expected Lives by, for example, manufacturer, type, period of manufacture, or material (for wood poles).
- *Duty Factor*. The identification of input data fields which influence asset duty factors should be considered, particularly for switchgear asset classes.

The CNAIM methodology has provision for a Measured Condition Modifier to incorporate information gained from diagnostic tests and measurements into the models. Established condition assessment techniques with empirical relationships include thermography, SF6 condition, oil analysis and partial discharge results. These could be incorporated into existing ACA models to improve the quality of calculated health score results and allow more differentiation between assets.

Following the inclusion of additional condition related inputs, the next natural step in developing asset health indices involves the disaggregation of asset systems into sub-components with their own health score assessment. For example, a Station Transformer could be regarded as a 'composite system' made up of a 'transformer' and separate 'tapchanger'. The health score of the overall transformer asset is then derived from a combination of the health scores of both of these sub-components.

7.2 Health Score Calibration

A small number of ACA models including the SCADAMATE Switches, Air Magnetic Circuit breakers, Air blast Circuit breakers, and SF_6 Circuit Breakers have been calibrated to align health score derivations with THESL's tactical asset management practices. Calibration factors are considered to be very aggressive where asset deficiencies are identified, and the models are heavily influenced, if not dependent, upon health score caps and collars.

It is understood that THESL are using this approach at the present time whilst the organisation is building confidence in both the ACA methodology and the outputs from the models. However, the company recognises that this style of model calibration limits the methodology's ability to provide a longer term strategic view of the asset population and intends to review calibration of the condition modifiers in the future.

The underlying CNAIM methodology provides a mechanism such that fundamental indications of empirically proven conditions, perhaps through the existence of Operational Restrictions, may be linked to a Reliability Modifier that directly impacts the asset health score. The use of a Reliability Modifier may offer a potential solution that could help provide a more strategic view of asset classes such as SCADAMATE Switches, Air Magnetic Circuit breakers, Air blast Circuit breakers, and SF_6 Circuit Breakers.

7.3 CoF Determination

THESL appear to have good asset information and a wide range of both fault data and asset failure information. These data sources have been used to perform a number of statistical analyses and evaluations that in turn have informed the ACA methodology.

The following areas have been noted during the review process where refinements to the determination of network performance and environmental consequences could be incorporated in the future:

- The existing ACA methodology for the quantification of Network Performance CoF works well for asset failures that result in unplanned outages and electrical supply interruptions. However, for network configurations that contain redundancy or possess higher levels of supply security and may not result in power outages, the current quantification method is likely to understate the system level risk when asset failure occurs. It is recommended that THESL consider how asset failures in such circumstances are quantified and incorporated into the ACA methodology.
- It is understood that there is an absence of reliable data relating to volumes of electrical asset insulant loss resulting from asset failures and the ACA methodology assumes that a total loss of insulant containment will take place as a result of failure. This assumption will hold true for distribution voltage switchgear but is unlikely to be an accurate portrayal of either EHV switchgear with multiple insulant chambers or transformer oils, and therefore is likely to overstate the Environmental Consequences of Failure for such assets. THESL may wish to consider exploring this area in more detail in the future.

The availability of good asset data provides an opportunity for increased accuracy in consequence quantification as even basic knowledge of asset makes, types and designs can be exploited when calculating the financial impacts associated with different types of asset failure. For example, the inclusion of weights and measures stated on manufacturer nameplates could be used to calculate volumes of waste generated and insulant losses; this would provide more granularity to the ACA model outputs.

THESL recognise that they have information sources which could be further exploited to provide additional input data in the derivation of consequences of failure. It is understood that THESL intend to explore this area in the future to refine and enhance the outputs from the ACA models.

7.4 Criticality

When determining the Safety Consequences of Failure, THESL have successfully employed a risk based locational rating referred to as a 'Traffic Factor' as a criticality. Unless they form part of a statutory collection requirement, or are generated by other departments within the business, input parameters like this are valuable, but potentially very expensive to collect and difficult to maintain.

One observation made during this review is the absence of any electrical system criticalities that associate assets with either strategic, commercially sensitive or contingency related circuits. Such criticalities can be used to reflect reductions in system level integrity or possess the potential to cause major supply disruption, and therefore may be subject to differences in either operational or working practices. This may influence both Network Performance and Financial Consequences of Failure.

REPORT

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Reimagine tomorrow.



Toronto Hydro-Electric Service Limited: 2018 Value of Service Study

Submitted to Toronto Hydro-Electric Service Limited

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1 Executive Summary

Nexant, Inc. was retained by Toronto Hydro-Electric Service Limited (THESL) to conduct its 2018 Value of Service (VOS) study to estimate the costs customers incur during power outages. This research project was designed to collect detailed outage cost information from THESL's residential, small and medium business (SMB), and large commercial and industrial (C&I) customer classes. This report summarizes the methodology and results of the study.

The primary objective of the VOS study was to estimate system-wide outage costs by customer class. The VOS analyses are based on data from three separate surveys (one for each customer class) conducted between January and April, 2018. The responses were used to estimate the value of service reliability for each customer segment, using procedures that have been developed and validated over the past 25 years by the Electric Power Research Institute (EPRI) and other parties.[1]

1.1 Response to Survey

Table 1-1 shows the total number of completed surveys by customer class and the target sample size for each class. The response rate among residential customers was strong, as over 1,000 customers completed surveys either online or via mail, exceeding the target of 800. The response rate for small and medium business customers was lower than expected. Even after increasing the incentive and drawing an additional sample, the total number of completed surveys was only 245. The study results are valid, but obtaining results by smaller geographic regions within the service territory (as with residential customers) was not feasible and the confidence bands are wider than they otherwise would have been if the targets had been reached. For large C&I customers, Nexant scheduled and conducted onsite interviews covering 100 entity/service address combinations, which was the sample design target for this customer class. In some cases, all of the data needed for the outage cost estimates was not available at the interview—either because the interviewee did not have it readily available or was not willing to disclose it. Nexant was able to follow up after the interview and obtain the necessary data for a number of customers, but was not able to obtain it for 16 of them. The number of complete data points for large C&I was thus 84.

Table 1-1:
Total Number of Completed Surveys by Customer Class

Customer Class	Target	Completed Surveys
Residential	800	1061
Small/Medium Business	800	245
Large Commercial & Industrial	100	84

[1] Sullivan, M.J., and D. Keane (1995). *Outage Cost Estimation Guidebook*. Report no. TR-106082. Palo Alto, CA: EPRI.

1.2 Outage Cost Estimates

Table 1-2 provides the cost per outage event estimates by customer class. Cost per outage event is the average cost per customer incurred from each outage duration. Given the dynamic survey instrument design which accounted for historical outage onset times, these values represent the average outage cost across all time periods. For a 1-hour outage, large business customers experience the highest cost ($71,808) and residential customers experience the lowest cost ($10.87).

Table 1-2:
Cost per Outage Event Estimates by Customer Class

Outage Duration	Residential ($/Event)	SMB ($/Event)	Large Business ($/Event)	Blended ($/Event)
1 minute	$8.45	$257.38	$32,438	$51.24
1 hour	$10.87	$857.84	$71,808	$131.81
4 hours	$17.56	$2,142.39	$275,182	$381.77
8 hours	$23.35	$4,098.01	$379,381	$626.90
24 hours	$34.53	$8,426.27	$992,647	$1,412.73

Figure 1-1 and Table 1-3 show cost per average kW by customer class. Cost per average kW is the cost per outage event normalized by average customer demand among respondents. This metric is useful for comparing outage costs across segments because it is normalized by customer demand.

Figure 1-1:
Cost per Average kW Estimates by Customer Class

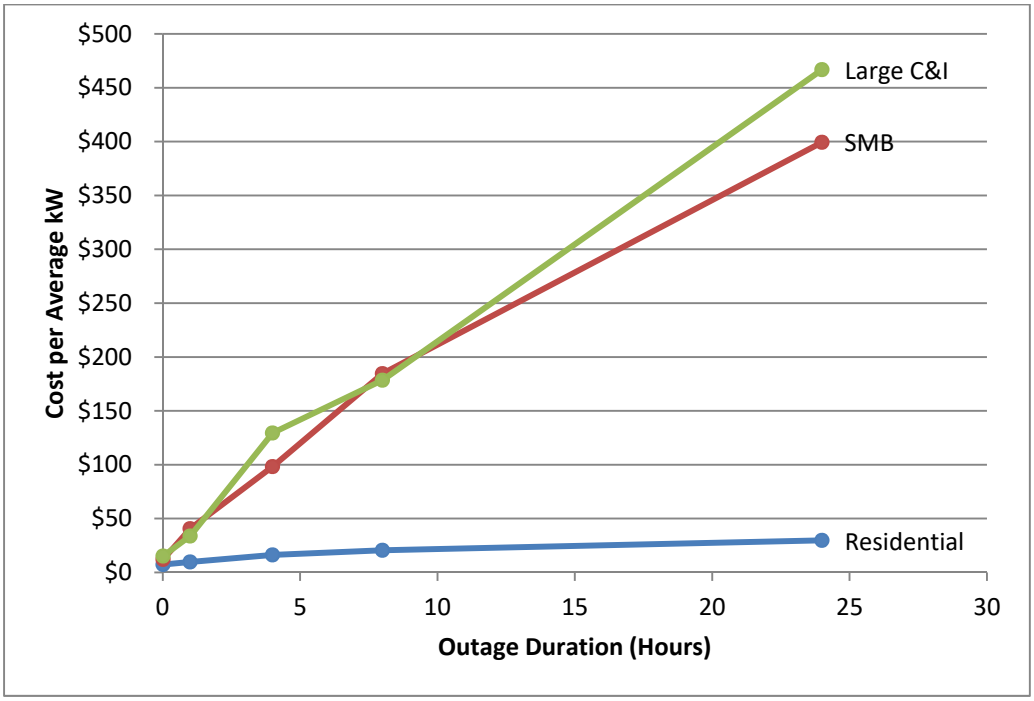


Table 1-3:
Cost per Average kW Estimates by Customer Class

Outage Duration	Residential ($/kW)	SMB ($/kW)	Large Business ($/kW)	Blended ($/kW)
1 minute	$7.31	$12.04	$15.25	$12.80
1 hour	$9.78	$40.68	$33.77	$33.14
4 hours	$16.32	$98.29	$129.41	$94.50
8 hours	$20.53	$184.57	$178.41	$153.83
24 hours	$29.80	$399.42	$466.81	$355.23

Table 1-4 provides the cost per unserved kWh estimates by customer class. Cost per unserved kWh is the cost per outage event normalized by the expected amount of unserved kWh for each outage scenario. This metric is useful because it can be readily used in planning applications, for which the amount of unserved kWh as a result of a given outage is commonly available. At 1-minute, cost per unserved kWh is at its maximum for each region and customer class because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. As duration increases, cost per unserved kWh decreases steeply because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate.

Cost per unserved kWh is useful, as it provides an "apples-to-apples" comparison of how customers value electric service versus what they pay for electric service. For all 4 customer classes and all outage durations, customers place a substantially higher value on an unserved kWh than what they would have paid if that electricity had been delivered. Residential customers experience an outage cost of $5.34 per unserved kWh for a 4-hour outage and $1.75 per kWh for a 24-hour outage, which are lower than the other customer classes, but still substantially higher than what they pay per kWh.

Table 1-4:
Cost per Unserved kWh Estimates by Customer Class

Outage Duration	Residential ($/kWh)	SMB ($/kWh)	Large Business ($/kWh)	Blended ($/kWh)
1 minute	$616.11	$722.43	$915.28	$768.06
1 hour	$13.21	$40.68	$33.77	$33.14
4 hours	$5.34	$24.57	$32.35	$23.63
8 hours	$3.55	$23.07	$22.30	$19.23
24 hours	$1.75	$16.64	$19.45	$14.80

Table 1-5 provides the duration cost per unserved kWh estimates by customer class. Toronto Hydro uses duration costs for its planning activities. This metric considers the cost of an outage event to be the full cost of the outage event minus the cost for a momentary, 1-minute outage. The duration cost for a 1-minute outage is thus always $0. The duration cost per unserved kWh is the duration cost per outage event normalized by the expected amount of unserved kWh.

Table 1-5:
Duration Cost per Unserved kWh Estimates by Customer Class

Outage Duration	Residential ($/kWh)	SMB ($/kWh)	Large Business ($/kWh)	Blended ($/kWh)
1 minute	$0.00	$0.00	$0.00	$0.00
1 hour	$2.94	$28.47	$18.51	$20.26
4 hours	$2.77	$21.62	$28.54	$20.45
8 hours	$2.27	$21.62	$20.39	$17.66
24 hours	$1.32	$16.13	$18.81	$14.26

Toronto Hydro was seeking a single, per-hour cost based on historical outages and Table 1-6 provides these "blended duration costs." The table shows these figures for different types of outages in Toronto Hydro service territory from 2010 to 2017. The "Outages Included" column shows which types of outages were included in the blended cost. All outages were categorized by Toronto Hydro as either "Momentary," "Planned," or "Sustained." Given that the results of this study are only valid for outages lasting 24 hours or less, all outages greater than 24 hours were excluded from the calculations. Within each outage type, outages could also be classified as "Loss of Supply Events" or could have occurred on "Major Event Days." These subcategories of outages were either left in the dataset or excluded, depending on the calculation.

The "Event Cost" column shows the average event cost of the outages in the dataset, based on the blended estimates in Table 1-5 and weighted by the number of customers impacted by the outage. The "Duration Event Cost" column shows the weighted average duration event cost, which is the event cost minus the blended 1-minute event cost estimate of $51.24. The "Duration" column shows the weighted average outage duration. The two "Hourly Cost" columns show each event cost per hour, or the "Event Cost" columns divided by the "Duration" column. Depending on the types of outages included, the weighted average duration ranges from 2.9 to 3.6 hours. The hourly event costs are within a relatively tight range, varying from $84.31 to $89.78, while the hourly duration event costs range from $69.94 to $71.87.

Table 1-6: Blended Duration Cost Based on Historical Outage Durations

Outages Included*	Subset of Outages Excluded	Event Cost		Duration (Hours)	Hourly Cost	
		Event Cost	Duration Event Cost		Hourly Event Cost	Hourly Duration Event Cost
Sustained	-	$288.96	$237.72	3.39	$85.32	$70.19
Sustained	Loss of Supply Events	$300.72	$249.48	3.57	$84.31	$69.94
Sustained	Major Event Days	$256.56	$205.32	2.86	$89.60	$71.70
Sustained	Loss of Supply Events, Major Event Days	$272.70	$221.46	3.09	$88.23	$71.65
Sustained, Planned	-	$288.44	$237.20	3.37	$85.54	$70.34
Sustained, Planned	Loss of Supply Events	$299.77	$248.53	3.54	$84.57	$70.11
Sustained, Planned	Major Event Days	$256.81	$205.57	2.86	$89.78	$71.87
Sustained, Planned	Loss of Supply Events, Major Event Days	$272.50	$221.26	3.08	$88.45	$71.82

* Only includes outages up to 24 hours in duration

Interruption costs for THESL are lower than those of other utilities for which recent studies have been conducted - notably Pacific Gas & Electric (PG&E) in 2012 and Southern California Edison (SCE) in 2019. The shape of THESL's outage cost distributions are similar to those of other studies, but they are lower in magnitude. Looking specifically at the survey data from THESL and SCE, significant differences exist in the underlying populations for the two utilities, making comparisons of the interruption costs tenuous. For example, Toronto's non-residential customer population comprises different industry types and the customers had higher annual consumption than SCE. This suggests that interruption costs from areas other than Toronto should not be used to estimate THESL's customer interruption costs.

1.3 Impact of Outage Timing

This study provided useful information on how outage costs vary across season and different times of the day. For the residential and SMB analyses on the impact of outage timing, onset times were aggregated into four key time periods with distinct costs per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

With fewer observations in the large C&I segment, onset times were aggregated into two key time periods as the analysis could not identify clear trends within the more granular time periods

used for residential and SMB customers. The two key time periods for large C&I customers were:

- Morning and Afternoon (7 AM to 5 PM); and
- Evening and Night (6 PM to 6 AM).

These groups of onset times were further divided among summer and winter for all three customer classes. Figure 1-2 provides the relative cost per outage event estimates for summer and Figure 1-3 provides the estimates for winter, which were derived from the customer damage functions described in Appendix A. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each outage cost estimate in Section 1.2 (referred to as the "base value"). As shown in the figure, outage costs for SMB and large C&I customers are sensitive to onset time. SMB outage costs vary from 46.6% lower than the base value on a summer evening to 80.6% higher on a winter morning. SMB outages in summer and winter mornings have the highest percentage increase as these outages likely start and end during normal business hours, potentially disrupting an entire day of work. Large C&I outage costs vary from 59.2% lower during summer nights to 18.3% higher during winter days. Considering that non-residential outage costs vary substantially depending on the onset time, it is important that planning applications apply these relative values.

Figure 1-2:
Relative Cost per Outage Event Estimates by Onset Time and Customer Class – Summer

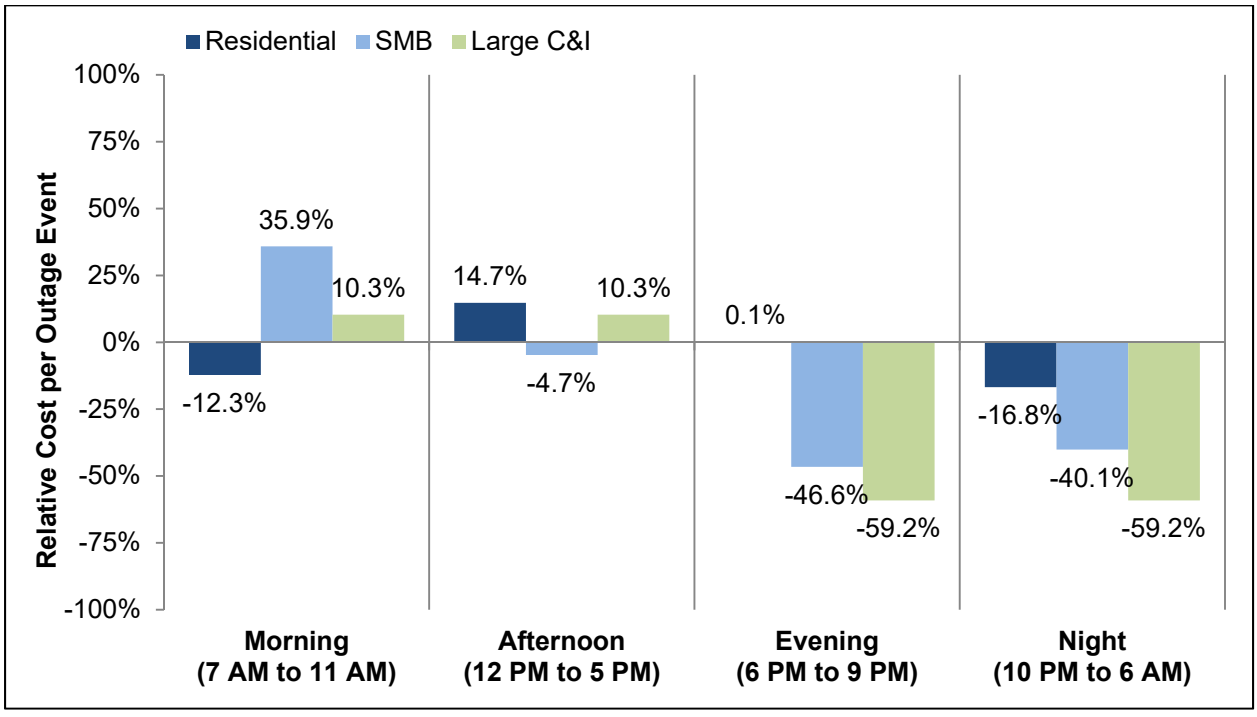
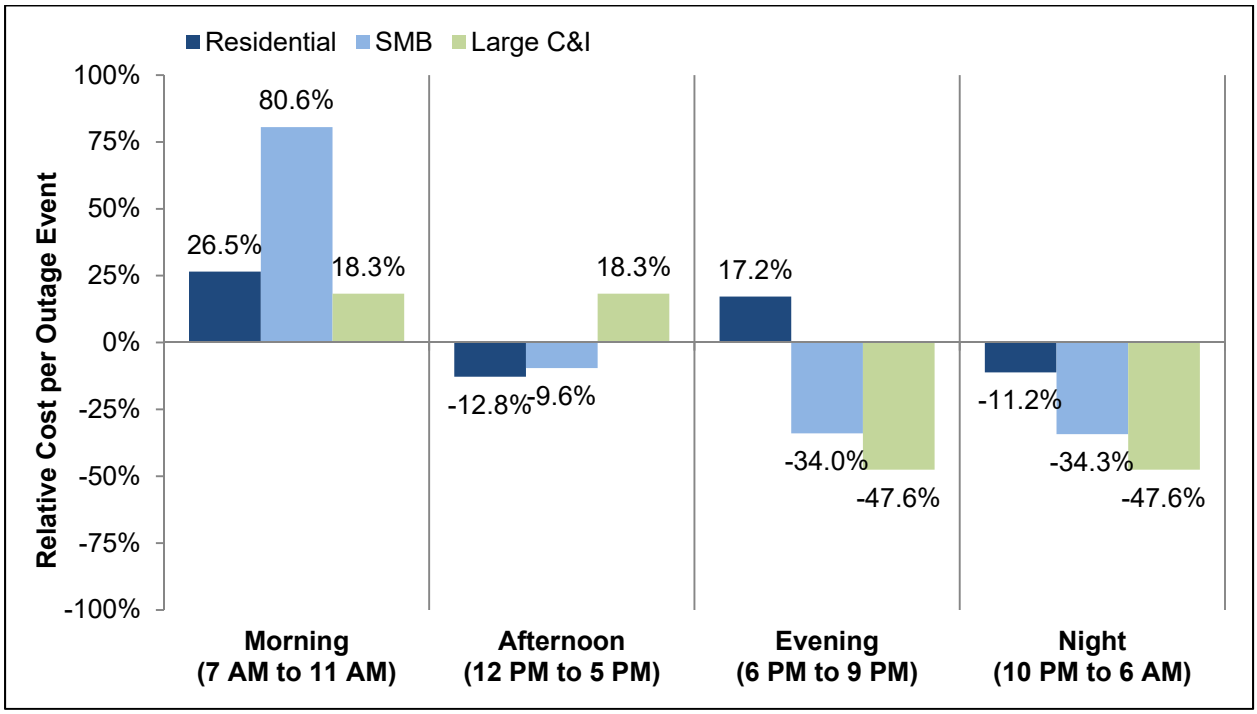


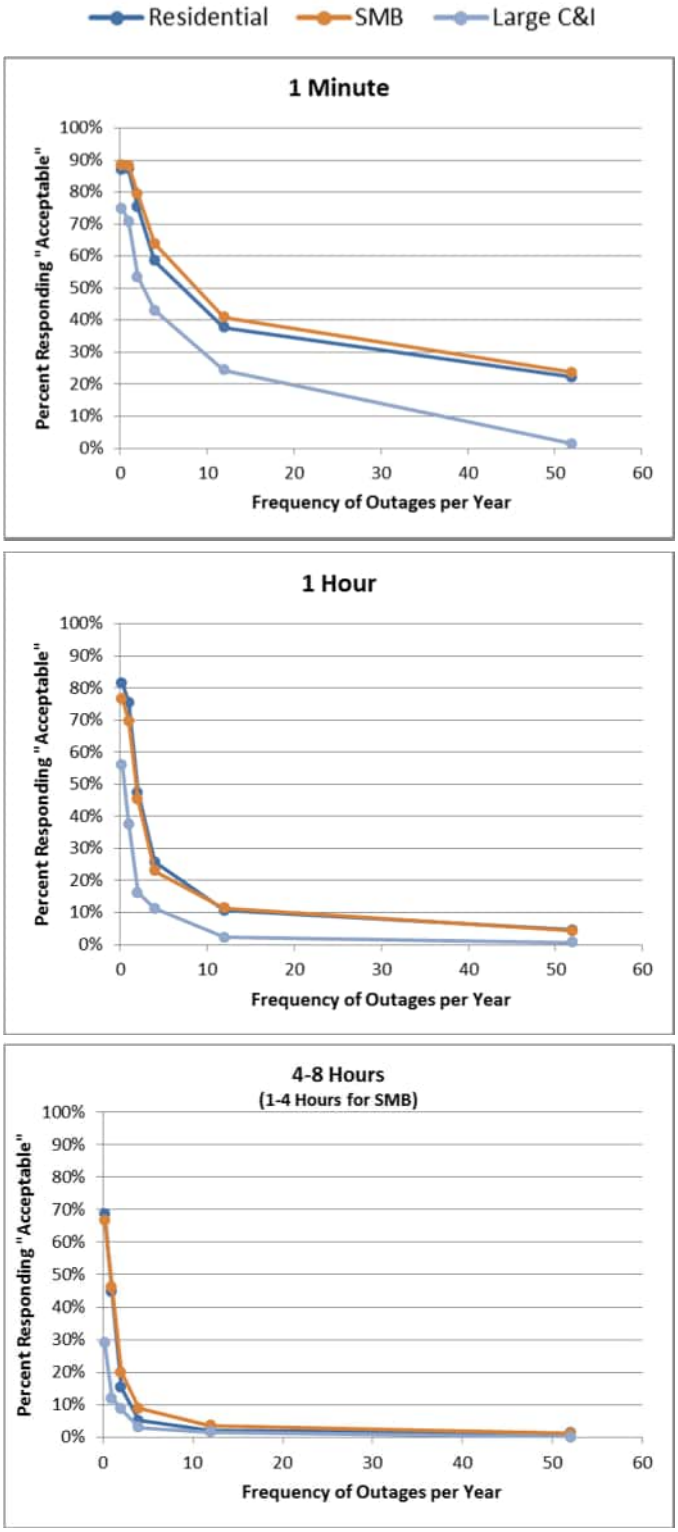
Figure 1-3:
Relative Cost per Outage Event Estimates by Onset Time and Customer Class – Winter



1.4 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 1-4 shows the percent of customers rating each combination of outage frequency and duration as acceptable. As expected, a customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. Large C&I customers have a higher standard than residential and SMB customers for what level of reliability is considered acceptable.

Figure 1-2:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable by Customer Class



2 Introduction

Nexant, Inc. was retained by Toronto Hydro-Electric Service Limited (THESL) to conduct its 2018 Value of Service (VOS) study – research to estimate the costs customers incur during power outages. This research project was designed to collect detailed outage cost information from THESL's residential, small and medium business (SMB), and large commercial and industrial (C&I) customer classes. This report summarizes the methodology and results of the study. The primary objective of the VOS study was to estimate system-wide outage costs by customer class.

As VOS cannot be measured directly, it is estimated from outage cost surveys of utility customers. These cost estimates can be used to assess the cost-effectiveness of investments in generation, transmission and distribution systems and to strategically compare alternative investments in order to determine which provides the most combined benefits to the utility and its customers. This comprehensive approach to valuing reliability, commonly known as "value-based reliability planning," has been a well-established theoretical concept in the utility industry for the past 30 years.[2] With the methodology employed in this study, the results can be directly applied to utility investments.

The responses were used to estimate the value of service reliability for each customer segment, using procedures that have been developed and validated over the past 25 years by the Electric Power Research Institute (EPRI) and other parties.

2.1 Study Methodology

The VOS analyses are based on data from in three separate surveys (one for each customer class) conducted between January and April, 2018. This survey methodology has been implemented by many electric utilities throughout the United States over the past 25 years. This study and the prior studies employed a common survey methodology, including sample designs, measurement protocols, survey instruments and operating procedures. This methodology is described in detail in EPRI's Outage Cost Estimation Guidebook.[3] The results of 34 prior studies conducted using this methodology are part of a meta-analysis of nationwide outage costs that is summarized in a 2015 report by Lawrence Berkeley National Laboratory (LBNL).[4]

2.2 Economic Value of Service Reliability

The purpose of VOS research is to measure the economic value of service reliability, using information regarding outage costs as a proxy. Under the general theory of welfare economics, the economic value of service reliability is equal to the economic losses that customers

[2] For an early paper on value-based reliability planning, see: Munasinghe, M. (1981). "Optimal Electricity Supply, Reliability, Pricing and System Planning." Energy Economics, 3: 140-152.

[3] Sullivan, M.J., and D. Keane (1995). *Outage Cost Estimation Guidebook*. Report no. TR-106082. Palo Alto, CA: EPRI.

[4] Sullivan, M. J., Schellenberg, J. & Blundell, M., 2015. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, Berkeley, CA: Lawrence Berkeley National Laboratory.

experience as a result of service interruptions. The history of efforts to measure customer outage costs goes back several decades. In that time, several approaches have been used. These include:

- Scaled macro-economic indicators (i.e., gross domestic product, wages, etc.);
- Market-based indicators (e.g., incremental value of reliability derived from studies of price–elasticity of demand for service offered under non-firm rates); and
- Survey-based indicators (i.e., cost estimates obtained from surveys of representative samples of utility customers).

The most widely used approach to estimating customer outage costs is through analysis of data collected via customer surveys. In a customer outage cost survey, a representative sample of customers is asked to estimate the costs they would experience given a number of hypothetical outage scenarios. In these hypothetical outage scenarios, key characteristics of the outages described in these scenarios are varied systematically in order to measure differential effects of service outage events with various different characteristics. A variety of statistical techniques are then used to identify and describe the relationships between customer economic losses and outage attributes.

Survey-based methods are generally preferred over the other measurement protocols because they can be used to obtain outage costs for a wide variety of reliability conditions not observable using the other techniques. These methods were selected for use for this THESL VOS study.

2.3 Valuation Methods

Two basic valuation methods are used to measure outage costs in the surveys – direct cost measurement and willingness-to-pay (WTP). Direct cost measurement techniques involve asking customers to estimate the direct costs they will experience during a service outage. WTP measurement techniques involve measuring the amount customers would be willing to pay to avoid experiencing the outage. In both approaches, the surveys ask respondents to provide these estimates for a number of outage scenarios, which vary in terms of the characteristics of the event.

2.3.1 Direct Cost Measurement

Nexant used direct cost measurement for non-residential customers (SMB, and large C&I), as outage costs for these customers are more tangible and much less difficult to estimate directly. At its most general level, the direct cost of an outage is defined as follows:

$$Direct\ Cost = Value\ of\ Lost\ Production + Outage\ Related\ Costs - Outage\ Related\ Savings$$

The *Value of Lost Production* is the amount of revenue the surveyed business would have generated in the absence of the outage minus the amount of revenue it was able to generate given that the outage occurred. It is the business's net loss in the economic value of production after their ability to make up for lost production has been taken into account. It includes the

entire cost of making or selling the product as well as any profit that could have been made on the production.

Outage Related Costs are additional production costs directly incurred because of the outage. These costs include:

- Labor costs to make up any lost production (which can be made up);
- Labor costs to restart the production process;
- Material costs to restart the production process;
- Costs resulting from damage to input feed stocks;
- Costs of re-processing materials (if any); and
- Cost to operate backup generation equipment.

Outage Related Savings are production cost savings resulting from the outage. When production or sales cannot take place, there are economic savings resulting from the fact that inputs to the production or sales process cannot be used. For example, during the time electric power is interrupted, the enterprise cannot consume electricity and thus will experience a savings on its electric bill. In many cases, savings resulting from outages are small and do not significantly affect outage cost calculations. However, for manufacturing enterprises where energy and feedstock costs account for a significant fraction of production cost, these savings may be quite significant and must be measured and subtracted from the other cost components to ensure outage costs are not double counted. These savings include:

- Savings from unpaid wages during the outage (if any);
- Savings from the cost of raw materials not used because of the outage;
- Savings from the cost of fuel not used; and
- Scrap value of any damaged materials.

In measuring outage costs, only the incremental losses resulting from unreliability are included in the calculations. Incremental losses include only those costs described which are above and beyond the normal costs of production. If the customer is able to make up some percentage of its production loss at a later date (e.g., by running the production facility during times when it would normally be idle), the outage cost does not include the full value of the production loss. Rather, it is calculated as the value of production not made up plus the cost of additional labor and materials required to make up the share of production eventually recovered.

2.3.2 Willingness-to-Pay Approach

Cost estimates for the residential segment are based on a WTP question, as residential customers do not experience many directly measureable costs during an outage. Considering that most of the outage cost for residential customers is a result of inconvenience or hassle, WTP is a better representation of their underlying costs. The WTP approach to outage cost estimation is quite different than the direct cost measurement approach. Rather than asking what an outage would cost the customer, the WTP approach asks how much the customer would pay to avoid its occurrence. This technique employs the concept of compensating

valuation, where customers are asked to estimate the economic value that would leave their welfare unchanged compared to a situation in which no outage occurred. This approach is especially useful when intangible costs are present, which by their nature are difficult to estimate using the direct cost measurement approach.

2.4 Report Organization

The remainder of this report proceeds as follows:

- **Section 3 – Survey Methodology:** This section covers the survey methodology, including details on the survey implementation approach by customer class, survey instrument design, sample design and data collection procedures for each customer class.
- **Section 4 – Outage Cost Estimation Methodology**: The results of this study focus on the following six metrics: cost per outage event, cost per average kW, cost per unserved kWh, duration cost per outage event, duration cost per average kW, and duration cost per unserved kWh. This section on the outage cost estimation methodology explains what each of these five key metrics represents, how they are calculated from the survey data and how they are related to each other.
- **Sections 5 through 8 – Results**: These four sections provide the results for residential customers (Section 5), small/medium business (Section 6), large C&I (Section 7), and blended (Section 8). Results are presented for the metrics defined in Section 4. Each section concludes with results related to the level of reliability that each customer class considers acceptable.
- **Appendix A – Customer Damage Functions:** This appendix details the customer damage functions, which are econometric models that predict how outage costs vary across customers, outage duration and other outage characteristics.
- **Appendices B through D – Survey Instruments:** These appendices contain the survey instruments used for the study for each customer class.

3 Survey Methodology

Table 3-1 provides an overview of the survey implementation approach by customer class. Residential customers were recruited with a letter that encouraged them to go online to complete the survey (the letter included a link to the online survey along with a unique access code specific to each customer). If a residential customer did not complete the survey online, Nexant arranged to have a paper copy sent to the customer's mailing address. Customers for whom THESL had email addresses were sent an email with a direct link to that customer's unique online survey. SMB customers were recruited by telephone. They were encouraged to fill out the survey online, but were also offered the option of receiving a paper survey to complete and submit through the mail. If the customer preferred to go online to complete the survey, a link to the online survey and a unique access code specific to each customer were provided in an email. Large C&I customers were recruited by telephone and received an in-person interview. THESL key account representatives assisted with recruitment by contacting large C&I customers to inform them of the study and request their participation.

Although all survey instruments included variations of willingness-to-pay (WTP) and direct cost questions, the results in Sections 5 through 8 are based on the valuation methods listed in Table 3-1. Cost estimates for the residential segment are based on a WTP question, as residential customers do not experience many directly measureable costs during outages lasting 24 hours or less. Considering that most of the outage cost for residential customers is due to inconvenience or hassle, WTP is a better representation of their underlying costs. For SMB and large C&I customers, direct cost measurement is the preferred valuation method, as their outage costs are more tangible and much less difficult to estimate directly.

Table 3-1:
Survey Implementation Approach by Customer Class

Customer Class	Sample Design Target	Recruitment Method	Data Collection Approach	Valuation Method	Incentive Provided
Residential	800	Letter/Email	Mail/Internet Survey	WTP	$10
SMB	800	Telephone	Mail/Internet Survey	Direct Cost	$50/$100
Large Business	100	Telephone	In-person Interview	Direct Cost	$150

3.1 Survey Instrument Design

The survey instrument asked customers to estimate interruption costs for six different hypothetical outage scenarios. The outage scenarios were described by five different factors: season, time of week, start time, end time, and outage duration. For each customer, the start time was the same for all scenarios to avoid confusion. Table 3-2 summarizes a set of outage scenarios for one particular customer. Each survey used either summer or winter as the season. Half of the surveys had summer as the season for scenarios A-E and winter as the season for scenario F. The other half had the seasons reversed. Each survey contained two scenarios with

a 4-hour duration—one for summer and one for winter. The time of week was "Weekday" for all scenarios, as this survey was designed to facilitate modeling of seasonal variation instead of weekend/weekday variation. The survey instruments are included as appendices in case more detail is required on other aspects of the survey.

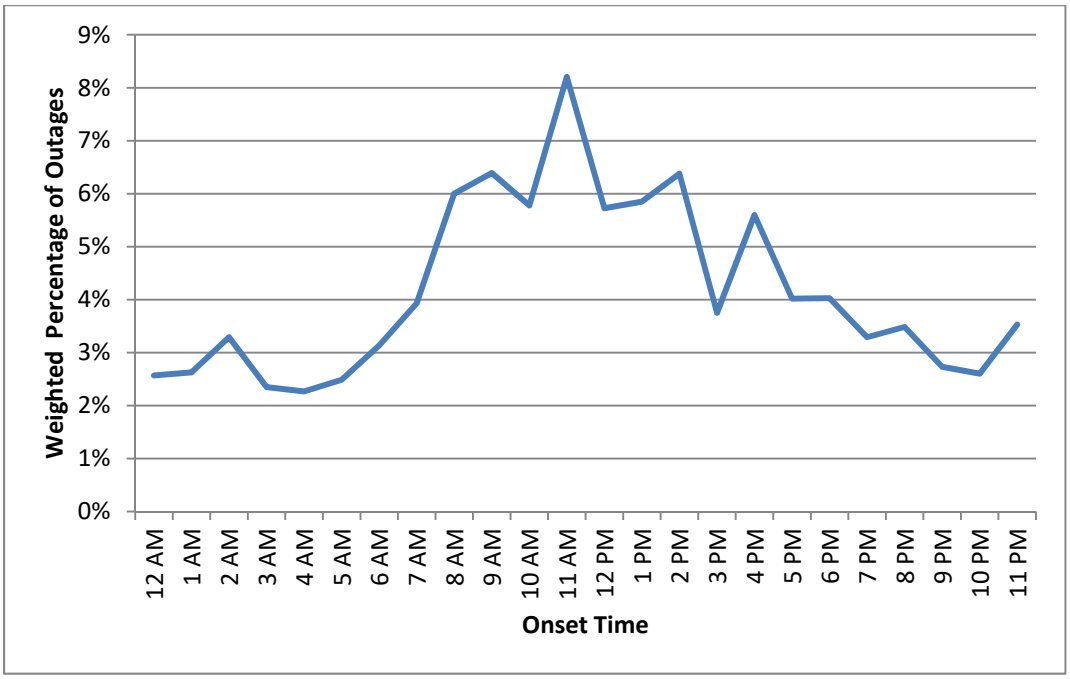
Table 3-2:
Example Set of Outage Scenarios

Scenario	Season	Time of Week	Start Time	End Time	Duration
A	Summer	Weekday	11:00 AM	3:00 PM	4 hours
B	Summer	Weekday	11:00 AM	11:01 AM	1 minute
C	Summer	Weekday	11:00 AM	Noon	1 hour
D	Summer	Weekday	11:00 AM	7:00 PM	8 hours
E	Summer	Weekday	11:00 AM	11:00 AM (Next Day)	24 hours
F	Winter	Weekday	11:00 AM	3:00 PM	4 hours

The distribution of hypothetical onset times among survey respondents was determined by examining the historical distribution of outages for THESL from 2010-2017. Figure 3-1 shows the distribution of outage onset times for sustained outages during this time period.[5] The outages were weighted by the number of customers impacted by the outage. The most common weighted onset time was the 11:00 AM hour, which accounted for just over 8% of impacted customers. The survey instrument randomized the outage scenarios in proportion to the distribution of onset times in Figure 3-1. The outage cost estimates provided in Sections 5 through 8 are thus representative of the average outage cost across all time periods.

[5] The distribution excludes outages categorized by THESL as "momentary" or "planned." It also excludes outages occurring on major event days during the period, or for which the cause was loss of supply.

Figure 3-1:
Distribution of Sustained Outages by Onset Time
Weighted by Total Customers Interrupted (2010-2017)



3.2 Sample Design

The study aimed for the following number of completed surveys for each customer class:

- 800 residential customers;
- 800 SMB customers;
- 100 large C&I customers.

Before detailing the sample design methodology and how these sample points were distributed among usage categories, it is important to note that a "customer" refers to a unique combination of "entity name" and "service address" in THESL's customer database. For residential customers, there was generally only one account ID associated with each unique combination. For non-residential customers, there could be multiple account IDs for an entity name-service address combination. When customers completed an outage cost survey, they provided cost estimates for the specific service address. Usage and customer contact information were aggregated across all of the accounts associated with each entity at each service address and then the customers were sampled.

Nexant stratified each customer class by the log of usage (a proxy for outage cost) by employing a two-step process to achieve an optimal sample stratification scheme. In the first step, Nexant identified the optimal stratum boundaries using the Dalenius-Hodges method. Next, it determined the optimal allocation among the Dalenius-Hodges strata using the Neyman allocation. This two-step approach is particularly useful for measuring skewed populations and

maximizes survey precision for a given sample size and number of strata. This sampling approach is necessary as the distribution of usage per customer is highly skewed.

Tables 3-3, 3-4, and 3-5 summarize the sample designs for residential, SMB, and large C&I customers respectively. The residential and SMB customer classes each had four sample strata—labeled as 'usage categories' in the leftmost column of each table. The large C&I customer class was divided into three strata. For each of the customer classes, the sample stratification method led to the largest usage category having a larger percentage of customers in the sample than in the population. This allowed the sample to capture the higher and more variable outage costs for customers in those categories.

Table 3-3:
Sample Design Summary – Residential

Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
0 to 0.25	62,103	9%	204	26%
0.25 to 0.57	194,060	30%	196	24%
0.57 to 1.1	252,994	39%	191	24%
1.1 and above	145,816	22%	208	26%
	654,973	**100%**	**800**	**100%**

Table 3-4:
Sample Design Summary – SMB

Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
0 to 1.35	14,668	23%	204	26%
1.35 to 4.78	22,380	35%	196	25%
4.78 to 25.8	17,499	27%	191	24%
25.8 and above	9,146	14%	208	26%
	63,693	**100%**	**800**	**100%**

Table 3-5:
Sample Design Summary – Large Business

Usage Category (Average kW)	Population	% of Population	Sample Design Target	% of Sample
235 to 911	158	34%	27	27%
912 to 1934	189	41%	31	31%
1935 and above	113	25%	42	42%
	460	**100%**	**100**	**100%**

3.3 Data Collection Procedures

This section summarizes the data collection procedures for each customer class.

3.3.1 Residential Customers

The residential survey was conducted online and via mail. It was distributed to the target respondents in two waves. In the first wave, respondents received a cover letter on THESL stationery explaining the purpose of the study and requesting their participation. This letter also contained a URL and unique respondent ID number so that respondents could complete the survey online. Approximately two weeks after the first wave was mailed, respondents who did not complete the online survey received a reminder letter with a paper copy of the survey. The letters and survey packet included an 800 number that respondents could call to verify the legitimacy of the survey and ask questions. Customers who completed the survey were sent a $10 incentive cheque in the mail.

3.3.2 Small & Medium Business Customers

SMB customers were first recruited by telephone to ensure that Nexant identified the appropriate individuals for answering questions related to energy and outage issues for that company; and to secure a verbal agreement from them to complete the survey. Telephone interviewers explained the purpose of the survey and indicated that an incentive was to be provided to thank the respondent for their time. The individuals were then sent an email containing an individualized survey link or had the survey package mailed or faxed to them containing:

- Additional explanation of the purpose of the research;
- Clear and easy-to-understand instructions for completing the survey questions;
- A telephone number they could call if they had questions about the research or wished to verify its authenticity;
- The survey booklet (or a link in the email to compete the survey online); and
- Return envelope with pre-paid postage (for the paper survey option).

One week after the survey link was emailed or the survey was faxed, respondents were given a reminder call. Customers who requested regular mail received their reminder calls after approximately two weeks. About ten days after the reminder calls were made to the email recipients, the email was re-sent to anyone who had not yet completed the survey. If the survey was still not completed within ten days, it was assumed that the customer would not complete the survey and they were not contacted again. An incentive of $50 was mailed to respondents who completed the survey form.

The recruitment effort for the initial sample of 3,200 customers did not yield the response rate normally seen with SMB customers for VOS studies. To boost the number of responses, Nexant obtained authorization from THESL to increase incentives from $50 to $100. It also drew an additional sample of 3,200 SMB customers to raise the total sample to 6,400. The response rate increased modestly from initial levels, but remained low compared to previous studies—as only 245 customers completed and submitted surveys out of a target of 800.

3.3.3 Large C&I Customers

For large C&I customers, an experienced telephone recruiter first located and recruited an appropriate representative at each of the sampled premises with the assistance of THESL. The target respondent was usually a plant manager or plant engineering manager – someone who was familiar with the cost structure of the enterprise. Once the target respondent was identified and agreed to participate, the scheduler set up an appointment with the field interviewer. Once the appointment was scheduled, Nexant emailed the customer a confirmation along with a written description of the study and an explanation of the information they would be asked to provide. The interview was scheduled at the convenience of the customer. A financial incentive of $150 was offered for completion of the information. On the agreed upon date, Nexant's field interviewer visited the sampled site and conducted the in-person interview.

4 Outage Cost Estimation Methodology

4.1 Outage cost metrics

The results sections for each customer class (Sections 5 through 7) primarily focus on the following five outage cost metrics:

- Cost per Outage Event
- Cost per Average kW
- Cost per Unserved kWh
- Duration Cost per Outage Event
- Duration Cost per Average kW
- Duration Cost per Unserved kWh

Before presenting the results, it is important to understand how each of these metrics was derived. This section begins with a description of the cost per outage event estimate, as it came directly from the survey responses and the other cost metrics were derived from this one.

Cost per outage event is the average cost per customer resulting from each outage duration. It was derived by calculating a weighted average of the values that the respondent provided on the survey. Each scenario on the survey focused on a specific outage event and then asked the respondent to provide the cost estimate. The respondent was essentially providing the cost per outage event estimate. Before calculating the weighted average of these estimates, the top 0.5% of values normalized by usage was dropped from the analysis for residential and SMB. These outliers were dropped because respondents may erroneously provide unrealistically high estimates when taking an outage cost survey, as a result of human error or misunderstanding of the question. This step was skipped for large C&I customers as trained interviewers were walking customers through the questions. In addition, for residential customers, answers were considered outliers when the respondent selected the maximum $100 WTP response for all of the six scenarios (25 respondents). This set of responses suggested that the respondent was not carefully considering the outage scenario. After dropping outliers, cost per outage event was derived as an average of the customer responses, weighted by usage category for each segment.

Cost per average kW is the average cost per outage event normalized by average customer demand. This metric is useful for comparing outage costs across segments because it is normalized by customer demand. Cost per average kW was derived by dividing average cost per outage event by the weighted average customer demand among respondents for each outage duration by customer class. It is a ratio of the average values as opposed to the average of the ratios for each customer. Therefore, for each outage duration and customer class, average cost per event was first calculated using the steps above and then divided by the average demand among respondents. The average demand for each respondent was

calculated as the annual kWh usage divided by 8,760 hours in the year, as shown in the following equation:

$$Average\ Demand = \left(\frac{Annual\ kWh\ usage}{8{,}760}\right)$$

As in the cost per outage event average calculation, the average customer demand (the denominator of the ratio) was weighted by usage category for each segment.

Cost per unserved kWh is the cost per outage event normalized by the expected amount of unserved kWh. This metric is useful because it can be readily used in planning applications, for which the amount of unserved kWh as a result of a given outage is commonly available. As in the cost per average kW calculation, cost per unserved kWh is a ratio of the average values as opposed to the average of the ratios for each customer. Therefore, for each duration and customer class, average cost per event was first calculated using the steps above and then divided by the expected unserved kWh. The expected unserved kWh is the estimated quantity of electricity that would have been consumed if an outage had not occurred.

Duration cost per outage event is the cost per outage event minus the cost for a momentary, 1-minute outage. The duration cost for a 1-minute outage is thus always $0. The other two duration cost metrics—duration cost per average kW and duration cost per unserved kWh—are calculated as described above, but with the adjusted event cost.

4.2 Special Considerations

Master metered customers: A number of large C&I customers were master metered, or bulk metered, meaning that one meter would serve the property owner, but that the building was occupied by multiple tenants. These tenants may or may not be sub-metered by a third party so that the property owner could bill them for electricity. THESL did not have contact information or consumption data for the tenants, as it did not directly meter the tenants. However, outage costs were incurred by the tenants. Interruption costs for master metered buildings were calculated by adding the outage costs for the property owner/manager with an estimate of the costs borne by the tenants. Tenant costs were estimated using either SMB or residential (depending on the type of tenant) cost per unserved kWh estimates and scaling them to the consumption level for the entire building.

Weekend/weekday differences: The outage scenarios in the survey instrument were designed to facilitate modeling seasonal differences in outage costs. Customers can only process a limited number of hypothetical scenarios before they get survey fatigue and introduce bias into the results. Therefore, all scenarios were for weekdays and the weekday/weekend differences for a recent interruption cost study for PG&E were used to adjust the estimates for this study for residential and SMB customers (but not for large C&I). The adjustments assume that interruptions are spread evenly across days of the week, such that weekend outage costs would be weighted by 2/7 and weekday costs by 5/7. The weekend adjustments for each time of day are shown below in Table 4.1.

Table 4-1:
Weekend Outage Cost Adjustments – Based on 2012 PG&E Study

Time of Day	Weekend Adjustment	
	Residential	SMB
Morning (7 AM to 11 AM)	-8%	-60%
Afternoon (12 PM to 5 PM)	-1%	-37%
Evening (6 PM to 9 PM)	20%	-61%
Night (10 PM to 6 AM)	4%	-58%

5 Residential Results

This section summarizes the results for residential customers.

5.1 Response to Survey

Table 5-1 summarizes the survey response for residential customers. With 1,061 total completed surveys, customer response was above the overall sample design target of 800. Overall, the survey had a 39.8% response rate that varied across usage categories. The second lowest usage category—with average kW of 0.25 to 0.57—had the highest response rate at 44 percent. The third usage category (0.57 to 1.1kW average) had nearly a 41 percent response rate. In the highest and lowest usage categories, the response rate was just over 37 percent. However, non-response bias among high and low usage residential customers is not a significant concern for the outage cost estimates because usage category is factored into the stratification weights in the analysis.

Table 5-1:
Customer Survey Response Summary – Residential

Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Responses	Response Rate
0 to 0.25	62,103	204	681	255	37.4%
0.25 to 0.57	194,060	196	653	287	44.0%
0.57 to 1.1	252,994	191	638	260	40.8%
1.1 and above	145,816	208	694	259	37.3%
All	**654,973**	**800**	**2,666**	**1,061**	**39.8%**

Before presenting the outage cost estimates, it is important to summarize the prevalence of invalid responses. This summary is only provided for the residential segment because its cost estimates are derived from a WTP question. Some respondents are confused by WTP questions or end up answering a question that is quite different from the one that is being asked. For example, customers sometimes react to questions about WTP by redefining the question so that it relates to their satisfaction with service or whether they think they are being fairly charged for the service they are receiving. Such “protest responses” do not accurately reflect the cost of an outage for a customer, so they were removed from the analysis.

To identify these protest responses, the survey included a follow-up question for respondents that indicated a WTP value of $0. If the respondent verified that WTP was $0 because the outage scenario would not in fact result in any noticeable costs, the $0 response was confirmed as valid and included in the cost estimate calculations. However, if the respondent indicated that WTP was $0 because they thought it was unfair to pay more for electric service, the response was deemed invalid and not included in the cost estimate calculations. Table 5-2 summarizes the prevalence of invalid responses by outage duration in the residential survey.

The percentage of responses deemed invalid varied from 5.1% for a 24-hour outage to 6.0% for a 4-hour outage. The residential interruption cost estimates are based on the number of responses indicated in the "Valid Responses" category, which is fewer than what would normally be expected from a study with 1,061 responses. Note that the number of responses for the 4-hour outage duration was double those of other durations, as two of the six scenarios had 4-hour hypothetical outages.

Table 5-2:
Summary of Invalid Responses – Residential

Outage Duration	Total Responses	Invalid Responses		Valid Responses
		N	%	
1 minute	1,061	55	5.2%	1006
1 hour	1,061	56	5.3%	1005
4 hours	2,122	127	6.0%	1,995
8 hours	1,061	56	5.3%	1005
24 hours	1,061	54	5.1%	1007

5.2 Outage Cost Estimates

Figure 5-1 and Table 5-3 provide the residential cost per outage event estimates by region. For a 1-hour outage, residential customers experience a cost of $10.87 on average across the entire service territory. Cost per outage event increases to $23.35 at 8 hours and $34.53 for a 24-hour outage. Residents of York and North York generally report higher interruption costs, while residents of East York and Scarborough report lower costs. For a 1-hour interruption, Costs range from $8.55 to $13.39 for a 1-hour outage, $13.04 to $23.10 for a 4-hour outage, $17.55 to $27.12 for an 8-hour outage and $21.09 to $44.47 for a 24-hour outage. The percentage difference between regions increases with duration, suggesting that outages have a relatively higher incremental impact in North York as duration increases. However, it should be noted that East York and York both have small sample sizes. This means that the standard errors are larger and the confidence bands are wider. The small sample size could also partially account for the unusual result for York of a 1-hour outage valued slightly less than a 1-minute outage. There is a difference in the point estimates between the two durations but the confidence bands are overlapping.

Figure 5-1:
Cost per Outage Event Estimates by Region – Residential

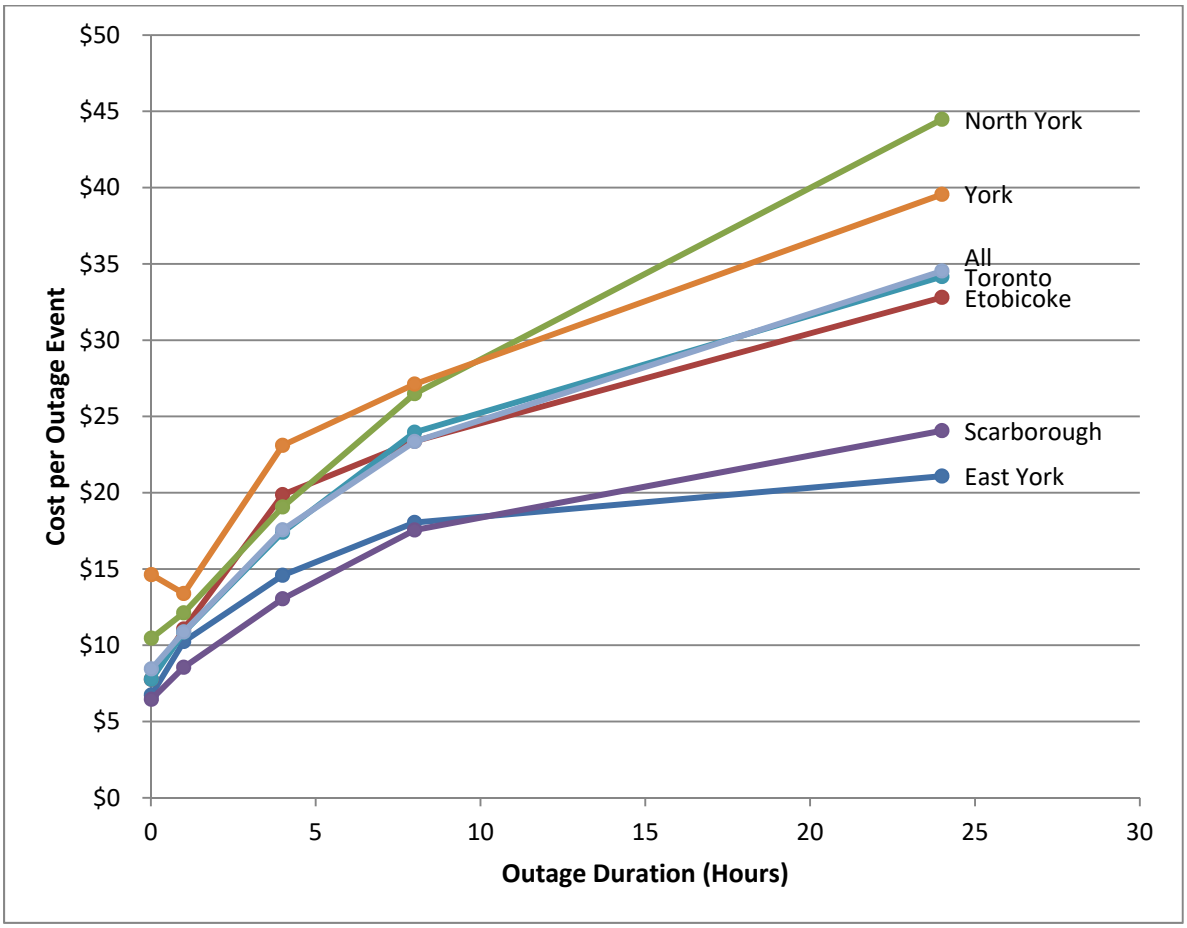


Table 5-4 summarizes residential cost per average kW. For a 1-hour outage, residential customers experience a cost of $13.21 per average kW. The cost per average kW estimates are roughly 20% higher than the cost per outage event estimates because average demand for residential respondents was around 0.8 kW. Scarborough and East York are again at the lower end of the cost range between regions. Costs range from$ 7.79 to $18.59 for a one-minute outage, $10.32 to $16.99 for a 1-hour outage, $15.77 to $29.33 for a 4-hour outage, $20.92 to $34.47 for an 8-hour outage and $26.86 to $50.31 for a 24-hour outage.

Table 5-5 provides the residential cost per unserved kWh estimates. For a 1-hour outage, residential customers experience a cost of $13.21 per unserved kWh, which is equivalent to the cost per average kW estimate because the expected amount of unserved kWh is also around 0.8 at 1 hour. For a 1-minute outage, the system-wide cost estimate is over $616 because the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. As duration increases, cost per unserved kWh decreases steeply because unserved kWh increases linearly with the number of hours while cost per outage event increases at a decreasing rate.

Table 5-3:
2018 Cost per Outage Event Estimates by Region – Residential

Region	Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
				Lower Bound	Upper Bound
East York	1 minute	29	$6.74	$2.77	$10.71
	1 hour	28	$10.24	$5.49	$14.99
	4 hours	55	$14.58	$10.25	$18.92
	8 hours	28	$18.04	$10.53	$25.54
	24 hours	28	$21.09	$11.75	$30.44
Etobicoke	1 minute	130	$7.76	$5.40	$10.12
	1 hour	132	$11.06	$7.89	$14.23
	4 hours	261	$19.87	$16.40	$23.35
	8 hours	130	$23.37	$16.17	$30.58
	24 hours	132	$32.80	$20.81	$44.79
North York	1 minute	224	$10.46	$8.12	$12.80
	1 hour	222	$12.12	$9.71	$14.53
	4 hours	447	$19.06	$16.41	$21.71
	8 hours	224	$26.49	$18.79	$34.18
	24 hours	223	$44.47	$28.35	$60.58
Scarborough	1 minute	150	$6.45	$4.67	$8.23
	1 hour	150	$8.55	$6.59	$10.52
	4 hours	290	$13.04	$11.27	$14.81
	8 hours	145	$17.55	$14.23	$20.88
	24 hours	146	$24.06	$19.89	$28.23
Toronto	1 minute	397	$7.76	$5.63	$9.89
	1 hour	397	$10.85	$9.02	$12.67
	4 hours	790	$17.40	$15.11	$19.68
	8 hours	402	$23.96	$19.35	$28.56
	24 hours	402	$34.16	$29.04	$39.28
York	1 minute	42	$14.62	$6.67	$22.57
	1 hour	42	$13.39	$7.88	$18.90
	4 hours	84	$23.10	$17.20	$29.00
	8 hours	42	$27.12	$18.97	$35.26
	24 hours	42	$39.56	$26.42	$52.69
All	**1 minute**	**972**	**$8.45**	**$7.31**	**$9.58**
	1 hour	**971**	**$10.87**	**$9.78**	**$11.96**
	4 hours	**1927**	**$17.56**	**$16.32**	**$18.81**
	8 hours	**971**	**$23.35**	**$20.53**	**$26.17**
	24 hours	**973**	**$34.53**	**$29.80**	**$39.27**

Table 5-4:
2018 Cost per Average kW Estimates by Region – Residential

Region	Outage Duration	N	Cost per Average kW	90% Confidence Interval	
				Lower Bound	Upper Bound
East York	1 minute	29	$8.39	$2.72	$14.06
	1 hour	28	$13.02	$6.19	$19.85
	4 hours	55	$18.72	$12.44	$25.00
	8 hours	28	$22.97	$12.66	$33.28
	24 hours	28	$26.86	$14.33	$39.40
Etobicoke	1 minute	130	$9.74	$6.72	$12.76
	1 hour	132	$13.89	$9.95	$17.84
	4 hours	261	$25.15	$20.84	$29.46
	8 hours	130	$29.52	$20.61	$38.43
	24 hours	132	$41.43	$26.55	$56.31
North York	1 minute	224	$10.86	$8.36	$13.36
	1 hour	222	$12.55	$9.91	$15.20
	4 hours	447	$19.73	$16.85	$22.62
	8 hours	224	$27.53	$19.60	$35.47
	24 hours	223	$46.12	$29.52	$62.72
Scarborough	1 minute	150	$7.79	$5.62	$9.95
	1 hour	150	$10.32	$7.90	$12.73
	4 hours	290	$15.77	$13.59	$17.94
	8 hours	145	$20.92	$16.97	$24.88
	24 hours	146	$28.76	$23.67	$33.84
Toronto	1 minute	397	$10.43	$7.47	$13.39
	1 hour	397	$14.57	$12.02	$17.11
	4 hours	790	$23.32	$20.16	$26.48
	8 hours	402	$32.30	$25.95	$38.64
	24 hours	402	$46.07	$38.90	$53.24
York	1 minute	42	$18.59	$8.09	$29.10
	1 hour	42	$16.99	$9.35	$24.64
	4 hours	84	$29.33	$20.93	$37.73
	8 hours	42	$34.47	$22.05	$46.90
	24 hours	42	$50.31	$30.56	$70.06
All	**1 minute**	**972**	**$10.27**	**$8.85**	**$11.69**
	1 hour	**971**	**$13.21**	**$11.84**	**$14.58**
	4 hours	**1927**	**$21.36**	**$19.79**	**$22.92**
	8 hours	**971**	**$28.41**	**$24.98**	**$31.85**
	24 hours	**973**	**$42.04**	**$36.28**	**$47.79**

Table 5-5:
2018 Cost per Unserved kWh Estimates by Region – Residential

Region	Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
				Lower Bound	Upper Bound
East York	1 minute	29	$503.52	$163.28	$843.75
	1 hour	28	$13.02	$6.19	$19.85
	4 hours	55	$4.68	$3.11	$6.25
	8 hours	28	$2.87	$1.58	$4.16
	24 hours	28	$1.12	$0.60	$1.64
Etobicoke	1 minute	130	$584.25	$402.91	$765.60
	1 hour	132	$13.89	$9.95	$17.84
	4 hours	261	$6.29	$5.21	$7.36
	8 hours	130	$3.69	$2.58	$4.80
	24 hours	132	$1.73	$1.11	$2.35
North York	1 minute	224	$651.50	$501.36	$801.64
	1 hour	222	$12.55	$9.91	$15.20
	4 hours	447	$4.93	$4.21	$5.65
	8 hours	224	$3.44	$2.45	$4.43
	24 hours	223	$1.92	$1.23	$2.61
Scarborough	1 minute	150	$467.11	$337.12	$597.11
	1 hour	150	$10.32	$7.90	$12.73
	4 hours	290	$3.94	$3.40	$4.49
	8 hours	145	$2.62	$2.12	$3.11
	24 hours	146	$1.20	$0.99	$1.41
Toronto	1 minute	397	$625.61	$447.93	$803.30
	1 hour	397	$14.57	$12.02	$17.11
	4 hours	790	$5.83	$5.04	$6.62
	8 hours	402	$4.04	$3.24	$4.83
	24 hours	402	$1.92	$1.62	$2.22
York	1 minute	42	$1,115.60	$485.23	$1,745.97
	1 hour	42	$16.99	$9.35	$24.64
	4 hours	84	$7.33	$5.23	$9.43
	8 hours	42	$4.31	$2.76	$5.86
	24 hours	42	$2.10	$1.27	$2.92
All	**1 minute**	**972**	**$616.11**	**$531.06**	**$701.17**
	1 hour	**971**	**$13.21**	**$11.84**	**$14.58**
	4 hours	**1927**	**$5.34**	**$4.95**	**$5.73**
	8 hours	**971**	**$3.55**	**$3.12**	**$3.98**
	24 hours	**973**	**$1.75**	**$1.51**	**$1.99**

Table 5-6 shows duration cost, duration cost per average kW, and duration cost per unserved kWh by region and overall. Duration cost is the event cost minus the event cost for a 1-minute outage. It represents the event cost beyond the momentary interruption. Thus, the duration cost for a one-minute outage is $0. The duration cost per unserved kWh is a similar calculation to Table 5-5, but it divides the duration cost—instead of event cost—by unserved kWh.

Table 5-6:
2018 Duration Cost Estimates by Region – Residential

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
East York	1 minute	29	$0.00	$0.00	$0.00
	1 hour	28	$3.50	$4.36	$4.45
	4 hours	55	$7.84	$9.76	$2.52
	8 hours	28	$11.30	$14.07	$1.80
	24 hours	28	$14.35	$17.87	$0.76
Etobicoke	1 minute	130	$0.00	$0.00	$0.00
	1 hour	132	$3.30	$4.14	$4.14
	4 hours	261	$12.11	$15.19	$3.83
	8 hours	130	$15.61	$19.59	$2.46
	24 hours	132	$25.04	$31.41	$1.32
North York	1 minute	224	$0.00	$0.00	$0.00
	1 hour	222	$1.66	$1.72	$1.72
	4 hours	447	$8.60	$8.93	$2.23
	8 hours	224	$16.03	$16.64	$2.08
	24 hours	223	$34.01	$35.31	$1.47
Scarborough	1 minute	150	$0.00	$0.00	$0.00
	1 hour	150	$2.11	$2.55	$2.54
	4 hours	290	$6.59	$7.96	$1.99
	8 hours	145	$11.11	$13.42	$1.66
	24 hours	146	$17.61	$21.27	$0.88
Toronto	1 minute	397	$0.00	$0.00	$0.00
	1 hour	397	$3.09	$4.15	$4.15
	4 hours	790	$9.64	$12.95	$3.23
	8 hours	402	$16.20	$21.76	$2.73
	24 hours	402	$26.40	$35.47	$1.48
York	1 minute	42	$0.00	$0.00	$0.00
	1 hour	42	$0.00	$0.00	$0.00
	4 hours	84	$8.48	$10.78	$2.69
	8 hours	42	$12.50	$15.89	$1.99
	24 hours	42	$24.94	$31.71	$1.32

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
All	1 minute	972	$0.00	$0.00	$0.00
	1 hour	971	$2.42	$2.94	$2.94
	4 hours	1927	$9.11	$11.08	$2.77
	8 hours	971	$14.90	$18.11	$2.27
	24 hours	973	$26.09	$31.71	$1.32

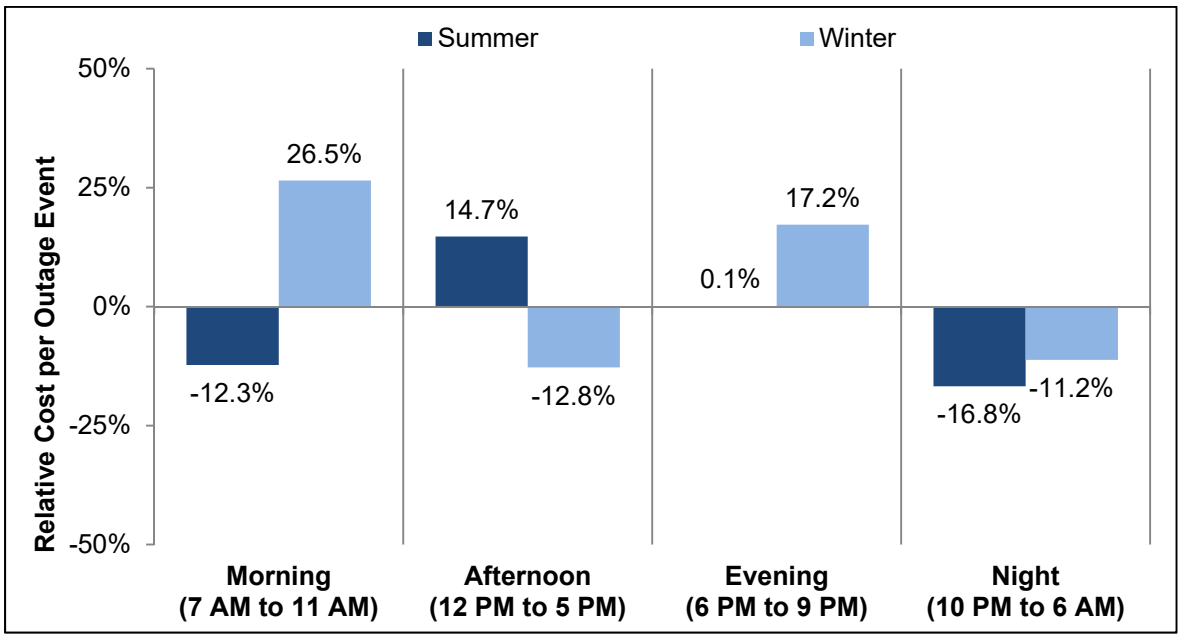
5.3 Impact of Outage Timing

For the residential analysis on the impact of outage timing, onset times were aggregated into 4 key time periods with distinct cost per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

Figure 5-2 provides the relative cost per outage event estimates, which were derived from the residential customer damage functions described in Appendix A. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each residential outage cost estimate in Section 5.2 (referred to as the "base value"). As shown in the figure, outage costs for residential customers are somewhat sensitive to onset time, varying from 16.8% lower than the base value on a summer night to 26.5% higher on a winter morning. Residential customers experience relatively high outage costs during winter mornings, winter evenings, and summer afternoons. These results could reflect the importance of home heating during winter mornings and evenings and home cooling during summer afternoons.

Figure 5-2:
Relative Cost per Outage Event Estimates by Season and Onset Time – Residential



5.4 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 5-3 and Table 5-7 shows the percent of residential customers rating each combination of outage frequency and duration as acceptable. As expected, a residential customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. Residential customers are willing to accept a relatively high frequency of short-duration outages.

Figure 5-3:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – Residential

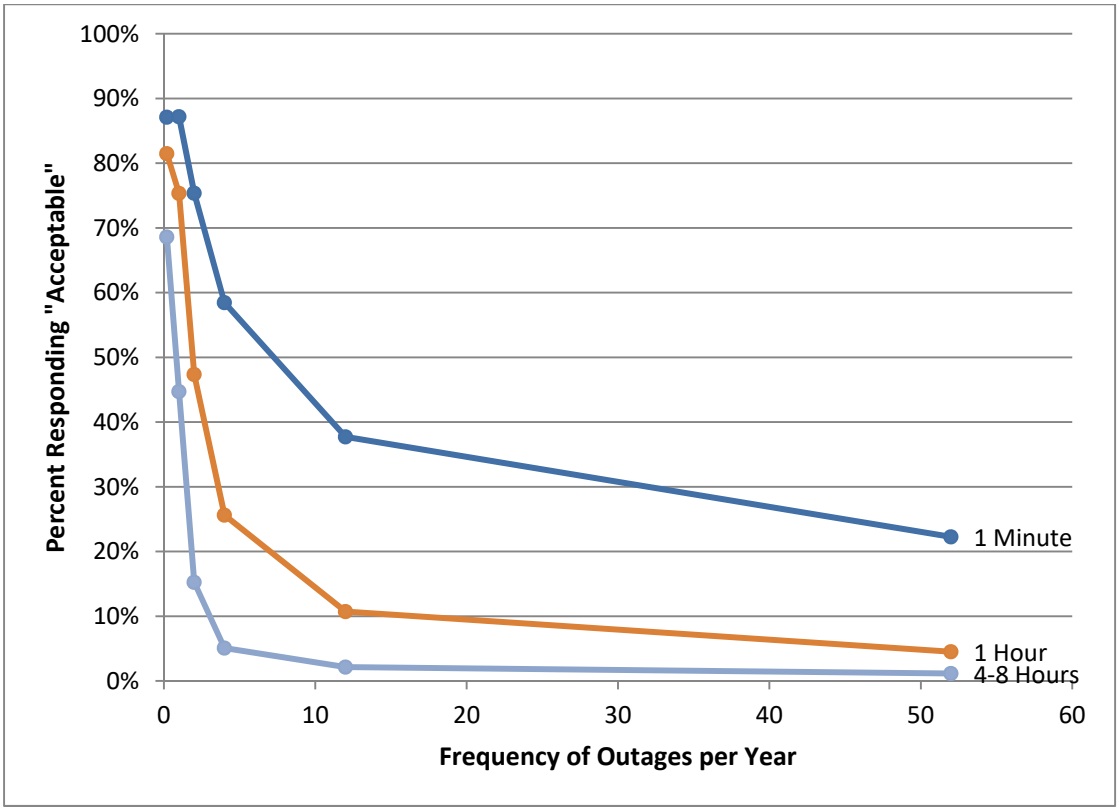


Table 5-7:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – Residential

Region	Frequency of Outages per Year	Outage Duration		
		1 Minute	1 Hour	4-8 Hours
All	Once every 5 years	87.1%	81.5%	68.6%
	1	87.2%	75.3%	44.7%
	2	75.4%	47.4%	15.3%
	4	58.5%	25.6%	5.1%
	12	37.7%	10.7%	2.1%
	52	22.3%	4.5%	1.2%

Table 5-8 shows two measures of satisfaction with service reliability. On a 5-point scale, with 1 as “Very Low” and 5 as “Very High,” residential customers report a 1.84 average rating for the number of power outages they experience. On a 5-point scale, with 1 as “Very Dissatisfied” and 5 as “Very Satisfied,” residential customers report a 4.05 average rating of their satisfaction with the level of service reliability they receive from THESL.

Table 5-8:
Satisfaction with Service Reliability – Residential

Question	Average Score
Do you feel the number of power outages your residence experiences is … (5-point scale, 1 for “Very Low” to 5 for “Very High”)	1.84
How satisfied are you with the reliability of the electrical service you receive from Toronto Hydro? (5-point scale, 1 for “Very Dissatisfied" to 5 for “Very Satisfied”)	4.05

6 Small & Medium Business Results

This section summarizes the results for SMB customers.

6.1 Response to Survey

Table 6-1 summarizes the survey response for SMB customers. With 245 total completed surveys, customer response was below the overall sample design target of 800. The study results are valid, but obtaining results by smaller geographic regions within the service territory (as with residential customers) was not feasible and the confidence bands are wider than they otherwise would have been if the targets had been reached. The original sample design had a sample draw of 3,200 customers for an expected response rate of 25 percent. Once the customers in the first sample draw had been contacted and it was clear that the response rate was below target, Nexant worked with THESL to boost responses by increasing incentives from $50 to $100 and adding 3,200 customers to the sample. Even with the increased incentives, the response rate remained low. It was similar across the four usage categories, ranging only from 3.5 percent to 4.2 percent.

Table 6-1:
Customer Survey Response Summary – SMB

Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Responses	Response Rate
0 to 1.35	14,668	204	1,638	62	3.7%
1.35 to 4.78	22,380	196	1,612	68	4.2%
4.78 to 25.8	17,499	191	1,620	56	3.5%
25.8 and above	9,146	208	1,530	59	3.8%
All	**63,693**	**800**	**6,400**	**245**	**3.8%**

6.2 Outage Cost Estimates

Figure 6-1 and Table 6-2 provide the SMB cost per outage event estimates. For a 1-hour outage, SMB customers experience a cost of $857.84. SMB cost per outage event increases to $4,098 at 8 hours and $8,426 for a 24-hour outage. Results for SMB customers are not broken down by region, as the number of completed surveys was too small to obtain meaningful results for the pre-amalgamation municipalities.

Figure 6-1:
Cost per Outage Event Estimates – SMB

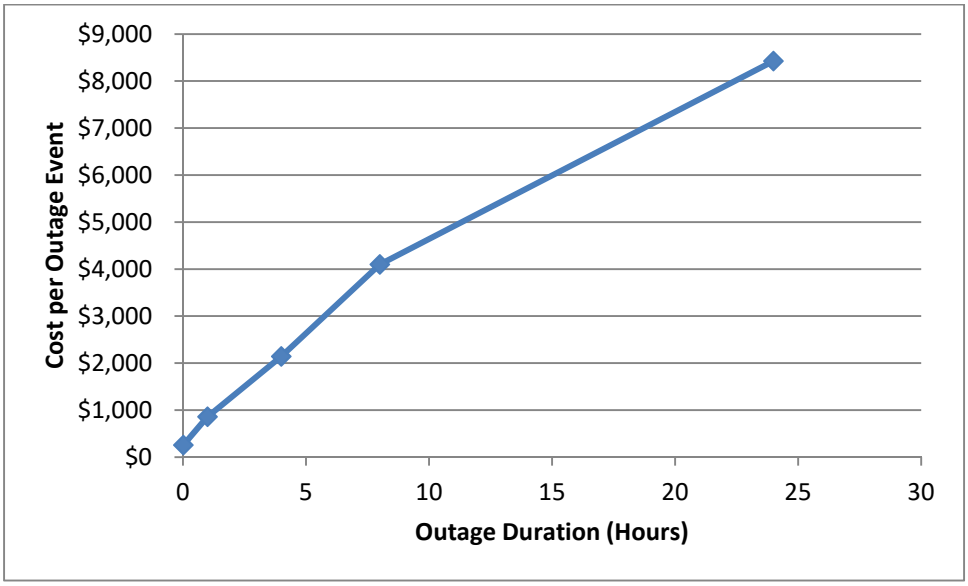


Table 6-2:
Cost per Outage Event Estimates– SMB

Region	Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	242	$257.38	$161.82	$352.95
	1 hour	242	$857.84	$611.74	$1,103.94
	4 hours	477	$2,142.39	$1,779.13	$2,505.66
	8 hours	240	$4,098.01	$2,844.42	$5,351.59
	24 hours	239	$8,426.27	$5,892.16	$10,960.38

Table 6-3 summarizes SMB cost per average kW. For a 1-hour outage, SMB customers experience a cost of $40.68 per average kW. The cost per average kW estimates are substantially lower than the cost per outage event estimates because average demand for SMB respondents was around 21 kW. Table 6-4 provides the SMB cost per unserved kWh estimates. For a 1-hour outage, SMB customers experience a cost of $40.68 per unserved kWh – same as the cost per average kW estimate. At 1-minute, the system-wide estimate is over $722, as the expected amount of unserved kWh (the denominator of the equation) is very low for a short-duration outage. For a 24-hour outage, cost per unserved kWh is $16.64.

Table 6-3:
Cost per Average kW Estimates – SMB

Region	Outage Duration	N	Cost per Average kW	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	242	$12.04	$6.88	$17.20
	1 hour	242	$40.68	$26.20	$55.15
	4 hours	477	$98.29	$77.21	$119.37
	8 hours	240	$184.57	$131.62	$237.52
	24 hours	239	$399.42	$259.59	$539.25

Table 6-4:
Cost per Unserved kWh Estimates – SMB

Region	Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	242	$722.43	$413.09	$1,031.76
	1 hour	242	$40.68	$26.20	$55.15
	4 hours	477	$24.57	$19.30	$29.84
	8 hours	240	$23.07	$16.45	$29.69
	24 hours	239	$16.64	$10.82	$22.47

Table 6-5 shows the duration cost, duration cost per average kW, and duration cost per unserved kWh for SMB. The duration cost is $0 for a 1-minute outage for all three metrics. For outage event, the duration cost ranges from $600 for a 1-hour outage to $8,169 for a 24-hour outage. Duration cost per average kW ranges from $28.47 for a 1-hour outage to $382 for a 24-hour outage. Duration cost per unserved kWh ranges from $28.47 for a 1-hour outage to $16.13 for a 24-hour outage.

Table 6-5:
2018 Duration Cost Estimates – SMB

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
All	1 minute	242	$0.00	$0.00	$0.00
	1 hour	242	$600.46	$28.47	$28.47
	4 hours	477	$1,885.01	$88.18	$21.62
	8 hours	240	$3,840.62	$179.67	$21.62
	24 hours	239	$8,168.89	$382.14	$16.13

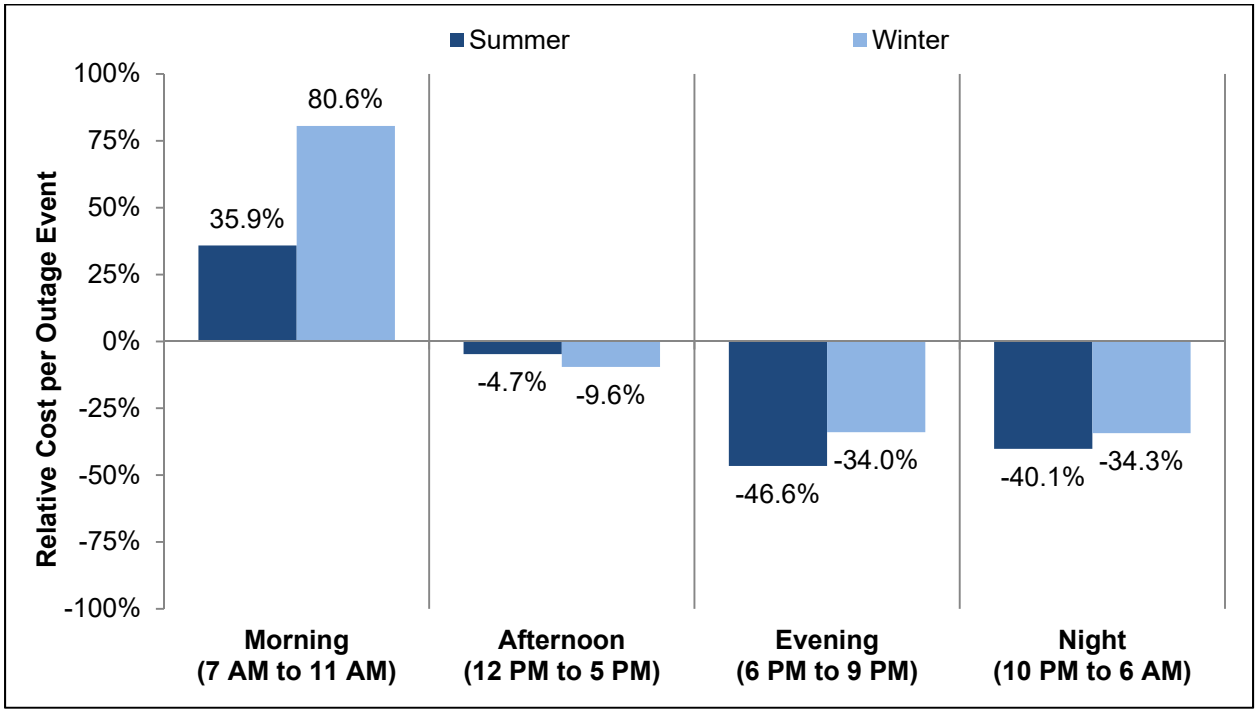
6.3 Impact of Outage Timing

For the residential analysis on the impact of outage timing, onset times were aggregated into 4 key time periods with distinct cost per outage event. These time periods were:

- Morning (7 AM to 11 AM);
- Afternoon (12 PM to 5 PM);
- Evening (6 PM to 9 PM); and
- Night (10 PM to 6 AM).

Figure 6-2 provides the relative cost per outage event estimates, which were derived from the SMB customer damage functions described in Appendix A. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each SMB outage cost estimate in Section 6.2 (referred to as the "base value"). As shown in the figure, outage costs for SMB customers are highly sensitive to onset time, varying from 46.6% lower than the base value on a summer evening to 80.6% higher on a winter morning. Outages with a morning onset time have the highest cost because these outages likely start and end during normal business hours, potentially disrupting an entire day of work. Considering that SMB outage costs vary substantially depending on the onset time, it is important that planning applications apply these relative values.

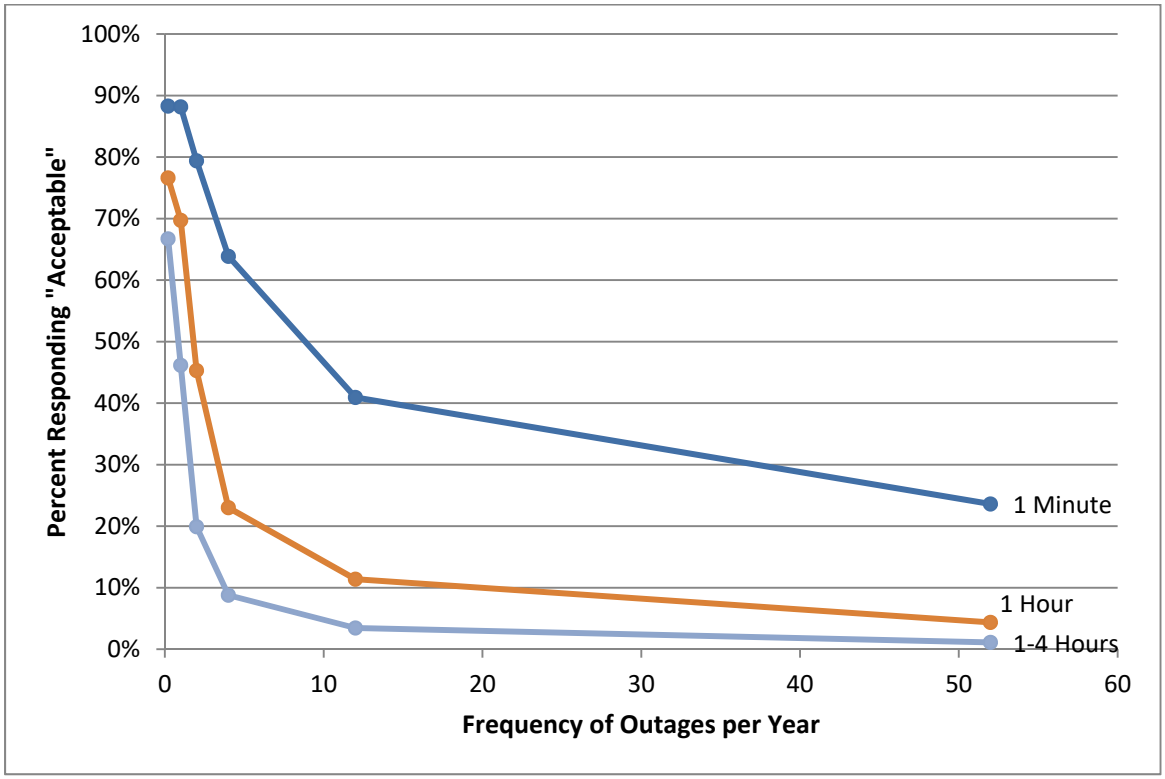
Figure 6-2:
Relative Cost per Outage Event Estimates by Season and Onset Time – SMB



6.4 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 6-3 and Table 6-6 show the percent of SMB customers rating each combination of outage frequency and duration as acceptable. As expected, an SMB customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. SMB customers are willing to accept a relatively high frequency of short-duration outages. A majority of SMB customers reports that 4 momentary outages per year is acceptable. One outage of 1 to 4 hours per year is acceptable to 46% of SMB customers, but four outages of this duration is acceptable to only 20 percent of customers.[6]

Figure 6-3:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – SMB



[6] The longer-duration interruption for SMB was coded in the online survey as "1 to 4 hours" instead of "4 to 8 hours."

Table 6-6:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – SMB

Region	Frequency of Outages per Year	Outage Duration		
		1 Minute	1 Hour	1-4 Hours
All	Once every 5 years	88.3%	76.6%	66.7%
	1	88.2%	69.7%	46.2%
	2	79.4%	45.3%	19.9%
	4	63.9%	23.0%	8.8%
	12	40.9%	11.4%	3.5%
	52	23.6%	4.4%	1.1%

7 Large Business Results

This section summarizes the results for large business customers.

7.1 Response to Survey

Table 7-1 summarizes the survey response for large C&I customers. Nexant conducted onsite interviews covering 100 entity/service address combinations, which was the sample design target for this customer class. In some cases, all of the data needed for the outage cost estimates was not available at the interview—either because the interviewee did not have it readily available or was not willing to disclose it. In cases where the interviewee did not have it, Nexant attempted to follow up with the interview subject after the interview to obtain the missing data and calculate the outage cost estimate. This was successful for a number of large C&I customers. However, Nexant was not able to obtain the necessary data for 16 customers. The number of complete data points for large C&I was thus 84.

Table 7-1 shows a breakdown of the sample design by the three sample strata. Response rates were similar between strata, ranging from 28 percent to 33 percent.

Table 7-1:
Customer Survey Response Summary – Large C&I

Usage Category (Average kW)	Population	Sample Design Target	Records Sampled	Complete Data Points	Response Rate
235 to 911	158	27	74	24	32%
912 to 1934	189	31	83	23	28%
1935 and above	113	42	113	37	33%
All	**63,693**	**100**	**270**	**84**	**31%**

7.2 Outage Cost Estimates

Figure 7-1 and Table 7-2 provide the large business cost per outage event estimates. For a 1-hour outage, large business customers experience a cost of $71,808. Large business cost per outage event increases to $379,381 at 8 hours and $992,647 for a 24-hour outage. The confidence intervals for these estimates are quite wide, as the large C&I customer class had a smaller sample size and much more variable outage cost estimates from customer to customer

Figure 7-1:
Outage Event Estimates – Large C&I

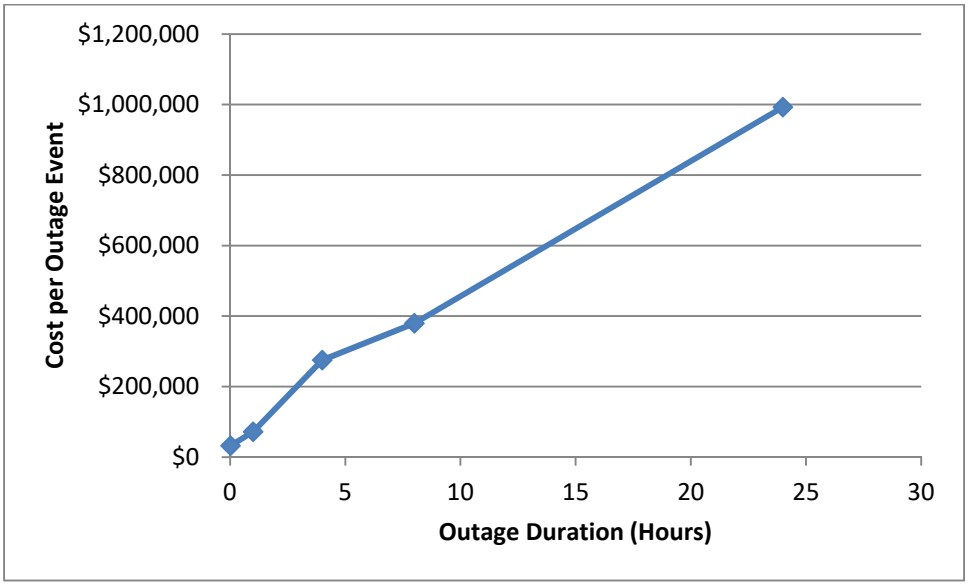


Table 7-2:
Cost per Outage Event Estimates – Large C&I

Region	Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	84	$32,438	$5,886	$58,990
	1 hour	84	$71,808	$30,636	$112,979
	4 hours	168	$275,182	$77,202	$473,162
	8 hours	84	$379,381	$120,328	$638,433
	24 hours	84	$992,647	$214,801	$1,770,493

Table 7-3 summarizes large business cost per average kW. The cost per average kW values range from $15.25 for a 1-minute outage to $467 for a 24-hour outage. Table 7-4 provides the cost per unserved kWh estimates. For a 1-minute outage, large C&I customers experience a cost of $915 per unserved kWh. For the remaining durations, cost estimates range from $19.45 to $33.77 per unserved kWh. Table 7-5 shows the duration cost metrics. These costs range from $39,369 to $960,209 for duration cost, from $18.51 to $452 for duration cost per average kW, and from $18.51 to $28.54 for duration cost per unserved kWh.

Table 7-3:
Cost per Average kW Estimates – Large C&I

Region	Outage Duration	N	Cost per Average kW	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	84	$15.25	$2.69	$27.82
	1 hour	84	$33.77	$13.62	$53.91
	4 hours	168	$129.41	$34.25	$224.57
	8 hours	84	$178.41	$51.42	$305.40
	24 hours	84	$466.81	$87.68	$845.95

Table 7-4:
Cost per Unserved kWh Estimates– Large C&I

Region	Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	84	$915.28	$161.23	$1,669.34
	1 hour	84	$33.77	$13.62	$53.91
	4 hours	168	$32.35	$8.56	$56.14
	8 hours	84	$22.30	$6.43	$38.18
	24 hours	84	$19.45	$3.65	$35.25

Table 7-5:
2018 Duration Cost Estimates by Region – Large C&I

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
All	1 minute	84	$0.00	$0.00	$0.00
	1 hour	84	$39,369.44	$18.51	$18.51
	4 hours	168	$242,743.76	$114.16	$28.54
	8 hours	84	$346,942.45	$163.16	$20.39
	24 hours	84	$960,208.73	$451.56	$18.81

7.3 Impact of Outage Timing

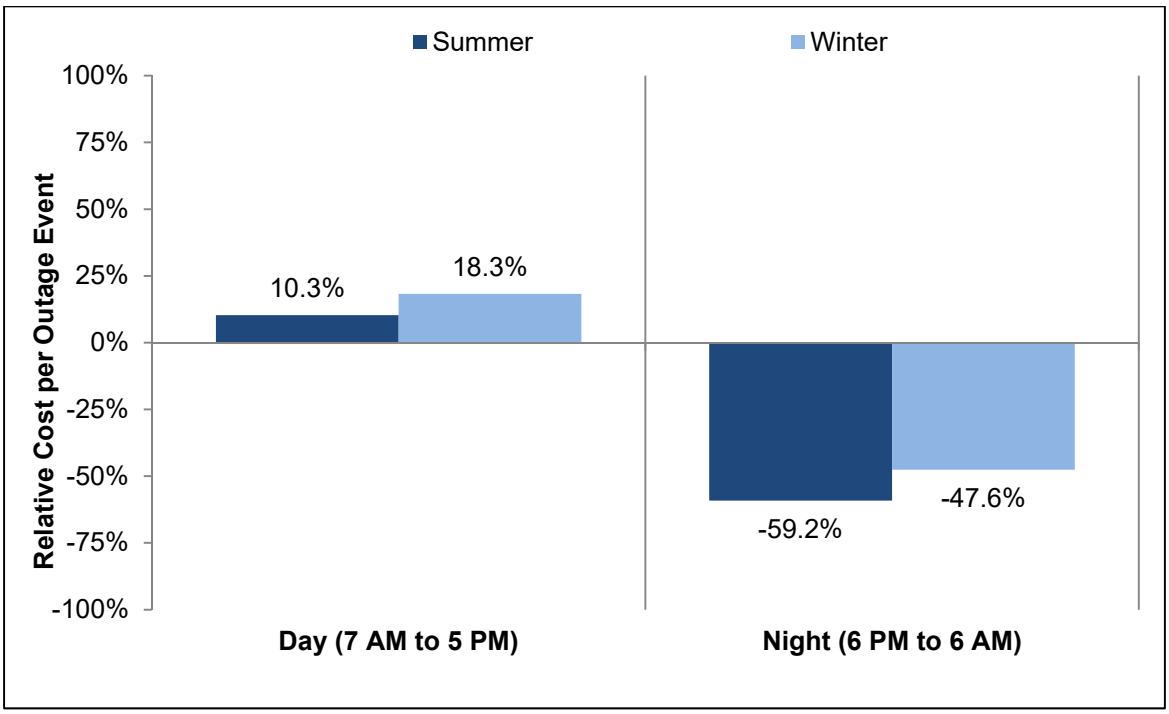
For the large business analysis on the impact of outage timing, onset times were aggregated into 2 key time periods with distinct cost per outage event. These time periods were:

- Daylight Hours (7 AM to 5 PM); and
- Evening and Night (6 PM to 6 AM).

Figure 7-2 provides the relative cost per outage event estimates, which were derived from the large C&I customer damage functions described in Appendix A. Unlike the other 3 customer

segments, the onset times were not further divided by day of week because this variable did not have a significant effect for large business customers. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each large business outage cost estimate in Section 7.2 (referred to as the "base value"). As shown in the figure, outage costs for large C&I customers are somewhat sensitive to onset time, varying moderately from 18.3% higher than the base value during daylight hours to 59.2% lower during the evening and night.

Figure 7-2:
Relative Cost per Outage Event Estimates by Season and Onset Time – Large C&I



7.4 Acceptable Level of Service Reliability

In the survey, respondents were asked to rate hypothetical levels of service reliability as acceptable or unacceptable. Each level of service reliability referred to a specific outage duration and frequency. Figure 7-3 and Table 7-6 show the percent of large business customers rating each combination of outage frequency and duration as acceptable. As expected, a large business customer's level of service reliability becomes less acceptable as outage duration increases and the number of outages per year increases. A single sustained outage more than 1 minute per year is considered unacceptable for a majority of large C&I customers. Four momentary outages is considered unacceptable by the majority.

Figure 7-3:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – Large C&I

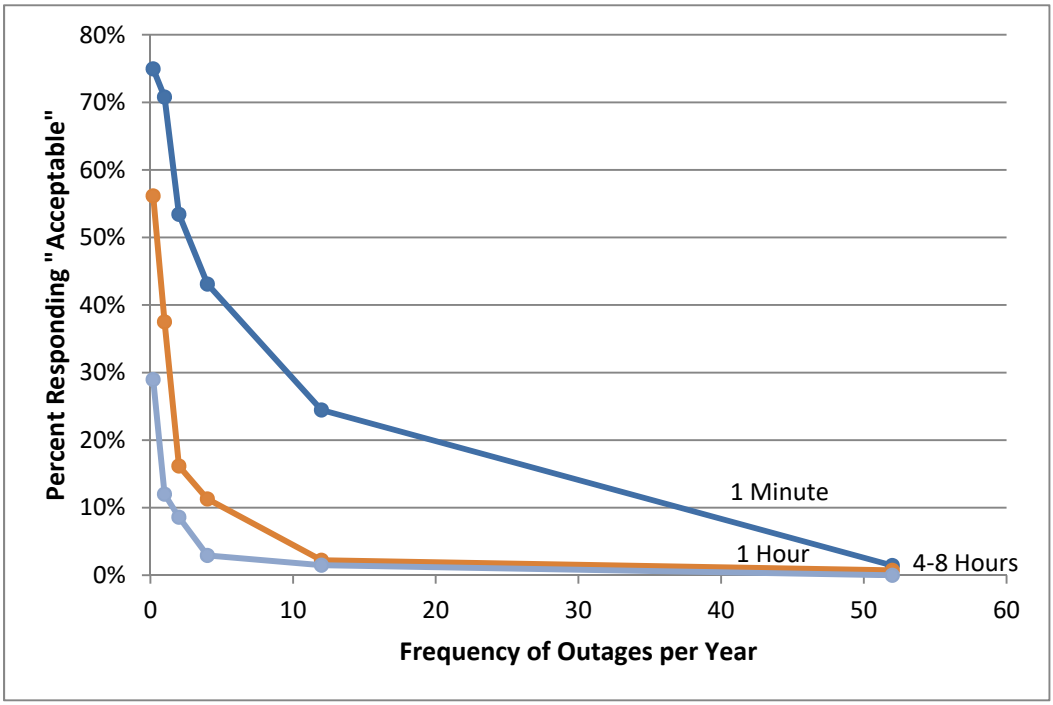


Table 7-6:
Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable – Large C&I

Region	Frequency of Outages per Year	Outage Duration		
		1 Minute	1 Hour	4-8 Hours
All	Once every 5 years	87.1%	81.5%	68.6%
	1	87.2%	75.3%	44.7%
	2	75.4%	47.4%	15.3%
	4	58.5%	25.6%	5.1%
	12	37.7%	10.7%	2.1%
	52	22.3%	4.5%	1.2%

8 Blended Results

This section summarizes the blended results for all customers. Sampling was conducted on a per-customer basis and the outage costs were collected and aggregated on a per-customer basis. The blended estimate calculations utilize the weighted average of per-customer costs as well as the weighted average of per-customer usage in order to scale the costs by kWh. Given that costs and usage are significantly higher for non-residential customers (particularly large C&I), their responses increase both average cost and usage. Thus the blended 'cost per average kW' and 'cost per unserved kWh' estimates account for non-residential customers having higher consumption.

Table 8-1 shows the blended cost per outage event estimate for each outage duration. The third column from the left—labeled 'N'—shows the number of completed surveys from residential, SMB, and large C&I combined. The blended event costs range from $51.24 for a 1-minute outage to $1,413 for a 24-hour outage. Tables 8-2 ad 8-3 show the cost per average kW and cost per unserved kWh values, respectively. Blended cost per average kW values range from $12.80 for a 1-minute outage to $355 for a 24-hour outage. Blended cost per unserved kWh values range from $768 for a 1-minute outage to $14.80 for a 24-hour outage.

Table 8-1:
Cost per Outage Event Estimates – Blended Results

Region	Outage Duration	N	Cost per Outage Event	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	1298	$51.24	$31.95	$70.53
	1 hour	1297	$131.81	$95.71	$167.91
	4 hours	2572	$381.77	$247.75	$515.79
	8 hours	1295	$626.90	$418.09	$835.72
	24 hours	1296	$1,412.73	$844.74	$1,980.72

Table 8-2:
Cost per Average kW Estimates – Blended Results

Region	Outage Duration	N	Cost per Average kW	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	1298	$12.80	$7.90	$17.70
	1 hour	1297	$33.14	$23.79	$42.49
	4 hours	2572	$94.50	$61.22	$127.78
	8 hours	1295	$153.83	$105.24	$202.43
	24 hours	1296	$355.23	$212.48	$497.98

Table 8-3:
Cost per Unserved kWh Estimates – Blended Results

Region	Outage Duration	N	Cost per Unserved kWh	90% Confidence Interval	
				Lower Bound	Upper Bound
All	1 minute	1298	$768.06	$473.82	$1,062.30
	1 hour	1297	$33.14	$23.79	$42.49
	4 hours	2572	$23.63	$15.31	$31.95
	8 hours	1295	$19.23	$13.15	$25.30
	24 hours	1296	$14.80	$8.85	$20.75

Table 8-4 shows the blended duration cost, duration cost per average kW, and duration cost per unserved kWh. The blended duration cost is $0 for a 1-minute outage for all three metrics. For outage event, the blended duration cost ranges from $80.57 for a 1-hour outage to $1,361 for a 24-hour outage. Duration cost per average kW ranges from $20.26 for a 24-hour outage to $340 for a 24-hour outage. Duration cost per unserved kWh ranges from $14.26 for a 24-hour outage to $20.45 for a 4-hour outage.

Table 8-4:
2018 Duration Cost Estimates – Blended

Region	Interruption	N	Duration Cost	Duration Cost per Average kW	Duration Cost per Unserved kWh
All	1 minute	1298	$0.00	$0.00	$0.00
	1 hour	1297	$80.57	$20.26	$20.26
	4 hours	2572	$330.53	$82.57	$20.45
	8 hours	1295	$575.66	$143.81	$17.66
	24 hours	1296	$1,361.49	$340.13	$14.26

Toronto Hydro was seeking a single, per-hour cost based on historical outages and Table 1-6 provides these “blended duration costs.” The table shows these figures for different types of outages in Toronto Hydro service territory from 2010 to 2017. The “Outages Included” column shows which types of outages were included in the blended cost. All outages were categorized by Toronto Hydro as either “Momentary,” “Planned,” or “Sustained.” Given that the results of this study are only valid for outages lasting 24 hours or less, all outages greater than 24 hours were excluded from the calculations. Within each outage type, outages could also be classified as “Loss of Supply Events” or could have occurred on “Major Event Days.” These subcategories of outages were either left in the dataset or excluded, depending on the calculation.

The “Event Cost” column shows the average event cost of the outages in the dataset, based on the blended estimates in Table 1-5 and weighted by the number of customers impacted by the outage. The “Duration Event Cost” column shows the weighted average duration event cost, which is the event cost minus the blended 1-minute event cost estimate of $51.24. The

"Duration" column shows the weighted average outage duration. The two "Hourly Cost" columns show each event cost per hour, or the "Event Cost" columns divided by the "Duration" column. Depending on the types of outages included, the weighted average duration ranges from 2.9 to 3.6 hours. The hourly event costs are within a relatively tight range, varying from $84.31 to $89.78, while the hourly duration event costs range from $69.94 to $71.87.

Table 8-5:
Blended Duration Cost Based on Historical Outage Durations

Outages Included*	Subset of Outages Excluded	Event Cost		Duration (Hours)	Hourly Cost	
		Event Cost	Duration Event Cost		Hourly Event Cost	Hourly Duration Event Cost
Sustained	-	$288.96	$237.72	3.39	$85.32	$70.19
Sustained	Loss of Supply Events	$300.72	$249.48	3.57	$84.31	$69.94
Sustained	Major Event Days	$256.56	$205.32	2.86	$89.60	$71.70
Sustained	Loss of Supply Events, Major Event Days	$272.70	$221.46	3.09	$88.23	$71.65
Sustained, Planned	-	$288.44	$237.20	3.37	$85.54	$70.34
Sustained, Planned	Loss of Supply Events	$299.77	$248.53	3.54	$84.57	$70.11
Sustained, Planned	Major Event Days	$256.81	$205.57	2.86	$89.78	$71.87
Sustained, Planned	Loss of Supply Events, Major Event Days	$272.50	$221.26	3.08	$88.45	$71.82

* Only includes outages up to 24 hours in duration

9 Comparison to Other Studies

Nexant (formerly as Freeman, Sullivan & Co.) has conducted dozens of VOS studies for utilities and also works with Lawrence Berkeley National Laboratory to maintain the Interruption Cost Estimation (ICE) Calculator and its underlying database of survey-based VOS studies. The results from most studies for individual utilities are not public, but relatively recent studies from PG&E (conducted in 2012) and SCE (conducted in 2019) have public results that are useful for comparison. For other non-public studies contained in the ICE Calculator database, the utility is not identifiable, but the data can be aggregated and compared to current results. The ICE Calculator meta-database contains the results from 34 studies that use a similar, survey-based methodology.

Tables 9-1, 9-2, and 9-3 show the outage cost estimates from the PG&E and SCE studies for the residential, small/medium business and large C&I customer classes respectively. The tables show the results after adjusting for inflation (3% annually) and the exchange rate between the U.S. dollar and Canadian dollar (1.29 $CAD per 1 $US). The 2012 study separated results between the Bay Area and Non-Bay Area for PG&E and the tables show both sets of results along with the estimates for the service territory as a whole. Bay Area outage cost estimates were considerably higher than outage costs for the Non-Bay Area, SCE, and THESL. Residential outage costs for THESL were comparable to those of the Non-Bay Area and SCE. Small/medium business outage costs for THESL are considerably lower than both PG&E and SCE for the cost per outage event, cost per average kW, and cost per unserved kWh. Large C&I outage cost per event estimates are comparable to the Non-Bay Area and to SCE. However, the cost per average kW and cost per unserved kWh estimates are lower, indicating higher consumption for THESL customers.

The shape of THESL's outage cost distributions are similar to those of PG&E, SCE, and other studies, but they are generally lower in magnitude. Looking specifically at the survey data from THESL and SCE, significant differences exist in the underlying populations for the two utilities, making comparisons of the interruption costs tenuous. For example, Toronto's non-residential customer population comprises different industry types and the customers had higher annual consumption than SCE. This suggests that interruption costs from areas other than Toronto should not be used to estimate THESL’s customer interruption costs.

Table 9-1:
Comparison to PG&E and SCE Studies – Residential

Metric	Outage Duration	PG&E (2012)			SCE (2019)	Toronto Hydro
		Bay Area	Non-Bay Area	All		
		$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD
Cost per Outage Event	1 minute	-	-	-	-	$8.45
	5 minutes	$12.60	$10.72	$11.41	$5.75	-
	1 hour	$20.36	$16.50	$18.31	$8.50	$10.87
	4 hours	$30.18	$22.94	$25.91	$16.49	$17.56
	8 hours	$41.02	$30.48	$35.26	$25.02	$23.35
	24 hours	$58.27	$40.09	$48.78	$41.22	$34.53
Cost per Average kW	1 minute	-	-	-	-	$10.27
	5 minutes	$18.27	$12.92	$15.02	$7.89	-
	1 hour	$28.68	$18.75	$22.89	$11.86	$13.21
	4 hours	$42.50	$25.48	$32.39	$22.18	$21.36
	8 hours	$57.78	$33.87	$44.07	$34.04	$28.41
	24 hours	$83.24	$45.56	$61.75	$56.73	$42.04
Cost per Unserved kWh	1 minute	-	-	-	-	$616.11
	5 minutes	$209.99	$153.15	$190.23	$94.70	-
	1 hour	$29.10	$18.13	$22.89	$11.86	$13.21
	4 hours	$10.37	$6.16	$7.82	$5.55	$5.34
	8 hours	$7.02	$4.08	$5.30	$4.26	$3.55
	24 hours	$3.45	$1.89	$2.57	$2.37	$1.75

Table 9-2:
Comparison to PG&E and SCE Studies – Small/Medium Business

Metric	Outage Duration	PG&E (2012)			SCE (2019)	Toronto Hydro
		Bay Area	Non-Bay Area	All		
		$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD
Cost per Outage Event	1 minute	-	-	-	-	$257
	5 minutes	$901	$245	$585	$670	-
	1 hour	$4,127	$1,500	$2,848	$3,881	$858
	4 hours	$10,178	$4,253	$7,354	$4,332	$2,142
	8 hours	$25,359	$6,831	$16,279	$5,825	$4,098
	24 hours	$52,034	$13,115	$32,870	$10,158	$8,426
Cost per Average kW	1 minute	-	-	-	-	$12
	5 minutes	$96	$30	$67	$86	-
	1 hour	$419	$188	$316	$541	$41
	4 hours	$1,087	$522	$832	$593	$98
	8 hours	$2,404	$859	$1,750	$857	$185
	24 hours	$5,364	$1,654	$3,702	$1,359	$399
Cost per Unserved kWh	1 minute	-	-	-	-	$722
	5 minutes	$1,099	$350	$760	$1,036	-
	1 hour	$403	$177	$301	$541	$41
	4 hours	$259	$122	$196	$148	$25
	8 hours	$296	$102	$213	$107	$23
	24 hours	$223	$69	$154	$57	$17

Table 9-3:
Comparison to PG&E and SCE Studies – Large Commercial & Industrial

Metric	Outage Duration	PG&E (2012)			SCE (2019)	Toronto Hydro
		Bay Area	Non-Bay Area	All		
		$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD	$2018 CAD
Cost per Outage Event	1 minute	-	-	-	-	$32,438
	5 minutes	$1,173,397	$37,442	$700,348	$22,164	-
	1 hour	$1,326,775	$84,672	$692,616	$100,281	$71,808
	4 hours	$1,653,916	$175,206	$919,075	$189,506	$275,182
	8 hours	$1,664,031	$227,018	$950,684	$301,139	$379,381
	24 hours	$3,469,269	$947,921	$2,268,128	$558,639	$992,647
Cost per Average kW	1 minute	-	-	-	-	$15
	5 minutes	$843	$26	$492	$27	-
	1 hour	$962	$63	$504	$98	$34
	4 hours	$1,193	$132	$673	$235	$129
	8 hours	$1,188	$170	$693	$370	$178
	24 hours	$2,562	$683	$1,613	$780	$467
Cost per Unserved kWh	1 minute	-	-	-	-	$915
	5 minutes	$9,991	$310	$5,807	$323	-
	1 hour	$939	$61	$491	$98	$34
	4 hours	$293	$33	$166	$59	$32
	8 hours	$146	$21	$86	$46	$22
	24 hours	$106	$28	$67	$32	$19

Table 9-4 shows the blended results from the ICE Calculator meta-database. The ICE Calculator inputs were customized to correspond to the same number of residential, small C&I (<50,000 annual kWh) and medium/large C&I (> 50,000 annual kWh) as in the current study. While customizing the database to a Canadian province was not an option, it was possible to customize to New York State, which borders Ontario. The results from the ICE Calculator in 2016 U.S. dollars are in column 3 and column 4 contains the ICE Calculator results adjusted for inflation and exchange rate. The results from the current study are in the right-most column. The ICE Calculator results are significantly higher than the results from the current study. The difference is driven by the results from the non-residential customer classes.

Table 9-4:
Comparison to ICE Calculator Meta-Data – Blended

Metric	Outage Duration	ICE Calculator	ICE Calculator	Toronto Hydro
		$2016 US	$2018 CAD	$2018 CAD
Cost per Outage Event	1 hour	$385.80	$527.99	$131.81
	4 hours	$906.26	$1,240.27	$381.77
	8 hours	$1,927.47	$2,637.86	$626.90
	24 hours	$1,727.42	$2,364.08	$1,412.73
Cost per Average kW	1 hour	$100.76	$137.89	$33.14
	4 hours	$236.68	$323.91	$94.50
	8 hours	$503.38	$688.91	$153.83
	24 hours	$451.14	$617.41	$355.23
Cost per Unserved kWh	1 hour	$100.76	$137.89	$33.14
	4 hours	$59.17	$80.98	$23.63
	8 hours	$62.92	$86.11	$19.23
	24 hours	$18.80	$25.73	$14.80

Appendix A Customer Damage Functions

This appendix details the customer damage functions, which are econometric models that predict how outage costs vary across customers, outage duration and other outage characteristics. For example, these models were used to develop the results in Sections 5 through 7 related to how outage costs vary by time of day and season for each customer class.

To model outage costs, Nexant used a two-part model. The two-part model first estimates the latent probability that customers experience an outage cost with a Probit model. Then, it estimates the outage costs for customers who reported values greater than zero with a Generalized Linear Model (GLM). The models were estimated with corrections to account for the structure of the survey data (i.e., clustering by customer, population weights and stratification). This approach was first used to model health care expenditures, which, like outage costs, follow a highly skewed distribution. Nexant applied this model to a meta-analysis of outage costs in studies prepared for Lawrence Berkeley National Laboratory in 2009[1] and 2015.[2]

Nexant employed out-of-sample testing to select and validate the best econometric model for each customer segment. Because the model coefficients were derived from a system-wide survey, Nexant used out-of-sample testing to ensure that the estimates were robust to a variety of conditions. For each customer segment, Nexant experimented with different model specifications and estimated each model while withholding 25% of the data from the regression. To select the final model, Nexant compared the out-of-sample predicted outage costs from each model with the reported outage costs.

A.1 Residential Customers

To predict outage costs for residential customers, Nexant estimated an econometric model for residential customers from the survey data. The analysis included variables that capture customer size, duration of the outage, season, and time of day that the outage occurs.

Table A-1 shows the variables included in the residential customer regression model and the estimated coefficients for each part of the model. The natural log of average kW usage captures the influence of customer size on reported outage costs while duration and duration squared capture the impact of outage duration on reported outage costs. The square of the duration variable is meant to capture the non-linear relationship between outage costs and duration. The coefficient on the usage variable is significant at the 1% level for the GLM model and the duration variables are significant at the 1% level for both models. Several of the outage timing variables are statistically significant for the Probit model. Most of the timing variables are

[1] Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

[2] Sullivan, M. J., Schellenberg, J. & Blundell, M. (2015). Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States, Berkeley, CA: Lawrence Berkeley National Laboratory.

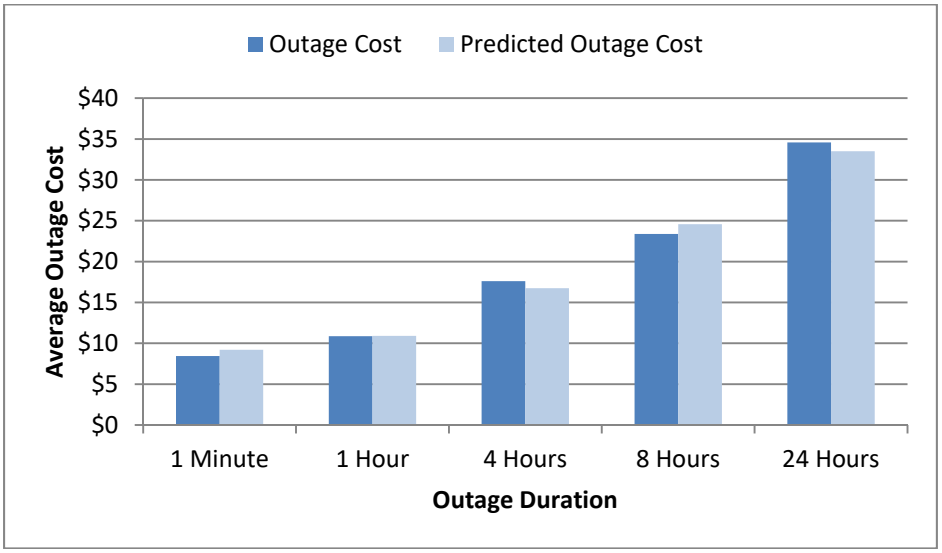
insignificant individually, however, they are included in the regression models because they are jointly significant and still increase predictive power.

Table A-1:
Coefficients of Customer Damage Function – Residential
(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	0.062	0.187***
Duration	0.118***	0.085***
Duration Squared	-0.004***	-0.002***
Outage Timing		
Summer Night	-0.376**	-0.128
Winter Night	-0.369**	-0.065
Summer Morning	-0.202	-0.184
Winter Morning	-0.181	0.171
Summer Afternoon	-0.316**	0.136
Winter Afternoon	-0.279*	-0.156
Summer Evening	-0.273*	-0.028
Winter Evening (Base)	(omitted)	(omitted)
Constant	0.227*	3.052***

Figure A-1 provides a comparison of the model predicted and reported outage cost values by outage duration. The model predicts well across all outage durations. The percent error for a 24-hour outage is -3%; an 8-hour outage is 5%; a 4-hour outage, -5%; an hour, 0%; and 1 minute, 9%.

Figure A-1:
Comparison of Predicted and Reported Outage Cost by Outage Duration – Residential



A.2 Small/Medium Business Customers

For SMB customers, variables that capture the size, outage timing, outage duration, and industry group were included for each premise. Multiple two-part models were tested. The criteria for selection of the final model included performance on out-of-sample tests, performance on in-sample tests and significance of coefficients on important variables.

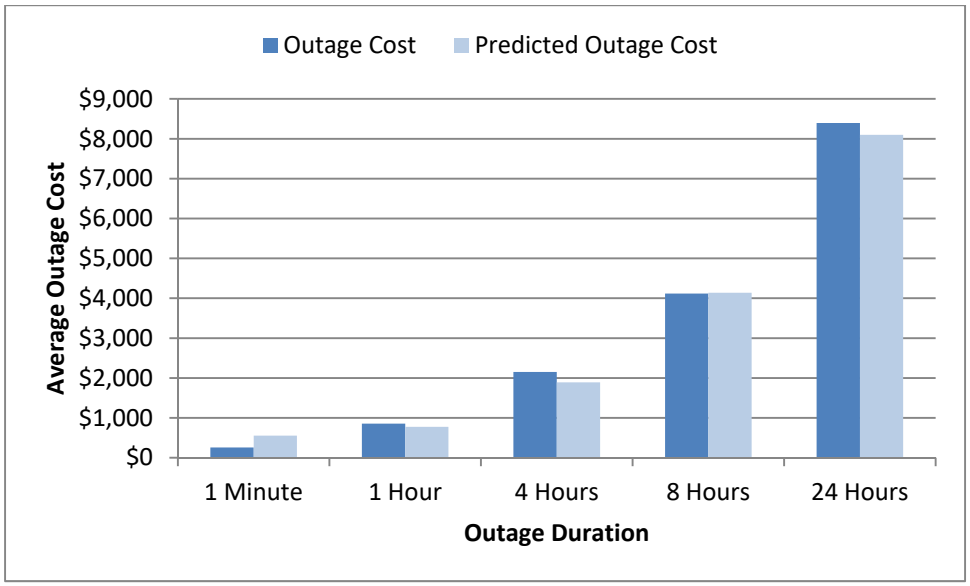
Table A-2 shows the variables included in the SMB customer regression model and the estimated coefficients for each part of the model. The coefficient on the usage variable is significant at the 1% level for the GLM model and the duration variables are significant at the 1% level for both models. Several of the outage timing variables are statistically significant for the Probit model, indicating that outage timing determines both whether or not an SMB customer experiences outage costs. Specifically, customers with morning and afternoon outages (as opposed to evening and night outages) were more likely to report a cost above zero. The industry variables are insignificant individually, however, they are included in the regression models because they are jointly significant and still increase predictive power.

Table A-2:
Coefficients of Customer Damage Function – SMB
(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	0.041	0.367***
Duration	0.223***	0.217***
Duration Squared	-0.006***	-0.006***
Outage Timing		
Summer Night	-0.067	-0.021
Winter Night	-0.163	0.288
Summer Morning	1.172***	0.522*
Winter Morning	0.967***	0.714*
Summer Afternoon	0.651**	0.244
Winter Afternoon	0.866***	0.177
Summer Evening	-0.025	-0.028
Winter Evening (Base)	(omitted)	(omitted)
Industry		
Agriculture, Agricultural Processing & Food Processing	(omitted)	(omitted)
Assembly/Light Industry/High Tech	0.048	-0.425
Grocery Store/Restaurant	0.384	-0.226
Lodging (hotel, health care facility, dormitory, etc.)	-0.12	0.038
Office	-0.495	-0.35
Retail	0.041	0.317
Other/Unknown	-0.335	0.022
Constant	-0.672**	6.065***

Figure A-2 provides a comparison of the model predicted and reported outage cost values by outage duration. The model predicts relatively well across all outage types. The percent error for a 24-hour outage is -4%; an 8-hour outage is 0%; a 4-hour outage, -12%; an hour, -9%; and 1 minute, 116%. Although the percentage difference for a 1-minute outage is quite high, the magnitude of the difference is not substantial considering that 1-minute outage costs are relatively low.

Figure A-2:
Comparison of Predicted and Reported Outage Cost by Outage Duration – SMB



A.3 Large Commercial & Industrial Customers

To predict outage costs for large business customers, Nexant estimated an econometric model from the survey data. Nexant included variables that capture the size, season, basic outage timing (night versus day), whether or not the premise is a multitenant facility, and variables to capture the duration of the outage. The Probit model also included basic industry group (commercial, industrial, public/institutional, other/unknown). As there were only 84 large business customers in the survey data, this model could not include as many variables as the SMB model.

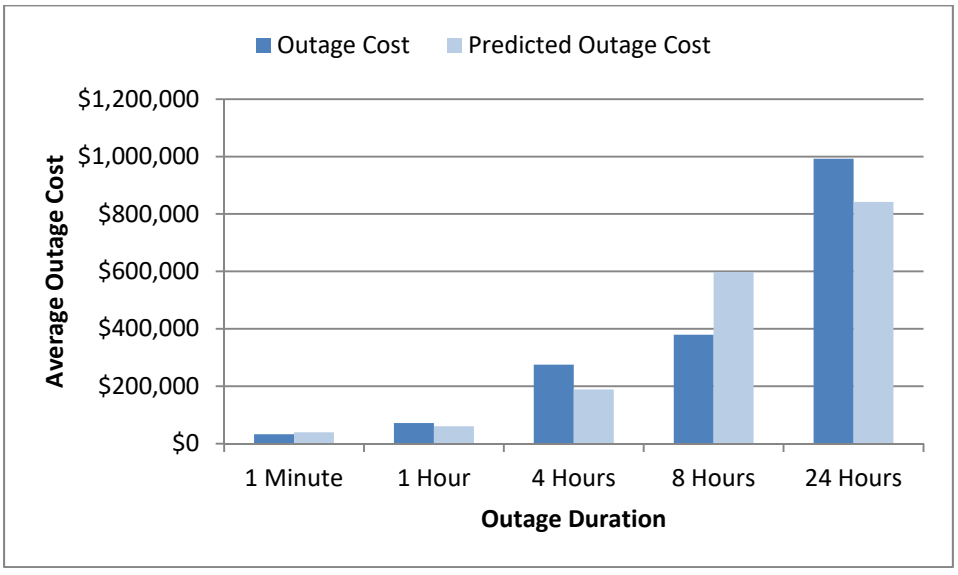
Table A-3 shows the variables included in the large business customer regression model and the estimated coefficients for each part of the model. The natural log of average kW is a significant predictor both of whether or not customers experience outage costs and of the magnitude of outage costs for customers who do report them. Both the duration and duration squared variables are significant at the 1% level in the GLM model. The 'Summer Night' and 'Winter Night' variables were significant at the 1% level for the GLM model, indicating outages that occur during the night are less impactful to large C&I customers. The multitenant variable, indicating whether the premise has multiple tenants, was not significant in the GLM model. This indicates that whether or not a premise has multiple tenants is an important predictor of the magnitude of outage costs for a given premise. The variable was not included in the Probit model due to data limitations.

Table A-3:
Coefficients of Customer Damage Function – Large Business
(Legend: * 10% Significance Level, ** 5% Significance Level, * 1% Significance Level)**

Variable	Probit Model	GLM Model
Natural Log of Average kW	-0.635***	0.747***
Duration	0.025	0.432***
Duration Squared	-0.001	-0.013***
Master Metered	(omitted)	-0.822
Outage Timing		
Summer Night	0.282	-1.029***
Winter Night	0.711	-1.228***
Summer Day	-0.202	0.056
Winter Day (Base)	(omitted)	(omitted)
Industry		
Commercial (Base)		-
Industrial	(omitted)	-
Other/Unknown	0.235	-
Public/Institutional	1.207**	-
Constant	4.395**	5.860***

Figure A-3 provides a comparison of the model predicted and reported outage cost values by outage duration. The percent error for a 24-hour outage is -15%; an 8-hour outage is 58%; a 4-hour outage, -31%; an hour, -16%; and 1 minute, 21%.

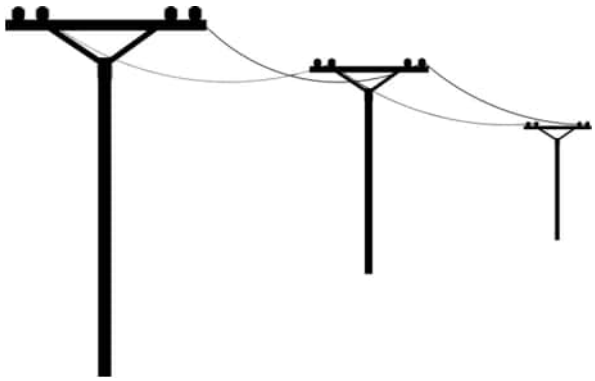
Figure A-3: Comparison of Predicted and Reported Outage Cost by Outage Duration – Large Business



Appendix B Residential Survey Instrument

Toronto Hydro 2017
Value of Service Study

Residential Customers



Thank you in advance for participating in this valuable study. Completing the survey will only take a few minutes of your time.

If you share a building with other owners or tenants, please answer the questions **only about your residence**.

All of your answers will be kept confidential. Your name and address will be kept anonymous and will not be associated with the information you provide.

Please return your completed survey in the enclosed return envelope to receive your $10 cheque as a token of our appreciation. If you have any questions, please contact Nexant Inc., the company we've retained to conduct this study on our behalf, at 1-877-932-0609 (Monday - Friday, 11 a.m. – 8 p.m.).

Sincerely,

Elias Lyberogiannis

Elias Lyberogiannis
General Manager, Engineering

This survey is also available online at: www.torontohydrosurveyres.ca
Your survey ID is «NEXID»

When completing this survey, please note that a "power outage" refers to a complete loss of electricity to your residence. Power outages can be caused by many factors such as bad weather, traffic accidents and equipment failures.

1. In the **past 12 months**, about how many outages of the durations listed below have you had at your home? Write in the number of outages on the blanks. (If none, use "0".)

_____ A short duration (one minute or less)
_____ Longer than one minute and up to 1/2 hour
_____ Longer than 1/2 hour and up to 1 hour
_____ Longer than 1 hour and up to 4 hours
_____ Longer than 4 hours and up to 24 hours
_____ Over 24 hours

2. Do you feel that the number of power outages your residence experiences is…

☐ Very low
☐ Low
☐ Moderate
☐ High
☐ Very high

3. How satisfied are you with the reliability of the electrical service you receive from Toronto Hydro?

☐ Very dissatisfied
☐ Somewhat dissatisfied
☐ Neither satisfied nor dissatisfied
☐ Somewhat satisfied
☐ Very satisfied
☐ Don't know

4. Do you or any of your household members work at home most of the time?

☐ No
☐ Yes -- What kind of business is it? _____

4a. **If you answered "Yes" in question 4**, how are you compensated for the work you perform at home?

☐ Self-employed
☐ Salary from employer
☐ Hourly wage from employer

5. Do you or does anyone in your household have any health conditions for whom a power outage could be a problem?

☐ No
☐ Yes – Please explain: _____

5a. **If you answered "Yes" in question 5**, have you registered with Toronto Hydro for the Life Support Notification Program at torontohydro.com/lifesupport?

☐ No
☐ Yes

Note – this notification program is only for planned power outages. We strongly encourage customers to always have back-up and to plan for power outages caused by unpredictable events.

Next, we'll ask you about 6 different types of electrical power outages. For each type of outage, we would first like to know how you and your household would adjust to the outage. Second, we would like you to estimate the extra expenses that your household would experience as a result of this type of outage as well as the estimated cost of inconvenience or hassle. Some of the expenses and inconveniences that people might experience include using candles if it's dark, going out to eat if you're unable to cook at home, food spoiling, etc.

Because every person may feel differently about the amount of extra expenses and the inconvenience or hassle, there are no right or wrong answers to these questions. We simply want your honest opinion.

IMPORTANT

As you answer the questions, please remember these two definitions:

Inconvenience or hassle costs
When a power outage occurs, a household may experience inconvenience or hassle costs while adjusting to the outage. These may include having to use candles if it's dark, having to dine out, not being able to watch television or not being able to use the internet.

Note: If you have solar photovoltaic (PV) panels installed, your household will still experience the power outage and your PV system will not feed electricity into the grid.

Extra expenses
These may include food spoilage, dining out, or lost wages for lost work time due to outages. In adding up your extra expenses, please do **not** include expenses that your household would have incurred whether or not the power outage happened. For example, if you decided to dine out during the outage **instead of** another night, the cost of the dinner should **not** be considered as an extra expense because it's simply shifted from another night. However, if you had to dine out during the outage **in addition to** another night, the cost of the dinner should be considered an extra expense.

Case A:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **4 hours** your household's electricity is fully restored. Note that **all** of the remaining cases occur at **<<ONSET>>**.

SUMMARY:
Conditions: <<SEASON1>> weekday **Start time:** <<ONSET>>
Duration: 4 hours **End time:** <<END1>>

A1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) _____

A2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ _____ extra expenses **and** inconvenience costs

A3. Of the above amount, how much of it would be **just for the extra expenses**?

$ _____ extra expenses **only**

A4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $_____

A4a. **If you selected $0 in question A4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

_____

_____

Case B:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **1 minute** your household's electricity is fully restored.

SUMMARY:
Conditions: <<SEASON1>> weekday **Start time:** <<ONSET>>
Duration: 1 minute **End time:** <<END2>>

B1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) _____

B2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ _____ extra expenses **and** inconvenience costs

B3. Of the above amount, how much of it would be **just for the extra expenses**?

$ _____ extra expenses **only**

B4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $_____

B4a. **If you selected $0 in question B4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

_____

_____

Case C:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **1 hour** your household's electricity is fully restored.

SUMMARY:
Conditions: <<SEASON1>> weekday **Start time:** <<ONSET>>
Duration: 1 hour **End time:** <<END3>>

C1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) _____

C2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ _____ extra expenses **and** inconvenience costs

C3. Of the above amount, how much of it would be **just for the extra expenses**?

$ _____ extra expenses **only**

C4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $_____

C4a. **If you selected $0 in question C4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

_____

_____

Case D:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **8 hours** your household's electricity is fully restored.

SUMMARY:
Conditions: <<SEASON1>> weekday **Start time:** <<ONSET>>
Duration: 8 hours **End time:** <<END4>>

D1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) _____

D2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ _____ extra expenses **and** inconvenience costs

D3. Of the above amount, how much of it would be **just for the extra expenses**?

$ _____ extra expenses **only**

D4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $_____

D4a. **If you selected $0 in question D4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

_____

_____

Case E:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **24 hours** your household's electricity is fully restored.

SUMMARY:
Conditions: <<SEASON1>> weekday **Start time:** <<ONSET>>
Duration: 24 hours **End time:** <<END5>>

E1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) _____

E2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ _____ extra expenses **and** inconvenience costs

E3. Of the above amount, how much of it would be **just for the extra expenses**?

$ _____ extra expenses **only**

E4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $_____

E4a. **If you selected $0 in question E4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

_____

_____

Case F:
On a **<<SEASON2>>** weekday, a complete power outage occurs at <<ONSET>> without any warning. You don't know how long it will last, but after **4 hours** your household's electricity is fully restored.

SUMMARY:
Conditions: **<<SEASON2>>** weekday **Start time:** <<ONSET>>
Duration: 4 hours **End time:** <<END6>>

F1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There's generally no one home at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a gas stove for indoor cooking
- ☐ Use a BBQ/propane grill or camping stove for outdoor cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) _____

F2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 3.

$ _____ extra expenses **and** inconvenience costs

F3. Of the above amount, how much of it would be **just for the extra expenses**?

$ _____ extra expenses **only**

F4. Suppose a company (other than Toronto Hydro) could provide you with a battery backup service to handle all of your household's electricity needs during this outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please check or specify one amount.)*

☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
$0	$1	$3	$5	$7	$10	$12	$15	$20	$25	$30	$40	$50	$75	$100

Other (please specify) $_____

F4a. **If you selected $0 in question F4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

_____

_____

ACCEPTABLE LEVEL OF RELIABILITY

Toronto Hydro works hard to prevent power outages, but eliminating all outages would be very costly, if not impossible. The following questions help us understand what you consider an acceptable level of service reliability from Toronto Hydro.

If each of the following occurred, would you think you were getting an <u>acceptable or unacceptable level of service reliability</u>?

6. An outage lasting **1 minute or less**... (Check one box on each line.)

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

7. An outage lasting **about an hour**... (Check one box on each line.)

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

8. An outage lasting between **4 hours and 8 hours**... (Check one box on each line.)

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

To better understand how electrical power outages affect your household, we would like to gather some information on your household characteristics. Please answer the following questions to the best of your ability. If you live in an apartment building or duplex, answer only for the part of the building you actually live in.

Some background information about the people living in your household will also help us understand how electrical power outages would affect your household. Again, all of your answers are *confidential*. Your name and address will be kept anonymous and will not be associated with the information you provide.

9. What type of residence is this? Please check one.

- ☐ Single family house (house on separate lot)
- ☐ Row or townhouse (walls adjacent to another house)
- ☐ A unit in a multi-family structure, 2-4 attached units (example: duplex, triplex, fourplex, or single family house converted to flats)
- ☐ A unit in a large multiple family structure, 5 or more attached units (example: apartment house, high rise condominium, garden apartments)
- ☐ Mobile home, house trailer
- ☐ Other (please describe) _____

10. Do you own or rent your residence?

☐ Own ☐ Rent/Lease ☐ Other (specify) _____

11. How many years have you lived at this address? (If less than 1 year, write "0".)

_____Years

12. Which of the following best describes your household? Please choose one.

- ☐ Individual living alone
- ☐ Single head of household with children at home
- ☐ Couple with children at home
- ☐ Couple without children at home
- ☐ Unrelated individuals sharing a residence
- ☐ Other (please describe) _____

13. In approximately what year was this residence built? _____

14. What is the size of your residence? _____square feet

15. How many people, **including yourself**, live in your home? _____

16. Please indicate the number of individuals in your household who are in each of these age groups.

_____ Under 6	_____ 25 to 34	_____ 55 to 59
_____ 6 to 18	_____ 35 to 44	_____ 60 to 64
_____ 19 to 24	_____ 45 to 54	_____ 65 or over

17. Which one of the following age groups best describes your age?

☐ Under 25 ☐ 25 to 44 ☐ 45 to 64 ☐ 65 or over

18. Which of the following categories best describes your total household income during 2017 before taxes and other deductions? Please include all income to the household including social security, interest, welfare payments, child support, etc.

☐ 0 - $9,999	☐ $20,000 - $29,999	☐ $50,000 - $74,999
☐ $10,000 - $14,999	☐ $30,000 - $39,999	☐ $75,000 - $99,999
☐ $15,000 - $19,999	☐ $40,000 - $49,999	☐ $100,000 or more

19. Do you own an electric vehicle?

☐ Yes ☐ No

20. Is electricity your primary source of heating in winter?

☐ Yes ☐ No ☐ I don't know

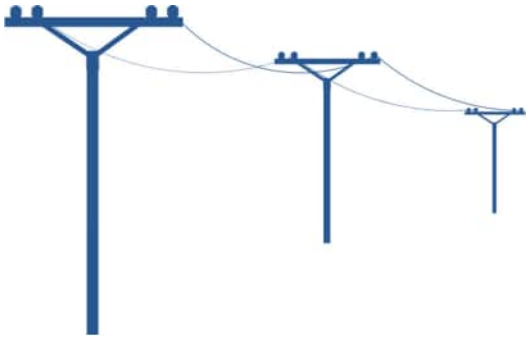
Please share any additional comments:

Please be sure to return your completed survey.
Thank you!

Appendix C Small/Medium Business Survey Instrument

Toronto Hydro
2017 Value of Service Study

Business Customers



Dear Customer,

Thank you for agreeing to participate in this important study. We're asking you to fill out this survey thinking only about the facilities that your company occupies **at this location:**

«SERVICE_ADDRESS», «SERVICE_CITY»

If your company shares a building with other businesses or you're the property manager at the above address(es), please answer the questions **only for the space your company occupies at this location and the activities your company undertakes**.

All your answers will be kept confidential. Your name and your company's name and address will be kept anonymous and will not be associated with the information you provide.

Please complete the survey to receive your $50 cheque. If you have any questions, please contact Nexant Inc., the company we've retained to conduct this study on our behalf, at 1-877-932-0609 (Monday - Friday, 9 a.m. – 8 p.m.).

Sincerely,

Elias Lyberogiannis

Elias Lyberogiannis
General Manager, Engineering

«NEXID»

When completing this survey, please note that a "power outage" refers to a complete loss of electricity to your facility. Power outages can be caused by many factors, such as bad weather, traffic accidents, and equipment failures.

1. In the **past 12 months**, about how many outages of the durations listed below have you had at your business location? Write in the number of outages on the blanks. (Use "0" if none.)

   A) Short duration or momentary (one minute or less) _____
   B) Longer than one minute and up to 1/2 hour _____
   C) Longer than 1/2 hour and up to 1 hour _____
   D) Longer than 1 hour and up to 4 hours _____
   E) Longer than 4 hours and up to 24 hours _____
   F) Over 24 hours _____

2. In general, how disruptive have these outages been for your company? (Please check one number.)

❑	❑	❑	❑	❑	❑	❑
1	2	3	4	5	6	7
Not at all disruptive						Very disruptive

3. Has your company ever sent employees home during a power outage?

   ❑$_1$ No
   ❑$_2$ Yes

4. In general, how long can an outage last at your facility before the costs become significant? Please estimate that time length in minutes and/or hours:

   _____ Hours and _____ Minutes

5. How much advance warning of a power outage does your company need to significantly reduce the problems caused by a power outage?

- ❑1 Advance notice would not reduce problem(s)
- ❑2 At least 1 hour
- ❑3 At least 4 hours
- ❑4 At least 8 hours
- ❑5 At least 24 hours

How satisfied are you with… (Please check one number.)	**Extremely Dissatisfied**						**Extremely Satisfied**
6. The reliability of the electrical service your company has experienced in the **last 12 months**?	❑ 1	❑ 2	❑ 3	❑ 4	❑ 5	❑ 6	❑ 7
7. The length of time it usually takes to restore service after an outage?	❑ 1	❑ 2	❑ 3	❑ 4	❑ 5	❑ 6	❑ 7
8. The responsiveness of Toronto Hydro when you have a power outage?	❑ 1	❑ 2	❑ 3	❑ 4	❑ 5	❑ 6	❑ 7

The next section describes **six** different types of power outages. We'd like to know the **costs to your business** of adjusting to each of these power outages.

For many businesses, the costs of a power outage depend upon the particular situation, and **may vary** from day to day depending upon business conditions. So for each outage type you'll be given the opportunity to report the **range of outage costs** that your business might face (from low to high), as well as to estimate **the cost that you would most likely have** under typical circumstances.

It's important to try to answer all of the questions. If a question is difficult for you to answer, **please give us an estimate** and feel free to **write down any comments about your answer**.

Case 1:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **4 hours** your company's electricity is fully restored. Note that **all** of the remaining cases occur at **«ONSET».**

SUMMARY:
Conditions: «SEASON1» weekday **Start time:** «ONSET»
Duration: 4 hours **End time:** «END1»

9. How disruptive would this power outage be to your business? (Please check one number.)

❑	❑	❑	❑	❑	❑	❑
1	2	3	4	5	6	7
Not disruptive at all						Very disruptive

10. Would your operations or services typically stop or slow down as a result of this power outage? (If yes, please state the number of hours.)

❑1 No----------> SKIP TO CASE 2 ON PAGE 6

❑2 Yes----------> _____ Number of hours that operations or services would stop or slow down (include time **during and after** the power outage)

11. What's the approximate dollar value of the operations or services that typically would be lost, at least temporarily, during the power outage and any slow period after the power outage? (If you're not sure please make your best guess.)

$_____ value of lost work or services

12. What percent of the operations or services typically would be made up after the power outage? (Please check one number.)

❑	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%

13. Would there be **labour costs** associated with this power outage such as salaries and wages for staff who would be unable to work or overtime pay to make up for operations or services? (If yes, please state the cost for lost labour as well as the cost for overtime labour to make up for lost work.)

❑1 No
❑2 Yes -->$_____labour costs of staff unable to work during the power outage

$_____labour costs in overtime/extra shifts to make up for lost work

14. Would there be any **damage costs** associated with this power outage such as damage to equipment, materials, etc.? (If yes, please state how much the damage cost for equipment would be and how much the damage cost to materials would be.)

    ❑1 No
    ❑2 Yes --->$_____damage to equipment

    $_____damage to materials

15. Would there be **additional tangible costs** associated with this power outage (such as extra restart costs, and costs to run and/or rent backup equipment)? (If yes, please state the additional costs.)

    ❑1 No
    ❑2 Yes --->$_____additional tangible costs

16. If you had to put a dollar value on **intangible costs** due to this power outage (such as inconvenience or dissatisfied customers), what would these costs be? (If yes, please state the intangible cost.)

    ❑1 No, there would be $0 intangible costs

    ❑2 Yes, there would be $_____ intangible costs

17. In addition to the costs discussed above, some organizations may avoid business expenses because of electrical outages. Some examples include a lower electrical bill, lower material outlays, and lower personnel costs. Would you experience any savings associated with this power outage? (If yes, please state the savings.)

    ❑1 No
    ❑2 Yes --->$_____savings

18. Considering **all** of the costs you might experience as a result of this **4-hour «SEASON1» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$_____	**$_____**	**$_____**
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 2:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **1 minute** your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	1 minute	**End time:**	«END2»

19. Considering **all** of the costs you might experience as a result of this **1-minute «SEASON1» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$_____	**$_____**	**$_____**
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 3:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **1 hour** your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	1 hour	**End time:**	«END3»

20. Considering **all** of the costs you might experience as a result of this **1-hour «SEASON1» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$_____	**$_____**	**$_____**
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 4:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **8 hours** your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	8 hours	**End time:**	«END4»

21. Considering **all** of the costs you might experience as a result of this **8-hour «SEASON1» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$_____	**$_____**	**$_____**
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 5:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **24 hours** your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	24 hours	**End time:**	«END5»

22. Considering **all** of the costs you might experience as a result of this **24-hour «SEASON1» weekday outage beginning at «END5»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$_____	**$_____**	**$_____**
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 6:
On a **«SEASON2»** weekday, a complete power outage occurs at «ONSET» without any warning. You don't know how long it will last, but after **4 hours** your company's electricity is fully restored.

SUMMARY:

Conditions:	**«SEASON2»** weekday	**Start time:**	«ONSET»
Duration:	4 hours	**End time:**	«END6»

23. Considering **all** of the costs you might experience as a result of this **4-hour «SEASON2» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$_____	**$_____**	**$_____**
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

WHAT LEVEL OF RELIABILITY IS ACCEPTABLE?

Toronto Hydro works hard to prevent power outages, but eliminating all outages could be very costly, if not impossible.

The following questions help us understand what you consider acceptable service from Toronto Hydro.

24. If each of the following occurred, would you think you were getting acceptable or unacceptable service from Toronto Hydro? Please check a box for each statement whether you find the outage period acceptable or unacceptable.

Outages lasting **1 minute or less...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **about an hour...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **between 4 hours and 8 hours…**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

ABOUT YOUR BUSINESS

Some background information about your company will help us understand how power outages affect your type of business.

Please remember all of your answers are *confidential*. Your name and address will be kept anonymous and will not be associated with the information you provide.

25. Which of the following categories best describes your business? (Please check one.)

- ❑1 Agriculture/Agricultural Processing
- ❑2 Assembly/Light Industry
- ❑3 Chemicals/Paper/Refining
- ❑4 Food Processing
- ❑5 Grocery Store/Restaurant
- ❑6 Lodging (hotel, health care facility, dormitory, prison, etc.)
- ❑7 High Tech
- ❑8 Lumber/Mining/Plastics
- ❑9 Office
- ❑10 Oil/Gas Extraction
- ❑11 Retail
- ❑12 Stone/Glass/Clay/Cement
- ❑13 Transportation
- ❑14 Utility
- ❑15 Other (please specify):_____

26. What's the approximate square footage of the facility referred to at the beginning of the survey? (Note: "facility" refers to the building(s) that your business occupies at that location.)

_____ Square feet

27. How many **full-time** (30+ hours per week) employees are employed by your company at that location?

_____ Full-time employees

28. List the number of people employed by your business at this company location in each of the following categories:

    _____ # of part-time year-round employees

    _____ # of full-time seasonal employees

    _____ # of part-time seasonal employees

29. What's the approximate value of your business's total annual revenue?

    $_____ per year

30. What's the approximate value of your business's total annual expenses (including labour, rent, materials, and other overhead expenses)?

    $_____ per year

31. Approximately what percentage of your business's annual operating budget is spent on electricity?

    _____ %

32. Does your company have any electrical equipment that's sensitive to fluctuations in voltage, frequency, short interruptions (less than two seconds), or other such irregularities in electricity supply? (If yes, please state the type of equipment.)

    ❑1 No
    ❑2 Yes ---->What equipment? _____

33. Does your business own or rent/lease any of the following devices to protect this equipment? (Please check all that apply.)

    ❑1 Back-up generator(s)
    ❑2 Uninterruptible power supply
    ❑3 Line conditioning device(s)
    ❑4 Surge suppressor(s)
    ❑5 Isolation transformer(s)

34. Does your business have any electrical equipment that would continue to operate during a power outage? (If yes, please state the type of equipment.)

    ❑1 No
    ❑2 Yes ----->What equipment? _____

Please share any additional comments:

THANK YOU FOR YOUR HELP!

Please provide your contact information so that we may mail you the incentive cheque.

The incentive cheque can be made out to any individual or charitable organization as designated by you. It should arrive in 2-4 weeks.

If you choose not to accept any incentive, please write “decline.”

Name on cheque: _____

Address (Line 1): _____

Address (Line 2): _____

City: _____

Province: _____

Postal Code: _____

Appendix D Large C&I Survey Instrument

Associated Delivery Numbers (Acct #)

NEXID #: «NEXID»

Date of Interview: _____

Interviewer Name: _____

Interview Start Time: _____

Interview End Time: _____

Name:	**Title:**
Name:	**Title:**
Name:	**Title:**

I'd like to talk to you about the costs of power outages for:
(Describe the part of the site served by the selected deliveries.)

Company Name:

Service Address:

If delivery serves only part of the site, describe location served:

_____

_____

_____

OUTAGE SCENARIOS

Case	Season	Day	Start Time	End Time	Duration
1	«SEASON1»	Weekday	«ONSET»	«END1»	4 hours
2	«SEASON1»	Weekday	«ONSET»	«END2»	1 minute
3	«SEASON1»	Weekday	«ONSET»	«END3»	1 hour
4	«SEASON1»	Weekday	«ONSET»	«END4»	8 hours
5	«SEASON1»	Weekday	«ONSET»	«END5»	24 hours
6	**«SEASON2»**	Weekday	«ONSET»	«END6»	4 hours

What are the operating hours of this facility?

Use military time. If open 24 hours, use 00:00 to 00:00.

	Weekday	
	Open	Close
Shift 1		
Shift 2		
Shift 3		

	Saturday	
	Open	Close
Shift 1		
Shift 2		
Shift 3		

	Sunday	
	Open	Close
Shift 1		
Shift 2		
Shift 3		

PRODUCT AND PROCESS DESCRIPTION

1) What products do you make and/or what services do you provide at this facility?

_____

_____

_____

_____

_____

2) What processes do you use to make these products and/or generate these services?

_____

_____

_____

_____

_____

OUTAGE EXPERIENCE

In the past 12 months, about how many outages of the durations listed below have you had at this business location? Write a number in each blank. *(Use 0 if none.)*

3.1) Short duration or momentary (one minute or less) _____

3.2) Longer than one minute and up to ½ hour _____

3.3) Longer than ½ hour and up to 1 hour _____

3.4) Longer than 1 hour and up to 4 hours _____

3.5) Longer than 4 hours and up to 24 hours _____

3.6) Over 24 hours _____

MOST RECENT OUTAGE EVENTS

Please describe your three most recent power outages:

	Outage Date *Mo/Yr*	Duration *Hrs/Mins/Secs*	Time *Military*	Weather Conditions *Clear/Stormy*	Description of Impacts
3.7)	_____	_____	_____	_____	_____
3.8)	_____	_____	_____	_____	_____
3.9)	_____	_____	_____	_____	_____

4) What normally happens to your facility's operations when a prolonged power outage (lasting more than one minute) occurs?
(Prompt for major equipment affected, worst effects on operations, etc.)

_____

_____

_____

5.1) Does an outage at this location have financial effects on other sites owned by your company?
1) Yes 2) No *(if No, skip to Q5.4)*

5.2) What type(s) or duration(s) of outages at this location have financial effects on other sites owned by your company?
(Probe for interdependencies of the production network.)

_____

_____

_____

5.3) What are the specific financial effects?

_____

_____

_____

_____

5.4) Does an outage at this location have financial effects at your customers' sites?

1) Yes 2) No

6.1) Does your firm generate any of its own electricity (separate from backup power)?

1) Yes 2) No *(if No, skip to Q6.4)*

6.2) What percentage of your electrical demand is supplied by your generation equipment?

_____ %

6.3) What is the rated capacity of your generation equipment?

_____ Circle one: kW MW hp

6.4) Does your firm have some form of backup electrical power?
1) Yes 2) No *(if No, skip to Q1C1)*

6.5) What percentage of your electrical demand could be supplied by your backup generation equipment?

_____ %

6.6) What's the rated capacity of your backup generation equipment?

_____ Circle one: kW MW hp

The next section describes six different types of power outages. We'd like to know the costs to your business of adjusting to each of these power outages. **Assume that all of the described outages arise from issues associated with Toronto Hydro's infrastructure and occur without advance warning, which means that you don't initially know how long each outage will last.**

For many businesses, the costs of a power outage depend upon the particular situation, and may vary from day to day depending upon business conditions. For each outage type, please estimate the costs that you'd be most likely to have under average circumstances.

Since some businesses have more than one building at one location, and others have multiple buildings in several locations, please remember to fill out these questions thinking only about the building(s) that your business occupies at the location specified for this survey.

It's important to try to answer all of the questions. If a question is difficult for you to answer, please give us an estimate and feel free to provide any comments about your answer.

Case	Season	Day	Start Time	End Time	Duration
1	«SEASON1»	Weekday	«ONSET»	«END1»	4 hours

1C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.1C6)

1C2) By what percentage would activities stop or slow down? _____ %

1C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _____ $

1C4) What percent of this lost output is likely to be made up? _____ %

1C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _____ $

EXTRA MATERIALS COST

1C6) Damage/spoilage to raw or intermediate materials _____ $

1C7) Cost of disposing of hazardous materials _____ $

1C8) Damage to your firm's plant or equipment _____ $

1C9) Costs to run backup generation or equipment _____ $

1C10) Additional materials and other fuel costs to restart facilities _____ $

SAVINGS ON MATERIAL COST

1C11) Savings from unused raw and intermediate materials (except fuel) _____ $

1C12) Savings on your firm's fuel (electricity) bill _____ $

1C13) Scrap value of damaged products or inputs _____ $

LABOUR COST

1C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: _____)

1C15) Labour costs to make-up lost output _____ $

1C16) Extra labour costs to restart activities _____ $

1C17) Savings from wages that were not paid _____ $

1C18) Other costs _____ $

1C19) Other savings _____ $

1C20) **Total costs** *(Ask only if respondent will not provide component costs)* **_____ $**

Case	Season	Day	Start Time	End Time	Duration
2	«SEASON1»	Weekday	«ONSET»	«END2»	1 minute

2C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.2C6)

2C2) By what percentage would activities stop or slow down? _____ %

2C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _____ $

2C4) What percent of this lost output is likely to be made up? _____ %

2C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _____ $

EXTRA MATERIALS COST

2C6) Damage/spoilage to raw or intermediate materials _____ $

2C7) Cost of disposing of hazardous materials _____ $

2C8) Damage to your firm's plant or equipment _____ $

2C9) Costs to run backup generation or equipment _____ $

2C10) Additional materials and other fuel costs to restart facilities _____ $

SAVINGS ON MATERIAL COST

2C11) Savings from unused raw and intermediate materials (except fuel) _____ $

2C12) Savings on your firm's fuel (electricity) bill _____ $

2C13) Scrap value of damaged products or inputs _____ $

LABOUR COST

2C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: _____)

2C15) Labour costs to make-up lost output _____ $

2C16) Extra labour costs to restart activities _____ $

2C17) Savings from wages that were not paid _____ $

2C18) Other costs _____ $

2C19) Other savings _____ $

2C20) **Total costs** *(Ask only if respondent will not provide component costs)* **_____ $**

Case	Season	Day	Start Time	End Time	Duration
3	«SEASON1»	Weekday	«ONSET»	«END3»	1 hour

3C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.3C6)

3C2) By what percentage would activities stop or slow down? _____ %

3C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _____ $

3C4) What percent of this lost output is likely to be made up? _____ %

3C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _____ $

EXTRA MATERIALS COST

3C6) Damage/spoilage to raw or intermediate materials _____ $

3C7) Cost of disposing of hazardous materials _____ $

3C8) Damage to your firm's plant or equipment _____ $

3C9) Costs to run backup generation or equipment _____ $

3C10) Additional materials and other fuel costs to restart facilities _____ $

SAVINGS ON MATERIAL COST

3C11) Savings from unused raw and intermediate materials (except fuel) _____ $

3C12) Savings on your firm's fuel (electricity) bill _____ $

3C13) Scrap value of damaged products or inputs _____ $

LABOUR COST

3C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: _____)

3C15) Labour costs to make-up lost output _____ $

3C16) Extra labour costs to restart activities _____ $

3C17) Savings from wages that were not paid _____ $

3C18) Other costs _____ $

3C19) Other savings _____ $

3C20) **Total costs** *(Ask only if respondent will not provide component costs)* **_____ $**

Case	Season	Day	Start Time	End Time	Duration
4	«SEASON1»	Weekday	«ONSET»	«END4»	8 hours

4C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.4C6)

4C2) By what percentage would activities stop or slow down? _____ %

4C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _____ $

4C4) What percent of this lost output is likely to be made up? _____ %

4C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _____ $

EXTRA MATERIALS COST

4C6) Damage/spoilage to raw or intermediate materials _____ $

4C7) Cost of disposing of hazardous materials _____ $

4C8) Damage to your firm's plant or equipment _____ $

4C9) Costs to run backup generation or equipment _____ $

4C10) Additional materials and other fuel costs to restart facilities _____ $

SAVINGS ON MATERIAL COST

4C11) Savings from unused raw and intermediate materials (except fuel) _____ $

4C12) Savings on your firm's fuel (electricity) bill _____ $

4C13) Scrap value of damaged products or inputs _____ $

LABOUR COST

4C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: _____)

4C15) Labour costs to make-up lost output _____ $

4C16) Extra labour costs to restart activities _____ $

4C17) Savings from wages that were not paid _____ $

4C18) Other costs _____ $

4C19) Other savings _____ $

4C20) **Total costs** *(Ask only if respondent will not provide component costs)* **_____ $**

Case	Season	Day	Start Time	End Time	Duration
5	«SEASON1»	Weekday	«ONSET»	«END5»	24 hours

5C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.5C6)

5C2) By what percentage would activities stop or slow down? _____ %

5C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _____ $

5C4) What percent of this lost output is likely to be made up? _____ %

5C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _____ $

EXTRA MATERIALS COST

5C6) Damage/spoilage to raw or intermediate materials _____ $

5C7) Cost of disposing of hazardous materials _____ $

5C8) Damage to your firm's plant or equipment _____ $

5C9) Costs to run backup generation or equipment _____ $

5C10) Additional materials and other fuel costs to restart facilities _____ $

SAVINGS ON MATERIAL COST

5C11) Savings from unused raw and intermediate materials (except fuel) _____ $

5C12) Savings on your firm's fuel (electricity) bill _____ $

5C13) Scrap value of damaged products or inputs _____ $

LABOUR COST

5C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: _____)

5C15) Labour costs to make-up lost output _____ $

5C16) Extra labour costs to restart activities _____ $

5C17) Savings from wages that were not paid _____ $

5C18) Other costs _____ $

5C19) Other savings _____ $

5C20) **Total costs** *(Ask only if respondent will not provide component costs)* **_____ $**

Case	Season	Day	Start Time	End Time	Duration
6	**«SEASON2»**	Weekday	«ONSET»	«END6»	4 hours

6C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.6C6)

6C2) By what percentage would activities stop or slow down? _____ %

6C3) What's the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _____ $

6C4) What percent of this lost output is likely to be made up? _____ %

6C5) I'd estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _____ $

EXTRA MATERIALS COST

6C6) Damage/spoilage to raw or intermediate materials _____ $

6C7) Cost of disposing of hazardous materials _____ $

6C8) Damage to your firm's plant or equipment _____ $

6C9) Costs to run backup generation or equipment _____ $

6C10) Additional materials and other fuel costs to restart facilities _____ $

SAVINGS ON MATERIAL COST

6C11) Savings from unused raw and intermediate materials (except fuel) _____ $

6C12) Savings on your firm's fuel (electricity) bill _____ $

6C13) Scrap value of damaged products or inputs _____ $

LABOUR COST

6C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: _____)

6C15) Labour costs to make-up lost output _____ $

6C16) Extra labour costs to restart activities _____ $

6C17) Savings from wages that were not paid _____ $

6C18) Other costs _____ $

6C19) Other savings _____ $

6C20) **Total costs** *(Ask only if respondent will not provide component costs)* **_____ $**

7.1) Now that we have discussed the *direct* costs associated with these outages, would you experience any *intangible* costs such as loss of good will, potential liability, or loss of future customers?

1) Yes *(if Yes, please explain)*
2) No

_____

_____

_____

ACCEPTABLE LEVEL OF RELIABILITY

Toronto Hydro works hard to prevent power outages, but eliminating all outages would be very costly, if not impossible. The following questions help us understand what you consider an acceptable level of service reliability from Toronto Hydro.

8.1) If each of the following occurred, would you think you were getting acceptable or unacceptable service from Toronto Hydro?

Outages lasting **1 minute or less...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **about an hour...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **between 4 hours and 8 hours…**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

ABOUT YOUR BUSINESS

Some background information about your business will help us understand how power outages affect your type of business. Please remember all of your answers are *confidential*. Your name and address will be kept anonymous and will not be associated with the information you provide.

9.1) Which one of the following categories best describes your business?

- ❑ Agriculture/Agricultural Processing
- ❑ Assembly/Light Industry
- ❑ Chemicals/Paper/Refining
- ❑ Food Processing
- ❑ Grocery Store/Restaurant
- ❑ Lodging (hotel, health care facility, dormitory, prison, etc.)
- ❑ High Tech
- ❑ Lumber/Mining/Plastics
- ❑ Office
- ❑ Oil/Gas Extraction
- ❑ Retail
- ❑ Stone/Glass/Clay/Cement
- ❑ Transportation
- ❑ Utility
- ❑ Other *(please specify)*: _____

9.2) What's the approximate square footage of the facility?

_____ Square feet

9.3) How many **full-time** (30+ hours per week) employees are employed by your business at this location?

_____ Full-time employees

9.4) List the number of people employed by your business at this location in each of the following categories:

_____ # of part-time year-round employees

_____ # of full-time seasonal employees

_____ # of part-time seasonal employees

9.5) What's the approximate value of your business' annual operations or services (income)?

$_____ per year

9.6) What's the approximate value of your business' <u>total</u> annual expenses (including labour, rent, materials, and other overhead expenses)?

$_____ per year

9.7) Approximately what percentage of your business' annual operating budget is spent on electricity?

_____ %

That concludes our interview today. Thank you very much for your time.

Please have customer sign / initial below acknowledging receipt of the $150 cheque.

Customer Name: _____ Date: _____

FOR INTERNAL USE ONLY:

Based on your observations of this facility, give a brief summary of the facility, any freak occurrences with their power supply, and the critical factors that minimize and/or exacerbate outage costs.

_____

_____

_____

_____

_____

_____

_____



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D4 Capacity Planning, Growth & Electrification

Toronto Hydro's capacity plan ensures that the distribution system is adequately sized to deliver reliable electricity to the utility's customers. To that end, the capacity planning process considers new load connections, increased distributed energy resources ("DERs") and broader electrification activities including the electrification of transportation. Fundamental to the capacity planning process is a 10-year weather-adjusted peak demand forecast ("System Peak Demand Forecast") that is developed using a driver-based forecasting methodology. The System Peak Demand Forecast is the basis for the Regional Planning forecast at the needs assessment stage to assess the adequacy of transmission facilities to supply the distribution grid.[1]

Capacity planning is becoming more complex as utilities address the unprecedented energy transition that is set to unfold over the coming years. National, provincial, and municipal decarbonization targets, as well as technical, societal, and economic factors are driving toward a decarbonized, decentralized and digitized energy system. This shift is expected to expand the role of clean electricity as source of energy for transportation and heating. Despite explicit industry and government net zero emission targets, there are still degrees of uncertainty around how these ambitious goals will be achieved. The pace and timing of the resulting growth and electrification from the pursuit of these targets will be driven by a complex interplay of policy, technological developments and consumer choice. Distribution system capacity planning must manage these interlinked growth drivers in an environment of greater uncertainty. Section D4.3 provides an overview of how Toronto Hydro has addressed this complexity and managed this uncertainty in its investment planning for 2025-2029.

For the 2025-2029 rate period, Toronto Hydro undertook enhanced capacity and connections capability assessments to monitor capacity related risks within its system. The enhancements include the preparation of the System Peak Demand Forecast with additional inputs for electric vehicles ("EVs"), data centers and Municipal Energy Plans, assessment of spare feeder positions, identification of system constraints that impact generation connections, and identification of unique drivers for demand growth.

Toronto Hydro also augmented its decision-making process with the results of long-term scenario modelling tool known as Future Energy Scenarios. The Future Energy Scenarios model is distinct from

[1] Please refer to Exhibit 2B, Section B for more information about Toronto Hydro's role in the Regional Planning Process.

the System Peak Demand Forecast in that it does not attempt to determine the most likely demand based on historical trends and other probabilistic sources of information. Rather, the Future Energy Scenarios model projects what the demand would be under various policy, technology and consumer behaviour assumptions that are linked to the varying aspirations, goals, targets and constraints of decarbonizing the economy by 2040 or 2050. The Future Energy Scenarios is described in more detail in Appendix A to this schedule.

This Exhibit describes Toronto Hydro's approach to capacity planning for 2025-2029 and is organized into the following sub-sections:

- **Section D4.1** outlines the capacity planning approach,
- **Section D4.2** describes in impact of growth and electrification considerations on the capacity planning process, and
- **Section D4.3** describes capacity needs and investments over the 2025-2029 period.

D4.1 Capacity Planning

Through its capacity planning process, Toronto Hydro assesses the adequacy of the distribution grid to deliver safe and reliable electricity to current and future customers. This process is linked with Regional Planning to ensure the adequacy of transmission facilities supplying the distribution grid. The System Peak Demand Forecast is the basis for the capacity planning process both at the distribution level and for Regional Planning at the needs assessment stage.

D4.1.1 System Peak Demand Forecast

The System Peak Demand Forecast determines the grid capacity investments that Toronto Hydro needs to make in the 2025-2029 rate period in order to continue to serve its customers and support economic growth and development in the City of Toronto. Using a probabilistic approach to forecast the peak demand at all transformer station buses that supply Toronto Hydro's distribution grid, the System Peak Demand Forecast yields summer and winter demand peaks, with the summer peak driving the 2025-2029 investment plan.

To arrive at the System Peak Demand Forecast, Toronto Hydro modelled organic system growth as part of the base forecast along with specific drivers that are relevant and material to the planning horizon. More specifically, Toronto Hydro considered three new specific drivers in the development

of the System Peak Demand Forecast: (i) hyperscale data centers, (ii) electrification of transportation and (iii) Municipal Energy Plans which include large anticipated connections in different areas of the city. Each of these drivers is discussed in further detail below.

The System Peak Demand Forecast methodology includes the following components and considerations:

1. Weather Normalization
2. Econometric Multivariate Regression
3. Hyperscale Data Centre Demand Driver Analysis
4. Electric Vehicle (EV) Demand Driver Analysis
5. Municipal Energy Plans – Uncommitted Connections
6. Monte-Carlo Simulation
7. TS Bus Growth Allocation & Layering of Load Transfers/Voltage Conversions and Customer Connections

D4.1.1.1 Weather Normalization

To determine the correlation between temperature and load, Toronto Hydro's analysis removed the impact of day-to-day fluctuations in temperature on peak load in order to arrive at a stable view of historical system performance. Toronto Hydro then applied the historical trend to the forecasted peak load to normalize the forecast for weather-related impacts.

D4.1.1.2 Econometric Multivariate Regression

In addition to weather, Toronto Hydro considered a range of macroeconomic assumptions as inputs to the System Peak Demand Forecast, including the following key variables:

1. Toronto Population
2. Toronto Employment Rate & Median Income
3. Consumer Price Index
4. Number of Business Licenses Issued/Renewed
5. Toronto Housing Starts
6. Average Home Price

Toronto Hydro relied on traditional forecasting approaches to establish a correlation between weather and peak demand, and between econometric variables and peak demand. Toronto Hydro

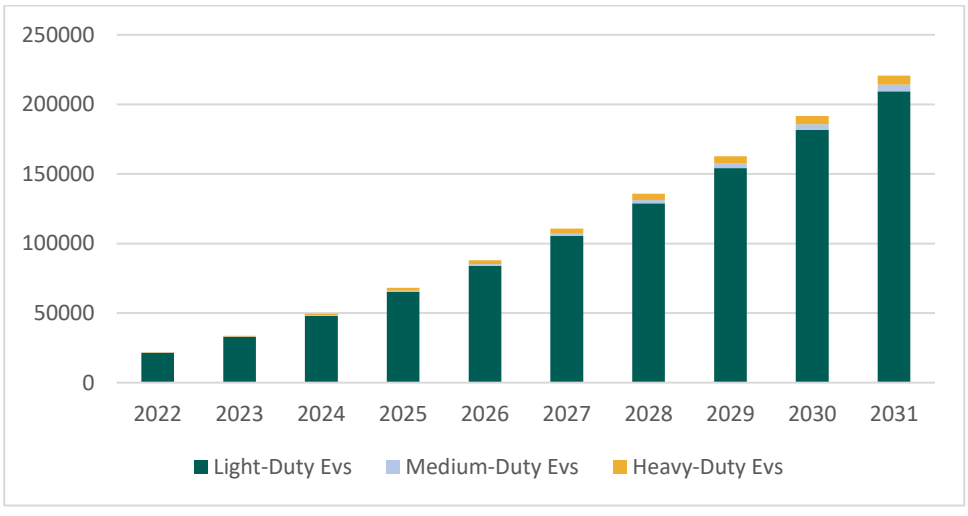
enhanced the traditional approach by incorporating considerations of the impact of varying weather on economic activity and its relationship to peak demand. This analysis enabled the utility to assess the impact of a changing climate on the econometric variables that affect peak demand.

D4.1.1.3 Hyperscale Data Centre Demand Driver Analysis

Toronto Hydro identified hyperscale data center connections as a new driver of significant peak demand growth over the 2025-2029 rate period and beyond. A hyperscale data center supports large processing and data storage operations using 5,000 servers or more and has the capability of a peak demand exceeding 25 MW. In order to better understand the impact of hyperscale data center connections on the grid and plan accordingly, Toronto Hydro modelled this driver separately. Through review of historical load connections, research into growth rates for comparable North American cities, and assessments of vacancy rates as well as available land space in the City, Toronto Hydro assessed the peak demand contributions of hyperscale data centers.

D4.1.1.4 Electric Vehicle Demand Driver Analysis

Toronto Hydro forecasted the impact of light-duty, medium-duty and heavy-duty EVs. Figure 1 below summarizes the volumes of EVs that underpin the forecast. The adoption models are aligned with the City of Toronto's Transform TO transportation electrification goals. The forecast also considered geographic distribution and typical charging profiles to arrive at area and system peak demand contribution from electric vehicle uptake by consumers.



/C

Figure 1: Peak Demand Forecast – EV Volumes

D4.1.1.5 Municipal Energy Plans

In the development of the System Peak Demand Forecast, Toronto Hydro considered the impact of Municipal Energy Plans for large projects, such as the re-development of Downsview, Port Lands and Scarborough Golden Mile.[2] Figure 2, shows the location of these projects in the city.

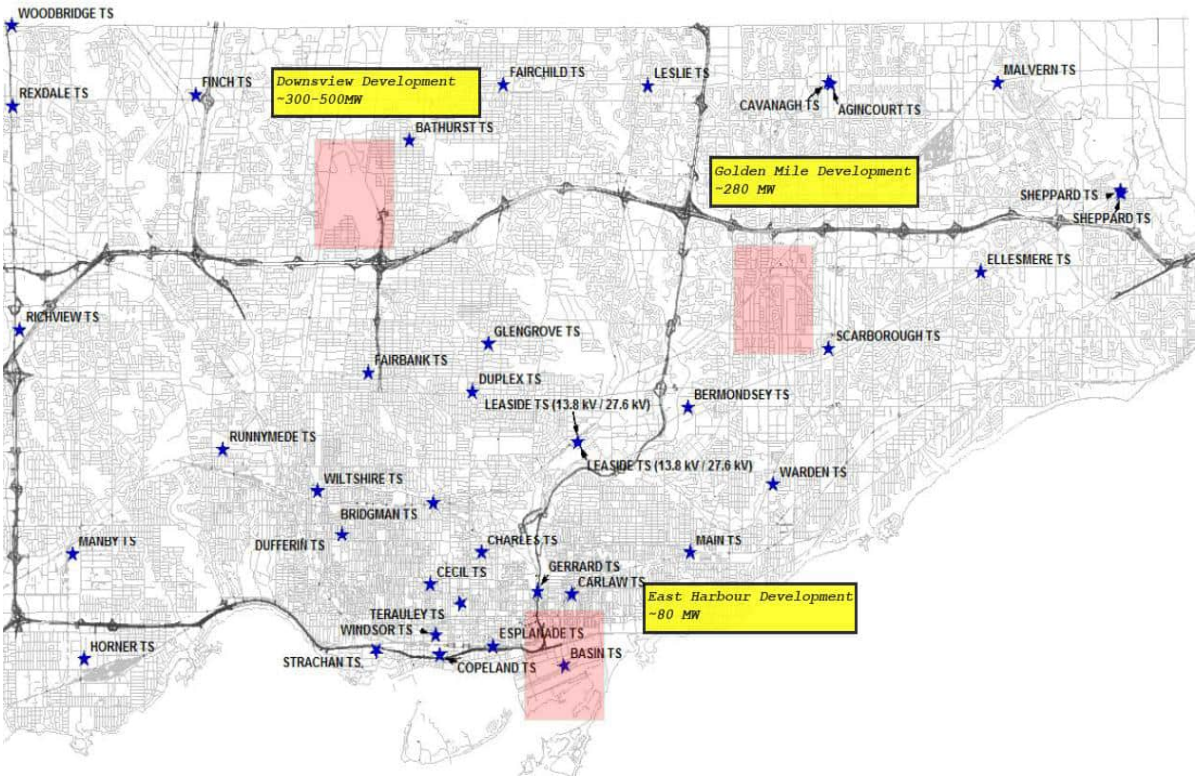


Figure 2: Municipal Energy Plan Locations

For the identified Municipal Energy Plans, Toronto Hydro included both firm connection commitments and the anticipated future loads in the System Peak Demand Forecast to ensure that the utility has sufficient lead-time to invest in new grid capacity that is required to serve this future demand. This approach is consistent with section 3.3.1 of the Distribution System Code which requires distributors to "plan and build the distribution system for reasonable forecast load growth." It is also aligned with the recommendation of the OEB's Regional Planning Process Advisory Group for distributors to incorporate Municipal Energy Plan information into their planning and forecasting

[2] City of Toronto, Official Plans – Secondary Plans, "online", https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/official-plan/chapter-6-secondary-plans/

processes in order to "identify current and future needs for new electricity infrastructure investments within local communities."[3]

D4.1.1.6 Monte-Carlo Simulation

Monte-Carlo Simulation is a sophisticated modelling technique that is applied to model the probability of different outcomes when the potential for random variables is present. It considers multiple sources of uncertainty to provide a range of possible outcomes for peak demand. For the System Peak Demand Forecast, Toronto Hydro modeled the variability of temperature to consider the impact of climate change on econometric indicators and simultaneously included drivers for data centers, electric vehicles, conservation and demand management, and distributed energy resources forecasts and applied a probability to determine the most likely outcome.

D4.1.1.7 TS Bus Growth Allocation and Layering of Load Transfers/Voltage Conversions and Customer Connections

The final step in the forecasting process involves allocating the demand outputs from each driver to the station buses and layering on any permanent load transfers through the Load Demand program to arrive at the System Peak Demand Forecast that describes impacts at both a system and bus level.

D4.1.2 Regional Planning Forecasts

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The Toronto regional planning process commenced in the fall of 2022 with the needs assessment phase.[4] The transmitter Hydro One Networks Inc. develops the regional planning needs assessment forecast using an extreme weather model, information from Toronto Hydro's System Peak Demand Forecast and a forecast of Conservation and Demand Management (CDM) and Distributed Generation (DG) from the IESO. On March 21, 2023, the IESO issued the Scoping Assessment Outcome Report identifying the need for an Integrated Regional Resource Plan ("IRRP") for the Toronto Region. This process is currently underway.

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The Needs Assessment Report issued in December 2022, prepared on the basis of 2021 actuals, indicated that the net summer peak demand in the Toronto region is expected to increase by an average of 2.1 per cent per year, reaching 6,700 MVA by 2031.[5] In the fall 2023, as part of the IRRP

[3] RPPAG, Municipal Information Document – Improving the Electricity Planning Process in Ontario: Enhanced Coordination between Municipalities and Entities in the Electricity Sector, (December 15, 2022) p. 2, "online", https://www.oeb.ca/sites/default/files/RPPAG-Municipal-Information-Document-20221202.pdf
[4] Exhibit 2B, Section B
[5] Exhibit 2B, Section B, Appendix A – Needs Assessment Report (Toronto Region)

process, Toronto Hydro prepared the 2023 System Peak Demand Forecasts, on the basis of 2022 actuals and other modelling refinements, indicating that the net summer peak demand is expected to increase by an average of 2.6 percent per year, reaching 6,000 MVA by 2031.

Figure 3 below shows: (i) Toronto Hydro's 2022 System Peak Demand Forecast, which is consistent with the Regional Planning Forecast issued by Hydro One as part of the Needs Assessment; and (ii) Toronto Hydro's 2023 System Peak Forecast which was provided to the IESO in the fall of 2023 as an input to the Toronto Region IRRP process currently underway. The System Peak Demand Forecasts are shown net of the forecasted impacts of CDM and DG. The primary difference between the 2022 System Peak Demand Forecast and 2022 Regional Planning Needs Assessment forecasts is the effect of extreme weather. As noted above, Toronto Hydro normalizes its forecast for weather fluctuations, whereas the Regional Planning forecasts rely on an extreme weather model.

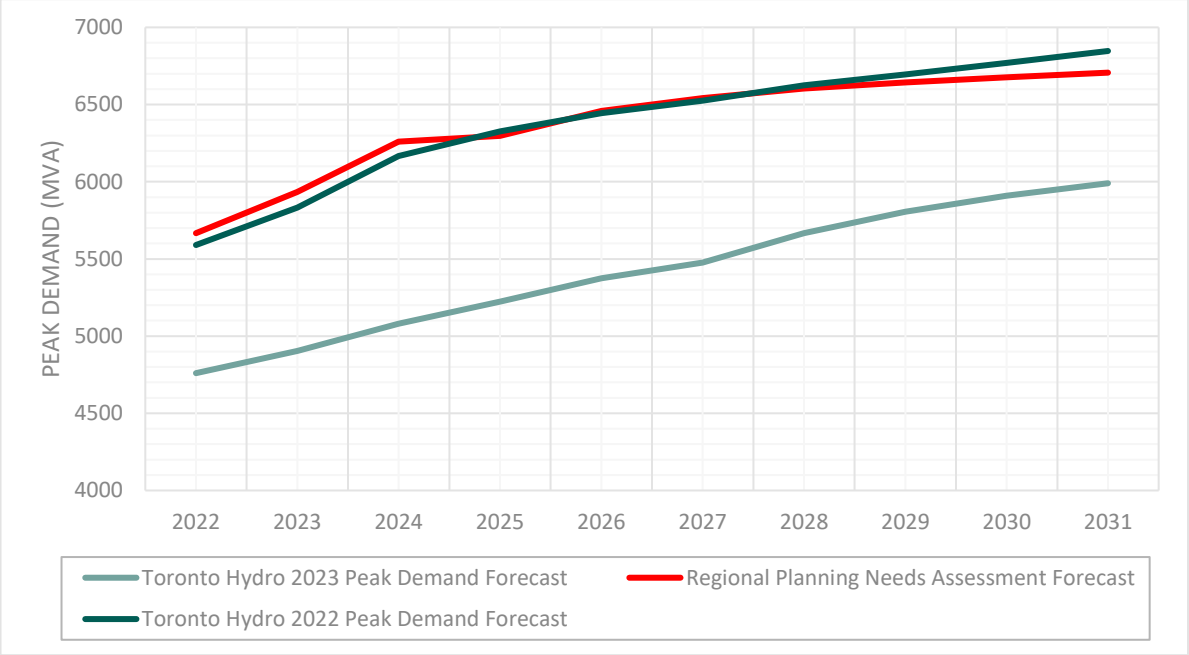

Figure 3: Toronto Hydro System Peak Demand Forecast and the Regional Planning Needs Assessment Forecast prepared by Hydro One

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D4.1.3 Connection Capability

In order to connect new customers, Toronto Hydro needs grid capacity as well as spare feeder positions (i.e. feeder breakers to which new feeders can be connected). As existing feeders reach

their capacity, new feeders must be pulled from a station into the distribution system to connect new customers. Although a station may have the capacity to supply the required demand, if there are no feeder positions to connect new feeders to the station, the station is unable to support new connections. To this end, Toronto Hydro must monitor the number of spare feeder positions at its stations to maintain the ability to connect new customers. When new feeders are needed and there are spare feeder positions are available, Toronto Hydro initiates projects in the Load Demand program to transfer feeder loads and free up feeder positions so that new customers can connect to the system in a timely and efficient manner.

D4.1.4 Generation Capacity and Capability Assessment

Toronto Hydro connects DERs to the distribution system in alignment with the Distribution System Code and in coordination with Hydro One Networks and the IESO. As part of its capacity planning process, the utility identified a number of constraints that impact DER connections to the distribution grid, including:

- limited breaker and station equipment capacity due to short circuit capacity constraints;
- reverse power flow limitations based on transformer thermal capacity and minimum load requirements;
- anti-islanding conditions for DG; and
- system thermal limits and load transfer capability.

Short circuit capacity constraints on station equipment are the primary constraint for DER connections. To determine the short circuit capacity at stations and other locations on the distribution system, Toronto Hydro employs sophisticated fault and power flow simulation models. These models predict how much fault current will flow to a specific location from generators located throughout the distribution system. The presence of DERs on distribution feeders can contribute to fault current that can cause station equipment, such as circuit breakers, to exceed short circuit capacity limits. Toronto Hydro completes a study for each new DER application to monitor the available existing short circuit capacity of the system.

D4.2 Capacity Planning and the Energy Transition

The decarbonization of the energy system to mitigate the existential and economic impacts of climate change is expected to create new roles for electricity, including powering transportation and building systems. Toronto Hydro recognizes that the pace and timing of these changes are driven by

a complex interplay of policy, technological developments and consumer choice. While there is certainty that fundamental change is ahead, there are degrees of uncertainty about how that change will unfold (e.g. the pace and adoption of EVs and heat pumps; the role of low emission gas; and the scale of local vs. bulk electricity supply). To contend with this uncertainty and complexity in its planning process, Toronto Hydro developed the Future Energy Scenarios modelling tool to understand possible changes to future peak demand under different scenarios. For more information about this tool please refer to Appendix A.

In order to be able to continue to deliver its central purpose of serving the electricity needs of the residents, businesses and institutions in the City of Toronto, the utility must take responsible actions in the 2025-2029 plan period to prepare the local grid and its operations for the unprecedented energy transition that is and will continue to gradually unfold across the economy. At the same time, the exact path and pace of the energy transition remains subject to various factors of uncertainty (policy, technology and consumer behavior), which means that Toronto Hydro must be careful to ensure that investments being made in the 2025-2029 rate period provide long-term value to customers and enable policy, technology and customer choice in effecting the energy transition. To balance both of these objectives, Toronto Hydro adopted a “least regrets” planning philosophy. The term “least regrets” refers to a strategic planning approach anchored in the decision-making theory of anticipating and minimizing regretful choices/outcomes when faced with uncertainty.

As part of its capacity planning process, Toronto Hydro took the following actions to identify least regrets investments in the 2025-2029 rate period:

- included additional drivers in its System Peak Demand Forecast (e.g. EVs, data centers and Municipal Energy Plans) to assess the anticipated future demand;
- augmented its decision-making process with the results of a Future Energy Scenarios model to understand the impact of different policy, technology and consumer behavior drivers; and
- used the Future Energy Scenarios to stress-test whether the utility’s capacity plan can accommodate energy transition needs (e.g. building heating electrification) in the early part of the next decade, if required.

The Future Energy Scenarios reveal that the impact of building electrification in the next two decades could be significant from a system peak demand perspective, but that there are notable differences (driven by policy, technology and consumer-behaviour choices) as to when and how building electrification could unfold. For example, the Consumer Transformation scenario of the Future

Energy Scenario shows that localized consumer-focused technology solutions such DERs (including energy efficiency) could materially curtail the annual peak demand curves in a future where buildings are increasingly electrified. In light of these circumstances, "least regrets" meant Toronto Hydro acted with a higher degree of caution in terms of building new capacity to prepare the distribution grid for wide-scale building electrification in the next two decades, as the policy and consumer-behaviour drivers of this type of demand remain uncertain, and technology advancement could offer more cost-effective solutions in the future. Practically, this meant that Toronto Hydro decided to take a "wait and see approach" to investments in new capacity for accommodating wide-scale building electrification in the mid-2030s and beyond.

Toronto Hydro's "least regrets" investment approach to growth and electrification is reinforced by the utility's Grid Modernization strategy summarized in Exhibit 2B, Section D5.

Toronto Hydro's traditional grid infrastructure is facing a shift driven by renewable energy integration, technology evolution, changing customer needs, and more. The Grid Modernization Strategy recognizes the need to prepare for these transformations by transitioning towards a more technologically advanced distribution system, and developing advanced capabilities that over time will provide greater flexibility to:

- take a "wait and see" approach to capital investment needs that have a higher degree of uncertainty, and
- implement increasingly cost-effective technology-based solutions to address grid needs and deliver reliability, resilience, system security and other valuable customer outcomes as electrification accelerates in the next decade and beyond.

Key elements of this investment strategy include investments in Non-Wires Solutions – such as contracted demand response ("Flexibility Services") and grid-scale renewable-enabling battery energy storage systems ("REBESS") – as well as major investments in the development of a more intelligent grid (e.g. contingency enhancements, and investments in sensors and next generation smart meters that are expected to improve grid observability, and the implementation of grid automation solutions such as FLISR). These modernization investments, once implemented on the grid and integrated into operations, provide Toronto Hydro with an enhanced capability to observe system performance at an asset-level and make real-time (and increasingly automated) operating decisions. Building these capabilities is necessary to improve accuracy and granularity of load forecasting and optimize the capacity and performance of a more heavily utilized grid.

D4.3 Capacity Needs and Investment Plan

As noted above, the primary drivers of capacity need and related investments over the 2025-2029 rate period are: customer connections (included as part of the base forecast), electrification of transit, electric vehicles, hyperscale data centers, and Municipal Energy Plans for three regions of the city discussed above. Figure 4 below shows the contribution of each of these drivers to the System Peak Demand Forecast.

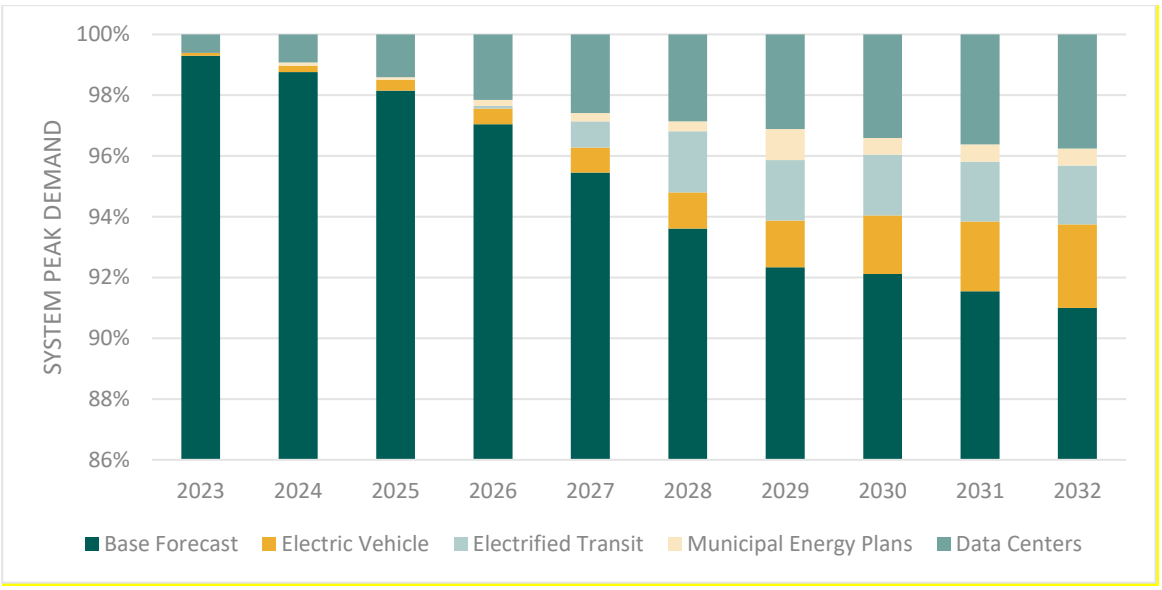

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Figure 4: Toronto Hydro System Peak Demand Forecast by Driver

In the development of the 2022 System Peak Demand Forecast, Toronto Hydro determined that building electrification (i.e. electrification of space and water heating) is not yet a significant driver of growth in the 2025-2029 rate period. As a result, the System Peak Demand Forecast continues to be a summer peaking forecast. However, to stress test the assumptions regarding building electrification against the least regrets planning philosophy, Toronto Hydro assessed whether the utility could accommodate a growing winter peak (driven by building electrification) in the 2025-2029 rate period if needed. To that end, the utility looked at scenarios of forecasted building heating loads derived from the Future Energy Scenario model outputs. More specifically, Toronto Hydro used the Consumer Transformation scenario, and its low efficiency equivalent, as the lower and upper bounds, of the sensitivity test.

The Consumer Transformation scenario models an energy transition pathway where consumers play a prominent role in driving results towards decarbonization. In addition to high levels of transportation electrification, there are high levels of heating electrification, energy efficiency and DERs. In the related low efficiency Consumer Transformation scenario, the uptake of electrified heat and transport technologies is the same, but the uptake of efficiency measures (e.g. building retrofits), and DERs (e.g. renewables and energy storage) is limited, resulting in a higher peak demand. Toronto Hydro selected the Consumer Transformation scenario and its low efficiency equivalent for this sensitivity analysis because these scenarios presented (i) the most variability in building heat, between the high and low efficiency assumptions, and (ii) the most material grid impact of the energy transition in terms of system peak demand.

Figure 5 below compares the Regional Planning Needs Assessment Forecast, the 2022 System Peak Demand Forecasts and the selected upper and lower bounds of the Consumer Transformation scenario. Figure 5 also overlays the 2023 System Peak Demand Forecast, which as noted above, is based on 2022 actuals. The FES scenarios were conducted on the basis of 2021 actuals. Toronto Hydro expects that if the FES scenarios were updated for 2022 actuals the relativity of the FES curves to the 2023 Peak Demand Forecast would be roughly similar.

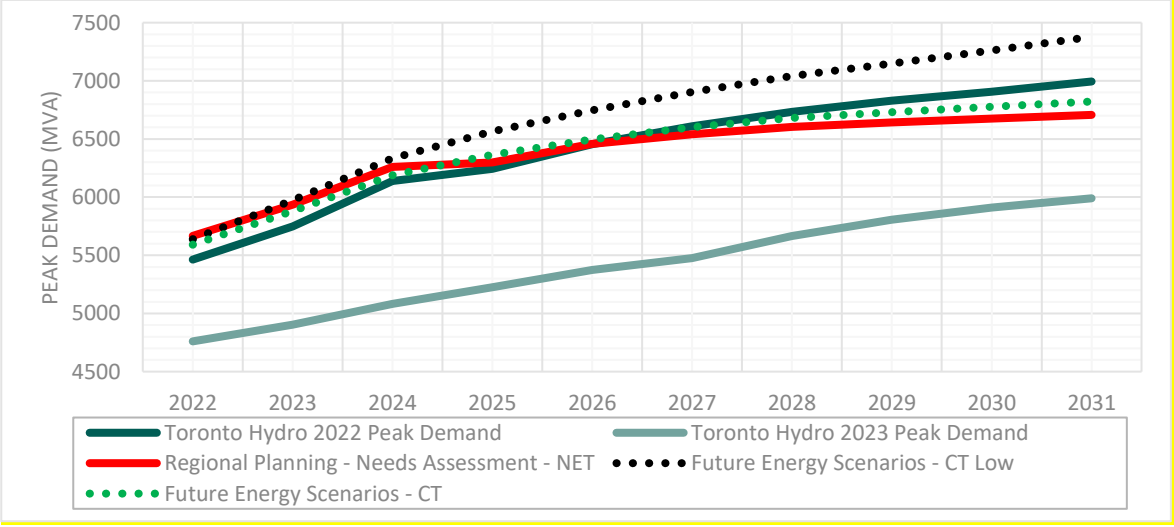

Figure 5: Comparison of Planning Forecasts and Future Energy Scenarios

As shown in Figure 5 above, Toronto Hydro's 2022 System Peak Demand Forecast is generally aligned with the Consumer Transformation (CT) scenario. From this analysis, Toronto Hydro concluded that the capacity investment plan can meet higher levels of building heating loads (which contribute to

winter peak) should this driver of electrification materialize at a faster pace than expected. As a result, Toronto Hydro has confidence that the investments in system capacity that the utility proposes to make in the 2025-2029 rate period are least regrets to address growth and electrification drivers that the utility faces in this decade and the early part of the next decade. That being said, it is possible that the utility could be faced with incremental capacity constraints at a localized level as a result of accelerated transportation and building electrification demand. To address this challenge, the utility proposes a Demand Related Variance Account to track variances in actual versus forecasted expenditures in a number of demand-related investment programs. For more information about this proposal please refer to Exhibit 1B, Tab 2, Schedule 1.

Based on the capacity planning process outlined above, Toronto Hydro proposes investments in various programs to meet the utility's fundamental obligation to connect new and expanded services to the grid in this decade and beyond. These programs include expansion to increase grid capacity and enhancements to better utilize existing equipment. Through programs such as Load Demand[6], Stations Expansion[7], and Horseshoe and Downtown Renewal[8], Toronto Hydro is renewing and enhancing stations, buses, feeders, and other equipment that will facilitate load growth at the appropriate locations. In areas where Toronto Hydro expects customers to connect more DERs, programs such as Grid Protection, Monitoring and Control alleviate short-circuit capacity constraints.[9] Furthermore, where feasible and cost-effective, Toronto Hydro's intends to leverage the Non-Wires Solutions program to (i) procure market-based flexibility services to avoid or defer capital investment, and (ii) deploy grid-scale storage solutions to enable the connection of renewable energy generation facilities.[10]

The sections that follow discuss in more detail the capacity investments that Toronto Hydro intends to make in key areas of the grid.

D4.3.1 Downtown Area

Figure 6 below shows all transformer stations in the Downtown area. Areas in green represent transformer stations that do not require relief within 10 years. The transformer stations in yellow

[6] Exhibit 2B, Section E5.3
[7] Exhibit 2B, Section E7.4
[8] Exhibit 2B, Section E6.2 and Section E6.3
[9] Exhibit 2B, Section E5.5.
[10] Exhibit 2B, Section E7.2.

require bus relief between 5 to 10 years while the transformer stations in red, require bus relief within 5 years.

Immediate relief to the midtown region in red is planned to be achieved through expansion and renewal work at Bridgman TS and Duplex TS, and through load transfers from Bridgman TS to Wiltshire TS. For more information please refer to Exhibit 2B, Sections E7.4 and E5.3.

The south west region of the downtown core, served by Copeland, Cecil and Strachan TS could become capacity-constrained before the end of the decade. While Copeland TS - Phase 2 introduces increased system capacity and spare feeder positions to the downtown core, it is expected to be constrained by 2032. The Load Demand and Flexibility Services programs addresses capacity limitations at these stations in the short term through station bus load transfers and demand response activities.

Incremental relief to Main TS and Strachan TS is planned to be achieved through switchgear and transformer replacements. For more information please refer to Exhibit 2B, Section E7.4.

/C

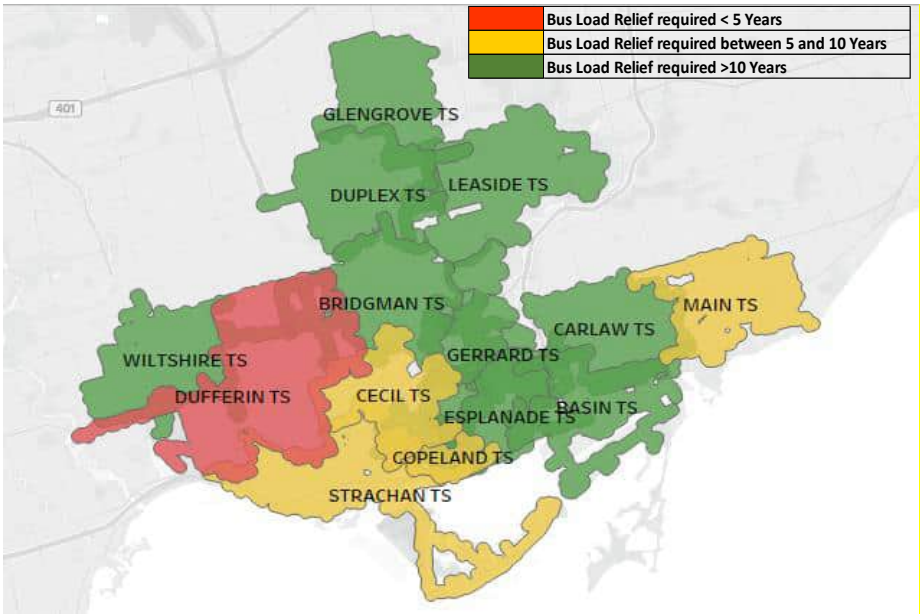

Figure 6: Downtown stations requiring load relief

D4.3.2 Horseshoe East Area

The Scarborough area in the Horseshoe East experienced significant load growth in recent years, and Toronto Hydro expects this trend to persist due to the development of the Golden Mile corridor, the Ontario Line, and the Scarborough subway extension. In particular, the Golden Mile Secondary Development Plan covers an area of 113 hectares of land in Scarborough bordered by Ashtonbee Road to the north, Birchmount Road to the east, Civic Road / Alvinston Road to the south and Victoria Park Avenue to the west. Taking these drivers into account, Toronto Hydro forecasts average growth of 3.0% per year over the next 10 years in the Horseshoe East Area. The System Peak Demand Forecast shows that the area is not expected to reach 90% of its capacity before 2031. The Horseshoe East Area is forecasted to experience a lack of feeder positions by 2032. This constraint is particularly acute at Warden TS and Ellesmere TS. However, Toronto Hydro notes that while Scarborough TS can provide relief to these stations in the short-term, increased demand in the Scarborough area due to continued development and electrification could drive the need for investment at Scarborough TS over the 2025-2029 rate period. Figure 7 highlights the load relief required in the short term. Toronto Hydro plans to provide capacity relief to the area by increasing the transformer size at Scarborough TS in the 2025-2029 rate period. The utility is also monitoring peak demand in the area for accelerated growth that could trigger additional investments in the 2025-2029 rate period.

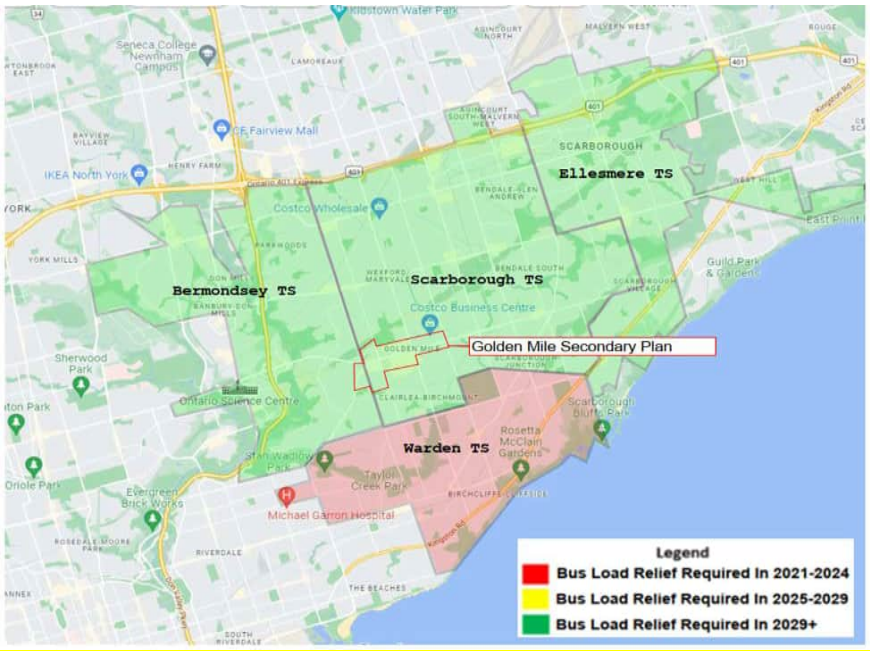

Figure 7: Scarborough TS and East Region

/C

D4.3.3 Horseshoe West Area

The Horseshoe West is also expected to experience notable load growth over the next decade, resulting in a forecasted average peak demand growth of 2.8% per annum. The System Peak Demand Forecast indicates that the majority of stations in this area are expected to reach capacity in the next decade or shortly thereafter. Moreover, by the end of the decade, Toronto Hydro forecasts the entire area to be highly loaded. The region surrounding the Downsview area (shown in Figure 8 below) is expected to see the highest growth due to redevelopment of this area. /C /C

In 2017, the City of Toronto approved of the Downsview Area Secondary Plan, covering 210 hectares, bounded by Sheppard Avenue to the north, Allen Road to the east, Wilson Avenue to the south, and Downsview Park and the Park Commons to the west, as shown in Figure 9.

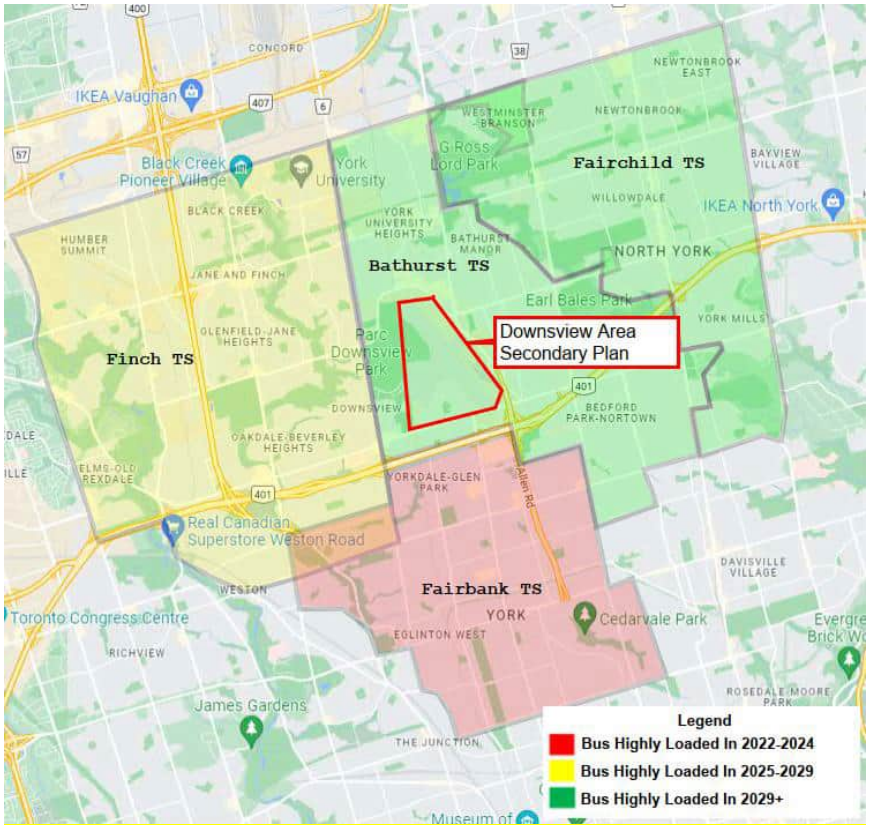

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Figure 8: Downsview Area and surrounding stations

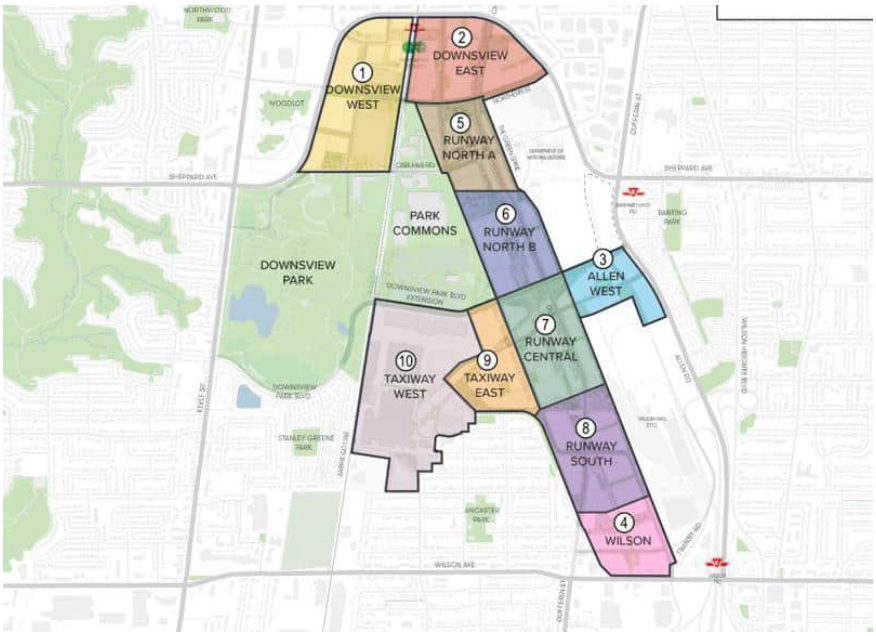

Figure 9: Downsview Area Secondary Plan

The Downsview Area Secondary Plan includes plans to expand each district with a mix of commercial, office, industrial and institutional buildings. The Allen East District is planned for a residential development of approximately 3,500 dwelling units. Load in the Downsview area is expected to reach 103 MW by 2029, 180 MW by 2034, and 509 MW by 2051.[11] Based on this growth, load relief is needed at a regional level to support rising demand due to development and electrification in the Horseshoe West area. Through the Toronto Regional Planning process, the utility proposes to construct a new transformer station (Downsview TS) to address this need. Please refer to the Stations Expansion Program at Exhibit 2B, Section E7.4 for more information. /C

[11] Exhibit 2B, Section E7.4.3.1 – Downsview TS.

Appendix A – Future Energy Scenarios Overview

The energy landscape is undergoing a fundamental shift driven by decarbonization mandates to mitigate the life-threatening impacts of climate change. This shift is expected to create new roles for electricity in the day-to-day energy needs of consumers, including powering transportation and building systems. Toronto Hydro recognizes that the pace and timing of these changes will be driven by a complex interplay of policy, technological developments and consumer choice.

While there is certainty that fundamental change is ahead, there is uncertainty about how that change will unfold (e.g. the pace and adoption of EVs and heat pumps; the role of low emission gas; and the scale of local vs. bulk electricity supply). This reality means that planning is becoming more complex for distributors like Toronto Hydro who must manage various interlinked growth drivers in an environment of greater uncertainty.

Future Energy Scenarios is a modelling tool that explores a range of possible changes to future peak demand based on the interplay of different policy, technology and consumer behaviour assumptions. This scenario-based approach embraces the uncertainty and variability of the energy transition and reveals possible pathways of change.

1 Public Policies and Objectives

Government at all levels are implementing decarbonization policies, including GHG emission targets and incentives to encourage consumers to electrify their transportation and heating needs. Key policies and incentives include:

Canada Greener Homes Grant provides up to $5,000 for electrified heating technologies such as heat pumps.[1] This grant was introduced in December 2020 and is expected to stay in place for seven years.

Incentives for Zero-Emissions Vehicles ("iZEV") program provides up to $5,000 for electric and hydrogen-fueled vehicles until March 2025.[2]

[1] Natural Resources Canada, Canada Greener Homes Grant, "online", https://www.nrcan.gc.ca/energy-efficiency/homes/canada-greener-homes-initiative/canada-greener-homes-grant/canada-greener-homes-grant/23441

[2] Transport Canada, Incentives for Zero-Emission Program, "online", https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/light-duty-zero-emission-vehicles/incentives-purchasing-zero-emission-vehicles

The Ontario Energy Board, working with distributors, recently implemented a **"Ultra-Low Overnight" rate option** to incentivize off-peak EV charging to encourage the uptake of EVs as an alternative to the rising fuel costs of internal combustion vehicles.[3]

Federal Zero Emission Vehicle Sales Targets: The federal government has committed to a mandatory 100% zero-emission vehicle sales target by 2030 for all new light-duty vehicles.[4]

City of Toronto's **Toronto Green Standard** sustainable design and performance requirements for new private and city-owned developments. The most recent version all but eliminates the use of natural gas in new buildings.[5]

Federal carbon pollution pricing system: Since 2019, every jurisdiction in Canada has had a price on carbon pollution, including a charge on fossil fuels like gasoline and natural gas. The fuel charge increases annually in relation to the carbon pollution price. The carbon pollution price will increase from $65 per tonne of carbon dioxide equivalent in 2023 to $170 per tonne by 2030.[6]

Many commercial and industrial customers in Toronto Hydro's service territory have adopted decarbonization and emissions reduction goals through Environmental, Social and Governance ("ESG") mandates. In an engagement with Key Account customers that Toronto Hydro completed in advance of preparing the 2025-2029 investment plan, the utility found that approximately 64% of the customers surveyed have plans to decarbonize their business and expect Toronto Hydro to support them by ensuring that the grid has sufficient capacity to serve their needs.[7]

1.1 Technological Advancements

Technological advancements are providing customers more choice in respect of their energy needs, and over time these choices can have significant impacts for the distribution grid. According the

[3] Province of Ontario, Ontario Launches New Ultra-Low Overnight Electricity Price Plan, "online", https://news.ontario.ca/en/release/1002916/ontario-launches-new-ultra-low-overnight-electricity-price-plan
[4] Transport Canada, Canada's Zero-Emission Vehicle (ZEV) sales targets, "online", https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/canada-s-zero-emission-vehicle-zev-sales-targets.
[5] City of Toronto, Toronto Green Standard, Version 4, "online", https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/toronto-green-standard/.
[6] Government of Canada, How carbon pricing works, "online", https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/putting-price-on-carbon-pollution.html; Government of Canada, Canada Revenue Agency. Fuel Charge Rates, "online", https://www.canada.ca/en/revenue-agency/services/forms-publications/publications/fcrates/fuel-charge-rates.html
[7] Exhibit 1B, Tab 3, Schedule 1 – Customer Engagement p. 18-19.

National Renewable Energy Laboratory's cost benchmarking studies, installed system costs per watt for solar PV from 2010 to 2020 have sharply decreased by 64% for a residential 7-kW rooftop system and 69% for a commercial 200-kW rooftop system.[8] Stand alone battery energy systems (BESS) experienced a similar 10% cost decline from 2020 to 2021.[9] The declining cost curves of these technologies are providing customers more economical choices to invest in distributed energy resources. Similarly, efficiency improvements in heat pumps are making these technologies more feasible alternatives to natural gas furnaces for space heating in cold weather climates.

1.2 Consumer Choices

Consumer choices and behaviors regarding energy use are gradually changing. Activities that previously did not affect the electricity system (including fueling vehicles and space heating) now have the potential to change electricity consumption patterns and shift system peaks. For example, residential and fleet EV charging could create new system needs like real-time voltage control to support a sharp rise from morning and/or afternoon charging on a scale similar to that created by air conditioning demand on hot summer days. Additionally, as heating systems are electrified (e.g. heat pumps), electricity system peaks can shift from summers to winters.

1.3 Future Energy Scenarios Framework

To better understand the challenges posed by the changing energy landscape, Toronto Hydro engaged a leading UK consultant Element Energy,[10] to develop the Future Energy Scenarios modelling tool. This is the first pathway study in Ontario to focus on the distribution-level impacts of the energy transition. The model was informed by a comprehensive investigation into the current state of the energy landscape in Toronto, including reviews of previous studies, data sets and policy. Emissions were not directly modelled in the Future Energy Scenarios, but policies and targets were built into the tool such that the key drivers are consistent with emissions goals.

Future Energy Scenarios employs bottom-up consumer choice and willingness-to-pay models which are based on the concept that consumers try to maximize their utility when making decisions. For example, in the case of different heating technologies, when a homeowner is deciding to replace a

[8] NREL, Solar Installed System Cost Analysis, "online", https://www.nrel.gov/solar/market-research-analysis/solar-installed-system-cost.html. Most cost components relate to capital costs, particularly module and inverter costs, meaning that the decreases apply universally.
[9] Ramasamy Vignesh, David Feldman, Jal Desai, and Robert Margolis. 2021. *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks: Q1 2021.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-7A40-80694. https://www.nrel.gov/docs/fy22osti/80694.pdf.
[10] Future scenario modelling has been a regular part of system planning by regulated energy utilities in the UK for several years, many of which have been supported by Element Energy.

heating system at the end of its life, they would likely weigh various factors in their decision making, including the upfront cost of different available technologies (e.g. gas-fired furnace, heat pump, hybrid heat pump, etc.), the ongoing operating costs, the complexity of installation, and the suitability of each technology for the property. The bottom-up models in Future Energy Scenarios convert the value of these factors to consumers into equivalent, monetary value or utility, so they can be compared quantitatively.

The outputs of the Future Energy Scenario model are distinct from the capacity planning forecast discussed in Section D4 because they do not predict what is likely to occur in the future. Case in point, the Future Energy Scenarios model does not assign probability to any of the identified scenarios. The Future Energy Scenarios complements the Peak Demand Forecast by enabling Toronto Hydro to explore various pathways and quantify the impacts of those pathways to peak demand. This information is valuable because it allows Toronto Hydro to identify and quantify investments that would be required to reinforce the grid in different scenarios. This capability supports Toronto Hydro's least regrets planning philosophy in that it allows the utility to stress test its Peak Demand Forecast against plausible scenarios to ensure that the utility (1) does not overbuild the system and (2) does not become a barrier to particular decarbonization pathways.

2 Scenario Worlds

The scenario framework captured the range of uncertainties with four main 'scenario worlds' consisting of individual projections for the uptake or pace of various technologies or consumer behaviour. As illustrated in Figure 1 below, each scenario world represents a different energy system pathway oriented on two main axes: speed of decarbonization and level of societal change. These scenario worlds illustrate a view of future energy system changes for a given set of economic, social and policy assumptions. Three of the scenario worlds reach net zero emissions by 2050.

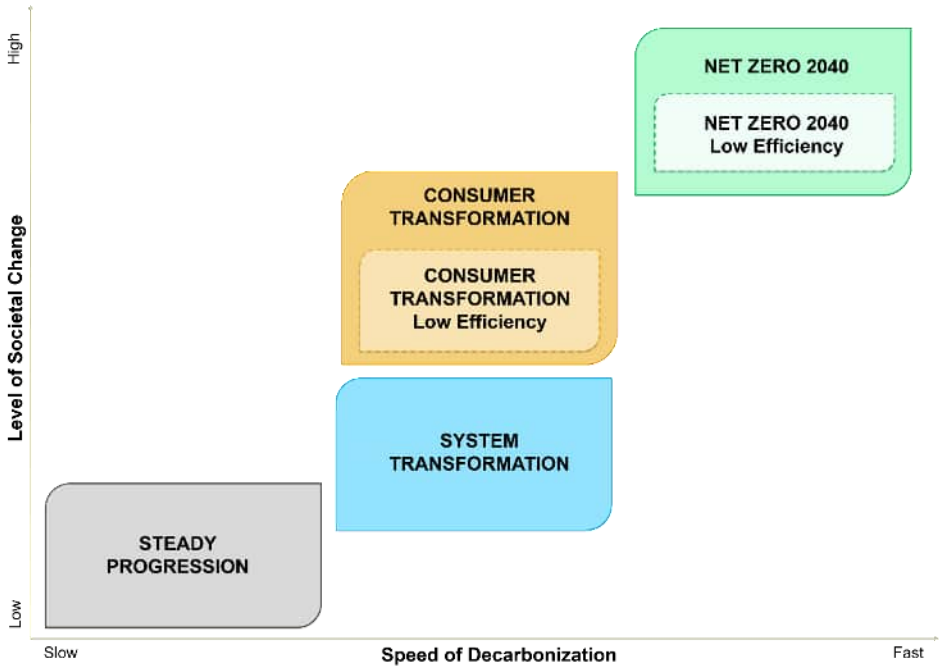

Figure 1: Scenario worlds defined by two axes: speed of decarbonization and level of societal change

The four scenario worlds are structured as follows:

- **Steady Progression** is a low-ambitious electrification scenario that makes general progress towards decarbonization but falls short of the net zero 2050 goal. This scenario reflects minimal consumer behaviour change and is the slowest decarbonization scenario.
- **System Transformation** is a top-down scenario driven by policy-makers. It entails high levels of transportation electrification, but lower levels of heating electrification, energy efficiency and DERs.
- **Consumer Transformation** is a scenario in which consumers play a more prominent role in driving results. In addition to high levels of transportation electrification, there are high levels of heating electrification, energy efficiency and DERs. **"Low Efficiency" Consumer Transformation** is a modified scenario where the uptake of efficiency measures (including building retrofits and DERs) is limited. This sensitivity analysis provides a helpful view into the potential impact of energy efficiency on the distribution grid.

- **Net Zero 2040** is the highest ambition scenario, which is focused on meeting key policy targets early. This scenario aligns with the City of Toronto's TransformTO net zero 2040 goals, and leverages highly ambitious levels of efficiency, electrification, and DERs. **"Low Efficiency" Net Zero 2040** is a modified scenario where the uptake of efficiency measures (including building retrofits and DERs) is limited.

The low efficiency modified scenarios for Consumer Transformation and Net Zero 2040 scenarios couple high electrification with a limited uptake of technologies and strategies which are able to mitigate peak demand growth. These sensitivity analyses provide a helpful view into the potential impact of energy efficiency on the distribution grid, as well as insight into the highest levels of demand that Toronto Hydro's system could face in the journey to decarbonize by 2050.

2.1 Future Energy Scenarios Driver Projections

Each scenario world was constructed by combining uptake forecasts for a number of individual drivers of growth, generation, flexibility and efficiency. Each driver was modelled separately on a Low/Medium/High/Very High basis and then mapped to the scenario worlds. Table 1 shows the calibration of the various drivers for each scenario world. The sections that follow describe the drivers in more detail. For an in-depth explanation of each of the growth driver uptake scenarios, refer to the Future Energy Scenarios report at Exhibit 2B, Section D4, Appendix B.

Table 1: Growth, Generation, Flexibility and Efficiency Drivers within Scenario Worlds

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Net zero by 2050?	No	Yes	Yes		Yes (by 2040)	
Core Demand						
Electrical efficiency	Low	Medium	High	Low	High	Low
Building stock growth	Single Projection					
Low-Carbon Transport						
Cars and light trucks	Low	Medium	Medium		High	
Medium/heavy trucks and Buses	Low	Medium	Medium		High	
Rail	Single Projection					

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Smart charging / V2G	Low	Medium	High	Low	High	Low
Decarbonized Heating						
Heat pumps	Low	Medium plus hybrid HPs	High		Early High	
Thermal Efficiency	Low	Medium	High	Low	Very High	Low
Gas heating in 2050	High	Medium due to hybrid HPs	Zero		Zero	
Gas grid availability	Remains at current availability	Reduced utilization	Decommissioned by 2050		Decommissioned by 2040	
Gas grid composition	Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas	Shift to biogas, SNG, or other renewable natural gas	Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas until 2050		Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas until 2040	
Distributed Generation						
Solar PV	Low	Medium	High	Low	Very High	Low
Onshore wind	Low	Medium	High	Low	High	Low
Biogas	Low	Medium	High	Low	High	Low
Other non-renewable generation	High	Medium	Medium	High	Low	High
Battery Storage						
Domestic battery storage	Low	Medium	High	Low	Very High	Low
I&C behind-the-meter battery storage	Low	Medium	High	Low	High	Low

2.1.1 Core Demand

The majority of current electricity demand within Toronto can be categorized as underlying demand from domestic customers and industrial and commercial ("I&C") customers. Underlying demand refers to all electricity usage relating to existing appliances, including electrical heating or cooling, but excludes demand from new low carbon heating technologies such as electric vehicle charging or heat pumps. The latter are modelled as separate segments.

Collectively this underlying demand from these two sectors is referred to as the "core demand". Future core demand for these two sectors is primarily controlled by two key variables:

The total number of customers connected to the system – which is controlled by the size of the building stock (number of buildings); and

The energy intensity of the customers within those properties – which is assumed to be controlled by the uptake and efficiency of customer appliances.

2.1.2 Low-Carbon Transport

Future Energy Scenarios created consumer-choice uptake scenarios for electric vehicles across the following transport segments:

- Light duty battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV);
- Medium and heavy-duty electric vehicles;
- EV buses; and
- Electrified rail.

The low, medium and high scenarios were developed for each vehicle segment based on factors such as vehicle attributes (i.e. price, running cost, performance), consumer attributes (i.e. travel and charging patterns, socio-economic factors), charging infrastructure, and policy and incentives (i.e. grants, carbon tax, phase-out dates etc.).

2.1.3 Decarbonized Heating

Heating is modelled by assessing the business case for various heating technologies across the domestic and I&C building stock types. Future Energy Scenarios considered the following heating technology types in the modelling:

- Traditional fossil-fuel heating technologies (natural gas boiler, natural gas furnace, oil and LPG burners and coal burners);
- Air source heat pump;

- Ground source heat pump;
- Hybrid heat pump;
- Biomass furnace/boiler, and
- Electric heater.

Uptake and efficiency of the heating technologies is varied across the scenarios to represent the possible futures depending on costs, incentives, thermal efficiencies, technological development, and consumer behaviour.

2.1.4 Distributed Generation, Storage, and Flexibility

A broad range of distribution-level generation, storage, and flexibility technologies were considered as part of Future Energy Scenarios. Figure 2 below depicts the total set of technologies modelled. For each technology, four scenarios were developed (low, medium, high, and very high) to include the range of possible future scenarios. Based on technology suitability, system needs, supporting policies, and financial incentives, there are three dominant generation technologies for Toronto: solar PV (both rooftop and ground-mounted), non-renewable generation, and energy storage.

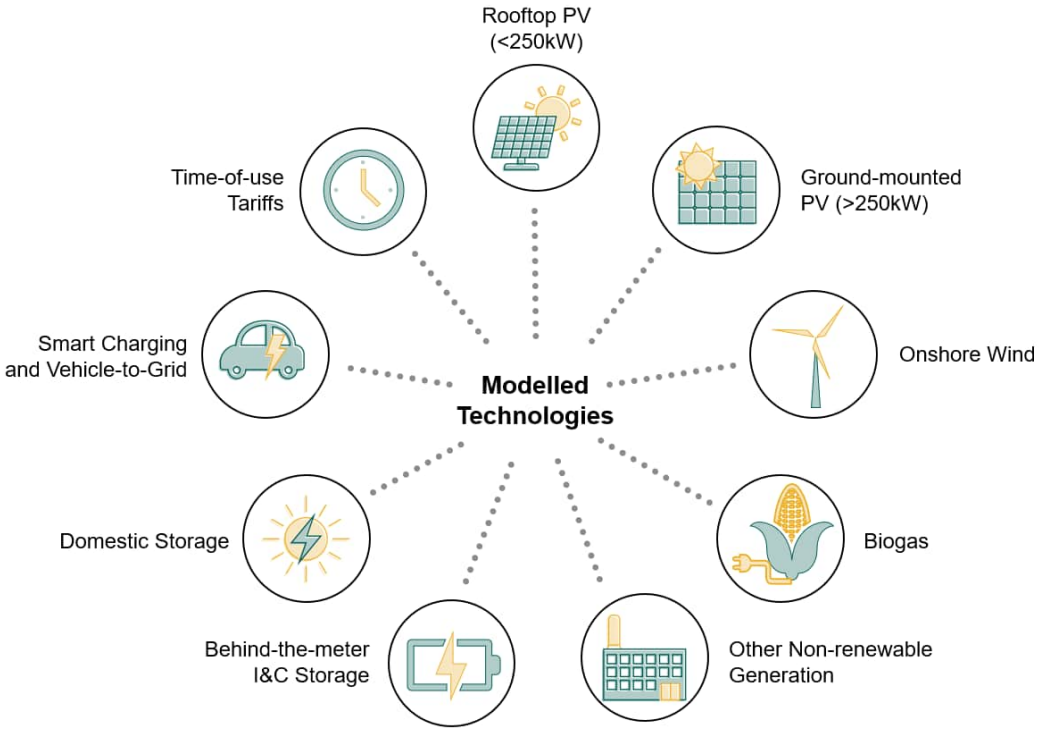

Figure 2. Distributed Generation, Storage, and Flexibility Technologies

2.2 System Impacts

The projected trends in technology adoption spanning energy demand, generation and storage in the Future Energy Scenarios were used to determine the associated load impacts across Toronto Hydro's distribution system.

The Future Energy Scenarios datasets were loaded into the model to create projections for the changing demand and generation on the system out to 2050. In order to provide a complete picture of the potential changes on the system, the Future Energy Scenarios model projects the annual consumption and peak electricity demand for the system's 88 terminal station bus pairs, as well as the total across all of Toronto Hydro's service area. In addition to producing the total peak demand for each asset, the model can also show the contribution of each technology to the peak. This enables a more complete understanding of the drivers behind changes in loading across the distribution system.

Figures 4 and 5 show the resulting peak system load for Toronto Hydro. The two most ambitious decarbonization scenarios (Consumer Transformation and Net Zero 2040) have the lowest peak demands by 2050 when the full benefits of appliance and building fabric efficiency measures, demand side flexibility, and renewable generation are realized. In the absence of these benefits being realized, the system peak loads by 2050 would be significantly higher, as illustrated by the two dashed lines for Consumer Transformation Low and Net Zero 2040 Low shown in Figures 3 and 4. The Low Efficiency scenario worlds are critical for considering Toronto's energy future, as they illustrate that a material reduction in peak demand can be achieved through the ambitious deployment of passive efficiency measures, renewable generation and active demand management.

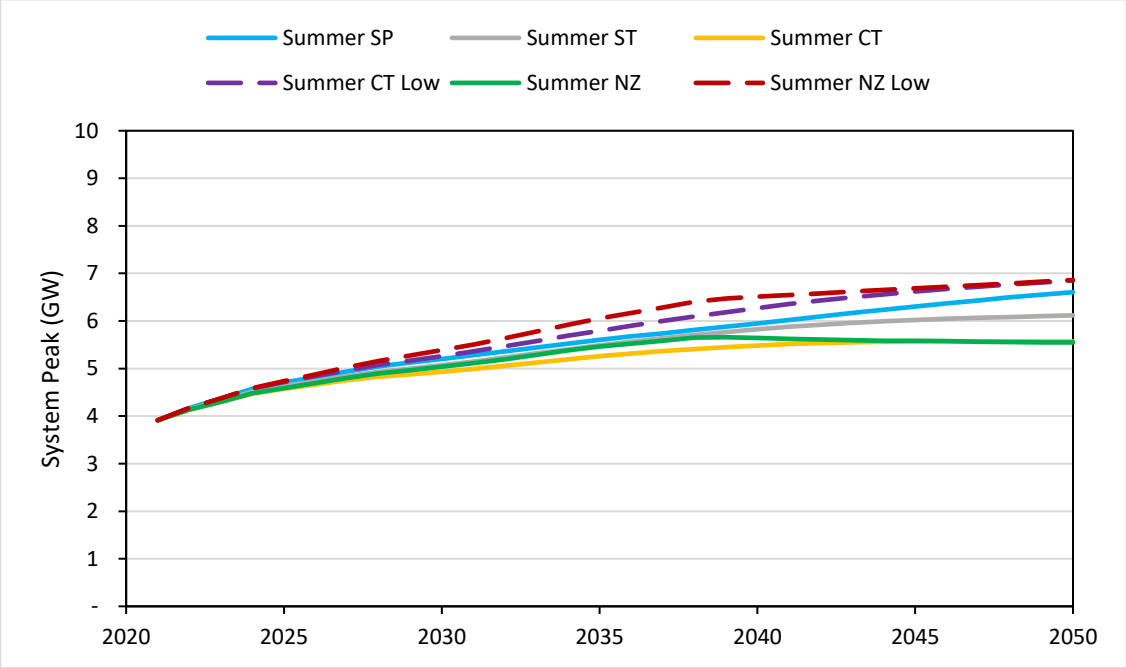

Figure 3: Summer System Peak for Scenario Worlds

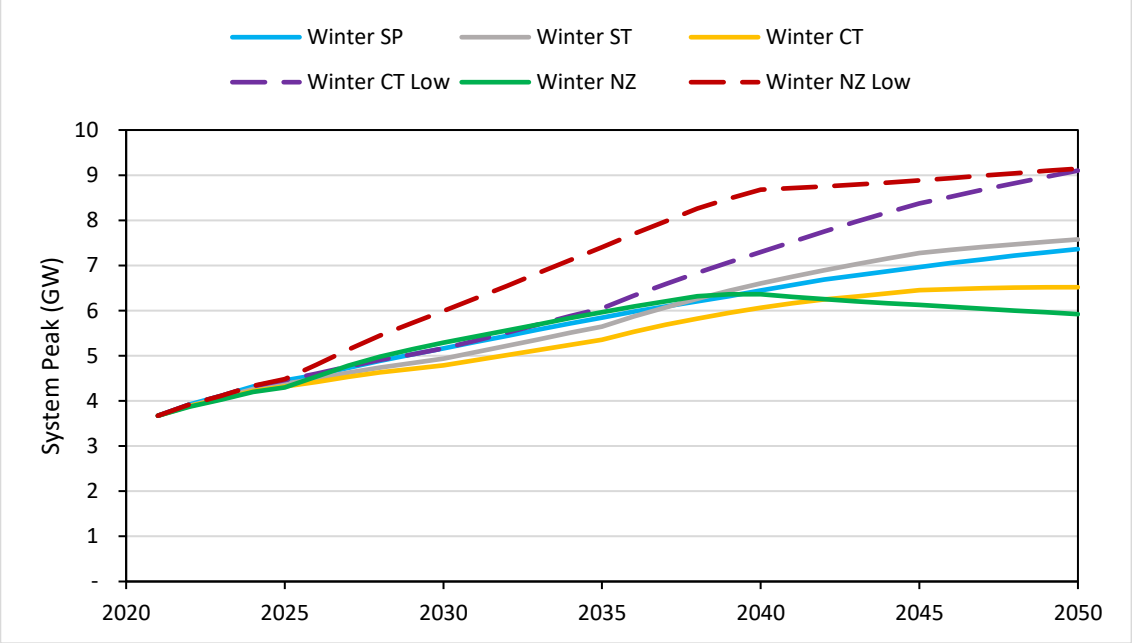

Figure 4: Winter System Peak for Scenario Worlds

3 Future Energy Scenarios – Key Takeaways

The Future Energy Scenarios confirms that Toronto can expect significant changes to its energy system resulting from electrification, renewable generation deployment, and improvements in energy efficiency. Peak demand increases are expected to be primarily driven by the electrification of the heating and transport sectors, due to the widespread uptake of technologies such as electric vehicles and heat pumps.

The nature of load changes on the distribution system varies considerably over the modelled time period. In the 2020s, electricity load growth is very similar across all scenario worlds, indicating that reinforcement is likely to be required regardless of the what pathway of decarbonization is chosen by consumers or governments. The 2030s sees the system peak shift to winter with loads increasingly being driven by heat pump uptake and EVs. In this decade, load growth also starts to diverge across the scenario worlds, highlighting the need for early planning and capacity investments to ensure the distribution system is prepared for both near-term and long-term energy system changes.

The Future Energy Scenarios also highlight the need for changes to generation, storage, and energy efficiency to happen in parallel with electrification of demand. All of the core scenario worlds assume that efficiency improvements increase significantly from the present day, continuing to reduce energy consumption in future years. Without such changes, grid demands are expected to increase more extremely, as demonstrated by the two “Low” scenario worlds shown in Figures 3 and 4.

Future Energy Scenarios



Report for Toronto Hydro by

Element Energy, an ERM Group company

30th May 2023

elementenergy
an ERM Group company

ERM

TORONTO HYDRO

Executive Summary

Introduction

The complexity of distribution system load forecasting is increasing significantly due to factors such as decarbonization, decentralization, digitization, changing customer behaviours and evolving economic and policy conditions. Significant changes in demand, generation and flexibility on electricity distribution networks are affecting network management and planning. New demands emerging from the electrification of heat and transport, growing levels of distributed generation (including variable renewable generation) and new sources of load flexibility (including energy storage) mean that local electricity distribution companies, such as Toronto Hydro, are facing increasing levels of uncertainty.

Element Energy, an ERM Group company, is a leading low carbon energy consultancy with considerable experience in supporting electricity distribution businesses, particularly in relation to their future energy scenario planning and load projections. Through extensive previous work in this area, Element has developed a modern, state-of-the art tool known as the Future Energy Scenarios (FES) Model. This tool is in active use across various electricity distribution companies and, as such, is fully equipped with the latest innovations in the field. The FES model has a strong track record of active use within the industry, including for the creation of various statutory outputs and reports under the scrutiny of the relevant energy regulators due to its base in robust modelling methodologies.

This report presents the Future Energy Scenarios prepared by Element Energy for Toronto Hydro and is the first of its kind for distribution companies in Canada. The Future Energy Scenarios provide an overview of possible future changes to power demand, energy consumption, generation and storage across Toronto and an assessment of their potential impacts on the Toronto Hydro electricity distribution network. This is predicated upon a highly granular consumer choice-based analysis of future loading conditions at each individual transformer station bus, providing a strong evidence base for network planning and the evaluation of future infrastructure investments. This establishes a common strategic outlook to support forecasting needs across different Toronto Hydro business functions and various stakeholder engagement and regulatory reporting requirements.

The report first provides an outline of the scenario framework used for the Future Energy Scenarios and introduces the concept of ‘scenario worlds’. This is followed by an overview of the modelling methodology, focusing on the consumer choice models utilized by Element Energy. Next, the report details how these models were used to develop future uptake scenarios for each of the drivers of demand and generation considered in the FES Model. These drivers include, for example, electric vehicles (EV), energy efficiency measures and solar photovoltaic (PV) installations. Following this, the methodology for modelling the network impacts of these changes is introduced and key results are presented. Finally, the report presents the conclusions drawn from this work.

Scenario Framework

Projections were developed using Element Energy’s suite of bottom-up consumer choice and willingness-to-pay models. These were informed by a comprehensive investigation into the current state of the energy landscape in Toronto, including reviews of previous studies, datasets, and policy. To capture the range of uncertainties in a coherent and meaningful way, four main ‘scenario worlds’ were developed, consisting of individual projections for different technology sectors. The scenario worlds represent different energy system pathways, three of which reach net zero emissions by 2050, and illustrate the best view of future energy system changes for a given set of economic, social and policy assumptions. At a high level, the four scenario worlds differ in terms of the speed of decarbonization and level of societal change they represent, as illustrated by Figure 1.

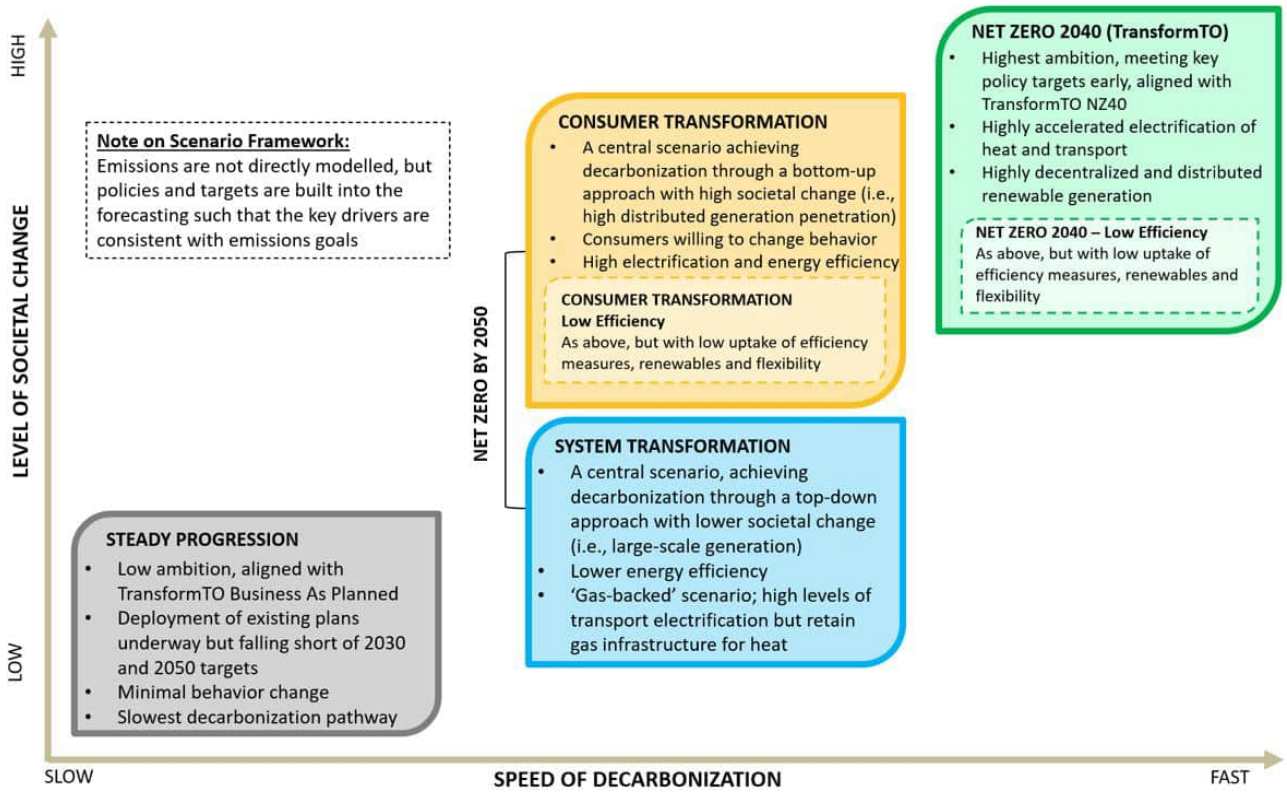

Figure 1: Scenario worlds defined by two axes: speed of decarbonization and level of societal change.

Each of the four scenario worlds consist of a unique combination of uptake trends for all the individual drivers of demand and generation in Toronto, such as electric vehicles, heating, solar PV and core demand. Element Energy's bottom-up consumer choice models produced three to four scenarios for every demand and generation driver, representing a range of possible futures for each technology. Based on the assumptions contained within them, these were then mapped to the overarching scenario worlds shown in Figure 1, so that each scenario world contains one scenario per technology.

The scenario worlds used in this work were developed through an assessment of existing sources that focus on the future of low carbon technologies in Canada[1], Ontario[2], and Toronto[3], as well as through engagement with Toronto Hydro's internal and external stakeholders. The most significant of the existing sources was TransformTO, the climate action strategy developed by the Toronto City Council, which similarly defines four scenarios of varying levels of ambition, including targets to be achieved in key sectors such as buildings, transportation, and generation. In contrast to the consumer choice-based modelling employed in the Future Energy Scenarios presented in this report, the development of the TransformTO scenarios placed a more explicit focus on greenhouse gas reduction, looking at the overall requirements necessary to meet local decarbonization targets. The TransformTO scenarios were used as a reference point to define the overall level of ambition modelled in the four Future Energy Scenario worlds shown in Figure 1. The *Business as Planned* scenario from Transform TO was used as a template for the lower ambition *Steady Progression* scenario world, which involves progressing with existing plans for decarbonization and sees some level of emissions reduction without reaching net zero by 2050. The *Net Zero 2050* scenario from Transform TO was used as a basis for the two central scenario worlds, *Consumer Transformation* and *System Transformation*, both of which reach net zero by 2050 but vary in levels of societal change and electrification. Finally, the TransformTO *Net Zero 2040* scenario was the foundation for developing the highest ambition scenario world which sees significant levels of electrification, behaviour change and efficiency.

[1] CER, Canada's Energy Future, 2021
[2] IESO, Annual Planning Outlook, 2022
[3] City of Toronto, TransformTO, 2021

Using this approach, the scenario worlds were able to capture local considerations of the energy transition that are specific to Toronto, whilst leveraging a robust and proven framework for network planning and load modelling. The four scenario worlds are structured as follows:

1. **Steady Progression:** Some progress is made towards decarbonization; however, this is the only scenario world that does not meet net zero by 2050.
2. **System Transformation:** The 2050 net zero target is met through a top-down approach with lower societal change and retention of the gas grid for biogas and renewable natural gas (RNG).
3. **Consumer Transformation:** The 2050 net zero target is met by a high degree of societal change as well as deep electrification of transport and heat in the standard scenario world.
    - **"Low Efficiency" sensitivity** – the uptake of electrified heat and transport technologies is the same as in the main Consumer Transformation world, but in this sensitivity the uptake of efficiency measures (building fabric & appliance), flexible technologies such as battery storage, and distributed renewable generation is limited.
4. **Net Zero 2040:** This is the fastest of the scenario worlds to achieve net zero, with the most ambitious level of societal change, utilizing both biogas and electric low-carbon technologies.
    - **"Low Efficiency" sensitivity** – Similar to the Consumer Transformation sensitivity described above, in this sensitivity the uptake of demand technologies is the same as in the main Net Zero 2040 world, but the uptake of efficiency, flexibility and distributed renewable generation is limited.

The low efficiency sensitivity cases described above for the Consumer Transformation and Net Zero 2040 scenarios couple high electrification with a limited uptake of technologies which are able to mitigate peak demand growth, and therefore provide insight on the highest loads which might be expected on Toronto Hydro's network to 2050.

Modelling Framework

The Future Energy Scenarios capture potential changes across a broad range of key sectors that are expected to impact upon network load. As described above, the projections were created using Element Energy's technology specific bottom-up consumer choice and willingness-to-pay models, which are based on a rigorous understanding of underlying technology costs, consumer behaviour and wider energy market drivers. In building these consumer choice models, historic deployment rates of technologies are analyzed to determine uptake levels, which are used to calibrate the model.

Where consumer choice modelling is applied within the Future Energy Scenarios, discrete choice modelling[4] is utilized. This is based on the concept that consumers try to maximise their 'utility', which is a monetized indicator representing the value of a technology to a consumer. Discrete choice models assess the perceived value to consumers of a range of competing technologies.

For example, in the case of different heating technologies, homeowners have to make a decision when replacing their old heating technology (e.g. a gas furnace) at the end of its life with a new technology (e.g. a heat pump, an electric heater or a new gas furnace). When making this decision, a customer would likely consider various factors including the upfront cost of the technologies, their running costs, the complexity of installation and the suitability of each technology for their property before reaching a decision. Discrete choice models convert the value of these factors to consumers into an equivalent monetary value, or 'utility', so that they can be compared quantitatively. This process is shown in Figure 2.

[4] Kenneth E. Train, Discrete Choice Methods with Simulation, 2002

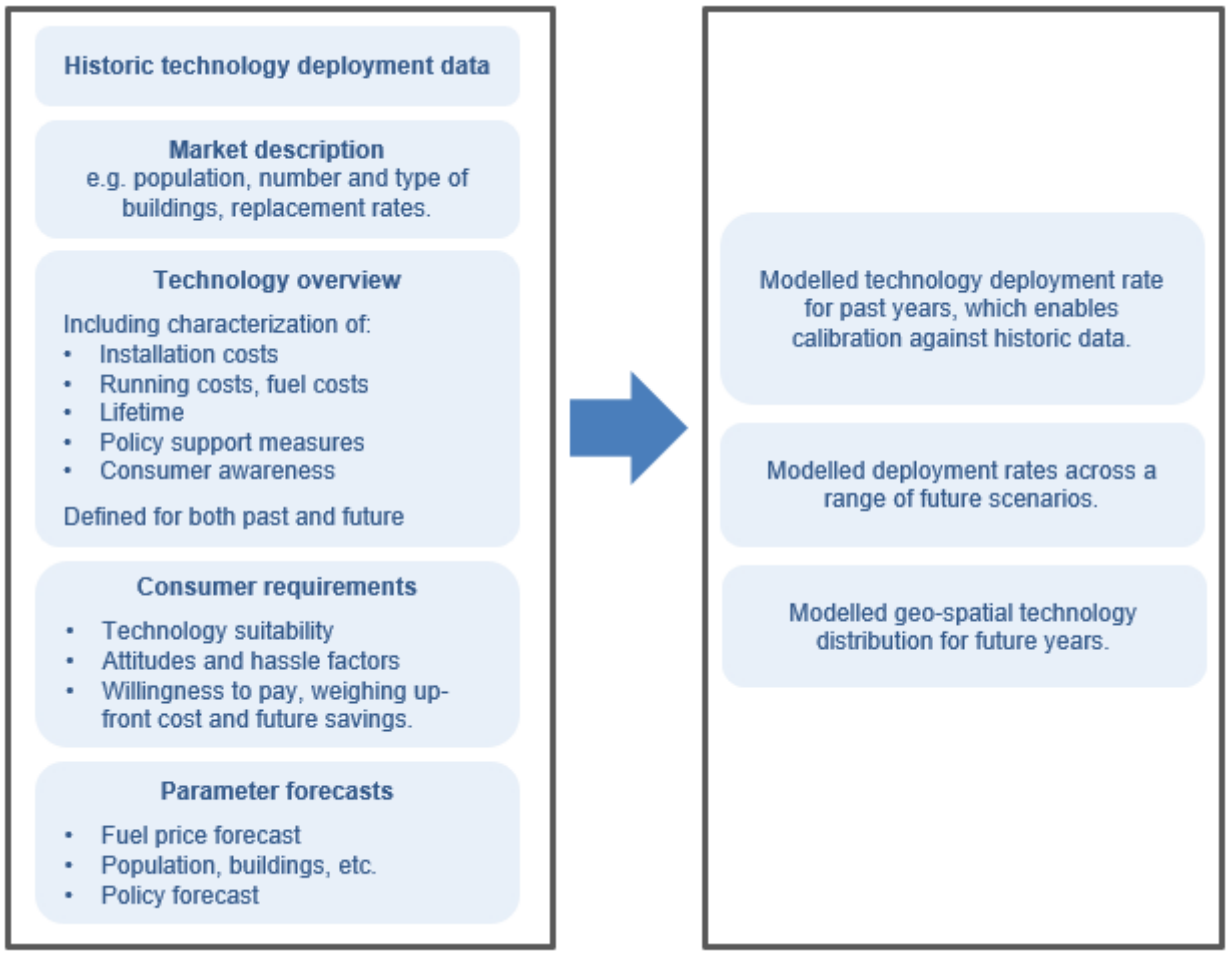

Figure 2: General approach to modelling future technology deployment.

The consumer choice models utilized in this work have been tailored to Toronto Hydro's network area to take into account specific local factors, such as policy measures (e.g. the Canada Green Homes Grant) and the breakdown of vehicle stock. Additionally, the modelling considers local geography when distributing demand and generation across the region, such as a detailed look at potential electric vehicle charging locations.

Development of Demand and Generation Driver Projections

Modern electricity networks supply energy to homes and businesses to service a broad range of applications. In this analysis, the electricity provided for most conventional applications is referred to as "core demand". At present, the majority of energy used for both transport and space heating is derived from non-electrical energy vectors (such as gasoline and diesel for transport, or natural gas for space heating). As part of the decarbonization of transport and space heating, there is potential for a significant level of electrification to occur across these sectors making them particularly important areas of analysis for electricity network planning and load modelling. As such, transport and space heating are each modelled separately to "core demand" in this analysis to support a more detailed understanding of potential future demands from these technology segments.

Similarly, increasing levels of distributed electricity generation (e.g. from solar PV, wind, etc.) also play an important role in modelling future loading across electricity networks as net zero strategies are implemented. Hence this analysis also explores the impact of distributed generation from a variety of technology options on future network loads under a range of scenarios.

As the energy provision of the distribution network grows due to factors such as the electrification of heat and transport as well as increasing distribution electricity generation, the peak instantaneous power demand experienced by the network generally also increases. To help reduce the amount of network reinforcement

required to accommodate increases in peak demands across the electricity network, several flexibility options exist which help to move demand at peak times to different times of the day. This analysis captures the impact of flexibility options such as energy storage as well as smart charging and vehicle-to-grid (V2G) options for electric vehicles. Energy storage is modelled as a distinct technology segment which can help to shift peak power loads by charging when demand is low and discharging when demand is high. Similarly, smart charging and V2G chargers can help to shift loads from EVs. Respectively, these act by managing when car batteries charge and enabling cars to discharge to the network at times of high demand, effectively acting as grid storage units. Without such management of charging, the demand from electric vehicles typically spikes during times of high network demand, contributing to high overall peaks at an asset and system level. Charging flexibility measures are captured within the modelling of transport demand by assuming different uptakes of smart charging and V2G in each scenario, and applying distinct load characteristics for each type of charging behavior.

The key sectors investigated in this analysis were core demand, heating, transport, generation, and energy storage via 17 unique technology segments and 72 different customer archetypes or classes. Analysis of each technology segment was carried out to a high level of geo-spatial granularity in order to assess the impact on each of the 88 individual transformer station buses selected for analysis within Toronto. Demand increases are expected to be driven primarily by the heating and transport sectors as a result of widespread electrification via the uptake of technologies such as EVs and heat pumps. Renewable generation projections in Toronto are dominated by solar PV, while energy storage is anticipated to play a role in domestic, industrial and commercial settings.

Load impacts of the demand, generation and storage sectors discussed above are aggregated to determine the total energy consumption and peak demand for each individual asset. This facilitates an assessment of when each asset may exceed its rated capacity, and by how much. This is a critical process for informing network planning and allowing Toronto Hydro to assess the costs and timescales of possible future infrastructure upgrades.

The modelling used to generate the Future Energy Scenarios for Toronto Hydro also highlights the importance of government policies in helping to achieve the relevant net zero targets in each case and further details of the illustrative policy assumptions that were utilized for each of the technology uptake projections are included in this report. The models used throughout the analysis can be updated to reflect future policy developments and market changes which will influence the uptake of low carbon technologies.

Network Impacts

The projected trends in technology adoption spanning energy demand, generation and storage in the Future Energy Scenarios were used to determine the associated load impacts across the Toronto Hydro distribution network.

The Future Energy Scenarios datasets were loaded into Element Energy's FES Model to create projections for the changing demand and generation on the network out to 2050. In order to provide a complete picture of the potential changes on the network, the FES model projects the annual consumption and peak electricity demand for the 88 assets on the network as well as the total across all of Toronto Hydro's service area. In addition to producing the total peak demand for each asset, the model can also show the contribution of each technology to the peak. This enables a more complete understanding of the drivers behind changes in network loading across Toronto.

The load modelling process used by the FES Model can be divided into four main calculation stages as illustrated in Figure 3: technology counts; annual consumption and generation; profile shapes and peak demand; and scaling calibration.

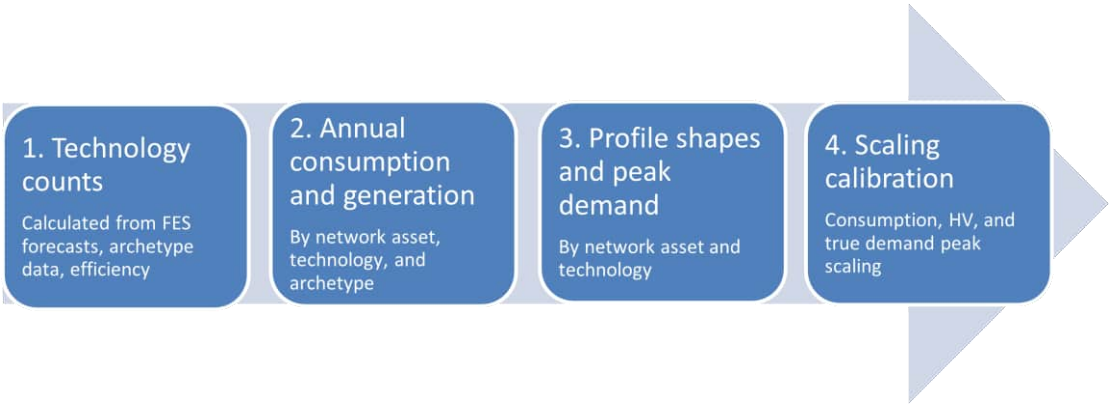

Figure 3: The main stages of the load modelling process.

Technology counts define the quantity of each technology in a given year, and their distribution across the network; in the cases of generation and storage technologies, these figures are given in terms of connected capacity rather than number of units. These figures are used, along with data regarding the characteristics of each technology, to calculate the energy consumption and generation values (MWh) each year. Peak power demand and generation (MW) is subsequently established through the application of load profiles, which describe how the energy consumption/production of each technology is distributed across the year, defined for each month at a half-hourly resolution (Figure 4). Finally, the scaling step calibrates modelled results by aligning them with real network load data for the base year provided by Toronto Hydro.

Applying load profiles to annual consumption shows how power demand for each technology varies across every modelled year. These power demands can then be summed across all relevant technologies to find the overall demand at every transformer station bus at any given time of day across the year. From this, the peak demand can be determined by extracting the maximum power value from any given year. A similar process is performed to find system peak, whereby the power demand from each asset is aggregated and the maximum value is again extracted. Load profiles are also used in the FES model to capture the impacts of flexibility measures. For example, the FES model applies distinct load profiles for smart charging and V2G that reflect how electric vehicles are able to shift charging demand away from times of peak load.

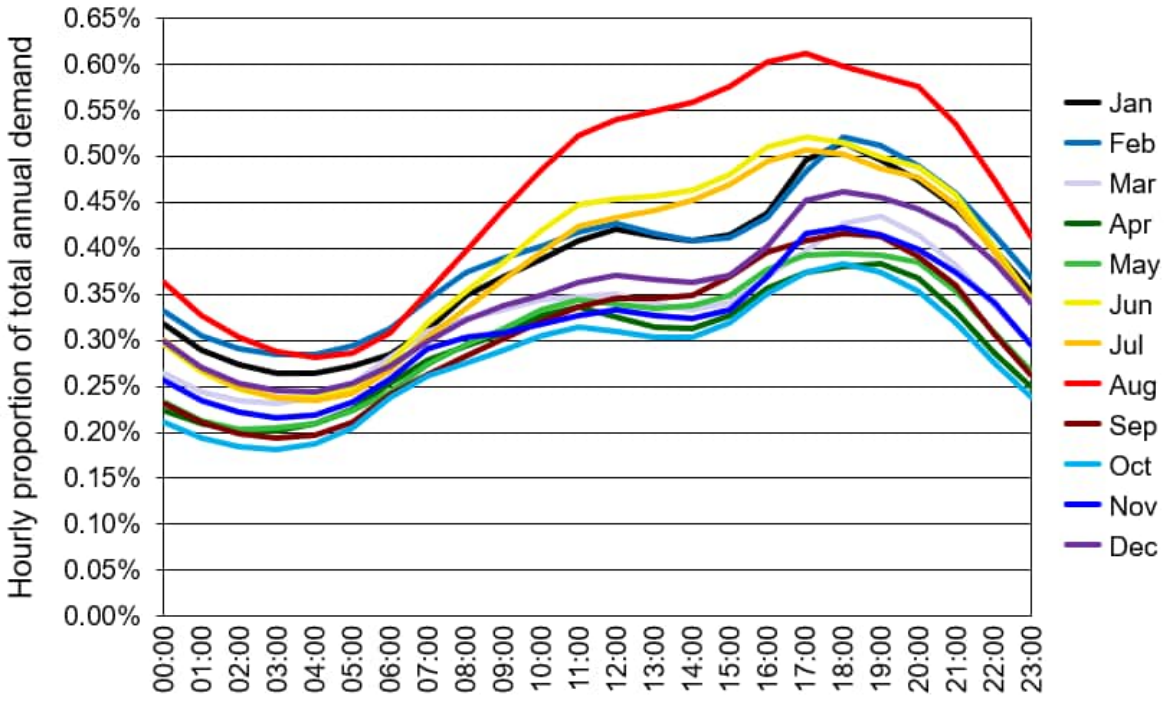

Figure 4: Example load profile: load profiles for domestic core demand.

The resulting peak network load for Toronto Hydro is shown in Figure 5, which illustrates how the two most ambitious decarbonization scenarios (Consumer Transformation and Net Zero 2040) have the lowest peak demands by 2050 when the full benefits of appliance and building fabric efficiency measures, demand side flexibility and renewable generation[5] are realised. If this is not the case, the network peak loads by 2050 are expected to be significantly higher, as illustrated by the two dashed lines for Consumer Transformation Low and Net Zero 2040 Low shown in Figure 5. The Low Efficiency scenario worlds are critical for considering Toronto's energy future, as they illustrate that a material reduction in absolute peak demand can be achieved through the ambitious deployment of passive efficiency measures, renewable generation and active demand management. This demonstrates the potential to avoid significant reinforcement costs and disruption throughout Toronto Hydro's network while pursuing decarbonization.

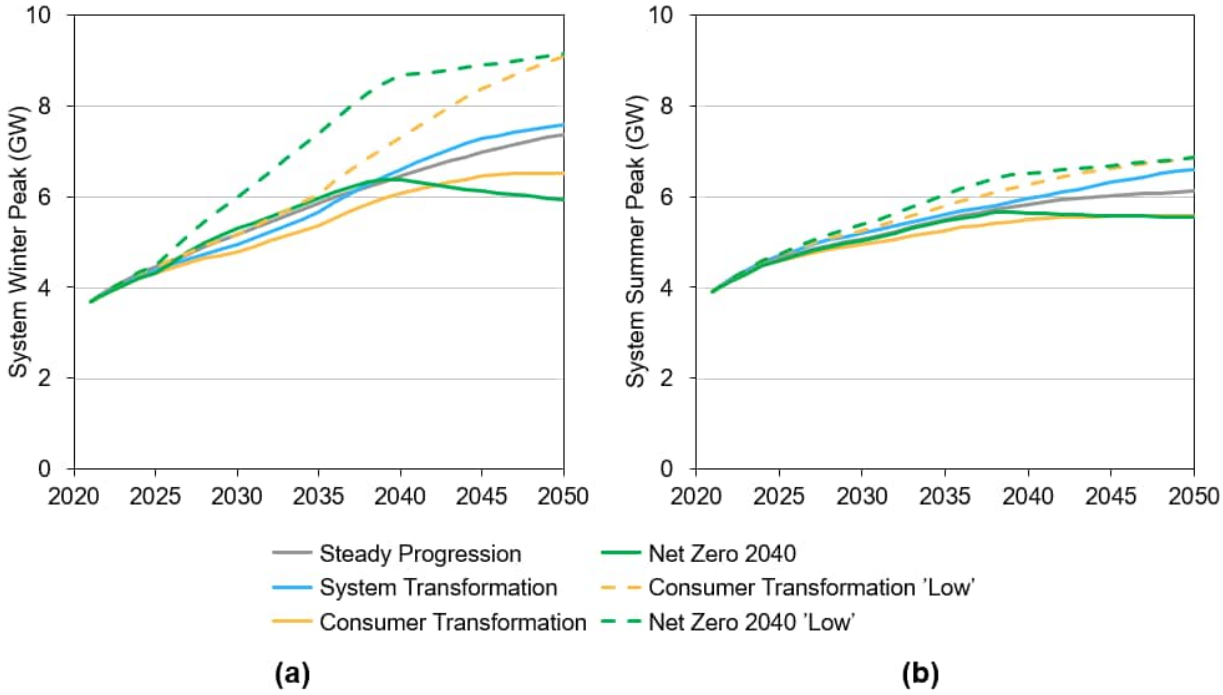

Figure 5: Network peak true demand in (a) winter and (b) summer in the four scenario worlds and two sensitivity scenarios.

In the base year, peak loads are expected to be higher in summer (3.9 GW) than in winter (3.7 GW), primarily due to high levels of air conditioning demand which constitutes a large portion of base core demand. In the 2020s, the network level load follows a similar trend in all scenario worlds, driven primarily by the connection of high voltage loads and uptake of electric heating. The 2030s see the time of network peak shifting to winter, with loads increasingly being driven by heat pump uptake and electric vehicles. As these technologies become more established, they are adopted in large numbers, especially in the more ambitious net zero compliant scenarios. These trends continue into the 2040s; however, increasing electricity demands are moderated by the uptake of renewable generation and storage, which also see an accelerated growth in the later years. The impact of efficiency measures is assumed to increase at an approximately constant rate over the full modelled timeline, with the more ambitious scenarios seeing a more rapid acceleration in the early years, followed by diminishing improvements in later years.

[5] Figure 5 shows the network-level peak *true demand* (i.e. gross), and so only the effect of behind-the-meter renewables (such as rooftop solar) would be seen in this plot. The sensitivity scenarios consider low uptake of both behind-the-meter and utility scale distributed generation.

Conclusions

This work has found that Toronto can expect significant changes to its energy system resulting from electrification, renewable generation deployment, and improvements in energy efficiency in every modelled scenario world. Peak demand increases are expected to be primarily driven by the electrification of the heating and transport sectors, due to the widespread uptake of technologies such as electric vehicles and heat pumps. For example, in all net zero compliant scenario worlds, the transport sector sees a full transition to electric vehicles across all vehicle types. Similarly, all domestic, commercial and industrial buildings are expected to derive heat from some form of electrified technology by 2050 in all of the net zero compliant scenario worlds.

The nature of load changes on the distribution network is expected to vary considerably over the modelled time period. In the 2020s, electricity load growth is very similar across all scenario worlds, indicating that reinforcement is likely to be required regardless of the chosen decarbonization approach. This highlights the need for early planning to ensure the distribution network is well-prepared for near-term energy system changes.

In the 2030s, uptake of electric vehicles and heat pumps begins to accelerate, causing a shift in the time of network peak from summer to winter. In the later years, the high peak demands caused by the electrification of heat and transport are moderated by the uptake of renewable generation and storage, which see accelerated growth in the 2040s. Future generation uptake is anticipated to be dominated by solar photovoltaics, which in some cases may be accompanied by domestic battery storage systems. Uptake of batteries by industrial and commercial customers is also expected to increase, helping to further alleviate grid constraints.

Another significant outcome of this work is the identification of the need for changes to generation, storage, and energy efficiency to happen in parallel with electrification of demand. All of the core scenario worlds assume that efficiency improvements increase significantly from the present day, continuing to reduce energy consumption in future years. Without such changes, grid demands are expected to increase more extremely, as demonstrated by the two sensitivity scenario worlds shown in Figure 5. These pathways would necessitate significantly higher levels of investment to upgrade assets across the network, showing the value of efficiency measures and demand flexibility.

Toronto Hydro's Future Energy Scenarios also highlight the importance of policy as a powerful tool in shaping the energy system. For example, in the low carbon heat uptake trends, the dominant factors in determining the uptake trajectories were the various assumptions regarding fossil fuel bans and financial incentives for cleaner technologies. This is of particular relevance as the Future Energy Scenarios demonstrate that policy support will be essential to the attainment of a 2040 or 2050 net zero target. There are many factors that can influence this at all levels of the energy system, but the modelling shows that policy is one of the higher impact options for accelerating the pace of change.

All scenarios modelled indicate a significant increase in peak demands across the Toronto Hydro network relative to current levels, highlighting the importance of early planning and preparation for the anticipated changes this will involve for the network. Figure 5 illustrates that the extent by which peak demands will increase across the network, particularly beyond 2030, is dependent on the pathway via which net zero targets are achieved. Further, the sensitivities applied to Consumer Transformation and Net Zero 2040 demonstrate the importance of efficiency measures, renewable generation and flexible demand technologies in limiting peak demand growth. Therefore, maintaining an up-to-date understanding of the latest government policies, technological advancements, evolving supply chains and changing consumer attitudes is crucial for planning the low-carbon energy transition. Regularly updating network projections with the latest available data and learnings is important for anticipating changes in technology deployment levels and the implications this will have for network planning as we transition to a low carbon future.

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Acronyms

AC	Air conditioning
ASHP ATA	Air-source heat pump: air-to-air
ASHP ATW	Air-source heat pump: air-to-water
BAP	Business as Planned (TransformTO Scenario)
BEV	Battery electric vehicle
BNEF	Bloomberg New Energy Finance
CDM	Conservation and Demand Management
CGA	The Canadian Gas Association
ECCo	Element Energy's Electric Car Consumer Model
EV	Electric vehicle
FES	Future Energy Scenarios
GSHP	Ground-source heat pump
HV	High voltage
Hybrid ASHP	Hybrid air source heat pump
I&C	Industrial and commercial
ICI	Industrial Conservation Initiative
IESO	The Independent Electricity System Operator
LDC	Local distribution company
LPG	Liquified petroleum gas
NAICS	North American Industrial Classification System
NZ40	Net Zero by 2040 (TransformTO Scenario)
OEB	Ontario Energy Board
PHEV	Plug-in hybrid electric vehicle
PV	Photovoltaic
RPP	Regulated Price Plan
RNG	Renewable natural gas
SUV	Sports utility vehicle
ToU	Time-of-Use
TTC	Toronto Transit Commission
V2G	Vehicle-to-grid
ZEV	Zero emissions vehicle

1 Introduction

The complexity of distribution system load forecasting is increasing significantly in Ontario and globally due to factors such as decarbonization, decentralization, digitization, changing customer behaviours and evolving economic and policy conditions. Significant changes in demand, generation and flexibility on electricity distribution networks are driving changes in how these networks are managed and how capacity, investment and revenue planning is implemented. New demands emerging from the electrification of heat and transport, growing levels of distributed generation including variable renewable generation, and new sources of load flexibility (including energy storage) mean that local electricity distribution companies, such as Toronto Hydro, are facing increasing levels of uncertainty.

In this context, Toronto Hydro and Element Energy have developed the Future Energy Scenarios to facilitate a more detailed understanding of how these various drivers will change and interact over time. By utilizing long-term scenario-based load modelling, Toronto Hydro is able to frame the range of potential developments and understand the conditions in which each is expected to take place. The scenario-based approach to load modelling also enables Toronto Hydro to test various sensitivities around future levels of demand, generation and flexibility to increase the robustness of Toronto Hydro's planning strategies.

1.1 Toronto Hydro

Toronto Hydro-Electric System Limited ("Toronto Hydro") is the electricity distributor licenced by the Ontario Energy Board to serve the City of Toronto. Toronto Hydro has approximately 787,000 residential, commercial and industrial customers and distributes about 18% of the electricity consumed in Ontario.

Toronto Hydro recognizes that the energy sector is on the cusp of transformative change. In order to tackle climate change through decarbonization, electricity is expected to serve critical new roles, including fueling transportation and buildings. Toronto Hydro also recognizes that the pace and timing of these changes will be driven by a complex interplay of technological developments, consumer choice and policy. While there is certainty that fundamental change is ahead, there is uncertainty about how that change will unfold (e.g. the pace and adoption of EVs and heat pumps, the role of low emission gas and the scale of local vs. bulk electricity supply). This reality means that system load forecasting is becoming more complex for distributors like Toronto Hydro and must manage various interlinked growth drivers in an environment of high uncertainty.

To help manage these challenges, Toronto Hydro engaged Element Energy to develop the Future Energy Scenarios model. The Future Energy Scenarios offer a range of plausible trajectories on the path toward decarbonization.

Toronto Hydro supported the development of the Future Energy Scenarios model by providing data and information to Element Energy, as requested. Toronto Hydro did not develop the Future Energy Scenarios model or underlying methodology and relied on Element Energy's experience and expertise to guide the project.

1.2 Element Energy

Element Energy, an ERM Group company, is a leading low carbon energy consultancy with considerable experience in supporting electricity distribution business, particularly in relation to their future energy scenario planning, projections and load modelling. We bring together a talented and dedicated team to address the problem of climate change and the transition to low carbon energy. We ensure our analysis is fully evidence based and provide grounded advice on what is required to achieve the change to zero carbon energy systems. We focus on enabling technological, social and policy solutions to the problem of climate change and planning for the impacts these solutions have on our changing energy networks.

The success of Element Energy's demand, generation, consumption, and customer load modelling tools is based on our commitment to ensuring that our high-resolution scenario load modelling tools and outputs are robust, easy to use, accurate and customized to the specific needs of each distribution business. With the changing requirements on electricity distribution networks and the impact of factors such as embedded

generation, energy storage, changing customer behaviour, new technology adoption, gas substitution, tariff reform and load control, we believe it is important to provide increased visibility of the impact of these factors under various future scenarios. This has necessitated the development of a robust, consumer choice-based load modelling approach that has the capability to produce reliable projections at a level of asset and customer resolution that has not previously been available to distribution businesses. We have implemented this approach for various distribution companies and other key stakeholders in the sector over the past 15 years and we bring the value of this experience and the existing tools and datasets we have developed to our work for Toronto Hydro.

Importantly, our extensive previous work in this area means that we have a modern, state-of-the art tool, the Future Energy Scenarios (FES) Model. This tool is in active use across various electricity distribution companies and, as such, is fully equipped with the latest innovations in this area, with a strong track-record of active use within the industry under the scrutiny and approval of the relevant regulators and associated reporting. The FES Model is also widely used by the various electricity distribution companies we work with to assess projections from their respective market operators and other key stakeholders in the sector.

1.3 Report Structure

This report provides an overview of the Future Energy Scenarios (FES) developed for Toronto Hydro. The report is structured to first outline the scenario framework and explain how individual scenarios are brought together to create four different possible future scenario worlds. Next, the report details how future scenarios were developed for each of the drivers of demand and generation considered in the FES. These drivers include, for example, the uptake of electric vehicles, energy efficiency measures and solar photovoltaic (PV) installations, etc. Finally, the report presents the key conclusions drawn from this work. The report is structured as follows:

Section 2 outlines narratives for four different future worlds and details how the different future scenarios for each of the key drivers are combined to produce these scenario worlds.

Section 3 explains the modelling framework, the application of bottom-up consumer choice approaches to developing uptake trends, and the customization process to capture local factors in Toronto.

Section 4 describes how the different individual uptake scenarios were developed for the key drivers of demand and generation, including the modelling methodology and the geospatial disaggregation across Toronto Hydro's operating region.

Section 5 presents the network impacts of the different scenario worlds, explaining why the trajectories follow different paths, and what this means in terms of real energy system developments.

Section 6 presents the conclusions drawn from this work.

2 Scenario Framework

The scenario framework is the method used by Element Energy to represent the range of uncertainties in the low carbon energy transition. This approach involves defining four **scenario worlds** that represent different energy system pathways, three of which reach net zero emissions by 2050. These pathways represent different positions on two main axes: speed of decarbonization and level of societal change (Figure 6Figure 6). Each of the four scenario worlds was constructed by combining uptake trends for all the individual drivers of demand and generation in Toronto, such as electric vehicles, heating, solar PV and core demand. To capture a broad range of different possible futures, three to four scenarios were produced for each driver and subsequently mapped to the scenario worlds (Table 1Table 1).

The scenarios worlds used in this work were developed through an assessment of existing sources that focus on the future of the low carbon transition in Canada[1], Ontario[2], and Toronto[3], as well as through engagement with Toronto Hydro's internal and external stakeholders. The most significant of the existing sources was TransformTO, the climate action strategy developed by the Toronto City Council, which similarly defines four scenarios of varying levels of ambition, including targets to be achieved in key sectors such as buildings, transportation, and generation. In contrast to the consumer choice-based modelling employed in the Future Energy Scenarios, the development of the TransformTO scenarios placed a more explicit focus on greenhouse gas reduction, looking at the overall requirements necessary to meet local decarbonization targets. Another key source was the framework used by the National Grid in the UK, which defines scenario worlds according to their level of societal change and speed of decarbonization. This framework served as a starting point for establishing, and visualizing, the difference between the scenario worlds, considering their positions on these two axes (Figure 6Figure 6).

A consumer choice-based approach was taken to modelling that aims to understand the types of customers across the network and thereby reflect the regional differences that may arise as part of the transition to a low-carbon society. The TransformTO scenarios were used as a reference point to define the overall level of ambition modelled in the four scenario worlds. The *Business as Planned* scenario from Transform TO was used as a template for the lower ambition *Steady Progression* scenario world, which involves progressing with existing plans for decarbonization and sees some level of emissions reduction without reaching net zero by 2050. The *Net Zero 2050* scenario from Transform TO was used as a basis for the two central scenario worlds, *Consumer Transformation* and *System Transformation*, both of which reach net zero by 2050 but vary in levels of societal change and electrification. Finally, the TransformTO *Net Zero 2040* scenario was the foundation for developing the highest ambition scenario world, which sees significant levels of electrification, behaviour change and efficiency.

Using this approach, the scenario worlds were able to capture local considerations of the energy transition that are specific to Toronto, whilst leveraging a robust and proven framework for network planning and load modelling. The four scenario worlds are structured as follows:

1. **Steady Progression:** Some progress is made towards decarbonization; however, this is the only scenario world that does not meet net zero by 2050.
2. **System Transformation:** The 2050 net zero target is met through a top-down approach with lower societal change and retention of the gas grid for biogas and renewable natural gas (RNG).
3. **Consumer Transformation:** The 2050 net zero target is met by a high degree of societal change as well as deep electrification of transport and heat in the standard scenario world.
    - **"Low Efficiency" sensitivity** – the uptake of electrified heat and transport technologies is the same as in the main Consumer Transformation world, but in this sensitivity the uptake of efficiency measures (building fabric & appliance), flexible technologies such as battery storage, and distributed renewable generation is limited.
4. **Net Zero 2040:** This is the fastest of the scenario worlds to achieve net zero, with the most ambitious level of societal change, utilizing both biogas and electric low-carbon technologies.
    - **"Low Efficiency" sensitivity** – Similar to the Consumer Transformation sensitivity described above, in this sensitivity the uptake of demand technologies is the same as in the main Net

Zero 2040 world, but the uptake of efficiency, flexibility and distributed renewable generation is limited.

The low efficiency sensitivity cases described above for the Consumer Transformation and Net Zero 2040 scenarios couple high electrification with a limited uptake of technologies which are able to mitigate peak demand growth, and therefore provide insight on the highest loads which might be expected on Toronto Hydro's network to 2050. Figure 6 shows a description and comparison of the scenario worlds, positioned relative to each other along axes denoting the requisite societal changes and the rate of decarbonisation achieved.

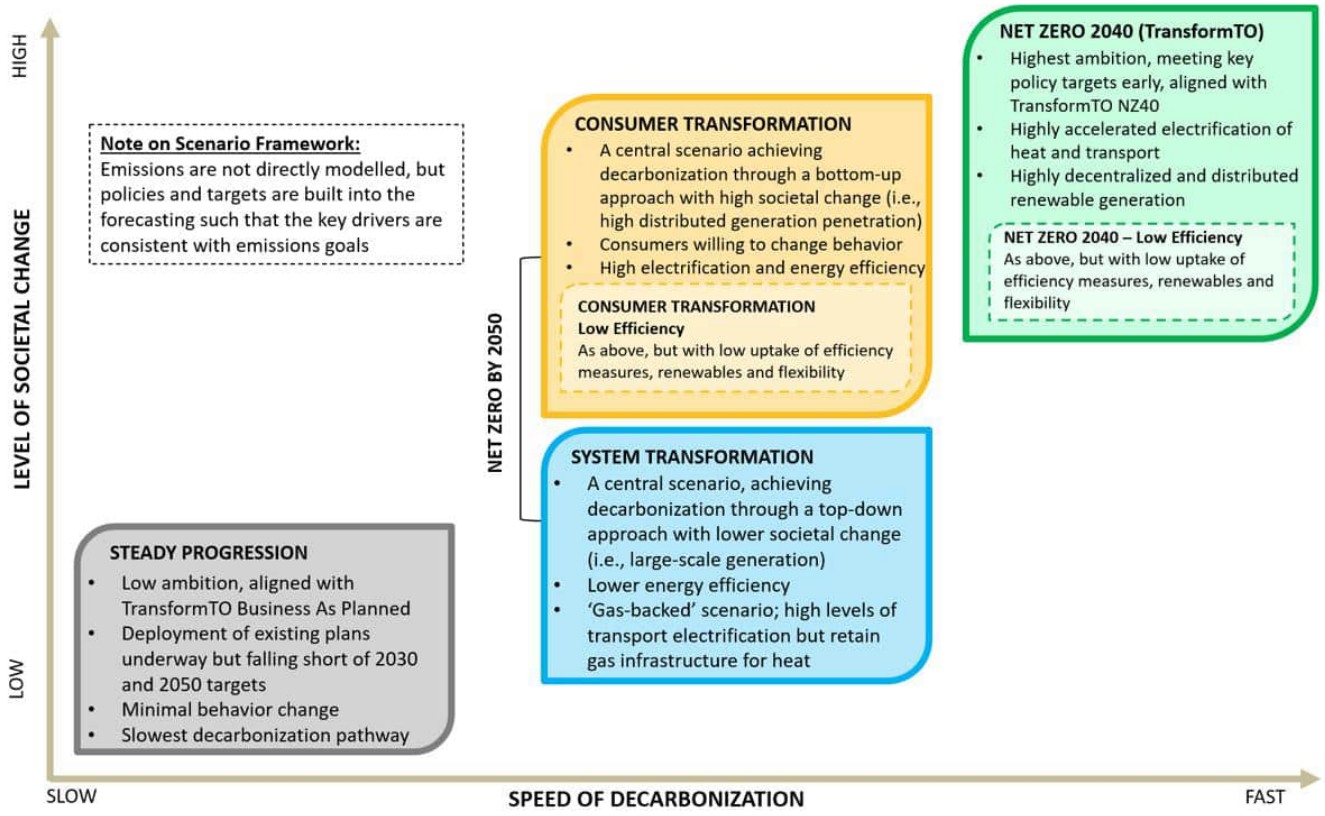


Figure 6: Scenario worlds defined on two axes: speed of decarbonization and level of societal change.

Table 1: Technology uptake scenarios that make up each of the four scenario worlds and the "Low" sensitivity cases applied to Consumer Transformation and Net Zero 2040.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Net zero by 2050?	No	Yes	Yes		Yes (by 2040)	
Core Demand						
Electrical efficiency	Low	Medium	High	Low	High	Low
Building stock growth	Single Projection					
Low-Carbon Transport						
Cars and light trucks	Low	Medium	Medium		High	
Medium/heavy trucks and Buses	Low	Medium	Medium		High	
Rail	Single Projection					
Smart charging / V2G	Low	Medium	High	Low	High	Low
Decarbonized Heating						
Heat pumps	Low	Medium plus hybrid HPs	High		Early High	
Thermal Efficiency	Low	Medium	High	Low	Very High	Low
Gas heating in 2050	High	Medium due to hybrid HPs	Zero		Zero	
Gas grid availability	Remains at current availability	Reduced utilization	Decommissioned by 2050		Decommissioned by 2040	
Gas grid composition	Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas	Shift to biogas, SNG, or other renewable natural gas	Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas until 2050		Mainly natural gas, with potential for biogas, SNG, or other renewable natural gas until 2040	
Distributed Generation						
Solar PV	Low	Medium	High	Low	Very High	Low
Onshore wind	Low	Medium	High	Low	High	Low
Biogas	Low	Medium	High	Low	High	Low
Other non-renewable generation	High	Medium	Medium	High	Low	High
Battery Storage						
Domestic battery storage	Low	Medium	High	Low	Very High	Low
I&C behind-the-meter battery storage	Low	Medium	High	Low	High	Low

2.1 Scenario World Overview

SP **Steady Progression**

The Steady Progression scenario world is aligned with the TransformTO *Business as Planned* (BAP) scenario, in which some progress is made towards net zero targets, but most sectors fall short of full decarbonization. This sees the deployment of existing plans but does not achieve 2030 and 2050 targets. The slow pace of change is largely a result of less ambitious energy policy and a lower level of consumer behaviour change.

By 2050, heating is still largely dominated by natural gas heaters, with a limited uptake of heat pumps and electric heating. There exists little policy to incentivize low carbon heating or to remove fossil fuel options from the market. In both domestic and I&C sectors, efficiency improvements are slow and capture only a basic level of home retrofit. The transport sector sees faster advancement in the low carbon transition, but still fails to fully decarbonize. The majority of cars and light trucks are electric by 2050, however uptake is inhibited by a lack of policy change and high battery prices.

Renewable generation sees a considerable increase from current levels, mostly driven by solar PV. However, wind and biogas generation see negligible uptake and renewable capacity still falls well below the levels required to replace non-renewable generation, which is not phased out.

ST **System Transformation**

System Transformation is a central scenario world that achieves decarbonization through a top-down approach, reaching net zero by 2050. This assumes lower energy efficiency, lower societal change, more large-scale generation, and retention of gas infrastructure for low carbon heating (RNG and biogas).

Heating is decarbonized primarily through electrification; however, a considerable portion of heating systems switch to hybrid heat pumps, making use of retained gas infrastructure. Electricity grid demand from heating is consequently lower, however, this is offset by relatively poor energy efficiency improvements. Heating projections were designed to align with the projections developed by the Canadian Gas Association.

Transport follows a full electrification pathway, with all vehicle types converting to electric powertrains by 2050 or before. These changes are driven by falling technology costs, an internal combustion engine vehicle ban in 2035, and a more ambitious carbon tax policy.

Distributed renewable generation capacity sees a moderate increase; however, electrification is assumed to be primarily facilitated by increases in larger transmission-connected generation. Similarly, grid flexibility sees some advancements, with vehicle-to-grid slowly replacing standard smart charging.

CT Consumer Transformation

Consumer Transformation is the second central scenario, achieving decarbonization primarily through bottom-up societal change rather than top-down system change. Shifts in consumer behaviour occur faster and earlier, with consumers increasingly prepared to engage with new smart technologies and flexibility markets. Widespread electrification is aided by high renewable generation penetration across the network, and steady improvements in energy efficiency.

Transport follows the same pathway as System Transformation, following a full electrification route that sees complete decarbonization by 2050. Similarly, the heating sector relies entirely on electrification, with ambitious policies introduced early on to incentivize heat pumps and ban fossil fuel systems. The gas grid is gradually decommissioned and, therefore, hybrid heat pumps are used only as a transition technology.

Since both heat and transport follow ambitious electrification pathways, electricity supply will need to scale up at a similar rate. Therefore, this scenario world sees a higher uptake in distributed renewable generation, driven primarily by falling technology costs. Non-renewables phase out completely by 2030, with this capacity replaced primarily by solar PV, wind, and biogas generation. Increases in generation are coupled with increases in efficiency, storage capacity and engagement in flexibility markets, facilitating a transition to a smarter energy system.

Consumer Transformation – Low Efficiency

The Low Efficiency sensitivity scenario is included to investigate the effects of coupling electrification on the scale of Consumer Transformation with low uptake of efficiency measures, flexibility and renewable generation. This will lead to higher peak loads and so provides useful insight for Toronto Hydro.

NZ2040 Net Zero 2040

Net Zero 2040 is the most ambitious scenario world and has been created to align with the TransformTO NZ2040 scenario. Key policy targets are met early, and electrification of heat and transport are accelerated such that full decarbonization is achieved by 2040. The approach taken is highly decentralized, with very high uptake in distributed generation and strong engagement from consumers. In order to develop these scenarios, it should be noted that underlying consumer choice models had to be manually tweaked to align with the required level of ambition.

Electric vehicle adoption follows a sharp uptake trajectory, driven by an evolving carbon tax policy, and an early ban on internal combustion engine vehicles in 2030. To reach full decarbonization by 2040, policy schemes to incentivize scrappage of older non-zero emissions vehicles are assumed in this scenario. Gas heating is banned in both existing and new homes by 2025, and financial incentives for low carbon heating continue until the mid-2030s, resulting in full electrification of heat by 2040.

Renewable generation scales to its highest potential within Toronto, helping to meet rapid increases in electricity demand across all sectors. Flexibility measures such as energy storage are also deployed at scale, helping to shift demand away from peak hours and reduce reinforcement requirements.

Net Zero 2040 – Low Efficiency

As described above for Consumer Transformation, a Net Zero 2040 Low Efficiency sensitivity scenario is included to investigate the effects of coupling the highest modelled electrification ambition with low uptakes of efficiency measures, flexibility and renewable generation. This will lead to the highest peak loads and so provides useful insight for Toronto Hydro.

3 Modelling Framework

3.1 Bottom-Up Consumer Choice Modelling

Element Energy has extensive experience with consumer choice modelling and has gathered a detailed understanding of which financial and non-financial parameters are relevant to describing consumer behaviour and modelled technology uptake. Element Energy has previously conducted detailed studies exploring the drivers for the uptake of various low carbon technologies, based on techniques such as willingness-to-pay analysis and consumer choice studies. The datasets from these studies have been used to determine the relative importance of the various technology attributes and uptake drivers.

Where consumer choice modelling is applied within the Future Energy Scenarios, the modelling for a given technology type generally follows the structure shown in Figure 7. This modelling approach is classified as discrete choice modelling[6]. Discrete choice models address a range of competing technologies, such as different vehicle types or heating technologies, and determine which technology is the most appealing to certain consumer types. Discrete choice modelling is based on the concept that consumers try to maximize their 'utility', which is a monetized indicator representing the value of a technology to a consumer. As technology attributes vary over time, they can be updated to follow market trends (changes in costs, subsidies, etc.). Changes in the economic evaluation of technology attributes allow for the modelling of market trends.

For example, in the case of different heating technologies, homeowners have to make a decision when replacing their old heating technology (e.g. a gas furnace) at the end of its life with a new technology (e.g. a heat pump, an electric heater or a new gas furnace). When making this decision, a customer would likely consider various factors including the upfront cost of the technologies, their running costs, the complexity of installation and the suitability of each technology for their property before reaching a decision. Discrete choice models convert the value of these factors to consumers is into an equivalent monetary value, or 'utility', so that they can be compared quantitatively.

[6] Kenneth E. Train, Cambridge University Press, 2002, "Discrete Choice Methods with Simulation".

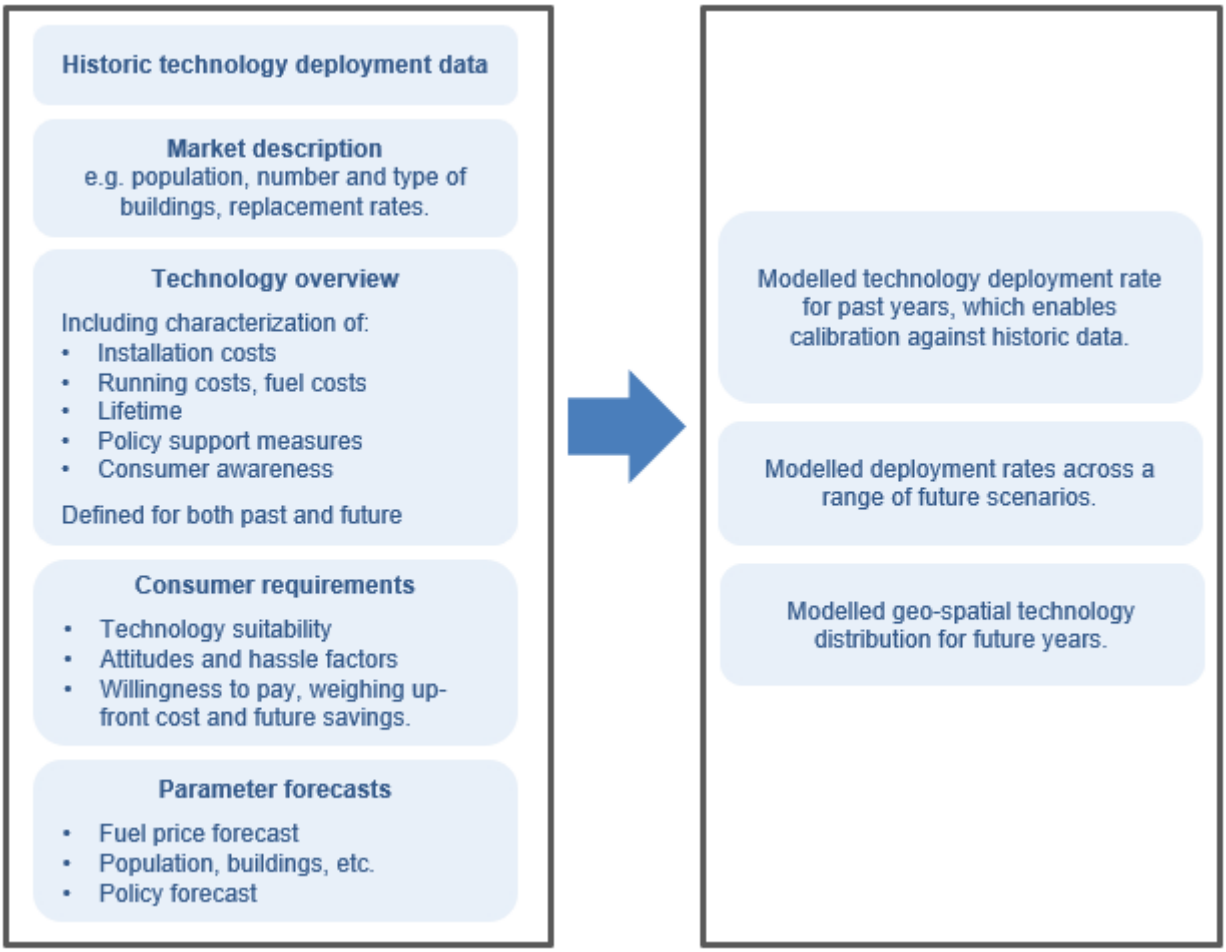


Figure 7: General approach to modelling future technology deployment.

This approach allows uptake trajectories to be based on real-world conditions (technology characteristics and costs) and actual purchasing decisions (including non-financial barriers such as charging infrastructure availability for electric vehicles or hassle barriers for heat pumps) rather than aspirational targets.

As shown in Figure 7, the first step is to gather and analyze all available datasets that describe historic deployment rates. This provides an understanding of the historic uptake levels at the most granular geospatial resolution possible. These datasets also support model calibration by enabling a correlation of how many units were deployed under historic market conditions. The subsequent modelling steps involve a variety of other parameters (such as market size, technology definition and consumer requirements), which are used to calculate a modelled purchase decision for each consumer type.

The consumer choice model evaluates the following for each year:

- The number of consumers making a purchase decision (by consumer type).
- Which technologies are purchased by consumer type, considering:
    - Financial parameters: capital cost, operational cost, taxes, fuel cost, revenues, policy incentives, etc.
    - Technology suitability and consumer awareness.
    - Hassle factors and attitudes around installation and adoption.

The modelling tools employ a tailored modelling logic to address the characteristics of the market and decision-making processes depending on the low carbon technology in question. In Section 4, the specific modelling methodologies for each technology included in this analysis are covered in more detail.

3.2 Local Factors and Customization to Toronto

Toronto Hydro's distribution area covers the city of Toronto. For planning purposes, the city is divided into 140 regions known as neighbourhoods[7], shown below in Figure 8. These neighbourhood were defined based on Statistics Canada census tracts and have a minimum population of at least 7,000 to 10,000.

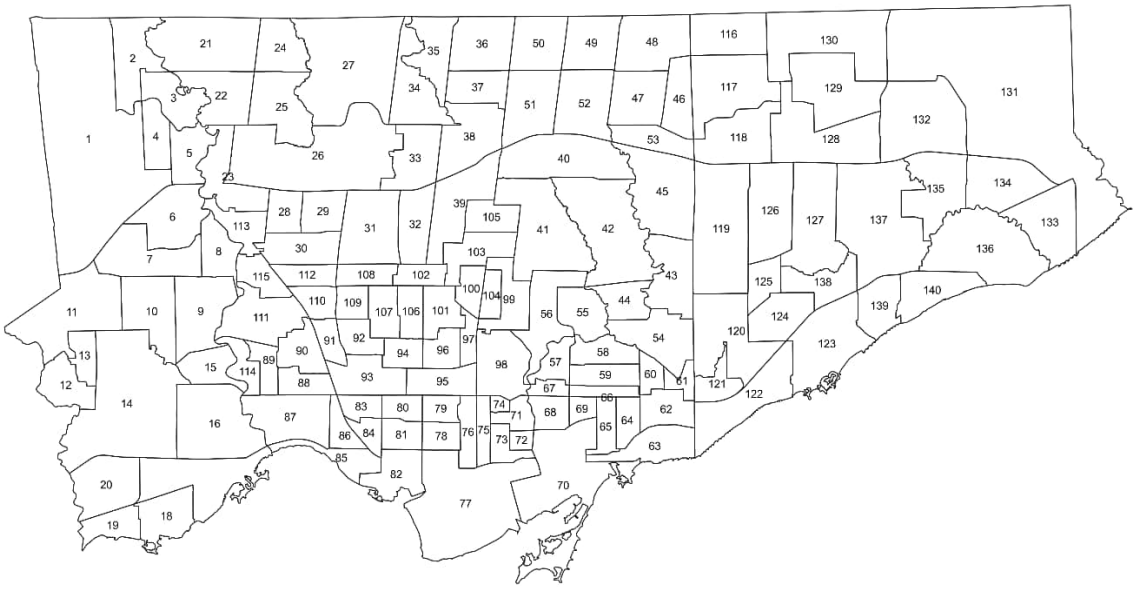


Figure 8: Toronto neighbourhoods.

Many of the drivers modelled in this work are resolved to neighbourhood level. In some cases, (e.g. electric vehicles), these are then further mapped to specific transformer station buses for the purposes of load modelling. For others, such as those based on building stock archetypes (e.g. core demand and heating technologies), modelling is performed using an archetype approach and relies on the asset-level connection counts from Toronto Hydro.

The consumer choice models utilized in this work have been adapted for Toronto Hydro to take into account specific local factors, such as policy measures (e.g. Canada Green Homes Grant) and the breakdown of vehicle stock as discussed in Section 4.3. Additionally, the modelling considers local geography when distributing demand and generation across the region, such as a detailed look at potential electric vehicle charging locations, discussed in Section 4.3.6, and an assessment of the most suitable locations for onshore wind turbines, discussed in Section 4.4.3.

[7] City of Toronto, About Toronto Neighbourhoods, 2022. *Note that since the time of analysis, some neighbourhoods have been split up because of very high population growth. Effective after April 12, 2022, the number of neighbourhoods in Toronto is 158.*

4 Development of Demand and Generation Driver Projections

Modern electricity networks supply energy to homes and businesses to service a broad range of applications. In this analysis, the electricity provided for most conventional applications is referred to as “core demand”.

At present, the majority of energy for both transport and space heating is derived from non-electrical energy vectors (such as gasoline and diesel for transport, or natural gas for space heating). As part of the decarbonization of transport and space heating, there is potential for a significant level of electrification to occur across these sectors making them particularly important areas of analysis for electricity network planning and load modelling. As such, transport and space heating are each modelled separately to “core demand” in this analysis to support a more detailed understanding of potential future demands from these technology segments.

Similarly, increasing levels of distributed electricity generation (e.g. from solar PV, wind, etc.) also play an important role in projecting future loading across electricity networks as net zero strategies are implemented. Hence this analysis also explores the impact of distributed generation from a variety of technology options (see Section 4.4) on future network loads under a range of scenario options.

As the energy provision of the distribution network grows due to factors such as the electrification of heat and transport as well as increasing distribution electricity generation, generally the peak instantaneous power demand experienced by the network will also increase. To help reduce the amount of network reinforcement required to accommodate increases in peak demands across the electricity network, several flexibility options exist which help to move demand at peak times to different times of the day. This analysis captures the impact of flexibility options such as energy storage, smart charging and vehicle-to-grid options for electric vehicles, as well as time-of-use tariffs. Energy storage is modelled as a distinct technology segment which can help to shift power loads by charging at times of low grid utilization and discharging during peak hours. Similarly, smart charging and vehicle-to-grid options can help to shift loads from EVs by managing when car batteries charge and allowing them to act as electrical storage units. This is captured as a sensitivity within the modelling of transport demand by assuming different charging behaviours for electric vehicles in Toronto.

The report sections below provide further details on the assumptions, scenarios and modelling methodology used in the analysis of core demand, heating, transport, generation and flexibility, and how these are used to establish the scenario framework used for projecting loads across the Toronto Hydro network out to 2050.

4.1 Core Demand

The majority of current electricity demand within the Toronto Hydro network can be categorized as underlying demand from either domestic customers or industrial and commercial (I&C) customers. Underlying demand here refers to all electricity usage relating to existing appliances, including electrical heating or cooling, but excluding demand from new low carbon technologies such as electric vehicle charging or heat pumps. Collectively this underlying demand from domestic and I&C customers is referred to as the “core demand” on the network. Future core demand for domestic and I&C customers is primarily dictated by two key variables:

- The total number of customers connected to the network, which is assumed to be controlled by the size of the building stock; and
- The energy intensity of the customers within those properties, which is assumed to be controlled by the uptake and efficiency of customer appliances.

This concept is illustrated in Figure 9. The following section details the modelling used to characterize Toronto’s current and future core demand.

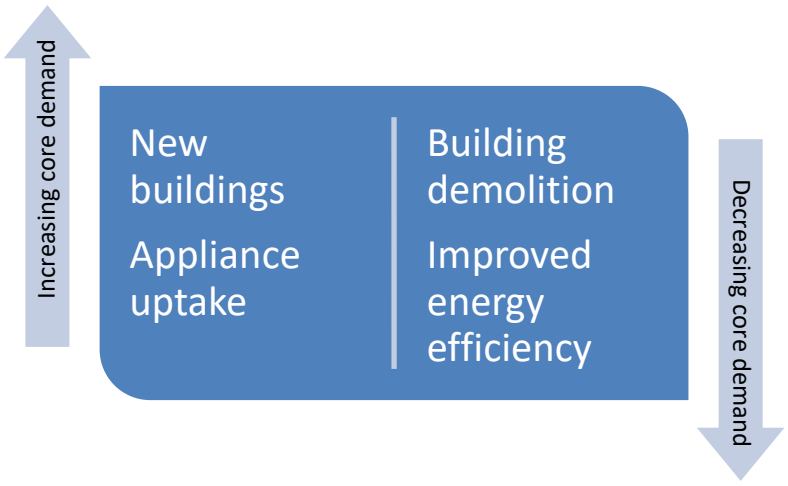


Figure 9: Illustration of core demand drivers and their effects.

The mapping of the different core demand parameters to the scenario worlds is given below in Table 2

Table 2: Domestic and I&C efficiency scenario mapping.

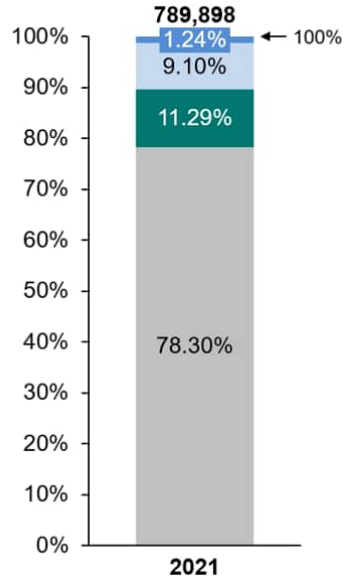
Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Domestic Electrical Efficiency	Low	Medium	High	Low	High	Low
I&C Electrical Efficiency	Low	Medium	High	Low	High	Low
Appliance growth	Single Projection					
Domestic Building Stock Growth	Single Projection					
I&C Building Stock Growth	Single Projection					

4.1.1 Archetype Definitions

Understanding the energy usage of different building types across the modelled region is essential for accurately characterizing the core demand. Customers on the Toronto Hydro network are classified into 11 "rate classes" based on different use cases and sizes, six of which are of particular interest from the perspective of modelling domestic and industrial core demand. Table 3 summarizes the rate classes, and Figure 10 shows the breakdown of Toronto Hydro's connections in the relevant rate classes (as denoted in Table 3). The majority of connections are residential.

Table 3: Toronto Hydro customer rate class definitions

Customer Type	Toronto Hydro Rate Class
Domestic	Residential
	Competitive Sector Multi-Unit Residential (CSMUR)
Industrial and Commercial (I&C)	General Service (GS) < 50kW
	GS 50 – 999kW
	GS 1 – 5 MW
	GS >5 MW (Large Users)
Other (not in scope of FES analysis)	*Street Lighting*
	Unmetered Scattered Load
	Standby Power
	microFit
	Retail Services



Rate Class	Connections	%
Customers over 5MW	54	0.01%
Customers between 1MW-5MW	494	0.06%
Customers between 50-999KW	9,768	1.24%
Customers under 50KW	71,887	9.10%
Multi-Unit Residential	89,209	11.29%
Residential	618,486	78.30%

Figure 10: Breakdown of relevant rate classes across the Toronto Hydro network.

Much of the analysis relating to core demand and low carbon technology uptake is contingent upon the use of building archetypes, also called classes, which build upon the connection data (split by the rate classes shown in Table 3) provided by Toronto Hydro. Archetypes allow the energy usage characteristics of a wide array of users to be considered in the analysis, providing high levels of regional variation while also supporting analytical efficiency. The building stock within Toronto Hydro's region has been split into 32 domestic and 40 non-domestic archetypes, each defined by a set of relevant characteristics. The process and resulting distribution are explained in more detail below.

Domestic Archetypes

The 2016 Census of Population[8] provides household statistics at neighbourhood resolution. This dataset was used to segment the domestic building stock into groups of four different structural types (single detached houses, double or row houses, low-rise apartments, and high-rise apartments) and four age categories (pre-1960, 1960-1980, 1980-2010, post-2010). The Census data contains records of more domestic properties than there are connections within Toronto Hydro's residential and multi-unit residential rate class data. This is because there are some residential properties, such as apartment blocks, which in some cases connect to the network as bulk-metered General Service connections within Toronto Hydro's rate classes. The bulk-metered residential properties are allocated to I&C archetypes in this analysis, while the number of buildings within the domestic archetypes matches the total number of residential and multi-unit residential rate class connections.

Figure 11 shows the distribution of residential and multi-unit residential rate class connections (i.e. domestic connections) across the Toronto neighbourhoods, per Toronto Hydro's rate class data[9].

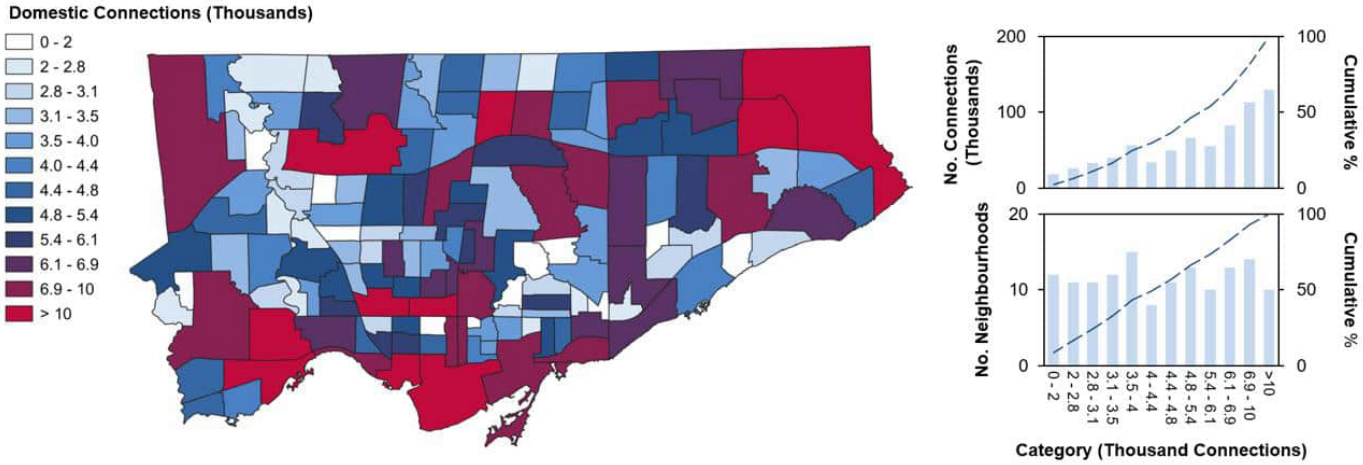


Figure 11: Distribution of domestic connections across Toronto neighbourhoods[9].

The distribution of dwelling types across neighbourhoods varies considerably, with more densely populated regions of the city having a higher proportion of apartment style homes utilizing multi-unit residential connections. This distribution of dwelling types (see Figure 12) has a significant impact on the uptake of various demand technologies seen in the scenarios.

[8] Statistics Canada, The Census of Population – Neighbourhood Profiles, 2016
[9] Toronto Hydro, Rate Class connection statistics, 2022

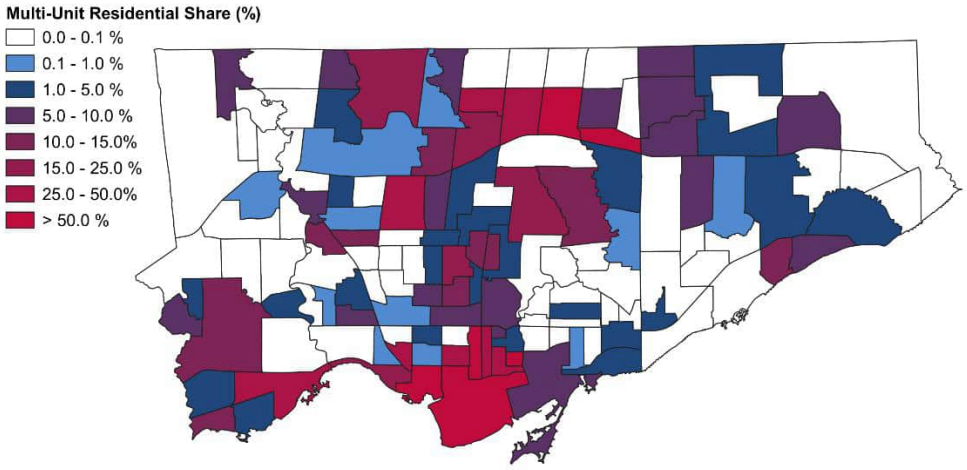


Figure 12: Share of multi-unit residential connections within Toronto Hydro's domestic rate classes.

The Toronto Hydro rate class data does not contain any additional information on the types of buildings present within the stock. Using neighbourhood and ward-level census data[8], as well as data from TransformTO[3] and The Survey of Household Energy Use[10], the connection counts were subdivided according to several parameters as follows (it is assumed that the distribution of building descriptors among the census households is retained in the Toronto Hydro rate class dataset for the purposes of subsequent calculations).

The parameters used to subdivide the stock into archetypes are heating fuel type (gas, electric, other), building age and the structural types listed above. These parameters were selected for the segmentation as buildings of similar structural type and age have similar energy usage characteristics. These factors also provide a reasonable indicator for which low-carbon heat source a building may be suited.

Archetypes are not expected to have the same share of heating fuel types – for example the proportion of homes currently using electric heating is higher within apartments than detached houses. Data from the Survey of Household Energy Use was used to determine the prevalence of existing heating fuels within each housing type.

It was found that the majority (>90%) of the building stock in Toronto currently uses natural gas as a heating fuel. Gas fuelled archetypes were subdivided into the four structural categories given above, while archetypes fueled by other means required less granularity (owing to their small share of the overall stock) and were hence categorized as houses or apartments. The breakdown of the archetypes' characteristics is illustrated in Figure 13. This leads to 32 domestic archetypes in total, consisting of 16 gas heating archetypes, 8 electric heating ones and 8 other heating archetypes as follows:

- **Gas heating**: 1 [Fuel Type] x 4 [Building types] x 4 [Age Categories] = 16 archetypes
- **Electric heating:** 1 [Fuel Type] x 2 [Building types] x 4 [Age Categories] = 8 archetypes
- **Other heating:** 1 [Fuel Type] x 2 [Building types] x 4 [Age Categories] = 8 archetypes

[10] Natural Resources Canada, Survey of Household Energy Use Data Tables, 2015

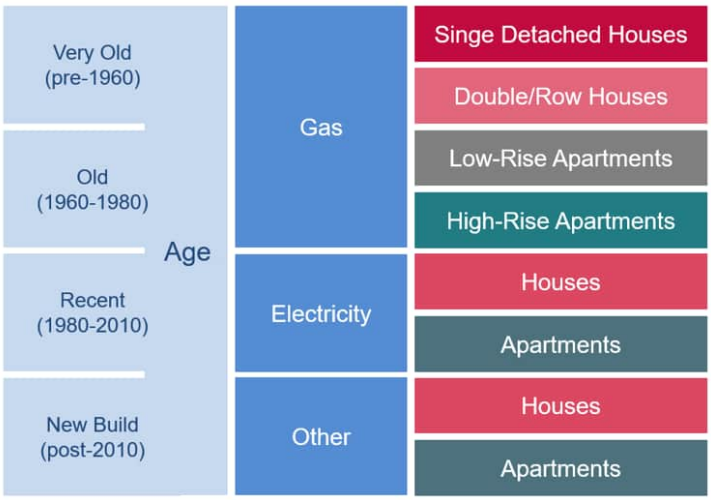


Figure 13: Breakdown of defining characteristics for domestic archetypes.

The distribution of archetypes within the Toronto Hydro rate classes is shown below in Figure 14[11].

The homogeneity of domestic multi-unit residential connections as high-rise apartment blocks is shown in Figure 14a, explaining the prevalence of this rate class in the City's urban centres in Figure 12. There is a relatively even split of building ages in Figure 14b, and the high proportion of gas heating discussed above can be seen clearly in Figure 14c.

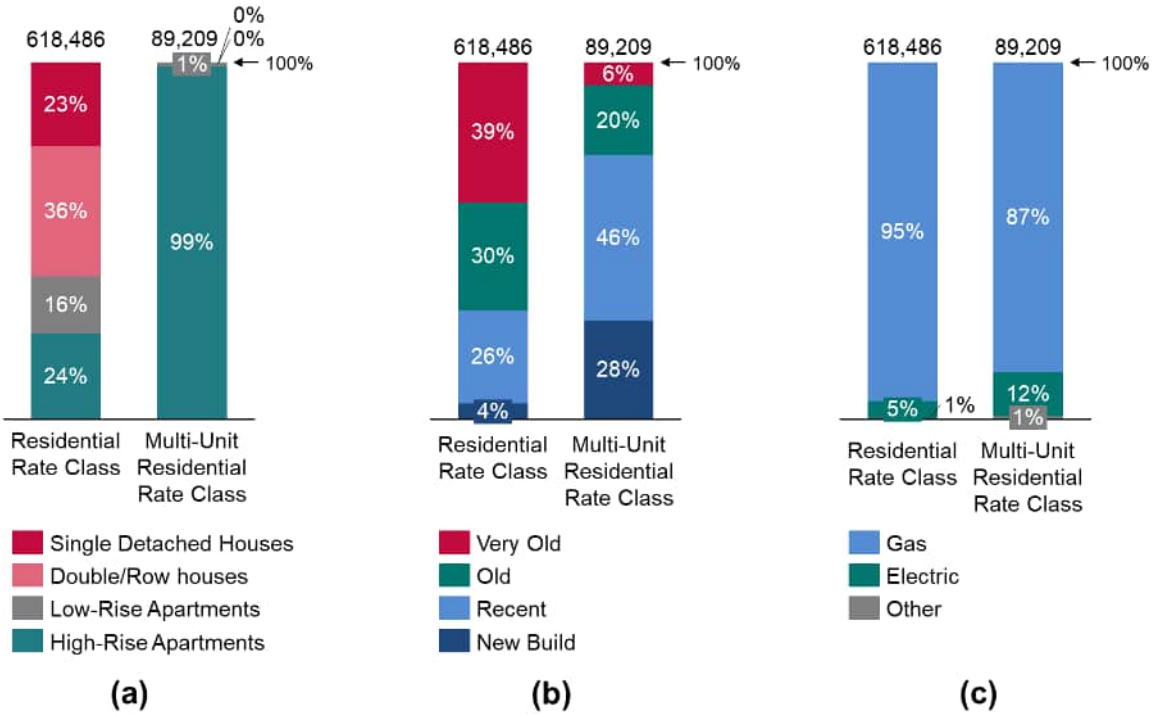


Figure 14: Distribution of Toronto Hydro's domestic building stock by (a) structural type; (b) age; and (c) current heating fuel (2021).

[11] There are a number of domestic properties which, owing to their metering arrangements and the handling of rate classes within the modelling, are categorized within I&C Multi-Unit Residential archetypes, and these are not accounted for in Figure 14.

Industrial and Commercial Archetypes

Figure 15 shows the distribution of employees across the city, in line with City of Toronto employment figures for 2020. The data shows that the majority of neighbourhoods contain relatively few employees, while most employees work in a few specific neighbourhoods. 70% of the neighbourhoods are home to fewer than 10,000 employees each, while 30% of the city's workforce is contained within just six (of 140) neighbourhoods (see inset graphs in Figure 15). There are two main centres of employment in the city: one in the city centre (bottom centre of the map) and one in Etobicoke North (top left of the map).

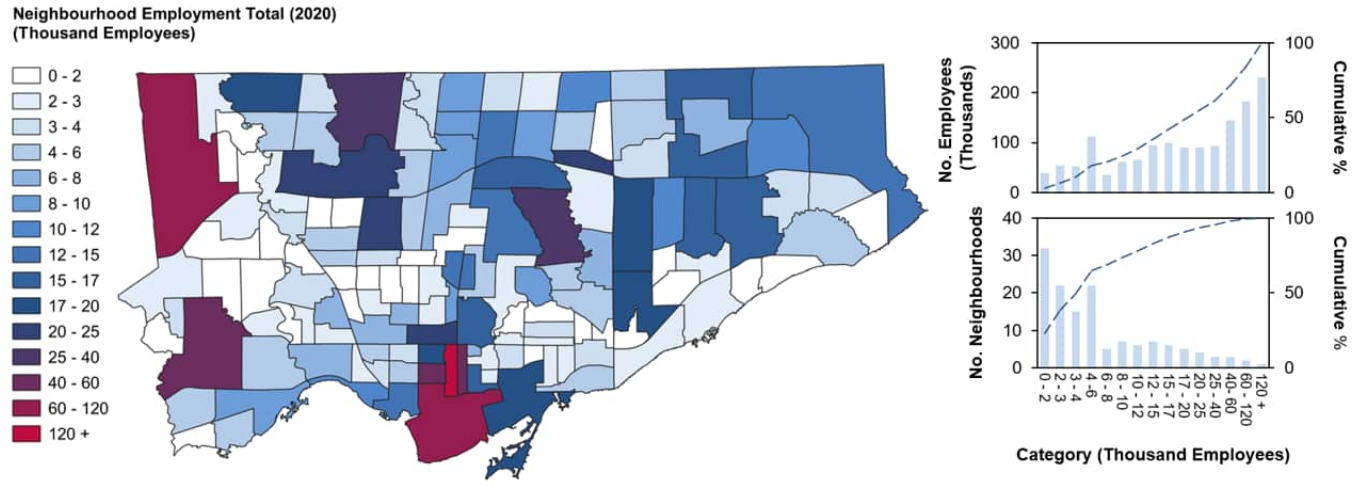


Figure 15: 2020 Distribution of Employees in Toronto[12].

The data also showed the number of establishments (i.e. workplaces) per neighbourhood per NAICS[13] sector which, when combined with the employee counts in Figure 15, can give an indication of the size of I&C buildings in different regions of the city. This dataset is shown below in Figure 16, presented as employees per establishment.

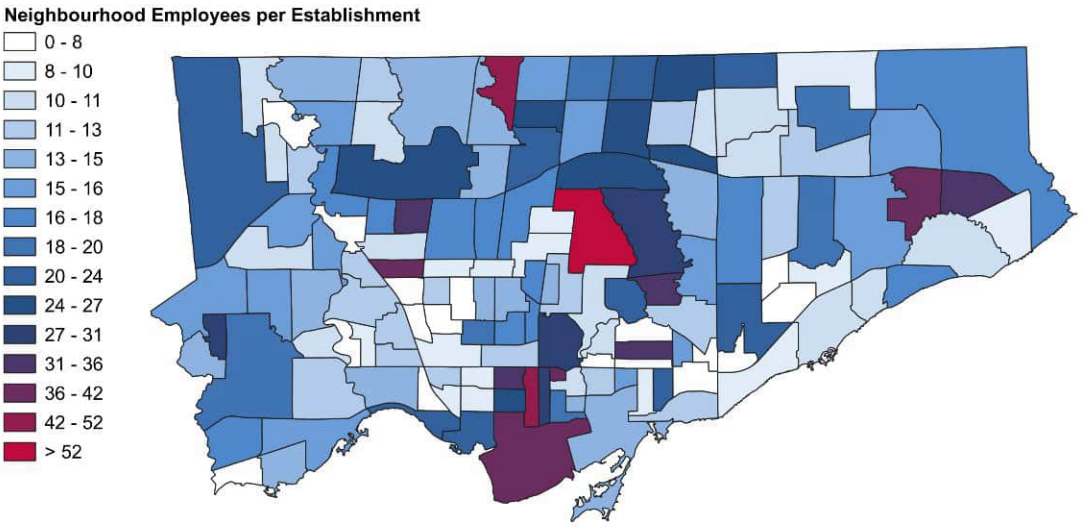


Figure 16: Employees per Establishment, 2020[12].

The dataset shown in Figure 15 is important because the derivation of the I&C building stock growth trend, as described in Section 4.1.2, is based upon employment projections. The growth in employment is assumed to

[12] City of Toronto, Toronto Employment Survey, 2020
[13] North American Industrial Classification System NAICS & SIC Identification Tools | NAICS Association

be in proportion to the growth in buildings in each neighbourhood, and therefore the employee density shown in Figure 16 is also implicitly retained in that analysis.

The sectoral split of employees and establishments in Toronto referenced above is shown below in Figure 17. Note that the full list of 21 NAICS sectors was condensed into seven simplified sectors for the purposes of this analysis.

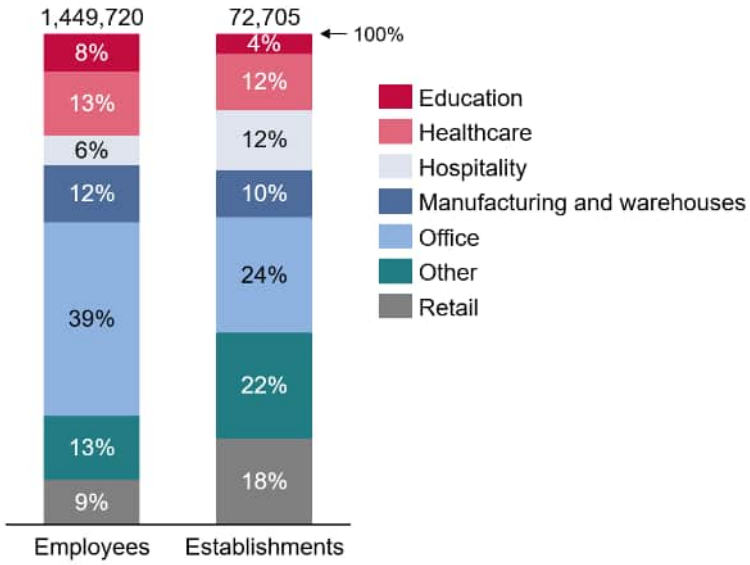


Figure 17: Simplified sectoral split of employees and establishments in 2020[12].

The seven simplified NAICS sectors described above formed the basis of the archetypes developed for this analysis. In addition to these seven, some multi-unit residential buildings are categorized as I&C connections in this analysis because they connect to the network via bulk-metered General Service connections, rather than individually metered multi-unit residential connections (see Table 3). Other characteristics considered were the fuel type (split into gas, electricity and other), and age (split by existing and new build). Note that it has been assumed for simplicity that all new builds in all scenarios will be fuelled either by gas or electricity. The breakdown of the archetypes' characteristics is illustrated in Figure 18. This leads to 24 existing and 16 new build archetypes as follows:

- **Existing:** 1 [Age Category] x 3 [Fuel Types] x 8 [Sectors] = 24 archetypes
- **New Build:** 1 [Age Category] x 2 [Fuel Types] x 8 [Sectors] = 16 archetypes

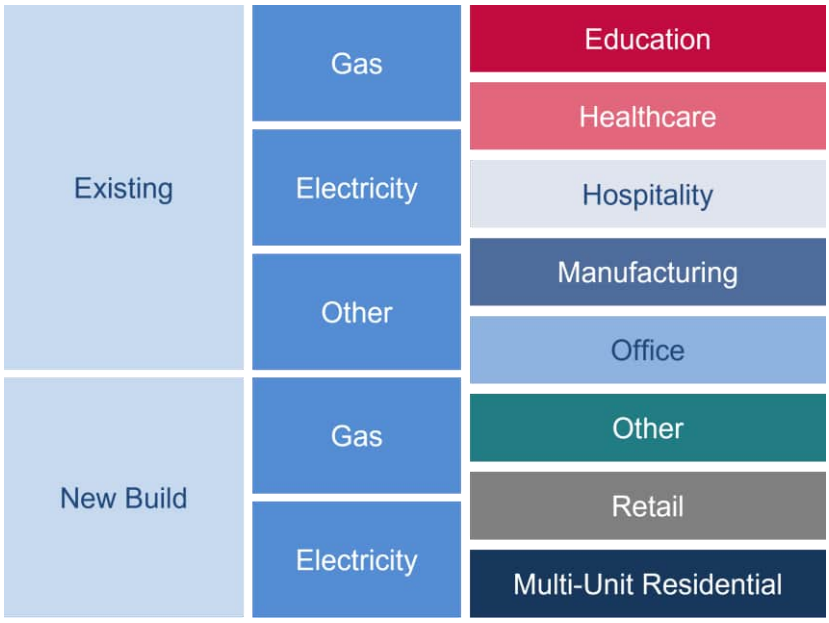


Figure 18: Breakdown of defining characteristics for the I&C archetypes.

Note that the archetypes are not characterized by rate class – customer counts for each non-domestic archetype were produced for all four I&C rate classes (see Table 3). To achieve this, a mapping between rate classes and NAICS sectors was produced (i.e. defining which NAICS sectors would be expected to contain which rate classes). The number of NAICS establishments present within the data differed slightly in each neighbourhood to the number of connections reported by Toronto Hydro. As such, the proportions of each sector were retained from the NAICS data but the overall total number of connections within each rate class was assigned according to the data provided by Toronto Hydro.

The resulting distribution of archetypes then formed the starting point for the analysis of I&C core demand and building stock growth in Toronto.

4.1.2 Building Stock

The number of buildings connected to the distribution network has been modelled as the net result of two competing factors – demolition of the existing stock and the rate of new build completions in each sector. As with the building archetyping, the building stock trends are split into domestic housing and I&C establishments.

Domestic Building Stock

Neighbourhood level net domestic growth projections (to 2041), based on the City of Toronto 2013 provincial growth plan were used for this analysis. The scenario referred to as the 2012 neighbourhood growth plan ("GP2012 NH"), has been used to model domestic stock growth. The data was extrapolated from 2041 to 2050 and mapped to the domestic housing archetypes discussed in Section 4.1.1.

Archetype specific (i.e. house and apartment) growth rates consistent with those contained in GP2012 NH were then applied to Toronto Hydro's domestic connection counts, using the distribution of dwelling types from the domestic archetypes. As such, the overall modelled growth differs slightly from the GP2012 NH trend, because the distribution of homes (and consequently the growth of the stock) in that dataset differs from that in the modelling presented in this report.

A 2008 study by Watson and Associates[14] on behalf of the City of Toronto contains historical data and projections around the ratio of demolitions to new builds across different housing types. The demolition rate derived from the report is applied to the net growth seen in each neighbourhood to find the total number of demolitions across the city (and implicitly the gross number of new builds). Figure 19 summarizes how the data described above were combined to produce a stock growth projection.

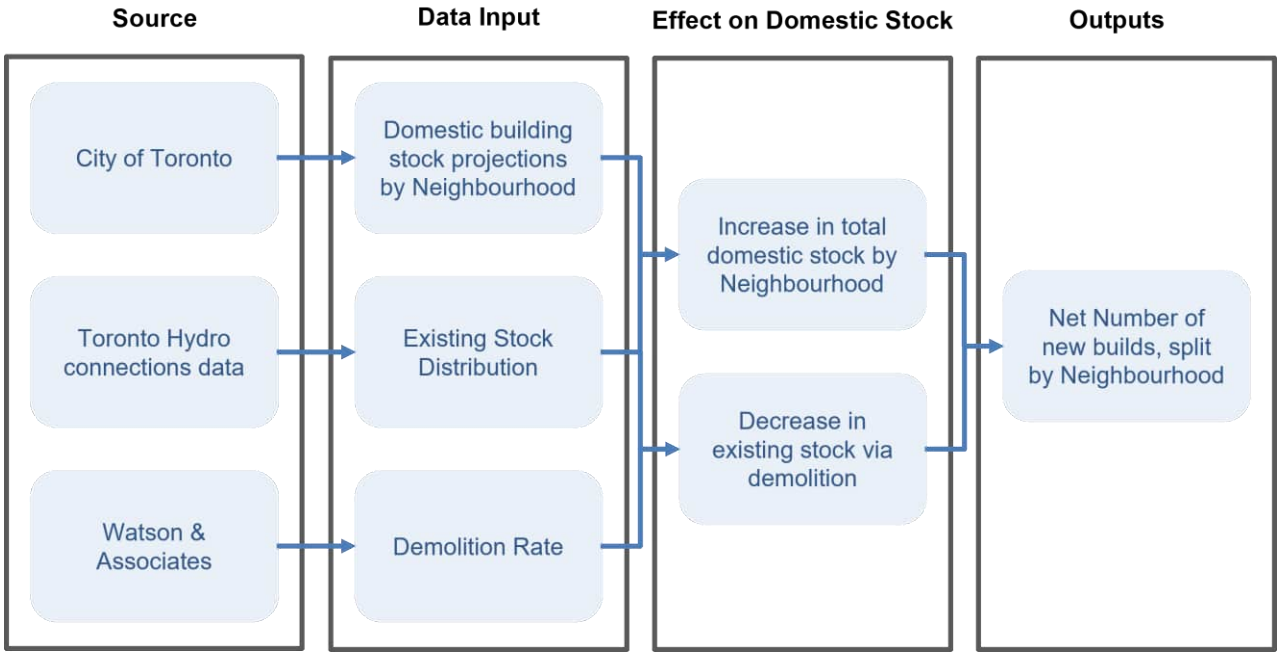


Figure 19: Method for developing domestic building stock growth projection.

Figure 20 shows the modelled net housing stock growth derived from the data sources described above. Growth (consistent with GP 2012NH) is applied to new builds only, while demolition is applied to existing stock only. The majority of growth is concentrated in apartments, which is also consistent with the neighbourhood growth plan.

[14] Watson & Associates, City of Toronto Development Charge Background Study, 2008

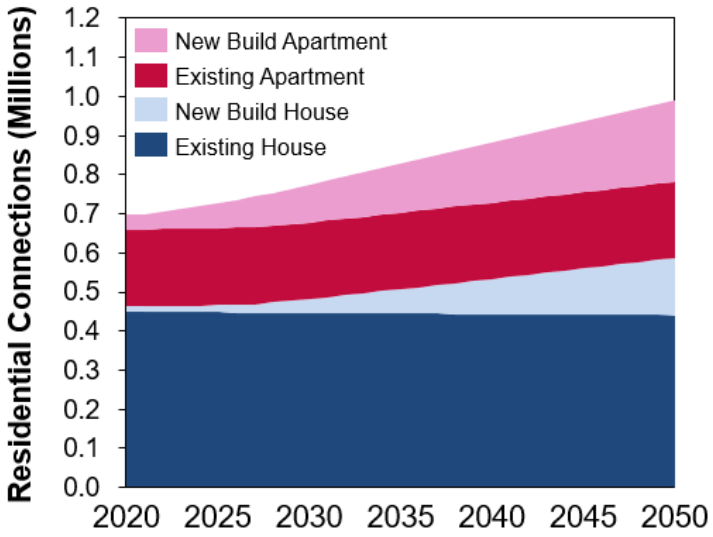


Figure 20: Modelled residential stock growth, split by dwelling type and age, rebased to Toronto Hydro connection counts in 2021.

Figure 21 shows a comparison of the overall modelled growth rate relative to that of the GP2012 NH data, TransformTO and the Canadian Ministry of Finance's population projection, showing a general alignment between the modelled approach and that of the data available in literature.

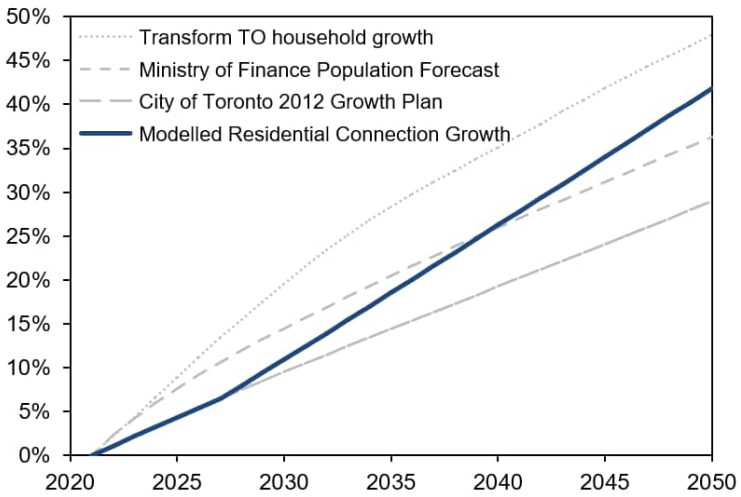


Figure 21: Comparison of modelled growth with different Toronto housing and population projections.

Figure 22 shows the modelled distribution of domestic buildings across the city in the base year and 2050. The differing building stock growth rates in action across different neighbourhoods can be seen by comparing the 2021 and 2050 distributions.

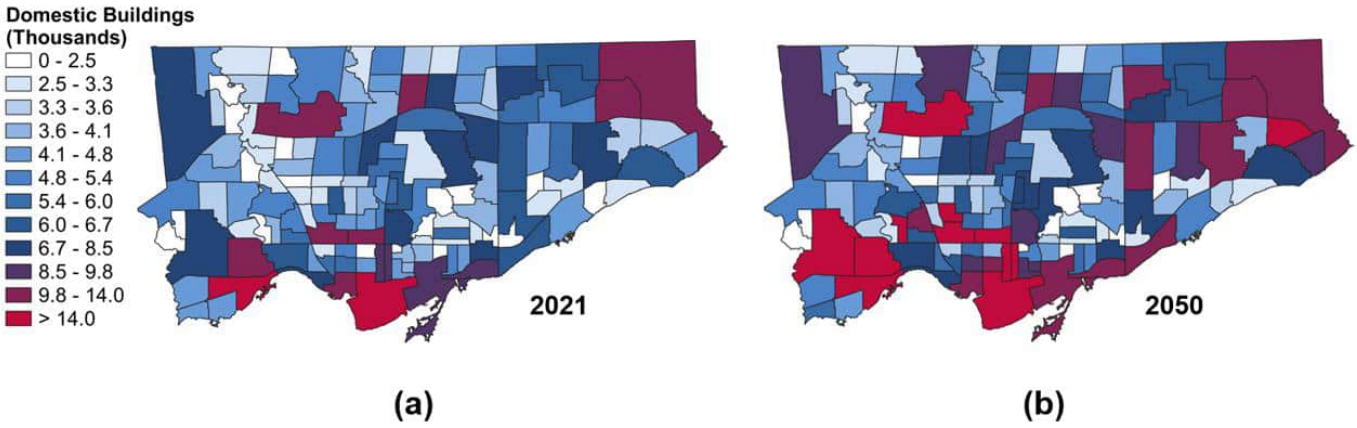


Figure 22: Maps of domestic building stock in (a) 2021 and (b) 2050.

Industrial and Commercial Building Stock

The analysis for I&C building stock was also based upon multiple data sources. The high-level process is displayed below in Figure 23.

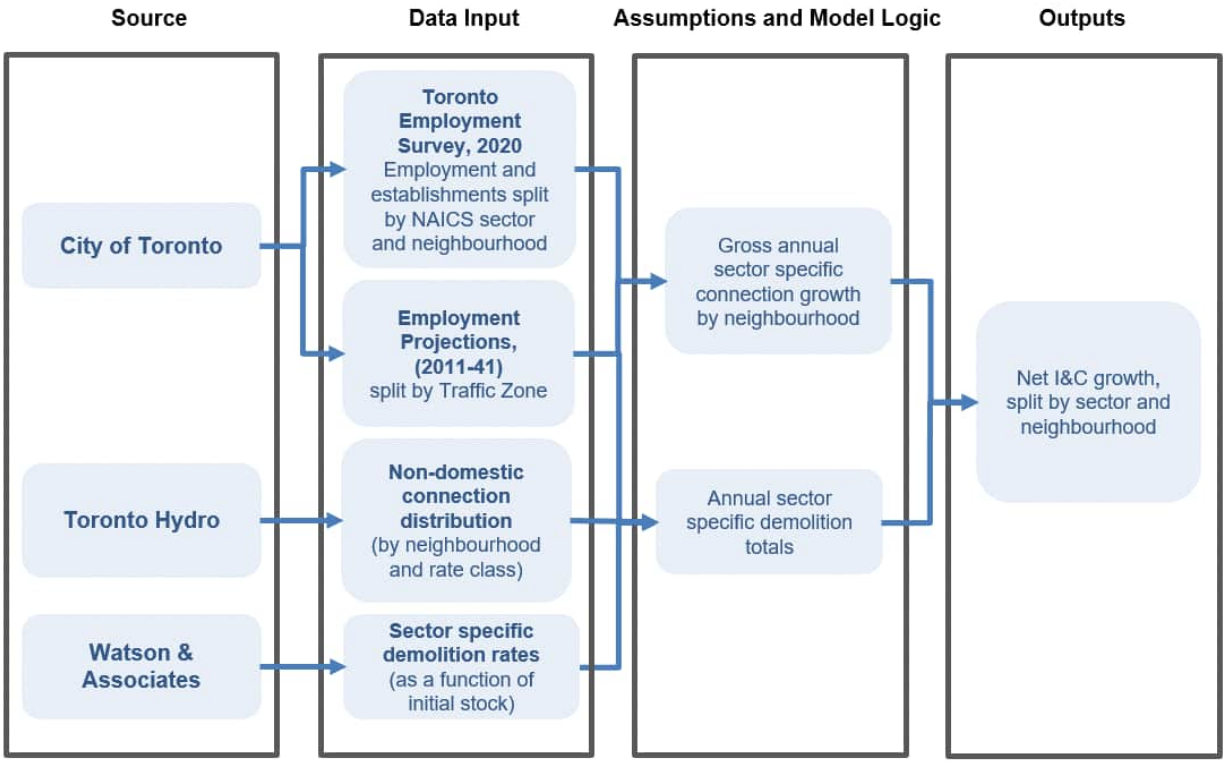


Figure 23: Method for developing the industrial and commercial building stock growth projection.

Alongside the employment statistics discussed in Section 4.1.1, City of Toronto industry employment projections from 2011 to 2041, split by Traffic Zones, were used in the I&C building stock growth analysis[15]. These projections contained five scenarios, combining different rates of economic growth and the projected impacts of the SmartTrack rail system[16]. These are summarized in Table 4 and Figure 24. Scenario 1 (medium growth, no SmartTrack) has been used as the basis for the FES analysis.

Table 4: Synopsis of City of Toronto employment projection scenarios.

Scenario	Growth	SmartTrack
Scenario 1	**Medium**	**False**
Scenario 2	Medium	True
Scenario 3	Low	False
Scenario 4	Low	True
Scenario 5	High	True

[15] Toronto Data Management Group, Traffic Zones Boundary Files, 2006 (Toronto Hydro's network area covers 677 traffic zones).
[16] City of Toronto, SmartTrack Stations Program, 2021

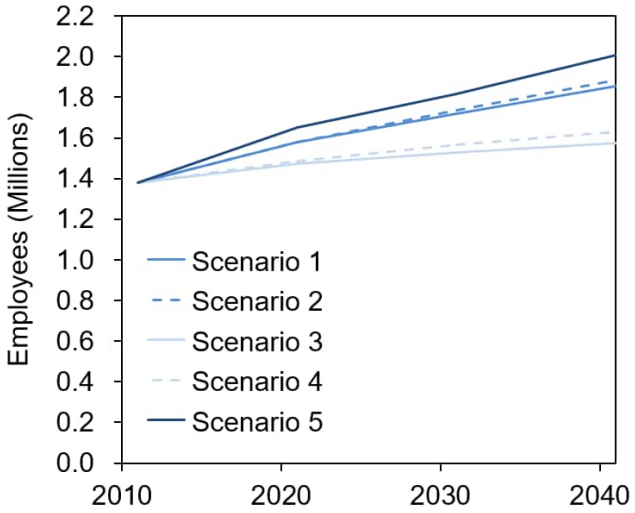


Figure 24: City of Toronto employment projection scenarios, 2011-2041.

The growth rate given by the medium growth employment projection described above has been used as a proxy for net I&C stock growth. The neighbourhood level NAICS sector split from the 2020 Employment Projection conducted by the City of Toronto was used to disaggregate the growth into neighbourhood regions. This was then rebased, using the neighbourhood distribution of the I&C archetypes discussed in Section 4.1.1.

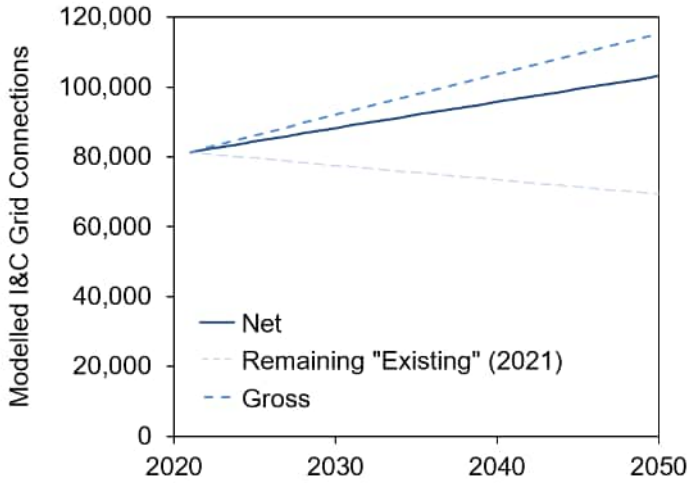


Figure 25: Modelled total I&C building stock projection.

Figure 26 shows the distribution of I&C buildings across Toronto in the base year and 2050. Unlike the domestic stock growth (shown in Figure 22), I&C building stock remains distributed around the city in a manner similar to the present day, with most growth occurring in regions which already have a high concentration of commercial buildings. High voltage I&C connections (defined as those in rate classes Customers between 1MW-5MW and Customers over 5MW) are excluded from this analysis. The growth in demand from these customers is modelled based on Toronto Hydro's assessment of the connections expected to come online in the near future.

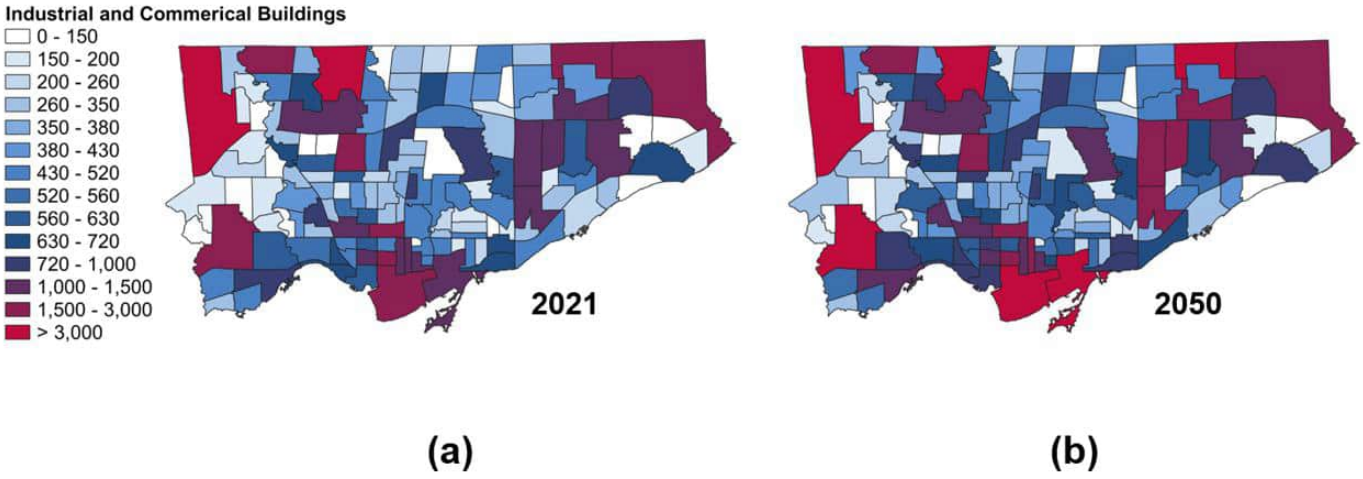


Figure 26: Maps of modelled I&C building distribution in (a) 2021 and (b) 2050.

4.1.3 Core Electrical Efficiency

Domestic Appliance (Non-Heat) Efficiency Projection

The domestic electrical efficiency projections were developed using appliance turnover as the mechanism for energy use reduction. Within the modelling, consumers are assumed to upgrade to a new appliance at the end of an average appliance lifetime, either to:

- an appliance with an average improvement in energy consumption, which was based on the Canada-wide energy use dataset containing annual energy consumption by appliance type; or,
- the most efficient available appliance, the energy consumption of which was taken from the Energy Star website.

Figure 27 shows the high-level methodology used to generate the domestic appliance efficiency projections.

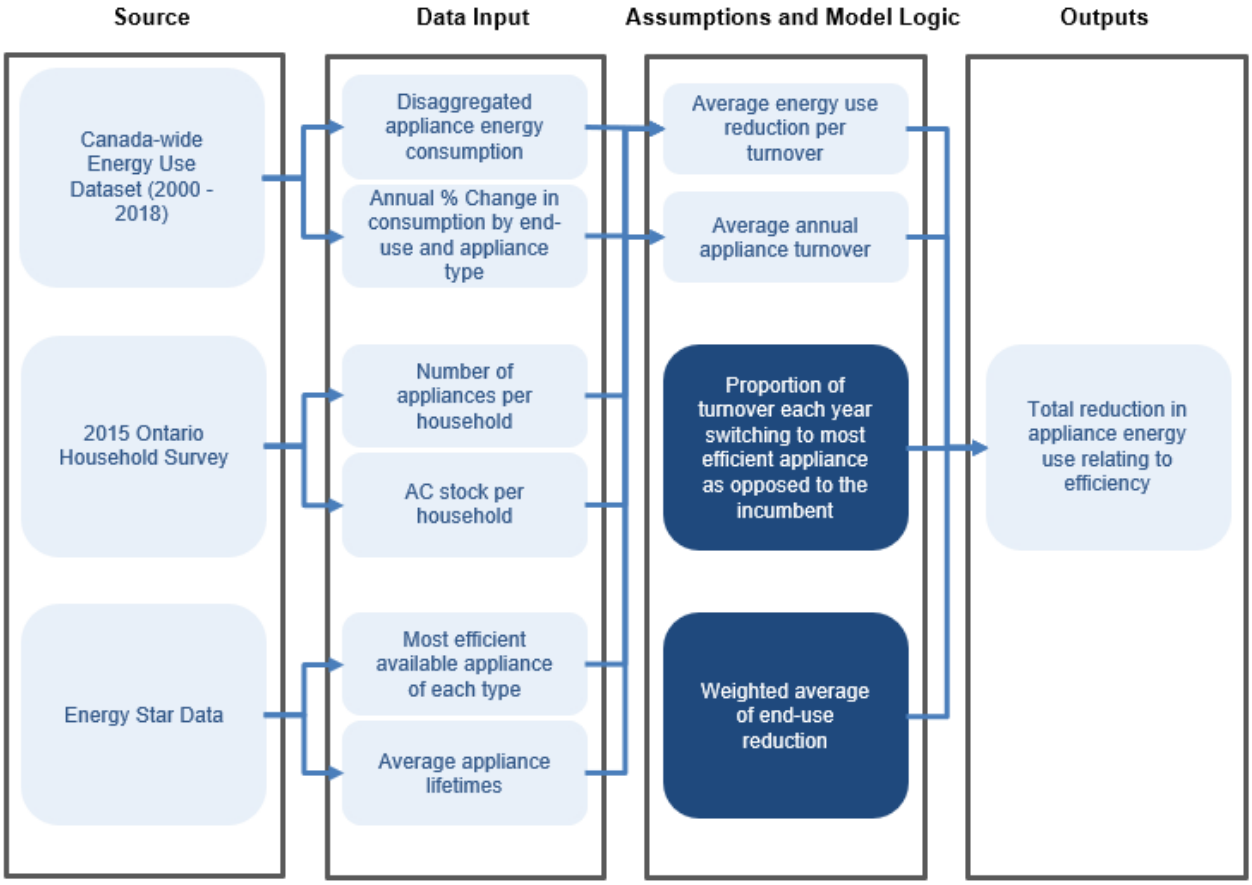


Figure 27: Domestic appliance efficiency projection methodology[17,18,19,20].

Using 2018 Conservation and Demand Management (CDM) data provided by Toronto Hydro, it was determined that the average participation rate of a residential appliance program was 1.5% of the total residential customers. In 2018, five residential appliance programs were available to consumers. As such, the Low scenario was formulated such that 7.5% of annual appliance turnover was to the most efficient appliance, in line with potential CDM intervention impacts. The remaining scenarios are summarized in Table 5 below.

[17] National Resources Canada, Canada-wide Energy Use Dataset | Energy Efficiency Trends Analysis Tables, 2000 – 2018
[18] National Resources Canada, 2015 Survey of Household Energy Use (SHEU-2015) Data Tables , 2015
[19] National Resources Canada, Energy Star | Choosing and Using Appliances With EnerGuide, 2013

Table 5: Scenario assumptions for domestic appliance efficiency projections.

Scenario	Description	Energy use reduction by 2050
Low	1.5% x 5 = 7.5% of annual turnovers switch to most efficient appliance	11%
Medium	Intermediate reduction between Low and High	24%
High	100% of appliances are turned over to most efficient by 2050	37%

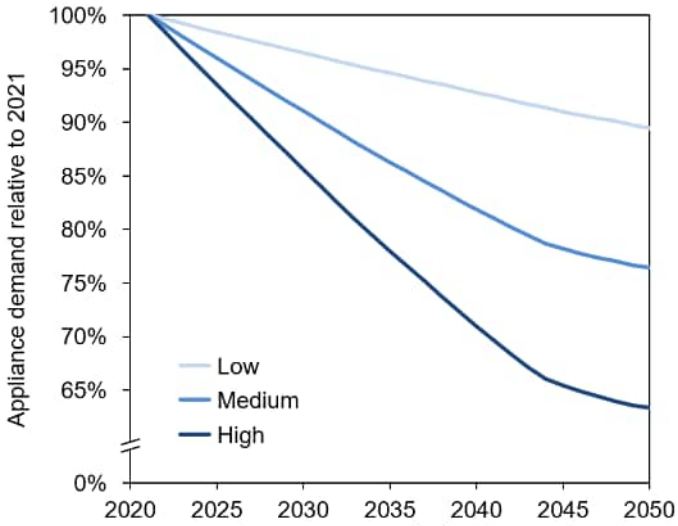


Figure 28: Domestic appliance (non-heat) energy demand reduction relative to 2021.

As shown in Figure 27, a key data input in generating the domestic appliance energy efficiency projections was the average number of appliances per household. These data were obtained from the National Comprehensive Energy Use Database[20] and are shown in Table 6.

Table 6: Historic average number of appliances per household.

Appliance	Per household stock (2018)
Refrigerator	1.28
Freezer	0.50
Dishwasher	0.57
Clothes washer	0.76
Clothes dryer	0.79
Range	1.00
Air conditioning (AC)	0.86[21]
Small appliances	17.35

An appliance growth projection was generated, where the per household stock for all appliances (excluding AC and small appliances) was assumed to be constant throughout the modelled time period, based on the observation that there was minimal historic growth in these appliances. Conversely, for AC and small appliances, a continuation of recent historical trends was assumed as shown in Figure 29.

[20] Natural Resources Canada, Residential Sector Canada Table 37: Appliance Stock by Appliance Type and Energy Source
[21] Toronto Public Health, Protecting Vulnerable People from Health Impacts of Extreme Heat, July 2011

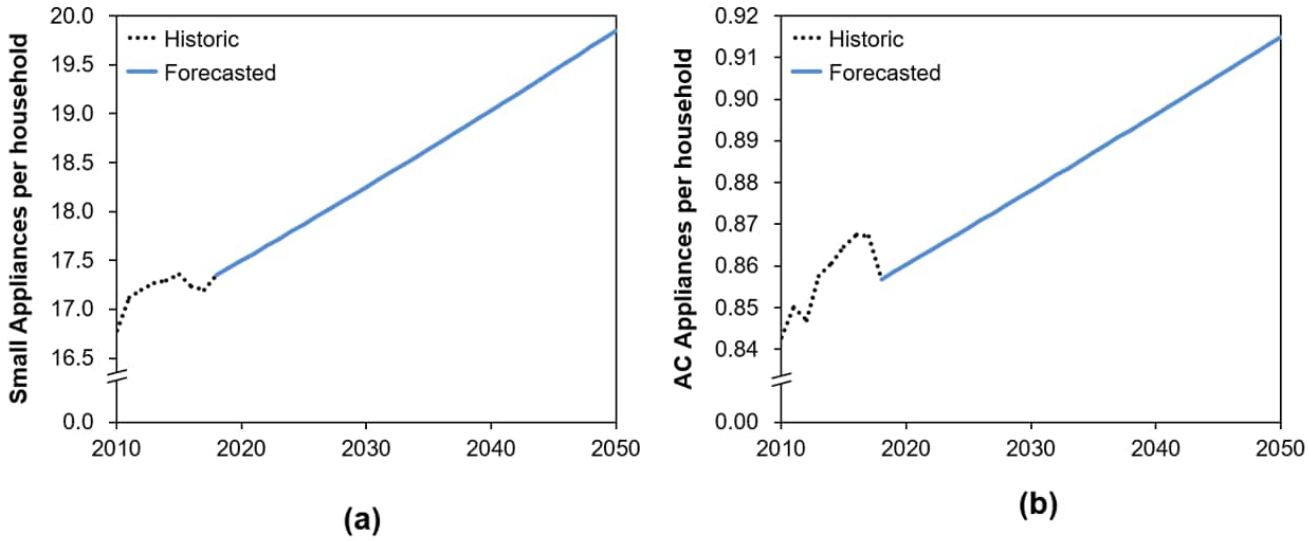


Figure 29: Growth projection for (a) small appliances and (b) AC units per household.

Industrial and Commercial Electricity (Non-Heat) Efficiency Projection

Figure 30 shows the high-level methodology used to create the I&C electricity efficiency projections. The same methodology was utilized for the I&C thermal efficiency projection, discussed in further detail in Section 4.2.3.

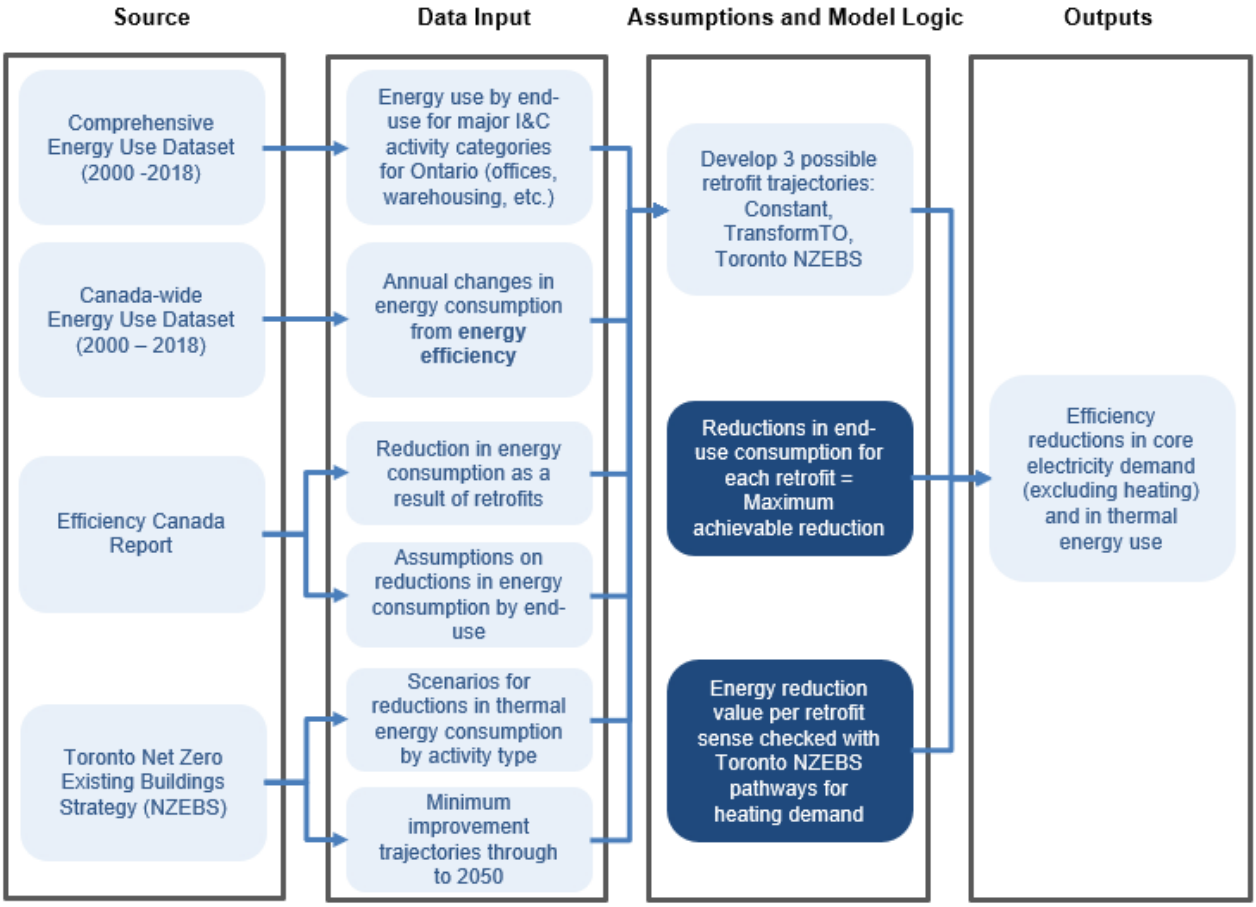


Figure 30: Methodology for I&C electricity and thermal efficiency Projections[22,23,24,25].

Canada-level data on the annual change in energy consumption from energy efficiency was used to develop the Low scenario, which follows a continuation of historic trends. For the Medium and High scenarios, energy use reductions were assumed to be driven by retrofits, with the reduction values by end-use taken from a report by Efficiency Canada and Carleton University[24]. The authors state that the retrofit reductions cited "go further than most current practice but stop well short of current best-practice deep retrofits", and thus can be categorized as an intermediate between incremental improvements and best in class improvements. The differentiation between the Medium and High scenarios were the retrofit rates, with the Medium scenario accomplishing 60% retrofits by 2050 and the High scenario achieving 100% retrofits in the same timeframe. Table 7 below summarizes the scenario descriptions that serve as the basis for the electricity efficiency projection. Figure 31 shows the resulting scenario projections out to 2050.

Table 7: Scenario description and electrical (non-heat) energy use reduction by 2050 relative to 2021.

Scenario	Description	Non-heat electrical reduction in 2050
Low	Continuation of historic energy efficiency trends	5%

[22] Natural Resources Canada Comprehensive Energy Use Database (2000 – 2018) | Commercial/Institutional Sector – Ontario
[23] Natural Resources Canada, Canada-wide Energy Use Database (2000 – 2018) | Total End-Use Sector - Energy Use Analysis
[24] Efficiency Canada and Carleton University, Canada's Climate Retrofit Mission, June 2021
[25] City of Toronto, City of Toronto NetZero Existing Buildings Strategy and Technical Appendix, 2021

Scenario	Description	Non-heat electrical reduction in 2050
Medium	Intermediate trend (66% retrofits by 2050)	18%
High	NZ40 rate (100% retrofits by 2050)	27%

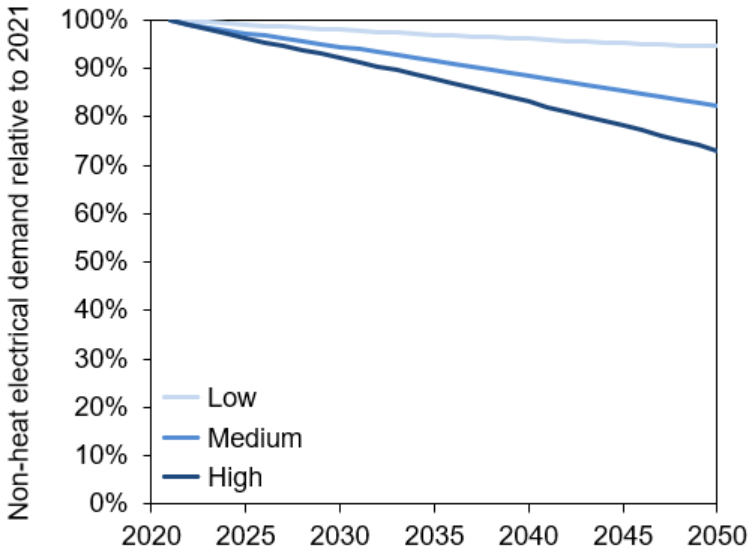


Figure 31: I&C projections for electricity (non-heat) energy demand reduction relative to 2021.

4.1.4 Flexibility Measures

Time-of-use (ToU) tariffs and energy storage are the primary flexibility measures relevant to core demand in this analysis. The approach to modelling the impact of ToU tariffs in the core demand projections is described below, while the modelling of domestic and I&C battery storage is discussed in more detail separately in section 4.5.

Under the Regulated Price Plan (RPP), a large fraction of domestic and small commercial customers (91%) in Toronto were on ToU tariffs before September 2020. In October 2020, the Consumer Choice regulation issued by the Ontario Energy Board (OEB) enabled price plan switching for RPP customers which has resulted in a reduction in the fraction of customers on the ToU plan[26], as shown in Figure 32.

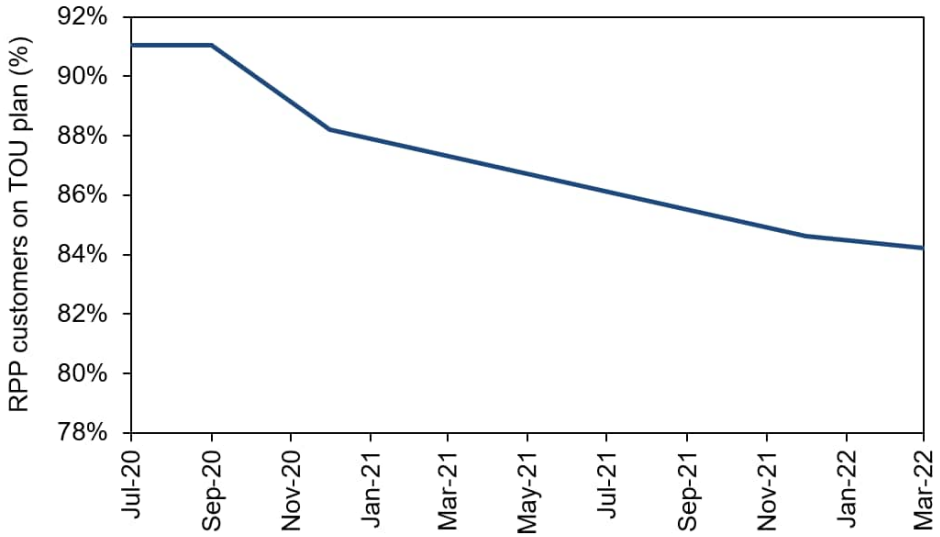


Figure 32. Price plan switching of eligible customers between ToU and tiered rate plans since the introduction of Consumer Choice, Ontario, Canada.

It is worth noting that a large portion of the observed switches occurred in the first few months after the regulation was implemented (47%). The latest available update on switching is from March 2022, which shows that 84% of eligible RPP customers remain on ToU tariffs. The current level of ToU tariff penetration across the Toronto Hydro network is captured in the modelling through the core demand profiles used (see Section 5.1). The March 2022 level of ToU tariff uptake is maintained throughout the modelling period for all scenarios.

[26] Ontario Energy Board (OEB), Frequency of Regulated Price Plan Switching Under Consumer Choice, 2021

4.2 Low Carbon Heating

There are two main pathways to decarbonize heat, each relying on varying levels of electrification and gas decarbonization. The key themes in each of these pathways are described in Figure 33.

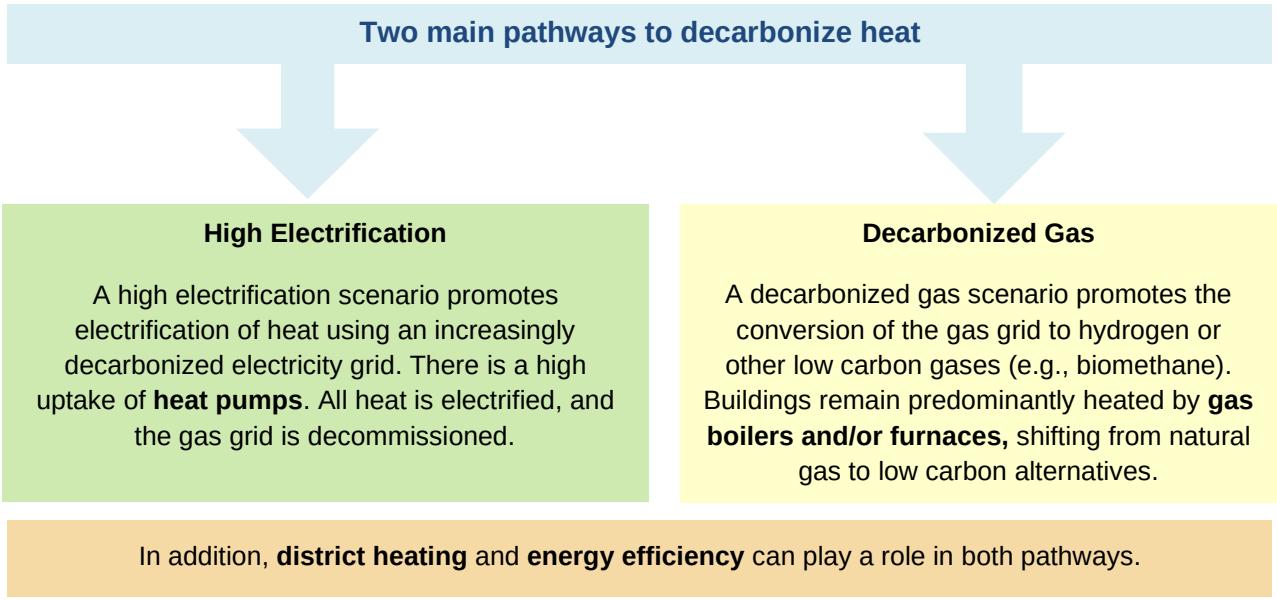


Figure 33: Heat pathway diagram.

The High Electrification and Decarbonized Gas scenarios represent two extremes of the future; in reality, the pathway for heat decarbonization in Canada, and Toronto particularly, could be a mix of these components, with different regions potentially opting for different technological solutions.

We developed scenarios for key drivers of the transition to low carbon heating, as laid out in Table 8. For energy efficiency and heating technologies, four scenarios representing incremental levels of ambition were generated using Element's consumer choice modelling (described in Section 4.2.1). The efficiency scenarios relate to the level of uptake of fabric improving efficiency measures among the region's building stock Note that "Early High" is used for heating technology uptake as opposed to "Very High" – this is because the scenario reaches the same level of heating technology deployment as the "High" scenario, but at a faster rate. As with other sectors, these technology specific uptake scenarios have then been mapped to a corresponding scenario world, as shown in Table 8.

Table 8: Scenario world mapping for low carbon heating.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Domestic thermal efficiency	Low	Medium	High	Low	Very High	Low
I&C thermal efficiency	Low	Medium	High	Low	Very High	Low
Domestic heating technologies	Low	Medium	High		Early High	
I&C heating technologies	Low	Medium	High		Early High	
Gas heating in 2050	High	Medium (due to hybrid heat pumps)	None		None	
Gas grid availability	Remains at current availability	Reduced utilization	Decommissioned by 2050		Decommissioned by 2040	

4.2.1 Modelling Approach

As discussed in Section 3.1, bottom-up consumer choice models were used to determine the uptake of decarbonized heating technologies. This analysis was predicated upon the locationally granular building stock trajectories (for domestic and non-domestic building types) described in Section 4.1.2. The domestic and I&C building trajectories were treated separately because their growth is driven by distinct factors.

Element Energy has a heating technology uptake model that assesses the business case of various heating technologies (Figure 34Figure 34) for different domestic and I&C building stock archetypes. In this model, the heating technologies are assumed to have a set lifetime (15 years for all scenarios), at the end of which the consumer chooses which technology to replace it with based on various factors. These factors include the following:

- Technology prices (capital costs and operational costs) including the available grants.
- Fuel and electricity costs.
- Thermal efficiencies for each archetype.
- Awareness of technology for domestic and I&C consumers.
- Willingness-to-pay for each archetype.
- Government policy.

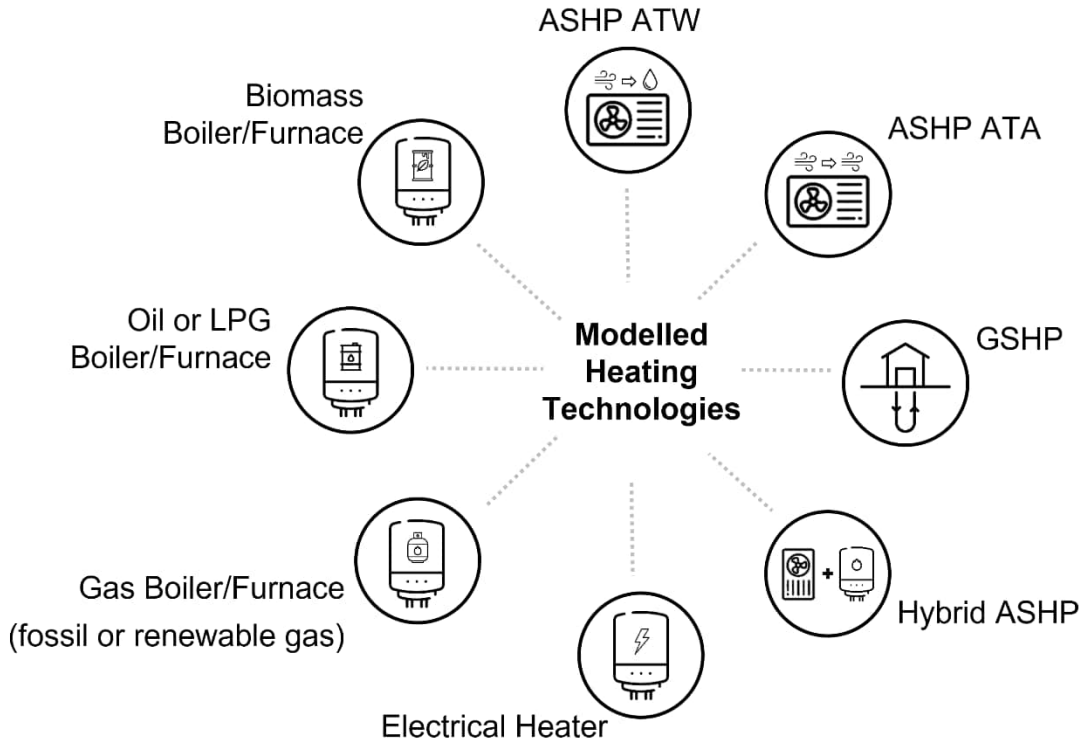


Figure 34: Modelled heating technologies.
Acronyms: ASHP ATW: air source heat pump – air to water; ASHP ATA: air source heat pump – air to air; GSHP: ground source heat pump; Hybrid ASHP: hybrid air source heat pump.

District heating is not classified as a distinct heat source in the consumer choice model, since the fundamental technologies used for heat generation are no different than those used in centralized applications; what differs is the distribution system. In addition to this, the driving factors leading to district heat uptake are more complex than for other low carbon heating options – uptake is related to variables beyond an individual consumer's choice or control, such as the heat density of the city, the proximity to existing or future significant sources of waste heat, or a region's planning laws. Considering Toronto specifically in conjunction with these general factors, two further points led to the decision to exclude district heating from our analysis of heat decarbonization in this case:

- Currently, fewer than 1% of buildings in Toronto are heated by district heating[3].
- Future rollout of district heating would affect the location and clustering of electrical loads, rather than the overall demand. At the geospatial resolution of this modelling (neighbourhoods and municipal stations), the impact of this is expected to be very small.

4.2.2 Policy Assumptions

As existing fossil fuel technologies are currently cheaper to install and run in many cases, top-down government intervention is assumed to be essential to drive uptake of decarbonized heating technologies.

IESO's Pathway to Decarbonization[27] reflects a ban on fossil fuel heating in new homes by 2030 and existing homes by 2035. This suggests that the most likely policy intervention going forward to decarbonize heat will be to phase out heating technologies that depend on high carbon fuels such as gas, oil and LPG. Element Energy's previous engagement with building-level heat professionals suggests that, if such policy interventions are to occur, they will first target new builds, followed by off-gas existing buildings, followed by on-gas existing buildings, depending on the general policy ambition.

[27] The Independent Electricity System Operator, Pathway to Decarbonization – Assumptions for Feedback, March 2022

Table 9 lists the assumed dates for when different existing heating technologies are phased out in order to reach net zero by either 2040 or 2050 depending on scenario. These dates apply to both domestic and I&C customers.

Table 9: Ban dates for choosing Business As Usual heating fuels in building types (new builds or existing builds).

Scenario	Existing heating fuel	New builds	Existing buildings	Ban date on Hybrid Heat Pump
Low	Gas	2035	No restrictions	No restrictions
	Oil & LPG	2035	2035	2035
Medium	Gas	2030	2035	No restrictions
	Oil & LPG	2030	2030	2030
High	Gas	2030	2035	2035
	Oil & LPG	2027	2027	2027
Early High	Gas	2025	2025	2025
	Oil & LPG	2025	2025	2025

Canada's Greener Homes Grant

The Canadian Greener Homes grant, effective from December 2020, grants up to $5,000 towards heat pumps and energy efficiency measures. The scheme can be used for a selection of low-carbon technologies, including those not used for heating (e.g. solar PV). The heat pump technologies that are supported by the scheme are listed below:

- Air-Source Heat Pump: Air-to-Air (ASHP ATA).
- Air-Source Heat Pump: Air-to-Water (ASHP ATW).
- Ground-Source Heat Pumps (GSHP).

There is currently no support for hybrid heat pumps under this scheme. The Greener Homes Grant is expected to last at least 7 years since its initiation, but this may be extended. Within our heating technology uptake scenarios, four policy scenarios were created describing a potential future for the Greener Homes Grant. These scenarios differ by level of support by technology, the heating technologies that are supported by the scheme and the scheme end date. The scenario mapping is shown in Table 10 below.

Table 10: The Greener Homes Grant policy support and duration assumed for each technology and scenario.

Scenario	GSHP	ASHP	Hybrid ASHP	End date
Low	$5,000	$4,000	$0	2027
Medium	$5,000	$4,000	$4,000	2030
High	$5,000	$4,000	$0	2030
Early High	$5,000	$4,000	$0	2035

4.2.3 Thermal Efficiency

Domestic Thermal Energy Efficiency Projection

For each building archetype, thermal efficiency trajectories were developed that then fed into the heat pump and load modelling on an archetype-specific basis. These trajectories are based on the following three components for each scenario:

- The baseline thermal demand of each archetype.
- The post-retrofit thermal demand of each archetype.
- The retrofit rate.

The baseline thermal demand was determined using data from the National Energy Use Database[28]. A post-retrofit thermal demand was then established for each archetype and scenario. For the Medium and High scenario, this is based on thermal demands after comprehensive building retrofits by building type and age based on a report by Efficiency Canada and Carleton University[24]. These were broadly aligned with post-retrofit demands for different building types from The City of Toronto's Net Zero Existing Buildings Strategy[29] (NZEBS), falling within the range of their *Recommended* and *Aggressive* scenarios. For the Very High scenario, which aligns with TransformTO's[3] Net Zero by 2040 (NZ40) scenario, deeper retrofits are assumed for each archetype, aligning with a total building energy efficiency gain of 75%. In the Low scenario, lower efficiency gains are assumed, and the post-retrofit thermal demand is aligned to TransformTO's Business as Planned (BAP) scenario, with a total building energy efficiency gain of 35%.

The retrofit rate represents the proportion of buildings retrofitted by year. The Low and Very High scenario retrofit rates are drawn from TransformTO BAP and NZ40, respectively. The High scenario retrofit rate is based upon the progress rate from NZEBS, while the Medium scenario retrofit rate sits midway between the Low and the High scenarios. Figure 35 shows the proportion of buildings retrofitted by 2050 for each scenario.

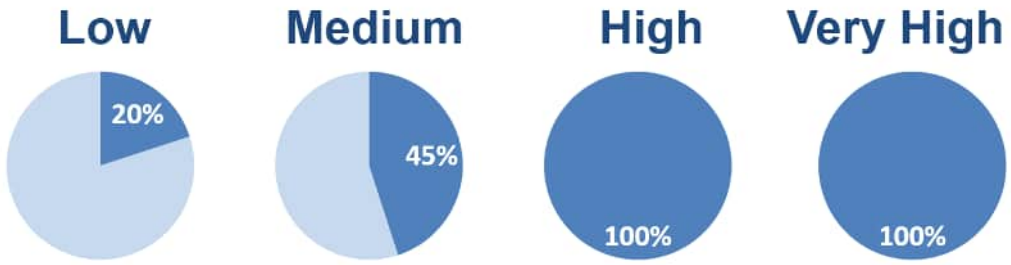


Figure 35: Proportion of domestic buildings retrofitted by 2050 by scenario.

The resulting thermal energy efficiency projections are shown below in Figure 36. Due to the deeper retrofits assumed in order to align the Very High scenario with TransformTO's NZ40 scenario, the overall thermal demand reduction achieved in the Very High scenario is higher than the citywide reduction of 73% put forth by the *Aggressive* scenario from the Toronto Net Zero Existing Buildings Strategy.

[28] Natural Resources Canada, National Energy Use Database – Ontario, 2018
[29] The City of Toronto, Net Zero Existing Buildings Strategy, May 2021

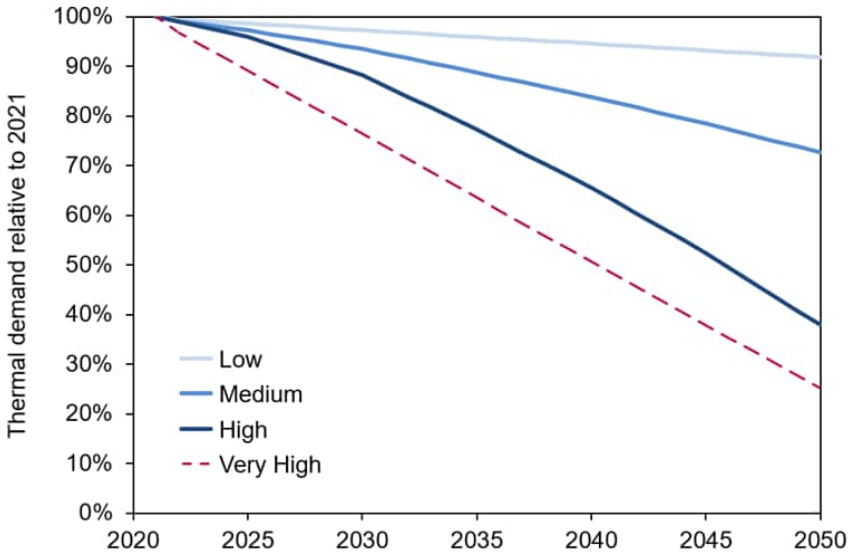


Figure 36: Domestic thermal energy efficiency projections out to 2050.

Industrial & Commercial Thermal Efficiency Projection

The baseline thermal demand by I&C archetype was determined using Ontario-level data from the Comprehensive Energy Use Dataset[28]. For the Low scenario, reductions in demand (and retrofit rate) are a continuation of energy use reductions from energy efficiency as taken from the Energy Efficiency Trends Analysis Tables of the National Energy Use Database[17]. The Medium and High scenarios base thermal demand reduction on retrofits, where the post-retrofit thermal demands by archetype were determined using the percentage reduction in thermal demand by end use from the Efficiency Canada and Carleton University report. These values are broadly aligned with the values from the *Recommended* pathway of The City of Toronto's Net Zero Existing Buildings Strategy. The retrofit rate for the High scenario is taken from the *Aggressive* pathway of The City of Toronto's Net Zero Existing Buildings Strategy, while the Medium scenario retrofit rate is the average of the BAP rate of TransformTO and the rate of the High scenario. Table 11 below shows the scenario descriptions that serve as the basis for the thermal efficiency projections. A Very High scenario was incorporated which matches the TransformTO NZ40 retrofit rate and retrofit reduction values. This represents a particularly ambitious scenario option since it exceeds the 60% reduction used in the *Aggressive* pathway of the Toronto Net Zero Existing Buildings Strategy which is based on "best in class" retrofits.

Table 11: Scenario description and thermal energy use reduction by 2050 relative to 2021.

Scenario	Description	Heating reduction in 2050
Low	Continuation of historic energy efficiency trends	10%
Medium	Intermediate trend (66% retrofits by 2050)	22%
High	NZ40 rate (100% retrofits by 2050)	33%
Very High	NZ40 rate and NZ40 reduction value	75%

The resulting thermal efficiency projections are shown below in Figure 37.

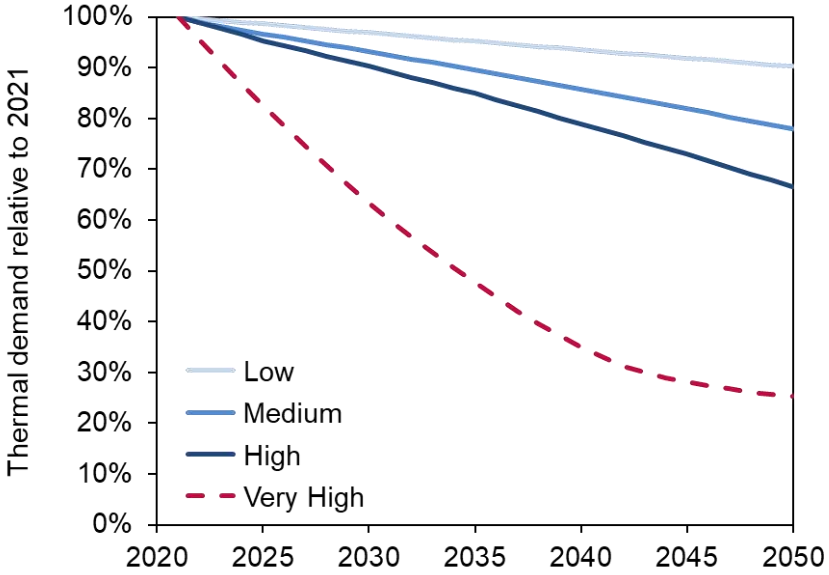


Figure 37: I&C thermal efficiency projections out to 2050.

4.2.4 Uptake Modelling Results

Element Energy's in-house consumer choice model was used to develop four scenarios for the uptake of low carbon heating across the domestic and I&C sectors, as described in Section 4.2.1. These scenarios represent a wide range of decarbonization ambition, resulting in varied levels of the uptake of heat pumps. The trajectories for the uptake of full electric heat pumps are shown below in Figure 38. The following sections detail the modelling assumptions and results for each of these scenarios.

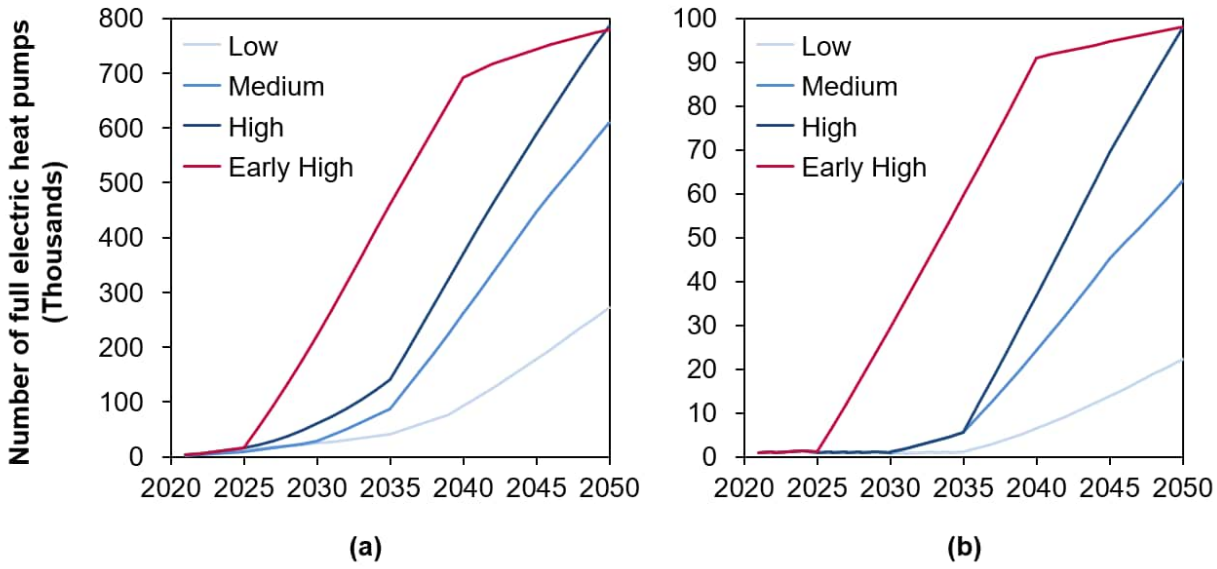


Figure 38: Comparison of full electric heat pumps modelled out to 2050 between scenarios for the (a) domestic and (b) I&C building stock.

Low Scenario - Steady Progression

In the Low scenario two policy interventions are considered, a ban on fossil fuel heating in new homes from 2035 and a ban on fossil fuel heating in off-gas properties from 2035 (Table 12Table 12). Additionally, the Greener Homes Grant is not assumed to last longer than the currently proposed duration of 7 years (from 2020). A low rollout in energy efficiency measures is modelled in this scenario. The resulting heating technology breakdown can be seen in Figure 39. This scenario fails to fully decarbonize the heating sector which still relies heavily on natural gas in 2050. The heat pumps that come into operation are predominantly in the new build and off gas grid sectors. Since there is no I&C sector support from the Greener Homes Grant, there is little financial motivation for heat pump uptake until policy forces the switch. This scenario suggests that without government intervention, the business case for gas heating will remain strong, resulting in low uptake of low-carbon heating technologies.

Table 12: Scenario assumptions for low-carbon heating technology uptake in the Low Scenario.

Heating technology	Date after which new builds can no longer choose heating fuel	Date after which existing buildings can no longer choose heating fuel	Date after which buildings can no longer choose a hybrid heat pump with heating fuel
Gas furnaces or boilers	2035	No restrictions	No restrictions
Other fossil fuel-based heaters	2035	2035	2035
Greener Homes Grant end date	2027	**Energy efficiency rollout scenario**	Low

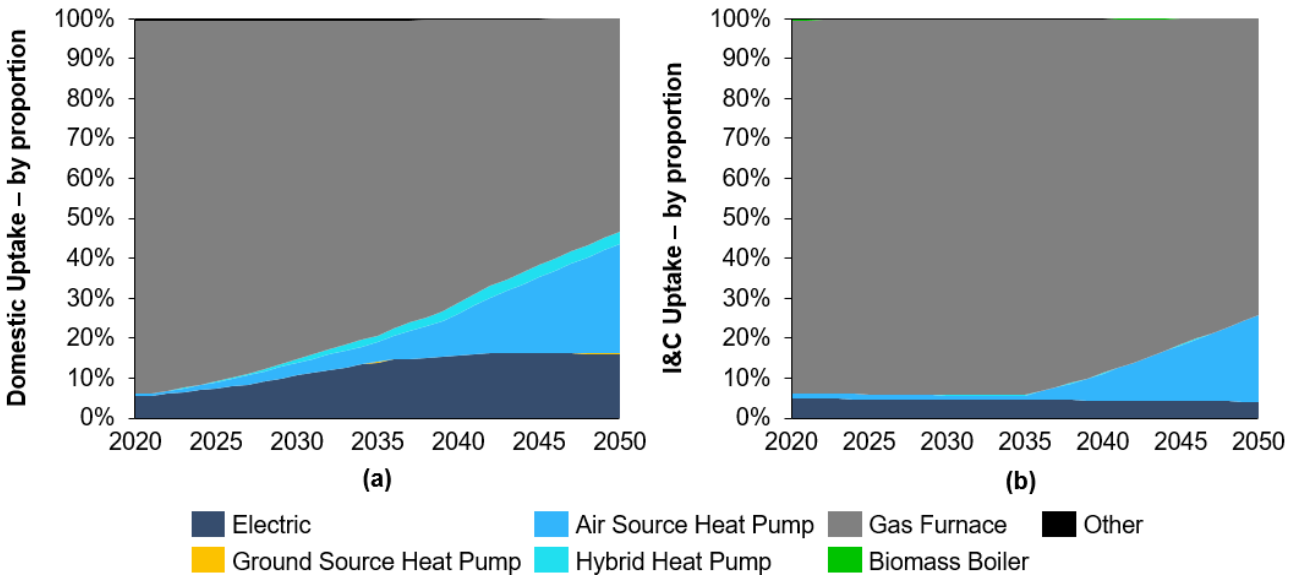


Figure 39: (a) Domestic and (b) I&C low carbon heating technology uptake - Low Scenario.

Medium Scenario – System Transformation

The Medium scenario is a gas-backed scenario and is based upon the *Hybrid Heating* pathway from The Canadian Gas Association's (CGA) report on pathways to achieving net zero building stock by 2050[30]. The report outlines three different decarbonization scenarios: *Efficiency*, *Hybrid Heating* and *Renewable Gases*. Each of these pathways are designed to meet net zero by 2050 by relying on the following factors to varying degrees depending on the scenario:

- Energy efficiency improvement programs.
- Stricter building regulations.
- Heat pumps (including hybrid heat pumps).
- Use of 'renewable gases', particularly renewable natural gas (RNG).
- Emissions offsets.

Table 13 shows the level of emissions reduction achieved in each of the three scenarios via the above drivers, according to the analysis.

Table 13: Canadian Gas Association Pathways showing the proportion of present-day emissions removed.

CGA Scenario	Gas demand reductions	Renewable gases	Emissions Offsets
Efficiency	43%	43%	14%
Hybrid Heating	56%	35%	9%
Renewable Gases	30%	55%	15%

The *Hybrid Heating* pathway has the lowest reliance on emissions offsets (as well as renewable natural gas) and was selected to inform the gas-backed Medium scenario in this analysis.

In the Medium scenario the ban on fossil fuel heating in new builds is brought forward to 2030 and existing off-gas properties can no longer choose non-gas fossil fuel heating from 2030 (Table 14Table 14). Existing on-gas properties are no longer able to select gas heating from 2035. To simulate the *Hybrid Heating* pathway in the consumer choice model, hybrid heat pumps are not phased-out from sales at this date, unlike in the other net zero compliant scenarios. Additionally, an extension to the Greener Homes Grant to support hybrid heat pumps as well as pure electric ones is modelled. A medium rollout of energy efficiency measures is modelled in this scenario.

Table 14: Scenario assumptions for low-carbon heating technology uptake in the Medium Scenario.

Heating technology	Date after which new builds can no longer choose heating fuel	Date after which existing buildings can no longer choose heating fuel	Date after which buildings can no longer choose a hybrid heat pump with heating fuel
Gas furnaces or boilers	2030	2035	No restrictions
Other fossil fuel-based heaters	2030	2030	2030
Greener Homes Grant end date	2030 with hybrids	**Energy efficiency rollout scenario**	Medium

[30] The Canadian Gas Association, Potential Gas Pathways to Support Net Zero Buildings in Canada, October 2021

In the Medium scenario a considerable proportion of heating systems in both the domestic and I&C sectors switch to hybrid heat pumps, making use of retained gas infrastructure (Figure 40Figure 40). It is worth noting that the source of the gas is not modelled for these scenarios; however, for the Medium scenario to be consistent with the 2050 net zero target, all fossil natural gas would need to be replaced with renewable natural gas, per the CGA's recommendations.

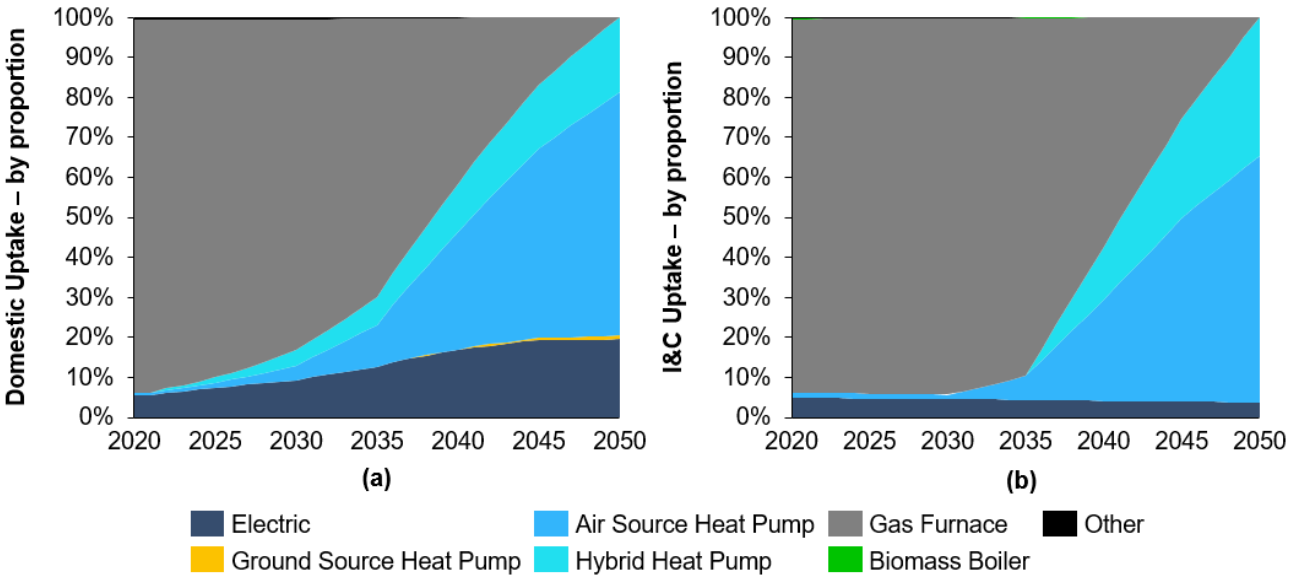


Figure 40: (a) Domestic and (b) I&C low carbon heating technology uptake - Medium Scenario.

High Scenario – Consumer Transformation

The High scenario relies on the full electrification of the heating sector. Like the Medium scenario, an extension to the Greener Homes Grant to 2030 is modelled; however, this is modelled without the additional support for hybrid heat pumps in this scenario. A ban on gas heating in new builds is enforced in 2030, with the ban on other fossil fuel heating brought forward to 2027, for existing and new builds (Table 15Table 15). In 2035, a ban on gas boilers is enforced for existing buildings, which includes switching to gas hybrid heat pumps. These bans, coupled with an assumption of a 15-year average lifetime of heating technologies, ensures a complete phase out of gas heating by 2050. A high rollout of energy efficiency measures is modelled in the High scenario. The resulting heating breakdown in Figure 41 shows that, for both the domestic and I&C sectors, the entire building stock is either using electric heating or fully electric heat pumps by 2050.

Table 15: Scenario assumptions for low-carbon heating technology uptake in the High Scenario.

Heating technology	Date after which new builds can no longer choose heating fuel	Date after which existing buildings can no longer choose heating fuel	Date after which buildings can no longer choose a hybrid heat pump with heating fuel
Gas furnaces or boilers	2030	2035	2035
Other fossil fuel-based heaters	2027	2027	2027
Greener Homes Grant end date	2030	**Energy efficiency rollout scenario**	High

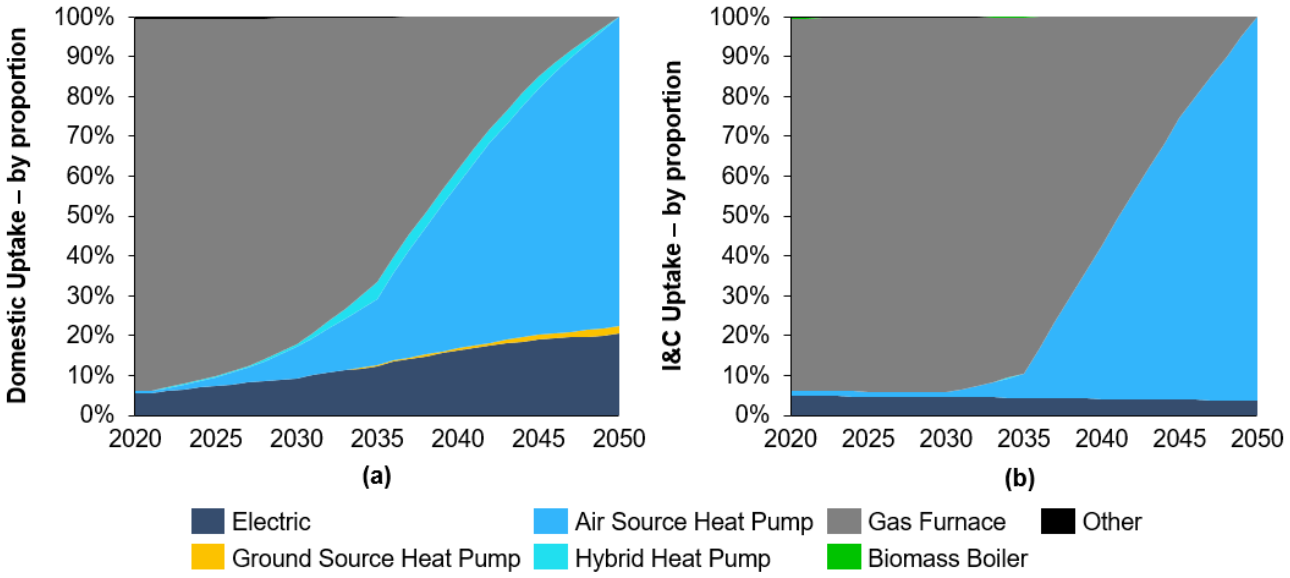


Figure 41: (a) Domestic and (b) I&C low carbon heating technology uptake - High Scenario.

Early High – Net Zero 2040

The Early High scenario reflects the highest government ambition in the scenarios modelled, with a 2040 net zero target. The scenario assumptions used in this scenario reflect early government action, with an all-encompassing ban on gas and other fossil fuel heating in 2025. The Early High scenario assumes a further extension of the Greener Homes Grant beyond the Medium and High scenarios to 2035, without any support for hybrid heat pumps (Table 16Table 16). A very high rollout of energy efficiency measures is also modelled in this scenario. The resulting heating technology breakdown in Figure 42 shows a fully electrified heating system by 2040 in both the domestic and I&C sectors.

Table 16: Scenario assumptions for low-carbon heating technology uptake in the Early High Scenario.

Heating technology	Date after which new builds can no longer choose heating fuel	Date after which existing buildings can no longer choose heating fuel	Date after which buildings can no longer choose a hybrid heat pump with heating fuel
Gas furnaces or boilers	2025	2025	2025
Other fossil fuel-based heaters	2025	2025	2025
Greener Homes Grant end date	2035	**Energy efficiency rollout scenario**	Very High

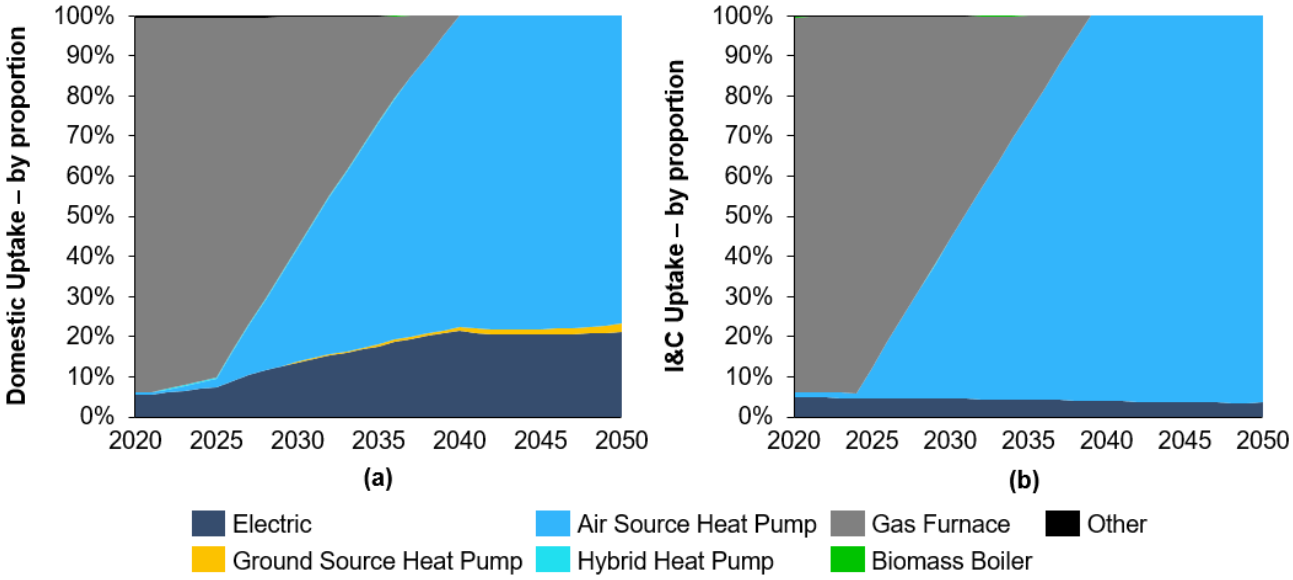


Figure 42: (a) Domestic and I&C (b) Low carbon heating technology uptake - Early High Scenario.

4.3 Electrification of Transport

There are several modes of transport relevant to Toronto, and in a similar manner to domestic and I&C buildings, different factors and market forces influence the manner in which different transport segments will decarbonize. Hence the penetration of electric vehicles (EVs) for each segment may differ in a given scenario world. The different sizes and requirements of transport types also lead to different technology mixes within sectors once decarbonized, as well as different assumptions for the energy required per unit of distance travelled. The main technology routes considered in the scenarios are summarized below in Figure 43.

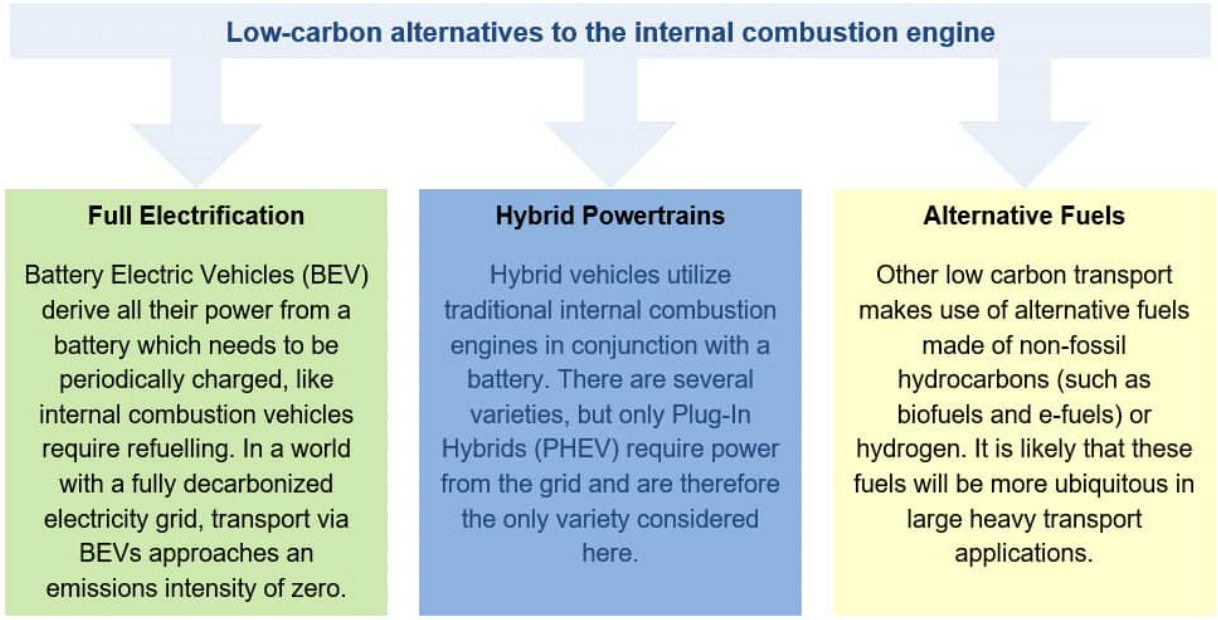


Figure 43: Main transport decarbonization pathways.

For the purposes of this analysis, transport has been segmented into Cars and Light Trucks, Medium- and Heavy-Duty Trucks, Buses, and Rail. Section 4.3.1 explains the electric vehicle uptake modelling process in more depth, while Section 4.3.6 gives an overview of how charging demand from these vehicles is allocated across the network. A summary of the penetration of electrified transport solutions in each of the four scenario worlds is given below in Table 17. The assumptions contained within each scenario are detailed in Sections 4.3.2 to 4.3.5 and 4.3.7.

Table 17: Scenario world mapping for transport electrification.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Cars and Light Trucks	Low	Medium	Medium		High	
Medium- and Heavy-Duty Trucks	Low	Medium	Medium		High	
Buses	Low	Medium	Medium		High	
Rail	Single Projection					
Smart Charging & V2G	Low	Medium	High	Low	High	Low

4.3.1 Modelling Approach

Electric Car Consumer Model (ECCo)

Element Energy's "Electric Car Consumer model" (ECCo) was used to generate bottom-up technology uptake scenarios for cars and light trucks, which consist of a varying mixture of full electric, hybrid and alternative-fuels based transport options. The model splits the private-individual and corporate-fleet customer bases into 18 archetypes based on attributes such as affluence and willingness-to-pay. The model then contains a parametric representation of consumer behaviour which was developed based on primary research conducted on a sample of 2,000 new car buyers. Within the model, consumers are "presented" with showrooms of future vehicles. Based on the real-world behaviour of the survey participants and the characteristics of consumer types within the model, the model reaches a purchase decision for each modelled individual which is likely to reflect real behaviour. For each model year the different consumer archetypes purchase an array of powertrains, which are typically observed to trend towards low-carbon options over time as the cost of these options fall. These results are then aggregated across all customer archetypes and converted to a total number of new car sales each year, which can also be converted to an overall share of the car stock held by a given technology.

Element Energy has refined this model over the course of the last decade, and it has been used extensively by clients in the UK including the Department for Transport and several electricity distribution businesses. The consumer choice approach it utilizes has consistently been shown to be more effective and accurate than other common approaches such as diffusion models and cost-comparisons. Figure 44 illustrates a high-level overview of the inputs and outputs of ECCo's modelling process.

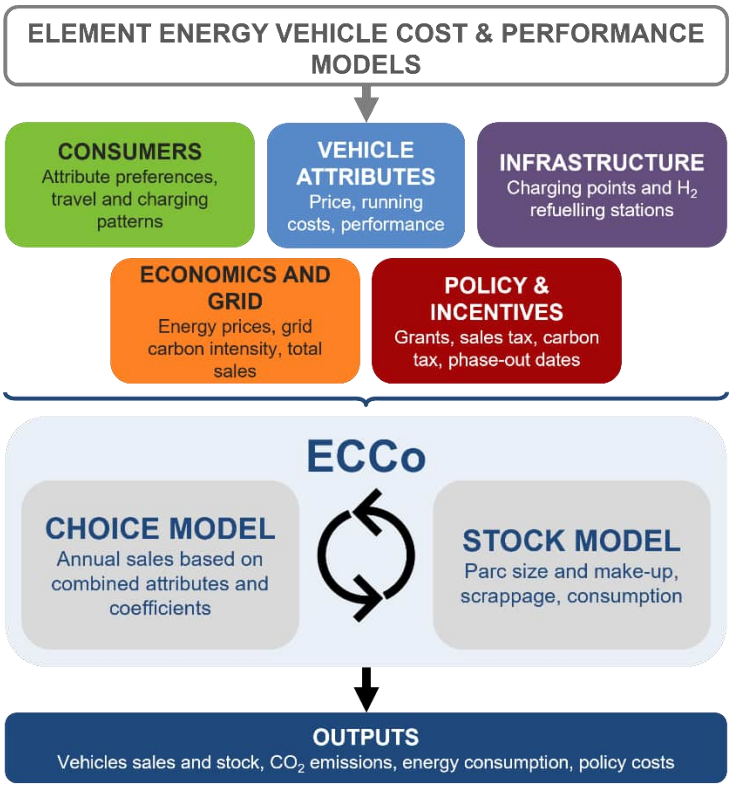


Figure 44: Schematic showing the process utilized by the ECCo model.

The modelling was tailored specifically to reflect the car ownership rates for different vehicle types in Canada and the physical attributes of the car types were also tailored to reflect the averages seen in the Canadian market. Inputs relating to vehicle economics such as tax rates, policy incentives and energy prices were aligned to those applicable in Toronto, including the Canadian Government's incentives for zero-emissions vehicles

(iZEV) scheme[31] (the assumptions used align with April 2022 policies). Details of Toronto's infrastructure (such as gas station and charge point locations) were also taken as an input.

This process was able to produce detailed Low, Medium, and High electrification uptake scenarios for Toronto's car and light truck stocks, containing a detailed breakdown of the percentage share of battery electric vehicles (BEVs), plug-in hybrid electric vehicles (PHEVs) and other fuel types prevalent within the transport stock from the base year (2021) to 2050.

Base Year Vehicle Stock

The base year car and truck stock in Toronto and its composition was found from a range of data sources. Statistics Canada publishes provincial level registration data[32] which splits the stock by car type (passenger vehicle, pickup trucks, etc.) and powertrain (gasoline, diesel, battery electric, etc.). Vehicles are also often split into classes for the purposes of analysis and legislation. For this study, the United States Federal Highways Agency system for car and truck classification is used, where vehicles are assigned to one of eight generic classes. Classes 1-2 contain passenger cars, light trucks, sports utility vehicles (SUVs) and people-carriers, while vehicles in classes 3-8 are medium- and heavy-duty trucks. The separate treatment of different vehicle classes is important to this analysis because the energy consumed per unit distance travelled by an EV, which is a key driver in the uptake model, differs between classes.

It is worth noting that the available data for Toronto lacked detail pertaining to specific use-cases or classes of individual vehicles, apart from a 2016 dataset from the Ontario Data Catalogue[33] which details the stock of commercial and private vehicles (with no additional granularity). Therefore, it has been assumed that the full population of private vehicles from this dataset consisted of classes 1-2 only, while all commercial stock consisted of classes 3-8. This is a reasonable assumption since the vehicle types in classes 1-2 and 3-8 are most frequently used in private and commercial capacities, respectively. In reality, there will be some overlap which is not possible to capture in this analysis.

In lieu of Toronto level data which could provide a more granular classification of the commercial vehicles, a provincial level breakdown published by Statistics Canada[32] has been used to derive the composition of the stock. This dataset categorizes vehicles by weight brackets, rather than vehicles class. As such, vehicles weighing less than 4.5 tonnes were categorized as classes 1-2 (Cars and Light Trucks); vehicles weighing between 4.5 and 15 tonnes were mapped to classes 3-7 (Medium-Duty Trucks); while vehicles weighing more than 15 tonnes were classified as class 8 (Heavy-Duty Trucks, such as semi-trailer trucks). The breakdown of the stock at the Ontario level has been assumed to be equivalent to that of Toronto.

In addition, the vehicle stock is further split into BEVs, PHEVs and non-EVs. This was based on Ontario level data on zero emission vehicle sales from 2017 onwards, also from Statistics Canada[34]. The implicit assumption within this is that all vehicles in this dataset have remained operational until the base year. The overall process is illustrated below in Figure 45.

TransformTO data[3] was used to derive an annual growth factor for the stock of cars and light trucks, which was applied to the base year stock (derived as described above) to give an absolute total number of cars and light trucks in the city each year. The total stock growth trend does not vary between scenarios.

[31] Government of Canada, Incentives for Zero-Emissions Vehicles (iZEV), April 2022
[32] Statistics Canada, Vehicle registrations by type of vehicle, September 2020
[33] Ontario Data Catalogue, Vehicle Population Data 2016, March 2019
[34] Statistics Canada, New zero-emission vehicle registrations, January 2022

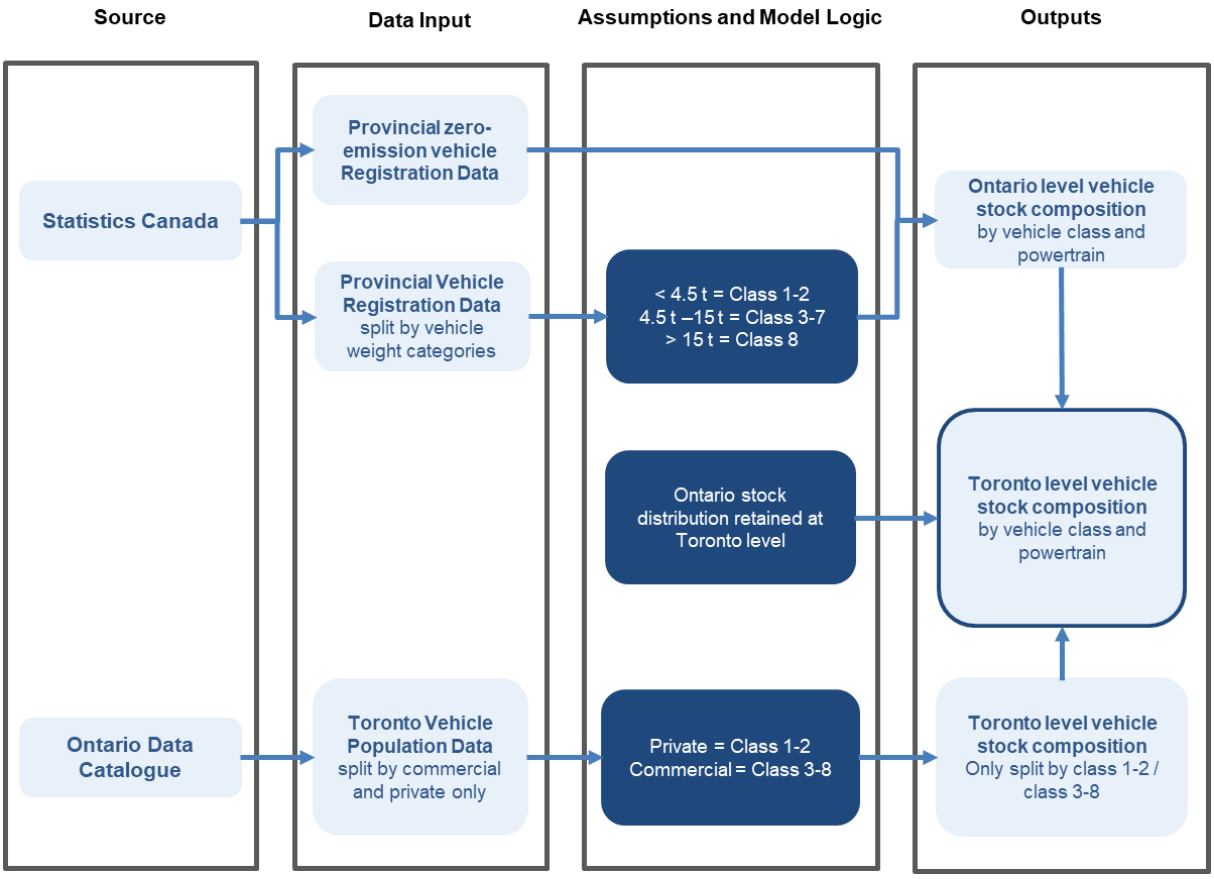


Figure 45: Methodology for deriving Toronto vehicle stock (cars and all truck types).

The bus stock in Toronto is owned and operated by the Toronto Transit Commission (TTC), who publish data regarding the makeup of their fleet including models, powertrains, age and depot locations in their annual Service Summary[35].

As of January 2022, there were 2,357 buses operational in the city, 79% of which were diesel powered. These buses span nine bus depots across Toronto. Under the assumption that all BEV and PHEV buses would charge solely at their designated depots, it is foreseeable that the peak impact of buses in specific areas of the grid could be significant, and hence is worthy of further analysis as described in Section 4.3.4.

[35] Toronto Transit Commission, Service Summary 2021, January 2022

4.3.2 Cars and Light Trucks

ECCo was used to model the development of the car stock from the common starting point derived as described in Section 4.3.1. By varying the assumptions related to policy, vehicles costs and infrastructure, three uptake scenarios for BEVs and PHEVs were developed representing a range of ambition levels. The trajectory for the total number of these types of cars in Toronto is shown below in Figure 46. The mapping of these scenarios to the overall scenario worlds is included in Table 17.

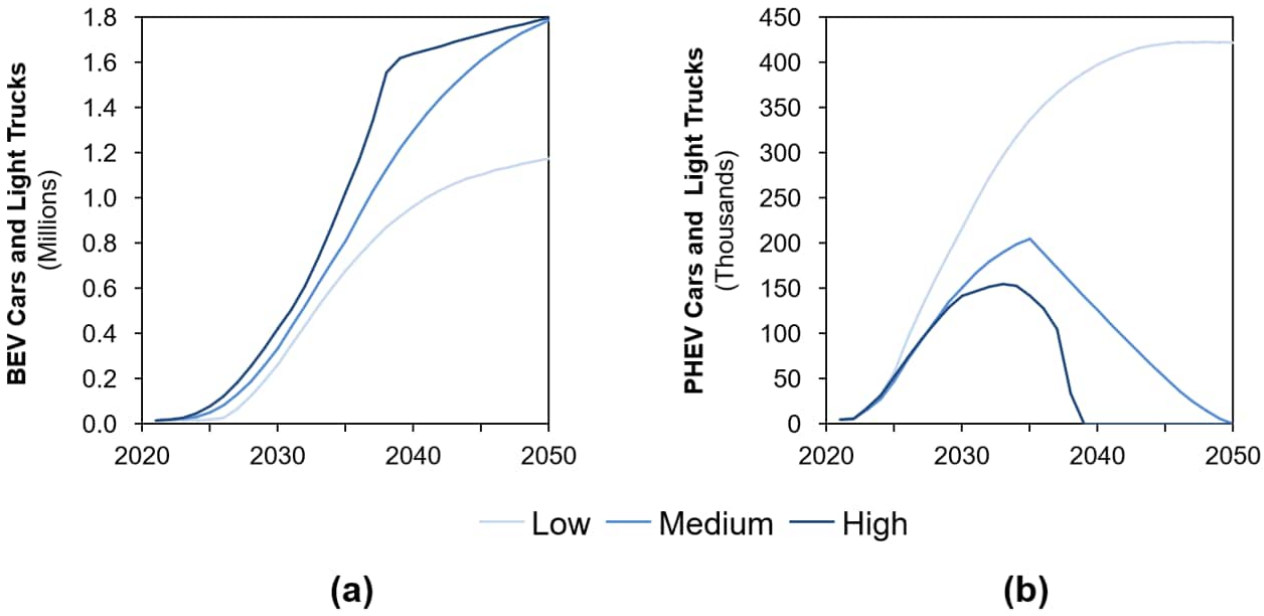


Figure 46: Comparison of Low, Medium and High stock profiles for (a) BEV and (b) PHEV cars and light trucks.

The above figure shows that the Medium and High scenarios differ primarily in the pace of their rollout of BEVs, with the Medium scenario relying more heavily on PHEVs as a transitional technology and for longer than the High scenario. However, the end states of both scenarios are comparable, with nearly 100% of the stock becoming fully electrified in both – meaning a rapid phase-out of hybrid and internal-combustion vehicles through the 2030s and 2040s.

Meanwhile, the Low scenario represents a markedly different view of the future of the transport sector. In this scenario, Toronto does not phase out hybrid or non-electric vehicles by 2050, implying a significant continued reliance on fossil fuels.

The assumptions underpinning each of the above trajectories, as well as a more detailed view of the stock breakdown in each case, are given below.

Low Scenario – Steady Progression

Table 18 describes the assumptions used in the Low scenario. A combination of low fossil fuel prices and high battery costs means that adoption of an EV would likely not be economically favourable for most consumers. Meanwhile, there is no top-down policy initiative established which could galvanize activity in the market, and as a result uptake is limited. In addition, the introduction of BEV SUVs and light trucks is delayed until 2023 and 2025, respectively, reflecting potential near-term supply constraints.

Table 18: Assumptions in Low electric transport uptake scenario.

Input		Assumption
Fuel Cost		Low crude price; current carbon tax policies[36]
Battery Cost		BNEF 2021; "High" price until 2024[37]
Non-zero emissions vehicles (non-ZEV) ban		N/A
Accelerated Non-ZEV removal period		N/A
Delay BEV introduction until	Cars	N/A
	SUVs	2023
	Light trucks	2025

Figure 47 shows the composition of Toronto's EV stock in the Low scenario, showing the continued reliance on non-BEVs and the stalled introduction of BEV SUVs and light trucks until the mid 2020s.

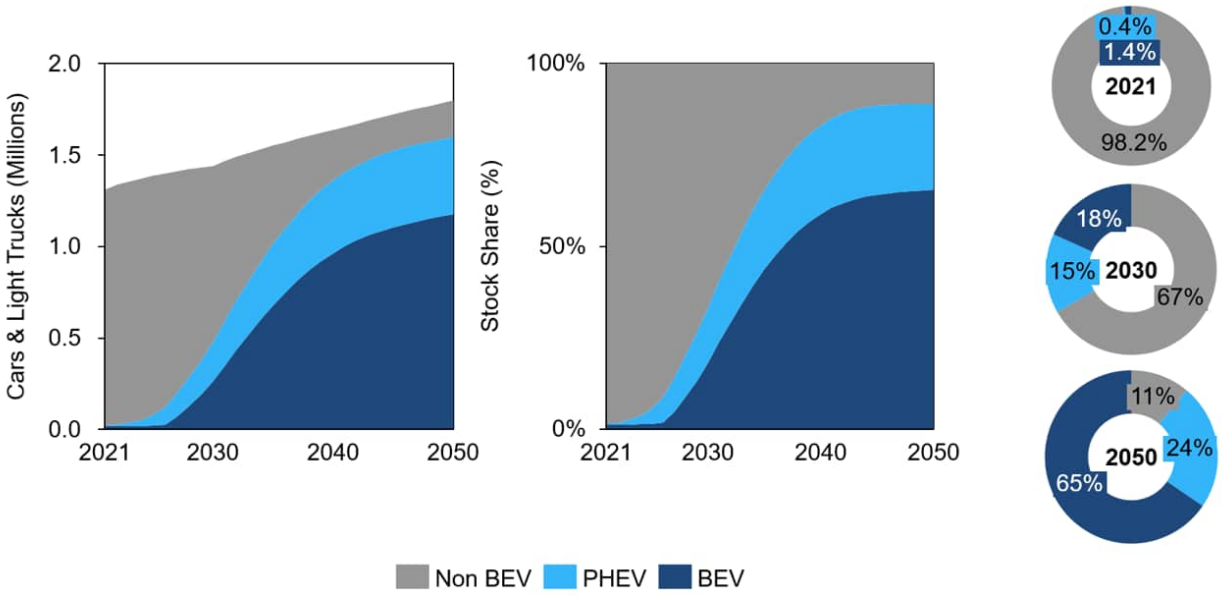


Figure 47: Low EV stock scenario – technology breakdown.

[36] Canada Energy Regulator, Canada's Energy Future, 2021
[37] Bloomberg NEF, Electric Vehicle Outlook, 2021

Medium Scenario – System Transformation & Consumer Transformation

Table 19 contains details the assumptions within the Medium scenario. As with the Low scenario, it is assumed that oil prices are low while battery prices remain high; but a non-ZEV sales ban is enacted from 2035 onwards. In addition, carbon taxation is increased from present levels, meaning the strength of the economic incentive to divest from fossil fuels increases. These factors have the effect of pushing consumers towards lower carbon options, resulting in a gradual and sustained phase out of non-BEVs. The effect of the non-ZEV phase out can be seen prominently on the PHEV trend in Figure 46b, where the curve begins to decline rapidly from 2035 onwards. Unlike the Low scenario, the Medium scenario does not delay the introduction of battery-electric SUVs and light-trucks.

Table 19: Assumptions in Medium electric transport uptake scenario.

Input		Assumption
Fuel Cost		Low crude price; evolving carbon tax policies[36]
Battery Cost		BNEF 2021; "High" price until 2024[37]
Non-ZEV ban		2035
Accelerated Non-ZEV removal period		N/A
Delay BEV uptake until	Cars	N/A
	SUVs	
	Light trucks	

Figure 48 illustrates the composition of Toronto's EV stock in the Medium scenario, showing the near complete decarbonization of this segment of transport by 2050.

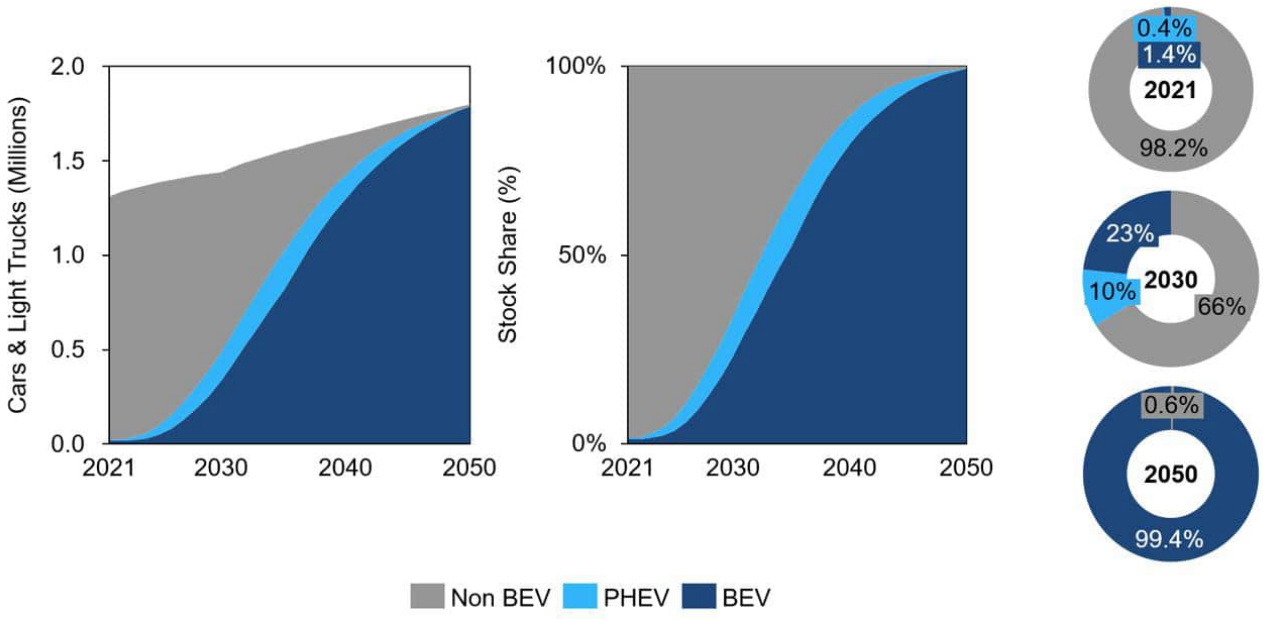


Figure 48: Medium EV stock scenario – technology breakdown.

High Scenario – Net Zero 2040

The High scenario, utilized in the Net Zero 2040 scenario world, is the most ambitious of the three scenarios. The High scenario assumes that fuel prices are high and battery costs are more favourable, meaning that consumers are more likely to decide to invest in an EV given the improved economics of this purchase decision. The carbon taxation scheme used in the Medium scenario is also retained here. Further, the non-ZEV ban applied in the Medium scenario is brought forward to 2030 (see Figure 46b) and is followed by a period of accelerated non-ZEV removal from Toronto to meet the 2040 net zero target. This could potentially be implemented via a policy mechanism such as a scrappage scheme or similar intervention. Table 20 summarizes the assumptions used in the High scenario.

Table 20: Assumptions in High electric transport uptake scenario.

Input		Assumption
Fuel Cost		High crude price; evolving carbon tax policies[36]
Battery Cost		BNEF 2021[37]
Non-ZEV ban		2030
Accelerated Non-ZEV removal period		2030-40
Delay BEV uptake until	Cars	N/A
	SUVs	
	Light trucks	

Figure 48 illustrates the composition of Toronto's EV stock in the High scenario, showing the total decarbonization of this segment of transport by 2040.

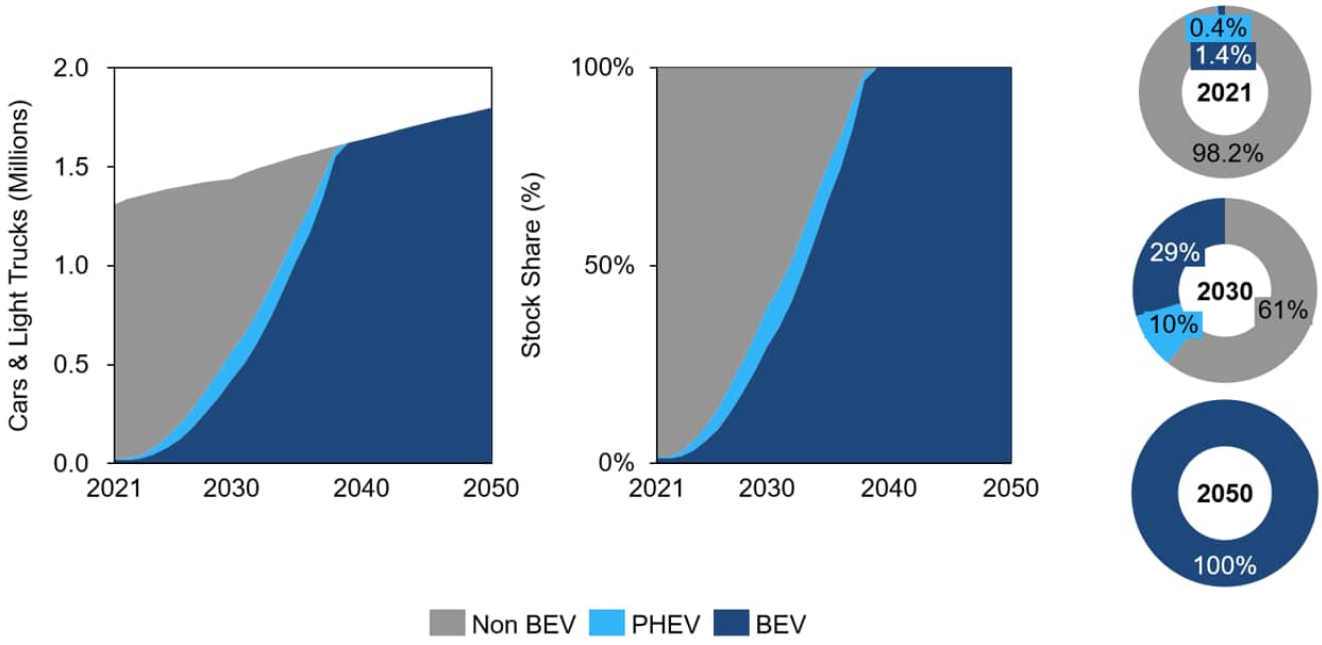


Figure 49:High EV stock scenario – technology breakdown.

4.3.3 Medium- and Heavy-Duty Trucks

The Low, Medium and High uptake scenarios for medium- and heavy-duty trucks are based on the assumptions listed below in Table 21.

Table 21: Truck uptake scenario assumptions.

Scenario	Scenario Narrative
Low	• 50% of truck sales by 2040 are ZEV • 100% of truck sales by 2050 are ZEV
Medium	• 30% of truck sales by 2030 are ZEV • 100% of truck sales by 2040 are ZEV • This aligns with Canadian Federal sales targets[38]
High	• Follows the ambitious targets of the California Air Resource Board to 2035[39] – see Figure 50 • Remaining non-ZEVs are all removed by 2040, by schemes such as scrappage bonuses.

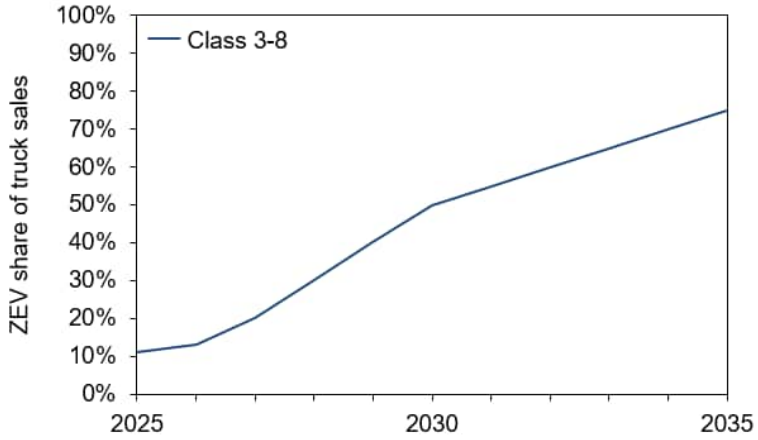


Figure 50: California Air Resource Board ZEV truck sales targets to 2035[39].

Figure 51 shows the three uptake scenarios developed using the above assumptions for class 3-7 and class 8 trucks separately. Again, these categories have been modelled separately because of their significantly different characteristics due to their weight. Principal among these differences is the energy consumed per unit of distance travelled (kWh/km). In general, the uptake of class 8 trucks (the largest commercial vehicles, such as semi-trailer trucks) leads their smaller counterparts by about two years. This is because it is assumed that the life span of such heavier vehicles is shorter and so they are replaced more frequently, meaning more of the stock is ready to be upgraded to low-carbon alternatives more quickly.

Somewhat similarly to the car and light-truck uptake trajectories described in Section 4.3.2, the Medium and High scenarios for medium and heavy trucks differ primarily in the rate at which full decarbonization of the stock is realized by 2050. Alternatively, in the Low scenario, the level of decarbonization achieved over the time horizon of this analysis is less complete. This is because in the Low scenario it takes until 2050 for all medium- and heavy-duty truck sales to be BEVs – so there is still a significant portion of the stock which consists of non-BEVs.

[38] Government of Canada, Incentives for Medium- and Heavy-Duty Zero-Emission Vehicles Program, July 2022
[39] California Air Resource Board, Medium- and Heavy-Duty ZEV requirement, 2020

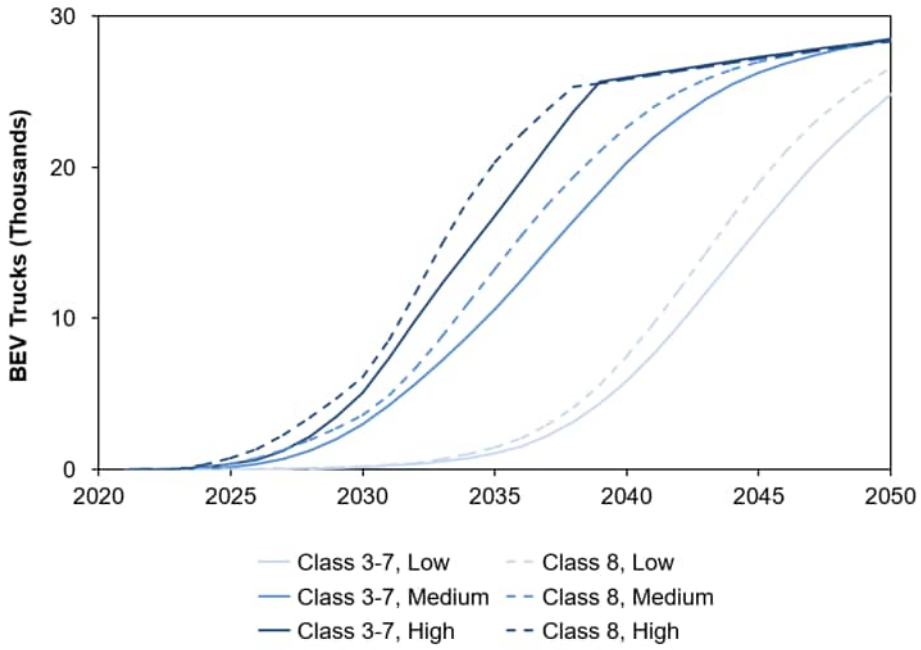


Figure 51: Stock scenarios for Class 3-7 (Medium-Duty) and Class 8 (Heavy-Duty) Trucks.

Figure 52 shows the comparative composition of the truck stock throughout the analysis for the three scenarios. The increased rate of removal of non-EVs in the High scenario is especially apparent, with 100% of medium and heavy trucks in Toronto (across all classes) switching to BEVs by 2040. In contrast, by 2050 approximately 20% of medium and heavy trucks remain non-electrified by 2050 in the low scenario.

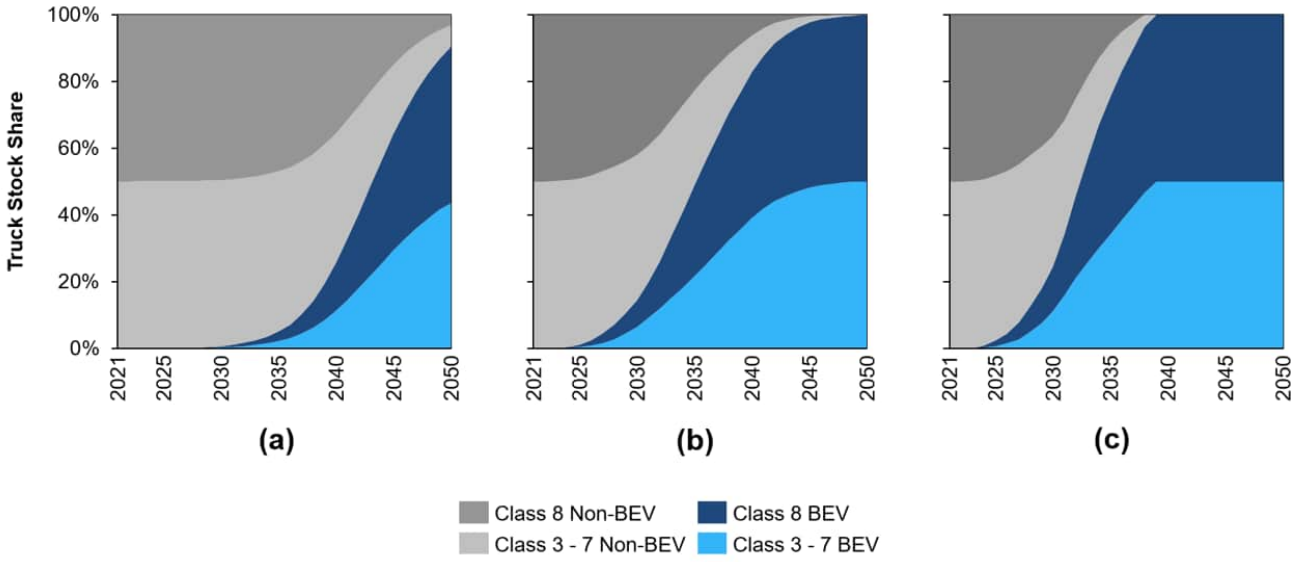


Figure 52: Truck stock split by class and powertrain in (a) Low, (b) Medium and (c) High electric truck uptake scenarios.

4.3.4 Buses

Given that the bus stock within Toronto is primarily owned and operated by a single organisation, the Toronto Transit Commission, the consumer choice approach used for other transport segments is less applicable here, so instead a simplistic representation of the TTC's decarbonization plans has been incorporated into the modelling of the bus fleet. Their current targets include the delivery of 300 BEV buses by 2025, with 100% ZEVs on the road by 2040[40]. The TTC aligned bus decarbonization phases used in this analysis can be summarized as follows:

- **Phase 1:** 20-50 BEV buses at every depot
- **Phase 2:** approximately 50% BEV rollout at every depot
- **Phase 3:** 100% BEV rollout at every depot

The date when individual depots convert their existing stock is staggered throughout each phase, and this is included in the modelling. The High scenario in this analysis aligns with the TTC's plans, while the Low and Medium scenarios include incremental delays to the completion of each phase. The assumptions applied to each scenario are set out in more detail below in Table 22. Note that in all scenarios, it is assumed that the bus stock in Toronto remains constant from the present day.

Table 22: Electric bus uptake scenario assumptions.

Decarbonization Phase	Year Phase Completed		
	Low	Medium	High (TTC compliant)
Phase 1	2029 (High + 4 years)	2027 (High + 2 years)	**2025**
Phase 2	2038 (High + 8 years)	2034 (High + 4 years)	**2030**
Phase 3	2052 (High + 15 years)	2045 (High + 8 years)	**2037**

[40] Toronto Transit Commission, TTC Green Initiatives, 2022

The number of electric buses present in Toronto under each of the above scenarios is shown below in Figure 53. The shape of the uptake curve in each scenario is similar due to the phased rollout of EVs across Toronto's buses, with the staggering between scenarios reflecting the different modelled timings for these phases.

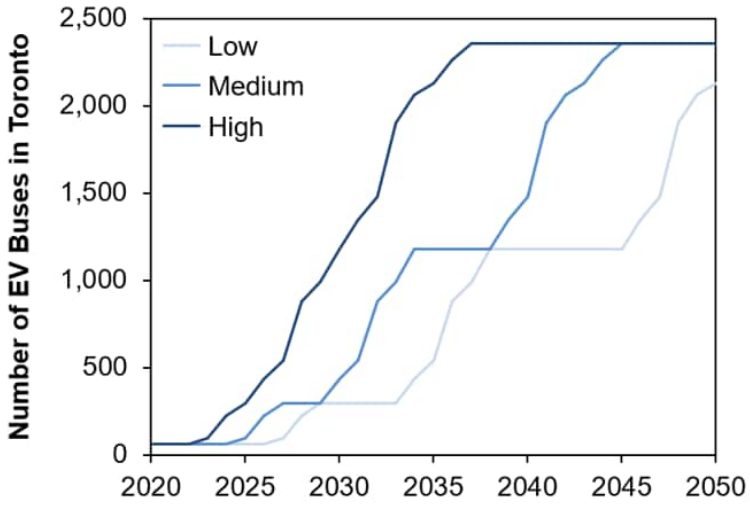


Figure 53: Electric Bus stock scenarios.

4.3.5 Rail

In Toronto, there are a number of different rail modes in operation, including:

- Subway
- Light rail
- Streetcar
- GO Transit
- Mainline Rail (VIA, Amtrak)

Of these, only the subway, light rail and streetcars are currently electrified. While there are some plans to electrify other rail modes, it is expected that these would operate on their own local network and connect to the transmission network, and so are not considered in this analysis. As of June 2022, when this analysis was undertaken, six subway and light rail expansion programs were underway or in advanced planning stages:

- Eglinton Crosstown Light Rail Transit
- Eglinton Crosstown West Extension
- Finch West Light Rail Transit
- Ontario Line
- Scarborough Subway Extension (Line 2 East extension)
- Yonge North Subway Extension (Line 1 North extension)

This also includes the closure of Line 3 Scarborough, planned for 2023. It is worth noting that after the analysis described in this report was completed, both the Waterfront Transit Network Expansion and Eglinton East Light Rail Transit projects have entered advanced planning stages. There is an opportunity for such updates to be incorporated in future iterations of this analysis. No additional significant extensions to the streetcar network are known to be planned.

To model the impacts from these extensions, a constant energy demand per km of track for each subway line has been assumed, calculated using current data on track length, energy demand and train frequency. The proposed extensions to subway lines[41] are then accounted for by multiplying the constant energy demand per km by the length of the proposed extension.

This additional demand is added to each subway line at the current grid connection and is only applied from the year of completion of expansion. This results in a single scenario, applied to all scenario worlds, with step increases in rail demand, in line with these expansions, as shown in Figure 54.

[41] The City of Toronto, Transit Expansion, June 2022

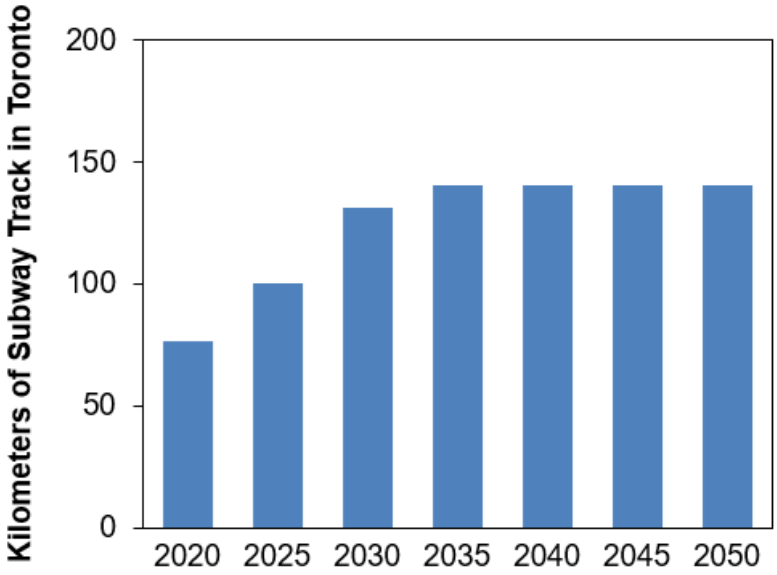


Figure 54: Total length of Subway Track in Toronto in kilometres.

4.3.6 Charging Distribution

The placement of transport demand within the modelling is challenging due to the nature of vehicles and the various ways in which they are utilized. Theoretically, any vehicle could charge at any number of points across the network as well as locations outside of the region served by Toronto Hydro. It is not enough to simply know the registered addresses of Toronto's cars; the use cases of the vehicles, the habits of their owners, and the infrastructure available for use must also be understood. The combination of these factors is referred to as "charging behaviour".

Cars and Light Trucks

The cars and light trucks represented by the Toronto-level trends presented in Section 4.3.2 are allocated to neighbourhoods as a starting point. In years preceding 2030, BEV and PHEV cars and light trucks are weighted towards neighbourhoods with greater modelled access to off-street parking, as these properties are able to install private residential charge points. This is a key driver of early EV uptake while public charging infrastructure is less mature. The distribution of homes with access to off-street charging is based on dwelling types and population density, as shown in Figure 55.

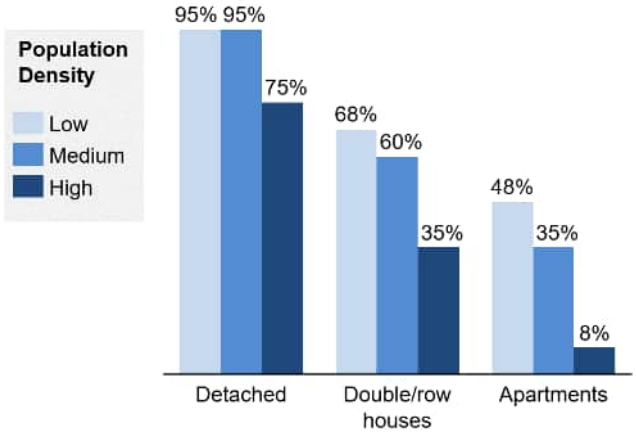


Figure 55: Level of access to off-street parking by dwelling type and population density of area[42].

After 2030, new EVs are distributed according to the current distribution of all cars across neighbourhoods, based on the assumption that access to charging will be ubiquitous across the city by that time, and a lack of private off-street charging will not impede the purchase of electrified cars and light trucks as was the case in the early years of the modelling. This then gives the distribution of EVs across the city's neighbourhoods for every modelled year. The neighbourhood an EV resides in will have a direct impact on the charging behaviour it is assumed to have in the subsequent modelling.

Cars and light trucks are assumed to charge in five distinct ways, detailed below:

- **Home charging** – owner has access to private "off-street" charging.
- **On-street residential** – owner lives in area with easy access to public charge points located by on-street parking spaces.
- **Destination** – vehicle is charged while parked at a trip destination.
- **En-route** – vehicle is charged during a journey.
- **Workplace** – owner charges their car at their workplace while at work.

Typically, most personal vehicles will be used in a variety of manners, so the customer base is further divided into eight archetypes based on the type of vehicle they own, their access to home charging and whether they commute. Within each of these eight driver types, the prominence of each of the above charging behaviours

[42] Element Energy and WSP Parsons Brinckerhoff, Plug-in electric vehicle uptake and infrastructure impacts study, 2016

varies. This breakdown is shown in Figure 56 and is derived from previous modelling work carried out by Element Energy for National Grid, which analyzed a dataset of 8.3 million charging events in the UK[43].

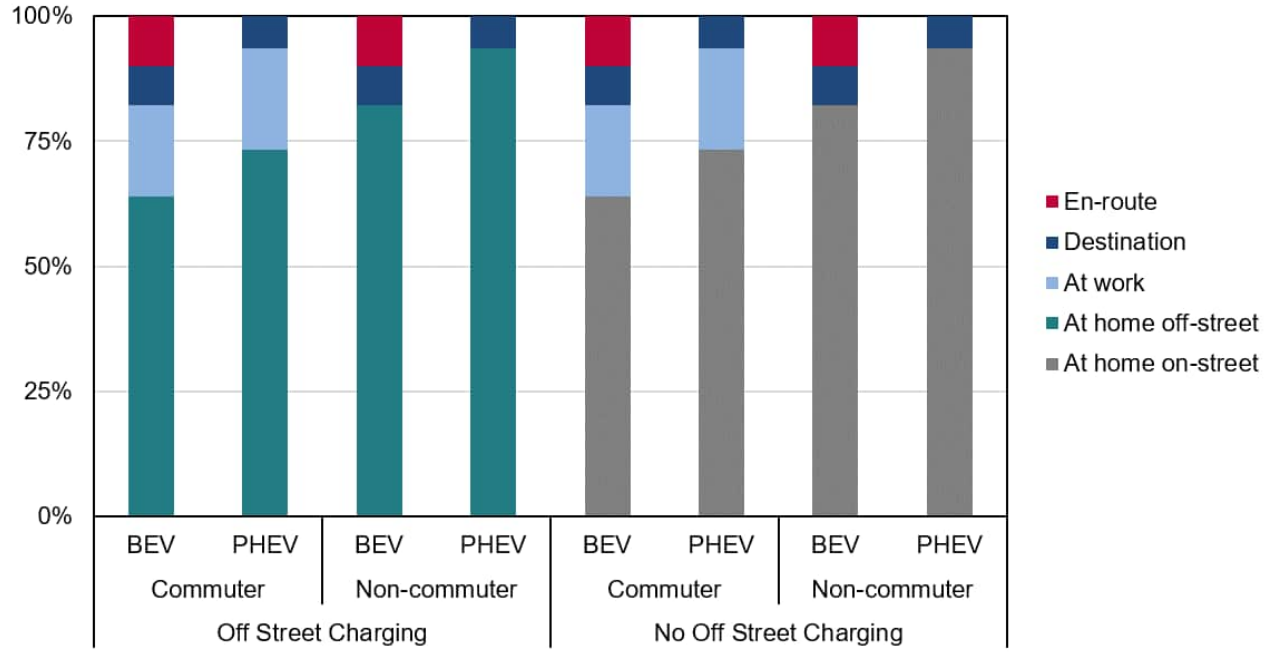


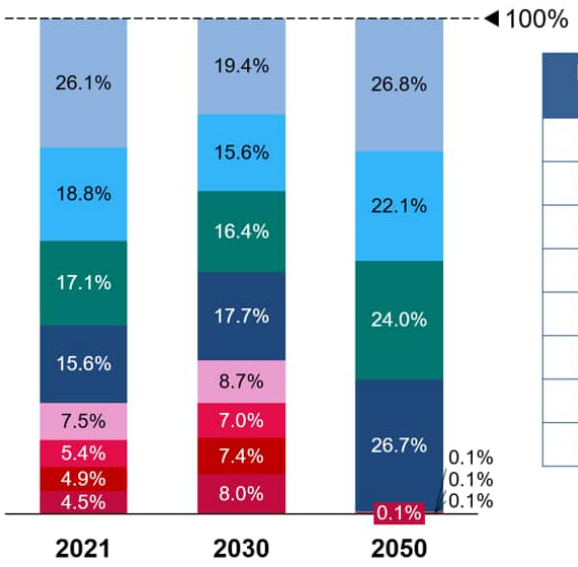
Figure 56: Prominence of charging behaviours across Toronto car and light-truck owners.

Data on the three variables defining the EV user archetypes shown in Figure 56 were used to distribute the archetypes between the neighbourhoods:

- **Powertrain proportions** (i.e. BEV / PHEV) were taken from the analysis described in Section 4.3.2. As such this parameter, and consequently the entire distribution of EV archetypes, changes between scenarios.
- **Commuting statistics** were taken from the 2021 census[44], which details the number of individuals commuting by different methods. This was combined with neighbourhood housing counts, also from the census, and data from a Toronto Metropolitan University study[45] regarding the levels of car ownership per household to give the share of cars used for commuting in each neighbourhood.
- **Home charging** was based upon access to private off-street charging and on-street public chargers, as described above (see Figure 55).

The combination of data types listed above gives a distribution of EV charging archetypes across the city which, due to the reliance on the split of BEVs and PHEVs within the vehicle stock, varies by scenario and year. Figure 57 shows the changing distribution of EV car and light truck archetypes for the Medium scenario.

[43] Element Energy, Electric Vehicle Charging Behaviour Study, 2019
[44] Statistics Canada, 2021 Census of population, 2021
[45] Toronto Metropolitan University, Household car ownership, 2018



EV Archetype	Powertrain	Off-Street Charging	Commuter
1	BEV	✓	✓
2	BEV	✓	✗
3	BEV	✗	✓
4	BEV	✗	✗
5	PHEV	✓	✓
6	PHEV	✓	✗
7	PHEV	✗	✓
8	PHEV	✗	✗

Figure 57: Changing EV charging archetype distribution at Toronto Level, Medium stock scenario

Since the EV archetype distribution varies by scenario, and because of the reliance of each archetype on different charging behaviours (as shown in Figure 56Figure 56), the physical positioning on the network of the loads due to EVs also changes between the uptake scenarios.

The location of charging events across the city (i.e. where each of the above archetypes charge their vehicles for the range of charging behaviours) was derived as follows:

- **Home charging** is consistent with the distribution of EV owners with access to off and on-street parking used to formulate the EV archetype distribution described above (Figure 58a).
- **En-route charging** is localized to existing gas stations which are within 500m of an expressway (Figure 58b). Other existing gas stations are not explicitly allocated any charging demand in the modelling. This is because the assumed prevalence of other charging types means that most drivers can charge at home or their destination for most journeys, while those on longer journeys can make use of stations near expressways.
- **Destination** and **Workplace** charging are localized to parking lots dependent on zoning data[46] (Table 23, Figure 58c, and Figure 58d).
- **Workplace** charging also considers demand from commuters who reside outside of Toronto, but commute into the city. It is assumed that en-route and destination charging events from non-Toronto residents evens out with Toronto residents who sometimes charge their cars outside of the city.

Table 23: Assumed mapping of parking lot zoning types to car and light truck charging locations.

Parking Lot Zoning Type	Destination	Workplace
Open Space	✓	✗
Commercial Residential Mixed Usage	✓	✓
Residential	✗	✗
Utility and Transportation	✓	✓
Heavy Industry	✗	✓
Employment	✗	✓
Business Park	✓	✓
Institutional	✓	✓
Commercial	✓	✓
“Other”	✓	✓

[46] City of Toronto Open Data Portal, Land use zoning by-law, 2022

Maps showing the modelled distribution of these charging locations throughout the city are shown below in Figure 58.

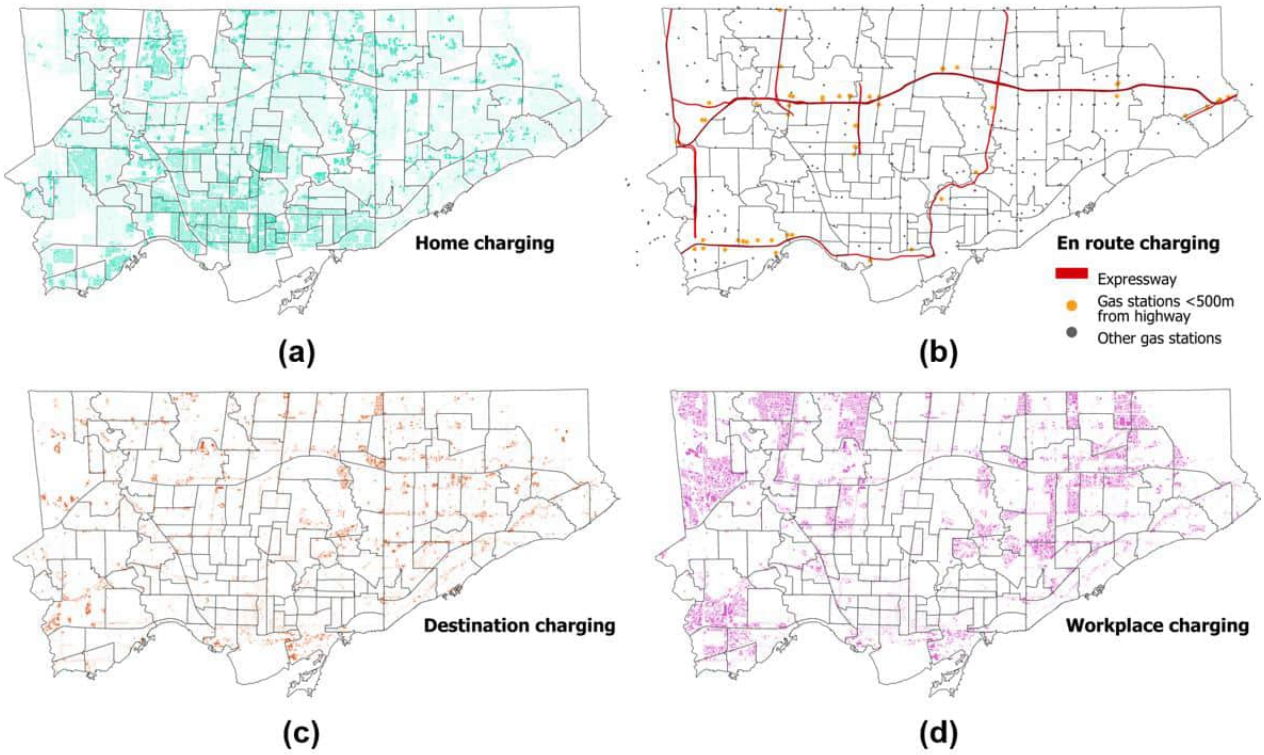


Figure 58: Charging type distributions for cars and light trucks.
(a) Home charging; (b) En-route charging; (c) Destination charging; (d) Workplace Charging.

Buses, Medium- and Heavy-Duty Trucks

As previously described in Sections 4.3.1 and 4.3.3, it is assumed that all medium- and heavy-duty trucks are used for commercial purposes only, in the same way that cars and light-trucks have been assumed to be for personal use. The modelling of medium- and heavy-duty trucks is split by weight class due to the differing energy requirements of each. In addition, different average journey lengths are assumed for each weight class to reflect the different usage patterns of medium sized trucks as compared with larger vehicles like semi-trailer trucks. Finally, all buses are treated as equal in the modelling.

As with destination and workplace charging, commercial vehicle depot charging is positioned according to parking lot zoning data[46]. The mapping used to locate charging depots for the commercial medium- and heavy-duty truck stock is shown below in Table 24. Based on research by Element Energy of truck driving behaviours across the UK[47], trucks are assumed to be able to do most of their charging at their home depot or at warehouses on their scheduled route. Longer distance trucking journeys likely require some en-route charging, however Toronto is assumed to be primarily a journey end or starting point for these trucks, so there is expected to be little en-route truck charging demand which affects Toronto Hydro's network. Therefore, all medium- and heavy-duty trucks are assumed to charge at their designated depot.

[47] Element Energy for Transport & Environment, Battery electric HGV adoption in the UK: barriers and opportunities, November 2022

Table 24: Assumed mapping of parking lot zoning types to medium- and heavy-duty truck charging locations.

Parking Lot Zoning Type	Truck Depot
Open Space	✗
Commercial Residential Mixed Usage	✗
Residential	✗
Utility and Transportation	✓
Heavy Industry	✓
Employment	✓
Business Park	✓
Institutional	✗
Commercial	✗
"Other"	✓

The current bus depots used by the TTC are assumed in the modelling of future bus stock (see Section 4.3.4) to remain in use until 2050, with no new additions. As such, all bus charging events are assumed to occur at the locations of these depots. The buses in the stock model are also designated to a specific depot, at which they are assumed to always charge.

The distributions of the charging locations for buses, medium- and heavy-duty trucks are shown below in Figure 59.

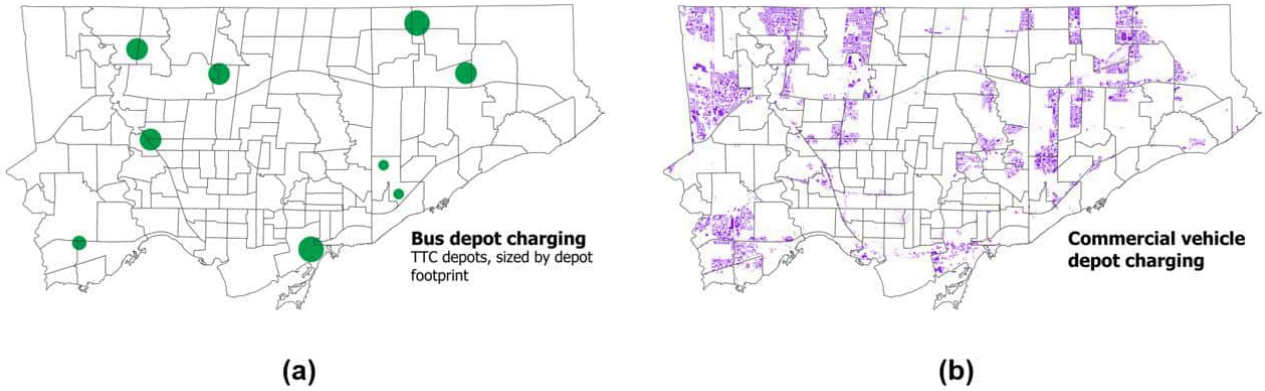


Figure 59: Charging distributions used for (a) buses and (b) medium- and heavy-duty trucks.

4.3.7 Smart Charging and Vehicle-to-Grid

With the push to electrify transport, Canadian local distribution companies (LDCs) have recently begun actively investigating the charging behaviour of EV users and the potential uptake of flexible demand-side technologies such as smart charging and "vehicle-to-grid" (V2G). However, most of these studies are ongoing and thus results are not yet available. Table 25 lists the EV charging studies explored for this work.

Table 25: Canadian LDC EV charging studies.

LDC	Description of study	Status
Toronto Hydro	EV smart charging pilot	Recruitment phase
Toronto Hydro	Utility-controlled smart charging study	Completed
Hydro One/ Peak Power	Vehicle-to-home (V2H) pilot program	Ongoing
Nova Scotia Power	Utility-controlled smart charging pilot	Ongoing
ENMAX	Smart charging study looking at demand shift potential based on incentives	Ongoing

Given the ongoing nature of these studies, there is currently limited data available on the potential of V2G technology in Canada. Subsequently, internal modelling was used to determine uptake scenarios for V2G technology. These scenarios were formulated to reflect likely levels of penetration of V2G and are conservative due to high costs of bi-directional chargers and current limitations around the business case for this technology[48].

With regards to smart charging, a few sources were used for data on the smart charging landscape within Canada and Toronto. The utility-controlled study performed by Toronto Hydro[49] had valuable baseline data on the charging behaviour of Toronto residents. Additionally, an analysis of the Plug N Drive survey in Toronto[50] identified that 83% of EV users "relied on overnight charging all of the time or some of the time". The data from these two sources, while specific to Toronto, doesn't map directly onto the smart vs. non-smart charging regimes required for this component of the analysis and were therefore used primarily as a sense check against an Ontario-level study performed by FleetCarma. The "Charge the North" study by FleetCarma[51] identified Ontario-level proportions of total charging energy by rate period. In the report, charging during the off-peak period was considered "smart"; in Ontario, off-peak charging was found to account for 85% of charging, which is close to the value reported in the Plug N Drive survey and is also close to the current ToU tariff penetration in Toronto (84%).

As the smart charging proportion matches closely with the current ToU tariff penetration, the Medium scenario envisions no change in smart charging activity, in line with the modelled ToU behaviour. The High scenario is a more ambitious view of the future, where the new overnight tariff structure proposed by the OEB, which targets EV users, is assumed to drive smart charging participation, reaching 100% in 2030. Finally, in the Low scenario, an equal but opposite rate of change of smart charging penetration as the High scenario is assumed, with participation decreasing to 70% in 2030, after which equilibrium is maintained. The scenarios developed, which outline the proportion of charging which is unmanaged, smart, or V2G, are shown in Figure 60. The Low scenario sees no adoption of V2G charging at any point, while there is a gradual introduction of V2G from 2030 onwards in the Medium scenario. In the highest ambition scenario, unmanaged charging is fully and

[48] Element Energy, V2GB – Vehicle to Grid Britain Requirements for market scale-up (WP4), June 2019
[49] Bauman, J. et. al., Residential Smart-Charging Pilot Program in Toronto: Results of a Utility Controlled Charging Pilot, June 2016
[50] IAEE, Driver Experiences with Electric Vehicle Infrastructure in Ontario, Canada and the Implications for Future Policy Support, Fourth Quarter 2020
[51] FleetCarma, Charge the North, 2019

rapidly phased out, and V2G uptake begins immediately from the base year. From 2030 onwards all EVs are charging in a flexible manner in the High scenario.

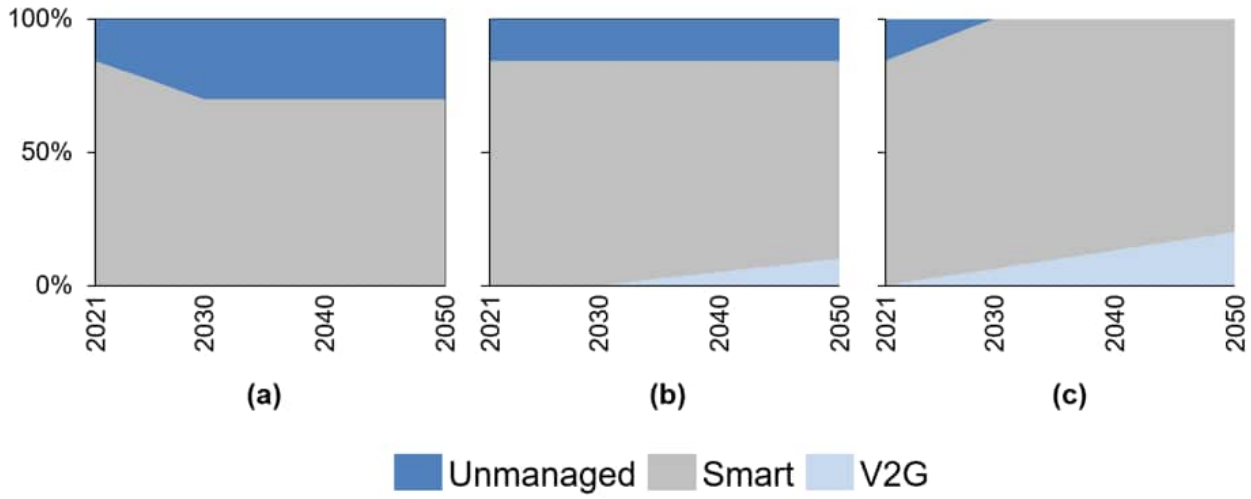


Figure 60: Proportion of EV drivers participating in various charging types, for the (a) Low, (b) Medium, and (c) High scenarios.

4.4 Electricity Generation

A range of generation technologies that can connect to the distribution network have been considered in the analysis. As with demand, three to four future uptake scenarios (e.g., Low, Medium, High, and Very High) have been developed for each technology, which have then been assigned to the four scenario worlds according to how they align with their respective narratives. The full mapping of generation uptake scenarios to the scenario worlds is shown in Table 26.

Table 26: Distributed generation technology uptake scenario mapping.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Rooftop solar PV*	Low	Medium	High	Low	Very High	Low
Ground-mount solar PV*	Low	Medium	High	Low	High	Low
Wind	Low	Low	High	Low	High	Low
Biogas	Low	Medium	High	Low	High	Low
Non-renewables	High	Low	Medium	High	Low	High

* Rooftop solar PV is defined as installations of capacity less than or equal to 250 kW and ground-mount solar PV refers to installations larger than 250 kW.

4.4.1 Modelling Approach

The approach used for modelling the uptake of distributed generation consists of three steps, as outlined in Figure 61. Existing generation is used as a baseline value and a pipeline is added to this value over a pre-defined number of years. After this point, uptake projections follow the long-term pathways that are generated based upon a range of methods, including consumer choice modelling, external datasets, and stakeholder engagement.

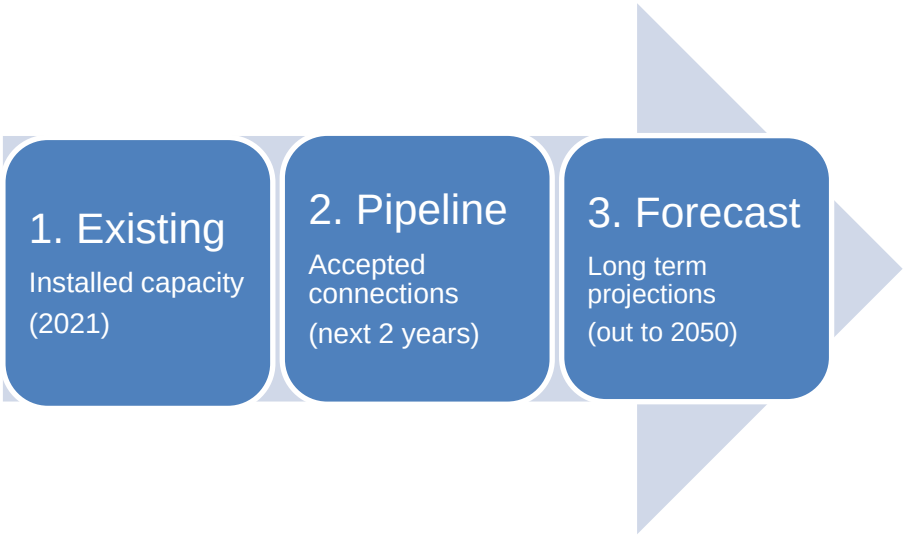


Figure 61: Pathway for modelling distributed generation.

Existing generation capacity was drawn from data provided by Toronto Hydro, which was checked against other sources such as the IESO Active Contracted Generation List[52]. The existing generation baseline included everything connected by the end of 2021.

[52] IESO, Active Generation Contract List, June 2021

The pipeline for all generation and storage was defined as the two years after the baseline, that is 2022 and 2023. The proportion of pipeline connections projected to connect varied by scenario and by size, as detailed in Table 27. These definitions reflect Toronto Hydro's understanding of how pipeline generation typically connects, based upon historic trends.

Table 27: Proportions of pipeline generation capacity that connects in each scenario.

Pipeline Generator Size	Low	Medium	High
< 1MW	40%	60%	100%
≥ 1MW	60%	90%	100%

The method used for developing long-term projections varied by generation technology and is summarized in Table 28. Solar PV uptake projections were developed using Element Energy's in-house consumer choice model, whilst wind projections were developed through consultation with Toronto Hydro stakeholders. Non-renewables uptake projections were based upon projections from the TransformTO dataset, and biogas projections were based upon varying levels of fuel switching as non-renewables are phased out. Note that there was no pipeline generation for wind or biogas. Existing and pipeline generation is distributed to transformer station buses according to the current or expected locations of deployment, while projected generation is distributed across the region according to various methodologies which are specific to each technology.

Table 28: Modelling method for distributed generation technologies.

Technology	Renewable	Pipeline duration	Long-term projection
 ***Solar PV***	✓	2 years	Element Energy in-house modelling and TransformTO proejctions
 ***Wind***	✓	No pipeline	Informed by consultation with Toronto Hydro Stakeholders
 ***Biogas***	✓	No pipeline	Informed by TransformTO non-renewables projections
 ***Non-renewables***	✗	2 years	Data drawn from TransformTO

The total level of generation in Toronto Hydro's network area is show in Figure 62, illustrating capacity across all four scenario worlds in 2021, 2030, and 2050. This figure demonstrates that, based upon the modelling, solar PV is likely to be the dominant distributed generation technology in Toronto Hydro's region in a decarbonized future. This is particularly pronounced in the Net Zero 2040 scenario world, where projections have been aligned with the Net Zero 2040 projections in TransformTO. All three net zero compliant scenario worlds phase out non-renewable generation technologies by 2050 and rely strongly on solar generation, whereas Steady Progression continues to rely on electricity from gas and diesel out to 2050. In the following sections, these results are discussed in more detail. Section 4.4.2 explores the modelling of solar PV, the largest single contributing factor to the generation mix in 2050 for all four scenario worlds.

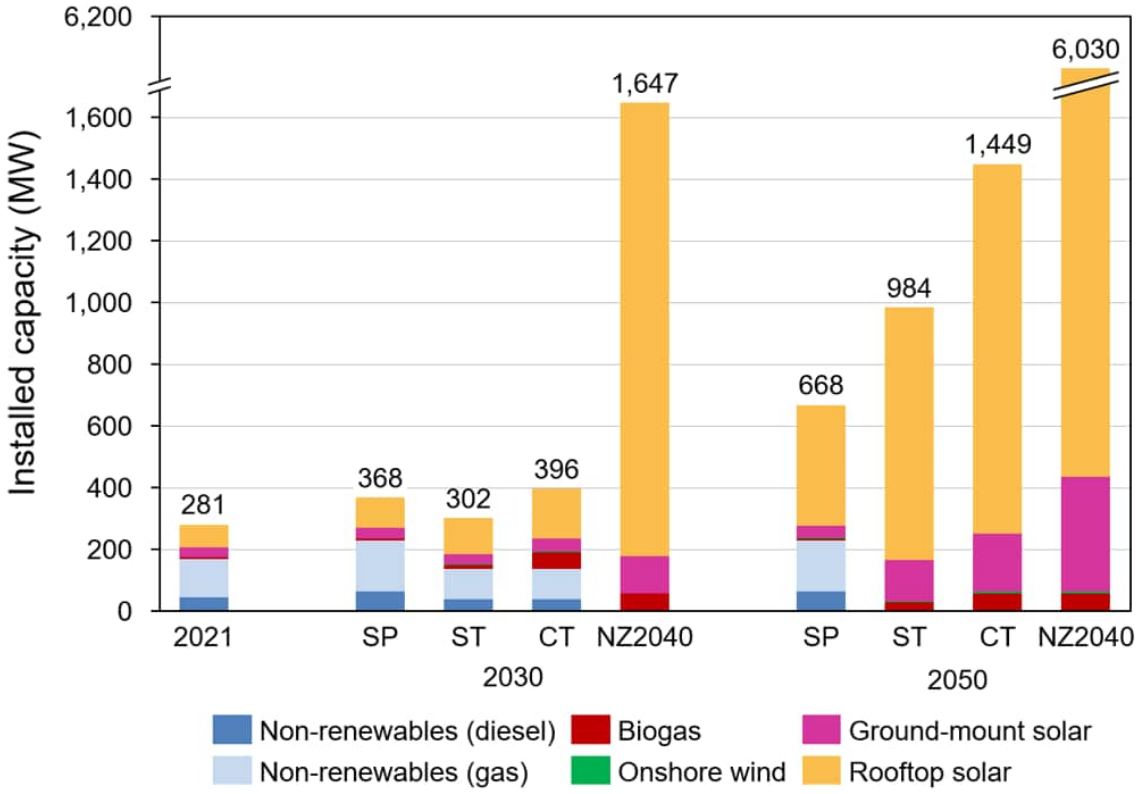


Figure 62: Capacity of distributed generation installed in Toronto Hydro's network area in 2021, 2030 and 2050.

4.4.2 Solar Photovoltaics

Solar PV uptake scenarios were derived using a consumer choice model for rooftop (≤250 kW) and large-scale (>250 kW) generation uptake. This uptake model accounts for variation in solar PV installation properties and economics by modelling different size bands. The size bands have been associated with typical installation types, as summarized in Table 29 below, and different installation costs applied to each band.

Table 29: Classification of solar PV size bands.

Solar PV Size Bracket (kW)	Classification
≤ 250	Rooftop
> 250	Ground-mounted

Rooftop Solar PV (≤ 250kW)

Small-scale solar PV is defined as being those installations that occur on rooftops of domestic and I&C buildings (Table 29Table 29). Figure 63 shows that the solar uptake in the Low, Medium and High scenarios, which are developed using Element Energy's consumer choice model, range between 400 MW and 1,200MW by 2050. These increase from a baseline of 75 MW in 2021 and a maximum pipeline of 3.4 MW. These pathways are developed by considering the economic case for purchasing solar panels from a consumer perspective. Post-pipeline uptake to 2050 is driven in large part by capital cost reductions[1,53], while increases in electricity prices[54] and net metering revenues[55] further incentivize uptake in future years. Rooftop solar is distributed across Toronto using customer counts in each neighbourhood and terminal station service area.

Future solar generation is calibrated using historic uptake data[52] and by considering the business case of purchasing solar panels in previous years[56]. Using this information, the model develops calibration coefficients that are used to adjust future solar generation projections.

In the Low scenario, it is assumed that the energy system will continue to rely on gas- and diesel-fired generation in 2050 and less emphasis is placed on incentives for the uptake of renewable generation. Conversely, in the High scenario, uptake is based upon the lowest projections of capital installation costs, higher revenues from net metering and avoidance of electricity charges. In the Very High scenario, projections are aligned with those from TransformTO[3], adjusted to the baseline and pipeline data provided by Toronto Hydro, resulting in an uptake of 5,600MW of rooftop solar generation installed by 2050. The Very High scenario is based on the technical potential of solar generation in Toronto and hence represents an upper bound where 100% of suitable buildings install solar PV.

[53] NREL, Solar Futures Study, 2021
[54] Higher electricity prices can result in higher uptake since consumers that install a solar PV system can avoid paying these high prices for their electricity to some extent and can also potentially achieve higher revenues when selling their generation back to the grid.
[55] OEB, Electricity Rates, 2022
[56] IESO, microFiT Program, 2022

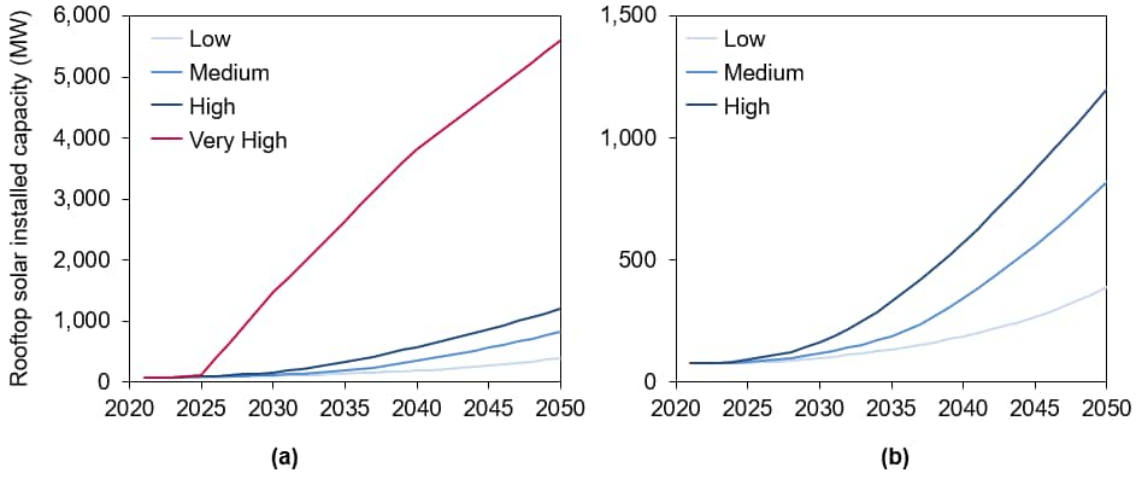


Figure 63: Installed capacity of rooftop solar PV in Toronto Hydro's network area out to 2050. (a) including "Very High" scenario, used in NZ40; (b) excluding "Very High" Scenario.

Ground-Mount Solar PV (>250kW)

Ground-mount solar PV is defined as those installations that have a capacity greater than 250kW and are likely to be deployed in parking lots or green space. Figure 64 shows that uptake in 2050 ranges between 39 MW and 371 MW across the Low to Very High scenarios. The overall approach is the same as that taken for Rooftop solar PV with the Low to High scenarios generated using Element Energy's consumer choice model and the Very High scenario aligned with the pathway in TransformTO. Ground-mount solar PV relies on the same drivers as for small solar PV but also draws some benefits from capacity market revenues[57]. A cost uplift has also been applied to account for additional costs associated with finding suitable areas to site generation. Where rooftop solar PV is distributed according to customer counts, ground-mount solar PV is distributed to available space in parking lots[58], in line with Transform TO assumptions on ground mounted PV deployment.

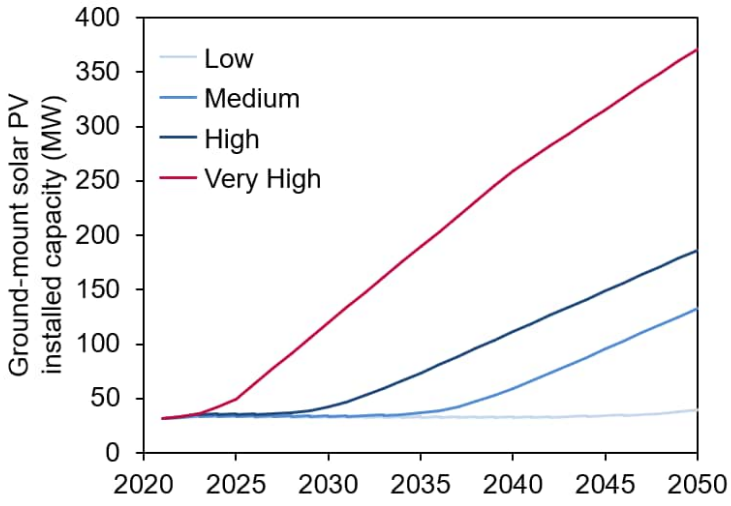


Figure 64: Installed capacity of ground-mount solar PV in Toronto Hydro's network area out to 2050.

[57] IESO Capacity Auction, 2022
[58] City of Toronto, Physical area of parking lots, 2019

4.4.3 Onshore Wind

Onshore wind projections were developed through consultation with key stakeholders within Toronto Hydro to establish a consensus on the expected range of uptake that could occur across the different scenario worlds. Due to there being very few historic onshore wind installations in Toronto (only four installations, the largest of which took place when no feed-in tariffs were in place), a meaningful calibration of the consumer choice modelling for onshore wind could not be conducted. The consultation process with Toronto Hydro stakeholders resulted in scenarios ranging between 0.76 MW and 8.3 MW of installed capacity by 2050. Projections are assumed to ramp up linearly after the pipeline years; however, the accepted generation data provided by Toronto Hydro does not include any onshore wind and so there is no projected pipeline capacity. Future uptake of onshore wind was distributed based upon greenspace in neighbourhoods adjacent to Lake Ontario which involved spreading uptake across this area rather than attempting to model individual turbine locations.

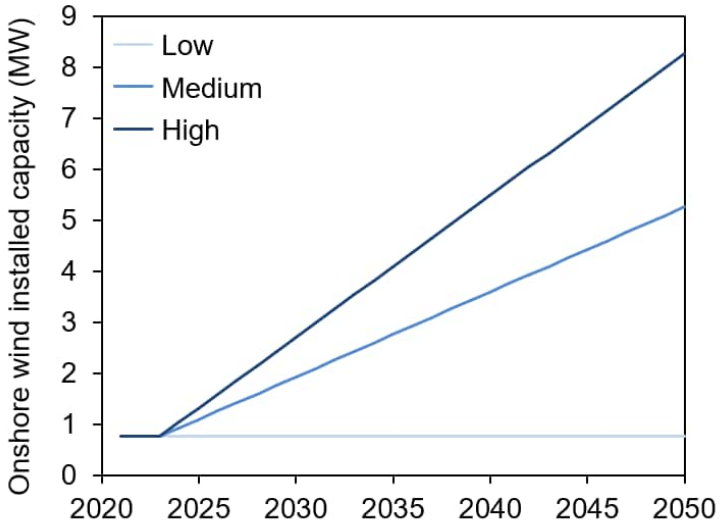


Figure 65: Installed capacity of onshore wind in Toronto Hydro's network area out to 2050.

4.4.4 Non-Renewables

Non-renewable generation considers all gas and diesel generators in Toronto, which currently make up the largest share of distributed generation. In the Low scenario, it is assumed that all non-renewable generation is phased out by 2030. This is consistent with the trajectories mapped out in TransformTO and is in line with ambitions of various municipalities in Ontario, including the City of Toronto[59]. The TransformTO trajectory for natural gas has been applied to all non-renewable generation, as TransformTO does not have specific categories for local CHP or diesel generation. This trajectory was scaled such that it aligns with existing generation connected to the Toronto Hydro network. In the Medium scenario, this trajectory is extended to 2050, assuming that the phase out follows the same pathway but at a slower rate. In the High scenario it is assumed that after pipeline generation is added, there is no phase-out of non-renewable generation and no new installations are added.

[59] Ontario Clean Air Alliance, Ontario Municipalities that have endorsed gas power phase-out, March 2021

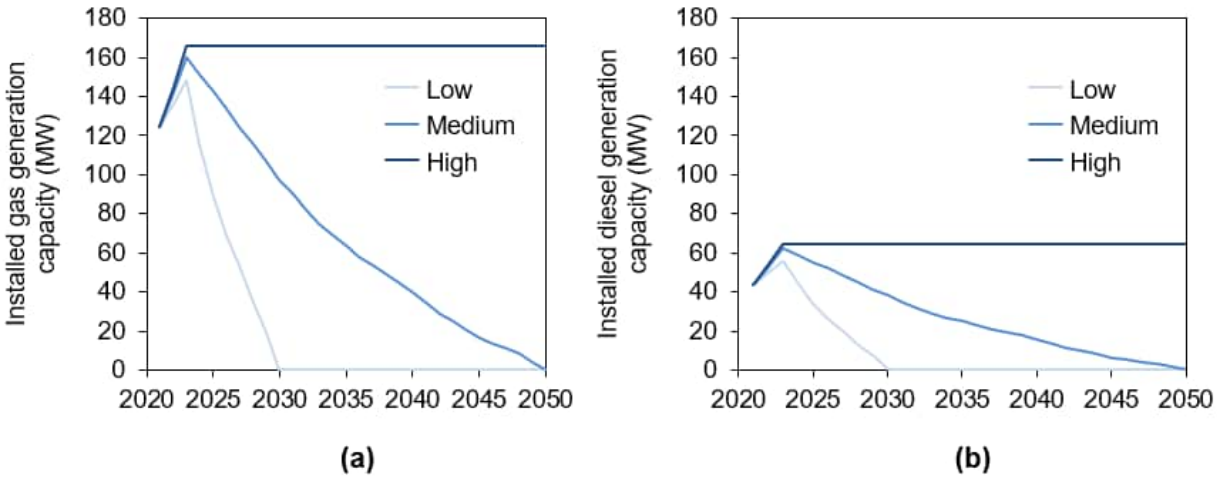


Figure 66: Projected installed capacity of (a) natural gas generation and (b) diesel generation.

4.4.5 Biogas

Biogas is assumed to act as a transition technology for natural gas and can be used in a variety of applications, including electricity generation. The High scenario for biogas pairs with the Low non-renewable scenario and is created by assuming 25% of phased-out non-renewable generation capacity is replaced by biogas. The Medium biogas scenario pairs with the Medium non-renewable scenario and assumes 10% of phased-out non-renewable generation is replaced by biogas. The Low scenario is a continuation of historic trends. In all biogas scenarios, there is no additional capacity in the pipeline. Since biogas is assumed to replace non-renewables, geo-distribution for biogas generation is based upon the historic distribution of gas generation.

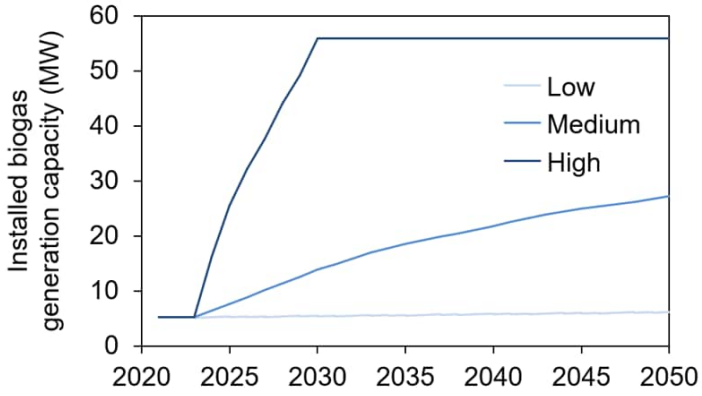


Figure 67: Installed capacity of biogas for electricity generation in Toronto Hydro's network area out to 2050.

4.5 Energy Storage

The uptake of two different battery storage use cases was modelled in this project. For each use case, three to four future uptake scenarios were developed and assigned them to the four scenario worlds as outlined in Table 30.

Table 30: Battery storage types modelled and their mapping to scenario worlds.

Parameter	Steady Progression	System Transformation	Consumer Transformation		Net Zero 2040	
			Standard	Low	Standard	Low
Domestic battery storage	Low	Medium	High	Low	Very High	Low
I&C behind-the-meter battery storage	Low	Medium	High	Low	High	Low

Grid-scale storage is assumed to be driven by network-level needs for energy storage and is therefore not modelled within the Future Energy Scenarios. This approach considers grid-scale storage to be a solution which would be deployed in response to needs identified by Toronto Hydro. Storage could also be developed by the IESO in response to overall system needs. However, it is likely that this would not be connected to Toronto Hydro's network, but rather in other areas in Ontario where land is cheaper and/or connected to the transmission network.

The uptake of battery storage for each use case is modelled based on a specific set of assumptions around the associated business case for those particular battery storage installations. Table 31 shows the different use cases, the relevant business case considered, and the modelling method used.

Table 31: Modelled battery storage use cases and the corresponding business cases and modelling methods.

Technology use case		Modelled business case	Modelling method
	***Domestic battery storage***	**Coupled to solar PV** Maximize own use	Consumer choice modelling coupled with domestic solar PV uptake modelling
	***I&C behind-the-meter battery storage***	**Arbitrage and system balancing** e.g., electricity price arbitrage, the Industrial Conservation Initiative (ICI), Operating reserve	Consumer choice modelling

The baseline and pipeline data for behind-the-meter storage, both domestic and industrial and commercial, was from the data provided by Toronto Hydro. The pipeline calculations follow the same methodology across the scenarios as used for generation (Table 27Table 27). Figure 68 shows the overall level of battery storage capacity installed across Toronto Hydro's region in all four scenario worlds in 2030 and 2050. Consumer Transformation and Net Zero 2040 show the highest battery storage uptake since these scenario worlds are assumed to have the greatest need for storage to help offset grid demands caused by high electrification and rapid uptake of low carbon technologies. In these scenarios, battery prices are assumed to follow their lowest cost trajectory, and higher revenue streams for both domestic and I&C behind-the-meter storage are assumed. For domestic storage, this corresponds to higher income from grid-export and higher savings from self-consumption, while I&C storage draws from a larger revenue stack which includes the Industrial Conservation Initiative (ICI), price arbitrage, and operating reserve. System Transformation sees less battery storage uptake due to lower assumed levels of electrification. Steady Progression sees the least uptake as the scenario world

with the lowest levels of ambition and decarbonization. In the following sections, the modelling approaches and assumptions for battery storage are outlined and the results are discussed in more detail.

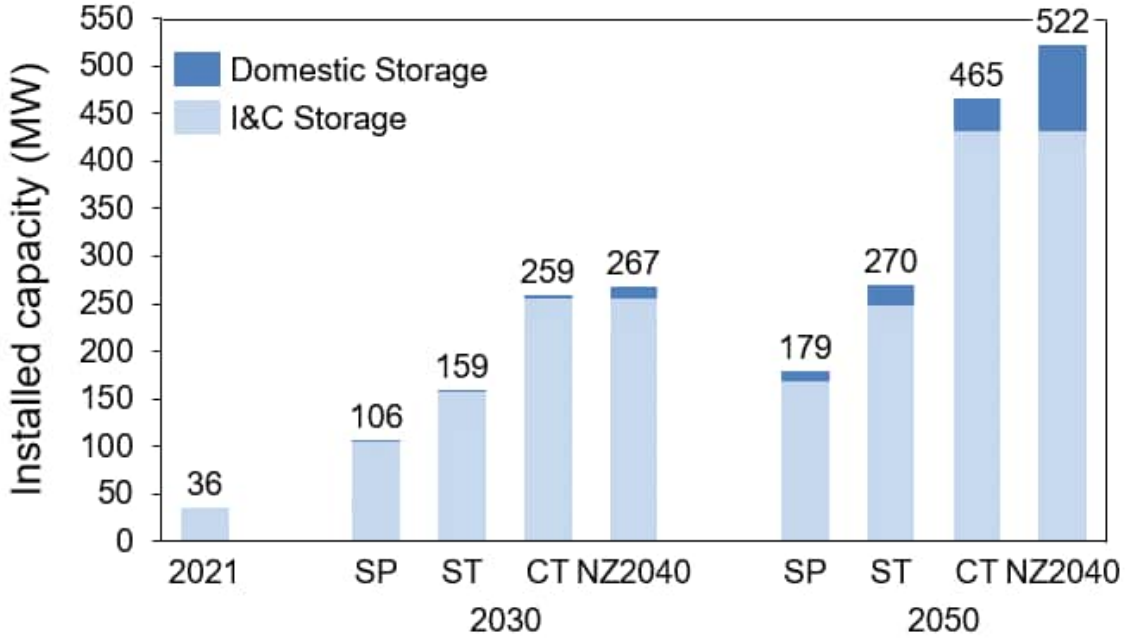


Figure 68: Capacity of battery storage installed in Toronto Hydro's network area in 2021, 2030 and 2050.

4.5.1 Domestic Battery Storage

The business case for domestic storage is coupled to the uptake of solar generation that is expected to connect at domestic residences (≤10 kW). Uptake scenarios for domestic storage are derived using a module of the solar generation consumer choice model. This considers the purchase decision for a solar PV system with a battery as well as retrofitting a battery to an existing solar PV installation which is less than five years old. Therefore, scenarios for domestic battery storage differ according to the underlying scenario for solar PV (since the batteries are added to households with solar PV) and by the battery cost projection used in each case. An average battery power is considered to be half the solar panel capacity, with a two-hour storage capacity, and account for variances in battery pack costs[60,61], installation costs, and product availability across the three scenarios. If the battery option is chosen, the owner is assumed to use it primarily to maximize their own consumption of their solar PV generated electricity.

The results from this modelling (Figure 69Figure 69) indicate that between 23% and 34% of all domestic solar PV owners in Toronto Hydro's network area may install a battery by 2050. While the proportion of solar PV owners with batteries is assumed to be the same in the High and Very High scenarios, the absolute capacity is much greater in the Very High scenario due to the substantially larger level of solar generation uptake. Therefore, the range of uptake in the Low to High scenarios is between 11MW and 34MW, while the Very High scenario sees an uptake of 90MW. Baseline and pipeline capacity for domestic battery storage are both assumed to be zero.

[60] NREL, Cost Projections for Utility-Scale Battery Storage: 2021 Update, June 2021
[61] KPMG, Development of decentralized energy and storage systems in the UK, October 2016

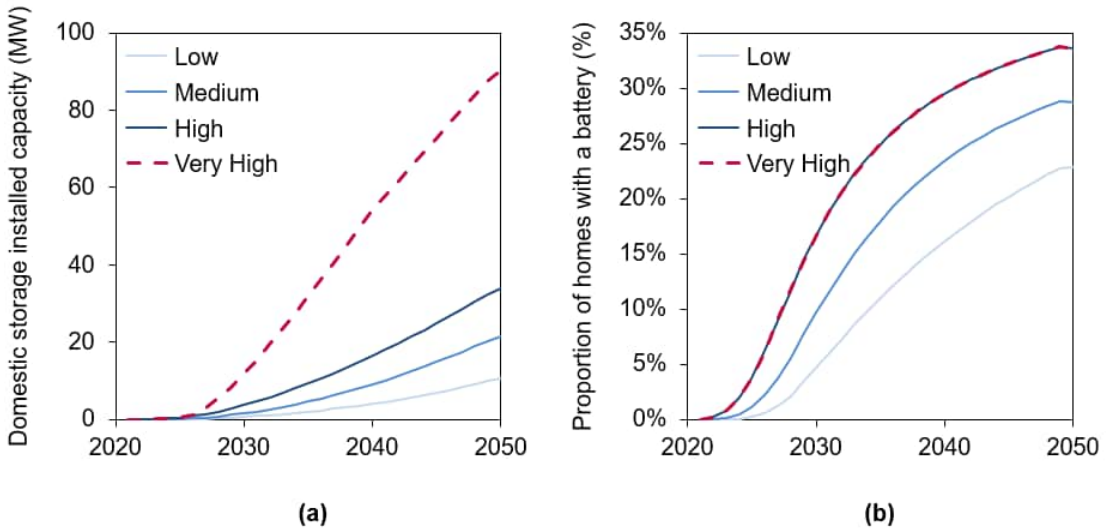


Figure 69: (a) installed capacity of domestic storage in Toronto Hydro's network area out to 2050, (b) proportion of all domestic customers who install a battery.

4.5.2 Industrial and Commercial Battery Storage

Uptake scenarios for I&C behind-the-meter storage were derived using Element Energy's consumer choice model, where I&C customers are divided into archetypes, based on different business types, and uptake is based on the payback period for investing in a battery and the willingness-to-pay of I&C organisations. Revenues from different sources are combined to find the maximum level of benefit that a storage owner could aggregate. These include wholesale price arbitrage[62], the Industrial Conservation Initiative (ICI)[63], operating reserve[64], regulation service, the capacity market[57], and the energy efficiency auction pilot. Of these, the ICI is the dominant revenue stream with a significant impact on uptake in each scenario[65]. In the Low and Medium scenario, these revenues are only accessible for customers with peak demand > 1MW. In the High scenario, these revenues are also accessible to manufacturing and warehouse archetypes with a lower peak demand. With most revenue streams only being available to customers with peak demand greater than 1MW, the modelling shows a significantly higher uptake of storage for customers connected to the high voltage network compared those connected to the low voltage network.

Figure 70 shows how these assumptions result in trajectories that reach between 129 - 381 MW in 2050. Pathways increase from a baseline of 11.8MW, with a pipeline ranging between 12.8MW in the Low scenario and 23.5MW in the High scenario.

[62] IESO, Hourly Ontario Energy Price, 2022
[63] IESO, Industrial Conservation Initiative Backgrounder, July 2022
[64] IESO, Ancillary Services, 2022
[65] Participants in the ICI pay global adjustment charges based upon their level of contribution to the top five hours of demand throughout the year. ICI revenues are calculated as the global adjustment charge that could be avoided by demand shifting with energy storage.

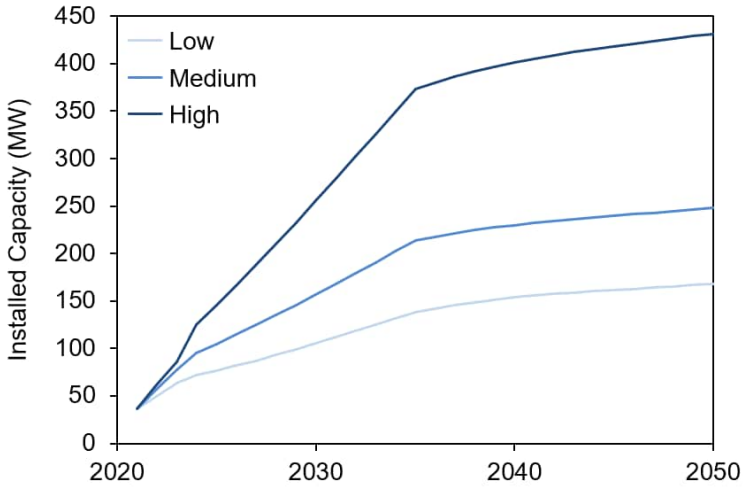


Figure 70: Installed capacity of I&C behind-the-meter battery storage in Toronto Hydro's network area out to 2050.

5 Network Impacts

Following the creation of the Future Energy Scenarios for Toronto Hydro, these datasets were loaded into Element Energy's FES Model to project the load growth and generation on the network out to 2050. This model projects the annual consumption and peak electricity demand for each of the 88 assets on the network as well as for the network as a whole, in order to provide a complete picture of the potential future changes to the network. In addition to the peak demand breakdown by asset, the peak by technology is also provided to facilitate a complete understanding of load growth and help the end user to plan and target network investments. Element Energy's load modelling systems are currently active across various electricity distribution companies and have a strong track-record of active use within the industry under the scrutiny and approval of the relevant regulators and associated reporting. As such, the FES Model is fully equipped with the latest innovations in this area.

5.1 Load Modelling Process

The load modelling process used by the FES Model can be divided into four main calculation stages (Figure 71Figure 71): technology counts, annual consumption and generation, profile shapes and peak demand, and scaling calibration. Technology counts define the raw numbers of each technology (or capacity figures in the case of generation and storage) and how they are distributed across the network. This information is then leveraged along with data regarding the characteristics of each technology in order to calculate annual consumption or generation (MWh) values. Peak demand (MW) is subsequently established through the application of load profiles, which describe how the energy consumption of each technology is distributed across the year. Finally, the scaling calibrates modelled results by aligning them with real network load data provided by the electricity distributer.

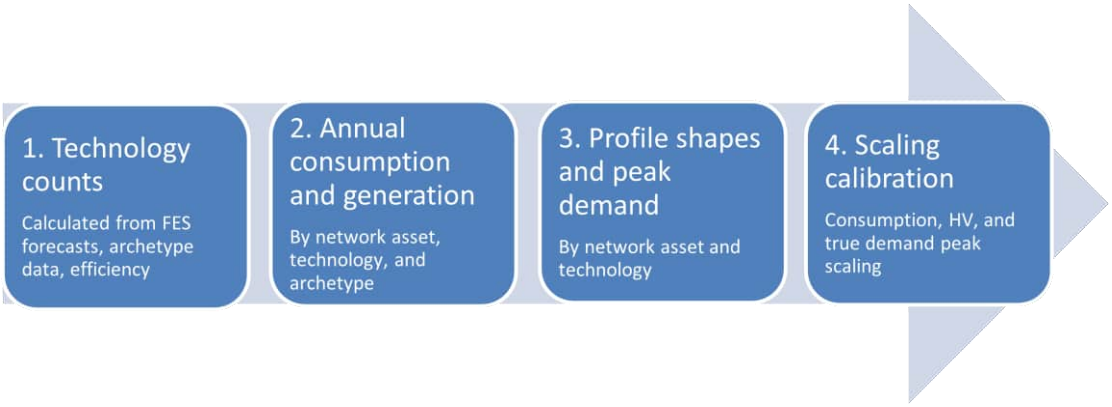


Figure 71: The main stages of the load modelling process.

Technology Counts

The first step of the process is to find the number of each technology (referred to as counts) in each year by transformer station bus and archetype. This typically begins with feeding in data from the FES, namely the geo-distributed technology projections and number of customers served by each transformer station bus (customer counts). These counts are then mapped to specific assets by leveraging the network topology which describes the connectivity between assets across Toronto.

Annual Consumption and Generation

The annual consumption and generation step involves finding how much energy is consumed or generated by a given technology in each year. Typically, this will leverage the counts as well as any information regarding the characteristics of each technology and customer type. This behavioural data varies by sector and may include such datasets as electric vehicle mileage, heating technology efficiencies and generation capacity factors.

The following steps are focused on demand, however a similar process is used for generation calculations.

Profile Shapes and Peak Demand

Following calculation of consumption values, the next stage in the load modelling process is the calculation of peak demand (MW), which is achieved primarily through the application of load profiles. Load profiles describe how the annual consumption from each technology and archetype is distributed across the year, defined for each month at a half-hourly resolution, as shown in Figure 72 for domestic core demand. These profiles are distinct for every key driver of load and there also exist options to use a minimum or average profile depending on the desired model outputs.

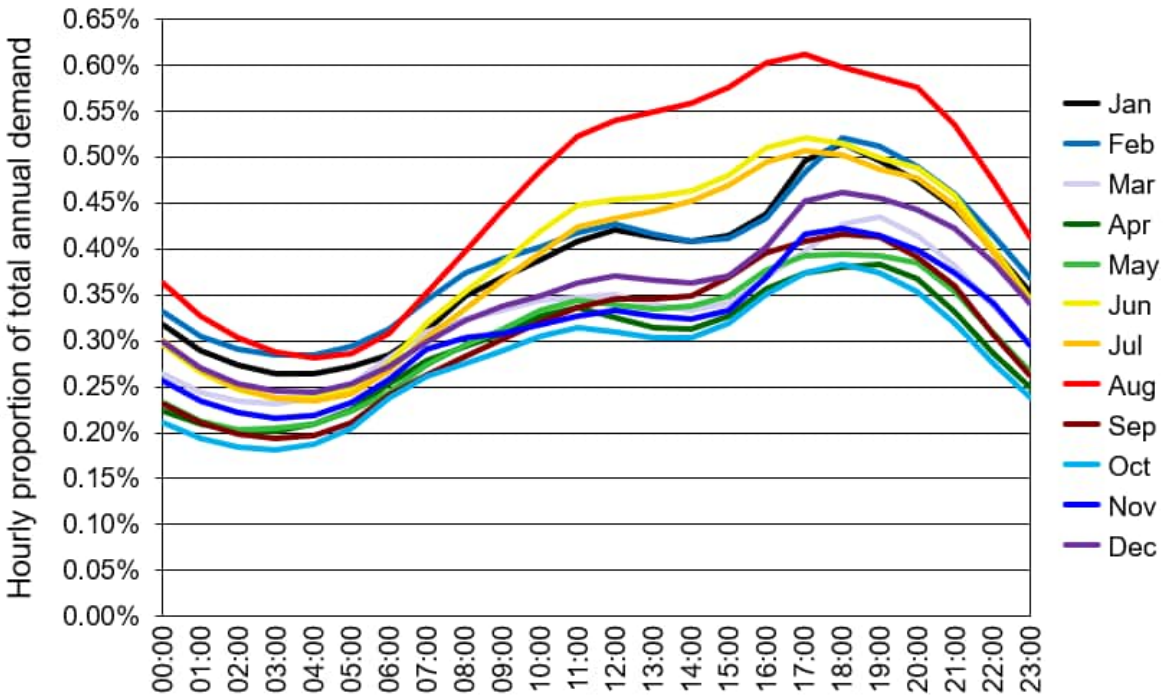


Figure 72: Load profiles for domestic core demand.

Applying load profiles to annual consumption shows how power demand for each technology varies across every modelled year. These power demands can then be summed across all relevant technologies to find the overall demand at every transformer station bus at any given time of day across the year. From this, the peak demand can be found by extracting the maximum power value from any given year. A similar process is performed to find system peak, whereby the power demand from each asset is aggregated and the maximum value is again extracted.

Scaling

Following calculation of annual consumption and peak demands, the results are calibrated by aligning values with real data from network assets. This dataset was provided by Toronto Hydro and processed by Element Energy in three scaling stages: consumption scaling, high voltage (HV) customer scaling and true demand peak scaling. The scaling steps begin with coarse adjustments at system level and finish with calibration of every technology at every transformer station bus, to make sure that the modelled load is fully aligned with real measured data from Toronto Hydro.

The consumption scaling calibrates the FES model by calculating a system-wide consumption estimate based upon Toronto Hydro consumption data aggregated from all customers connected to the network. This estimate is then compared with the base year modelled system consumption values from the FES model and appropriate scaling is applied. The HV scaling process then calibrates the model outputs by making scaling adjustments to the high voltage customer loads. The final calibration step, true demand peak scaling, focuses in on each technology at each transformer station bus for which appropriate monitoring data is available, to

ensure results are as accurate as possible. This is a more granular process than consumption scaling since true demand peak scaling applies unique scaling factors at each transformer station bus to ensure alignment both in total system load and individual asset loads.

5.1.1 Load Modelling Case Study: Low Carbon Heating

The type of data inputs that are used and the way in which they are processed is specific to the technology that is being modelled and therefore, the focus here is on the modelling process for the heating sector as one example (Figure 73Figure 73). In this case, the FES inputs include technology projections, building archetype definitions/distributions[66], new build growth, building demolition rates, and thermal efficiency trends. This case-study focuses specifically on the first two steps of the load modelling process since the peak demand calculation and scaling stages are generic and applied in the same way for all sectors.

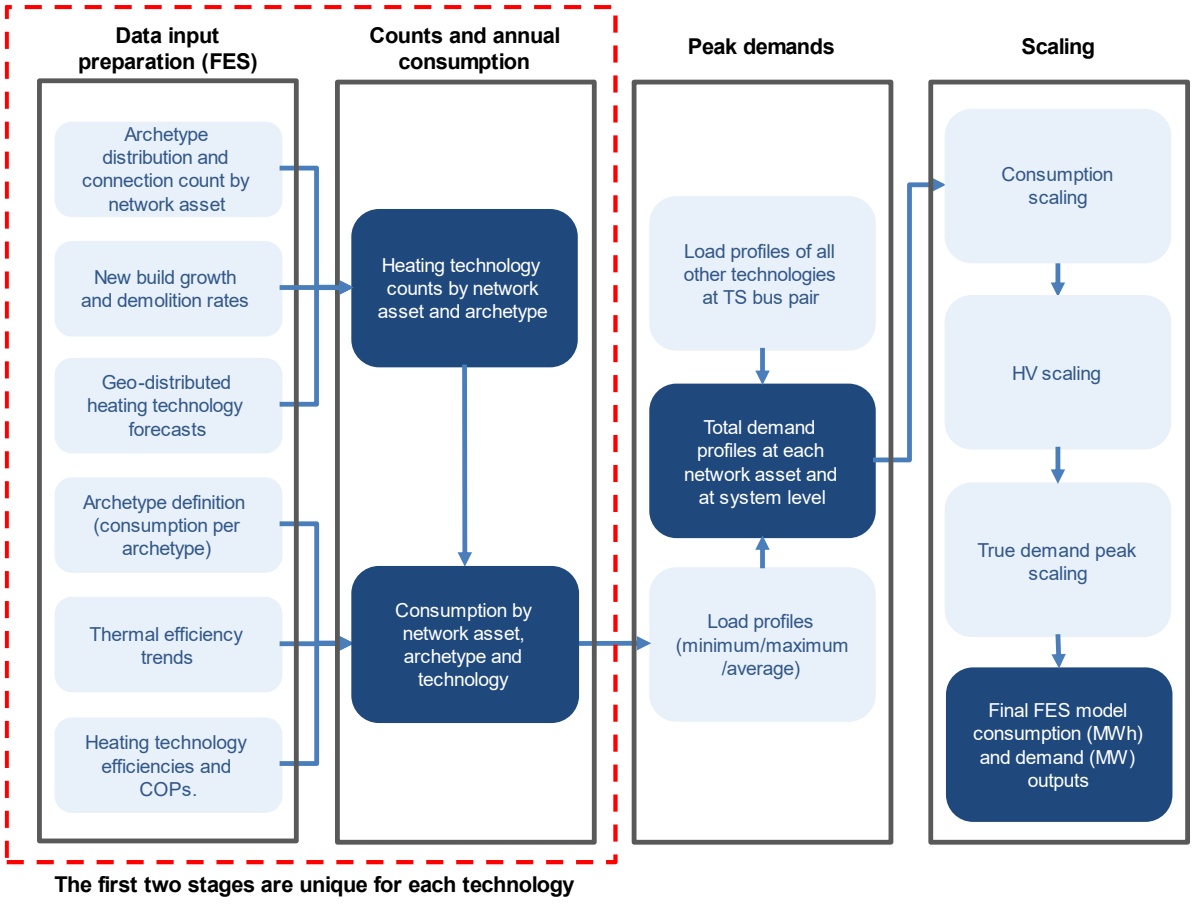


Figure 73: Detailed diagram of the load modelling process.

Technology Counts

For the heating sector, technology counts are found by first combining the archetype distribution, connection counts, new build growth, and building demolition rates to determine the number of customers of each archetype at each transformer station bus. Heating technology numbers are then established by applying the archetype specific heating technology uptake trends from the FES to find the number of each heating technology by archetype at each transformer station bus, for each year in the analysis horizon.

Annual Consumption

Once the heating technology counts are established, the annual consumption may be calculated by feeding in information about the typical characteristics of each heating technology and each building archetype. This

[66] Element Energy's FES modelling involves the definition of a set of archetypes that describe the different types of building that occur within Toronto. See section 4.1.1 for further details. The archetype distribution defines the proportion of each archetype at each transformer station bus.

includes heating technology efficiencies[67], thermal efficiency trends, and archetype definitions, which contain information about the average annual consumption for each consumer archetype.

Peak demands and Scaling

Following the annual consumption step, most technologies follow a similar methodology for the peak demand and scaling calibration. As detailed in Section 5.1, peak demands are found through the application of load profiles, which is followed by the three scaling stages (consumption, HV, and true demand peak).

5.2 Network Level Results

The final results of the load modelling process are summarized in Figure 74, which illustrates how the projected winter and summer system peak loads vary between different scenario worlds across all modelled years. Throughout the 2020s, summer peak is greater than winter peak and there is little variation across the scenarios, however, by 2050 the scenario worlds diverge considerably; Net Zero 2040 has the lowest system load, followed by Consumer Transformation, Steady Progression and System Transformation.

Figure 74 also shows the two low-efficiency scenarios, which are based upon Consumer Transformation and Net Zero 2040. More detail on the scenarios is given in section 2. The purpose of these sensitivity scenarios is to illustrate what the maximum system peak could be, caused by high levels of electrification without any measures to counter the added demand. These sensitivities represent the highest-load scenarios and would therefore lead to the highest levels of grid constraints and reinforcement costs.

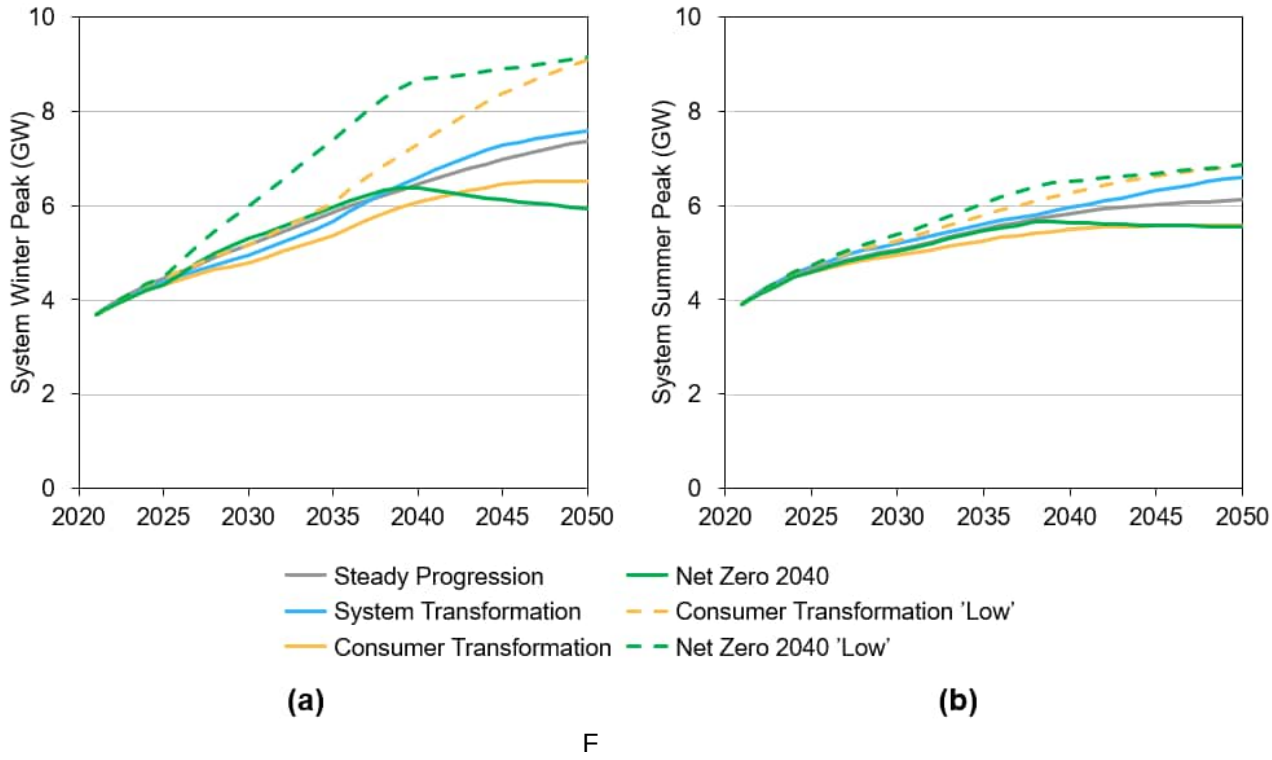


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Figure 74: Network peak in (a) winter and (b) summer for the four main scenario worlds and two low-efficiency sensitivity cases.

These results can be explained with reference to the scenario framework in Section 2 and the assumptions surrounding key drivers of load. In the base year, peak loads are expected to be higher in summer (3.9 GW) than in winter (3.7 GW), primarily caused by high levels of air conditioning demand which constitutes a large

[67] For heat pumps, this also includes coefficients of performance.

portion of base core demand. In the 2020s, the network level load follows a similar trend in all scenario worlds, driven primarily by the connection of high voltage loads and uptake of electric heating.

The 2030s see the time of network peak shifting to winter, with load driven by heat pump uptake and electric vehicles. As these technologies become more established, they are taken up in large numbers especially in the more ambitious net zero compliant scenarios. These trends continue into the 2040s, however, increasing electricity demands are moderated by the uptake of renewable generation and storage, which also see an accelerated growth in the later years. The impact of efficiency measures is assumed to increase at an approximately constant rate over the full modelled timeline, with the more ambitious scenarios seeing a more rapid acceleration in the early years, followed by diminishing improvements in later years.

These effects are seen most clearly in the Net Zero 2040 pathway, which has one of the higher system peaks during the 2030s, but by 2050 it is the lowest of all six scenario worlds at 5.9 GW. Rapid uptake of low carbon technologies drive load growth in the early years, however, improvements in energy efficiency, both thermal and non-thermal, balance out this effect and having achieved full decarbonization by 2040, the system peak then begins to fall. By 2040, heating and transport have fully transitioned to low carbon alternatives, relying primarily on electric technologies such as EVs and heat pumps. After this point, the energy system continues to see a sustained growth in distributed generation and flexibility measures, which help to meet the high peak demands caused by early electrification. Furthermore, the 2040s see additional improvements in energy efficiency, which reduce overall energy consumption, as well as continued high levels of consumer engagement, shifting demand away from times of high grid congestion. As a result, this is the only scenario which sees a reversal of previous trends such that peak demand begins to decrease.

Consumer Transformation has a consistently low peak demand and is the lowest of all scenarios until the early 2040s. Many of the factors that produce this trajectory are shared with Net Zero 2040 including high consumer engagement, participation in flexibility markets and an overall shift towards a smarter energy system. However, decarbonization is achieved ten years later in this scenario due to the uptake of low carbon technologies following a more gradual trajectory compared to Net Zero 2040. Consequently, peak demand is lower in the early years, however the later years see the system peak plateau at approximately 6.5 GW.

The two low-efficiency sensitivity scenarios, which are based on Consumer Transformation and Net Zero 2040, illustrate the network impacts of high electrification coupled with low levels of distributed generation, efficiency, and flexibility. These scenarios show the network would experience higher peaks under these conditions and hence represent the highest possible constraints that Toronto Hydro's network might experience. Implicitly, these also represent the situations requiring the largest amount of network reinforcement and network investment. Over the modelled time period, the Net Zero 2040 sensitivity presents the highest peak load, due to assumptions surrounding the early adoption of low carbon technologies. However, the 2050 peak demand on both sensitivities is the same since both achieve full decarbonization, with a similar technology mix, by 2050.

Steady Progression has a consistently higher peak despite relatively lower levels of electrification, which can be largely attributed to lower levels of energy efficiency, distributed generation, and flexibility/storage. Consequently, the system peak in 2050 is projected to reach 7.4 GW. This scenario world illustrates clearly how a less ambitious decarbonization plan does not necessarily lead to lower electricity demand on distribution networks.

System Transformation has the highest system peak in 2050 out of all the main four scenario worlds. Until the late 2030s, it follows a similar trajectory to Steady Progression and Consumer Transformation, after which peak demand begins to increase at a faster rate, reaching 7.6 GW in 2050. The main cause of this is that, despite a partial reliance on retained gas infrastructure, this scenario world still assumes that electrification will be the primary route to decarbonization. However, System Transformation does not contain the same level of ambition in efficiency improvements, renewable generation, flexibility, and smart technologies. Therefore, the demands of high electrification are not offset to the same extent as in the Consumer Transformation and Net Zero 2040 scenarios.

Figure 75 shows the scale of the impact of flexibility, efficiency and behind-the-meter renewable generation on the summer and winter peaks in the Consumer Transformation and Net Zero 2040 scenario worlds. The value to the network of these measures is clearly largest in winter, though summer peak is still significantly reduced in both scenarios. The reduction of peak demand by more than a third (Net Zero 2040) would avoid the need for a significant amount of network reinforcement, and consequently would save Toronto Hydro a large amount of investment.

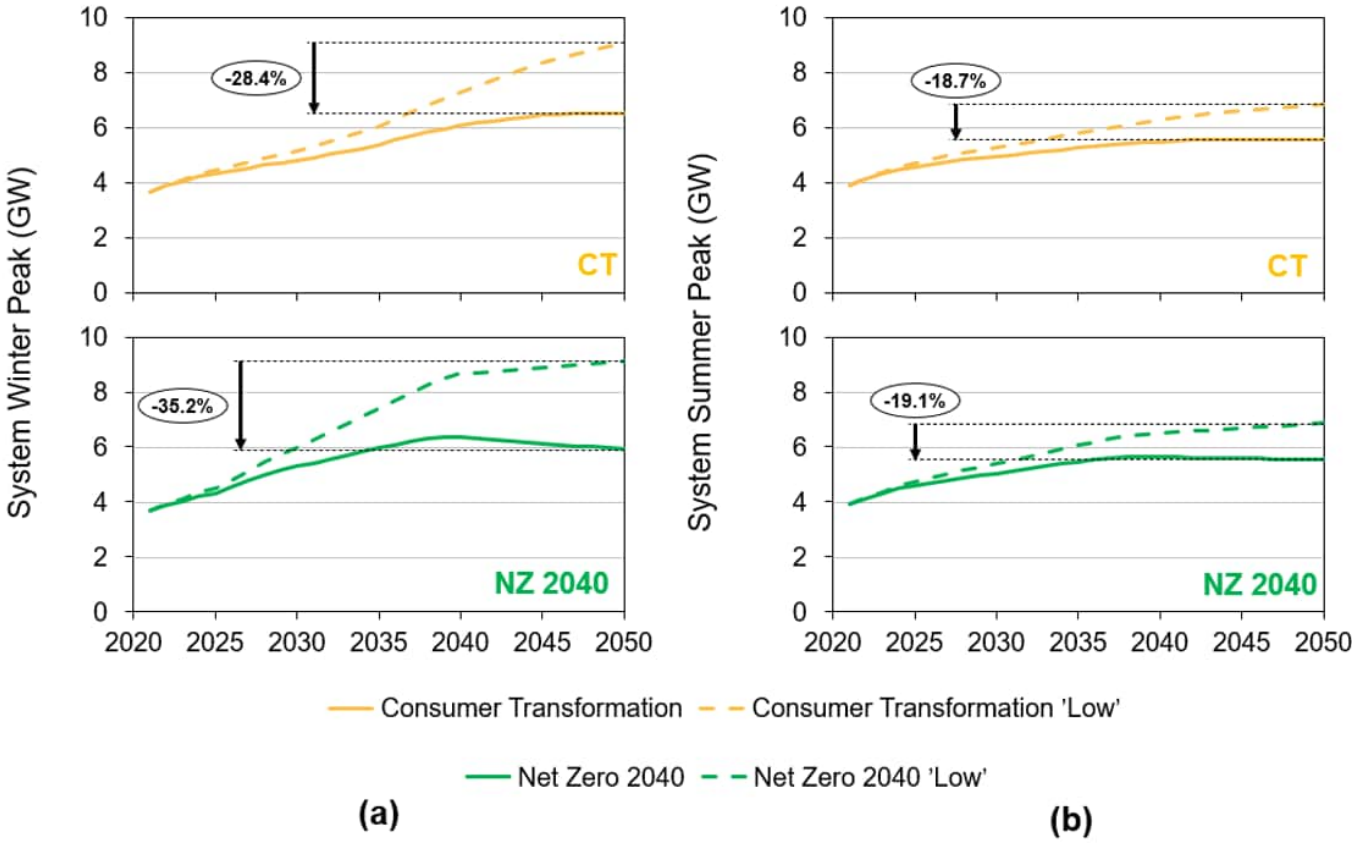

Figure 75: Comparison of peak true demand in the Consumer Transformation and Net Zero 2040 scenarios in (a) winter and (b) summer, in the Standard and Low-Efficiency sensitivity cases

6 Conclusions

This report has detailed the Future Energy Scenarios developed for Toronto Hydro that map out a number of future pathways for Toronto's energy system and evaluate the ways in which this may impact the distribution network. In order to capture the range of uncertainties in a coherent and meaningful way, four key 'scenario worlds' were developed, each built up of individual projections for different technology sectors. projections were developed using Element Energy's suite of bottom-up consumer choice and willingness-to-pay models which were informed by a comprehensive investigation into the current state of the energy landscape in Toronto, reviewing previous studies, datasets, and policy.

This work has found that, in all scenario worlds, Toronto can expect significant changes to its energy system resulting from electrification, renewable generation deployment, and improvements in energy efficiency. Peak demand increases are expected to be primarily driven by the electrification of heating and transport sectors which are expected to see widespread uptake of technologies such as electric vehicles and heat pumps. For example, in all net zero compliant scenario worlds, the transport sector sees a full transition to EVs across all vehicle types. Similarly, all domestic, commercial and industrial buildings are projected to be heated by heat pumps or electric resistive heating by 2050 for all scenarios that achieve net zero within this timeframe.

The nature of load changes on the distribution network is expected to vary considerably over the modelled time period. In the 2020s, electricity load growth is very similar across all scenario worlds, indicating that reinforcement is likely to be required regardless of the chosen decarbonization approach. This highlights the need for early planning to ensure the distribution network is well-prepared for near-term energy system changes.

In the 2030s, uptake of electric vehicles and heat pumps begins to accelerate, causing a shift in the time of network peak from summer to winter. In the later years, the high peak demands caused by the electrification of heat and transport are moderated by the uptake of renewable generation and storage, which see accelerated growth in the 2040s. Future generation uptake is anticipated to be dominated by solar photovoltaics, which in some cases may be accompanied by domestic battery storage systems. Uptake of batteries by industrial and commercial customers is also expected to increase, helping to further alleviate grid constraints.

Another significant outcome of this work is that it identified the need for changes to generation, storage, and energy efficiency to happen in parallel with electrification of demand. All of the core scenario worlds assume that efficiency improvements increase significantly from the present day, continuing to reduce energy consumption in future years. Without such changes, grid demands are expected to increase rapidly, as demonstrated by the two sensitivity scenario worlds. These pathways would necessitate significantly higher levels of investment to upgrade assets across the network.

Toronto Hydro's Future Energy Scenarios also highlight the importance of policy as a powerful tool in shaping the energy system. For example, in the low carbon heat uptake trends, the dominant factors in determining the uptake trajectories were the various assumptions regarding fossil fuel bans and financial incentives for cleaner technologies. This is of particular relevance to the attainment of a 2040 or 2050 net zero target, with the Future Energy Scenarios illustrating that this target will require key policy support for it to be achieved. There are many factors that can influence this at all levels of the energy system, but policy is one of the higher impact options observed in the modelling for accelerating the pace of change. Finally, the magnitude of changes to the energy system in recent years, both locally and globally, highlight the importance of maintaining an up-to-date understanding of the latest trends. Technological advancement, evolving supply chains, changing consumer attitudes, and evolving government policies have the potential to precipitate considerable impacts in technology deployment levels. As a result, regularly refreshing network load scenarios with the latest available data and learnings is an important part of planning for these changes and the low carbon energy transition.

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D5 2025-2029 Grid Modernization Strategy

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D5.1 Introduction: The Grid Modernization Imperative

Toronto Hydro is at an important turning point in its modernization journey. A confluence of external drivers – including accelerating climate change; emerging decarbonization and energy innovation policy mandates; rapid digitalization of the economy; and potential decentralization of the energy system (i.e. Distributed Energy Resources) – threatens to overwhelm grid capacities and capabilities in the long-term if not proactively addressed. To avoid both (i) long-term decline in system performance and (ii) becoming a barrier to the energy transition (in terms of both long-term costs to ratepayers and the grid's ability to serve and integrate customer loads and resources), Toronto Hydro has determined that it is necessary to accelerate strategic investment in specific field and information technologies that will deliver near-term benefits to customers while setting the utility on a path toward sustainable performance and improved efficiency as the pressures of climate change and the energy transition mount.

Trends, forecasts, and scenarios for the underlying drivers of the grid modernization imperative are covered in detail throughout Toronto Hydro's 2025-2029 Distribution System Plan, including in the following key sections:

- **Section D4** covers the projected impacts of decarbonization, electrification, and digitalization of the economy (e.g. data centre proliferation) on system utilization;
- **Section E3** provides an overview of Toronto Hydro's expectations for growth in DERs ("Distributed Energy Resources");[1] and
- **Section D2.1.2** discusses the impacts of climate change on grid performance and resiliency.

Toronto Hydro expects that the trifecta of electrification, DER proliferation, and worsening climate change will place increasingly complex demands on the utility's system assets and operations. The utility's central concern is securing its ability to continue delivering safe, reliable, and affordable electricity over the long-term and in the face of uncertainty. Climate change and electrification will have the dual effect of (i) increasing reliability risk on the system due to greater system utilization and more frequent impacts from adverse weather, and (ii) increasing the average customer's sensitivity to outages due to an increased reliance on electricity as their primary source of energy.

[1] In Toronto Hydro's system context, distributed energy resources are largely centered around solar technologies, energy storage systems, wind, natural gas, biogas, and customer assets for demand response programs. In the future, the term may expand to include micro-wind and fuel cells.

Furthermore, potentially high levels of DER penetration will add complexity and instability to the system, exacerbating the challenge of maintaining today's high standards of reliability and safety performance.

This escalation of risk and demand cannot be fully or efficiently met with a status-quo approach. Advanced, digital technologies will be necessary to upgrade the operating characteristics and capabilities of the grid, effectively unlocking incremental value from traditional infrastructure. These technologies – including sensors, remotely operable switches, next generation smart meters, predictive and prescriptive analytics, and automation schemes – will enable Toronto Hydro to not only adapt to the challenges it foresees in 2030 and beyond, but also take advantage of the opportunities presented by new kinds of customer-owned technologies such as battery storage and flexible loads for the benefit of all ratepayers.

D5.1.1 Toronto Hydro's 2025-2029 Grid Modernization Strategy

This document serves as a comprehensive overview of Toronto Hydro's 2025-2029 Grid Modernization Strategy and a guide to where the detailed investment plans can be found through the DSP ("Distribution System Plan"). As described throughout this summary document, Toronto Hydro has developed a grid modernization strategy which addresses emerging challenges and opportunities in a manner that leans first and foremost into the deployment of proven technologies (e.g. reclosers, switches, smart meters, analytics), which will deliver benefits to customers in the near-term (e.g. improved reliability), while laying the foundation for more advanced use cases that will be required in 2030 and beyond. From a materiality perspective, most of these investments are a continuation or renewal of programs that Toronto Hydro has been rolling-out at a gradual pace over the last two decades (e.g. grid sensors; remote-operable switches; smart meters), while others (e.g. achieving "self-healing" grid operations) represent the culmination of transformational efforts that have been a part of the utility's long-term modernization roadmap for many years. In many cases – including, for example, the introduction of mid-line reclosers and the implementation of a "self-healing" grid – Toronto Hydro's objectives are informed by the success of peer utilities in other progressive jurisdictions – including various U.S. states and Canadian jurisdictions such as Alberta – where investments in digital transformation and automation have proceeded at a more rapid pace in recent years.

Complimenting this focus on proven technology is a secondary emphasis on innovation. There are certain challenges – e.g. cost-effectively increasing the amount of distributed generation that can

connect to congested feeders – for which the optimal technological and commercial solutions are not yet settled or mature. In these areas, Toronto Hydro is planning to increase its investment in pilot projects and industry partnerships, which the utility believes can contribute to accelerated progress across the entire sector.

The remainder of this introductory section provides a brief overview of the differences between the traditional versus modernization grid. **Section 2** provides a detailed overview of the three major portfolios that constitute Toronto Hydro's Grid Modernization Strategy: (i) Intelligent Grid, (ii) Grid Readiness, and (iii) Asset Analytics & Decision-making. **Section 3** contains a series of appendices which provide more detailed discussions of certain key capabilities and projects that are not discussed in detail elsewhere in the DSP.

For a detailed summary of the how Toronto Hydro determined the expenditure levels for its 2025-2029 modernization programs and the role of Customer Engagement, please refer to Section E2 of the DSP. For an overview of how Toronto Hydro's modernization strategy is reflected in the utility's 2025-2029 key performance targets, please refer to Exhibit 1B, Tab 3, Schedule 1.

D5.1.2 Redefining Distribution Capabilities: The Traditional versus Modern Grid

In the traditional concept of the electric power grid in Ontario, seen in the top of Figure 1 below, the grid connects large central generating stations through a high-voltage transmission system to a distribution system that directly feeds customer demand. Generating stations consist primarily of nuclear- and hydro-powered turbines that spin to produce electricity. The transmission system in this model historically grew from local and regional grids into a large interconnected network that is managed by coordinated operating and planning procedures. Peak demand and energy consumption also grew at predictable rates, and technology evolved in a relatively well-defined operational and regulatory environment.

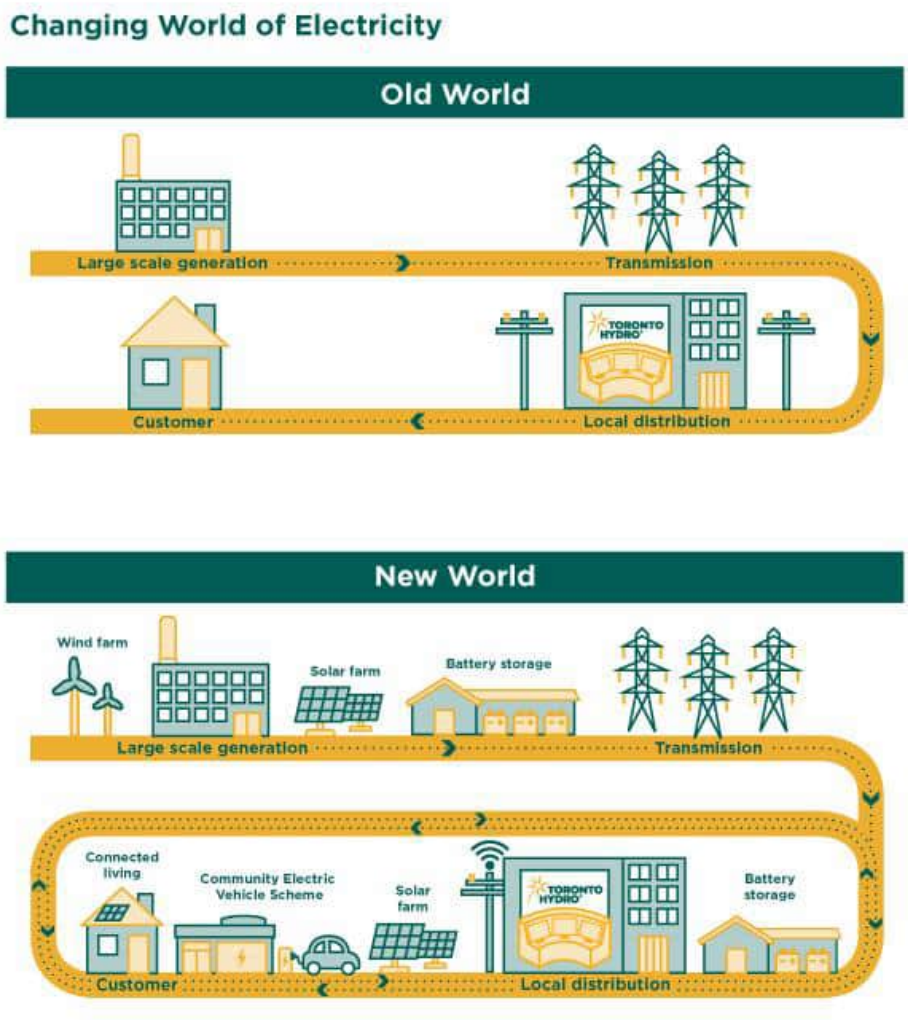

Figure 1: The Changing World of Electricity: Old vs New

The grid modernization imperative now requires utilities to go beyond "simply" delivering reliable one-way power to customers. Technology on the grid is changing, and the traditional, unidirectional model of electrical generation, transmission, and distribution is set to change with it. Segments of customers are poised to become prosumers: no longer will they only consume power, but they will also have the capability to supply the grid with power. At the same time, electrification will not only put additional load on the grid, but also create opportunities for flexibility and creative new solutions for load management. This represents an unprecedented challenge and opportunity to move the grid into a new era of reliability, availability, and efficiency that will contribute to economic, social,

and environmental health and ensure that electricity can rise to the challenge of being the primary, and perhaps the only, source of energy in many consumers' lives. This will be made possible through proactive grid and operational investments to enable advanced monitoring and automation and digital transformation as seen in the lower half of Figure 4

Much of the required technology for the transition to a modernized grid already exists on the grid today, and in many cases, it is a matter of expanding its deployment to achieve sufficient granularity of grid transparency and control, and then building upon these field technologies with predictive and prescriptive analytics and automated controls. For example, sensors and remotely-operable SCADA ("Supervisory Control and Data Acquisition") switches have existed on the grid for quite some time, but using them to sense where a fault has occurred and remotely operating the SCADA switches to isolate the fault is the additional benefit of a modern, connected grid. A comparison of technologies in the traditional grid vs. the modern grid is summarized in Table 1 below.

Table 1. Traditional vs. Modern Grid.

Characteristics	Traditional	Modern / Smart Grid
Technology	**Electromechanical:** Traditional energy infrastructure is electromechanical. This means that it is of, relating to, denoting a mechanical device that is electrically operated. This technology is typically considered to be "dumb" as it has no means of communication between devices and little internal regulation.	**Digital:** The smart grid employs digital technology allowing for increased communication between devices and facilitating remote control and self-regulation.
Distribution	**One-way Distribution:** Power can only be distributed from the main plant using traditional energy infrastructure.	**Two-way Distribution:** While power is still distributed from the primary power plant, in a smart grid system, power can also go back up the lines to the main plant from a secondary provider. An individual with access to alternative energy sources, such as solar panels, can actually put energy back on to the grid.
Generation	**Centralized:** With traditional energy infrastructure, all power must be generated from a central location. This eliminates the possibility of easily	**Distributed:** Using smart grid infrastructure, power can be distributed from multiple plants and substations to aid in balancing the load, decrease peak time strains, and limit the number of power outages.

Characteristics	Traditional	Modern / Smart Grid
	incorporating alternative energy sources into the grid.	
Sensors	**Few Sensors:** The infrastructure is not equipped to handle many sensors on the lines. This makes it difficult to pinpoint the location of a problem and can result in longer downtimes.	**Sensors Throughout:** In a smart grid infrastructure system, there are multiple sensors placed on the lines. This helps to pinpoint the location of a problem and can help re-route power to where it is needed while limiting the areas affected by the downtime.
Monitoring & Control	**Manual Monitoring, Limited Control:** Due to limitations in traditional infrastructure, energy distribution must be monitored manually.	**Self Monitoring, Pervasive Control:** Monitors itself using digital technology, allows it to balance power loads, troubleshoot outages, and manage distribution without need for direct intervention from a technician.
Restoration	**Manual:** In order to make repairs on traditional energy infrastructure, technicians have to physically go to the location of the failure to make repairs. The need of this can extend the amount of time that outages occur.	**Self-Healing:** Sensors can detect problems on the line and work to do simple troubleshooting and repairs without intervention. For problems related to infrastructure damage, the smart grid can immediately report to technicians at the monitoring centre to begin the necessary repairs.
Customer Choices	**Fewer:** The traditional power grid system infrastructure is not equipped to give customers a choice in the way they receive their electricity. Alternative energy sources, for example, have to be separated from power plants and traditional grid infrastructure.	**Many:** Using smart technologies, infrastructure can be shared. This allows more participants and forms of alternative energy to come on the grid, allowing consumers to have more choice.
Flexibility	Non-Flexible and Non-Controllable Loads	Flexible and Controllable Loads

D5.2 Grid Modernization Strategy Overview

The Grid Modernization Strategy outlines a five-year plan with objectives for accelerating the transformation of Toronto Hydro's existing grid infrastructure into a more technologically advanced distribution system. The overall goal of this strategy is to deliver on the utility's long-term vision of improving reliability and resiliency, efficiently accommodating and managing an expected influx of DERs, and preparing for electrification across various sectors. It also aims to leverage improved grid observability (i.e. real-time data from sensors) and advanced analytics to enable data-driven decision-making for applications such as predictive asset management, grid planning and optimization, and load forecasting.

The strategy focuses on three core areas as shown in Figure 2 below, namely: Intelligent Grid, Grid Readiness and Asset Analytics & Decision-making. Technology serves as the binding force to enable interconnection between the three core areas.



Figure 2: The Grid Modernization Pieces

The **Intelligent Grid** area is focused on expanding observability and controllability of the grid such that automated tools like FLISR ("Fault Location, Isolation, and Service Restoration") and ADMS ("Advanced Distribution Management System") are able to provide enhanced fault restoration

capabilities, improve operational efficiency, and better optimize system configuration and real-time performance. The **Grid Readiness** area focuses on building capabilities to support decarbonization and decentralization of energy resources, with a focus on leveraging field technologies and analytics, including major platforms like DERMS ("Distributed Energy Resource Management System" or "Energy Centre"), to better facilitate DER connections and optimize DER capabilities for services such as demand response. The last area, **Asset Analytics & Decision-making**, encompasses the digital advancements required to lay the foundation for a future-proof digital core that can support the large volumes and varieties of data obtained from initiatives in the other two core areas, leverage advanced analytical capabilities to extract more value from current assets, and drive greater efficiency in investment planning.

The following sections present details about the three focus areas and strategic initiatives tied to them.

D5.2.1 Intelligent Grid

The ***Intelligent Grid*** portfolio within the Grid Modernization Strategy is designed to improve reliability, resiliency and situational awareness of the distribution system. The portfolio places a strong emphasis on harnessing the power of advanced field technologies and operational systems to enhance grid intelligence and responsiveness. The key components of Toronto Hydro's Intelligent Grid concept are illustrated in Figure 3 below.

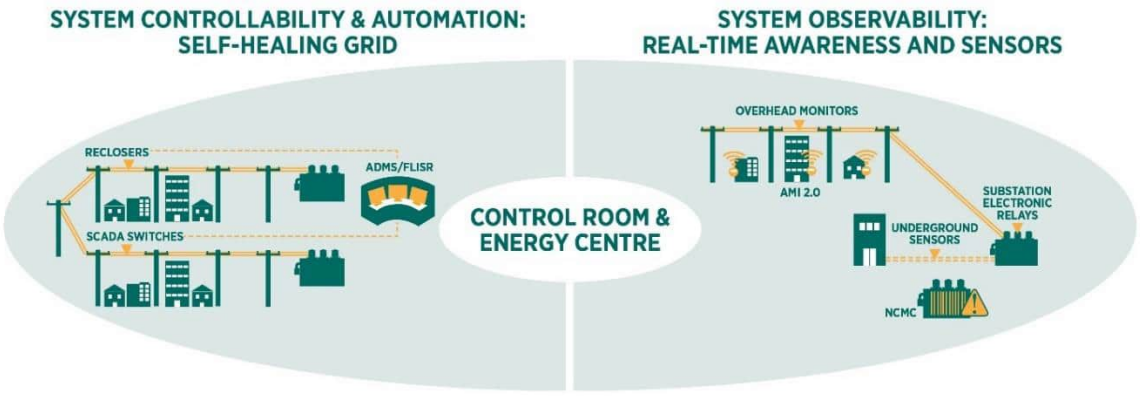

Figure 3: The Major Components of an Intelligent Grid

Investments in this portfolio aim to strengthen two domains of the distribution system, namely: System Observability and System Controllability and Automation.

- **System Observability: Real-Time Awareness & Sensors** entails adding more sensors, relays and monitoring technology at specific nodes across the distribution grid, including customer meters. These assets will provide additional data collection points across the grid, which Toronto Hydro will leverage to improve overall situational awareness ("grid transparency"), facilitate quicker fault location, and gain access to important insights at the edge of the grid. This data will be used in conjunction with advanced analytics platforms to analyze variables such as voltage levels, asset loading, and power flows. Improved system observability will help Toronto Hydro proactively identify developing issues, respond promptly to events, and utilize available resources efficiently.

- **System Controllability & Automation: Self-Healing Grid** entails (i) adding more switching assets on the grid – mainly SCADA-controlled tie switches, sectionalizers, and reclosers – and (ii) implementing automation technologies including FLISR ("Fault location Isolation and System Restoration"). The switching devices will provide Toronto Hydro with greater control and flexibility over grid operations, allowing remote switching and monitoring and improved fault isolation and restoration. With increased system controllability, Toronto Hydro can respond swiftly to changing conditions, optimize grid performance in real-time, reduce the number of customers impacted and the duration of interruption during faults or disruptions, and reduce truck rolls. These investments will also establish the basis for a "self-healing," automated grid, which Toronto Hydro aims to implement beginning in 2030 following planned upgrades to the utility's ADMS (which includes the FLISR technology that is required to enable distribution automation).

Section D5.2.1.1 and D5.2.1.2 below provide additional details on each of these categories. For a high-level summary of all the initiatives and investment programs that constitute the Intelligent Grid portfolio, refer to Section D5.2.1.3.

D5.2.1.1 System Observability: Real-Time Awareness and Sensors

Expanding visibility into the operating conditions of the distribution grid is a critical part of Toronto Hydro's *Intelligent Grid* strategy for 2025-2029, and will help the utility achieve three core capabilities:

1. **Enhanced Fault Location:** Locating faults and other system disturbances faster and more efficiently in order to improve reliability and operate the grid more cost-effectively.
2. **Enhanced Decision-making and Grid Optimization:** Providing greater insight into real-time feeder and asset loading, condition, and other relevant operating characteristics. This assists the utility in managing short- and long-term uncertainty as well as driving optimal real-time operational decisions and longer-term investment planning decisions.
3. **Enhanced Asset Diagnostics:** Greater visibility into high-risk and previously hard-to-monitor assets will improve asset diagnostics, mitigating the risk of asset failure and impacts to personnel safety and environmental damage.

The most significant investment Toronto Hydro is making to enhance grid observability in the 2025-2029 rate period is the replacement of end-of-life, legacy smart meters with next generation smart meters (also known as Advanced Metering Infrastructure 2.0 or "AMI 2.0"). While AMI 2.0 has the long-term potential to provide the high frequency, multi-parameter insights that will be required to address certain emerging operational pressures and requirements, many of the potential benefits and use cases for AMI 2.0 are currently untested and will require significant investment in data analytics, digital systems integrations, and business process changes. In the interest of providing immediate benefits to customers while diversifying the long-term options available to Toronto Hydro for monitoring the system, the utility is planning to explore and leverage a broader suite of field technology investments for the 2025-2029 period within the System Enhancements investment program (Exhibit 2B, Section E7.1).

This will involve the targeted deployment of sensors that will provide the utility's planners and grid operators with real- or near-real time insight into asset performance and operating conditions at critical points on the grid. To achieve these benefits, the System Observability segment (Section 7.1.1.3) will deploy several sensory assets, such as overhead and underground powerline sensors, online cable monitors, and transformer monitors. The NCMC ("Network Condition Monitoring & Control") (Exhibit 2B, Section E7.3) and Stations Renewal (Exhibit 2B, Section E6.6) programs add further monitoring and communications capabilities to various aspects of the distribution system.

Toronto Hydro expects that investments to improve observability will deliver both tactical operational benefits and long-term asset management benefits. As the distribution grid becomes more complex – with the addition of more devices and evolving customer interactions with the grid – it is essential that investments in grid observability keep pace, allowing Toronto Hydro to make informed operational and asset management decisions. Targeted observability investments will

enable more detailed insights into power flows by leveraging data from deployed field devices, in addition to more granular customer consumption data via AMI 2.0. The objective is to provide an accurate view of the state of the distribution grid, for applications such as automated fault management, DER management, and asset condition management. Furthermore, field devices such as sensors are significantly less expensive than building out new infrastructure to accommodate load growth. While these devices do not themselves provide additional capacity, they can be leveraged in targeted ways to ensure that Toronto Hydro's demand forecasts and assumptions are informed by increasingly granular information, and that appropriately sized capacity investments are planned for the right parts of the system at the right time. They will also help capacity optimization as well as more effective non-wire solutions planning and operations.

Investment programs within the System Observability portfolio will focus on service areas with significant operational value (e.g., DER-rich feeders, feeders with poor visibility, feeders with poor reliability, etc.). Before rolling out new observability technologies at scale, Toronto Hydro will run smaller pilots to test the technology for specific use cases, ensuring that the benefits are clear for customers, and that sufficient time is allotted to pursue potential overlapping use cases related to AMI 2.0. Ultimately, Toronto Hydro is looking to gain a broad range of experience developing applications and use cases for potentially scalable sensor technologies and AMI 2.0 in the 2025-2029 rate period, with the goal of initiating a fully formed observability strategy in 2030-2034.

The portfolio objectives will be primarily addressed through the following initiatives, which are summarized in the section below.

1. Deployment of Overhead and Underground Sensors
2. Online Cable Monitoring
3. Transformer Monitoring
4. Network Condition Monitoring & Control
5. Stations Digital Relays
6. AMI 2.0

D5.2.1.2 System Controllability & Automation: Self-Healing Grid

In Toronto Hydro's grid modernization journey, System Controllability and Automation will continue to play a vital role in transforming the grid into an intelligent and responsive system. System controllability refers to the ability to actively manage and control grid operations in real time using remotely operated devices. These devices provide significant reliability and efficiency benefits in and

of themselves, and are also the essential physical nodes which create the basis for a "self-healing" grid, i.e. a grid that can detect, isolate, and fix faults and disturbances in the grid in real-time, with minimal or no human intervention. The self-healing aspect is ultimately enabled by implementing advanced operational control technologies such as FLISR.

1. Preparing the Horseshoe System for Automation by 2030

One of the most significant objectives for Toronto Hydro's Grid Modernization Strategy in the 2025-2029 rate period is to advance the ongoing process of readying Horseshoe system feeders for the transition to a **self-healing operation beginning in 2030**.[2] Specifically, Toronto Hydro is aiming to have 90 percent of feeders in the Horseshoe system ready for automation by 2030. This will be accomplished in part through the System Enhancements program, which will install SCADA-controlled switches and reclosers on at least 34 feeders to bring them to the minimum optimal number of switching points per feeder of 2.5, which is required to enable an effective self-healing automation scheme.[3]

The other essential part of Toronto Hydro's strategy toward preparing a self-healing grid is FLISR implementation. FLISR is a centralized software system that works to automatically detect the location of a fault, isolate the affected section of the network, and reroute power to as many customers as possible, while minimizing the impact on the overall system. FLISR works together with the aforementioned physical field devices to enable distribution automation.

Implementing fully automated FLISR within Toronto Hydro's dense, urban service territory is a complex and significant undertaking which the utility plans to address using a methodical and staged approach over the 2025-2029 rate period. The utility is planning to implement "manual FLISR" at an average of five transformer station areas per year between 2025 and 2028, ultimately covering all 20 transformer stations in the Horseshoe area prior to 2030. Manual FLISR refers to the concept of running the FLISR system in the control room where the system suggests switching instructions to the operators to execute for power restoration. This affords system controllers the opportunity to review the FLISR system's prescribed switching operations to ensure they are safe and appropriate before implementing the switching plan. Running manual FLISR for an adequate period of time is an

[2] The Horseshoe system is the open-loop primary distribution system that serves all of the City of Toronto's inner suburbs.
[3] The 2.5 standard refers to the need for a feeder to have a minimum of two SCADA-controlled sectionalizing points and one SCADA-controlled tie-point, with the latter counting as 0.5 because it belongs to two feeders simultaneously.

important stepping-stone toward implementing automatic FLISR as it ensures that automation can be implemented with the necessary confidence that it will function properly, with the intended benefits and minimal risk to safety and system integrity. In parallel with the roll-out of manual FLISR, Toronto Hydro plans to make essential upgrades to its ADMS platform in 2025-2029, readying those systems to support fully automated FLISR in 2030 and beyond.

A U.S. Department of Energy report on five utilities that implemented FLISR projects found that, on average, FLISR reduced the number of CIs ("Customers Interrupted") by up to 45 percent and reduced the CMIs ("Customer Minutes of Interruption") by up to 51 percent for a relevant outage event. This was generally consistent with utility expectations of system performance going into the projects. Fully automated switching schemes generally outperformed operator-initiated remote switching schemes.[4] Toronto Hydro expects to see significant benefits from its roll-out of automatic FLISR in 2030 and beyond.[5] Note as well that, as discussed in the U.S. Department of Energy's final report on the results of its Smart Grid Investment Grant Program, utilities that successfully integrated their distribution automation schemes with observability enhancing technologies were able to "remotely pinpoint the location and extent of outages, better direct resources, and equip repair crews with precise, real-time information – often shaving hours or days off restoration time following major storms."[6]

Benefits such as these are a critical part of ensuring Toronto Hydro's grid is capable of cost-effectively delivering improved reliability and resiliency in anticipation of electrification and pressures from adverse weather. However, to be positioned to fully realize these benefits, the utility must invest in completing the milestones outlined above.

For more information on Toronto Hydro's FLISR system, please refer to Section D5.3.2.

[4] U.S. Department of Energy, Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration, https://www.smartgrid.gov/files/documents/B5_draft_report-12-18-2014.pdf
[5] It is important to note that the benefits cited from the U.S. Department of Energy Study rely upon the US standard for momentary outages of <5mins. Percentage improvements may be lesser for Toronto Hydro given the standard of <1min for momentary outages in Ontario. Regardless, the positive effective on the lived reliability experience of customers will be the same or similar. Note that the level of FLISR benefits achieved by a given utility is also dependent on that utility's unique operating reality.
[6] U.S. Department of Energy, Smart Grid Investment Grant Program Final Report Executive Summary, https://www.energy.gov/sites/prod/files/2017/03/f34/Final%20SGIG%20Report%20-%20Executive%20Summary.pdf

2. Additional Controllability Investments to Improve Reliability, Resiliency and Grid Flexibility

As noted earlier in this section, even without the advanced benefits of automated FLISR, the deployment of incremental remote-operable switching devices will have material benefits for reliability, resiliency and operational flexibility. Therefore, in addition to completing the "self-healing grid" strategy discussed above, Toronto Hydro is planning to continue deploying SCADA-controlled devices more broadly as part of the System Enhancements program. This includes continuing to deploy additional sectionalizers and tie switches on the feeders most in need of additional switching capabilities.

As a general design guideline for area rebuilds and new feeders, Toronto Hydro requires that there be no more than approximately 700 customers within a switching region or section. Currently, many feeders on Toronto Hydro's system do not meet this standard, meaning that these feeders have relatively limited flexibility to deal with certain contingency events and interruptions. This results in sub-optimal levels of reliability performance risk for affected customers. In 2025-2029, to support its reliability targets and improve the operational flexibility of the Horseshoe and Downtown overhead systems, Toronto Hydro is planning to install 298 SCADA operated switches and 220 reclosers, prioritizing feeders with the worst reliability performance and greatest reliability risk levels. For a detailed overview of these investments, refer to the Contingency Enhancement segment within the System Enhancements program (Section E7.1).

Note that reclosers are a new feature of Toronto Hydro's portfolio of grid technologies. A recloser is a device which automatically detects and interrupts fault conditions, and then re-establishes connectivity if the fault condition has been cleared. In other words, when a transient fault occurs downstream of a recloser (like a tree branch touching a line), the recloser will temporarily open the circuit to clear the fault and then automatically reclose it, restoring power. If the fault is persistent, the recloser will typically operate a pre-set number of times before locking out (remaining open) to ensure safety, automatically isolating faulted sections of the feeder such that customers on healthy feeder sections do not experience an interruption. Reclosers provide benefits to the system by substantially reducing the number of customers who experience a sustained interruption under certain high-impact fault scenarios.

Toronto Hydro completed a recloser deployment pilot project in early 2023, which successfully demonstrated that modern recloser technologies can work effectively on the utility's distribution

system and that these units have the potential to contribute material improvements in the number of customers impacted by sustained outages in many of the higher-impact fault scenarios Toronto Hydro deals with on a regular basis.[7] Importantly, reclosers can also be operated remotely, much like a SCADA-operable load break switch, meaning that they will also form an integrated part of Toronto Hydro's FLISR-enabled distribution automation scheme. By targeting high-priority locations and responding to customer concerns, Toronto Hydro will enhance its ability to restore power quickly during outages, including high-impact contingency events such as major storms.

With the combination of these switching investments, Toronto Hydro expects to see benefits in CI ("Customer Interruptions") and CMO ("Customer Minutes Out"), as well as operational cost savings. Overall, Toronto Hydro estimates that by 2030, there will be improvements in the range of three to seven percent for SAIFI and four to seven percent for SAIDI on the overhead system due to Contingency Enhancement investments. Toronto Hydro has also estimated operational cost savings from the deployment of its SCADA switches to be about $22,500 per switch over its lifetime.[8] Finally, Toronto Hydro has also estimated the quantified customer reliability benefits of its 2025-2029 Distribution System Plan, which includes the benefits of additional switches and reclosers. This analysis can be found in Exhibit 1B, Tab 3, Schedule 1.

3. Advanced Distribution Management System ("ADMS") Upgrades

The FLISR capabilities discussed in the automation section above are part of a broader software solution known as an ADMS. At its core, an ADMS is a software solution that integrates and consolidates functionalities from several systems, such as the utility's Outage Management System ("OMS") and Distribution Management System ("DMS"), which handle a wide array of mission-critical outage management and distribution system management functions; SCADA, which enables real-time monitoring and control; and the DER Management System or DERMS, which monitors and controls DERs. The role of an ADMS is to provide the utility with a comprehensive and unified view

[7] Microprocessor relays employed in the latest generation of reclosers are able to identify the different types of faults that occur and be programmed to provide a faster, more appropriate response. Prior to this development, protection schemes – specially in high density areas with short feeders like the City of Toronto – often had to choose security and dependability over reduction in response times and increased feeder segmentation. Today's feeder protection devices must be ready to respond to more dynamic situations and the new generation of reclosers with microprocessor relays are key in this regard to address emerging challenges by improving segmentation and protecting Toronto Hydro's circuits and assets.

[8] Based on average truck roll cost of $300 per hour for one-hour, average number of SCADA switch operations per year (calculated over 2018-2022), and an average switch lifetime of 25 years.

of its operations by acting as a central hub which pulls data from, and interacts with, this constellation of software and systems.

Toronto Hydro's ADMS is poised to play an increasingly significant role in the utility's operations. As the grid evolves with the integration of distributed energy resources, electric vehicles, smart devices, and changing consumption patterns, the complexities of managing the network will also increase. The utility will require its ADMS to optimize the integration and management of DERs, leverage real-time data processing capabilities and analytics to manage the two-way flow of electricity and information as the grid becomes smarter, perform more advanced outage management functions (including FLISR), manage demand response programs, and leverage enhanced analytics and data integration to improve system and operational efficiency.

As part of its Intelligent Grid strategy for 2025-2029, Toronto Hydro plans to upgrade its existing systems into an ADMS platform that better integrates "best-fit" system components and will be capable of meeting the emerging demands on the grid while enabling efficiencies. Given the critical nature of these systems to Toronto Hydro's day-to-day operations and overall system reliability and security, technical upgrades are necessary in 2025-2029 to ensure the ADMS components have continued vendor support. Furthermore, many of Toronto Hydro's ADMS components operate in silos and have limited ability to communicate effectively with each other, often contributing to process delays and inefficiencies that may result in longer outages. Upgrades to ADMS will ensure optimal components are enabled and these components are effectively integrated. These upgrades will also support future automation functionalities (e.g. in support of the self-healing grid) and improve business process efficiencies.

For more information on Toronto Hydro's planned ADMS upgrade project, please refer to Exhibit 2B, Section E8.4.

D5.2.1.3 Intelligent Grid Program Summaries

The Intelligent Grid technologies introduced above are summarized in Table 2. For more detail on each technology, please refer to the Investment Program column. For select technologies, more detail has been provided in the appendices of this strategy.

Table 2. Intelligent Grid Program Summaries

Capability Domain	Technology	Benefits	Costs (2025-2029)	Investment Program
System Observability	Overhead & Underground Sensors	• Improves outage response time and quicker service restoration for customers • Improves SAIDI & SAIFI metrics through data that enables proactive asset management • Provides data for advanced analytics platforms and data-driven asset management decision-making	$4.7M	Exhibit 2B, Section E7.1 - System Enhancement
	Online Cable Monitoring	• Identifies cables at risk of failure before failure • Provides insights on assets that are difficult or costly to inspect; • Monitors load growth and allows for proactive prioritization of capacity availability • Saves operating expenditures and • Reduces planned outage times through proactive cable maintenance		
	Transformer Monitoring	• Real-time transformer monitoring to identify early signs of failure • Provides additional information for diagnostics and future asset management purposes • Enables the data necessary for more granular system forecasting		

Capability Domain	Technology	Benefits	Costs (2025-2029)	Investment Program
	Network Condition Monitoring & Control (NCMC)	• Reduces flooding-related equipment damage; • Enables the early detection of conditions that can cause vault fires to improve response time and mitigate damage and safety risks; • Provides real-time loading data and remote switching capabilities • Reduces the need for crews to perform inspections	$6.0M	Exhibit 2B, Section E7.3 -Network Condition Monitoring & Control
	Stations Digital Relays	• Accommodates increasingly sophisticated customer needs, including DER integration; • Enables Toronto Hydro to operate its system more efficiently by increasing observability and controllability; • Allows for fault recording for historical view of issues; • Provides relay diagnostics for easier maintenance; • Improves fault coordination	$48.9M	Exhibit 2B, Section E6.6 - Stations Renewal Narrative
	AMI 2.0	• Contributes to reliability objectives by enabling dispatchers to more effectively direct field crews due to last gasp capabilities. • Improves response time for emergency response and outage restoration activities that require customer level outage information • Improves the cost-effectiveness of planning and operational decision-making • Increases visibility into the distribution system particularly at the edge of the grid • Enhances load forecasting and future demand forecast at secondary transformer level using more granular data • Enables more accurate residential load profiles to support efficient resource allocation	$248.1M	Exhibit 2B, Section E5.4 -Metering Narrative

Capability Domain	Technology	Benefits	Costs (2025-2029)	Investment Program
System Controllability & Automation	SCADA Switches	• Reduces fault isolation times on targeted feeder trunks • Reduces average duration of outages for targeted feeders by installing SCADA-enabled tie and sectionalizing points • Reduces the duration of sustained interruptions; • Reduces the time to locate and clear faults; • Enables technologies such as FLISR	$132.9M	Exhibit 2B, Section E7.1 - System Enhancement
	Reclosers	• Reduces the time to locate and clear faults • Reduces the number of customers impacted on a feeder outage • Increases grid efficiency by differentiating between temporary and sustained faults • Enhances observability since reclosers are equipped with advanced monitoring capabilities • Improves reliability upstream of device		
	FLISR	• Improves reliability by quickly detecting and isolating fault, minimizing number of affected customers and reducing outage durations • Improves resiliency to faults and disruptions by minimizing the impact of incidents thereby improving overall grid resilience (such as customers affected during outage resulting in reduced economic losses for customers and businesses)	$34.2M	Exhibit 2B, Section E8.4 - IT/OT Systems

Capability Domain	Technology	Benefits	Costs (2025-2029)	Investment Program
	ADMS	• Improves grid reliability, reduces outage durations, enhances efficiency and increases customer satisfaction through consolidation of intelligent-device data for increased situational awareness and state estimation • Enhances outage restoration by providing real time situational awareness, automating FLISR workflows and facilitating increased coordination between field crew and control centre • Increases data analysis for data-driven decision making, optimizing grid operations, enhancing system reliability, optimizing asset utilization and identifying energy conservation opportunities		

1

D5.2.1.4 Intelligent Grid Track Record

Toronto Hydro has a proven track record of effectively implementing Intelligent Grid initiatives and realizing key benefits for customers. This section highlights two major examples of Intelligent Grid accomplishments from recent years: Network Condition Monitoring & Control and Contingency Enhancement.

1. Network Condition Monitoring & Control

Toronto Hydro developed and implemented its NCMC ("Network Condition Monitoring and Control") program in order to increase situational awareness on the low voltage secondary distribution network, with the objective of improving system reliability, environmental performance, and operational efficiency of the network. As discussed in the program evidence (Section E7.3), the NCMC program, which was launched in the latter part of the 2015-2019 period, has represented Toronto Hydro's first full-scale implementation of a new set of distributed grid technologies since the roll-out of the first generation of smart meters in 2006-2008. Toronto Hydro believes that the lessons learned, skills developed, organizational capacity gained, and customer benefits realized through this experience will prove foundational to the successful and efficient implementation of the Intelligent Grid roadmap for 2025-2029.

Toronto Hydro plans to complete the initial scope of the NCMC program by 2026, after which the utility will begin to pilot additional capabilities that could be added to network vaults in the future. As of the end of 2022, the utility has completed over a third of the program and achieved the following benefits from enhanced observability (i.e. water level sensors, vault and transformer operating temperature sensors, oil level and tank pressure sensors, and real-time loading data) and controllability (i.e. remote switching) within its network vaults:

- Over the last two years, the utility has responded to:
  - 56 **water level alarms**, helping to prevent potentially catastrophic vault flooding
  - **temperature alarms** in 14 vaults, allowing for pre-emptive response to potentially catastrophic failures
  - 34 **low oil alarms,** which have helped Toronto Hydro substantially reduce the incidence of high-volume oil spills (see Figure 3 in Section E7.3).

- In the second half of 2022, Toronto Hydro saved approximately $79,000 in operating costs by **remotely checking protectors** (e.g. after heavy rainfall events) in commissioned vaults rather than sending trucks and crews.

- In the first half of 2023, Toronto Hydro has saved approximately $120,000 through the **reduced need to deploy crews to vaults during switching events.**

- In the last two years, **real-time loading data** from commissioned network units was used by controllers during multiple contingency events to determine accurate loading conditions and improve operating decisions:
    - In January 2022, a fire in a cable chamber was caused by the network's secondary cables. Loading analysis was required to determine if a widespread outage on the Windsor network would be required. Controllers used real-time loading data as the input and determined that it was possible to support a multiple contingency event to isolate the affected area without resulting in a large outage on the network.
    - In February 2022, a fault occurred on the Cecil network which supplies highly sensitive customers such as banks and hospitals. Using the NCMC real-time data allowed the crews to identify the fault and re-energize the network in an hour. In addition, NCMC capabilities allowed Toronto Hydro to confirm that the network was able to operate on second contingency and avoid taking the network down completely.
    - In February 2023, a feeder on the George and Duke network experienced a cable fault and a neighbouring feeder tripped shortly after, causing the need for an N-2 assessment. The use of real-time loading data determined that the multiple contingency event could be supported on the network.

- Real-time loading also helps support planned work in addition to failures. Historically, when real-time loading data was not available, Toronto Hydro could not schedule an outage on multiple feeders and vaults simultaneously for planned work, as the specific impact to the network would not be known or definitive. For example, in April 2022, the Cecil network was assessed and confirmed through loading data that multiple feeders and vaults could be taken out of service to support planned work. This allowed the planned work to be scheduled on time.

- As a result of the implementation of NCMC, Toronto Hydro expects to reduce the number of planned vault inspections required for each network vault per year, reducing maintenance costs in that program by approximately $300 per vault starting in 2027.

Toronto Hydro expects these benefits to scale as program implementation continues through 2023-2025. For more information on the progress and benefits of NCMC, refer to Section E7.3.

2. Contingency Enhancement (Horseshoe System Controllability)

Toronto Hydro has been steadily modernizing its Horseshoe distribution system for many years through both its System Renewal efforts and complimentary System Service programs including the Contingency Enhancement segment (Section E7.1). A primary focus of these efforts has been the deployment of SCADA-operated switches which allow control room operators to remotely transfer load and isolate feeder sections under fault conditions or on a planned basis. Figure 4 below shows the number of switches Toronto Hydro has installed per year since 2005. [9]

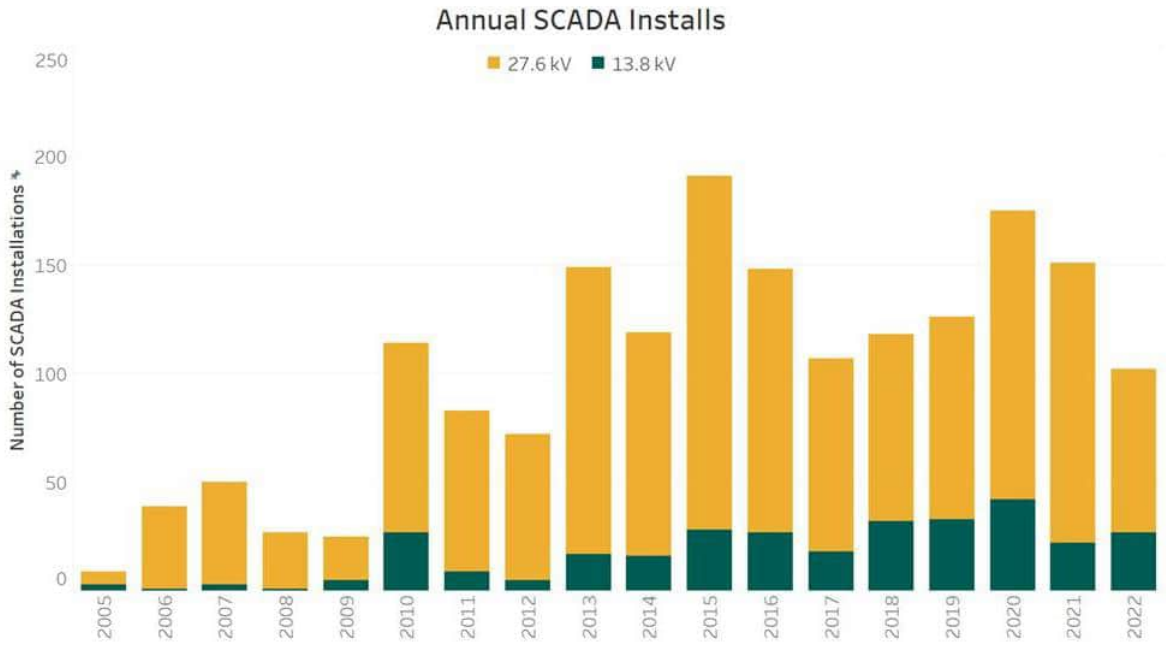

Figure 4. Annual SCADA Switch Installations (2005-2022)

[9] This graph represents all SCADA installations throughout the system, including those not installed through the Contingency Enhancement program.

As discussed in Section E7.1.3.1, these investments have been an important contributor to Toronto Hydro's improving reliability performance over the last decade. Adding SCADA switches (which includes replacing old manual switches with SCADA switches) on a feeder has also had other benefits, including avoided truck rolls and reduced outage restoration efforts in certain contingency scenarios, and reduction of safety risks by reducing the need for manual switching.

As discussed above, these existing switches, combined with the switches and reclosers to be installed throught2023 to2029, will form the physical basis for Toronto Hydro's self-healing grid in 2030 and beyond. Once implemented, Toronto Hydro expects self-healing grid capabilities to deliver significant additional value from these field devices in the form of substantial incremental reliability improvements.

D5.2.2 Grid Readiness

With advancements in technology and the societal imperative to decarbonize the energy system, Toronto Hydro expects the market for DER adoption to continue to mature and expand, likely at an accelerating pace. In response, the utility is planning for a scenario of rapid growth for various types of distributed resources and technologies, including rooftop solar systems, behind-the-meter battery storage systems, and demand response technologies. However, the utility's ability to integrate DG ("Distributed Generation") at pace with planning scenarios is challenged by (i) the precisely calibrated protection schemes potentially mis-operating, compromising the ability of the grid to operate safely and reliably; and (ii) lack of effective tools to analyze and enable interconnection as applications become increasingly complex. If projects materialize and they are integrated well, DG, and more broadly DERs, can play a role in shifting reliance away from the bulk system, supporting an adaptable and resilient distribution network, and empowering consumers to actively participate in the energy ecosystem and clean energy transition.

As the rate of DER uptake increases, it is essential for Toronto Hydro to reinforce the grid to effectively accommodate and integrate these technologies. To this end, Toronto Hydro's Grid Readiness portfolio, illustrated in Figure 5, is dedicated to enhancing what the utility views as the four critical functions of the DER enablement cycle: facilitating, leveraging, monitoring and forecasting, and innovating.

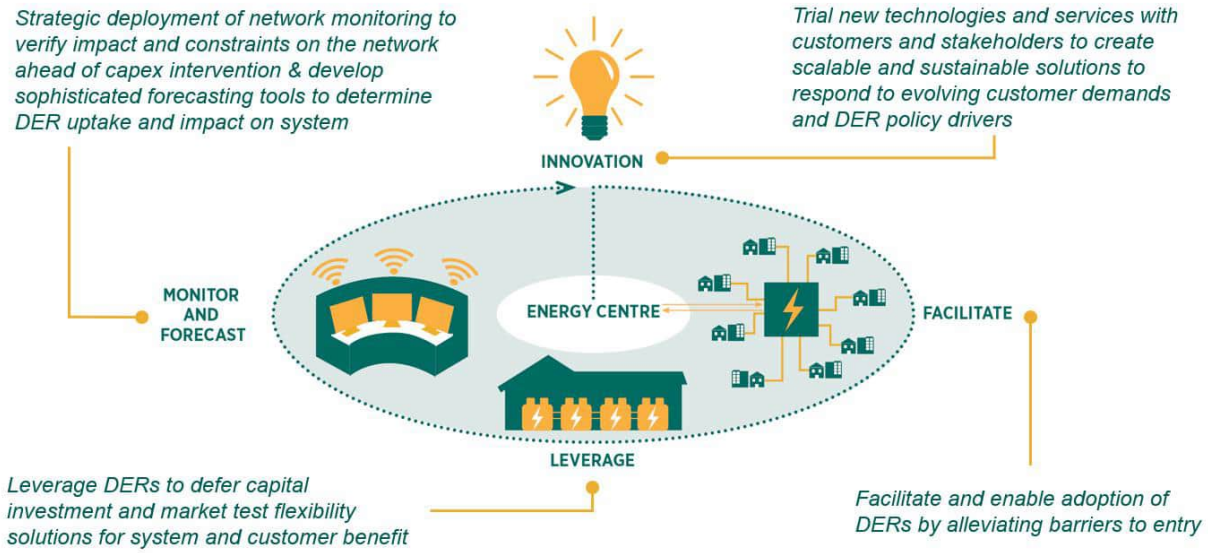

Figure 5: Major Components of the Grid Readiness Strategy

Toronto Hydro has grouped Monitoring and Forecasting together to establish the following three capability domains within the Grid Readiness portfolio:

- **Facilitating DER Connections** entails alleviating DER connection constraints on the grid where feasible and simplifying the process for customers and stakeholders seeking to connect their DERs to the grid. By improving the connection process and providing accessible, high quality geospatial data, Toronto Hydro aims to remove barriers to DER uptake and deliver an end-to-end high-quality customer journey.

- **Leveraging DER Connections** entails harnessing the capabilities of connected DERs to enhance grid flexibility and reliability, and supporting demand response programs in pursuit of grid optimization. Leveraging the inherent flexibility and capabilities of DERs means Toronto Hydro can address the changing dynamics of the grid, adapt to evolving customer needs, and build resilient energy infrastructure for the future.

- **Monitoring and Forecasting DER Connections** entails positioning Toronto Hydro to anticipate, analyze, and manage the impacts of DERs on the grid along various relevant timescales and at the necessary levels of granularity, thereby giving the utility the greatest

chance at successfully building for, and optimizing the utilization of, DERs on its system over the long-term.

Progress in these three domains will also be supported in 2025-2029 by an **Innovation program**, which is summarized in Section D5.2.2.4.

Overall, the strategy in these four critical functions is to continue in the direction of adapting and transforming today's grid into a future-ready smart and flexible grid that, by 2030, is not only prepared to cost-effectively accommodate the accelerating growth of DERs, but also is able to take advantage of the broader potential of DERs to enhance system efficiency, reliability, adaptability, and sustainability for all customers. Failure to pursue these capabilities and innovations in 2025-2029 risks positioning Toronto Hydro as an unwelcome barrier to the potential for widespread DER adoption in the City of Toronto.

D5.2.2.1 Facilitating DER Connections

Toronto Hydro is forecasting a nearly 70 percent increase in connected DER capacity by the end of 2029, though that figure could be higher or lower depending on how potential drivers of DER uptake (e.g. government policy) align to encourage and support a faster uptake.[10] Longer-term, Toronto Hydro's Future Energy Scenarios study projects that the amount of renewable distributed generation and battery storage capacity connected to the grid could grow by as much as 540 percent by 2035 under the "High" scenario and as much as 1,350 percent by 2050, as shown in Figure 6**Error! Reference source not found.**[11,12]

[10] Refer to Exhibit 2B, Section E3 for a comprehensive discussion of forecasted DER connections in 2025-2029.
[11] Renewables in the FES study largely consist of rooftop and ground-mounted solar
[12] Refer to Exhibit 2B, Appendix E for a detailed explanation of policy drivers for each of the scenarios

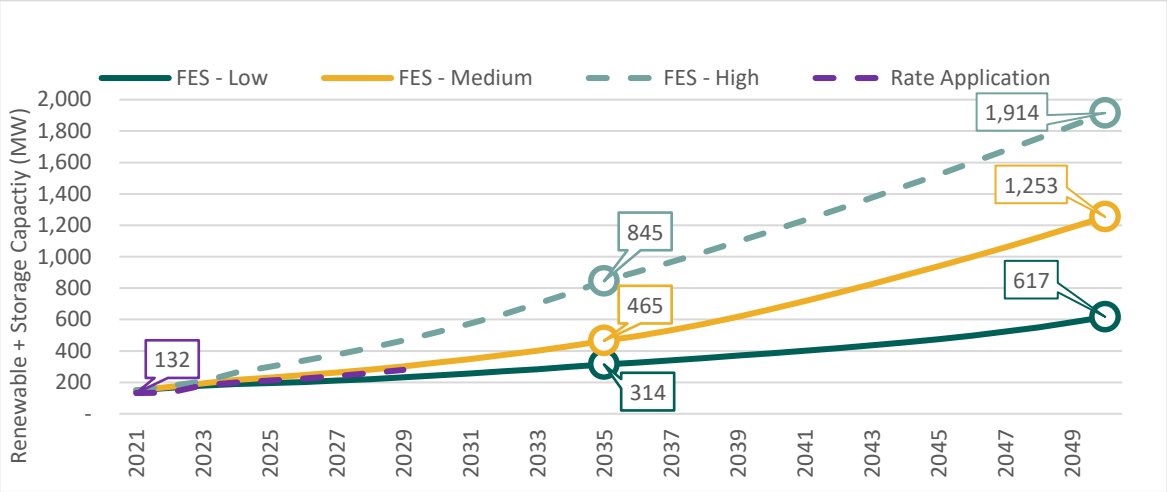

Figure 6: Future Energy Scenarios Renewable + Storage DER Connected Capacity Projections (in MW)

As discussed in detail in Exhibit 2B, Section E3, there are a number of safety and reliability constraints limiting Toronto Hydro's ability to connect DERs, including short circuit capacity, thermal limits, anti-islanding measures, and the ability to transfer loads between feeders in the event of a contingency. While these technical limitations are not widespread on Toronto Hydro's system today, the pace of DER adoption contemplated in the energy transition could lead to pervasive challenges that would make it necessary for the utility to turn away increasing volumes of connection applications.

With this context in mind, Toronto Hydro is planning a number of proactive investments and initiatives that are grouped under the Facilitating DER Connections domain of its Grid Modernization Strategy. These initiatives are intended to achieve the following strategic outcomes:

1. Simplify the process for customers and contractors seeking to connect DERs to the grid;
2. Develop tools to help customers and clean technology investors identify efficient locations to install DERs on the grid;
3. Equip Toronto Hydro with high quality data to anticipate, analyze, and assess DER applications; and
4. Alleviate technical barriers to connecting DERs by investing in additional hosting capacity.

Customers looking to connect DG and ESS ("Energy Storage Systems") require access to the distribution system, which is facilitated through a DER interconnection application; the utility is obligated to enable and connect DERs under Section 6.2 of the DSC ("Distribution System Code") in

a timely manner. Toronto Hydro is committed to providing and maintaining high quality customer service from end-to-end of the interconnection journey through the creation of a **Customer Connections Portal** to centralize all requests and provide a one-window seamless and consistent experience. Creating a single, accessible source for customers and staff alike provides the ability to offer reliable connection quotes in a timely manner.

As connection request volumes increase and the system becomes more saturated with DERs, Toronto Hydro expects that the complexity of these requests will similarly increase due to the need to balance current and future requirements of both existing and future DER owners. Eventually, the utility will begin to face limitations on its ability to cost-effectively accommodate new DERs in specific locations on the grid. Toronto Hydro believes that an important role for the utility in this emerging landscape will be to equip customers with easily accessible, accurate, and up-to-date information as to where in the service territory DERs can be accommodated most efficiently, and where it may not be possible or cost-effective to connect new DERs. To accomplish this, Toronto Hydro is committed to developing the capabilities required to display a **Hosting and Load Capacity Map** (or equivalent data portal) which will provide estimated available capacity for DER interconnection and load capacity at different locations on the network based on an automated hosting and load capacity analysis. Visualization of available capacity will provide a two-fold advantage to both the utility and its customers: the utility planners will be better informed to evaluate incoming applications and devise future system upgrade investments, and customers will be better informed to understand the cost complexity of current applications and strategize future DER project investments.

Toronto Hydro expects that the two initiatives above will only make large amounts of DER interconnections possible if data flow from the end-to-end journey is seamless and of high quality to aid grid operation and business decisions. To that end, the **Geospatial Information System (GIS) DER Asset Tracking** initiative will bind the DER visualization and interconnection process journey by streamlining the data management and flows across the different platforms associated with the journey to provide comprehensive records that unlock value in various business functions including DER-related product and service offerings and high-fidelity engineering, planning, and forecasting models.

Finally, in addition to streamlining processes and publishing hosting capacity data, Toronto Hydro will, where necessary, feasible and cost-effective, continue to invest in infrastructure and field technologies which can help alleviate DER connection constraints (i.e. hosting capacity constraints) on its grid. This includes the demand-driven **Generation Protection, Monitoring and Control**

program (Exhibit 2B, Section E5.5), which involves installing monitoring and control technology at DER sites and exploring a range of additional options including bus-tie reactors at transmission stations to relieve short-circuit capacity constraints. This also includes a renewable-enabling focus for the utility's **Energy Storage Systems** segment (Exhibit 2B, Section E7.2.2), where battery storage systems will be installed on feeders where power quality and minimum load-to-generation ratios have exceeded 3:1.

In summary, the Facilitating DER Connections capability domain will be primarily addressed through the following initiatives, which are further summarized in Section D5.2.2.4:

1. Enhancing DER Connection Process
2. Hosting Capacity Map
3. GIS DER Asset Tracking
4. Generation Protection, Monitoring & Control (Exhibit 2B Section E5.5)
5. Renewable Enabling Battery Energy Storage Systems (Exhibit 2B Section E7.2)

D5.2.2.2 Leveraging DER Connections

The growth in grid-connected DERs comes with opportunities for utilities to leverage them for grid services and improved grid reliability and resiliency. Utilities across North America are building capabilities to utilize DERs to achieve benefits such as demand response. As the adoption of DERs continues to accelerate across Toronto, it brings opportunities for the utility to move from "walking" with DERs – by approving and enabling their connection – to "jogging" with DERs and unlocking further value in their ability to actively support reliable grid operation as qualified alternatives to traditional infrastructure investments.[13] In 2025-2029, Toronto Hydro plans to expand its use of distributed resources for demand response purposes (i.e. flexibility services) and expand its capabilities to monitor, control and dispatch DERs through a centralized platform.

Toronto Hydro has forecasted a number of capacity constraints emerging on a number of stations on the network in the short-to-medium term. The utility has previously explored LDR ("Local Demand Response") in the 2015-2019 rate period in the Cecil TS ("Transformer Station") area, and expanded this into the Manby TS and Horner TS areas in 2020-2024. The success set the stage for Toronto Hydro to build on LDR into a **Flexibility Services program**, to procure flexibility from customers and

[13] Adapted from Gridworks' Walk-Jog-Run Distribution Grid Planning Framework

aggregators to meet distribution system needs (for a comprehensive discussion of the Flexibility Services program, including accomplishments and enhancements in the 2020-2024 rate period, refer to Section E7.2.1). The program intends to leverage customer-owned flexible assets to provide the utility with new tools for managing and prioritizing capacity constraints that are present and will continue to emerge from the electrification and digitalization of various sectors and communities within this city. The program will also provide customers with new revenue mechanisms and opportunities to engage with their distribution company. Toronto Hydro expects this program will continue to grow and evolve in 2025-2029 as the utility accelerates its journey toward leveraging DERs in real-time and at scale, which will be necessary to navigate the energy transition effectively and efficiently for customers.

As discussed in the Facilitating DER Connections section above, Toronto Hydro also plans to continue deploying ESS in front of the meter, with a primary focus on leveraging ESS to alleviate certain real-time conditions that can prevent Toronto Hydro from connecting customer-owned DERs. Between the ESS and the Flexibility Services programs, the need for technology that can support adequate management of bi-directional distribution grid flows will be increasingly essential. Currently Toronto Hydro manually operates Toronto Hydro-owned DERs and manages them through vendor-specific platforms. As DER penetration increases, the utility's DERMS platform will require a **centralized dispatching and scheduling** module implemented to efficiently manage and operate the volume. Through this centralized platform, Toronto Hydro will be better equipped to plan future utility-owned ESS connections for peak shaving, and offer flexibility services with automated dispatch of demand response.

This capability domain will be primarily addressed through the key initiatives listed below, which are summarized in Section D5.2.2.4 and full details available in the Appendix.

1. Flexibility Services (Exhibit 2B Section E7.2)
2. Energy Center Enhancement for Leveraging DERs

D5.2.2.3 Monitoring and Forecasting

Once DERs are connected at high volumes, they can contribute to grid instability; operating the grid in real-time with larger volumes of DERs proves to be a greater challenge, coupled with fewer options to act when conditions suddenly change. Therefore, establishing the necessary monitoring and

forecasting capabilities for DERs will be a crucial component of Toronto Hydro's Grid Readiness portfolio.

One of the largest initiatives that Toronto Hydro is undertaking which could significantly improve monitoring capabilities for DERs is the roll-out of **AMI 2.0**, which is discussed in detail in Section D5.3.1. AMI 2.0 is closely tied to both the Intelligent Grid and Grid Readiness portfolios as it allows the utility to monitor the behaviour of behind-the-meter technologies. Similarly, data that will be obtained through the GIS DER Asset Tracking, FLISR, AMI 2.0, and sensors initiatives will be integrated within the utility's **DERMS** platform to improve on the existing monitoring and forecasting modules available on the platform. Toronto Hydro envisions that the wealth of new data obtained will augment two core operational functions: state estimation and load and generation forecasts to identify and develop better planning decisions through conventional and Non-Wires Solutions methods and share information with IESO for more accurate information to create bulk supply and demand decisions.

Finally, to ensure Toronto Hydro is equipped with the intelligence necessary to plan long-term expansions of the grid and to engage in long-term procurements for flexibility services, the utility must continue to invest in accurate and geospatially granular long-term technology adoption and demand forecasts and scenarios. As discussed in Section 2B Exhibit D4.4.5, for its 2025-2029 investment planning cycle, Toronto Hydro invested in an Ontario-leading **FES ("Future Energy Scenarios")** model to project installed capacity for various technologies including DERs looking out to 2050 to better understand potential impacts on overall system demands. This initial modelling exercise provided net demand impacts at the level of station bus pairs. As a next step, Toronto Hydro intends to explore options for increasing the granularity of these scenarios, including by introducing feeder and/or supply-point (e.g. distribution transformer) impacts, which will provide the details necessary to plan increasingly targeted investments to support local DER integration and consumer electrification patterns.

The capability domain will be primarily addressed through the following initiatives, which are summarized in Section D5.2.2.4 and full details available in the Appendix:

- AMI 2.0
- Energy Centre Enhancements
- Low Voltage Level Forecasting

D5.2.2.4 Grid Readiness Program Summary

The Grid Readiness technologies introduced above are summarized in Table 3 below. For more detail on each technology, please refer to the Investment Program column. For each technology, more detail has been provided in the appendices of this strategy.

Table 3. Grid Readiness Program Summaries

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
Facilitating DER Connections	Enhancing DER Connection Process	Customer web portal to manage the end-to-end DER interconnection process. Portal will allow customers and/or contractors to review, submit, track, and if necessary cancel their DER interconnection applications in a single platform. Portal can also allow Toronto Hydro to semi-automate request handling and change orders for approvals and handovers between internal teams.	Toronto Hydro is expected to face non-linear growth in DER interconnection applications, which would contribute to overall evaluation and processing times. Current process methodology relies heavily on manual processes, including email-based communication and file sharing between employees and applicants, which will challenge Toronto Hydro's ability to deliver within its current lead times.	• Increased ability to handle application volume • Reduction in costs owing to labour hours attributed to manual data entry and tracking and processing applications; • Consolidated and transparent communication channels providing timely application updates to customers • Reduction in data entry errors and faster customer notifications if further or corrected data is required	$2M	IT/OT Systems (Exhibit 2B, Section E8.4)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
	Hosting and Load Capacity Map	Interactive web map and/or data portal enabling customers to view available DER hosting and load capacity prior to applying. Map will be built upon a hosting and load capacity analysis conducted on part or all of the distribution grid at the feeder level.	Toronto Hydro historically performs studies and analyses to identify the feasibility of DER interconnection requests on an application by application method, which is time-consuming and resource intensive. Rising volumes of applications will challenge Toronto Hydro's ability to deliver within its current lead times. Furthermore, the overall success rate and efficiency of DER connections can be improved by providing actionable information to prospective applicants.	• Increased visibility into the available capacity of the grid to host DERs • Integration with customer connections portal to update available capacity based on DERs awaiting install • Increased visibility of system nodes with immediate or near-term capacity constraints • Reduction in dependency on "general guidelines" within technical screens with insight into the required depth and analytical rigour to process applications	$1M	IT/OT Systems (Exhibit 2B, Section E8.4)
	GIS DER Asset Tracking	Streamlined data management and data flows across the different platforms associated with DER interconnection requests (connections portal, Geographic Information System ("GIS"), Energy Centre) to enhance visualization and control capabilities of DERs.	Toronto Hydro currently relies on manual data entry to transfer DER asset data records between platforms. This causes process inefficiencies and issues with data quality. Transferring GIS onto the Energy Centre backend requires manual routine updates which hinders Toronto Hydro's ability to develop more advanced applications of Non-Wire Solution program concepts. Generally, advanced smart grid capabilities are highly dependent on data quality and systems integration.	• Robust organization of DER interconnection data from application submission through to installation and commissioning • Reduce and/or eliminate poor quality or missing data from manual data entry between different platforms • Increased efficiency of data transfer through integration of data from DER platforms without the need for manual effort in syncing data	$1.5M	IT/OT Systems (Exhibit 2B, Section E8.4)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
	Grid Protection, Monitoring and Control	Installation of bus-tie reactors and exploration of other technologies to alleviate short circuit capacity constraints at select stations and Monitoring and Control Systems (MCS) for renewable DERs to prevent anti-islanding concerns and support system capability to connect and control distributed generation.	Toronto Hydro has identified and forecasted a number of stations with short circuit capacity limits, capping the amount of DER connections. Additionally, several feeder circuits have surpassed the recommended generation to minimum load ratio, increasing the amount of time required by inverters to respond to anti-islanding scenarios and decreasing the likelihood of inverters responding to anti-islanding scenarios.	• Remote and automated isolation of DER connections under specified conditions • Ensures operation of the distribution network within safe and allowable short circuit current limits • Avoids unintentional islanding and reducing the islanding risk of DER sources • Increased ability to observe large DERs in real-time to enable the maximum allowable amount of connected distributed generation	$35.0M	Grid Protection, Monitoring & Control (Exhibit 2B, Section E5.5)
	Renewable Enabling Energy Storage Systems (“ESS”)	Deployment of grid-side battery ESS with a primary focus on managing and alleviating constraints against connecting customer-owned renewable energy generation facilities. This can be accomplished by operating ESS as a load on feeders with high generation and low load demand. As a secondary matter, the utility will also continue to explore other grid supporting use cases for distributed, front-of-the-meter ESS.	Integration of renewable energy sources such as solar require a reliable and flexible solution to address the potential of grid instability and to enable integration of high levels of renewable energy.	• Increased peak load management • Improving overall power quality by resolving load-balancing on feeders with MLGR issues • Bolsters public policy objectives by encouraging DER uptake to reduce GHG emissions	$22.5M	Non-Wires Solutions Program (Exhibit 2B, Section E7.2)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
Leveraging DER Connections	Flexibility Services	Programmatic approach to address localized distribution issues through targeted procurement of demand response (i.e. peak shaving) services from owners of DERs and flexible loads.	Increased electrification will require Toronto Hydro to identify short-to-medium term capacity constraint-releasing methods alongside the more traditional "poles and wires" approach investment strategy.	• Improved reliability through demand congestion management • Deferred (or avoided) capital investments where demand is uncertain • Bolsters public policy objectives by encouraging DER uptake to reduce GHG emissions • Increased customer engagement and participation through revenue-based mechanisms	$5.7M (OPEX)	Non-Wires Solutions Program (Exhibit 2B, Section E7.2)
	Energy Centre Enhancement for Leveraging DERs	Implementation of the Advanced Scheduling and Dispatch module within Energy Centre (DERMS) to (i) enable real-time control and management between storage management systems and (ii) augment the Flexibility Services program.	Currently existing Toronto Hydro owned DER assets are manually operated and/or managed through vendor-specific platforms. This operational method will become unsustainable without a centralized dispatching and scheduling platform to optimize coordination of assets and participation in Flexibility Services programs.	• Enhanced integration of energy storage projects • Improved resource utilization of DERs • Improved coordination of DER dispatch and scheduling on one platform	$150K (OPEX)	IT/OT Systems (Exhibit 2B, Section E8.4)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
Monitoring & Forecasting DER Connections	AMI 2.0 for DER Monitoring	Deployment of next-generation smart meters in 2025-2029. These meters will provide new and enhanced forms of telemetry at the customer supply point, including data that will be relevant to monitoring and managing the impacts of DERs and electrified consumer technologies (e.g. EVs). Toronto Hydro will explore use cases from this data to inform the next phase of the DER monitoring and control strategy in 2030.	As DER penetration increases, the variability in household level voltage will require more fine-tuned DER monitoring and management to anticipate and address situations such as voltage violations and overloading.	• Improved observability of customer level loads and voltages • Increased capability of current and future flexibility service programs • Optimize DER dispatch to address grid conditions in local areas • Enhanced baseline data for use in developing long-term investment planning forecasts and other decision-making analytics	$248.1M (Total Revenue Meter replacement cost in 2025-2029)	Metering Program (Exhibit 2B, Section E5.4)
	Energy Centre Enhancement for Monitoring and Forecasting	The implementation of other Grid Modernization initiatives creates more powerful monitoring and forecasting capabilities within DERMS/Energy Centre to identify and act on any operational issues, deviations from expected performance, or potential grid constraints caused by DERs. Integration of more granular data into Energy Centre can build on DER disaggregation and day ahead local forecasting capabilities to broaden flexibility services and	DER penetration requires monitoring and forecasting capabilities to understand the impact the assets will have on the grid due to the bi-directional power flow introduced onto the network.	• Improved ability to coordinate with IESO (bulk supply and demand planning) • Improved load and generation forecasting abilities • Enhanced monitoring of DERs to identify possible voltage fluctuations • Increased visibility of DERs through disaggregation display (e.g. regions, area, transformers) for future Non-Wires Solutions program locations	$2.5M	IT/OT Systems (Exhibit 2B, Section E8.4)

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
		energy storage programs as they develop.				

Capability Domain	Technology	Description	Need	Benefits	Approx. Costs	Investment Program
	Low Voltage Level Forecasting	Future Energy Scenarios (FES) provides an overview of possible future changes to power demand, energy consumption, generation, and storage across the City of Toronto with an assessment of their potential impacts on the distribution network. The scenarios are predicated upon a granular, consumer choice-based analysis of future loading conditions at the desired modelling level. In 2025-2029, Toronto Hydro will consider options for enhancing the geospatial granularity of this model to support targeted, local investment planning and various other value streams related to electrification and the energy transition. This will require incremental investment in modelling capacity.	Population growth and increased electrification to support the energy transition to Net Zero represents an increasing level of uncertainty due to the many different economic and policy conditions that can alter the anticipated level of electrification. A strategic framework and methodology are required to inform and support network planning and future infrastructure investments. While Toronto Hydro can presently model these factors at the station bus level, it is necessary to enhance the model granularity to provide better insight into how electrification and DERs could impact the system at the low-voltage level (i.e. feeder and neighbourhood level).	• Standardized strategic outlook of different drivers of change to support needs across different Toronto Hydro business functions as well as planning consultations with customers and stakeholders • Increased insight for planners into the potential geospatial distribution of electrification on the network and technologies representing the make-up • Optimized decision making for investment planning at the feeder level with real-time data from the system observability program to confirm and adjust future forecasting	Initiative will be funded as a Software Enhancement (Estimate TBD)	IT/OT Systems (Exhibit 2B, Section E8.4)

1

D5.2.2.5 Grid Readiness Track Record

Over the last decade, Toronto Hydro has strived to be a leader in Ontario when it comes to exploring and implementing technologies and solutions for facilitating, leveraging, monitoring and forecasting DG and DERs more broadly. The following are some major highlights from recent years.

1. Electric Vehicle ("EV") Smart Charging Pilot

Toronto Hydro partnered with Plug'n Drive and Elocity Technologies to trial an EV Smart Charging Pilot aimed at understanding EV charging patterns and behaviours in Toronto and gathering information to assist in the development of future EV programs to support current EV drivers and those wishing to switch over to an EV. Benefits of this pilot include supporting the development of additional tools for EV owners to monitor, schedule, and control their charging sessions, and collecting data and insights to understand impacts of EV charging on the distribution grid.

2. Non-Wires Solutions

Toronto Hydro has been a leader in the procurement of demand response services from customers. The utility's Local Demand Response program (LDR) was the first utility-driven NWS program in Ontario and has been deployed successfully since the 2015-2019 rate period. This program was designed to help address short-to-medium-term capacity constraints at targeted transformer stations by identifying opportunities where DR, including behind-the-meter and customer-owned DERs, can be leveraged to support the broader distribution system cost-effectively. In the 2015-2019 rate period, Toronto Hydro successfully used LDR to reduce summer peak demand at Cecil TS by about 8 MW, helping to avoid anticipated capital investment. In the 2020-2024 period, the utility has been pursuing similar DR services in the areas of Manby TS and Horner TS, and, through the OEB Grid Innovation Fund and Innovation Sandbox program, is working with the IESO, Power Advisory, and Toronto Metropolitan University's Centre for Urban Energy to implement a Benefit Stacking Pilot, which will trial an auction mechanism to procure DR resources to provide local system service, and aggregate these resources to offer their capacity into the IESO wholesale market. In 2025-2029, Toronto Hydro is planning to expand its Local Demand Response program into a more diverse Flexibility Services program and procure up to 30 MW of demand response capacity in the Horseshoe North area. For more details on Toronto Hydro's Non-Wires Solutions programs, refer to Section E7.2.

3. DER Integration

Toronto Hydro has a well-established program for DER facilitation and integration, and has been actively supporting DER connections for its residential, commercial, and industrial customers. As of the end of 2022, Toronto Hydro has 2,424 unique DER connections to its distribution grid with a total capacity of 304.9 MW. For more information on Toronto Hydro's experience with, and plans for, connecting and integrating DERs, please refer to Section E3 (Capability for Renewables), E5.1 (Customer Connections), and E5.5 (Grid Protection, Monitoring and Control).

4. BESS ("Battery Energy Storage Systems")

Toronto Hydro has been active in the energy storage space since 2017, with several existing projects completed or underway. The utility has learned a great deal with respect to procuring, designing, constructing, commissioning, and utilizing BESS over the last six years. The Bulwer project, a front-of-the-meter BESS that is entirely owned and operated by Toronto Hydro, has been instrumental for developing knowledge around utilizing BESS to provide distribution-level grid support. This project was built in the 2015-2019 rate period and energized in January 2020. Over the 2020-2023 period, this project has been tested, commissioned, and transitioned to operations for deployment. This project helped Toronto Hydro develop:

- New processes for monitoring and controlling BESS assets on a daily basis;
- IT frameworks for integrating BESS software platforms safely and seamlessly with existing Toronto Hydro IT infrastructure;
- Methodologies for determining charging schedules, managing BESS state of charge, and measuring peak-shaving at the feeder level; and
- Maintenance of BESS assets.

Toronto Hydro also has experience with behind-the-meter BESS projects, including one at the 500 Commissioners street facility, and two that are located on customer sites (i.e. Metrolinx ECLRT and TTC eBus garages). These projects have also provided valuable experience and have supported the development of various capabilities that will be valuable in deploying, facilitating, monitoring, forecasting, and leveraging BESS going forward. For more details on Toronto Hydro's experience with BESS and the strategy for 2025-2029, please refer to Section E7.2.

5. FES ("Future Energy Scenarios")

To support preparation of the 2025-2029 Distribution System Plan, and in recognition of the growing uncertainty with respect to future load growth and DER adoption rates, Toronto Hydro commissioned the province's first Future Energy Scenarios model and report to provide a detailed overview of possible future changes to power demand, energy consumption, generation and storage across Toronto and an assessment of their potential impacts on the electricity distribution network. This project was a major step forward in the utility's development of a more robust long-term strategic grid planning function and was essential to the adoption of a "least regrets" approach to capacity planning for the 2025-2029 period, which is discussed in detail in Section D4. Going forward, Toronto Hydro intends to explore opportunities to further enhance its demand forecasts and scenario analyses, including by investing in more granular geospatial models which can support improved capacity planning at the neighbourhood level in anticipation of long-term trends in the uptake of technologies such as EVs and heat pumps.

D5.2.2.6 Innovation Program

Progress across all domains of the *Grid Readiness* portfolio (and related elements of the broader Grid Modernization Strategy) will be supported in 2025-2029 by an **Innovation Program**, which will focus on designing and executing targeted innovation projects in collaboration with customers, stakeholders, and technology providers, with the objective of creating scalable and sustainable solutions to enduring or imminently anticipated problems with respect to widespread DER integration and electrification of the energy economy. A robust innovation program will help the utility allocate the funding necessary and create the organizational pathways required to address the novel challenges and opportunities that policy-supported DER proliferation and integration will present to the grid and utility operations over the next decade.

Learnings from all of the innovation pilots will be shared within the industry to foster industry-wide collaboration and reduce innovation risks. Where the pilot is successful, Toronto Hydro aims to scale the solution and roll it into existing business practices to provide rate payers benefits.

There are a number of innovation project concepts that Toronto Hydro is considering for the 2025-2029 rate period. Some examples of potential projects are listed below in Table 4, while full descriptions are in Section D5.3.8: Appendix I – Innovation Pilot Projects and Exhibit 1B, Tab 4, Schedule 2, Appendix A..

Table 4. Sample Innovation Pilot Project Summaries

Pilot Concept	Description	Need	Benefits
Flexible Connections	Explore and develop technological and commercial offerings that could allow customers to more cost-effectively connect distributed generation ("DG") on constrained parts of the grid. A "flexible" connection is one which could be controlled and curtailed in real-time by leveraging smart-grid technologies controlled by the utility. This could be achieved through development of an advanced Energy Centre (DERMS) system coupled with intelligent device installation utilized through a communications platform.	Integrating DG into the distribution network poses several technical constraints (e.g. voltage violations) if not proactively managed and coordinated. DG customers looking to connect on constrained parts of the network may be prevented from connecting, or could faced high costs and long lead times because of the need for system upgrades. Allowing Toronto Hydro to control the customer's DG output in automated coordination with critical system operating parameters could provide a more cost-effective solution in the future.	• Reduced delays and costs for customers looking to connect DG on parts of the grid approaching thermal and voltage limits • Increased customer engagement through new commercial arrangements • Optimized usage of existing network infrastructure • Improved overall hosting capacity for DERs
EV Commercial Fleet	Examining the impact of commercial EV fleet charging at depots and other charging segments and optimize charging schemes based on the flexibility requirements and preferences of Toronto Hydro and pilot participants.	Widespread adoption of commercial fleet electrification may face high connection costs, creating a barrier to EV adoption, as well as incurring significant distribution system upgrade costs if not managed in coordination with the utility.	• Quantify and minimize the impact of commercial fleet electrification on the grid • Quantify the total cost of ownership for smart scheduling and charging solutions for EV fleets • Identify necessary infrastructure to facilitate fleet transition to EVs

Pilot Concept	Description	Need	Benefits
Electric Vehicle Demand Response	Identify viable demand response models that facilitate coordinated charging and potential discharging of EV batteries to support network needs. An initial pilot project with some customers has been successful in demonstrating load shifting to off-peak times and load deferral by utility-initiated curtailment. Future projects will target a broader set of control technologies that enhance consumer choice and scalability over time.	The shift from combustion engine vehicles to electric poses several potential system challenges, such as overloading secondary distribution transformers, exerting additional electrical stress on overhead conductors and underground cables, and increasing peak load at various system levels. Together, these challenges can lead to distribution system instability; for instance, when a cluster of EV's on the same transformer charge simultaneously.	• Increased customer participation in new charging mechanisms • Deferred (or avoided) capital investment in station upgrades through smart EV charging management • Quantify EV charging impact on the secondary distribution grid
Advanced Microgrid	Identify viable microgrid topologies within Toronto Hydro's network and trial a microgrid on the distribution system to observe system resiliency in real-time grid conditions.	The increasing frequency of extreme weather events has the potential to cause widespread and extended power outages, which is a consideration for the imperative to electrify the city. This is a particular concern for population segments and services that rely on power for mission-critical needs.	• Quantify commercial viability of community microgrids to improve grid resiliency • Flexible resource to sustain operations during outages • Provide ancillary services to the wider grid • Facilitate new methods of connecting higher penetrations of renewable energy generation

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D5.2.3 Asset Analytics & Decision-Making

The *Asset Analytics & Decision-Making* portfolio within the Grid Modernization Strategy covers improvements that Toronto Hydro plans to make in order to more fully and sustainably leverage the value of existing and new forms of distribution system data and intelligence. Toronto Hydro possesses large quantities of data, including condition of its assets, the historical performance of its system, and electricity consumption. Through the investments planned within its Intelligent Grid and Grid Readiness portfolios, the utility foresees the accumulation of even more robust datasets over the next decade, including increasing volumes and varieties of real- or near-real-time network and asset conditions and performance data. At the same time, data analytics and automation solutions have emerged within the wider industry, which create opportunities for more effective delivery of traditional value streams for customers (e.g. reliability, safety, cost control) during the energy transition, while also enabling a more dynamic local energy market. This means that the availability of current, high-quality, and readily accessible data sets will graduate from a "nice to have" to "must have" for utility operations. Having the systems and expertise to support more detailed insights will become critical in the years ahead. Therefore, achieving the corresponding level of data quality and analytical rigour will require Toronto Hydro to continue investing in its people, processes, and digital tools.

The *Asset Analytics & Decision-Making* portfolio outlines the strategic focus areas for the advancement of Toronto Hydro's digital asset management capabilities in 2025-2029. The utility's objective is to accelerate progress on the foundational data analytics and decision-making capabilities that will be necessary to manage costs and operate effectively as changes in the energy sector accelerate beginning later this decade and into the 2030s. Toronto Hydro is focused on three main capability domains depicted in Figure 7 below.



Figure 7: Major Components of the Asset Analytics & Decision-making Portfolio

These domains address the following investment needs:

1. **Asset Information Strategy & Integration:** This domain involves developing and documenting an Asset Information Strategy, and implementing a "digital backbone" that can support effective delivery and governance over the strategy and associated data standards. Activities in this domain will include identifying critical asset-related information and creating the processes and systems for storing and integrating it, as well as making the information readily available to business users.
2. **Asset Planning Tools & Frameworks:** This domain involves acquiring or enhancing the major software platforms and underlying decision-making frameworks that support Toronto Hydro's core Asset Management planning functions. These enhancements will be focused on further strengthening the alignment of specific capital and maintenance investment decisions with the utility's customer-focused investment plan and finding efficiencies within the planning process itself.
3. **Asset Analytics:** This domain focuses on developing new descriptive, predictive, and prescriptive analytical capabilities to drive efficiency and create value throughout the various stages of asset planning and operations.

The following sections provide additional detail on each of these domains. The activities and investments described throughout the Asset Analytics & Decision-Making portfolio will predominantly take the form of information technology projects, which are funded through either

the IT/OT Systems Program (Exhibit 2B, Section E8.4) or the Information Technology OM&A program (Exhibit 4, Tab 2, Schedule 17). The incremental activities involved in embedding these solutions within evolving business processes, including implementation management, documentation, training, and administration, will require additional support from analysts, engineers, and various other professionals across the organization.

D5.2.3.1 Asset Information Strategy & Integration

The Asset Information Strategy & Integration domain involves developing and documenting an Asset Information Strategy, and implementing a "digital backbone" that can support effective delivery and governance over the strategy and associated data standards. Activities in this domain will include identifying critical asset-related information and creating the processes and systems for storing and integrating it, as well as making it readily available to business users.

As a key part of the effort to modernize the grid and grid operations, distribution utilities like Toronto Hydro will be gathering greater volumes and varieties of data in the next decade, with the intention of leveraging this data to develop value-adding applications and insights, as well as supporting automation of the grid (which in many cases is fundamentally a data-analytics-driven effort). The most important foundational step toward making this level of data-driven operations achievable and sustainable is ensuring that the process begins with a clear and comprehensive **Asset Information Strategy**. As part of its ISO55001 journey, documented in Exhibit 2B, Section D1, Toronto Hydro is currently in the process of creating a consolidated Asset Information Strategy, with the goal of having a clear asset data management strategy that identifies and prioritizes required asset information for current and future applications, outlines asset data quality requirements, assigns data ownership, retention levels, and backup requirements, and establishes change management processes. Toronto Hydro currently has multiple systems (such as GIS and ERP) which it uses for asset information purposes. The Asset Information Strategy and associated information standards will establish a system-agnostic guideline for all of the utility's key asset-related information and provide the basis for integration of relevant systems in order to create a "single source of truth" for critical data which will be stored as a central repository for analytics purposes.

The second foundational step is to proceed with further integration of relevant enterprise systems and additional data sources (such as images captured through maintenance activities) into a fully harmonized asset data registry, or "**digital backbone**" for asset planning and grid strategy. The digital backbone, in the context of this strategy, is the foundation of integrated data sources and systems,

and storing those asset data effectively to enable more advancement in asset planning capability. Toronto Hydro has made gradual and targeted progress on this front in recent years, building on the implementation of new data warehousing and blending tools in 2017 to create purpose-built databases that bring asset and system information together for operational reporting and decision-making purposes. However, looking ahead at future demands for higher quality data and analytics, there are opportunities that the utility is aiming to pursue in 2025-2029 through the IT-OT Systems program (Section E8.4). One most significant opportunities involves enhancing asset data analytics by unifying data across major enterprise systems, including the utility's Geographical Information System ("GIS"), Enterprise Resource Planning ("ERP") system, and Customer Care & Billing ("CC&B") system. Fully and permanently consolidating relevant data in these systems is a significant investment, and there are a variety of possible approaches to achieving the desired end state. Toronto Hydro intends to explore and implement appropriate and cost-effective solutions for further integrating these major databases in 2025-2029, not only because these integrations will be increasingly necessary, but also because the utility anticipates substantial benefits to customers and stakeholders in the form of improved efficiency, analysis, and reporting. For example, high quality data on the condition of assets on the system can improve the timing and level of maintenance performed on those assets, leading to a lower failure risk and improved service for customers. The core features of a digital backbone are summarized in Figure 8 below.

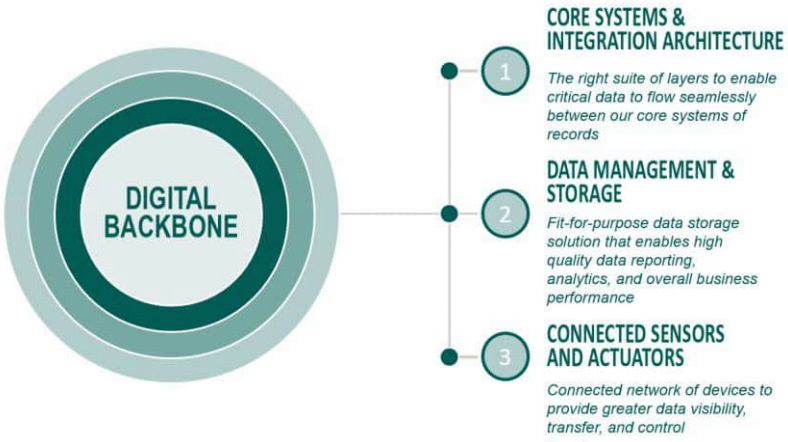


Figure 8: Core Components of a Digital Backbone[14]

[14] McKinsey & Company, Enhancing the Tech Backbone, n https://www.mckinsey.com/industries/industrials-and-electronics/our-insights/enhancing-the-tech-backbone

D5.2.3.2 Asset Planning Tools & Framework

The Asset Planning Tools & Framework domain involves enhancing the major software platforms and underlying decision-making frameworks that support Toronto Hydro's core Asset Management planning functions. These enhancements will be focused on further strengthening the alignment of specific capital and maintenance investment decisions with the utility's long-term, customer-focused investment plan and finding efficiencies within the planning process itself.

Toronto Hydro has been refining its risk-based asset management framework for many years, with the goal of being an industry leader when it comes to the use of risk inputs such as asset health scores to optimize operating and capital expenditure decisions. Having matured its asset management risk and outcomes frameworks in recent years, the utility has now begun to invest in digital platforms that will bring greater consistency, transparency, sophistication and efficiency to the implementation of these underlying decision-making frameworks within business planning processes. An overview of these future capabilities is summarized in Figure 9.

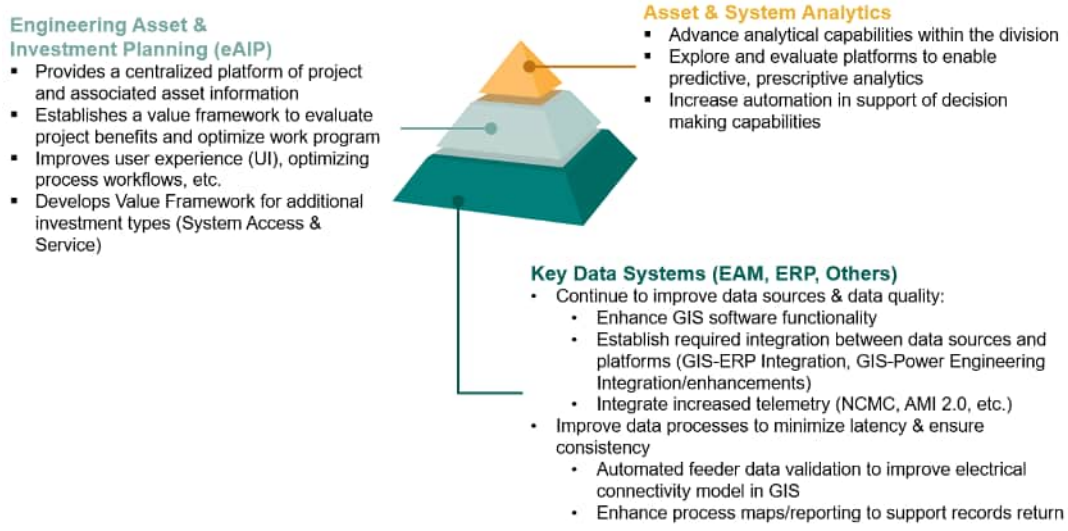


Figure 9: Asset Management Capabilities

As summarized in Section D1.2.1.1, a major element of this effort is the ongoing implementation of Copperleaf C55 as Toronto Hydro's new **Engineering Asset Investment Planning ("EAIP")** solution. At the heart of this tool is a custom value framework which assigns relative value to investments based on their likely contribution to Toronto Hydro's key performance outcomes, including their contributions to risk-based measures where applicable. This value framework will be leveraged to

compare projects within and across programs and to produce value-optimized investment plan recommendations within prescribed funding and operational constraints, ensuring that Toronto Hydro's investment planning decisions are informed by data-driven assessments of costs and benefits in alignment with the utility's outcomes-oriented strategy.

Rather than relying on generic, "off the shelf" framework elements, Toronto Hydro is developing an industry-leading, fully customized value framework for its EAIP implementation, with the goal of ensuring that planners and management are confident in the outputs and recommendations from the tool. Given the customized nature of the implementation, it is an ongoing multi-year effort. Toronto Hydro is currently on track to begin leveraging EAIP's optimization capabilities for the majority of its system investment program by the beginning of the 2025-2029 rate period.

Following on the heels of the EAIP implementation, Toronto Hydro intends to explore and implement further extensions of its risk and value frameworks into other aspects of the decision-making cycle for its assets. For instance, upstream of EAIP is the initial process whereby planners are tasked with identifying suitable capital project candidates, which they then feed into the EAIP system for program management and optimization purposes. Toronto Hydro's goal in 2025-2029 is to extend the logic of its risk and value framework into this earlier step in the process by implementing an asset analytics tool which is capable of algorithmically generating recommended interventions on the system, which Toronto Hydro expects will support greater efficiency in planning by equipping planners with more effective decision-making intelligence. For example, planners will benefit from EAIP as it will reduce manual effort in determining optimized projects for each portfolio segment by an estimated 50 percent (pending implementation insights). This is further discussed in the Asset Analytics section below.

Toronto Hydro also intends to explore **Asset Performance Management ("APM")** applications in 2025-2029. An APM solution is a software tool (or set of tools) that can help an asset-intensive organization optimize the performance of its physical assets throughout their lifecycle by leveraging condition information – especially real-time condition information – to produce analytics that can inform more precise and accurate decision-making. Today, APMs are most commonly deployed by organizations such as manufacturers and power producers, where any production downtime can have a significant financial impact on the business, warranting investment in the creation of a "digital twin" of the plant (i.e. a high-resolution digital replica of the infrastructure) and the deployment of sensors and controls that capture detailed information that can then be leveraged by the analytics engine of the APM to predict and manage plant performance. Due to the highly distributed nature

of Toronto Hydro's plant and the general absence of real-time asset condition information, there is not, at present, an obvious business case for implementing a full-scale APM. However, in recent years, Toronto Hydro has deployed real-time sensors in certain parts of the system (e.g. the Network Condition Monitoring and Control Program discussed above in section D5.2.1.4, as well as Exhibit 2B, Section E7.3) and intends to leverage these new telemetry points to explore and pilot the use of APM-like capabilities, with the goal of assessing whether there may be long-term value in these solutions.

In addition to the digital platform solutions discussed in this section, Toronto Hydro remains committed to continuously improving its foundational risk-based decision-making frameworks for its assets. For more details on these efforts, please refer to Section D1 and D3 of the Distribution System Plan.

D5.2.3.3 Asset Analytics

The Asset Analytics domain focuses on developing new, more advanced analytics capabilities to draw insight, drive efficiency and create value throughout the various stages of asset planning and operations. As mentioned in Section D1, Toronto Hydro has been ramping up its efforts to develop a more robust asset analytics function. This effort involves two major elements: (i) recruiting and developing engineers and analysts with progressive data analytics and coding skillsets, and (ii) investing in the information technologies necessary to support efficient and effective use of data for analytics and machine learning applications.

As in many other business sectors, the utility asset management space has become ripe for investment in innovative data analytics. This is due in part to two major factors:

1) The amount of data collected on the distribution system (e.g. condition, loading, and outages) and various correlated external conditions (e.g. weather patterns, consumer behaviours, and third-party geospatial data) has grown exponentially and will continue to do so as digitalization of the industry continues and the utility deploys more smart devices as part of its Grid Modernization Strategy; and

2) The development of advanced analytical tools, algorithms, and computing power and storage have made it easier and more cost-effective to analyze large volumes of data.

In the asset management space, utilities have the opportunity to leverage this data to create new kinds of analytics which could help identify and avoid inefficiencies, and lead to the discovery of opportunities to enhance the performance and value derived from distribution assets, with the eventual goal of having a network that can carry out automated decisions as depicted in Figure 10.

Asset analytics can be broken down into three categories which range in complexity:

(i) *Descriptive (and exploratory) analytics*, which relies on techniques such as data aggregation, data mining, and data visualization, to summarize historical data and provide a clear understanding of what has happened in the past;

(ii) *Predictive analytics*, which relies on techniques including regression analysis, time series analysis, and machine learning algorithms, uses historical data and statistical algorithms to make predictions about future events or trends; and

(iii) *Prescriptive analytics*, which includes techniques such as optimization, simulation, and decision analysis, to not only predict future outcomes but also recommend actions that can be taken to affect those outcomes.

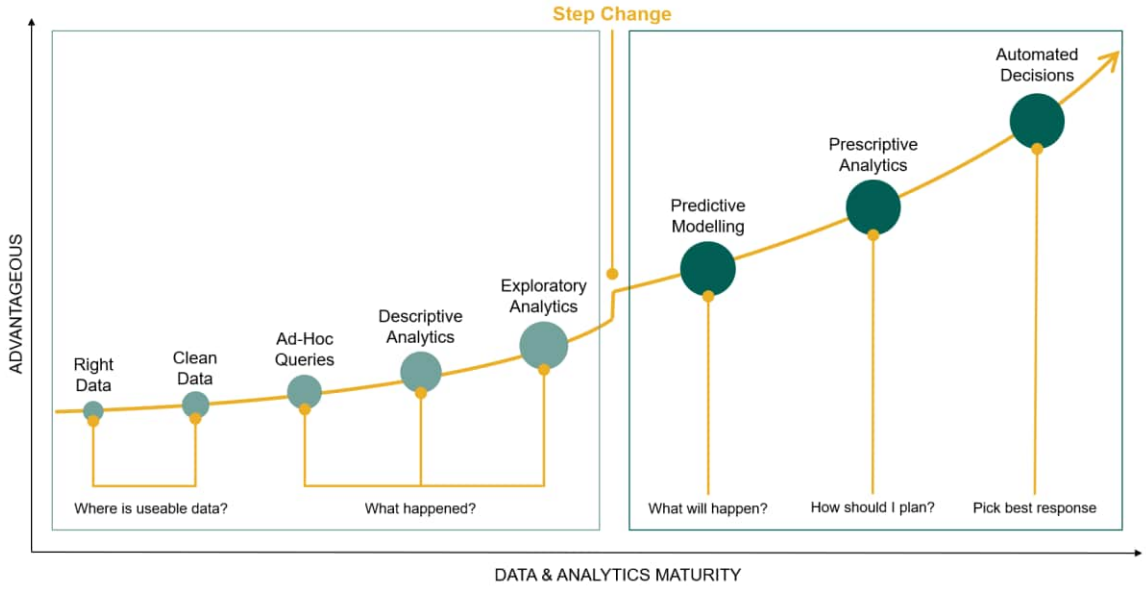


Figure 10 : Analytics Maturity Graph

Toronto Hydro has made strides on all three of these fronts in recent years and is planning to accelerate investment in these areas in the 2025-2029 rate period.

Descriptive Analytics: Since the procurement and implementation of more analytic platforms, such as data warehouse, data blending and visualization platforms in the 2015-2020 period, business units across the Toronto Hydro organization have steadily adopted these tools to enhance business processes and create an array of descriptive analytics. By moving beyond manual data workflows and the limited capabilities of basic visualization tools, Toronto Hydro has made many reporting and decision-making processes more efficient and effective, and this is especially true within the Asset Management parts of the organization. For example, Toronto Hydro leveraged a reporting technology solution to develop workflows in preparing data for analytics, relieving staff of manual data processing to focus on other value-added tasks. In the 2025-2029 rate period, Toronto Hydro's aim is to continue expanding the use of more sophisticated descriptive analytics, with a particular emphasis on investing in more effective geospatial visualization capabilities.

Predictive and Prescriptive Analytics: Toronto Hydro plans to accelerate the development and implementation of predictive and prescriptive analytics within asset management and grid operations in 2025-2029. The utility is prioritizing several initiatives, including the following:

- As mentioned in the Asset Planning Tools & Frameworks section above, Toronto Hydro is planning to implement an asset analytics engine which will leverage the utility's asset risk data, system topography, and other inputs to predict the future performance of the system with greater granularity and accuracy. The goal is for this analytics engine to also produce optimized recommendations for geographically defined capital projects based on their likely contribution to key value measures and system performance. This solution will complement the work program optimization capabilities within EAIP and complete Toronto Hydro's efforts to inject consistent predictive and prescriptive analytics into all stages of project planning. This will help to ensure the overall costs and benefits of the capital portfolio are optimized from the point of project conception to the point where projects are released for construction within the annual execution work program. Toronto Hydro also expects that these analytics will aid planners, analysts, and senior decision-makers in making planning decisions more efficiently by, for example, combining the functionality of three separate applications in one. Finally, the utility also expects an asset analytics engine to have regulatory benefits as it will support more efficient development of the long-term capital

investment plan scenarios and associated risk and performance projections that are required for a five-year Distribution System Plan.

- In preparation for the 2025-2029 investment planning cycle and as a way of complementing the Stations Load Forecast process, Toronto Hydro introduced the Future Energy Scenarios model in 2022. This is a bottom-up, consumer choice model that produced projections under a variety of potential energy system transformation scenarios. Toronto Hydro's goal for the project was to enrich its long-term strategic planning capabilities and provide its stakeholders with an understanding of the way in which electricity demand, consumption and generation may change in the future and the range of uncertainty involved. Further information on Future Energy Scenarios can be found in Section D4. During the 2025-2029 rate period, Toronto Hydro plans to refine the model with new inputs, as well as develop a more granular level of forecasting to further enhance its investment planning process.

- Toronto Hydro is exploring opportunities to leverage analytics in predictive maintenance for its electric assets as well. For example, the utility is currently running a pilot project that will explore the use of high-resolution satellite imagery and artificial intelligence as a basis for creating a risk-based decision-support tool for the Vegetation Management program. Such a tool would be analogous to the asset-driven analytics engine discussed in the bullet above, insofar as it would leverage AI-driven predictive capabilities to forecast the system impacts of tree contacts at a granular level, while also leveraging predictive insights to recommend feeder-specific tree-trimming cycles and identifying high-risk areas that could benefit from spot trimming.

- More broadly, Toronto Hydro is aiming to take an agile approach in 2025-2029 to exploring and producing homegrown and vendor-supported analytics applications for targeted use cases. For example, the utility's in-house analytics teams have already developed demonstration models for electric vehicle detection leveraging AMI data, computer vision (e.g. using machine learning to identify and classify trip hazards from inspection photos), and data interpolation (e.g. predicting the likely cause of outages classified as "unknowns"). Toronto Hydro foresees numerous value-added use cases for machine learning models and advanced analytics, and plans to develop the resources and vendor partnerships in 2025-2029 that will allow for a more sustained approach to realizing these benefits for customers.

As discussed above and in Sections D1 and D3, Toronto Hydro has a steady track-record of leveraging its analytics tools to create efficiencies and drive innovation across various departments and functions, including most recently the development of models that demonstrate the potential for machine learning to assist in the identification of key trends such as EV adoption on the grid. The following are two additional highlights of the many analytics enhancements achieved in the last five years, specifically in the Maintenance Planning area.

1. Asset Deficiency Automated Prioritization Tool ("ADAPT")

Toronto Hydro has redesigned its priority decision framework through the introduction of ADAPT, a work request prioritization tool that uses an Alteryx workflow to use the deficiencies reported through inspection programs completed by contractors. The workflow takes in inspection reports and assigns priority and corrective actions using a job mapping devised by maintenance planning engineers.

a. Select benefits:

- Reduced manual engineering reviews of major assets by 40 percent
- Reduced errors from synchronization of inspection form and personnel changes
- Introduction of single notification that can bundle one or more deficiencies where appropriate, resulting in downstream operational efficiencies

2. Preventative Maintenance Units Tracking Workflow

Toronto Hydro introduced a new workflow centered around translating plant maintenance order statuses from ERP to maintenance unit attainments. This previously was completed through manual data processing and handling.

b. Select benefits:

- Reduced approximately 300 hours of labour per year
- Improved accuracy and consistency of data and data-sharing
- Provision of ad-hoc updates and more transparency in workflow changes when required

D5.3 Appendices

D5.3.1 Appendix A – AMI 2.0

1. Introduction and Role in Toronto Hydro's Grid Modernization:

Toronto Hydro was among the first utilities in Ontario to implement smart meters between 2006 and 2008 to support the efficient and effective operation of the distribution system. Primarily, these new meters improved on capabilities such as accuracy in customer billing, account connection/disconnection, and tampering detection. Rapid advancements in technology have made these first-generation meters outdated and obsolete. As the majority of these meters also reach end of useful life in the coming years, Toronto Hydro plans to replace them with next-generation smart meters – AMI 2.0.

AMI 2.0 goes beyond a billing device – the meters represent a network of sensors that provides previously unattainable visibility into performance and behaviour at the edge of the grid. They are equipped with improved hardware that supports data collection intervals up to every 5-15 minutes (and in some cases even more frequently). When this granular data collection is paired with higher bandwidth and shorter latency to improve transmission, the communication of meters expands system observability and can go further with other grid data to provide valuable insights into system operation, energy consumption patterns, and grid performance. AMI 2.0 has the potential to form a significant part of the digital backbone of the grid modernization strategy by improving the visibility and accuracy of data on voltage levels, power flows, and load consumption. These improvements are instrumental in painting a never-before-seen picture of the secondary network; along with sensors installed as part of the System Enhancement program, the utility will gain additional insights into the loading profiles of secondary transformers. Greater visibility means better analytics and decision-making for grid operations, asset management, and investment decisions at the secondary level.

However, fully realizing the modernization benefits that AMI 2.0 can provide is heavily predicated on investments in implementation and maintenance of the IT infrastructure beyond the physical meter, deployment of organizational capabilities such as advanced analytics and data governance/management, and alignment across multiple organizational stakeholders. Benefits realization in these categories will occur on independent timelines. Once the physical meter infrastructure is brought online, Toronto Hydro will undertake the specific IT projects required to set

up system infrastructure to enable the use of AMI 2.0 insights for operations, asset management, and customer care.

2. Strategy for the upcoming rate period:

Approximately 70 percent of Toronto Hydro's residential and small commercial meters will have surpassed their expected useful life by 2025. Therefore, the utility intends to replace approximately 680,000 meters during the 2023-2028 period. As part of this replacement, the utility will introduce next generation smart meters and roll out the supporting network infrastructure.

3. Benefits:

The AMI 2.0 initiative brings about edge-computing network infrastructure and advanced capabilities to understand how electricity is generated and consumed in real-time. Some key advantages are listed below and summarized in Figure 11:

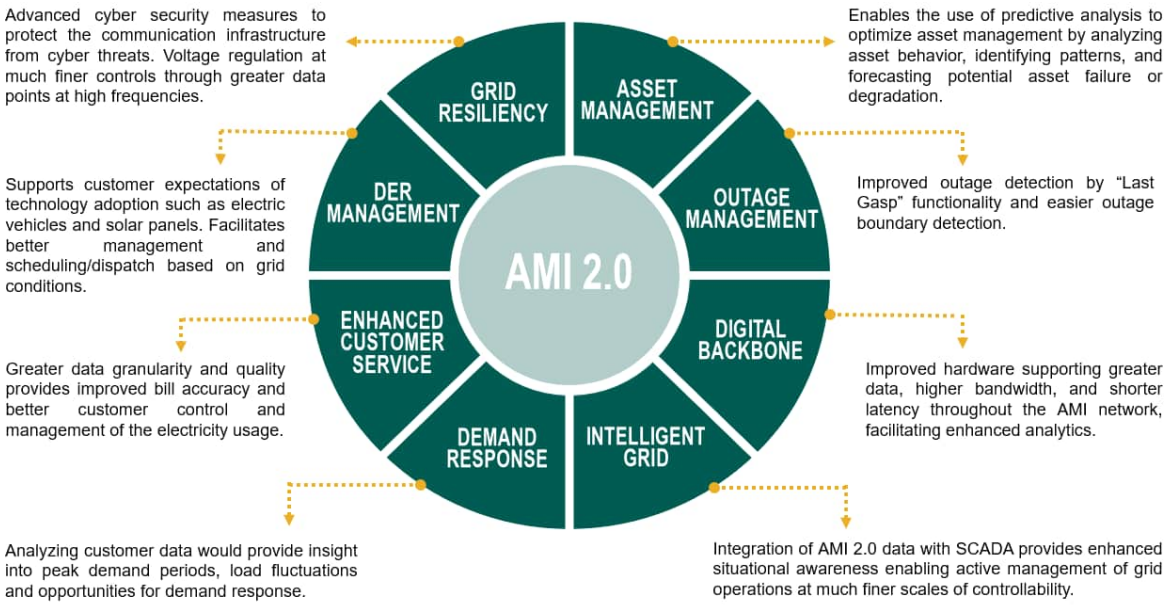


Figure 11: An Overview of AMI 2.0 Benefits

Improved visibility of the secondary network:

- Better investment planning can be realized by way of more granular data. The current FES model makes projections at the transformer station bus level, but with added visibility into the secondary network, the model could be expanded to the secondary transformer level.

This represents a step change in investment planning, as exhaustive geospatial projections provide planners better data for investment planning decisions.

- Better voltage regulation can be achieved by way of capturing voltage at many more points and at greater frequencies, allowing operators to regulate network voltage with much more control.
- Phase load balancing can be achieved by way of phase detection at endpoints of a circuit (the meter) – currently, crews are sent into the field to perform this measurement. Performing phase detection remotely, especially during storms, can reduce costs and improve grid reliability through real-time grid management.

Provision of last gasp functionality: AMI 2.0 meters enable automatic outage and restoration notifications ("last gasp") – currently, these notifications are required to be verified by phone or service call. Last-gasp meter alerts enable grid operators to identify outage locations and dispatch repair crews to more precise locations where they are needed, reducing costs and boosting the effectiveness of outage management operations. Meters also provide pinging capabilities, allowing the control room to monitor the status of outages and verify restoration quickly and accurately.

Improved understanding of customer-owned assets

- AMI 2.0 will provide insight into system voltages at the premise level, which is critical for determining when voltage violations from DERs and other assets are occurring and what actions may be necessary to mitigate such impacts. With more advanced DER monitoring and management, the utility could allow higher utilization factors for DERs as a result of greater confidence in DER management.
- Customers will be able to pair their meters with third-party software to provide a variety of services to control devices in their homes to manage their usage. This is particularly useful as a "plug'n'play" approach for future pilot projects that the utility may consider; with infrastructure already available, these pilots can be more feasible and cost-effective.

Scalability of infrastructure: AMI 2.0 can "future-proof" the meter as the ability to provide over-the-air updates will remove the risk of obsolescence of metering hardware over time. New capabilities of meters identified over time can also be rolled into new software and distributed over updates, providing flexibility to accommodate future technologies and customer expectations.

Enhanced data granularity and measurement

- The abundance of data provided by these meters will support development of analytical tools to expand on modernization capabilities such as predictive and prescriptive analytics, which will improve maintenance programs, asset management, and operational decision-making.
- Future integration with Energy Center will increase situational awareness and assist in curtailing/dispatching DERs for cases such as load management and reactive power management for voltage regulation.

4. Peer Success Stories:

For most utilities, the original business case for implementing AMI is generally focused around cost savings achieved from avoided truck rolls and the end of manual metering. Now that smart meters are becoming more commonplace in the industry, utilities are learning that the value of AMI goes beyond energy billing. These smart meters are representing a transformational shift in not only how utilities interact with their customers, but also how these meters serve as end-point sensors to obtain granular information about system operations and customer behaviour for data-driven decision making. Toronto Hydro has highlighted one of several peer success stories to give a sense of how utilities have achieved value from their AMI initiatives:

Peer Success Story	
Pacific Gas & Electric, California[15]	
Problem: PG&E relied on a limited number of research meters (~1,000) and SCADA data deployed at 60 percent of their substations to gather customer load information needed for distribution planning. The utility wanted a flexible way of aggregating load shapes for various configurations over different groupings of customers, which was not possible with their current method. Method: PG&E spent five years to develop the tools and processes (as well as transitioning to using AMI data as part of the utility planning process). Upon full transition, 4 million smart meters (representing 90	Selected Benefits: • Layered dashboard allowing operators and planners to visualize voltages from individual customer premise up to aggregated feeder level loads • Production of forecasts using hourly profiles for each circuit, customer class, and DER type • Improved peak planning from 24hours * 2days * 12 months = 576 data points to load shapes utilizing 8760 data points (number of hours in a year), representing a 15x increase in data • Development of 'Load Shape Viewer,' a tool that creates normalized load shapes with sensitivity

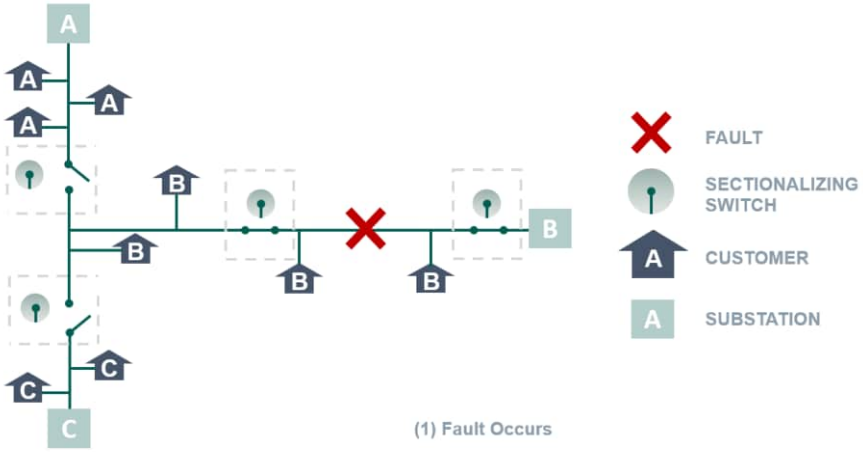
[15] U.S Department of Energy, Voices of Experience: Leveraging AMI Networks and Data, https://www.smartgrid.gov/files/documents/VOEAMI_2019.pdf

percent of their customers) were online with 99 percent accuracy, utilizing a 2-way 900 MHz RF mesh network.	from SCADA, weather, and temperature data input

D5.3.2 Appendix B – Fault Location, Isolation, & Service Restoration

1. Introduction and Role in Toronto Hydro's Grid Modernization:

Fault Location, Isolation, and Service Restoration (FLISR) technology represents a transformative approach to power outage management; it enables quicker detection, precise isolation, and automated restoration of power in the event of faults or disruptions. FLISR leverages advanced sensors, a communication network, and intelligent devices (like SCADA switches and reclosers) already present on the grid to automatically determine the location of a fault. Once the fault is located, the software uses remotely operable devices to rapidly reconfigure the flow of power so that some or all of the customers on a feeder can avoid experiencing an outage. As this requires the ability to isolate portions of the network and re-route power from other sources, it is critical that the system is configured with sufficient sectionalizing SCADA switches and feeders that are tied by multiple paths to a single or multiple substation(s).[16]



[16] U.S Department of Energy, Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration, https://www.smartgrid.gov/files/documents/B5_draft_report-12-18-2014.pdf

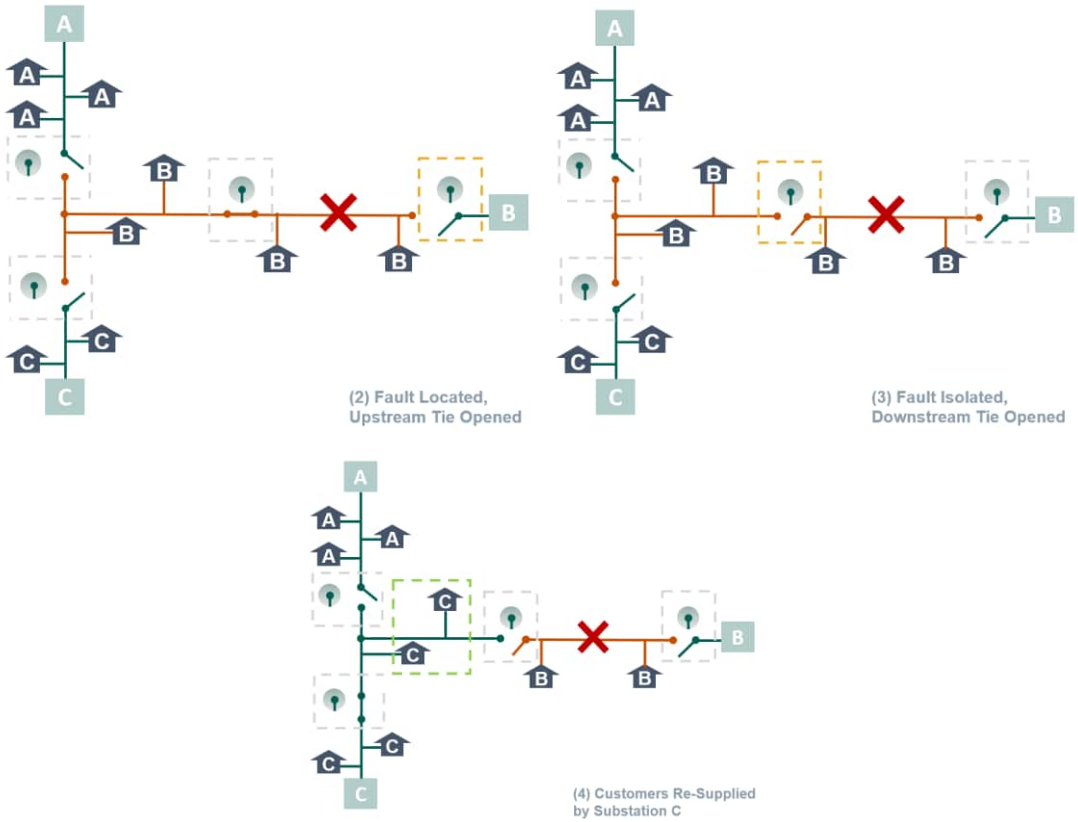


Figure 12: Schematic Overview of FLISR Operation in Four Stages

In Figure 12, (1) represents a fault scenario where the FLISR system locates the fault using sensors and reclosers that monitor flow of current. It then communicates the condition to other devices and/or the grid operators. Once the fault is located, FLISR opens the SCADA controlled switches from both sides of the fault, one immediately upstream closer to the source (2) and one downstream (3). At this stage the fault is isolated successfully. FLISR then closes the normally open SCADA controlled tie switch to reenergize the un-faulted part of the feeder (4). This process helps in minimizing the duration of outages which can be seen in Figure 13. In this illustrative scenario, FLISR automation is theoretically capable of reducing the restoration time from 45-75 minutes to 1-5 minutes.

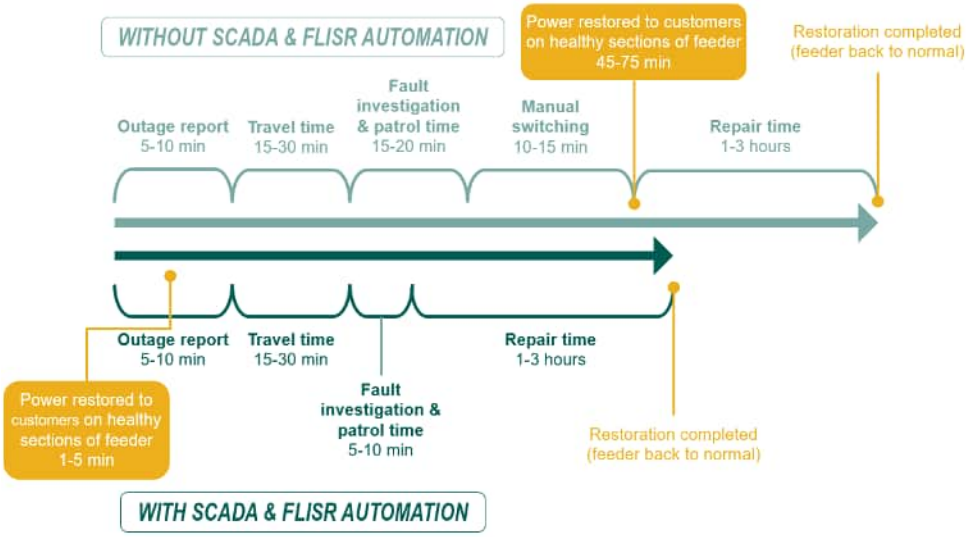


Figure 13: Typical timeline of Manual Restoration and FLISR

2. Toronto Hydro's Journey so far:

As FLISR utilizes information from a number of systems, it requires a substantive backbone of capabilities to successfully operate. Toronto Hydro is already set up with SCADA and Distribution Management System ("DMS") integration such that switches or feeders with faults are automatically displayed on the DMS. Fault status indicators were added to DMS in 2019, allowing controllers to more easily identify fault locations and determine which switches to operate in order to re-route power. And in 2020, voltage and current measurements were also added, as shown in Figure 14 below.

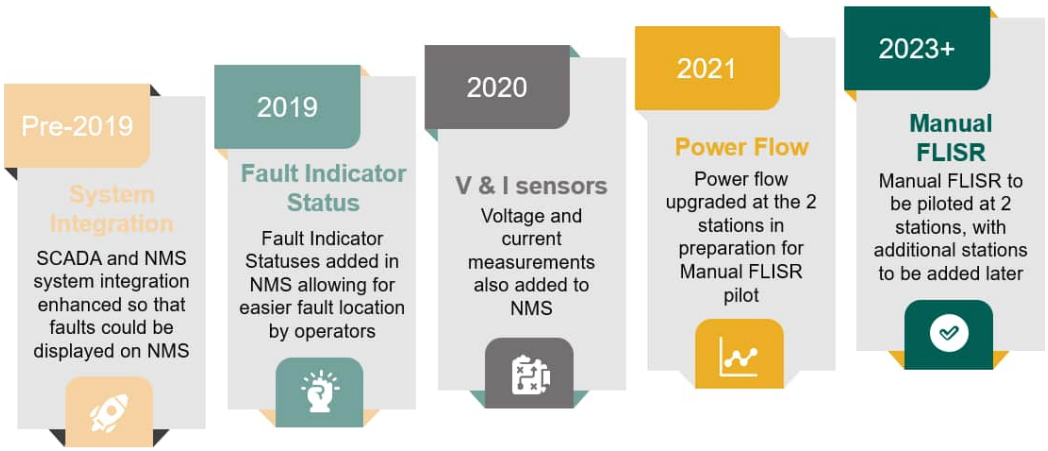


Figure 14: Timeline of FLISR Implementation

In 2021, a power flow upgrade was implemented which later enabled pilots at two stations (Finch and Bathurst) where manual FLISR started in 2023. The power flow upgrade is a data exercise that ensures accurate and high-quality data within Toronto Hydro's GIS and DMS systems. This data includes load from smart meters, conductor and other engineering attributes from CYME (Power Engineering Software), network topology and connectivity from GIS, as well as switch ratings. This integration will continue in the future as more monitoring and sensing devices are added to the system. Ultimately, having power flow is a more proactive way of operating the system versus switching blindly and risking reaching alarm limits. Power flow allows the utility to identify feeder capacities in real time, which in turn helps to identify the optimal switching procedure for the system. This is very powerful, especially in scenarios when feeders are close to overloading. It ensures operations do not have a negative impact on the system (i.e. moving load to a highly loaded feeder without this visibility). As more and more feeders reach their capacity due to growth on the system, this capability will become more important.

As part of its FLISR journey, Toronto Hydro is currently piloting manual FLISR at two stations (Finch and Bathurst), both of which are expected to be live prior to the 2025-2029 rate period. Manual operation is the first step in virtually every FLISR application as the fully automated FLISR solution typically requires extensive validation and calibration processes to ensure effective and reliable operations. This validation is done through manual validation of switching operations by control room operators. Operating the FLISR system manually and at a few stations at first will allow Toronto Hydro to evaluate the accuracy of the system's recommendations and assess how long it takes to come up with the solution. The learnings from the manual FLISR pilot will be used for change management when the system is fully rolled-out on the network. Prior to FLISR implementation, the "business-as-usual" procedure at Toronto Hydro consisted of the SCADA system notifying controllers of circuits that are experiencing faults. Controllers would then note down (on paper) which switches were seeing a fault. The circuits would then be identified in NMS and the procedure to restore power would then start. With manual FLISR, when an outage occurs, the system will determine its solution on how to sectionalize and restore power. The pilot will compare the "business as usual" procedure with the FLISR recommended procedure. This will help the project to continue to iterate until an optimal solution is reached.

3. Strategy for 2025-2029 rate period:

Over the next two years, Toronto Hydro will continue refining its data and network model. As this is carried out at pre-determined stations around the network, manual FLISR will be enabled. During the

period between 2025 and 2028, manual FLISR will be tested at these target locations by the control room operators. The current criteria to move from manual to automatic FLISR at a station is for the manual system to see at least 20 faults of different types. Essentially, the safe transition from manual to automatic FLISR is contingent on a station seeing a certain number and diversity of outages, which is outside of the utility's control. However, as the utility begins piloting the system at the two initial stations, this requirement could change as more information about the operation of manual FLISR is gathered on Toronto Hydro's network. Additionally, planned ADMS upgrades during the 2025-2029 rate period are also necessary for auto FLISR enablement. Given these considerations Toronto Hydro's goal is that by 2030, stations in the Horseshoe area of the system should all be prepared for transition to fully-automatic FLISR.

4. Benefits:

Some of the major benefits of implementing FLISR technology are listed below:

- **Improved Reliability**: FLISR technology will enhance grid reliability by quickly detecting and isolating faults, minimizing the number of affected customers and reducing outage durations.
- **Improved Resilience**: With FLISR in place, the grid will become more resilient and adaptable to faults and disruptions. The ability to automatically detect, isolate and restore power enables the grid to self-heal and minimize the impact of incidents thereby improving overall grid resilience.
- **Minimized Customer Impact:** FLISR will minimize the duration of outage as well as the number of customers affected. This will result in reduced economic losses for customers and businesses.
- **Proactive Maintenance:** The FLISR technology and associated intelligent devices will provide valuable historic fault data which can be utilized to identify areas of concern and proactively addressing potential issues. By identifying fault patterns and identifying areas prone to recurring issues, informed decisions can be made about asset management.

D5.3.3 Appendix C – Enhanced DER Connection Process

1. Introduction and Role in Toronto Hydro's Grid Modernization:

The DER interconnection process is centered around two core steps: (1) the customer or installer provides the technical specifications about the planned system; and (2) the utility evaluates the

impacts to the grid and then either approves the application or communicates any necessary changes. However, obtaining the necessary information and keeping all parties up to date on the application status can be challenging— especially for utilities where the number of interconnection requests are growing.[17] As the adoption of DERs continues to accelerate across Toronto, it is likely that the city will see an increasing installed capacity base of DERs over the 2025-2029 rate period**Error! Reference source not found.**. In light of this, Toronto Hydro is committed to supporting t he energy transition by connecting DERs to the distribution system in alignment with the Distribution System Code and in coordination with Hydro One and the IESO.

One of the primary challenges faced by Toronto Hydro due to the rising number of DER interconnections requests is the substantial amount of resources needed to evaluate and process applications. At present, Toronto Hydro's application processing methodology relies heavily on manual processes, including email-based communication and file sharing between employees and applicants. This approach results in a resource-intensive and time-consuming procedure; with a rising volume of requests, the utility's current approach will challenge the ability to process applications within current lead time.

Increasingly, utilities across the world are using tools such as web portals to manage interconnection process and keep the customer informed about the end-to-end process. In its commitment to embrace an accessible, transparent, and customer-centric energy system, Toronto Hydro plans to develop a user-friendly customer portal to simplify the connection process and provide greater transparency for customers' DER integration journeys. This portal will enable customers to seamlessly review, submit, track (and if necessary cancel) their DER interconnection applications in a single, accessible source. On Toronto Hydro's end, there is potential to integrate semi-automated request handling and change orders, enabling seamless approvals and handovers between internal teams.

The shift towards a streamlined, digital connection process not only reduces administrative burden and manual data entry effort, but also fosters a more inclusive approach – one that reduces barriers to widespread DER adoption. The portal will also facilitate DER data collection in a centralized repository which in turn gives Toronto Hydro new analyses capabilities to identify DER trends,

[17] U.S Department of Energy, Voices of Experience (VOE), https://www.smartgrid.gov/voices_of_experience#:~:text=The%20Voices%20of%20Experience%20(VOE,and%20testing%20the%20emerging%20technology

impacts, and usage patterns for continuous grid operations improvement. The advanced functionality from a customer portal positions Toronto Hydro as a utility that is ready to embrace automation and handle the anticipated increase in DER connections. Through this initiative, Toronto Hydro is setting the stage for a more streamlined, data-driven, and efficient approach to DER integration – benefiting both the utility and its customers.

Peer Success Story	
PEPCO – Integrating Work Management[18]	
Problem: Noticed an increase in incoming calls and employees were spending more time helping customers understand the interconnection application process and finding missing information. Method: Embarked on a journey to develop an online portal in 2012 to allow customers to input their applications and help PEPCO manage workflow, data tracking, and regulatory reporting with a go-live in 2016. Portal development focused on splitting the application process into two steps and reorganizing staff around the steps: one team helps the customer and contractor with application journey from receival through approval to install; another team works with the customer journey from system build through authorization to operate.	Selected Benefits: • Intuitive and interactive application process guides customers step-by-step • Provides data validation, reducing application errors and missing information • Allows customers to monitor their application's status in near real-time through a personalized dashboard • New online contractor account includes the ability to designate access to multiple users • Quickly moves the application to the next step in the process • Ability to see aggregated reports for all pending applications submitted online by contractor • Online signature feature eliminates the need for physical signatures • Upload attachments online—no need to email or mail supporting documents

2. Benefits:

Toronto Hydro recognizes there is a wealth of opportunity in improving its current connections process methodology that relies heavily on manual processes through the use of emails and file sharing. Customers using Toronto Hydro's current system sometimes have concerns about DER applications and who to reach out to on the status and lead times for their applications. A streamlined, semi-automated customer connections portal can provide Toronto Hydro with the following benefits:

- Reduced delays and costs owing to reduction in manual data entry and labour hours in tracking and processing applications

[18] *Supra* Note 17

- Consolidated and transparent communication channels providing timely application updates to customers
- Reduction in data entry errors and quicker customer notifications if further or corrected data is required

These enhancements will be necessary to ensure the utility can continue to provide high-quality customer service and meet connections application performance targets in the face of potentially higher rates of DER adoption over 2025-2029 and beyond.

D5.3.4 Appendix D – Hosting and Load Capacity Map

1. Introduction and Role in Toronto Hydro's Grid Modernization:

Determining the DER capacity that the distribution system can accommodate is often a challenge, and without proper planning and integration, DERs and incremental loads may adversely impact system stability and hinder maximum benefits utilization. Toronto Hydro performs ad hoc studies and analysis to identify the feasibility of DER connection requests, which is a time-consuming process.

Hosting capacity analysis (HCA) has emerged as a valuable option preferred by several utilities across the world. It enables the assessment of available capacity for new DERs without the need for costly and time-consuming studies. In particular, it can illustrate the preliminary capacity of DERs that the power system can accommodate at a given point of interconnection without exacerbating grid parameters such as short circuit current. An effective HCA can assist Toronto Hydro in making informed decisions regarding strategic grid investments to reduce future barriers to DER integration. Additionally, it can boost efficiency and transparency of the DER planning and interconnection process to accommodate the increasing volume of DER connection requests.

This initiative complements the customer connections portal as the HCA can be used to generate a user-friendly hosting capacity map, such as the sample depicted in Figure 15 below, that provides preliminary geographical insights into the available interconnection capacity within Toronto Hydro's distribution system. The HCA map can be embedded or sit alongside the connections portal, enabling customers to guide the scope of their application prior to submission. The HCA map supports a customer-centric energy system, providing greater upfront visibility in potential application complexities and guiding customer investment strategy for future DER projects.

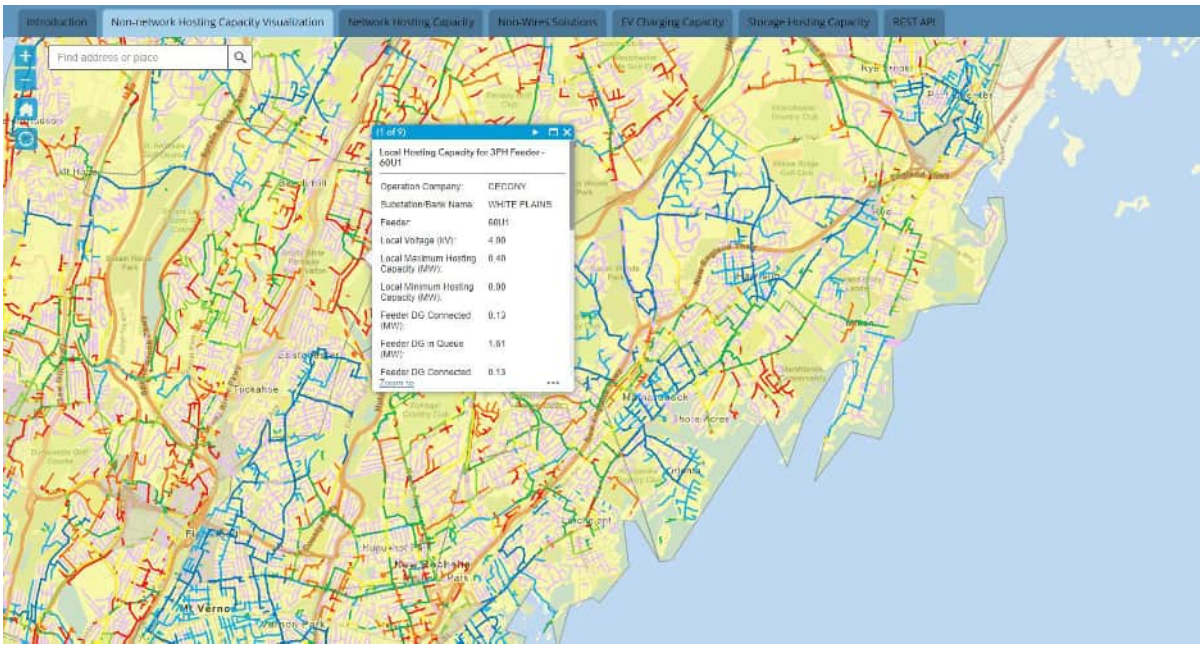


Figure 15: HCA Map Example – Consolidate Edison New York

Over the 2025-2029 rate period, Toronto Hydro intends to explore, develop and implement a Hosting Capacity Analysis and associated presentment tools. As part of this initiative, the utility will explore opportunities to calculate and present complimentary analyses, including load capacity constraints. Developing a hosting and load capacity analysis and presentment solution is a significant multi-year undertaking, as it will require upgrades to data quality and availability, the automated integration of various data systems, the development and implementation of complex, automated system analysis, and the procurement and implementation of a customer-facing geospatial visualization tool.

Peer Success Story

Hawaiian Electric Company (HECO) – Performing Daily Updates

Problem:

HECO originally looked at circuit penetration using the 15%-of peak rule, then transitioned to 50% of daytime minimum load and slowly rose up to 250% as more information and technologies became available to mitigate concerns; however, HECO determined that different feeder characteristics and infrastructure impact how much DER a circuit can handle.

Method:

HECO built a circuit model in "Synergi" (i.e. an asset simulation and optimization software) that feeds into their in-house hosting capacity tool. The tool runs an analysis of all primary circuits (from the substation to

the transformer) and includes any PV systems (even if that system has not yet been installed). Location maps are created by running the analysis annually and ad-hoc. The tool provides an allowable amount of PV that can be easily interconnected for the entirety of the circuit.

Maps are updated daily based on new applications that are approved, which means that subsequent new installations looking to apply are evaluated against the capacity threshold for that circuit. If the installation size exceeds the hosting capacity limit, the application is sent for a supplemental review to specifically verify the location and how it would impact the circuit.

HECO separately reviews other conditions such as voltage rise/drop using a spreadsheet model to evaluate impact on the secondary network. This is especially important in sunny Hawaii where most DER installations are PV because the secondary side can experience voltage violations since most PV customers tend to generate maximum output at the same time (typically midday) rather than at various times throughout the day.

2. Benefits:

Some major benefits of implementing a Hosting Capacity Map for Toronto Hydro's service area are as follows:

- Increased visibility into the available capacity of the grid to host DERs to identify suitable locations for installations
- Integration with a future customer connections portal to update available capacity based on approved (but not yet installed) DER applications
- Increased visibility of system nodes with immediate or near-term capacity constraints to inform system upgrade planning to increase long-term hosting capacity
- Reduction in rule of thumb technical screens with introduction of granular analysis for the entire distribution system with regular updates

D5.3.5 Appendix F – GIS DER Asset Tracking

1. Introduction and Role in Toronto Hydro's Grid Modernization:

A forecasted increase in DER interconnections requests means that current data management practices that Toronto Hydro employs will no longer suffice without generating considerable administrative burdens and compromising data quality. Currently data from DER assets is manually entered, which is time consuming and prone to incomplete/incorrect data transfer. Toronto Hydro recognizes that automation will be a necessary core function at the heart of its data management methodology across difference processes associated with DER interconnection requests. While the

customer connections portal initiative is a step towards automation by allowing DER asset data to be automatically recorded once an application is submitted and then approved, it lacks capability to visualize geographical and electrical connections to the distribution system.

Hence, a new tool that has emerged within the industry to bridge this gap is the concept of GIS DER Asset Tracking. The initiative explores the process and tools to streamline and standardize DER asset data in Toronto Hydro's GIS system. It aims to identify key asset information and connectivity data as well as integration requirements within GIS such that Toronto Hydro's record keeping procedure is streamlined and thorough. Apart from data quality and management, another key functionality of DER Asset Tracking which will be touched upon in the Monitoring & Forecasting activity is real-time monitoring and control of DERs. Currently DERMS is connected to Toronto Hydro's SCADA system to read real-time data; however, its System Map and DER one-line diagrams are not connected to GIS data in real-time – meaning that changes in physical location and configurations are updated on a monthly frequency requiring routine updates of the GIS extract file from GIS software onto the DERMS backend. As the number of DER assets continue to increase, a set frequency methodology will no longer fit Toronto Hydro's control toolbox in order to establish future extensions of programs related to demand response, market prices, voltage fluctuations and more.

As Toronto Hydro embarks on its mission to become a utility of the future, integration of DER asset information in GIS systems for monitoring and control purposes will be crucial to encourage and accommodate new DER connections. GIS DER Asset Tracking rounds off the other two *Facilitating DER Connection* initiatives as it links together the seamless flow of data from end-to-end of the connections journey and provides the right kind of data required to refresh a hosting capacity analysis with the least amount of manual intervention needed. The three initiatives work together to give confidence that Toronto Hydro understands on a granular level where current DER assets sit on the system and where future ones can be anticipated and accommodated in a timely manner.

2. Benefits:

Toronto Hydro recognizes that streamlining the data management process associated with DER connections requests comes with a wealth of benefits. Some major benefits of implementing GIS DER Asset Tracking is as follows:

- Robust organization of DER interconnection data from application submission through to installation and commissioning through industry-leading data management practices

- Reduce and/or eliminate poor quality or missing data from manual data entry between different platforms
- Increased efficiency of data transfer through integration of data from systems such as the proposed customer connections portal, GIS, and Energy Centre without the need for manual effort in syncing data across platforms

D5.3.6 Appendix G – Energy Center Enhancements

1. Introduction and Role in Toronto Hydro's Grid Modernization:

Distributed Energy Resource Management System (DERMS) is a powerful software tool which can be used to integrate, aggregate, monitor and control DERs located in front or behind the meter in real-time. As deployment of these assets such as solar panel and battery energy storage systems continues to expand, utilities face the challenge of preparing for a well-coordinated integration of DERs on grids that were historically designed for predictable, one-way energy flows.

From an operational perspective, this includes proper management, control, and operational oversight given the variability in DER output to prevent issues such as high voltages during peak hours, abnormally low voltage during load recovery periods, and intermittent voltage fluctuations. From an ownership and operation perspective, the delineation of who owns and manages DER assets also lends uncertainty in how to achieve optimal grid management; key considerations include the majority of DER growth comes from assets not owned by the utility, immature technology can complicate interoperability, the number and distribution of DER endpoints can challenge the scalability of utility-driven solutions, and dispatch of DER assets may not necessarily align with stakeholder values (e.g. a third-party owned DER may be dispatched to reduce an electric bill which may not be aligned with the utility operator at that point in time).

The introduction of a DERMS serves as a vital step in consolidating the visibility of DERs across the grid, and it lays the groundwork for exploring third-party involvement and partnerships in DER and DERMS ownership and control as the complexity of ownership models and interoperability increases in a maturing technology space.

Most DERM systems have the capability to exchange data and control with other enterprise supervisory control systems such as control systems with the ADMS platform. DERMS also serves as the system of record for all DER related data, and provides operators visibility to the parts of the grid not visible to the ADMS. DERMS comprise of the following core functions:

- **Aggregate**: DERMS take the services of multiple DERs and present it as an aggregated smaller group of more manageable virtual resources that are aligned with grid configuration.
- **Translate**: DERMS can extract a variety of data from different DERs that may use various communication protocols and present it to the upstream controller in a streamlined view.

- **Simplify**: DERMS has the capability to provide simplified services that are useful to distribution operations, which are power-system centric as opposed to DER centric.
- **Optimize**: DERMS can provide requested services by coordinating functions depending on location and circumstance.

Toronto Hydro incorporated DERMS in 2019 in the form of its Energy Center. Phase 1 of system implementation focused on real time monitoring of DERs; in its current state, the Energy Center provides visibility to approximately 2,200 DERs connected to the system, including three utility-owned battery energy storage systems. Currently DER control capabilities are unavailable, although utility-owned DER sites can be controlled via SCADA on vendor specific platforms. With almost four years of experience in operating the Energy Center, there is now a need to explore expansions to it.

2. Current Energy Center Modules – Monitoring and Forecasting:

Energy Center facilitates real time monitoring of DERs through visualization of the complete portfolio of DERs to provide up-to-date information on the status, performance, and health of DER assets. This data is used to assist in promptly identifying any operational issues or deviations from expected performance. The data can also be parsed by DER type, as well as a hierarchical outlook across the system, regions, terminal stations, and municipal stations, which is particularly useful to gain perspective of DER distributions across the system by type to assist with grid planning. Individual DER monitoring, as shown in Figure 16, expands on details such as one-line diagrams, alarms, generation/consumption, and charging/discharging, which is useful for operators to identify potential issues such as voltage fluctuation and SOC battery issues. Overall, a consolidated view of DER asset performance makes it easier and quicker for decision-making.

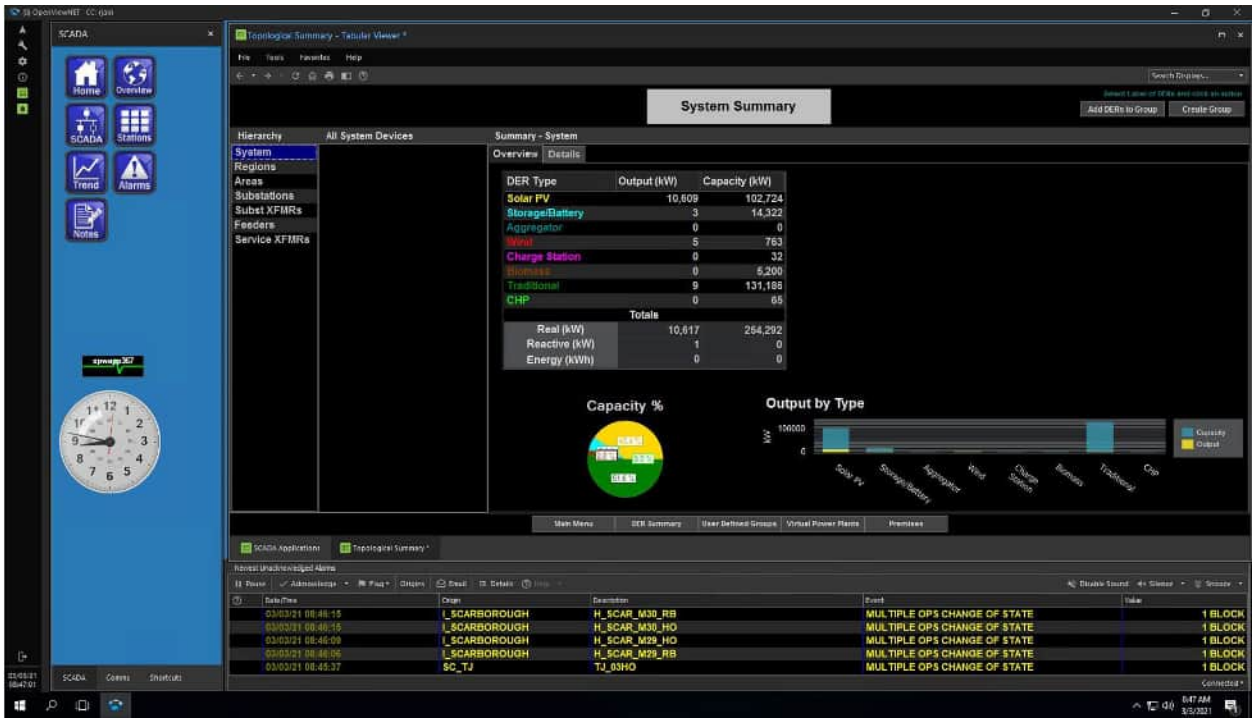


Figure 16: Energy Center Overview Screen

The second function currently available in Energy Center is a forecasting tool that enables Toronto Hydro to create accurate load and renewable generation forecasts for periods ranging from 1 – 35 days. These forecasts use the historical archive of area load, renewable generation and weather data, and a variety of user-selected algorithms/models to generate load demand and renewable generation outlooks for the selected period. These forecasts enable the utility to anticipate fluctuation in generation and consumption patterns of DERs and accordingly plan for contingency actions. In current operations, Toronto Hydro uses load forecasting at two stations to carry out LDR programs by way of battery dispatch scheduling to achieve peak shaving.

3. Building on Monitoring and Forecasting:

As Toronto Hydro continues to evaluate and connect more DER assets, generating insights and value derivation from these assets becomes limited without access to quality, structured data. While the current implementation of the Energy Center allows the utility to see direct information about their DER assets on one platform, understanding how DER operation and coordination will affect the grid down to the feeder level is not yet possible due to lack of visibility. Similarly, asset data related to DERs are not yet streamlined and are updated manually on a set frequency, which means that

synchronizing data into the Energy Center for new assets occurs in a piecemeal approach with room for data error.

This is where the integration of technologies mentioned throughout the Grid Modernization strategy will play a role in augmenting the monitoring and forecasting capabilities of the Energy Center. System observability enhancements such as AMI 2.0 and sensor installations will provide more granular customer consumption data and patterns as well as visibility into feeder loading conditions and power flows. This coupled with the roll-out of FLISR enables automated fault management, removing the human element of complex decision-making in real-time. In such an environment, the Energy Center can now play a new role – if the grid is now able to more intelligently identify and minimize feeders off-supply, data integration and communication with the Energy Center now means that utility-managed DER assets are able to play a role in restoring or stabilizing other parts of the grid through fault and post fault events. Greater visibility of the grid at the low-voltage level also opens up the ability to run more granular forecasts in the Energy Center to develop operational plans. This can be used at multiple stations beyond the two currently used for LDR and provide data to support targeted expansion of the program. Furthermore, forecasting scenarios that factor in geospatial distribution of DER assets and their implications on the capacity of the system at target points on the network will become an essential tool in the utility's investment planning process, deferring or avoiding capital expenditure where it makes sense. Finally, the implementation of GIS DER Asset Tracking ensures that the organization has confidence in data available in the Energy Center and has the added ability of running forecasts ahead of time for asset applications that have been accepted but not yet connected to understand implications, if any, before the DER is switched on.

4. Future Modules - Scheduling and Dispatch Module:

Currently, Toronto Hydro is unable to efficiently schedule, aggregate, and optimize a set of utility-owned DER assets. Instead, existing DER assets are manually operated and/or managed through vendor-specific platforms. Specifically, the control and management of utility-owned DERs is complicated due to the increased training, management, and licensing requirements for multiple platforms and the lack of control of all sites from a single, centralized location. There is a clear commitment from Toronto Hydro to increase energy storage capacity through the Non-Wires Solutions program; successful implementation necessitates a centralized dispatching and scheduling platform.

Therefore, Phase 2 involves the implementation of an **Advanced Scheduling and Dispatch** module in the Energy Center which features a consolidated platform for real-time control and management, as well as establishing interoperability between storage management systems and Energy Center. Having a system that provides control capabilities allows the utility to better collaborate on upcoming pilot projects using innovative technologies (e.g. IESO's Grid Innovation Fund), improve use case development for demand response, and simulate and understand risks associated with maturing technologies.

The DER Advanced Scheduling & Dispatch module allows scheduling for objectives such as peak shaving, back feed avoidance, and load flattening. It can create schedules for any level of electrical network hierarchy using any type of controllable DER, including batteries, curtailable wind and solar generators, demand response programs, and backup diesel generators. The time intervals of the schedules can be as little as 5 minutes or as much as 1 hour, and the schedules can be for up to 35 days into the future. As part of implementation into the Energy Centre, the module will support two key functions: (i) Peak Shaving and Control (Dispatch) of DERs; and (ii) Automation of Demand Response. The module is expected to go-live in 2024 following a launch and test of the module on development, quality assurance, and production environment of Energy Center, as well as successful test of schedule and dispatch functionality of at least three utility owned BESS assets.

The module is expected to provide some of the following benefits:

- Enhanced Integration of DERs: optimize and coordinate charging and discharging of utility-managed BESS assets to balance capacity and demand in feeders with current or expected REG assets, which are non-dispatchable;
- Efficient management on a consolidated platform: eliminate reliance on various vendor-managed platforms, eliminating or reduction costs associated with training, maintenance, and licensing as well as quicker and efficient IT upgrades onto one system, reducing downtime; and
- Participate in projects and expanded flexibility service programs: enable Toronto Hydro to participate in upcoming pilot projects related to DERs by facilitating a "plug-and-play" solution for new technologies to be tested, and facilitate studies to quantify value in expansion or new offerings in flexibility services at constrained or soon-to-be constrained areas of the grid.

D5.3.7 Appendix H – Low-Voltage Level Forecasting

1. Introduction and Role in Toronto Hydro's Grid Modernization:

The Future Energy Scenarios (FES) provide an overview of possible future changes to power demand, energy consumption, generation and storage across Toronto, as well as an assessment of their potential impacts on Toronto Hydro's electricity distribution network. FES was contracted through Element Energy, an UK-based energy consulting firm, that has provided similar load forecasting models to various distribution network operators and the electricity system operator in the UK. While the first iteration of FES focused on forecasting load at the bus level, Toronto Hydro is aiming to explore the extension of this modeling exercise to the low voltage network; for example, on the feeder or secondary transformer level. The full FES report can be found in Exhibit 2B Section D Appendix E.

FES is predicated upon a highly granular consumer choice-based analysis of future loading conditions at the desired modelling level (i.e. bus-level, feeder-level), providing a strong evidence base for network planning and the evaluation of future infrastructure investments. To capture the range of uncertainties in a coherent and meaningful way, multiple scenarios are developed (represented as "scenario worlds"), consisting of individual projections for different technology sectors. The scenario worlds represent different energy system pathways, and illustrate the best view of future energy system changes for a given set of economic, social, and policy assumptions.

The projections are created using Element Energy's technology specific bottom-up consumer choice and willingness-to-pay models, which are based on a rigorous understanding of underlying technology costs, consumer behaviour and wider energy market drivers. These projections create uptake scenarios for each of the drivers of demand and generation considered in the FES model. These drivers include, for example, electric vehicles, energy efficiency measures and solar photovoltaic installations.

2. Benefits:

FES establishes a common strategic outlook to support forecasting needs across different Toronto Hydro business functions and various stakeholder engagement and regulatory reporting requirements. FES results give planners insight into the potential geospatial distribution of electrification on the network and allow for detailed analysis into the make-up of that electrification; be it EVs, DERs, or heat-pumps.

The increased granularity that feeder or secondary transformer level modelling provides would give planners even greater levels of detail about the system and further narrow down areas of the network which require investment. For example, feeder or secondary transformer data could be used to confirm the real-time data that is collected as part of the system observability program.

D5.3.8 Appendix I – Innovation Pilot Projects

1. Flexible Connections Pilot

a. Introduction and Role in Toronto Hydro's Grid Modernization:

The rapid integration of Distributed Energy Resources (DERs) assets into the distribution network poses several technical constraints if not proactively managed and coordinated. These include reverse power flow (particularly in low load scenarios), compromised power quality, voltage violations, and elevated fault levels. Consequently, DER customers looking to connect to the network may be faced with financial and time-related burdens associated with network upgrades due to technical and standards constraints. In order to improve customers' ability to access available capacity at an affordable connection cost, alternative solutions could be explored, capitalizing on innovative technological and commercial offerings.

The Flexible Connections Pilot seeks to develop and implement a comprehensive framework that facilitates the efficient and cost-effective integration of DG assets into constrained areas of the distribution network. This would be achieved through development of an advanced DERMS system coupled with intelligent device installation utilized through a communications platform. "Flexible" refers to the network's real-time adaptability in managing network constraints and DG access to network capacity without the need for network upgrades.

b. Description of Pilot:

Flexible DG connections allow DER assets to connect to the network on a constrained basis whereby their operation can be controlled by the network operator within network operational limits. To enable this offering, Toronto Hydro would need to develop both the technical and commercial systems as part of a holistic approach. Firstly, seamless operation of DER assets will require Energy Centre to have the ability to not only monitor, but also control DERs. Real-time awareness of system characteristics will require sensors and smart devices installed on the network – this is currently being achieved as part of Toronto Hydro's Intelligent Grid strategy. The coordination of these devices and the management system will require a robust telecommunications platform to facilitate the necessary information exchange and control capabilities. Finally, extensive customer engagement and the development of novel commercial agreements between the utility and participating DER customers will enable practical implementation. The streamlined approach is geared towards enabling faster, cheaper DER connections while avoiding the need for Toronto Hydro to embark on similarly expensive and time-consuming network infrastructure upgrades.

c. Benefits:

A Flexible Connections pilot allows Toronto Hydro to identify and mitigate any unintended consequences of flexible connections before providing it as a standard offering. Additionally, Toronto Hydro can better understand and manage local DER customer concerns to ensure proposed commercial arrangements are attractive offerings, therefore enabling sufficient trial participation. If implemented, Toronto Hydro would benefit from cost-efficient reinforcement decisions and enabling DER connections with lower electrical losses by locating generation closer to demand. DER customers connecting to the network would benefit from reduced time delays and cost upgrades. Customers could also benefit from earlier participation in future Flexibility Service offerings and increased dynamic control of DG outputs without compromising network safety.

2. EV Commercial Fleets Pilot

a. Introduction and Role in Toronto Hydro's Grid Modernization:

In 2020, fleet energy consumption accounted for 33 percent of CO_2 emissions in the City of Toronto. The successful electrification of commercial fleets is needed to achieve the city's net-zero target by 2040. Specific objectives include having 30 percent of registered vehicles in Toronto be electric and ensuring that 50 percent of the TTC bus fleet is zero-emissions by 2030.

As the demand for system flexibility increases and battery technology costs decrease, the electrification of transportation becomes increasingly important in accelerating the transition to net-zero emissions. However, widespread adoption of commercial fleet electrification may trigger considerable costs to upgrade the distribution system, and may result in significant connection costs due to the higher payloads of commercial vehicles and dissimilarity in load profiles when compared to domestic charging. Therefore, it is essential to investigate and identify the impact of commercial EV fleet charging on the distribution network and develop technical and commercial strategies to facilitate their integration while reducing associated costs for customers.

The unmanaged electrification and charging of fleets could pose a substantial load impact on the distribution system. This project aims to collaborate with fleet owners to assess the impact of commercial EV fleets on the grid, both in terms of quantifying and minimizing load impact. Additionally, the project will explore opportunities to coordinate commercial fleets as a flexible load within the distribution system for both at-home and depot charging scenarios.

b. Description of Pilot:

The Commercial EV Pilot will examine the impact of commercial EV fleet charging at homes and at depots, and optimize charging schemes based on the flexibility requirements/preferences of Toronto Hydro and agreed upon by project partners. These tasks will offer insights into managing charging schemes for the most common charging locations, identifying methods for easy and cost-effective fleet electrification, and optimizing commercial fleet charging while considering flexibility services. Moreover, the project will assess the usefulness and benefits of flexibility services to Toronto Hydro. Additionally, demand forecasting and mitigation planning can be achieved once data is aggregated from the above studies.

The project's scope entails collaboration with major commercial fleet operators to assess the impact of their fleet's electrification on the distribution system. Various testing methods are employed to gain insight into diverse charging options and develop an effective implementation strategy for fleet operators. The project encompasses quantifying and minimizing the network impact of commercial EVs through trialing different methods, exploring the total cost of ownership of smart solutions for EV fleets operators, and determining the necessary infrastructure to facilitate the EV transition. Technical solutions are tested and implemented by fleet operators and Toronto Hydro, including flexibility services to grid from commercial EV fleets on domestic connections and planning tools for depot energy modeling and optimization with profiled network connections.

c. Benefits:

The project would develop the ability to quantify and minimize the impact of commercial fleet electrification on the distribution network, investigate and quantify the total cost of ownership for intelligent scheduling and charging solutions for EV fleets, and identify the necessary infrastructure, including network, charging, and IT components, to facilitate the transition to EV fleets and enable effective load management.

3. Electric Vehicle Demand Response Pilot

a. Introduction and Role in Toronto Hydro's Grid Modernization:

The adoption of electric vehicles (EVs) in Toronto is expected to accelerate due to a range of policies, incentives, and grants from all three governments, some of which include: the new Ultra-Low Overnight Electricity Price plan released by the Ontario Energy Board (OEB), a federal proposal for a Zero-Emission Vehicle Mandate (25 percent of all passenger vehicles sales must be electric by 2026,

jumping to 60 percent by 2035), and Ontario investment in the construction of two new EV battery plants in St. Thomas. Additionally, Toronto Hydro's own Future Energy Scenarios load forecasting tool (FES) sees 300k BEV cars on Toronto roads by 2030 and 1.8M by 2050 in a Consumer Transformation scenario. This transformative shift poses several network challenges, such as overloading secondary distribution transformers, exerting additional electrical stress on overhead conductors and underground cables, and increasing peak load at various levels. Together, these challenges can lead to distribution system instability; for instance, when a cluster of EV's on the same transformer charge simultaneously. Conversely, beyond low carbon transport, EVs can be leveraged as a DER thanks to the ability to charge and discharge from its battery. In order to maintain system stability and enable EV uptake in Toronto, it is crucial to explore EV demand response strategies in the forefront of change.

The EV Demand Response pilot aims to identify viable technical hardware and control models along with demand response (DR) events to facilitate coordinated charging and potential discharging of EV batteries to support network needs. This would be achieved through development of applications, hardware integration, and mechanisms to identify and trigger EV DR events to support trials and roll-out with Toronto-based market participants.

b. Description of Pilot:

EV demand response programs would allow Toronto Hydro to manage EV charging in real-time based on grid conditions, appropriate to the type of conditions occurring on the network. Currently, phase 1 of an EV Smart Charing pilot is being trialled with Elocity. This explored testing new hardware to convert simple chargers to "smart" by adding a device to connect to the internet and turn on-off as well as inclusion of a customer application and utility portal to trigger DR events. In a subsequent phase, Toronto Hydro intends to explore:

1. A review of available technologies for smart charging;
2. Test technical control options such as the Open Charge Point Protocol (OCPP) with electric vehicle supply equipment (EVSE), leverage other EVSE providers to trigger DR events, and onboard a vehicle telematics control to directly connect with vehicle original equipment manufacturer's (OEM) applications; and
3. Broader corporate tool integration into Energy Center and other metering systems to further real-time situational awareness to deploy EV DR assets to address specific network needs

The pilot would benefit from stakeholder engagement with customers, automakers, EV charge-point manufacturers and operators, industry bodies, and academia to inform and shape a full-scale EV DR program. By developing a strategy that builds on industry-wide learnings, the pilot aims to facilitate the uptake of EVs while helping Toronto Hydro reduce peak demand and defer network upgrades.

c. Benefits:

Toronto Hydro is uniquely positioned to evaluate and test relevant mechanisms in the largest city in Canada, where significant EV uptake is expected to occur in the next 10-30 years, and where its urban environment limits the amount of off-street charger installations. If implemented, the pilot is expected to leverage current initiatives and inform future approaches to other Non-Wire Solution programs such as:

- Local Demand Response program – measured meter data from individual chargers can be compared to aggregated transformer meters to verify the impact on the secondary distribution grid
- Hosting Capacity Map – identification of potential capacity constrained areas, providing visibility for medium to long term planning
- Intelligent Grid portfolio – sensors and automation tools being installed under this portfolio can provide real-time visibility and signals for EV demand response trials.

If EV Demand Response is rolled out as a business as usual offering, it could represent a flexible and intelligent solution to managing EV load and maintaining grid stability; one where benefit stacking could be applied in the future as consumer behaviours and markets evolve. Furthermore, EV customers could benefit from increased participation with the utility to better manage electricity use through a wider range of choices on charging times, types, and incentives.

4. Advanced Microgrid Pilot

a. Introduction and Role in Toronto Hydro's Grid Modernization:

The increasing frequency of extreme weather events has the potential to cause widespread and extended power outages. This is a particular concern for population segments and services that rely on power for mission-critical needs. An intelligent, whole systems approach is required to create a resilient energy system, ensuring a secure balance between energy supply and demand despite internal/external factors.

The Advanced Microgrid pilot seeks to build upon a white paper completed by Quanta Technologies and perform a desktop study on viable microgrid topologies within Toronto Hydro's network followed by a field demonstration if applicable.

b. Description of Pilot:

Microgrids are electric energy systems that can function while either connected to a main distribution grid or disconnected from it. While disconnected, it is composed of DERs, storage units, and energy loads, and typically uses the same technologies and techniques as a larger utility grid. Microgrids can connect and disconnect from the distribution grid, allowing for the exchange of energy and the supply of ancillary services, and the systems can either be located behind-the-meter (BTM) or front-of-the-meter (FTM).

Currently, the main barrier to widespread implementation of microgrids is financial viability. There continues to be uncertainty and limitations for the various business models proposed for these systems, including revenue structures and pricing schemes. While single-customer microgrids have been tested at research institutes in Toronto and within utilities in the US, there has not yet been a demonstration of multiple-customer or utility microgrids in Toronto as literature review has found that most use cases for microgrids are met in part by existing commercially available technology. These include, but are not limited to, capacity deferrals, improving power quality, providing black start capability, and avoiding DER curtailment. However, gathering data to support microgrid viability in the context of a urban setting requires a demonstration specifically in Toronto Hydro and Ontario's energy system structure in collaboration with project partners such as key accounts, vulnerable customers, and customers with critical loads.

Overall, it is expected the trial will provide clarity on the commercial viability of one or more microgrid models. Key factors include the preferred level of system complexity, level of utility control, public-private investment vs ownership, and evidence supporting regulatory review and reform if required. These factors will help shape the scope and breadth of future microgrid projects that Toronto Hydro would like to see connected to the grid, whether initiated by the utility or its customers. The pilot can also leverage the future DERMS/Energy Centre for dispatch and monitoring of DERs within the microgrid boundary.

c. Benefits:

An advanced grid pilot allows Toronto Hydro to test viable microgrid topologies within the Toronto Hydro network and Ontario energy system structure to determine the commercial viability of grid resiliency and grid services. Additionally, through the course of the pilot, Toronto Hydro would benefit from understanding and managing overall customer and third-party concerns about power safety, quality, and security, which can be used to augment core operations and other NWS programs. If microgrids are provided as a standard offering, either FTM or BTM, Toronto Hydro would benefit from a flexible resource to sustain operations during outages, provide ancillary services to the wider grid, and enable new methods to connect renewable resources. Customers within microgrid boundaries would benefit from a significant reduction in interruptions and outage times as well as participating in new service offerings if applicable.

D6 Facilities Asset Management Strategy

Toronto Hydro manages a broad portfolio of facilities comprised of 185 stations, two control centres, two data centres, and four work centres. These assets house and protect grid equipment, and create the necessary conditions to enable employees to work effectively and efficiently. Investments in the renewal, maintenance, enhancement, and expansion of facilities assets enable the utility deliver its services in a safe, reliable, and sustainable manner.

The primary objectives of the Facilities Asset Management Strategy (the "Strategy") are to maintain the safety, reliability, and functionality of stations and work centres. Meeting these objectives requires the utility to regularly inspect and sustain its facilities assets and the critical building systems in good working order. In addition to these table stakes, the Strategy addresses emerging needs and priorities to expand the distribution grid to serve growing customer demand, enhance facilities assets to decarbonize Toronto Hydro's emissions, and provide greater resilience against physical threats such as vandalism and natural threats such as extreme weather.

The Strategy governs Toronto Hydro's facilities Investment Planning and Forecasting ("IPF") process through the following streams, which are described in more detail below.

1. Asset Management Process
2. Facilities Enhancements Initiatives
3. Long-term Planning Considerations

The scope of investments covered by the Strategy includes the following types of facilities assets and building systems:

- Structural and envelope assets such as walls, façades, beams, and columns;
- Architectural and interior assets such as roofs, doors, finishes, and ceilings;
- Fire and life safety assets and systems such as fire alarms, sprinklers, signage, and emergency lighting;
- Mechanical, electrical, and plumbing assets and systems such as HVAC, lighting, plumbing fixtures, sump pumps, and hot water tanks; and
- Civil and sitework assets such as walkways, driveways, parking spaces, gates, and barriers.

D6.1 Asset Management Process

Toronto Hydro facilities asset management process is aligned and integrated with the utility's overall Asset Management strategy detailed in Exhibit 2B, Section D1.

The condition and lifecycle stage of an asset are the primary considerations in the development of the facilities asset investment plan. Generally, the utility replaces facilities assets that are identified to be in poor condition and past useful life. After an asset is identified as having these characteristics, the utility implements a plan to upgrade or replace the asset to restore and enhance its functionality in accordance with current standards and objectives.

Toronto Hydro considers the following types of inputs in the asset lifecycle management process:

- Building Conditions Assessment ("BCA");
- Asset Registry data maintained through Toronto Hydro's Computerized Maintenance Management Software ("CMMS");
- Industry standard useful life data (i.e. ASHRAE and RS Means Data);
- Assessments and reports by experts (e.g. Asbestos Containing Materials Report, Designated Substances Report, Water Infiltration Report, Roof Condition Assessment, lighting assessment reports, Current Condition and Code Compliance of Vertical Service Ladders, and Security Systems Assessment);
- Lessons learned from past projects; and
- Business impact to Toronto Hydro.

The Building Condition Assessment ("BCA") is central to evaluation and prioritization of asset renewal investments which feed into the utility's overall planning process described in Exhibit 2B, Section D1.

To enable the BCA, the utility collects and analyzes information about the condition of its facilities assets on an ongoing basis, as follows:

- **Daily:** Asset condition observations are captured on a daily basis through the Preventive Maintenance Program ("PMP") and the CMMS system.
- **Monthly:** Toronto Hydro conducts monthly field inspections and safety audits to review asset condition observations captured in the CMMS and perform preventive checks.

- **Annually:** The utility annually reviews asset condition observations captured in the CMMS through the daily and monthly processes, as well as lessons learned from that year's projects, to verify and revise the BCA score for each building as required; and
- **Biennial:** Toronto Hydro resets the BCA cycle and fully re-evaluates buildings biennially.

The BCA follows the Uniformat II categorization, which assigns each building asset and system three scores for each of the following parameters:

Table 1: Building Condition Assessment Uniformat II Categories

Rating	Current Condition	Probability of Failure	Impact of Failure
1	Critical – not serviceable or irreparable	System Failure – Immediate Attention	Critical System
2	Poor – not functioning as intended	Imminent Breakdown - Critical (1-2 Years)	Building Functionality
3	Fair – functioning with noticeable wear/use	Imminent Breakdown – Non-Critical (Rate Plan)	Run-to-Fail
4	Good – functioning with minor wear/use	Improbable Breakdown – (5-10 Years)	Redundancy of Cost-Effective Upgrade
5	Excellent – in new or near-new condition	Highly Improbable – (10+ Years)	Elective Upgrade

The scores are then combined in a weighted formula, along with site priority factors based on building usage, to provide a single ranking known as the Risk Priority Number ("RPN"). The RPN supports Toronto Hydro's decision-making by pinpointing the most critical needs by building system and provides a ranked, quantified evaluation of assets.

D6.1.1 Lifecycle Analysis

Lifecycle economic analysis is an important aspect of cost-effective lifecycle asset management. The objective of this analysis is to minimize the asset's total lifecycle cost while ensuring safe and reliable asset performance. Toronto Hydro achieves this objective by tracking the end of economic life, which is the point where total cost of the asset (including ownership and maintenance costs) is at its lowest over the asset's lifecycle. Along with the BCA and other inputs discussed herein, the lifecycle analysis enables Toronto Hydro to make well-informed asset renewal investment decisions.

D6.1.2 Legislative and Technical Standards

Toronto Hydro's facilities standards are based on legislative requirements and technical, professional, or regulatory standards. The former include the Ontario Building Code, the Ontario Fire Code, and *Accessibility for Ontarians with Disabilities Act, 2005*.

Technical standards vary from project to project and may include: ASHRAE (American Society of Heating, Refrigerating and Air-Conditioning Engineers); ESA (Electrical Safety Authority); TSSA (Technical Standards and Safety Authority); CSA (Canadian Standards Association); EUSR (Electrical Utility Safety Rules); and in the future, ISO55001 (International Organization for Standardization – Asset Management).

D6.2 Facilities Enhancements Initiatives

In prioritizing facilities asset investments, the top drivers are safety (including compliance with legislative requirements), reliability of electrical distribution equipment, and functional availability to ensure business continuity. Once investments have been triggered by one or more of these drivers, Toronto Hydro evaluates whether there is opportunity for the asset's repair or replacement plan to have increased enhancement to achieve additional goals, including greater resilience against natural and physical threats such as extreme weather and vandalism, or deliver reductions in greenhouse gas emissions, including advancing energy efficiency outcomes.

Weather Resilience and Physical Security Enhancements: The natural, physical, social, and geopolitical circumstances affecting Toronto Hydro's distribution system also affect the utility's facilities and drive a key part of facilities enhancements. As discussed in Exhibit 2B, Section D5, the effects of climate change such as rising average annual temperatures, average annual precipitation, and extreme temperature and precipitation patterns require Toronto Hydro to prepare its infrastructure—including its facilities supporting the core distribution infrastructure—to withstand and adapt to these conditions. Separately, but equally importantly, hardening stations and work centres to prevent and mitigate physical security risks such as unauthorized access, vandalism, theft, trespassing, workplace violence, or terrorism is essential to ensuring the security and safety of the utility's personnel and the general public, and the reliability of the distribution system, especially in the face of pervasive cyber security threats emerging against the electric utilities sector. As described in Exhibit 2B, Section E8.2, Toronto Hydro plans to address these needs through targeted investments in renewing stations and work centre assets (such as exterior cladding, windows, and

roofs where critical equipment is housed), and improvements to security systems (e.g. the installation of network-based cameras and access card readers).

Energy Efficiency and Decarbonization Enhancements: In 2022, natural gas equipment in Toronto Hydro buildings contributed approximately 25% of the utility's total direct greenhouse gas emissions.[1] As detailed in Exhibit 2B, Section D7, Toronto Hydro's goal is to reach Net Zero emissions by 2040. To achieve this important goal in a gradual and paced manner, the utility intends to incorporate equipment swaps (e.g. natural gas to electric) and upgrade its facilities to improve energy efficiency (e.g. through increasing building envelope insulation and LED retrofits) where possible.

D6.3 Longer-Term Planning Considerations

As part of the IPF process, Toronto Hydro evaluates whether property purchases will be required to accommodate the future expansion needs of the distribution system. For example, this may include the need to construct new transformer stations to increase the grid's peak capacity or the siting of other equipment such as energy storage systems to enable the connection and integration of renewable electricity generation facilities. When facilities investments are required to support grid expansion, the Facilities Asset Management team collaborates with the Capacity Planning team to evaluate and integrate facilities investment options and incorporate them into the business case for particular projects, such the Downsview TS business case in the Stations Expansion program (Section E7.4).

The utility owns a small number of municipal stations properties that are decommissioned and no longer functioning to distribute electricity to customers. To determine if these properties can be designated as surplus to be disposed, Toronto Hydro evaluates whether the property is suitable for future grid expansion. The evaluation includes the costs and benefits of a potential sale versus the ongoing property maintenance and operation costs to ensure that the decision to sell or retain the property is financially sound.

[1] Exhibit 2B, Section D7.

Stations buildings house critical distribution equipment such as power transformers and switchgear. When these assets are planned for expansion or major upgrades, Toronto Hydro must also take the necessary steps to ensure that major building systems are functional and up-to-date prior to installing the new equipment. As an example, such systems include building waterproofing and flood management systems that protect electrical equipment and other important structural infrastructure from leaks. Therefore, Toronto Hydro plans and executes investments to support stations upgrades and expansions ahead of major capital projects at stations to ensure safety, reliability, and business continuity.

Similarly, for work centres, Toronto Hydro looks ahead to evaluate if it can accommodate and functionally support future resourcing requirements. As the utility's workforce expands to deliver capital and operations programs and address new requirements and objectives supporting the energy transition, additional work centre investments may be required to accommodate more staff. Those investments have not yet been built into the 2025-2029 plan as the utility continues to evaluate options for its head office strategy, as discussed below.

D6.3.1 Head Office Strategy

The 14 Carlton head office's location in proximity to Union Station and public transit lines enables Toronto Hydro to attract and retains talent from the Greater Toronto Area ("GTA").

The head office building poses several limitations that make its upkeep challenging, noted below:

- **Safety**: the building has an aged standpipe system with fire hose cabinets and no overhead automatic sprinklers, requiring manual fire suppression with a fire hose.
- **Mechanical**: the current heating and cooling system is an outdated 5-pipe system. Limitations on headroom clearance between floors and a controls system past useful life mean that any upgrade to a modern HVAC system would be very costly and challenging.
- **Electrical**: the building's voltage is not up to date with electrical service standards and the building is at its electrical service capacity. Upgrades would require rewiring the building and installing a new vault to upgrade electrical capacity.
- **Historical Site**: the property is designated under Part IV of the *Ontario Heritage Act*, which requires heritage permitting for building envelope repairs. This limits façade projects and repairs and opportunities for modernization (e.g. the installation of modern external HVAC ducting).

- **Layout**: the office layout has been built around the vintage architectural and structural elements, which pose limitations on efficient layouts for workstations, resulting in a less-dense workspace than what would be possible given the available square footage.
- **Environmental:** due to the building's age, it contains hazardous materials, including asbestos, that must be considered in all projects and that incur increased hazard management costs, longer times for project schedules, and business impacts.
- **Energy Efficiency: t**he building's age and structural limitations render it challenging and costly to achieve energy efficiency and decarbonization goals.

Significant renewal investment is required to remediate the risks and deficiencies of the head office. However, in an effort to manage costs responsibly, the Strategy takes a unique approach to this nearly one-hundred-year-old head office, compared to stations buildings of similar age and heritage protection that house critical grid distribution equipment which serves many customers. Over the 2025-2029, Toronto Hydro intends to evaluate options for the long-term investment strategy of the head office. While this analysis is pending, the utility plans to continue with a method of "managed deterioration" at the head office, engaging in reactive stopgap repairs to address safety, ensure compliance with legislative requirements, and maintain business continuity.

D7 Net Zero 2040 Strategy

To mitigate the impacts of climate change, Toronto Hydro is committed to reducing its direct greenhouse gas ("GHG") emissions (referred to as Scope 1 emissions) in order to reach "net zero" by 2040.[1]

Toronto Hydro's Net Zero by 2040 strategy builds upon the utility's record of climate action and environmental leadership.[2] Environmental leadership actions include implementing energy efficiency measures at stations and work centres, programs to increase waste diverted from landfills, reducing paper use, and facilitating the installation of renewable energy generation resources and battery energy storage systems for customers and as part of the utility's distribution system.

The City of Toronto (Toronto Hydro's sole shareholder) has declared that climate change is an emergency requiring immediate and sustained action, and has initiated an ambitious plan to achieve net zero community-wide emissions by 2040. Additionally, the Government of Canada passed the *Canadian Net-Zero Emissions Accountability Act*,[3] establishing a legally binding requirement for the federal government to establish a GHG emissions reduction plan for achieving net zero emissions in Canada by 2050.[4] Finally, the Province of Ontario has established a target of reducing GHG by 30 percent below 2005 levels by 2030.[5]

The International Panel on Climate Change ("IPCC") concluded that global warming of 1.5°C is hazardous to humans and natural ecosystems, and should be limited as much as possible. The risks of climate change for Toronto Hydro's operations include more frequent and severe storms and extreme heat, and increased flooding and lightning strikes.[6] These risks significantly endanger the utility's operations and are already manifesting. Severe weather in 2021 caused $2.1 billion of insured damage in Canada, compared to an average of $422 million a year between 1983 and 2008.[7]

[1] The utility's direct or "Scope 1" emissions are primarily emitted by its buildings, its vehicle fleet portfolio, and its sulfur hexafluoride-insulated (SF_6) electrical distribution equipment.
[2] Toronto Hydro, Environmental Performance, https://www.torontohydro.com/about-us/environmental-performance
[3] Canadian Net-Zero Emissions Accountability Act, S.C. 2021, c. 22.
[4] Canadian Net-Zero Emissions Accountability Act, S.C. 2021, c. 22, ss. 6-7.
[5] Government of Ontario, Climate Change, https://www.ontario.ca/page/climate-change: Target to reduce GHG emissions to 30% below 2005 levels by 2030.
[6] International Panel on Climate Change, IPCC, AR6 Summary for Policymakers at page 14, https://www.ipcc.ch/report/ar6/wg2/downloads/report/IPCC_AR6_WGII_SummaryForPolicymakers.pdf
[7] Insurance Bureau of Canada, News & Insights, Severe Weather in 2021 Caused $2.1 Billion in Insured Damage, "online", https://www.ibc.ca/news-insights/news/severe-weather-in-2021-caused-2-1-billion-in-insured-damage

Weather events leading to significant outages, such as the wind storm that occurred in May 2022, are anticipated to increase in frequency and severity as the climate continues to change.

Near-term GHG emissions reductions and mitigation actions are critical to reducing the adverse impacts, damages and losses from climate change.[8] To this end, Toronto Hydro is acting to reduce the GHG emissions it produces, with the target of emitting as close to zero emissions by 2040 as possible and purchasing carbon credits or enabling carbon sinks to offset any remaining emissions so that the utility reaches "net zero" direct emissions. Toronto Hydro's primary effort is to reduce its direct GHG emissions and credible offsets will only be used to eliminate remaining GHG emissions if zero direct emissions cannot be attained. The sections below review the three main types of direct emissions that Toronto Hydro produces and the utility's plan to reduce each to net zero by 2040.

With this plan, Toronto Hydro is building on its track record of environmental leadership.[9] Since 2013, the utility reduced its direct GHG emissions by 26 percent by increasing buildings' energy efficiency, minimizing fleet vehicle idling time, and electrifying light-duty fleet vehicles. Toronto Hydro intends to sustain these emissions reductions and implement new initiatives to reduce the remaining emissions to net zero. These investment objectives are part of Toronto Hydro's 2025-2029 investment plan which was put to customers for feedback as part of the Phase 2 Customer Engagement survey.

Toronto Hydro's 2025-2029 custom scorecard includes a measure tracking the utility's progress against a target to reduce 2.6 kilo tonnes of carbon dioxide (CO2) and carbon dioxide equivalents (CO2E) by the end of the rate period. This measure holds the utility accountable to its customers and stakeholders for delivering on the commitment to reach net zero by 2040 to mitigate the impact of climate change.

Toronto Hydro's Vehicle Fleet Emissions

Toronto Hydro's fleet produced 23 percent of its direct emissions in 2022, making this transition strategy a critical component of the utility's net zero by 2040 objective. Toronto Hydro is reducing the emissions produced by its fleet of vehicles by transitioning its procurement standards to prioritize electric and hybrid vehicles whose motors are powered by clean electricity (as per the IESO, over 90

[8] *Supra* Note 6
[9] *Supra* Note 2

percent of Ontario's electricity system is currently emissions-free).[10] Emissions from an electric vehicle are up to 90 percent less than a similarly sized internal combustion engine ("ICE") vehicle.

In addition to decreased emissions, electric and hybrid vehicles are a sound financial investment as they incur lower operational costs due to decreased fuel consumption and vehicle maintenance requirements. The Federal Government has established a price on carbon pollution, which will rise from $65/tonne to carbon dioxide equivalent (tCO2e) in 2023 to $170/tCO2e in 2030.[11] As a result, the price of fuel for ICE vehicles will continue to increase each year. Currently, driving an electric vehicle reduces the annual cost of fuel and maintenance by $1,500 to $2,000 each year. These savings will continue to rise as the price of carbon continues to increase the price of fuel.

Toronto Hydro currently owns and operates 13 electric and 20 hybrid light-duty vehicles. Toronto Hydro plans to continue to purchase fully electric or hybrid light-duty vehicles in a paced manner. Consumer demand and supply chain factors, including manufacturer capability and battery availability, currently pose some limitations on vehicle availability. Toronto Hydro mitigates this risk by using lifecycle assessments to determine when vehicles will need to be replaced and accordingly placing orders for longer lead time purchases of electric vehicles. Toronto Hydro also extends the lifecycle of vehicles to allow time for the procurement of electric or hybrid replacements where the total cost of ownership (including the maintenance costs, replacement costs incurred while the vehicle is unavailable for maintenance, and sunk costs) of extending the vehicle lifecycle does not exceed the estimated total cost of ownership of a new ICE vehicle.

Many vehicle manufacturers are committed to increase the production of electric vehicles and stopping the production of ICE vehicles by 2040.[12] Toronto Hydro's plan to transition to electric and hybrid vehicles protects the utility from manufacturing availability risk and allows the utility to pace its procurement in a fiscally responsible manner that avoids the risk of stranded asset costs.

While manufacturers are committed to increasing electric vehicle production, heavy-duty electric vehicles (such as bucket trucks) remain an emerging technology characterized by a rapidly evolving

[10] Independent Electricity System Operator ("IESO"), Pathways to Decarbonization Report (15 Dec 22) at page 6, https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization
[11] Government of Canada Federal Benchmark for Carbon Pollution Pricing System, 2023-2030, https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html
[12] Accelerating to Zero Coalition, Signatories, Automotive Manufacturers, https://acceleratingtozero.org/signatories-views/

market. As a result, Toronto Hydro cannot yet conclude whether the heavy-duty electric vehicles that are currently available on the market will meet the utility's functional needs and provide sufficient reliability to service the distribution system in emergency situations. As a result, Toronto Hydro is deferring the large-scale transition to fully electric heavy-duty vehicles to the next decade. The utility intends to stage for success of future large-scale adoption of heavy-duty electric vehicle technologies through trials in the 2025-2029 rate period. These trials can enable Toronto Hydro to better understand how this emerging clean technology can be effectively integrated into its critical operations, and to leverage that experience and understanding to support commercial and industrial customers in their fleet electrification journeys.

While the transition to electric vehicles is ongoing, Toronto Hydro will continue to operate and maintain ICE vehicles such as pick-up trucks, cube vans and bucket trucks. Toronto Hydro is using idling reduction technology and biofuels to reduce its fleet emissions in the near term while the utility's fleet still includes combustion engines. Employee communications on electric vehicle use and idling reduction are also used to encourage employees to role model emissions reduction behaviours.

Fleet electrification is discussed in further detail in the Fleet and Equipment capital program (Exhibit 2B, Section E8.3) and the Fleet and Equipment Services OM&A program (Exhibit 4, Tab 2, Schedule 11).

Toronto Hydro's Facilities Emissions

In 2022, the utility's consumption of natural gas at its occupied buildings produced 26 percent of its direct GHG emissions. Toronto Hydro has a paced plan to gradually reduce its buildings emissions by decreasing its natural gas consumption using a combination of energy conservation measures and fuel switching projects. Energy conservation measures include the installation of air curtains and light-emitting diode ("LED") lights to increase the energy efficiency of the utility's buildings. Fuel switching projects include replacing natural gas fueled heaters with electric heating systems. The energy input requirements for an air source heat pump are less than a similarly-sized natural gas

system since heat pumps are more efficient.[13] As a result, fuel switching to heat pumps also contributes to the utility's energy efficiency goals in addition to its decarbonization goals.

To smooth and constrain investment profiles, Toronto Hydro intends to take a paced approach to this work, increasing energy efficiency at its buildings to reduce natural gas consumption before fully transitioning from natural gas to electricity. This approach reduces the overall volume of electrical heating and cooling assets that the utility would have to install and provides energy savings through efficiency. Finally, a paced approach enables Toronto Hydro to minimize interruptions to its business operations by effectively scheduling building upgrades and equipment replacements to coordinate with the times the work centres are occupied by employees, rather than conducting the work reactively and interrupting normal business operations. This work must commence in the 2025-2029 rate period in order to execute a paced approach and realize the associated benefits of smoothing the investment costs and minimizing operational disruptions.

Toronto Hydro's plan to reduce natural gas emissions by electrifying buildings' heating and cooling systems puts Toronto Hydro in a position of proactive alignment with current and future government policy developments that restrict or ban natural gas heating. In its Transform TO Net Zero Strategy, the City of Toronto indicated the need to "accelerate a rapid and significant reduction in natural gas use" stating that "catalyzing the electrification of building heating systems, as a preferred alternative to the use of fossil-fuel heating systems, will be key."[14][15] The City further stated in that document that the use of natural gas in buildings must be phased out by 2040 to achieve its net zero targets.[16] Similar policy proclamations could be made by other levels of government if the urgency of climate change action intensifies, and if they are made, Toronto Hydro would be in a position of proactive alignment.

One of the factors Toronto Hydro considered in establishing the plan to reduce emissions from its buildings is the optimal lifecycle of its assets.[17] The optimal lifecycle considers the operational costs of maintaining and operating existing equipment against the cost of capital investments in

[13] Natural Resources Canada, Publications, Heating and Cooling with a Heat Pump, https://natural-resources.canada.ca/energy-efficiency/energy-star-canada/about/energy-star-announcements/publications/heating-and-cooling-heat-pump/6817#b5
[14] City of Toronto, Transform TO Net Zero Strategy, November 2021, Attachment B, p. 8, https://www.toronto.ca/legdocs/mmis/2021/ie/bgrd/backgroundfile-173758.pdf
[15] Ibid.
[16] Ibid, p. 6.
[17] See Facilities Asset Management Strategy, Exhibit 2B, Section D6.

replacement assets on an ongoing basis. Changing maintenance and replacement costs influence the optimal lifecycle cost model. To this end, the rising price on carbon pollution impacts the cost of Toronto Hydro's natural gas consumption. Toronto Hydro's emissions reduction plan can avoid up to $330,000 in carbon tax costs associated with natural gas by 2030, assuming the carbon tax continues to increase annually by $15 per tonne.[18]

The investments required to reduce emissions from buildings are discussed in further detail in the Facilities Management and Security capital program (Exhibit 2B, Section E8.2) and the Facilities Management OM&A program (Exhibit 4, Tab 2, Schedule 12).

Toronto Hydro's Sulfur Hexafluoride (SF6) Emissions

Emissions from Toronto Hydro's SF6-insulated equipment represented 51 percent of its total direct emissions in 2021. Toronto Hydro intends to limit SF6 emissions, and the associated GHG emissions, through the elimination of SF6 leaks from existing distribution equipment and reducing the installation of new SF6-containing equipment where feasible. This plan is intended to minimize the release of potent emissions and prepare for anticipated legislation. SF6 is a potent GHG with a with a global warming potential 22,800 times greater than carbon dioxide. SF6 has been used in electrical transmission and distribution equipment in the electricity industry since the 1950s due to its excellent insulating properties and stability.[19] Toronto Hydro has used sealed SF6 equipment since the 1950s and in some instances, in place of air-vented equipment to mitigate the risk of failure due to ingress of dirt, road contaminants, and flooding. Reliability, safety, and environmental implications are critical considerations in determining the optimal method of eliminating SF6 emissions.

The energy sector is under increased pressure to reduce reliance on SF6 because it is a potent GHG. Legislation is expected to limit the use of SF6 in the future. Such legislation has already been implemented in other jurisdictions, including California.[20] Proactively minimizing the use of SF6 reduces Toronto Hydro's operational risks, as replacement costs would be material if Toronto Hydro were required to comply with new legislation on short notice, increasing the risk of stranded assets and operational replacement costs.

[18] *Supra*, Note 11.
[19] United States Environmental Protection Agency, Sulfur Hexafluoride (SF6) Basics, "online", https://www.epa.gov/eps-partnership/sulfur-hexafluoride-sf6-basics
[20] California Air Resources Board, Regulation for Reducing Greenhouse Gas Emissions from Gas-Insulated Equipment, Title 17, "online", https://ww2.arb.ca.gov/sites/default/files/2022-05/gie21-final-regulation-unofficial.pdf

Toronto Hydro plans to install assets that use alternatives to SF6, such as solid dielectric transformers, in order to meet its Net Zero 2040 target and prepare for any anticipated legislation. The utility's approach addresses challenges associated with eliminating SF6 emissions, including leak detection difficulties and a lack of operationally suitable alternatives. Toronto Hydro identified alternatives, such as solid dielectric equipment, for approximately 75 percent of existing SF6 applications. However, the balance of approximately 25 percent cannot be replaced at this time as the currently available alternative equipment does not have sufficient rating for the required electrical current. As a result, Toronto Hydro must take a two-pronged approach to mitigating SF6 emissions:

1. Eliminate SF6 use where operationally feasible; and
2. Improve leak prediction and detection capabilities to address SF6 emissions proactively.

This approach is embodied in Toronto Hydro's Underground System Renewal – Horseshoe capital program, discussed in Exhibit 2B, Section E6.2. This program details the investments that Toronto Hydro intends to make in solid dielectric switchgear to try it as an alternative option to SF6-insulated switchgear.[21]

Toronto Hydro is committed to eliminating SF6 by installing alternatives in all new construction projects where doing so is operationally feasible and where physical space, cost, design standards, and equipment availability allow Toronto Hydro to trial viable alternatives to SF6 insulated equipment. The utility is also exploring other insulation alternatives to SF6 gases; however, these gases are not currently widely deployed by other utilities and remain at the pilot stage.

Toronto Hydro also continues to improve leak prediction and detection capabilities to address SF6 emissions proactively.[22] The utility investigates the cause of failures in SF6 equipment to identify trends and enhance the inspection process to allow greater focus on common failure points. The investigation data also allows Toronto Hydro to identify the equipment types and manufacturers that are experiencing quality issues and select vendors that supply more reliable equipment. The utility communicates the common failure points identified through investigations to manufacturers to improve the manufacturing process. For example, when the investigation process identified multiple leaks from bushings related to welding issues, Toronto Hydro worked with the relevant manufacturer

[21] Underground System Renewal – Horseshoe, Exhibit 2B, Section E6.2, p. 31.
[22] Preventative and Predictive Maintenance – Underground, Exhibit 4, Tab 2, Schedule 2, Page 2 & 24; Preventative and Predictive Maintenance – Stations, Exhibit 4, Tab 2, Schedule 3, Page 3

to improve the welding inspection process prior to equipment delivery. Additionally, the utility installed SF6 leak detection alarms for some equipment. These alarms provide early notification when a leak condition exists and enable rapid mitigation of impacts to the environment.

Conclusion

The 2025-2029 investment plan supports Toronto Hydro's Net Zero 2040 by strategy through investments in the electrification of Toronto Hydro's fleet and buildings, enhancements to building envelope efficiency, and elimination of SF6 emissions from equipment. These investments mitigate business continuity risk and manage long-term costs associated with decarbonization policies, such as the federal tax on carbon emissions. Deferring these investments to future periods would entail greater disruption to business operations, thereby increasing expenses and hampering productivity. Paced decarbonization investments also protect Toronto Hydro and its ratepayers against the risk of sudden legislative changes governing the use of SF6 gas and phase-outs of ICE vehicles which could require corporations like Toronto Hydro to decarbonize their emissions in an accelerated manner.

D8 Information Technology Investment Strategy

Informational technology ("IT") is a critical enabler for utility operations. Toronto Hydro relies on IT assets and systems to satisfy its obligations as a distributor, deliver its capital plans and operational programs, and pursue efficiencies and innovation.

The primary objective of Toronto Hydro's IT Asset Management and Investment Planning Strategy (the "Strategy") is to derive sustainable value from IT assets for the utility and customers. IT systems provide optimal value when they deliver expected levels of service in a sustainable manner and effectively mitigate ongoing risks (e.g. impacts of failure, cyber security) at optimal costs. This schedule describes the IT asset management principles and IT investment planning methodology that enables Toronto Hydro to achieve this key objective.

IT asset management includes the purchase, operation, maintenance, renewal, replacement and disposition of IT data, hardware, and software assets. IT asset management is defined by IT standards, and includes:

- Requirements for data, hardware, and software assets (e.g. physical, performance, compatibility, security, etc.);
- IT architecture establishes expected service levels (e.g. performance measurement, reliability requirements, incident / problem management for the assets); and
- Lifecycle management schedules for each type of asset.

Sustainment is necessary for maintaining the functionality and currency of existing IT systems. Enhancement involves improving existing systems and facilitating their organic growth requirements, such as meeting the needs of increasing numbers of staff or customers. Transformation refers to implementation of new systems or modules that add new business capabilities, provide higher protection levels for digital assets and safeguard customer and employee privacy.

To enable the Strategy, Toronto Hydro uses well-defined IT standards and up-to-date IT asset information. To that end, the utility uses an internal framework which provides high-level criteria to consider in the IT investment decision-making process. The process leads to the development of a five-year roadmap of prioritized investments, including a detailed plan for the first year.

D8.1 IT Asset Management

Toronto Hydro developed IT standards to streamline and optimize the lifecycle of IT assets, define system architecture, and gain operational efficiencies through the standardization of IT assets and components. The utility defines its IT standards based on information provided by equipment vendors (e.g. statistics on mean time to failure), internal historical data regarding asset failures, and industry best practices, and reviews its IT standards regularly to ensure that they remain current and relevant for the utility.

Toronto Hydro adopted distinct yet mutually reinforcing IT standards and architecture for data, hardware, software, security, assets and standards for processes (e.g. testing, monitoring and alerting), as described in greater detail below. For example, having aligned hardware and software standards enables the utility to implement virtualized hardware platforms—a collection of hardware resources which are required to complete desired computing operations that exceed the requirements of a single hardware machine.

The virtualization of the infrastructure provides the following benefits:

- Better management of IT assets, incidents, problems, changes, configurations, security, capacity, and availability of IT assets;
- Enhanced reliability of IT systems;
- Streamlined procurement processes and reduced operating costs;
- Operational efficiencies;
- Simplified monitoring of IT assets;
- Enhanced security; and
- Easier migration to new hardware and technology, including cloud solutions where required.

D8.2 IT Hardware Standards

IT hardware standards define the management of the physical IT components from acquisition through disposal. Common IT hardware asset management practices include resource forecasting, procurement management, life cycle management, redeployment, and disposal management. Toronto Hydro applies these practices to the categories of hardware assets described in Figure 1 below.



Core Backend Infrastructure Assets

- Responsible for the computation, storage and communication necessary to support IT systems:
- **Computing**: servers and security appliances;
- **Storage**: disk arrays, flash arrays, backup systems; and
- **Communication**: network and telephony assets.



Endpoint Assets

- Enable end-users to execute, process, complete and review business tasks and operations:
- **Computing:** desktops, laptops and tablets;
- **Printing**: printers and plotters; and
- **Communication:** desk phones, mobile phones.

Figure 1: IT Hardware Asset Categories

IT hardware and architecture standards specify which types of hardware assets Toronto Hydro requires to ensure a highly reliable, scalable and manageable platform for business applications, and document the capacity and lifecycle of these different assets.

The utility must periodically refresh IT Hardware assets to guarantee expected service levels of the systems and minimize the risk of asset failure and impact to the business or customer services (e.g. from the failure of assets supporting customer-facing applications such as the self-service portal or outage map). Through its IT hardware standards, Toronto Hydro seeks to define the optimal timing of asset replacement such that the utility operates hardware assets with the lowest acceptable failure rate at optimal costs. As illustrated in Figure 2 below, the lifecycle of IT assets generally follows a "bath tub curve" that breaks out into three distinct regions:

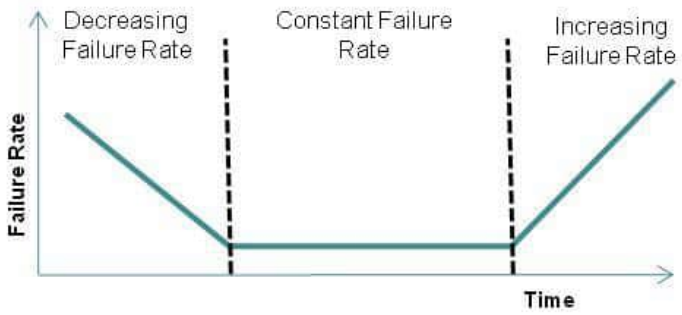


Figure 2: IT Hardware Asset Lifecycle Failure Rate over Time

- **Decreasing Failure Rate:** This is the region of the curve associated with a reduced failure rate over time. This is typical in the release of a new product, where once upfront implementation issues and defects are addressed, failure rates tend to drop.
- **Constant Failure Rate:** As a failure rate decreases to a certain low point, it stabilizes and remains virtually constant. The cost of ownership in this area of the bathtub curve is steady and financially optimal.
- **Increasing Failure Rate**: As the product ages beyond useful life, its failure rate starts to increase again due to general operational wear and tear. As a result, system failures and associated maintenance costs start to rise steeply in this portion of the bathtub curve.

Based on the criticality of the infrastructure, industry best practices, and vendor specifications, IT hardware standards define the optimal time for asset replacements before reaching the "Increasing Failure Rate" portion of the lifecycle. This approach minimizes the risk of interruption to the core processes and technology that Toronto Hydro relies on to execute its capital plans and operational programs. This approach also helps the utility incur IT-related operational and capital expenditures prudently and at reasonable levels, while also increasing the flexibility to adapt IT infrastructure in accordance with customers' evolving needs and preferences and changing business circumstances.

D8.3 IT Software Standards

Toronto Hydro categorizes its software applications as Tier 1, Tier 2 and cloud-based solutions. The criteria used to classify these applications include the level of impact on critical business functions, system complexity, maintenance costs, and the number of application users.

- **Tier 1** applications enable Toronto Hydro's critical business operations and support company-wide business processes. They are functionally integrated with other applications, and are supported by complex, highly redundant underlying infrastructure such as databases, middleware, storage, and network. As a result, Tier 1 applications generally have higher maintenance costs and a larger user base than Tier 2 applications. Examples of Tier 1 applications include the Enterprise Resource Planning System, Network Management System, and Geospatial Informational System.

- **Tier 2** applications enable divisional and departmental processes. These applications have less complex integration with other enterprise applications, and are typically supported by infrastructure with a lower complexity and lower target for overall availability. Tier 2

applications generally have lower maintenance costs, and cater to a smaller user base than Tier 1 applications. For example, several of Toronto Hydro's operational divisions use ProjectWise as a document management system. Another example of a Tier 2 system is Power Monitoring Expert, used by the utility's engineers to provide insights into electrical system health and energy efficiency.

- **Cloud-based** applications enable both company-wide and specific business processes. The unique feature of a cloud-based solution is that it resides on vendor infrastructure and is accessed through the internet. Toronto Hydro establishes system service level agreements with each cloud service provider to set service conditions, e.g. relating to business continuity and cyber security. An example of a cloud-based application is Intelex which Toronto Hydro uses to manage health and safety inspections and incident reporting processes. Another example is Oracle Field Services Cloud (OFSC), a mobile workforce management system that allows dispatchers and field crews to collaboratively manage major events, assemble crews, manage priorities, and communicate across different groups to respond to major events in a timely and effective manner.

Toronto Hydro enhances system functionality, reduces the risk of system failures and cyber security breaches, and aligns its software assets with vendor support cycles through regular software upgrades. Continuing to run and rely on software applications beyond the end of vendor support increases the risk to system reliability and of greater exposure to cyber security threats. Similar to IT hardware assets, if an application is not upgraded before the vendor support cycle expires, Toronto Hydro may need to procure specialized technical resources to maintain and support the application. Timely software upgrades also help reduce unforeseen IT-related operational and capital expenditures by minimizing the risk of asset failure.

Through its IT software standards, Toronto Hydro seeks to maintain the compatibility of software applications with the underlying components (e.g. servers and operating systems) to ensure uninterrupted IT system operations and deliver the desired end user experience and functionality. Since many IT systems and their underlying components are often on different end-of-life and vendor support cycles, maintaining compatibility among various software applications can be a complex task. Nonetheless, it is a key consideration in mitigating security and reliability risks to IT systems from the underlying components.

Toronto Hydro's IT software standards consider average vendor release cycles, as well as the need to minimize incompatibility risks with underlying components. Through the application of the Strategy, the utility implements software asset upgrades depending upon need and risk factors, including where the asset reaches its maximum age or is more than one version behind the latest vendor-released version, or based on specific compatibility drivers and considerations (e.g. hardware upgrades).

D8.4 IT Cyber Security Standards

With the emergence of advanced persistent threats and nation-state actors, advanced cyber security attacks against critical infrastructure are becoming more widespread. The proliferation of a large number of potentially exploitable internet of things (IoT) devices (e.g. for home automation) enables attackers to form "botnets" to perform large-scale distributed denial of service (DDoS) attacks against enterprises.[1] Furthermore, the advent of cryptocurrencies has led to the emergence of ransomware attacks that extort organizations by encrypting critical data and demanding for ransom payments in untraceable cryptocurrencies.

The primary role of Toronto Hydro's cyber security practice is to maintain a strong cyber security posture through a combination of sustaining existing systems and enhancement initiatives, commensurate to the perceived threat level and the organization's risk tolerance.

The utility sustains existing systems with the maintenance and organic and strategic growth of existing information security capabilities. From the threat, risk and compliance perspective this includes the orchestration of recurring enterprise IT asset security patching as well as lifecycle upgrades of perimeter and endpoint security controls, such as firewalls, intrusion prevention systems and malware protection software. The identity access management aspect of the program ensures that the organization maintains secure, role-based access to resources, and proper logging for audit and forensic analysis purposes.

Toronto Hydro's enhancement initiatives expand baseline cyber security capabilities through the adoption of advanced threat protection technologies and user education processes aimed at curbing

[1] The internet of things (IoT) refers to the interconnected network of physical devices, vehicles, home appliances, and other items embedded with electronics, software, sensors, and connectivity which enables these objects to collect and exchange data. The IoT allows these devices to communicate with each other and with a centralized system, enabling them to perform a wide range of tasks and functions without human intervention

the exposure to social engineering attacks. The utility explores pioneering technologies and cyber defence mechanisms to ensure the security of its digital assets and safeguard the privacy of customer and employee personal information and gain stakeholder confidence.

Pursuant to the Strategy, Toronto Hydro requires all systems delivered through sustainment, enhancement, and transformation initiatives beyond cyber security-specific initiatives, to meet stringent standards that are aligned with the Ontario Energy Board Cyber Security Framework and stipulated within the utility's application security, network security, cloud security, data security and endpoint security standards. This ensures a strong cyber security posture for every system deployed within or for Toronto Hydro.

D8.5 IT Investment Planning Process

IT investment planning is the process of developing, prioritizing, and managing a continuous five-year roadmap of investments, including a detailed project plan for the first year. As part of the Strategy, Toronto Hydro developed an Enterprise Technology Portfolio (ETP) framework to ensure consistency in IT investment decisions, establish and maintain governance of investments and achieve alignment with the utility's strategic objectives and target outcomes. The capital and cloud (OM&A) expenditures detailed in Exhibit 2B, Section E8.4 and Exhibit 4, Tab 2, Schedule 17, reflect the roadmap for the next rate period.

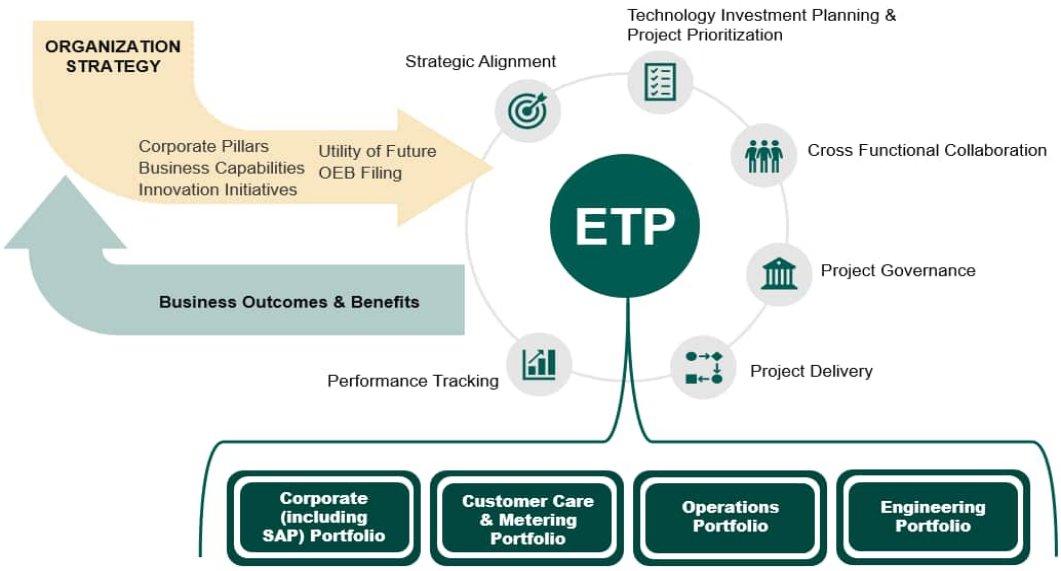


Figure 3: Enterprise Technology Portfolio Framework

D8.5.1 Enterprise Technology Portfolio (ETP) Framework

Through the ETP framework, the utility centralizes the intake of all technology requests from across the organization, plans IT investments and prioritizes initiatives and projects in accordance with the Strategy. In prioritizing initiatives and projects, the utility considers:

- Operational factors such as IT asset lifecycle, business impacts, change management, resource availability, and internal and external project dependencies.
- Financial factors such as costs versus benefits and approved budgets
- External factors such as IT industry best practices and trends, utility industry trends, vendors' information, and trends of evolving regulatory and compliance requirements are also taken into consideration as needed.
- Strategic alignment with key investment priorities and objectives established through the utily's integrated planning process detailed in Section E2.

Based on these inputs, ETP roadmaps are designed with the following objectives:

(i) Enabling technology investments that advance business and customer outcomes;
(ii) Ensuring optimal levels of IT system reliability and availability; and
(iii) Compliance with the utility's IT standards.

Each roadmap includes a detailed plan for the first year and provides a higher-level plan for the remaining period. This agile approach provides necessary certainty and precision for the implementation of near-term initiatives, and high-level parameters for longer-term initiatives, giving the utility the ability to respond effectively to changes in external drivers and risks, such as:

(i) Fluctuations in software and hardware costs;
(ii) Changes in the release dates of certain applications;
(iii) New technology products disrupting the marketplace and industry;
(iv) New threats, vulnerabilities, or modes of cyber security attacks;
(v) New or evolving requirements from regulatory bodies such as the Ontario Energy Board, Measurement Canada and the Independent Electricity System Operator (IESO); and
(vi) Changes in industry best practices such as the adoption of cloud solutions.

Toronto Hydro maintains a flexible and agile approach by continually balancing its roadmap against the strategic objectives of the organization for the planning period. For example, to support grid

modernization during the 2025-2029 rate term, Toronto Hydro intends to prioritize projects that enable monitoring and operational capabilities of its distribution system. Examples of such efforts will include installing enhanced communication infrastructure, introducing advanced grid configurations, enabling enhanced monitoring, automation and remote control, and providing greater insight into the grid operations through analytics into grid performance and grid reliability. For more information on these types of investments, please refer to the Grid Modernization Strategy at Exhibit 2B, Section D5 and the Advanced Distribution Management System Business Case in Exhibit 2B, Section E8.4, Appendix A.

D8.5.2 Project Governance Framework

Beyond the ETP framework, the utility relies on a formal business case for the governance and approval for projects within the one-year window. Stakeholders from various functions in the organization collaborate in the creation, review, and approval of each business case. This process includes business units, IT functional and technical teams, IT security teams and change management professionals. Stakeholders' inputs determine the scope, business requirements, current state business processes, future state business processes, options analyses, the preferred approach and the associated costs and benefits. Once the business case is approved, the project proceeds to execution. Toronto Hydro uses a robust project management framework to manage and oversee the progress of the project against key parameters such as the approved budget, scheduled, scope, identified risks and target benefits.

D8.5.3 Evaluation of Options

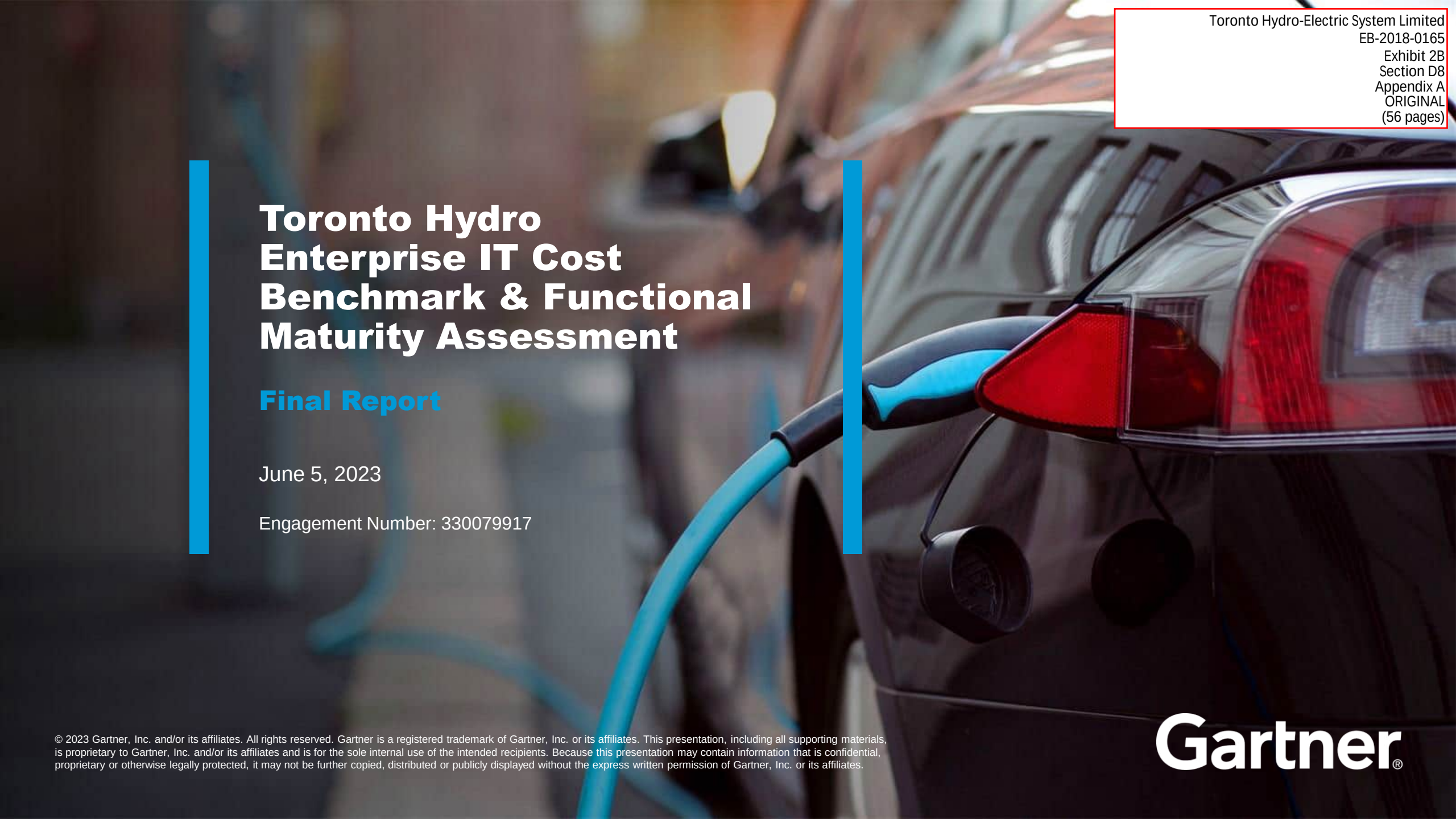
With the emergence and increasing availability of cloud-based solutions, Toronto Hydro deploys the Strategy to evaluate multiple options to meet business needs, including cloud-based solutions such as software-as-a-service, platform-as-a-service, and infrastructure-as-a-service. For each project, the utility grounds its investment decisions on a rigorous and consistent comparison and evaluation of on-premise and cloud-based solutions, with reference to various criteria such as: transformation potential, rollout velocity, the size of the solution, the business criticality of the underlying functions, data and cyber security considerations, the flexibility of adopting new features, the window of available vendor maintenance, and the total cost of ownership.

For example, when considering projects implemented in 2020-2024 for critical grid management systems, such as Network Management Systems, Toronto Hydro completed a detailed analysis and

determined that the on-premise solution in these cases provided the optimal outcomes. This decision was based on the business criticality of these systems in managing the grid and the high degree of sensitivity to cyber security risks. Another key factor that informed the utility's decision was the need for flexibility in maintenance windows to avoid operational interruptions due to unplanned events such as storms.

In a different example, Toronto Hydro implemented a cloud-based solution to support its enterprise health and safety business processes. The utility selected this solution over any available on-premise alternatives because unlike on-premise alternative, the selected cloud-based solution required limited integration to other Toronto Hydro systems and offered the ability to adopt new industry best practices in a shorter period of time. From a cyber security standpoint, the selected solution does not house sensitive health and safety information, which limits the risk exposure to an acceptable level. From a financial standpoint, the utility determined that the total cost of ownership for the cloud solution would be lower than the implementation of a comparable on-premise solution. Cumulatively, these considerations led Toronto Hydro to select a cloud-based solution to support its enterprise health and safety processes.

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit 2B
Section D8
Appendix A
ORIGINAL
(56 pages)



Toronto Hydro Enterprise IT Cost Benchmark & Functional Maturity Assessment

Final Report

June 5, 2023

Engagement Number: 330079917

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01
Summary of Findings

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TH's 2022 IT spend as a % of Revenue has increased since 2017, however is very similar to the peer group average; higher spend levels are due to inflation, investments in digital transformation and maturing IT's capabilities

- Toronto Hydro was compared to a peer group of eight utility organizations with similar revenue and operating expenses, with a major focus of electricity distribution in major urban centers
- Toronto Hydro's 2022 IT Spending as a % of Revenue was 3.2% compared to an average of 3.0% for the peer group, and 3.3% of OpEx compared to 3.9% for the peer group. The $28 million IT spending increase in 2022 over 2017 was due to inflation (~$10 million), increasing Operational Expenses (i.e. ERP support, cloud services, cyber security) and investments in the Customer Information System.
- Increase in IT Spending over 2017 is similar to industry peers
- In 2022, Toronto Hydro allocated 11% of IT Spending to "transform", almost three times more than in 2017. This is the result of investments in digital transformation.
- Toronto Hydro's IT staffing levels are materially lower than the peer group average (5.8% IT FTEs as a % of total Employees** versus 8.2%). IT Staffing levels as a % of total Employees** has decreased slightly from 6.2% in 2017.

Metric	Toronto Hydro (2022)		Toronto Hydro (2017*)		Peer Group Average (2022)	ITKMD Utility Industry (2022)
	% Spend	$ Spend (millions)	% Spend	$ Spend (millions)	% Spend	% Spend
IT Spend as a % of Revenue						
- Operational	1.5%	$55.2	1.0%	$39.2	1.8%	2.0%
- Capital	1.7%	$59.6	1.2%	$47.9	1.2%	1.0%
- Total	3.2%	$114.8	2.2%	$87.1	3.0%	3.0%
IT Spend as a % of OpEx						
- Operational	1.6%	$55.2	1.1%	$39.2	2.3%	2.4%
- Capital	1.7%	$59.6	1.3%	$47.9	1.6%	1.3%
- Total	3.3%	$114.8	2.4%	$87.1	3.9%	3.7%
Run, Grow, Transform*** (% of total IT Spend)						
- Run %	71%	$81.1	71%	$61.8	65%	70%
- Grow %	18%	$21.2	25%	$21.8	20%	18%
- Transform %	11%	$12.4	4%	$3.5	15%	12%
- Total	100%	$114.8	100%	$87.1	100%	100%
IT FTEs as a % of Employees**	5.8%		6.2%		8.2%	6.8%

* Toronto Hydro's 2017 data has not been adjusted for inflation (2017 inflation adjusted spend @ 2.1%[1] year over year would = $97 M)
** This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors
*** See page 31 for "Run, Grow, Transform" definitions

[1] Average Canadian Consumer Price Index increase 2017-2022
Note: Totals may not equal due to rounding

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TH's focus on digital transformation has meant a higher allocation to applications spending; IT spending by cost category is balanced and in line with peer organizations

- Overall allocation to Applications spending is more than the peer group (51.2% of IT spend versus 41.9%). This is normal during a period of growth and transformation. Applications spending is the largest contributor to the overall increase in IT spending when compared with 2017, up $18 million. This can be largely attributed to Customer Information System upgrades.
- The allocation to IT Management & Administration (which includes Governance & Service Management, IT Security, IT Operations Management and Service Continuity / Disaster Recovery) was 14.8%, compared to 10.8% for the peer group. Increased investment in Cyber Security services and capabilities is the main reasons for this variance.
- Allocation to both hardware (14.1% of IT spending in 2022) and software (31.1% of IT spending in 2022) is virtually the same as the peer group.
- Toronto Hydro relies less on Outsourcing (21.3% of IT spend in 2022) than the peer group (26.6%). This is balanced by a higher allocation to Personnel (33.4% of IT spend in 2022) as compared with the peer group (26.6%).

Metric	Toronto Hydro (2022)		Toronto Hydro (2017*)		Peer Group Average (2022)	ITKMD Utility Industry (2022)
	% Spend	$ Spend (millions)	% Spend	$ Spend (millions)	% Spend	% Spend
IT Spend Distribution by Area						
- Enterprise Computing	14.7%	$16.9	25.0%	$21.8	14.6%	15%
- Voice & Data Network	9.5%	$10.9	9.5%	$8.3	19.8%	12%
- Workplace Services	6.9%	$7.9	6.1%	$5.3	9.2%	7%
- IT Service Desk	3.0%	$3.4	2.3%	$2.0	3.8%	3%
- Application Development	24.7%	$28.4	46.9%[2]	$40.8	18.9%	25%
- Application Support	26.5%	$30.4			23.0%	21%
- Governance & Ser. Mgmt.	5.9%	$6.7	10.3%[3]	$9.0	4.6%	8%
- IT Security	5.7%	$6.5			2.4%	4%
- IT Ops. Mgmt.	2.8%	$3.2			3.2%	3%
- Ser. Con't / DR	0.4%	$0.5			0.6%	1%
- Total	100%	$114.8	100%	$87.1	100%	100%
IT Spend per Cost Category						
- Outsourcing	21.3%	$24.4	19.9%	$17.3	26.6%	26.0%
- Personnel	33.4%	$38.4	39.8%	$34.7	26.6%	31.0%
- Software	31.1%	$35.7	27.6%	$24.0	31.9%	30.0%
- Hardware	14.1%	$16.2	12.7%	$11.1	14.9%	13.0%
- Total	100%	$114.8	100%	$87.1	100%	100%

* Toronto Hydro's 2017 data has not been adjusted for inflation (2017 inflation adjusted spend @ 2.1%[1] year over year would = $97 M)

[1] Average Canadian Consumer Price Index increase 2017-2022

[2] 2017 Application Development includes Application Support

[3] 2017 Governance & Service Mgmt. includes IT Security, IT Ops Mgmt. and Service Continuity / Disaster Recovery

Note: Totals may not equal due to rounding

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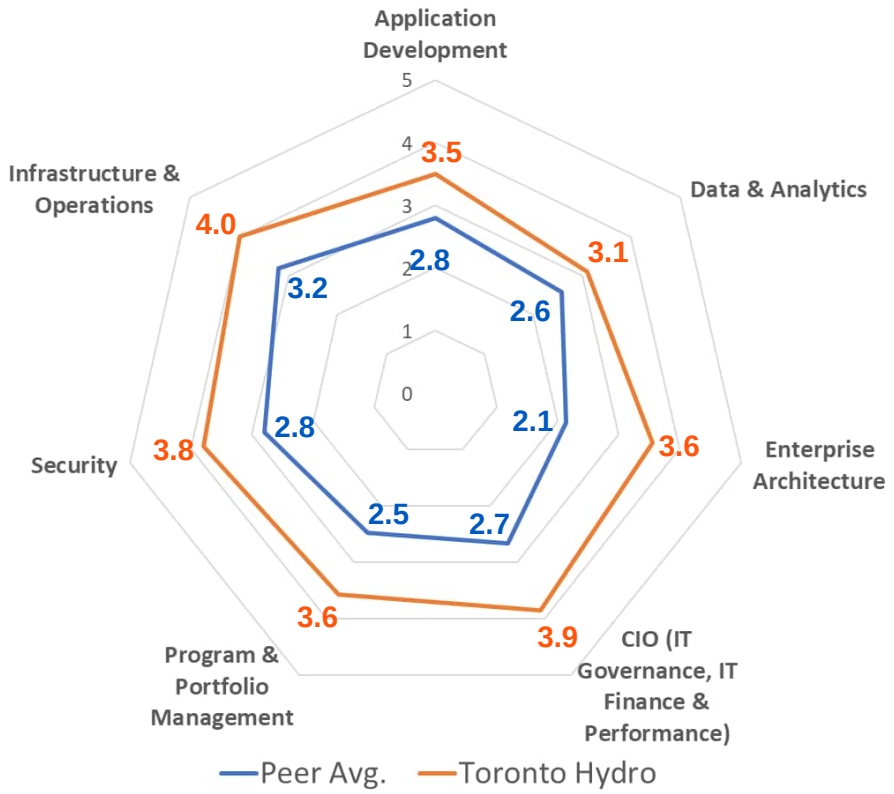
The IT capability assessment showed that Toronto Hydro's maturity across all domains is slightly higher than peers

- Toronto Hydro was compared to a peer group of 9 to 14 organizations (depending on data available for each IT domain) from the energy and utility industry with revenues between $1 billion and $3 billion USD
- 64 functional activities across 7 IT domains were assessed by comparing Toronto Hydro's current state (as defined by IT domain leadership) to Gartner's best practices.
- Toronto Hydro's overall IT maturity was 3.6 compared to 2.7 for the peer group. Higher levels of maturity were seen across all domains included in the scope of the assessment. This reflects Toronto Hydro's focus and investment in maturing IT capabilities.
- Within Toronto Hydro, Infrastructure & Operations (I&O) was the most mature domain at 4.0 and Data & Analytics (D&A) was the least mature at 3.1. I&O is a well-established domain whereas D&A is relatively new, hence these results are not surprising.
- Steady efforts have been made to improve capabilities within the Program & Portfolio Management, Enterprise Architecture and IT Security domains.
- Assessing maturity results relative to peers is interesting, however, comparing current maturity levels with how important the capability is for the organization to achieve its overall objectives is more important (see next page).

IT Domain Maturity Levels

Toronto Hydro's Overall IT Maturity Level: 3.6

Peer Maturity Level: 2.7



Maturity scores are assessed on a scale from 1-5, with the score of 5 representing Gartner's best practices for the IT domain

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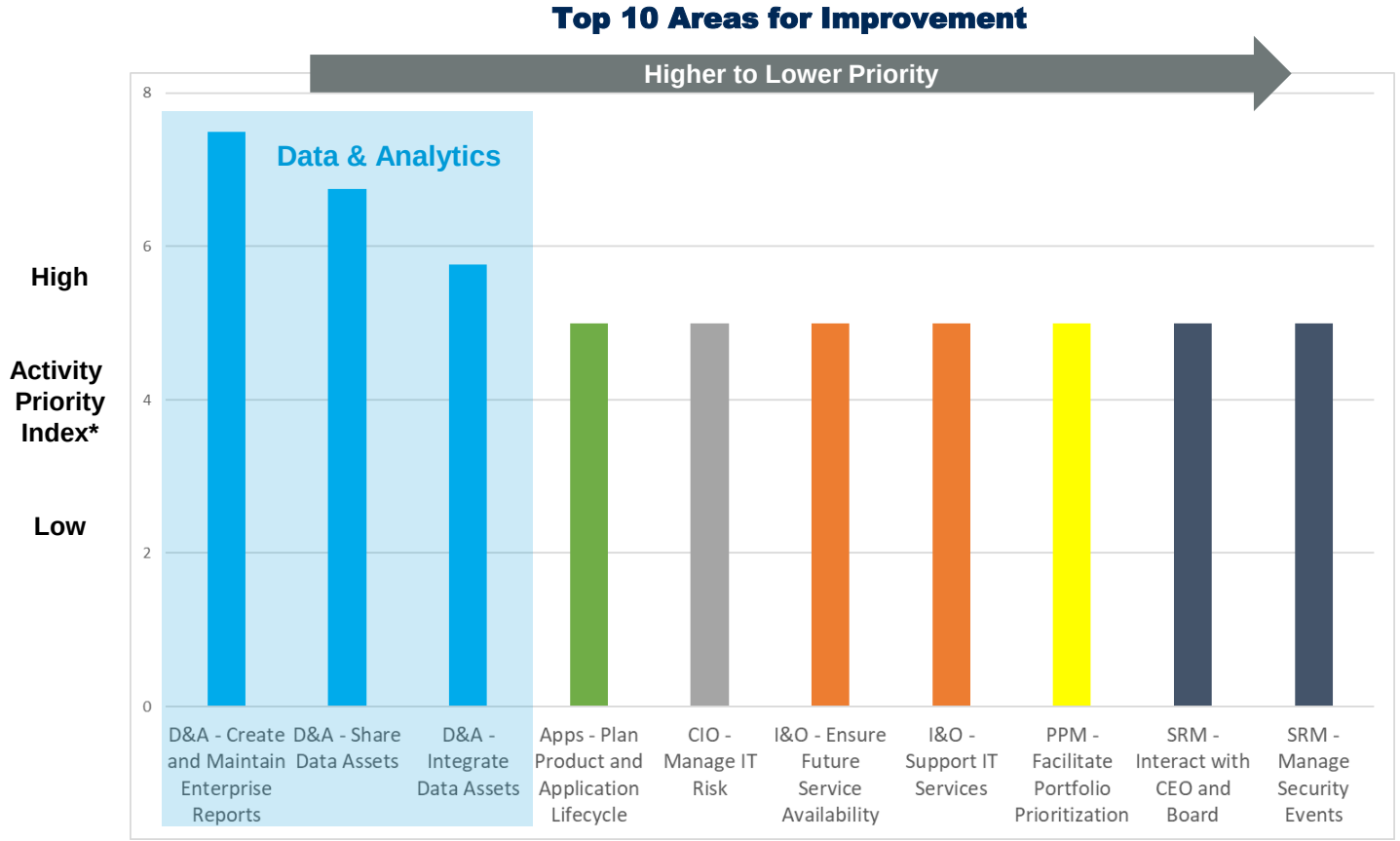
Based on maturity assessment results, opportunities for improvement exist in each domain, however improving Data & Analytics capabilities would add the most value to Toronto Hydro

- 38 of 64 functional activities had a positive Activity Priority Index meaning there is value to Toronto Hydro in improving the capability
- Each in-scope domain had a number functional activities identified for improvement:
  - Chief Information Officer (CIO)[1] = 7
  - Applications = 3
  - Data & Analytics = 5
  - Enterprise Architecture = 5
  - Infrastructure & Operations = 5
  - Program & Portfolio Management = 7
  - IT Security = 6
- When relative importance is considered, improvements to the maturity of the Data & Analytics domain would add the most value to Toronto Hydro

[1] includes Managing IT Governance, Managing IT Finance and Managing Performance



***Activity Priority Index: Activity Priority Index (API) for an activity is computed as importance minus maturity multiplied by its importance. A higher API score indicates a greater priority for improvement to the organization.**

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02
Objectives and Approach

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Gartner understanding of business context and objectives

Context

- Toronto Hydro wanted an independent and objective expert assessment of process maturity of its IT functional areas and to establish a reliable baseline of its overall IT spend and staffing position relative to comparable peer organizations.
- In the short-term, these maturity and cost baseline assessments would provide a fact-based action plan for the organization's regulatory filing and catalyze a roadmap of initiatives that Toronto Hydro's IT Leaders will drive to advance maturity and efficiency levels consistent with Toronto Hydro's Business and IT strategic objectives.
- Longer term, these maturity and cost baseline assessments would form the basis for a transformational strategy as a result of the current state baseline and recommendations of this annual effort.
- Gartner's insights and recommendations will highlight IT capabilities needed for Toronto Hydro to align to existing organizational strategies, increase the pace of value being brought to the business, and enable the promise for future transformational aspirations.

Engagement Objectives

Gartner combined several unique and proprietary Gartner assets and capabilities that give Toronto Hydro a fact-based, objective starting point for its ongoing strategic direction. These capabilities include:

- Gartner Research maturity models aligned to key capability areas that integrate Gartner Research insights and industry leading frameworks to support maturation objectives.
- Gartner's world-leading IT Benchmark database to support a fact-based comparison, using a custom-built peer group to Toronto Hydro's environment, to anchor the current state in key IT enterprise-level cost and staffing measures.

Outcomes of the engagement will include:

- A current state summary of Toronto Hydro's maturity across the organization
- A current state summary of Toronto Hydro's IT spend and staffing levels relative to peers with a comparable environment that will identify optimization opportunities to focus future strategic efforts.
- A set of prioritized recommendations based on the comparative analysis that will advance Toronto Hydro in areas directly impactful to the to IT and business objectives.
- Guidance on appropriate re-measurement periods and the foundation to measure progress objectively.

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Gartner conducted an IT assessment that included a review of process maturity of key IT functions and an enterprise-level benchmark of IT spend and staffing relative to peers

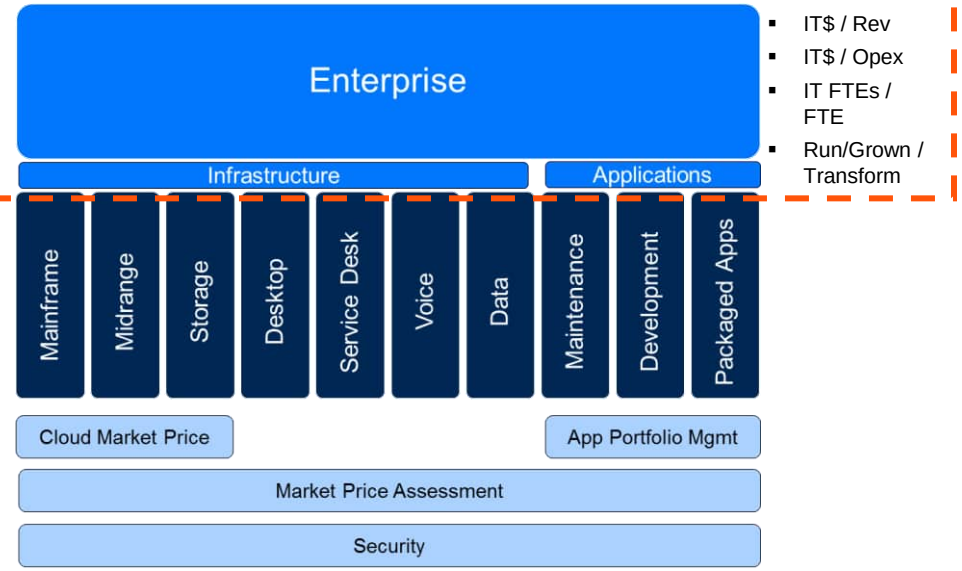
PROCESS MATURITY

Current State Assessment of IT Process Areas:

- CIOs (IT Governance, IT Finance, Performance Mgmt.)
- Applications
- Data & Analytics
- Enterprise Architecture & Technology Innovation
- Infrastructure & Operations
- Program & Portfolio Management
- Security & Risk Management

Scope of Assessment

SPEND AND STAFFING



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03
Enterprise IT Spending & Staffing Analysis

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3.1
IT Spending & Staffing Benchmark – Methodology Overview

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Toronto Hydro's IT Assessment focuses on process maturity and spending and staffing as compared to peer organizations

Section 3.0 Focus

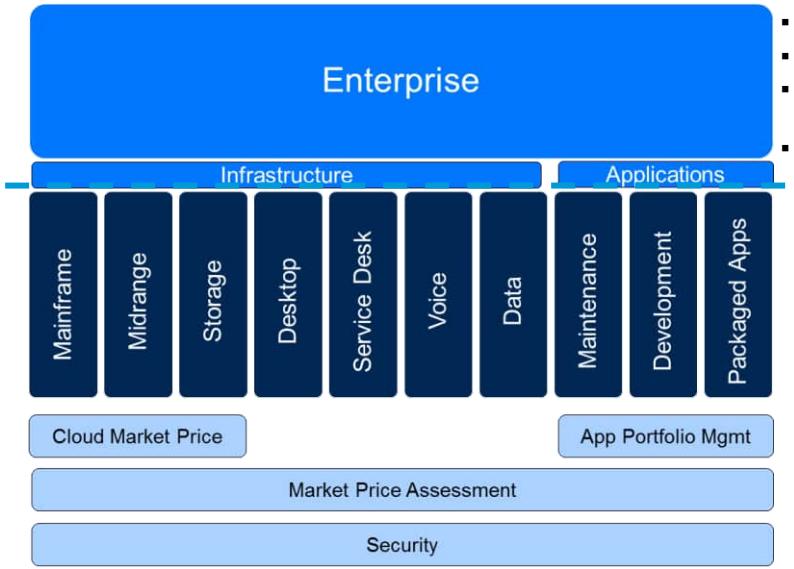
PROCESS MATURITY

Current State Assessment of IT Functional Areas:

- CIOs (IT Governance, IT Finance, Performance Mgmt.)
- Applications
- Data & Analytics
- Enterprise Architecture & Technology Innovation
- Infrastructure & Operations
- Program & Portfolio Management
- Security & Risk Management

+

SPENDING AND STAFFING



- IT$ / Rev
- IT$ / Opex
- IT FTEs / FTE
- Run/Grow / Transform

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Spending & Staffing Benchmark Methodology Overview

Gartner used its industry-leading benchmarking consensus models to evaluate total IT Spending and Staffing relative to a hand selected group of industry peers and IT Key Metrics Data for the Utilities industry.

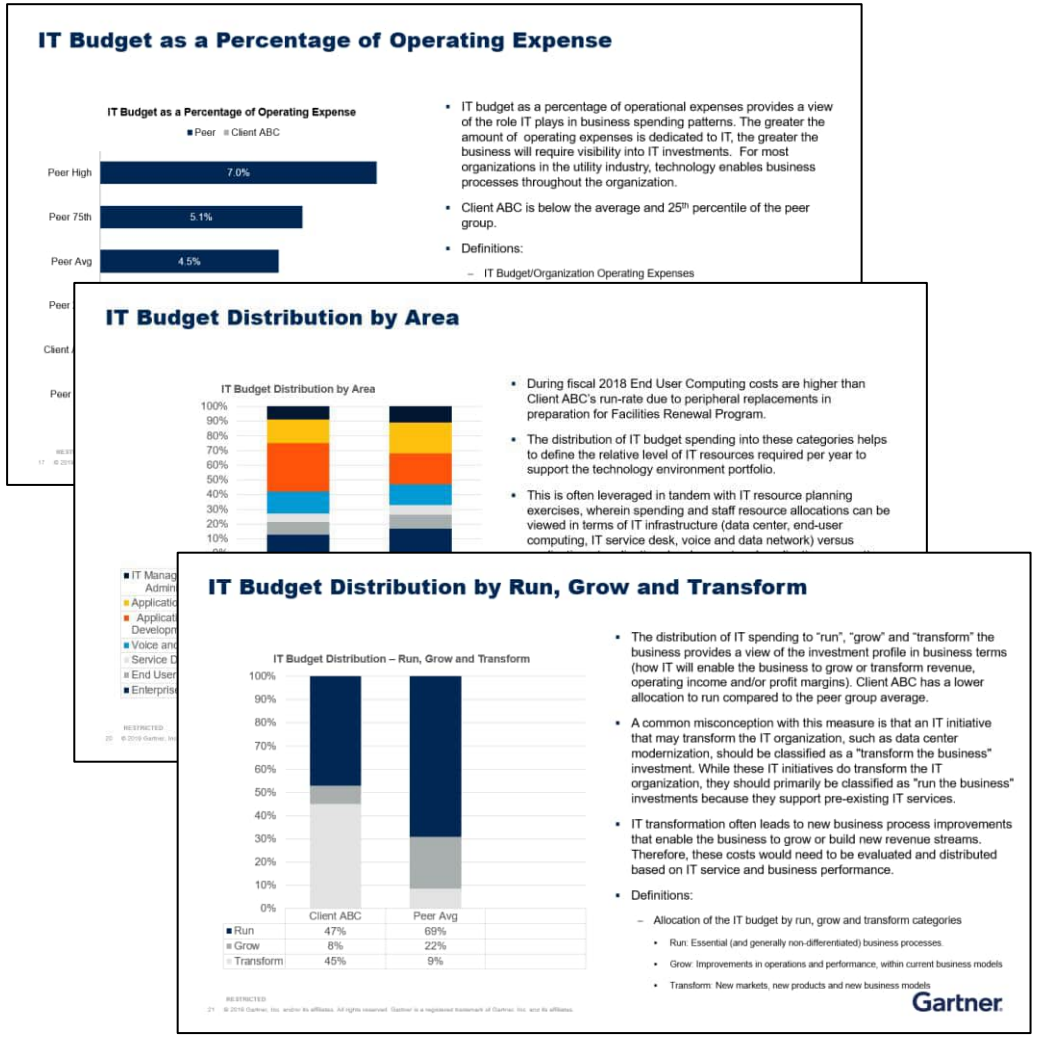
The Enterprise View: IT Spending and Staffing Assessment analysis will provide and compare the following metrics:

Spending Measures

- IT Spending as a % of Revenue
- IT Spending as a % of Operating Expense
- IT Spending Per Employee
- Capital vs. Operational Spending
- Run vs. Grow vs. Transform Spending
- Distribution of IT Spend—Hardware, Software, Personnel, Outsourcing, Other
- Distribution of IT Spend—by IT Function

Staffing Measures

- IT Staff as a % of Company Employees
- Distribution of IT Support—by IT Function



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3.2
Enterprise IT Spending & Staffing Benchmark Results

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Analysis Notes

- Toronto Hydro's data submission for this benchmarking engagement includes:
  - 2022 actuals for Revenue, Operating Expenses and Total Employees
  - 2022 actuals (January to December) for IT Spending & Staffing

- 2017 Toronto Hydro & Peer IT Spending & Staffing data was taken from Gartner's "IT Budget Assessment Final Report" dated March 16, 2018

- Peer Group data is from 2020-2022

- Gartner's IT Key Metrics Data (ITKMD)* is from 2021

* ITKMD is a Gartner Benchmark Analytics solution that delivers indicative IT metrics in a published format as directional insight for IT organizations. This solution represents a subset of the metrics and prescriptive capabilities that is available through Gartner Benchmark Analytics.

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Peer Group Profiles

Selection Criteria	
Primary Criteria	Utilities Industry
Secondary Criteria	Nature of Business (electricity focused, includes distribution within major centers), Total Revenue, Total Operating Expenses, # of Employees and Geography

Custom Peer Group Profile		
Number of Organizations	8	
Geographical Location	Canada, USA, Europe, South America, Australia, New Zealand	
	Toronto Hydro*	**Peer Group Average**
Total Revenue	**$3.60 Billion**	**$3.63 Billion**
Total Operating Expense	**$3.48 Billion**	**$3.08 Billion**
Total Employees	**1,245**	**2,890**

2021 IT Key Metrics Data (ITKMD) Utilities
123
Utilities
Global
2021 ITKMD

* Toronto Hydro data is for fiscal year ending December 31, 2022
** All analysis is in Canadian dollars, using the exchange rate of 1 USD = 1.277 CAD

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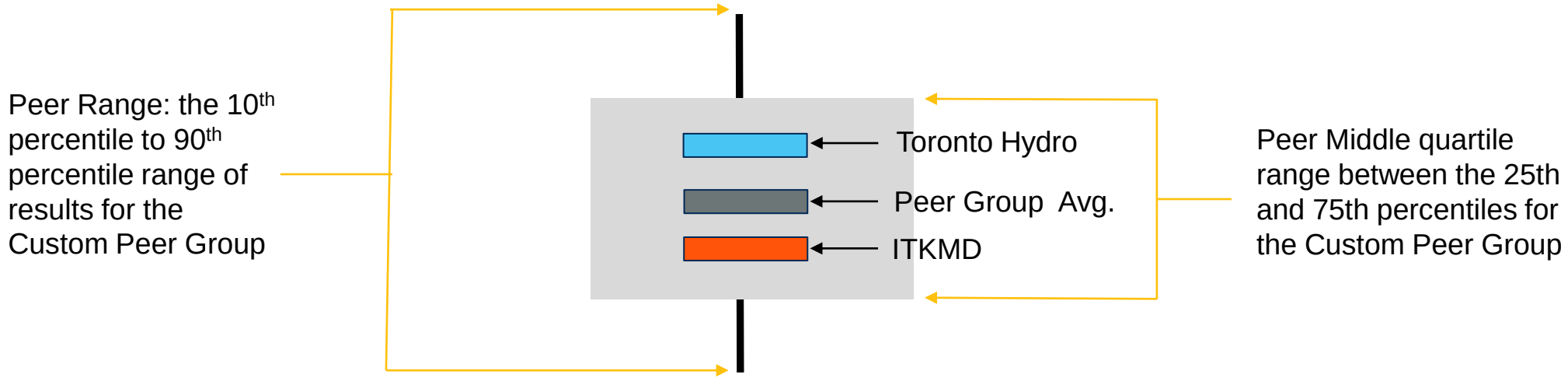
Benchmark Analysis Methodology
Peer Comparisons

Toronto Hydro's results are displayed in comparison with the following reference points:



There are not necessarily "good" or "bad" results for any individual metric.

Differences in spending and staffing metrics derived from this analysis provide insight into current strategic IT investment levels versus your competitive landscape.

These measures should also be considered within the context of your future state organizational objectives.

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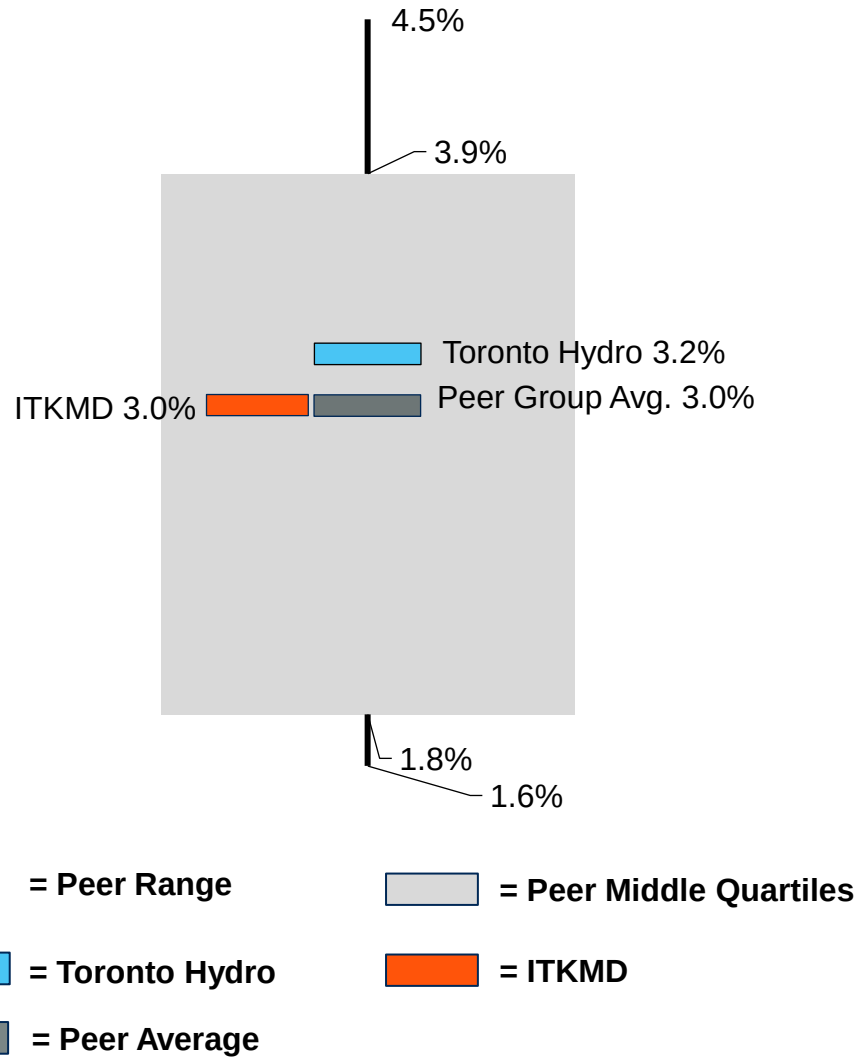
IT Spend as a Percentage of Revenue



Observations

- TH's 2022 IT Spending is a % of Revenue was 3.2% compared to an average of 3.0% for the peer group. This represents a spend level that is very similar to the peer group and ITKMD for Utilities organizations.

Description	• IT spending as a percentage of revenue provides a view of the role IT plays in the spending patterns of the organization. The greater the amount of the operational expenses that is dedicated to IT, typically the greater need for visibility into the IT investments the organization will require.	
Definition	IT Spending includes capital and operations spending for technology during the study period, including labour, software, hardware, telecommunications expenses; includes project spending	
Calculation	IT Spend / Revenue	**Toronto Hydro: $114,759,546 / $3,601,700,000**

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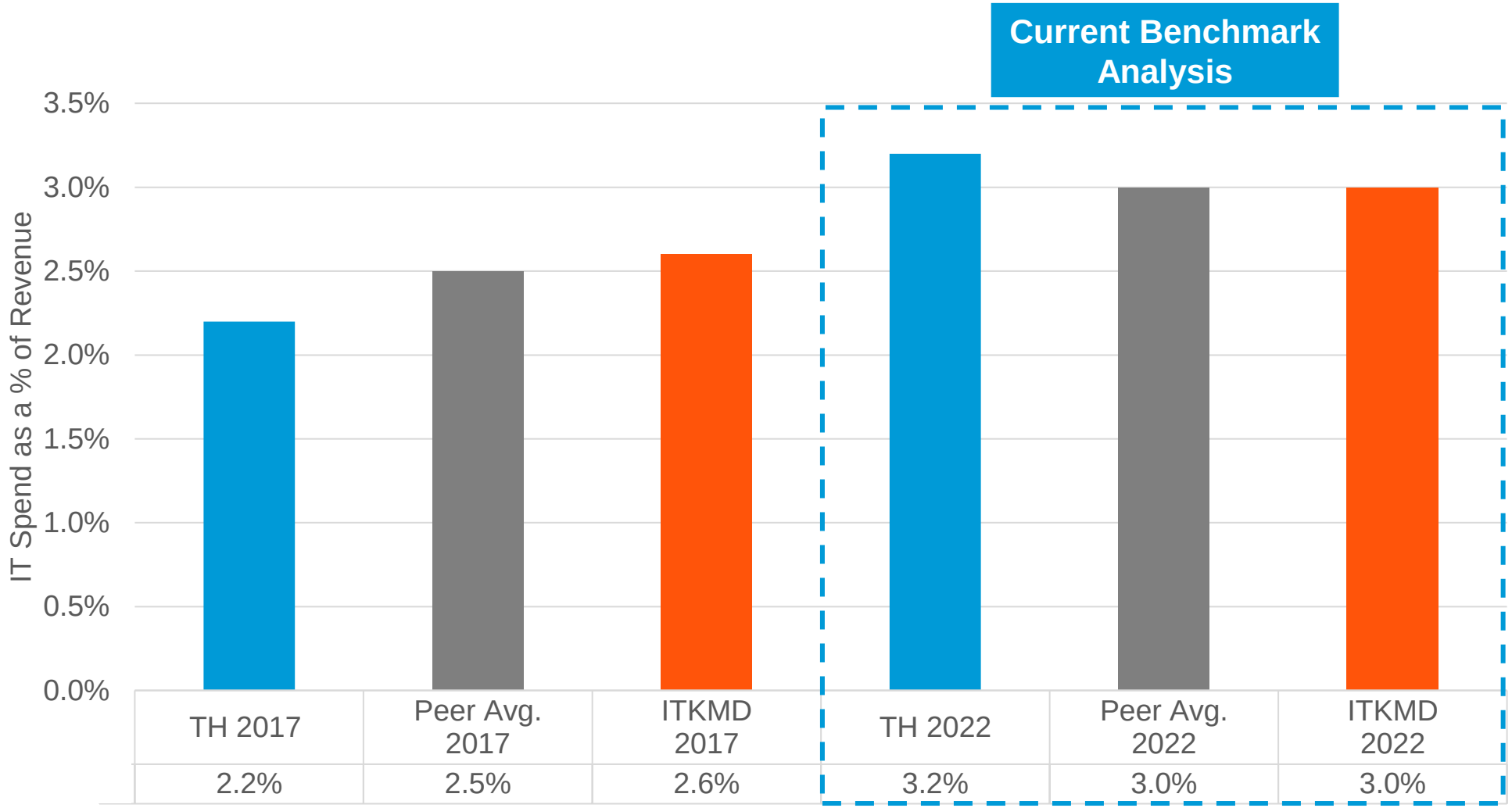
IT Spend as a Percentage of Revenue – Multi Year View



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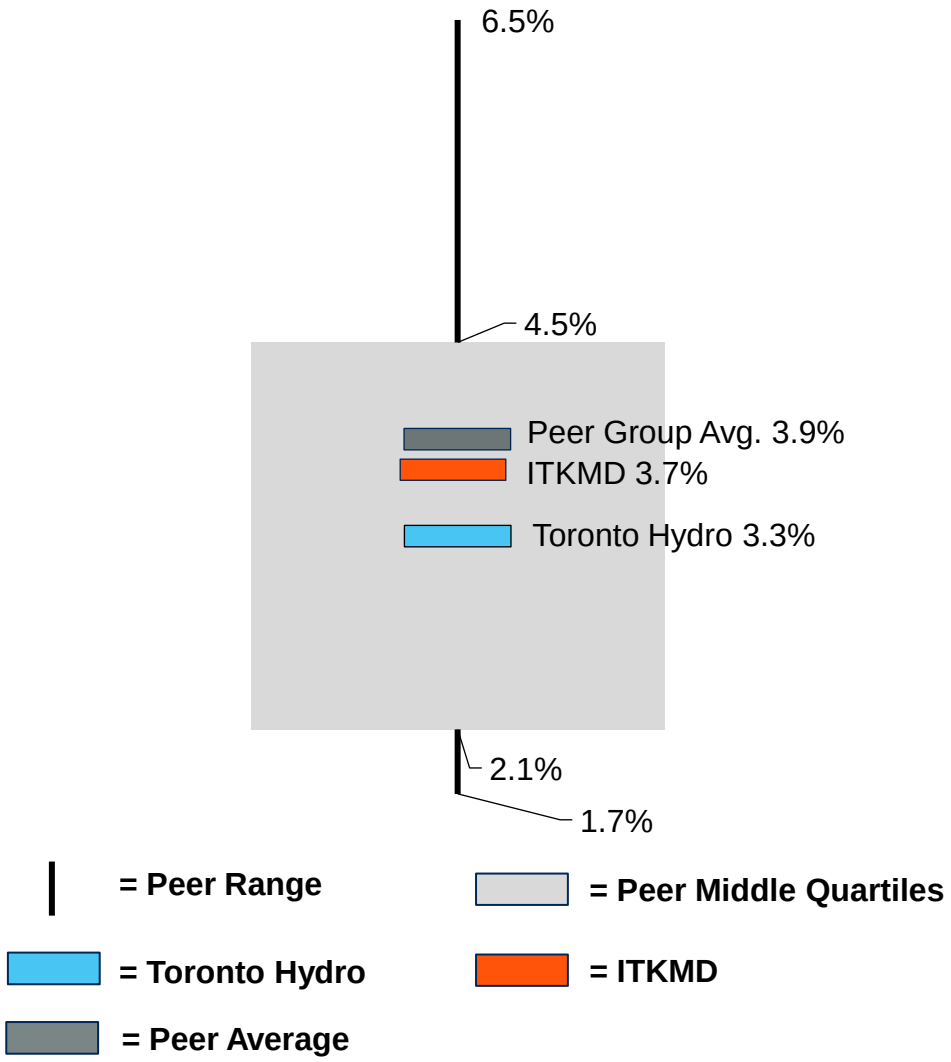
IT Spend as a Percentage of Operational Expense



Observations

- TH's 2022 IT Spending as a % of Operating Expense was 3.3% compared to an average of 3.9% for the peer group. This represents a spend level that is very similar to the peer group (15% less) and ITKMD for Utilities organizations (11% less).

Description	• IT spending as a percentage of operational expenses provides a view of the role IT plays in the spending patterns of the organization. The greater the amount of the operational expenses that is dedicated to IT, typically the greater need for visibility into the IT investments the organization will require.	
Definition	IT Spending includes capital and operations spending for technology during the study period, including labour, software, hardware, telecommunications expenses; includes project spending	
Calculation	IT Spend / Operational Expense	**Toronto Hydro: $114,759,546 / $3,348,600,000**

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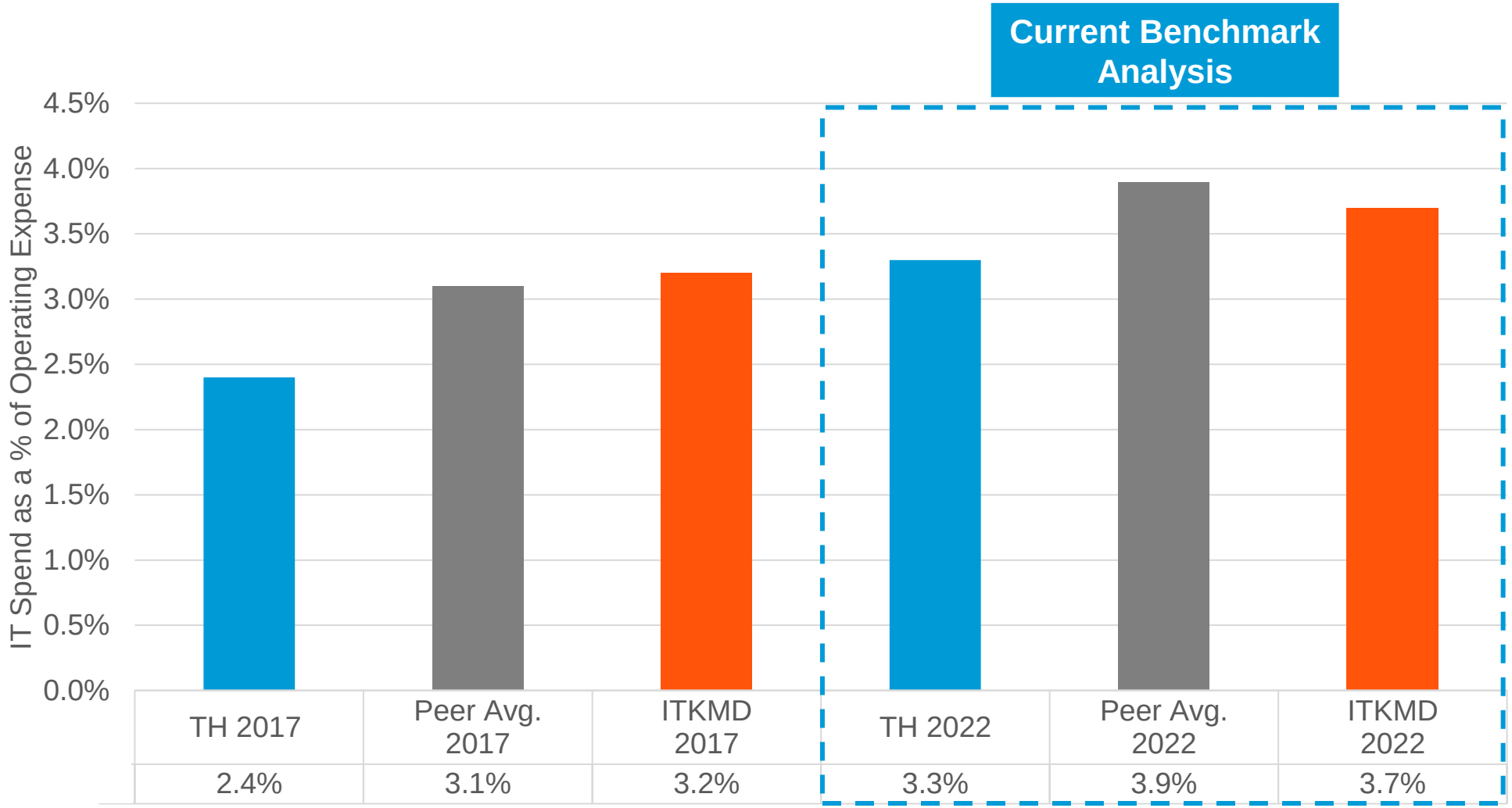
IT Spend as a Percentage of Operating Expense – Multi Year View



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Employees versus Users at Toronto Hydro

- Gartner typically collects the number of employees for an IT Enterprise Benchmark and bases two standard metrics on employee count: IT Spending per Employee and IT FTEs as a Percentage of Employees.
  - Many of the IT departments Gartner works with, and has in our peer benchmark database, typically do not know the number of contractor labour or level of outsourcing in the lines of business, and Gartner does not normally collect a number of users.
- As with other measures comparing IT spending to business measures, these two metrics can be influenced by both the numerator and denominator.
- For TH, these two metrics appear to be skewed compared to the peer group when based on the employee count.
- As a test of this assumption, Gartner focused the analysis using TH number of Users rather than Employees and compared results.
- While metrics based on Employees are 116% to 133% more than the peer group, the results based on Users are between 29% and 35% less than the peer group.
  - The metrics based on Users are in line with the other metrics (IT Spending as a Percentage of Revenue and Operational Expense), supporting the assumption that it is TH employee count, not IT spending or staffing that drives the results on slides 24 and 26.

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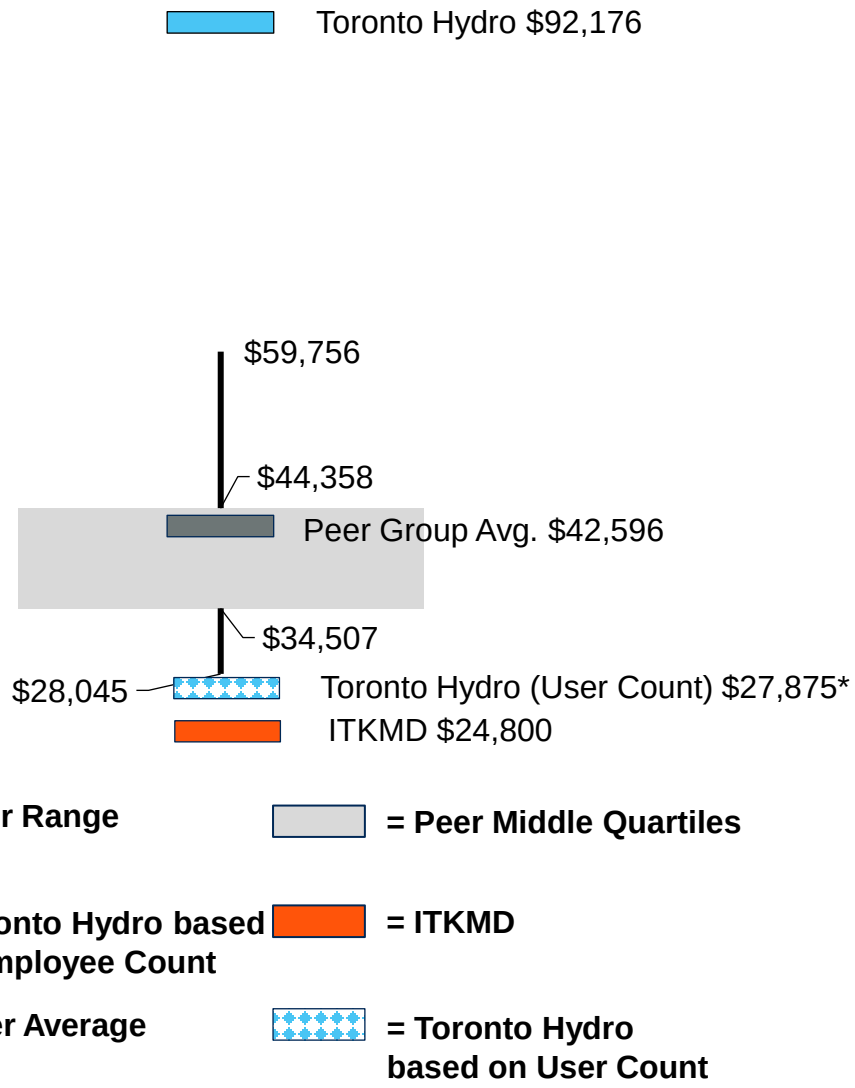
IT Spend per Employee



Observations

- IT Spend per User for TH is 35% less than the peer group average of $42,596, and similar with the ITKMD average for the utilities industry
- Given TH's usage of contract employees, Gartner has used the IT spend per User metric rather than IT spend per Employee

Description	• IT spending per employee provides insight into the amount of technology support an organization's workforce receives. • High spending can imply higher levels of automation and/or higher investment in IT in general. Low spending levels can be related to higher overall staffing levels and or lower IT investment than peers. • Large variations within industry groups can represent different business models for service or product delivery.	
Definition	IT Spending includes capital and operations spending for technology during the study period, including labour, software, hardware, telecommunications expenses and includes project spending. Organization Employees includes staff, exclusive of Contractors.	
Calculation	IT Spending / Organization Employees	**Toronto Hydro: $114,759,546 / 1,245**

* Gartner's benchmarking definition for "employees" does not include contractors. This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors.

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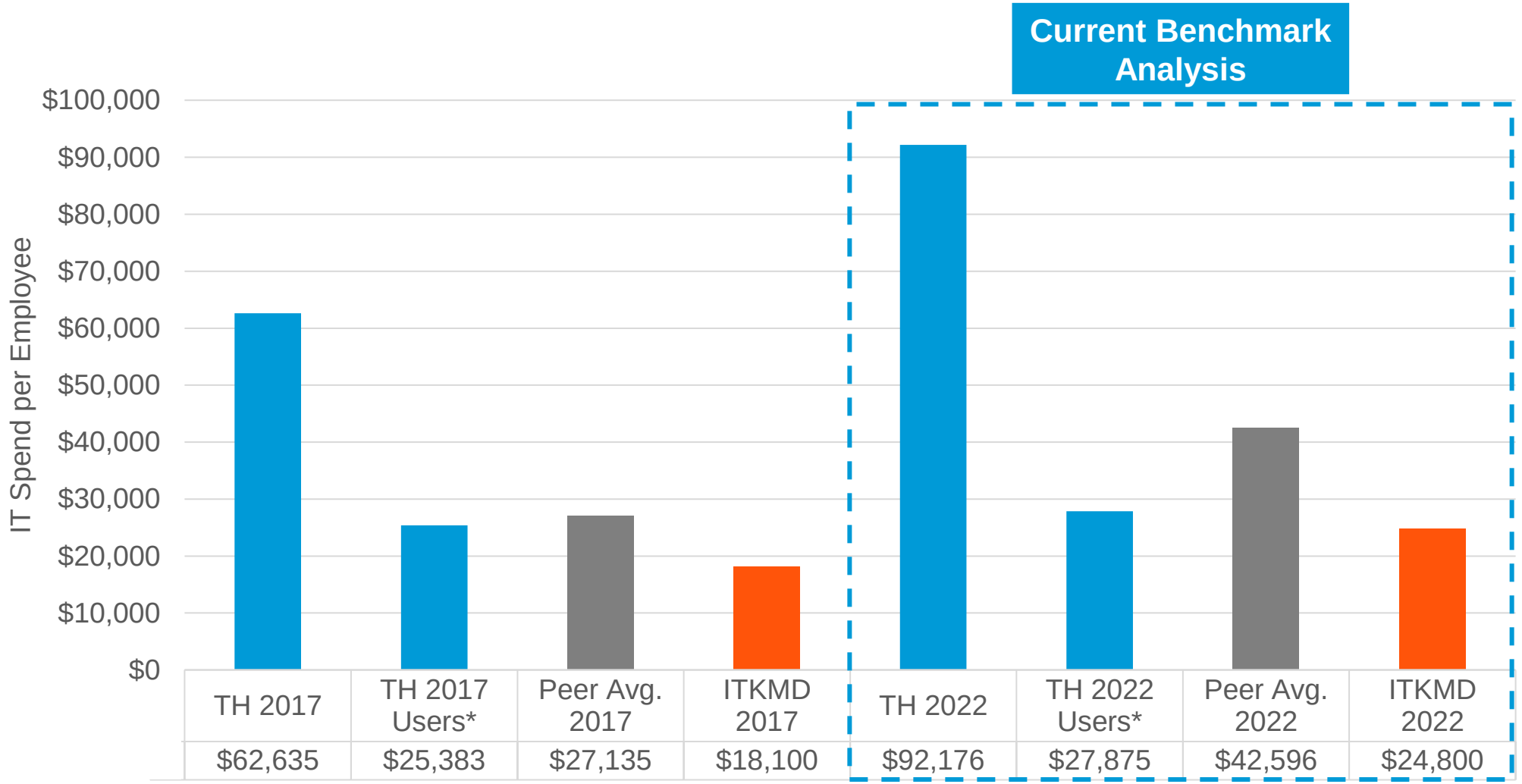
IT Spend per Employee – Multi Year View



* Gartner's benchmarking definition for "employees" does not include contractors. This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors.

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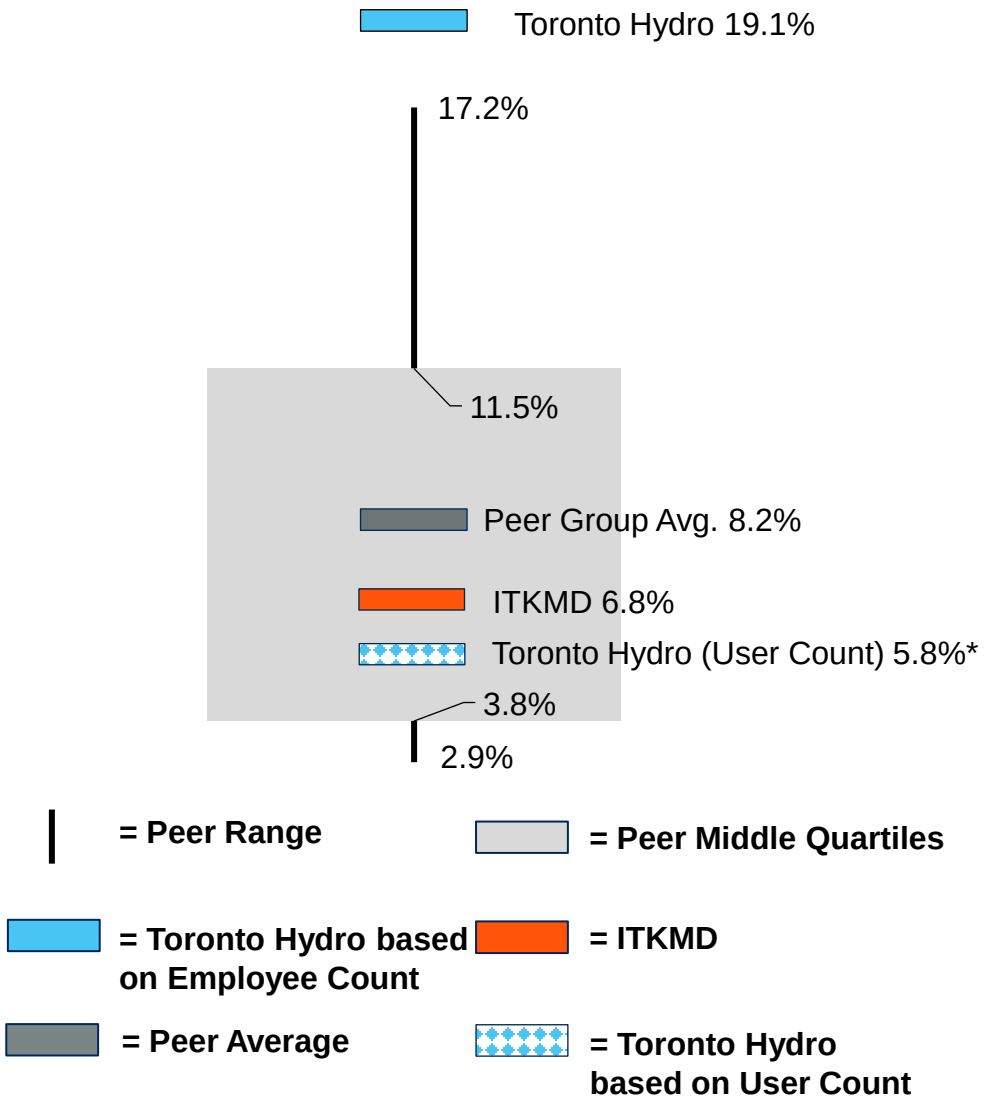
IT FTEs as a Percentage of Total Employees



Observations

- IT FTEs as a % of Total Users is 29% below the peer group average and 15% below the ITKMD average for the utilities industry
- Given TH's usage of contract employees, Gartner has used the IT FTEs as a % of Users metric rather than IT FTEs as a % of Employees*

Description	• The percentage of IT FTEs in the organization compared to the total number of employees is a key measure of how critical IT support is to the business. This measure can be heavily influenced, however, by the level of outsourcing an organization may have. • Organizations with high levels of manageability and automation should require fewer operations staff. Manual processes and lack of standards will increase the number of IT FTEs needed.	
Definition	IT FTEs includes in-house and contractor FTEs, does not include managed services adjusted FTEs. Organization Employees includes employees, exclusive on Contractors.	
Calculation	IT FTEs / Organization Employees	**Toronto Hydro: 238 / 1,245**

* Gartner's benchmarking definition for "employees" does not include contractors. This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors.

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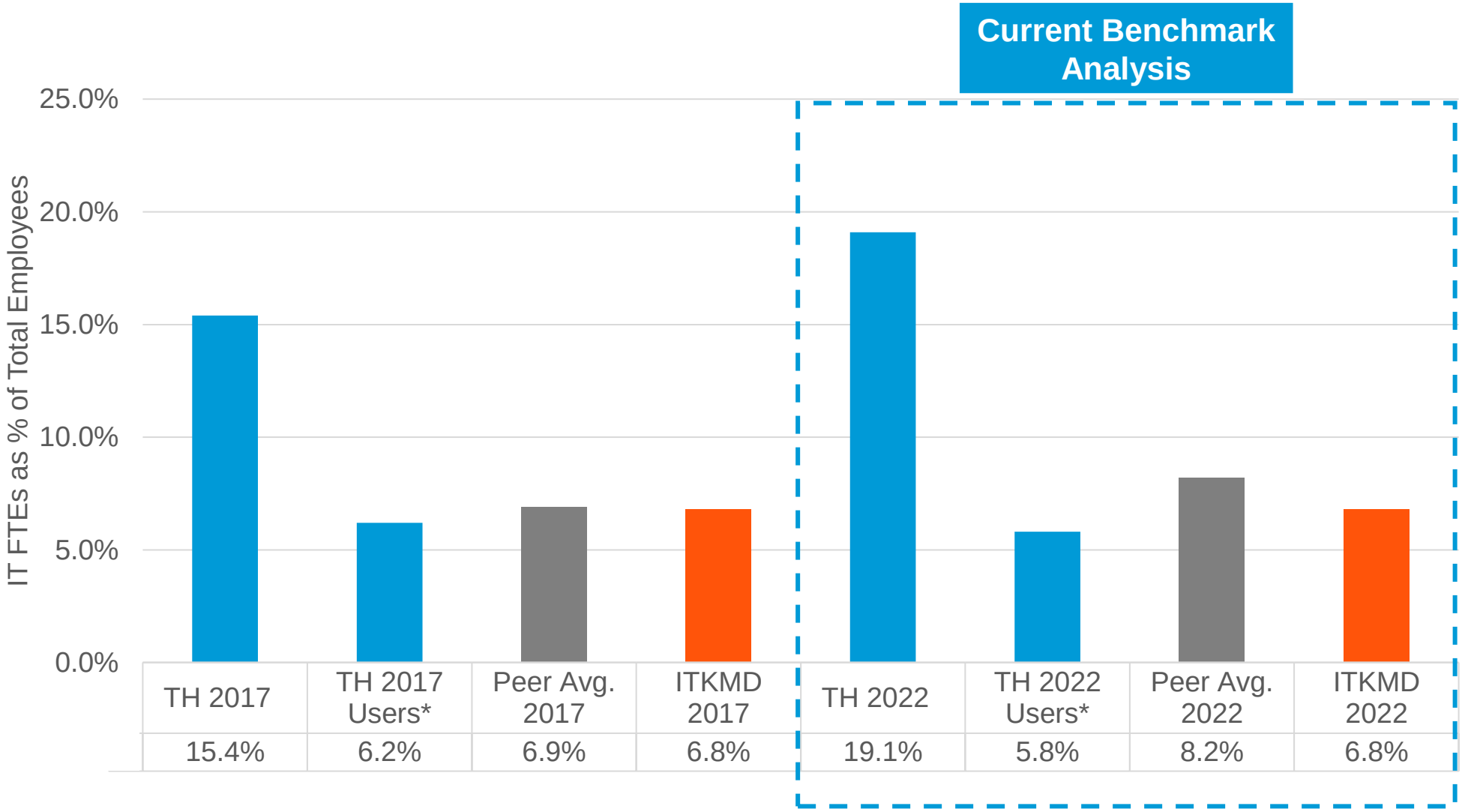
IT FTEs as Percentage of Total Employees – Multi Year View



* Gartner's benchmarking definition for "employees" does not include contractors. This metric considers "users" as a proxy for employees due to Toronto Hydro's use of contractors.

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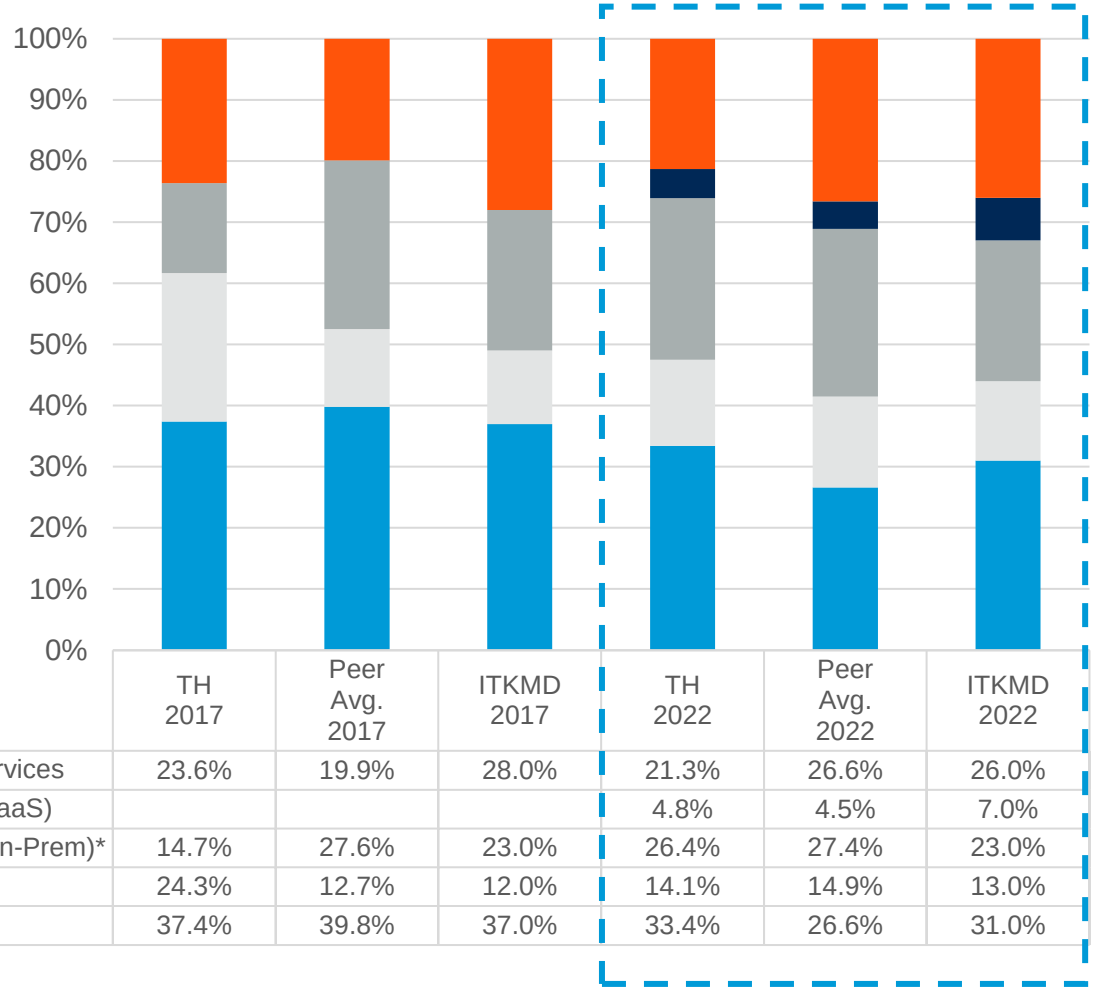
IT Spend Distribution by Cost Category

Current Benchmark Analysis



	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
External Services	23.6%	19.9%	28.0%	21.3%	26.6%	26.0%
Software (SaaS)				4.8%	4.5%	7.0%
Software (On-Prem)*	14.7%	27.6%	23.0%	26.4%	27.4%	23.0%
Hardware	24.3%	12.7%	12.0%	14.1%	14.9%	13.0%
Personnel	37.4%	39.8%	37.0%	33.4%	26.6%	31.0%

Observations

- Toronto Hydro relies less on Outsourcing (21.3% of IT spend in 2022) than the peer group (26.6%). This is balanced by a higher allocation to Personnel (33.4% of IT spend in 2022) as compared with the peer group (26.6%).
- Allocation to both hardware (14.1% of IT spending in 2022) and software (31.2% of IT spending in 2022) is virtually the same as the peer group.

Description	• This measure can be helpful in adding context to the IT investment strategy from a sourcing perspective, in terms of accounting-based resources that may be insourced versus services delivered by a third party. • As an organization increases or decreases the level of outsourced services, it may find an inverse effect in its associated personnel, hardware and/or software expenditures, depending on the scope of services retained and on requirements.
Definition	Allocated IT Spending among the different cost categories

* In 2017 Gartner benchmarking did not separate Software as a Service (SaaS) from On-Premises Software. 2017 “Software (On-Prem)” includes all software spending.

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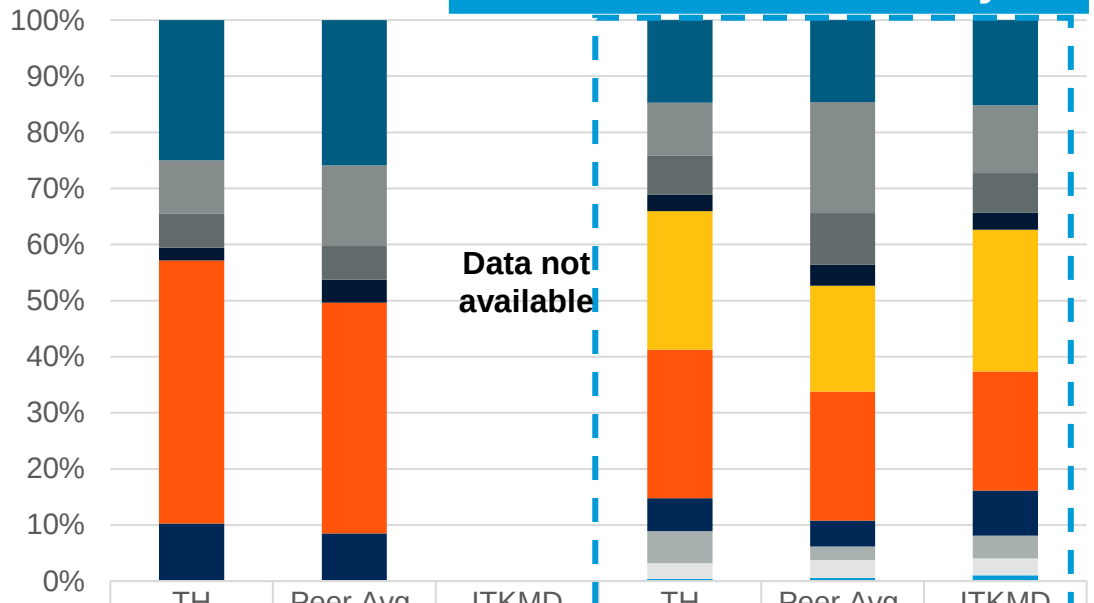
IT Spend Distribution by IT Functional Area

Current Benchmark Analysis



	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
Enterprise Computing	25.0%	25.9%		14.7%	14.6%	15%
Network	9.5%	14.4%		9.5%	19.8%	12%
Workplace Services	6.1%	6.0%		6.9%	9.2%	7%
IT Service Desk	2.3%	4.1%		3.0%	3.8%	3%
Application Development				24.7%	18.9%	25%
Application Support*	46.9%	41.2%		26.5%	23.0%	21%
Governance & Service Management**	10.3%	8.5%		5.9%	4.6%	8%
IT Security				5.7%	2.4%	4%
IT Ops. Mgmt				2.8%	3.2%	3%
Ser. Con't / DR				0.4%	0.6%	1%

Observations

- Overall allocation to Applications spending is more than the peer group (51.2% of IT spend versus 41.9%). This is normal during a period of transformation. Applications spending is the largest contributor to the overall increase in IT spending when compared with 2017, up $18 million.
- The allocation to IT Management & Administration (which includes Governance & Service Management, IT Security, IT Operations Management and Service Continuity / Disaster Recovery) was 14.8%, as compared to 10.8% for the peer group. Increased investment in Cyber Security services and capabilities is the main reasons for this variance.

Description	• This information is often leveraged in tandem with IT resource planning exercises, wherein resource allocations can be viewed in terms of IT infrastructure versus applications versus IT overhead. • While this measure is helpful in identifying relative volumes of IT resource consumption by IT functional area, as compared to Peers, it does not aid in identifying whether resources are being leveraged in a cost-effective or productive manner.
Definition	Allocated IT Spending among the different functional areas

* In 2017 application development and application support were not separated
** In 2017 Governance & Service Management included IT Security, IT Operations Management and Service Continuity / Disaster Recovery

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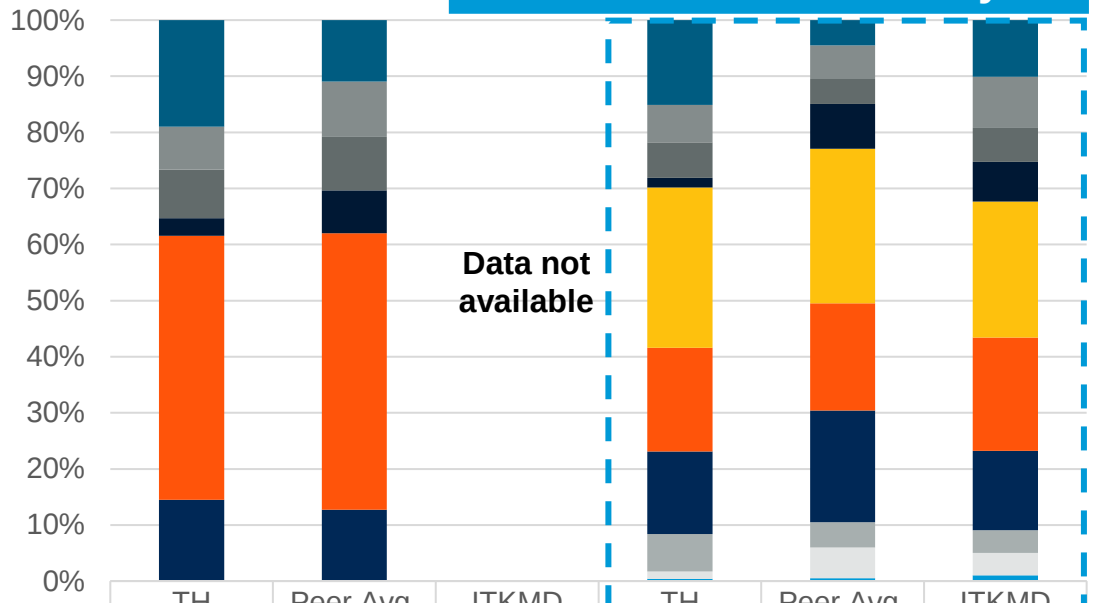
IT FTEs Distribution by IT Functional Area

Current Benchmark Analysis



	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
Enterprise Computing	19.0%	10.9%		15.1%	4.5%	10%
Network	7.7%	9.9%		6.7%	6.0%	9%
Workplace Services	8.7%	9.5%		6.3%	4.4%	6%
IT Service Desk	3.1%	7.6%		1.7%	8.0%	7%
Application Development				28.6%	27.5%	24%
Application Support*	47.2%	49.2%		18.5%	19.1%	20%
Governance & Service Management**	14.5%	12.7%		14.7%	19.9%	14%
IT Security				6.7%	4.5%	4%
IT Ops. Mgmt				1.3%	5.5%	4%
Ser. Con't / DR				0.4%	0.5%	1%

Observations

- IT FTE distribution for TH is similar to the peer group with the exception of Enterprise Computing (235% more), ITSD (78% less) and IT Operations Management (76% less)
- TH leverages on-site data centers supported by IT FTEs, no cloud infrastructure is used

Description	• By viewing human resources (IT FTEs) within the context of the total portfolio, organizations are able to identify which environment is the most labour- intensive as a % of the IT labour pool. Typically, application activities (development and support) demand the most resources from both cost and staffing perspectives. The degree to which an organization outsources should be considered alongside such staffing metrics.
Definition	Distributes In House and Contractor IT FTEs among the different functional areas

* In 2017 application development and application support were not separated

** In 2017 Governance & Service Management included IT Security, IT Operations Management and Service Continuity / Disaster Recovery

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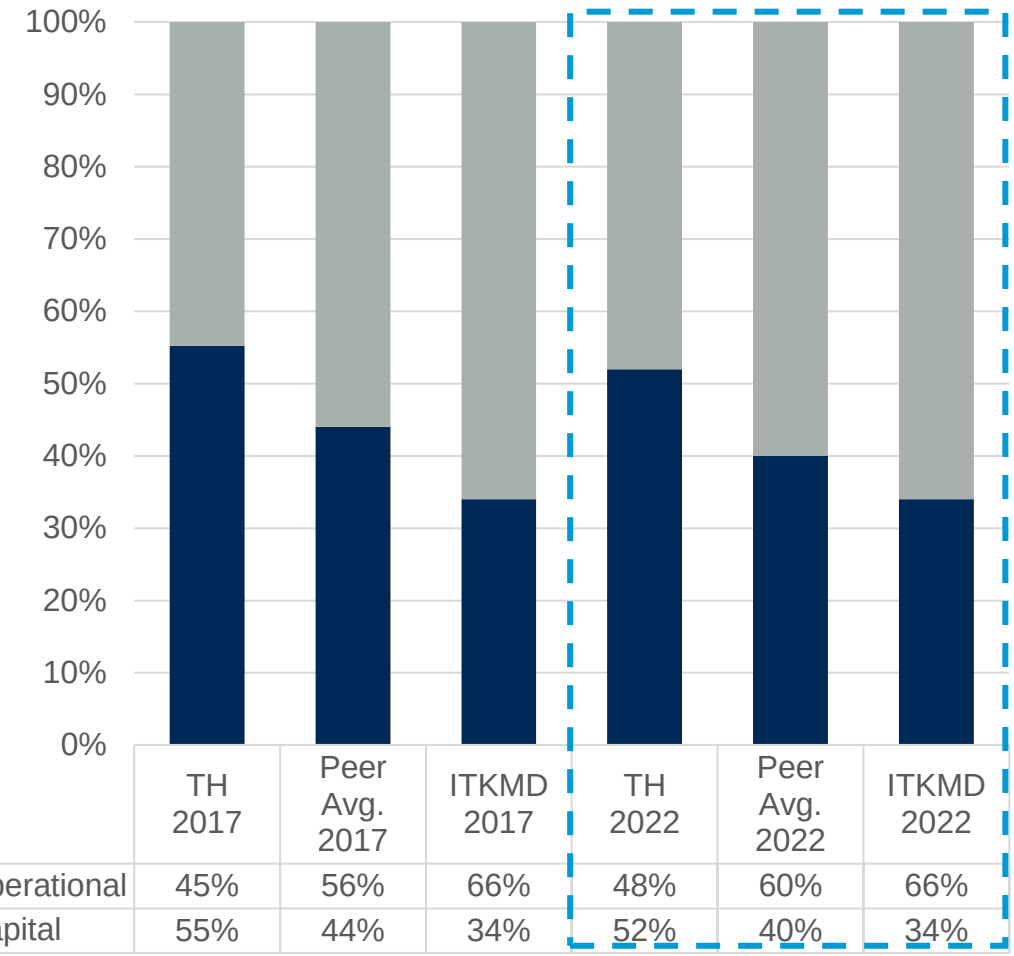
IT Spend Distribution – Operations vs. Capital

Current Benchmark Analysis



	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
Operational	45%	56%	66%	48%	60%	66%
Capital	55%	44%	34%	52%	40%	34%

Observations

- TH allocated more of its IT spending to capital (52%) than the peer group average of 40%
- Applications and Infrastructure are increasingly cloud-based, creating an escalating shift away from more traditional capital-based models to operational funding.
- There can be unanticipated or overlooked operating budget increases as a result of Software as a Service (SaaS) and Infrastructure as a Service (IaaS) contracts. The resultant shift from capital expenditure (CapEx) to operating expenditure (OpEx) can cause budgetary and cost management pressures.

Description	• IT capital expenses vs. operational expenses helps to portray the investment profile for an organization in a given year.
	• Organizations with a higher capital spending may…
	  ○ Be investing heavily in strategic IT infrastructure
	  ○ Have reached a planned point of investment in their infrastructure lifecycle
	  ○ Not have been managing asset investments well (i.e., “catching up”)
	  ○ Simply have a more aggressive capitalization policy
	• The break out of Run, Grow, Transform spending that follows may provide more insight

Definition	Distribution of IT Operational spending versus Capital spending

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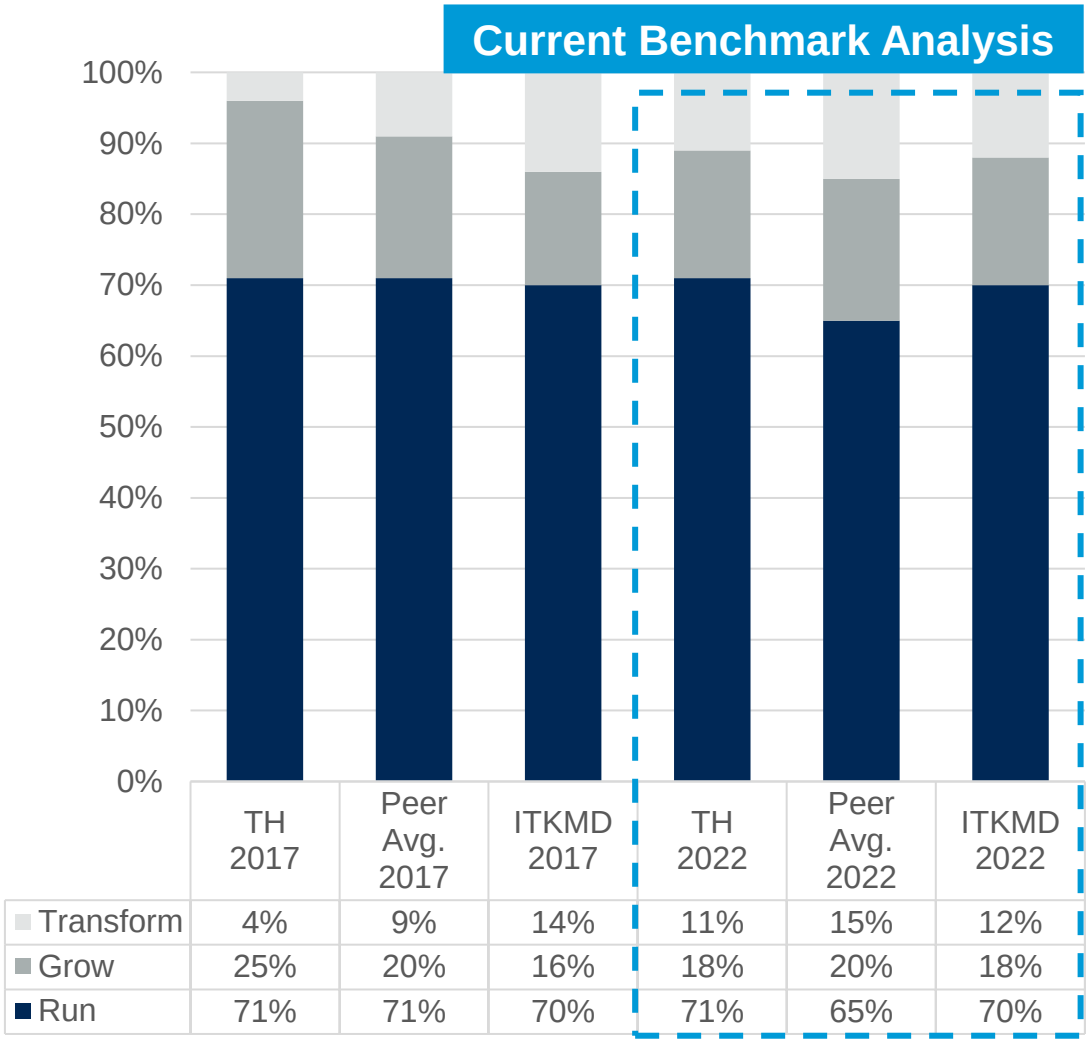
IT Spend Distribution by Run, Grow and Transform



	TH 2017	Peer Avg. 2017	ITKMD 2017	TH 2022	Peer Avg. 2022	ITKMD 2022
Transform	4%	9%	14%	11%	15%	12%
Grow	25%	20%	16%	18%	20%	18%
Run	71%	71%	70%	71%	65%	70%

Observations

- In 2022, Toronto Hydro allocated 29% of IT Spending to “change the business” activities (18% Grow and 11% Transform), similar to the peer group average of 35% and the 2017 level of 29%
- However, TH allocated more to the “Transform” category in 2022 (11%) compared with 2017 (4%). This is the result of digital transformation investments.

Description	• The distribution of IT spending provides a view of the investment profile in business terms (how IT will enable the business to grow or transform revenue, operating income and/or profit margins)
Definition	Allocation of IT Spending by Run, Grow and Transform, where: • Run: Essential (and generally non-differentiated) business processes. • Grow: Improvements in operations and performance, within current business models • Transform: new services and new operating models

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04
IT Maturity Assessment Analysis

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Toronto Hydro's IT Assessment is focused on process maturity and spending & staffing as compared to peer organizations

Section 4.0 Focus

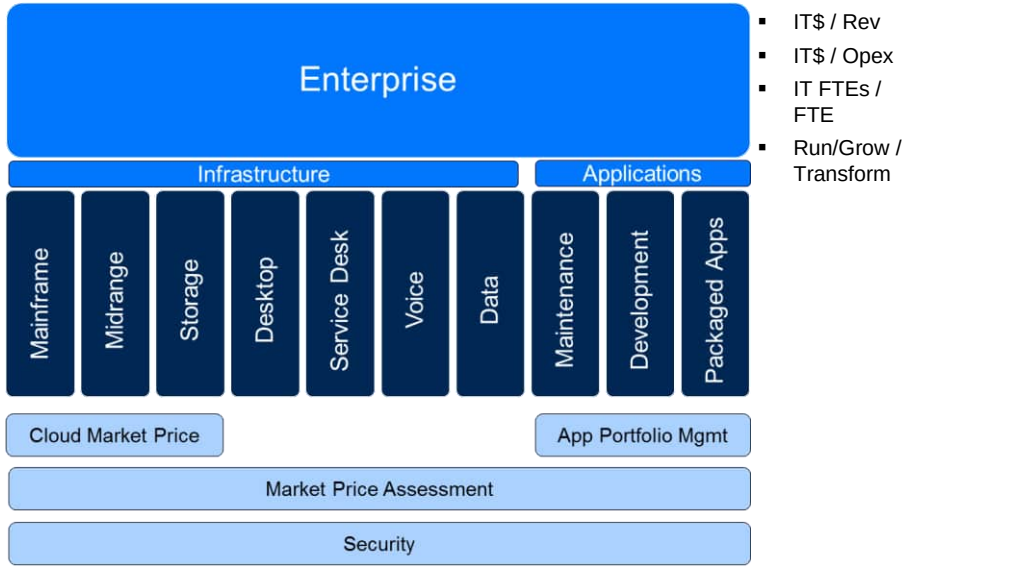
PROCESS MATURITY

Current State Assessment of IT Functional Areas:

- CIOs (IT Governance, IT Finance, Performance Mgmt.)
- Applications
- Data & Analytics
- Enterprise Architecture & Technology Innovation
- Infrastructure & Operations
- Program & Portfolio Management
- Security & Risk Management

+

SPENDING AND STAFFING



- IT$ / Rev
- IT$ / Opex
- IT FTEs / FTE
- Run/Grow / Transform

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IT Maturity Assessment Methodology Overview

Gartner used its industry-leading IT maturity models (IT Score) to evaluate Toronto Hydro's IT capabilities across the in-scope domains relative to peers. IT Score provides insights on maturity and importance to gain perspective on the highest priority activities to improve.

Maturity

- Measured on a scale ranging from 1 (low) to 5 (high), maturity measures how advanced an activity is relative to Gartner's best-practice research.

Importance

- Measured on a scale ranging from 1 (unimportant) to 5 (critical) based on participants' inputs, importance measures how important each activity is to the overall effectiveness in meeting objectives.

Prioritization

- Activity priority index (API) identifies the activities that should be prioritized for improving maturity. It is defined as the average gap between importance and maturity and is computed for each activity and weighted by its average importance.

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Analysis Notes

- Toronto Hydro completed Gartner's IT Score surveys to baseline current maturity and importance levels
- Results were reviewed and calibrated across IT domains in working sessions with Gartner and the Toronto Hydro project team

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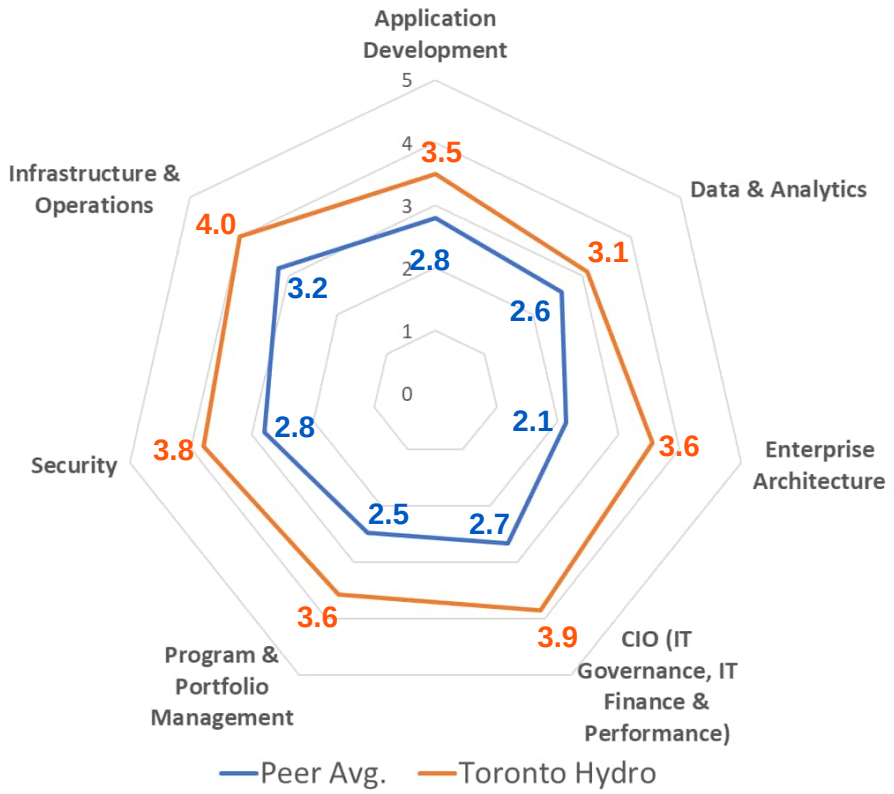
The IT capability assessment showed that Toronto Hydro's maturity across all domains is slightly higher than peers

- Toronto Hydro was compared to a peer group of 9 to 14 organizations (depending on data available for each IT domain) from the energy and utility industry with revenues between $1 billion and $3 billion USD
- 64 functional activities across 7 IT domains were assessed by comparing Toronto Hydro's current state (as defined by IT domain leadership) to Gartner's best practices.
- Toronto Hydro's overall IT maturity was 3.6 compared to 2.7 for the peer group. Higher levels of maturity were seen across all domains included in the scope of the assessment. This reflects Toronto Hydro's focus and investment in maturing IT capabilities.
- Within Toronto Hydro, Infrastructure & Operations (I&O) was the most mature domain at 4.0 and Data & Analytics (D&A) was the least mature at 3.1. I&O is a well-established domain whereas D&A is relatively new, hence these results are not surprising.
- Steady efforts have been made to improve capabilities within the Program & Portfolio Management, Enterprise Architecture and IT Security domains.
- Assessing maturity results relative to peers is interesting, however, comparing current maturity levels with how important the capability is for the organization to achieve its overall objectives is more important (see next page).

IT Domain Maturity Levels

Toronto Hydro's Overall IT Maturity Level: 3.6

Peer Maturity Level: 2.7



Maturity scores are assessed on a scale from 1-5, with the score of 5 representing Gartner's best practices for the IT domain

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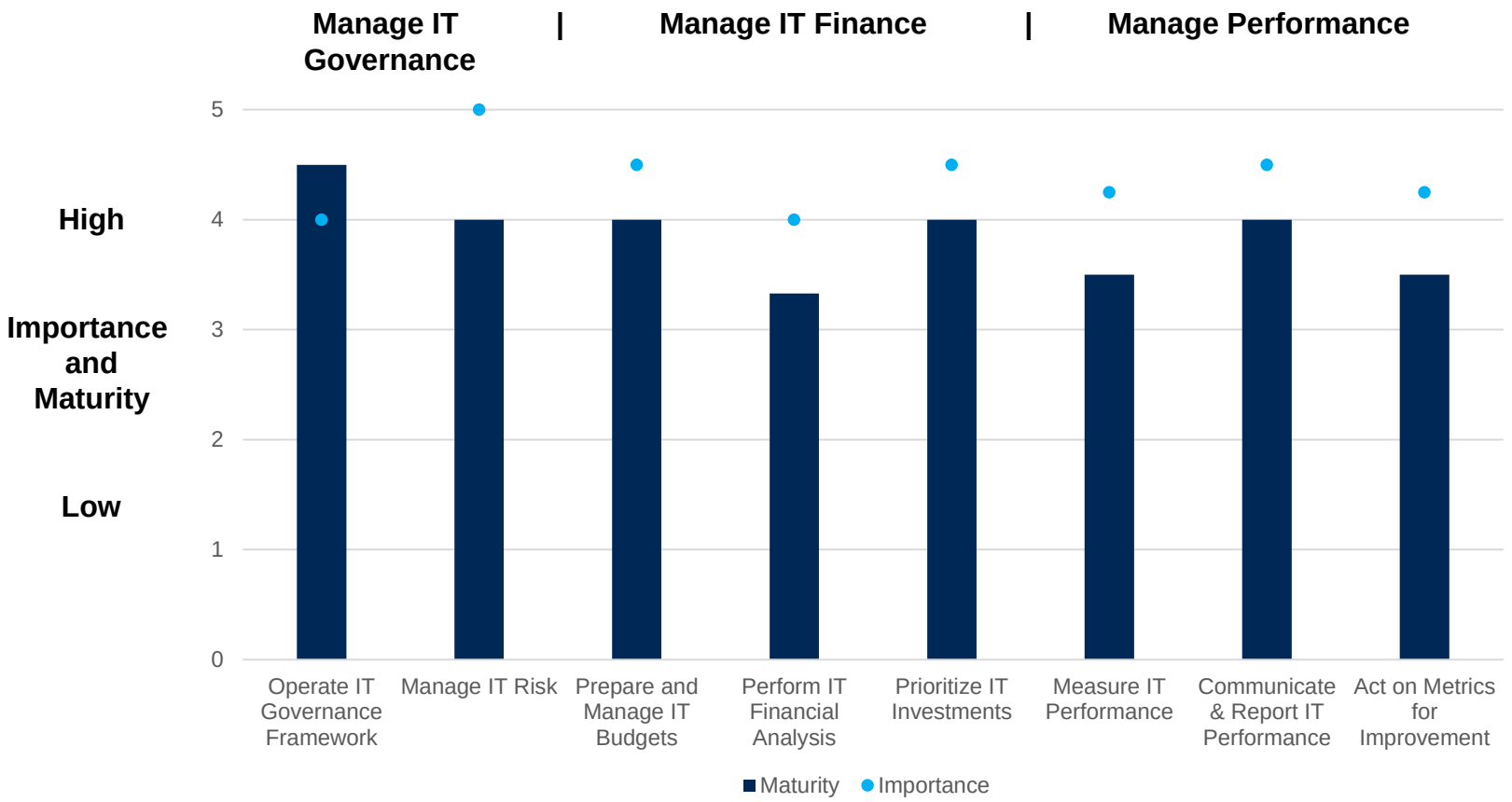
Chief Information Officer (CIO)
How Do Maturity and Importance Compare?



Lowest Maturity
- Perform IT Financial Analysis
- Measure IT Performance
- Act on Metrics for Improvement

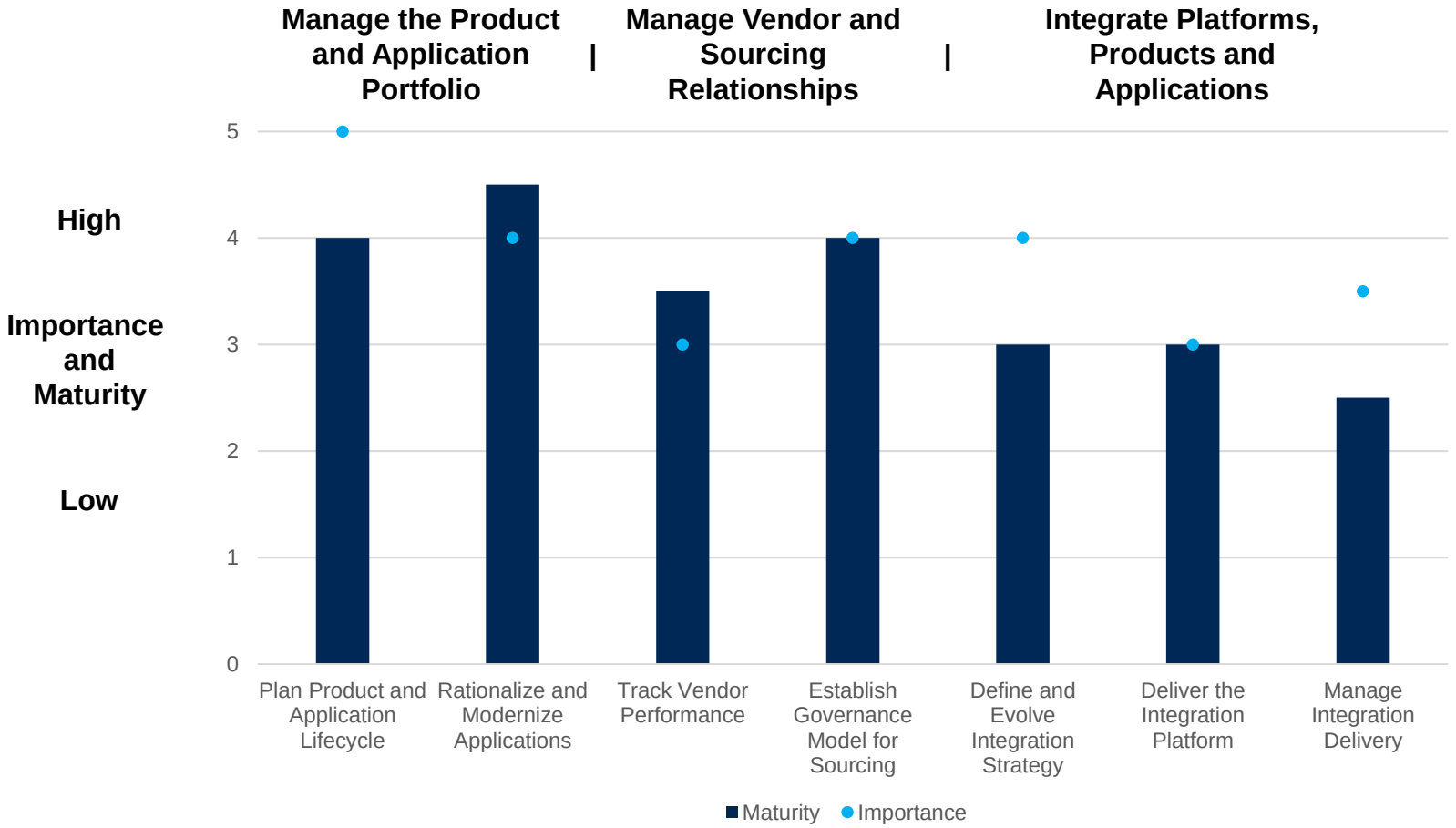
Highest Importance
- Manage IT Risk
- Prepare and Manage IT Budgets
- Prioritize IT Investments

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Chief Information Officer (CIO)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Manage IT Governance	Operate IT Governance Framework	4.5	4: the IT governance framework is adaptive and enables the agility of I&T decision making across the enterprise 5: the IT governance framework enabled autonomous I&T decision making across the ecosystem, digital platform and enterprise
	Manage IT Risk	4.0	4: an IT risk discipline considers both risk and reward on I&T decision making from a business and perspective. The business carried formal accountability for IT risk as part of its enterprise risk management.
Manage IT Finance	Prepare & Manage IT Budgets	4.0	4: I&T budgets are aggregated across the enterprise and support products. Budgets are compared with actual performance and revised at least quarterly to accommodate changing business priorities
	Perform IT Financial Analysis	3.3	3: IT performs cost analysis on all I&T across the enterprise as part of the formal monthly or quarterly IT management process. I&T spending by service is well understood by business unit and includes measurement and reporting against business-based SLAs. Spending optimization initiatives include joint business and IT savings 4: IT streamlines and automates financial analysis, which emphasizes growth and competitive differentiation. IT performs financial analysis at the I&T product level in terms that the business understands. IT and business leaders follow an adaptive, iterative, organization-wide value-optimization process
	Prioritize IT Investments	4.0	4: the CIO and senior enterprise executives prioritize all investments at the enterprise level at least quarterly to achieve innovation and differentiation. Business cases for I&T requests contain business outcomes and use specific value and risk methods.
Manage Performance	Measure IT Performance	3.5	3: IT performance is measured through business-value-based SLAs that correlate to business outcomes and employee experience. 4: IT and business performance is fused and jointly measured through strategic business benefits realization and external customer / citizen satisfaction.
	Communicate & Report IT Performance	4.0	4: IT proactively communicates to senior business executives how I&T across the enterprise is leveraged for business capabilities and competitive differentiation, which influences strategy and innovation investments
	Act on Metrics for Improvement	3.5	3: The IT organization has defined a process-to-service map that identified IT processes' relationship to IT service outcomes, and remediation efforts result in improvements in end-to-end service quality. 4: Empowered, multidisciplinary business/IT product teams prioritize their own continuous improvement objectives for products, business processes, business outcome and external customer / citizen experience

Applications
How Do Maturity and Importance Compare?



Lowest Maturity
- Manage Integration Delivery
- Deliver the Integration Platform
- Define and Evolve Integration Strategy

Highest Importance
- Plan Product and Application Lifecycle
- Rationalize and Modernize Applications
- Establish Governance Model for Sourcing
- Define and Evolve Integration Strategy

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Applications
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Manage the Product & Application Portfolio	Plan Product & Application Lifecycle	4.0	4: the product and application roadmaps include opportunities of emerging technology for the next 2-5 years
	Rationalize & Modernize Applications	4.5	4: rationalization and modernization initiatives are integral part of business transformations 5: rationalization and modernization of products and applications is continuous and a separate discipline with dedicated resourced and ongoing funding
Manage Vendor & Sourcing Relationships	Track Vendor Performance	3.5	3: a role of vendor manager is established to track groups of vendors and associated records. Formal spreadsheets (scorecards) are put in place to ensure consistency of tracking across vendors 4: performance of all vendors is institutionalized, and organization uses it to derive insight to assist with vendor selection. Internal customers are polled to obtain full measure of overall customer satisfaction for each vendor
	Establish Governance Model for Sourcing	4.0	4: vendor relationships are managed by a team that has representation from all business sectors to ensure cross-organization representation
Integrate Platforms, Products & Applications	Define and Evolve Integration Strategy	3.0	3: an integration strategy team is established to provide integration delivery services to the applications teams. A formal centrally managed sourcing strategy is available
	Deliver the Integration Platform	3.0	3: one or more strategic integration tool has been selected, recommended and centrally supported. Integration solutions are implemented on the strategic tools by consistently adopting centrally defined common patterns and guidelines
	Manage Integration Delivery	2.5	2: application delivery teams autonomously address integration issues, optionally using a set of approved products that are supported by an integration platform team 3: an integration strategy team is in charge of delivering, on demand, integration solutions and/or strategic tools to support the applications delivery teams

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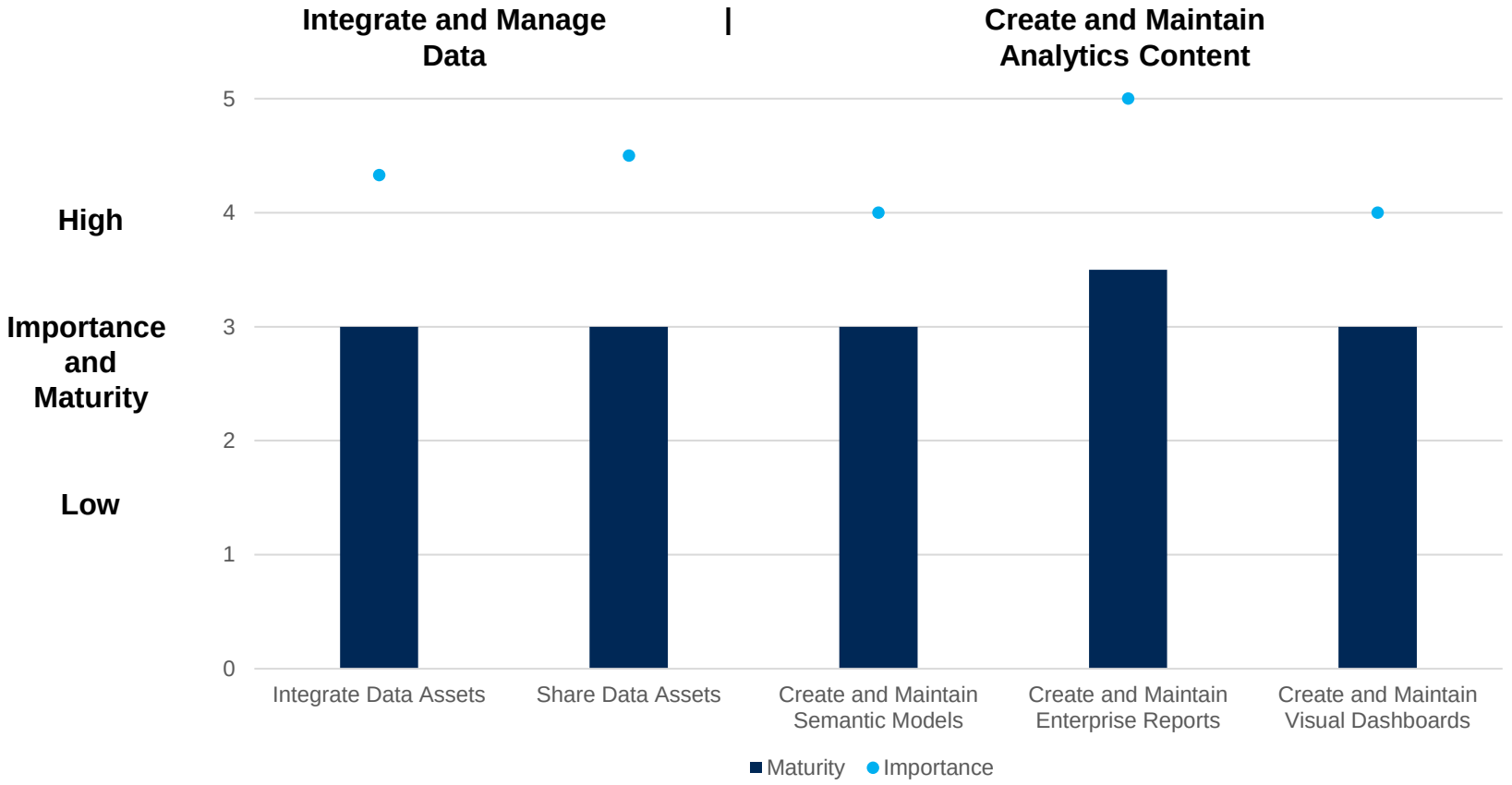
Data & Analytics
How Do Maturity and Importance Compare?



Lowest Maturity
- Integrate Data Assets
- Share Data Assets
- Create and Maintain Enterprise Reports
- Create and Maintain Visual Dashoards

Highest Importance
- Create & Maintain Enterprise Reports
- Share Data Assets
- Integrate Data Assets

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Data & Analytics
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Integrate & Manage Data	Integrate Data Assets	3.0	3: data integration practices combine multiple styles of integration to adapt to changing demands within a single use case
	Share Data Assets	3.0	3: data semantics can be shared regionally and mapped over various sources and applications
Create & Maintain Analytics Content	Create & Maintain Semantic Models	3.0	3: semantic models are created by IT and business to facilitate reporting and analysis by clearly defining dimensional attributes and measures
	Create & Maintain Enterprise Reports	3.5	3: there is a consistent process to develop interactive reports. Reports can also be distributed via e-mail 4: consumers of reports access reports using search as opposed to more complicated hierarchical folders. Moreover, reports can be delivered to mobile devices.
	Create & Maintain Visual Dashboards	3.0	3: departments and business units are enables to build their own dashboards. Also, dashboards include geospatial and location intelligence capabilities

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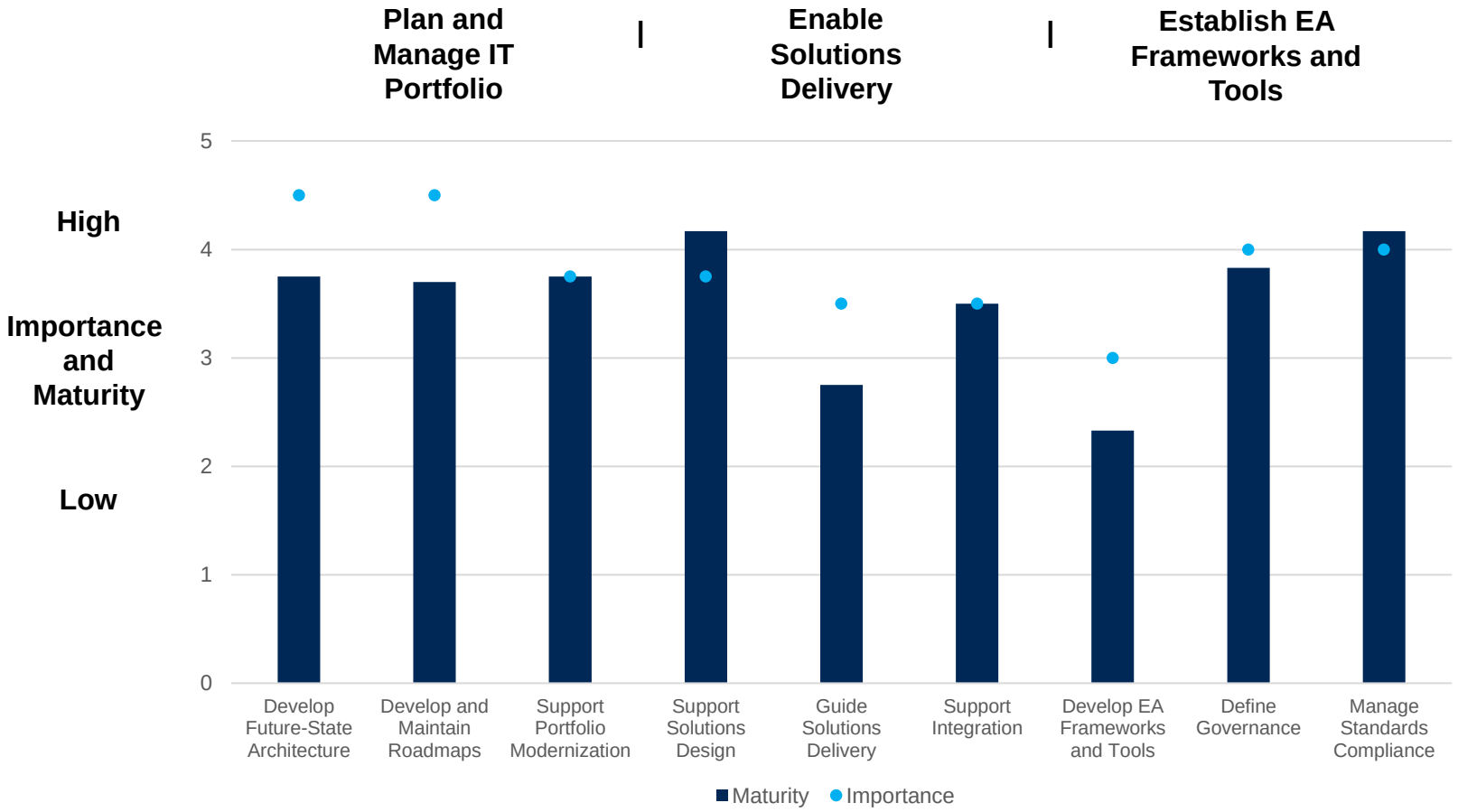
Enterprise Architecture & Technology Assessment
How Do Maturity and Importance Compare?



Lowest Maturity
- Develop EA Frameworks and Tools
- Guide Solutions Delivery

Highest Importance
- Develop Future State Architecture
- Develop and Maintain Roadmaps

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Enterprise Architecture & Technology Assessment (1 of 2)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Plan & Manage IT Portfolio	Develop Future-State Architecture	3.8	3: EA coordinates with stakeholders to create an enterprise future-state plan across technology domains and/or business areas 4: EA regularly recalibrates the future-state plan based on criticality of business capabilities and technical debt
	Develop & Maintain Roadmaps	3.8	3: EA applies a formal process to roadmap how IT initiatives support business capabilities, while tracking project ro product costs, benefits, risks and interdependencies 4: EA continuously reviews and refreshes roadmaps that reflect multiple time horizons and business scenarios designed to improve or maintain capability health
	Support Portfolio Modernization	3.8	3: EA has a comprehensive view across the technology stack and advises IT delivery teams on sunset or update decisions based on an analysis of costs and benefits and business needs 4: EA tracks how existing technologies support business capabilities and targeted outcomes and makes recommendations based on opportunity cost and impact on speed to value
Enable Solutions Delivery	Support Solutions Design	4.2	4: EA helps development teams apply a customer-centric lens to solutions design and supporting architectural decisions for improved usability
	Guide Solutions Delivery	2.8	2: EA engages with development teams across the delivery life cycle through a stage-gated process to review compliance with internal standards 3: EA provides packaged guidance to keep solutions development on track with targeted business outcomes and manage risk to business processes and operations
	Support Integration	3.5	3: EA manages reusable services (APIs) and defines standards to support ease of integration 4: EA regularly assesses integration standards for relevance and defines and curates reusable services that accelerate integration

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Enterprise Architecture & Technology Assessment (2 of 2)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Establish EA Frameworks & Tools	Develop EA Frameworks & Tools	2.3	2: EA develops use cases to demonstrate the value of tools and frameworks and to justify investment. Usage is prescriptive and in support of projects or products, focusing on gathering artifacts, documentation and modeling 3: ES assess tool and framework utility holistically to best support future and current-state architecture
	Define Governance	3.8	3: EA aligns the governance framework with IT strategy and includes business context and cross-functional perspectives in strategic review of technology standards 4: EA connects governance with enterprise digital strategy by means of a forum like a strategy review board and analyyzes exceptions to review and update standards
	Manage Standards Compliance	4.2	4: EA promotes guardrails by offering self-service tools, highlighting business benefits such as speed and innovation and accelerating remediation for granted exceptions

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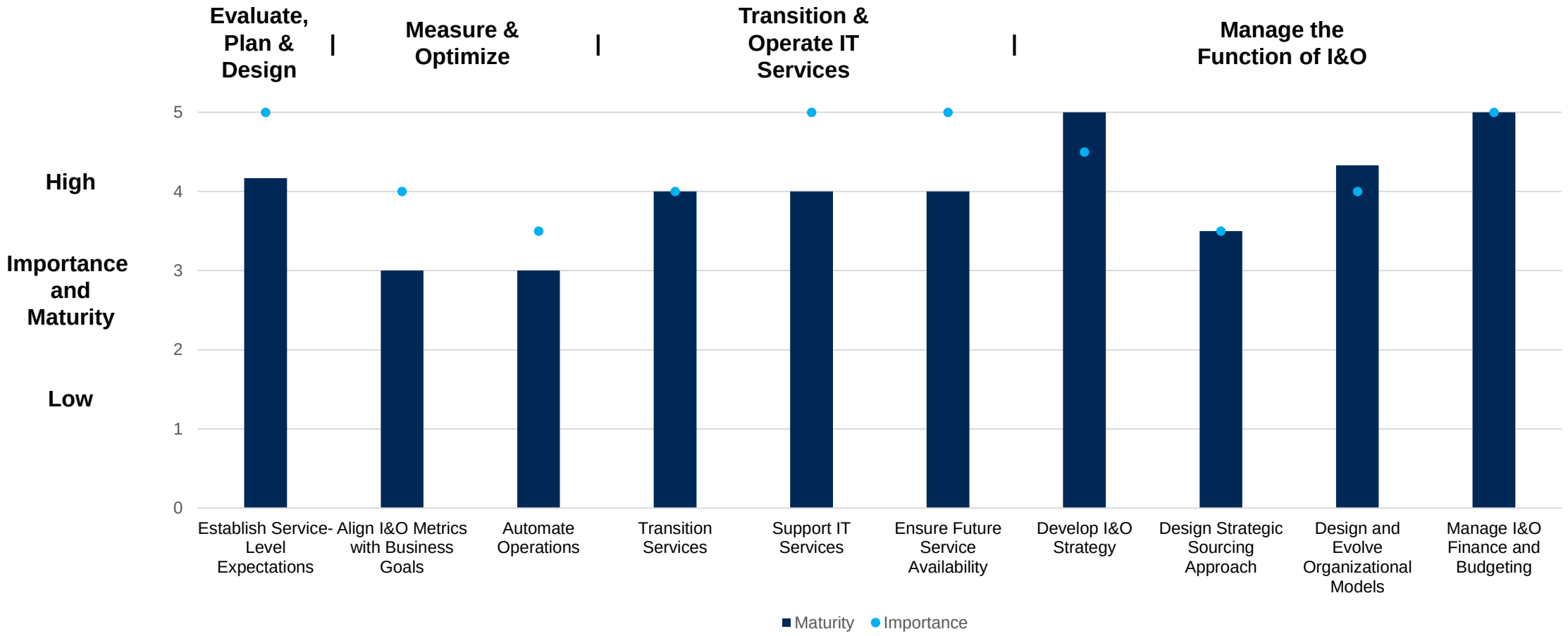
Infrastructure & Operations
How Do Maturity and Importance Compare?



Lowest Maturity
- Align I&O metrics with Business Goals
- Automate Operations
- Design Strategic Sourcing Approach

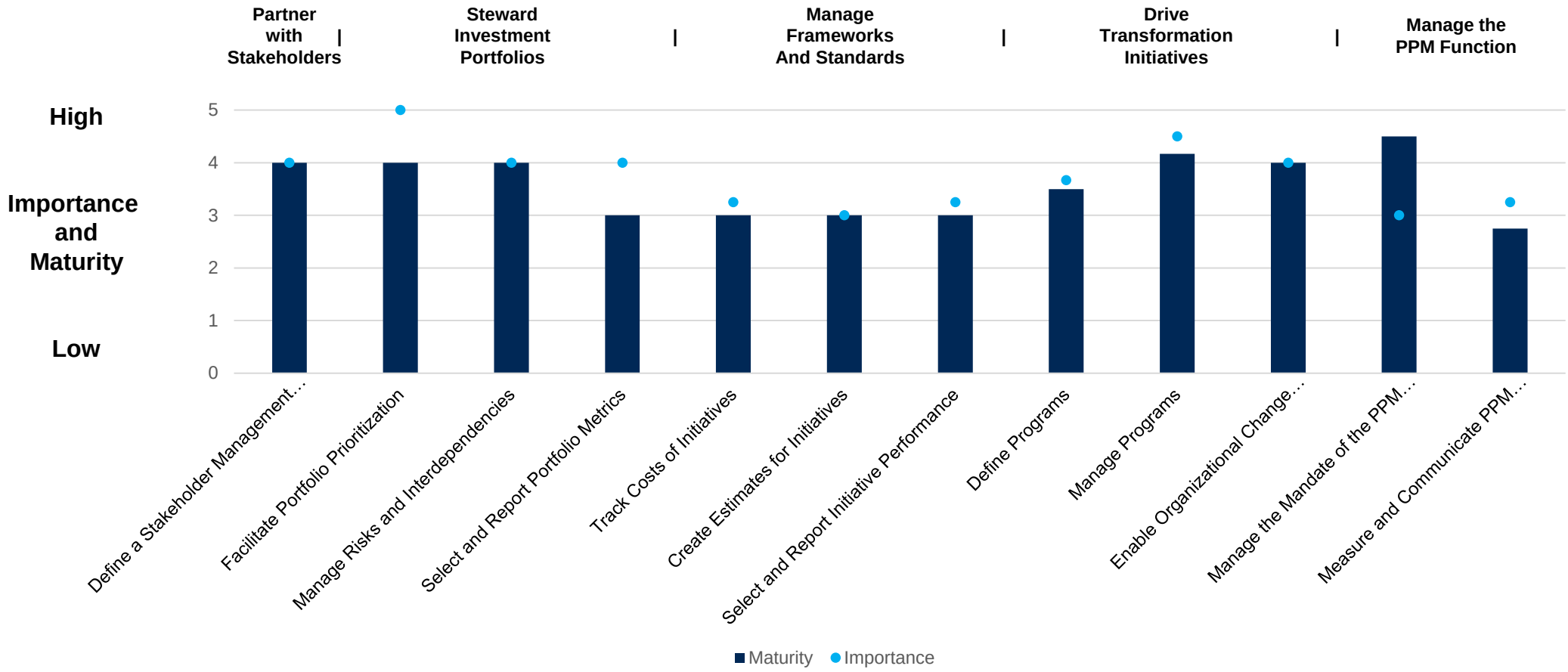
Highest Importance
- Establish Service-Level Expectations
- Support IT Services
- Ensure Future Service Availability
- Manage I&O Finance and Budgeting

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Infrastructure & Operations
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Evaluate, Plan & Design	Establish Service-Level Expectations	4.2	4: service levels that support critical business processes are defined and monitored in terms of their impact on user experience and critical workflows
Measure & Optimize	Align I&O Metrics with Business Goals	3.0	3: I&O is informed of business goals associated with applications and projects and generates periodic status and performance reports to the business in standard formats
	Automate Operations	3.0	3: automation is used to perform frequently repeated tasks, and staff has access to training on automation tools
Transition & Operate IT Services	Transition Services	4.0	4: a clear and robust service design process is in place, incorporating complete requirements. DevOps automation delivers business value quickly and effectively
	Support IT Services	4.0	4: I&O uses a service-based approach, with integrated ITSM and operational management tools. Key process owner, service owner and product owner roles are in place
	Ensure Future Service Availability	4.0	4: asset relationships are developed and stored in a CMDB; the estate is monitored at the service level; and measures are in place to manage the estate and deliver higher availability and stability
Manage the Function of I&O	Develop I&O Strategy	5.0	5: build strategies in collaboration with business partners, and follow agile methodology to respond quickly and adapt iteratively to enable changes in business priorities and strategies
	Design Strategic Sourcing Approach	3.5	3: base sourcing decisions on enterprise needs, cost optimization and categorized vendors. Determine solutions in collaboration with other IT teams 4: base sourcing decisions on fit-for-purpose analysis and identify solutions in collaboration with IT partners and input from business
	Design & Evolve Organizational Models	4.3	4: map out critical handoffs between teams and organize team members around service delivery 5: support cross-functional teams)such as DevOps teams or automation centers of excellence) and organize around IT products and/or business goals
	Manage I&O Finance & Budgeting	5.0	5: explain to business leaders how financial decisions positively affect business objectives and ensure transparency by engaging stakeholders to drive informed IT consumption behaviour

Program & Portfolio Management
How Do Maturity and Importance Compare?



Lowest Maturity
- Measure and Communicate PPM Performance

Highest Importance
- Facilitate Portfolio Prioritization
- Manage Programs

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Program & Portfolio Management (1 of 2)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Partner With Stakeholders	Define a Stakeholder Management Approach	4.0	4: the PPM function helps product, project or program managers classify their stakeholders based on their communication styles and challenge stakeholder assumptions when necessary
Steward Investment Portfolios	Facilitate Portfolio Prioritization	4.0	4: the PPM function's support enables portfolio decision makers to align roadmaps with organization objectives, define a target portfolio structure based on the relative importance of business capabilities and reprioritize as the investment roadmap changes
	Manage Risks & Interdependencies	4.0	4: the PPM function frequently seeks input on risk to achieving business outcomes from a diverse det of stakeholders and established risk-escalation rules
	Select & Report Portfolio Metrics	3.0	3: the PPM function aggregates, tracks and reports a mix of standard operational and benefit metrics
Manage Framework & Standards	Track Costs of Initiatives	3.0	3: the PPM function defines standard frameworks to track the overall costs of initiatives
	Create Estimates for Initiatives	3.0	3: the PPM function tailors the approach to estimation and level of support depending on the characteristics of the initiative and uses input from experienced estimators to improve the accuracy of estimates.
	Select & Report Initiative Performance	3.0	3: the PPM function uses standard metrics, tailors its reporting approach to fir context and need, and enables self-service tools for stakeholders

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Program & Portfolio Management (2 of 2)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Drive Transformation Initiatives	Define Programs	3.5	3: programs are proactively defined to manage technical, or resource dependencies related to a common business objective 4: programs are defined top-down to support business capabilities and are assessed on measurable business outcomes
	Manage Programs	4.2	4: the PPM function takes a program-centric view of resource allocation, budge reprioritization and design of the program manager role
	Enable Organizational Change Management	4.0	4: the PPM function sequences change initiatives and adjusts change management approached to drive adoption
Manage the PPM Function	Manage the Mandate of the PPM Function	4.5	4: the PPM function defines its activities as a set of services to meet t he varied needs of stakeholders 5: the PPM function reshapes its mandate or temporarily fixes the way it engages with key stakeholder to align with the evolving priorities of the digital business
	Measure & Communicate PPM Performance	2.8	2: the PPM function reports basic initiative-level metrics to stakeholders at regular intervals 3: the PPM function tracks the function's performance against operational and strategic objectives and provides customized reports to stakeholders

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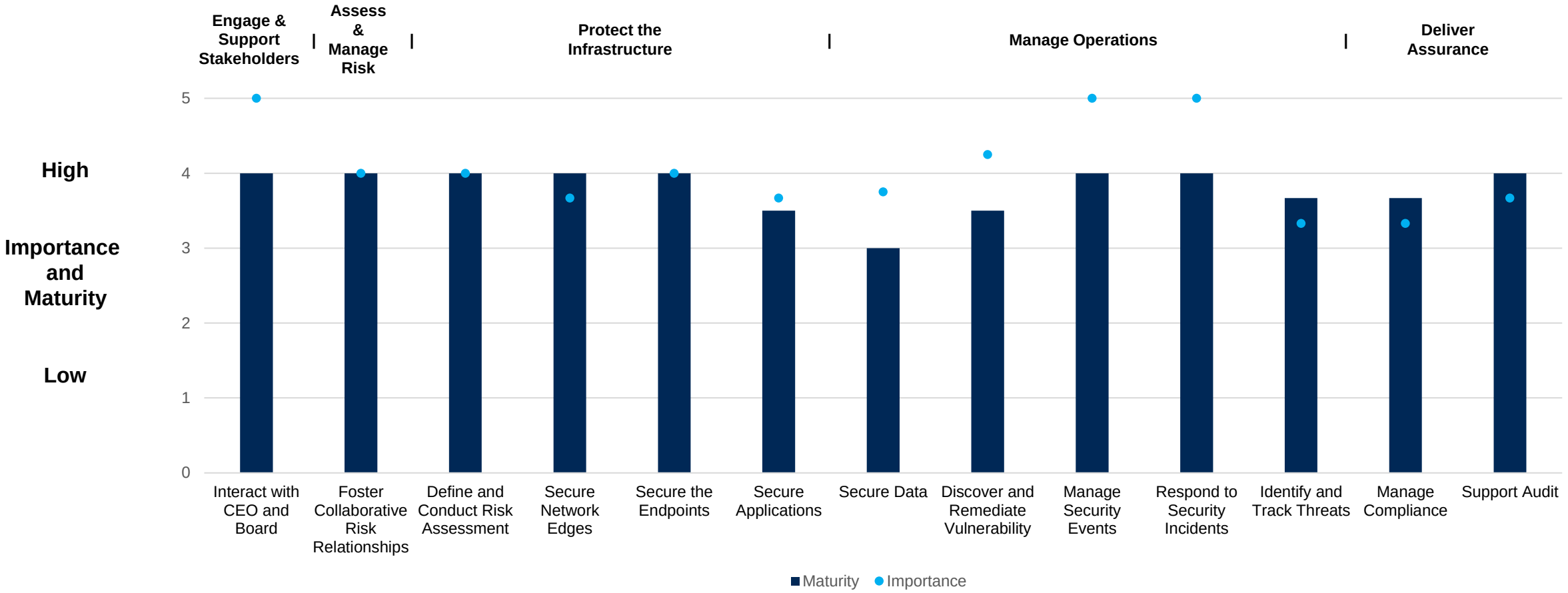
Security & Risk Management
How Do Maturity and Importance Compare?



Lowest Maturity
- Secure Data
- Secure Applications
- Discover and Remediate Vulnerabilities

Highest Importance
- Interact with CEO and Board
- Manage Security Events
- Respond to Security Incidents

Importance: Measured on a scale ranging from 1 (Not Important) to 5 (Most Important). Importance measures how important each functional activity is to the overall effectiveness of your function in meeting its business objectives.

Security & Risk Management (1 of 2)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Engage & Support Stakeholders	Interact with CEO & Board	4.0	4: SRM develops and communicates standardized reports in business-friendly language, aligned to business objectives that are made available to the board and CEO on a regular basis
	Foster Collaborative Risk Relationships	4.0	4: SRM works with other stakeholders on future challenges and encourages staff across functions to minimize activity duplications and maximize collaboration
Assess & Manage Risk	Define & Conduct Risk Assessments	4.0	4: SRM has defined a risk assessment process that periodically reassesses risk and aggregates findings against a defined taxonomy
Protect the Infrastructure	Secure Network Edges	4.0	4: SRM ensures network access and network traffic within networks are controlled and monitored
	Secure the Endpoints	4.0	4: endpoint security controls are expanded to include detection and response
	Secure Applications	3.5	3: SRM implements automated discovery and security assessment for applications 4: SRM collaborates with application development to implement application security policies and implements monitoring automation
	Secure Data	3.0	3: SRM identifies threats and compliance issues to implement protection and monitoring controls

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Security & Risk Management (2 of 2)
Current Maturity Levels

Objective	Activity	Current Maturity	Maturity Level: Gartner Description
Manage Operations	Discover & Remediate Vulnerabilities	3.5	3: SRM prioritizes vulnerabilities based on business context and monitors patching effectiveness 4: SRM uses threat intelligence to further prioritize vulnerabilities
	Manage Security Events	4.0	4: SRM regularly assesses monitoring effectiveness to increase alert accuracy and uses event and incident data to improve detection accuracy
	Respond to Security Incidents	4.0	4: SRM works with other functions to formalize all aspects of crisis response plans, maintains detailed response playbooks for a variety of incidents and conducts tabletop test on plans
	Identify & Track Threats	3.7	3: SRM uses analytics to identify patterns of threats, reverse-engineers attached to identify indicators of compromises and considers scenarios of future attacks to tailor detection efforts 4: SRM combines internal and external data to develop hypotheses of future attacks, applies attribution techniques across multiple platforms and timelines, and compiles common attacker profiles to tailor monitoring of future attacks
Deliver Assurance	Manage Compliance	3.7	3: SRM typically tracks current regulations and works closely with internal experts to ensure compliance 4: SRM centrally tracks current regulations and works closely with internal and external experts to ensure compliance
	Support Audit	4.0	4: support of audit activities is based on prioritized audit objectives. Partial data collection is based on time and effort analysis to meet audit support requirements

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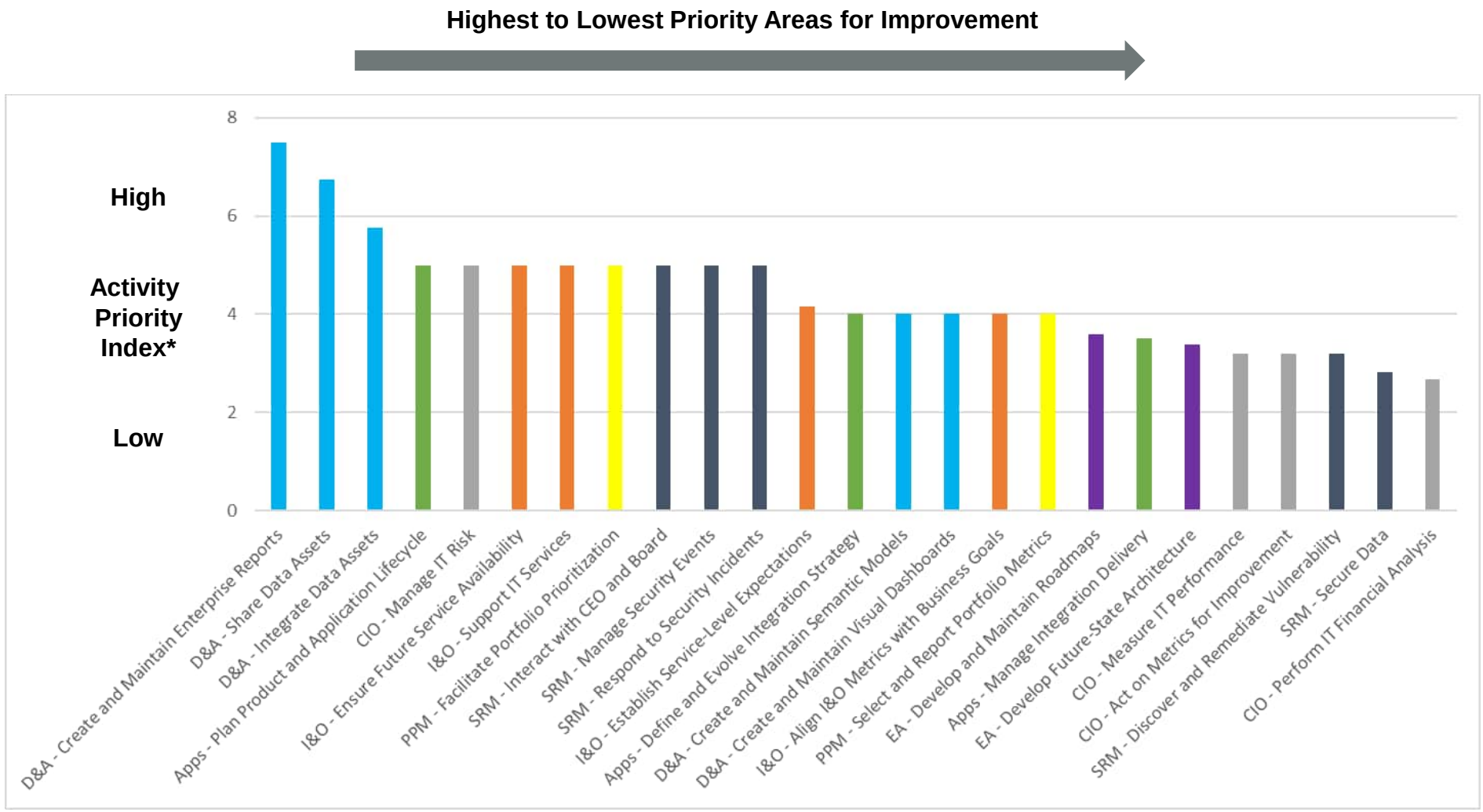
Top 25 Improvement Opportunities: Activity Priority Index (API)

The Activity Priority Index (API) represents an order of priority for the IT functions, based on which below are least mature and of greatest importance for Toronto Hydro



*Activity Priority Index: Activity Priority Index (API) for an activity is computed as importance minus maturity multiplied by its importance. A higher API score indicates a greater priority for improvement to the organization.

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E1 Capital Expenditure Plan Introduction

Section E consists of the following sections that details Toronto Hydro's 2025-2029 Capital Expenditure Plan:

- **Section E1 – Capital Expenditure Plan Introduction:** Provides basic information about the expenditure plan, including drivers and expenditures by category.
- **Section E2 – Capital Expenditure Planning Process Overview:** Provides a detailed explanation of the business planning process, including customer engagement, that Toronto Hydro undertook to develop the 2025-2029 Capital Expenditure Plan.
- **Section E3 – System Capability Assessment for Generation Connections:** Provides information on the capability of Toronto Hydro's distribution system to accommodate renewable energy generation ("REG") and other distributed energy resource ("DER") connections.
- **Section E4 – Capital Expenditure Summary:** Provides a comprehensive summary of Toronto Hydro's capital expenditures over the current 2020-2024 and future 2025-2029 rate periods, including explanatory notes on material variances.
- **Sections E5-E8:** Provides detailed, program-specific justifications and business cases for Toronto Hydro's capital expenditure plan in each of the System Access (E5), System Renewal (E6), System Service (E7), and General Plant (E8) categories.

The following is an introduction to the 2025-2029 Capital Expenditure Plan.

E1.1 2025-2029 Capital Expenditures

Toronto Hydro's capital programs are presented according to the Ontario Energy Board's ("OEB") Chapter 5 Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022):

- System Access Investments (Section E5);
- System Renewal Investments (Section E6);
- System Service Investments (Section E7); and
- General Plant Investments (Section E8).

In the current rate period, Toronto Hydro's operating parameters shifted from a relatively linear and stable environment to a more dynamic growth-oriented context, predicated on increases in future customer demand driven by an unprecedented energy transition that is creating new and expanded

roles for electricity within the economy. In recognition of this evolving landscape, and customers' needs and priorities for the upcoming planning period, Toronto Hydro adopted four focus areas to structure and guide its planning process for 2025-2029, as further described in Section E2:

- **Sustainment and Stewardship:** Risk-based investments in the renewal of aging, deteriorating and obsolete distribution equipment to maintain the foundations of a safe and reliable gird.
- **Modernization:** Developing advanced technological and operational capabilities that enhance value and make the system better and more efficient over time.
- **Growth and City Electrification:** Necessary investments to connect customers (including DERs) and build the capacity to serve a growing and electrified local economy.
- **General Plant:** Investments in vehicles, work centers and information technology (IT) infrastructure to keep the business running and reduce Toronto Hydro's greenhouse gas emissions.

For ease of reference Table 1 below provides a program and segment concordance between these areas of focus and the OEB investment categories per Chapter 5 of the OEB's Filing Requirements.

Table 1: Program & Segment Concordance to OEB Investment Category

OEB Investment Category	Capital Program	Segments	Concordance to Focus Areas
System Access	Customer and Generation Connections	Load Connections	Growth
		Generation Connections	Growth
	Externally Initiated Plant Relocations & Expansions	Externally Initiated Plant Relocations & Expansions	Growth
	Load Demand	Load Demand	Growth
	Metering	Revenue Metering Compliance	Modernization
		Wholesale Metering Compliance	Modernization
	Generation Protection, Monitoring, and Control	Generation Protection, Monitoring, and Control	Growth
System Renewal	Area Conversions	Rear Lot Conversion	Sustainment
		Box Construction Conversion	Sustainment
	Underground System Renewal - Horseshoe	Underground System Renewal - Horseshoe	Sustainment
		Cable Chamber Renewal	Sustainment

OEB Investment Category	Capital Program	Segments	Concordance to Focus Areas
	Underground System Renewal - Downtown	Underground Cable Renewal	Sustainment
		Underground Residential Distribution Renewal	Sustainment
		Underground Switchgear Renewal	Sustainment
	Network System Renewal	Network Unit Renewal	Sustainment
		Network Vault Renewal	Sustainment
		Network Circuit Reconfiguration	Sustainment
	Overhead System Renewal	Overhead Infrastructure Resiliency Improvement	Modernization
		Overhead System Renewal	Sustainment
	Stations Renewal	Transformer Stations	Sustainment
		Municipal Stations	Sustainment
		Control & Monitoring	Modernization
		Battery & Ancillary Systems	Sustainment
	Reactive and Corrective Capital	Reactive Capital	Sustainment
		Worst Performing Feeders	Sustainment
System Service	**System Enhancements**	Contingency Enhancement	Modernization
		Downtown Contingency	Modernization
		System Observability	Modernization
	Non-Wires Solutions	Energy Storage Systems	Growth
	Network Condition Monitoring and Control	Network Condition Monitoring and Control	Modernization
	Stations Expansion	Downsview TS	Growth
		Hydro One Contributions	Growth
General Plant	**Enterprise Data Centre**	Enterprise Data Centre	General Plant
	Facilities Management and Security	Facilities Management and Security	General Plant
	Fleet and Equipment	Fleet and Equipment	General Plant
	IT/OT Systems	IT Hardware	General Plant
		IT Software	General Plant
		Communication Infrastructure	General Plant

E1.2 Investment by Category

Tables 2 below compares capital expenditures by investment category for the current 2020-2024 period and the future 2025-2029 rate period. Section E4 provides further explanations of the shifts in planned expenditures over the two rate periods.

Table 2: Planned Capital Investment by OEB Investment Category ($ Millions)

Category	Total 2020-2024	Total 2025-2029	Var. ($)	Var. (%)
System Access	630.0	**1,071.7**	441.7	70%
System Renewal	1,458.2	**1,970.3**	512.1	35%
System Service	225.6	**353.0**	127.4	56%
General Plant	418.6	**562.5**	143.9	34%
Other	55.1	**44.3**	(10.8)	(20%)
Total	**2,787.4**	**4,001.8**	**1,214.4**	**44%**

E1.3 Investment by Trigger Drivers

For categorization purposes, each capital program described in Section E5 through E8 is assigned one or more drivers of work, including a single trigger driver (representing the catalyst for the investment) and typically one or more secondary drivers.[1] Programs are allocated to each of the four investment categories in accordance with their trigger drivers. A description of each trigger driver is provided in the table below.

Table 3: Investment Category Trigger Drivers

Category	Driver	Description
System Access	***Customer Service Requests***	• Toronto Hydro strives to connect demand and DER customers to its system as efficiently as possible in alignment with its obligation under the Distribution System Code. This obligation holds unless it poses safety concerns for the public or employees or compromises the reliability of the distribution system. In situations where the existing infrastructure falls short of enabling a connection, the utility undertakes system expansions or enhancements to accommodate the customer's needs.

[1] The list of capital investment drivers used in this application were developed based on the OEB's example drivers from Chapter 5 of the OEB's Filing Requirements.

Category	Driver	Description
	Mandated Service Obligation	• Toronto Hydro prioritizes full compliance with all legal and regulatory requirements and government directives.
System Renewal	***Functional Obsolescence***	• Specific asset types and configurations can become obsolete for a variety of technical and operational reasons. Typically, functionally obsolete assets can no longer be effectively maintained or utilized as intended. Toronto Hydro will act to retrofit or replace these assets within a timeframe that is specific to the unique circumstances of the asset population in question.
	Failure	• Toronto Hydro must reactively repair or replace assets or critical components that have failed while in service.
	Failure Risk	• Toronto Hydro takes proactive measures to identify, assess, and mitigate failure risk within its asset populations. Failure risk is determined by evaluating the likelihood of failure (e.g., by leveraging asset condition assessments) and the likely impact of failure ("criticality") on various outcomes, including safety, reliability, cost, and the environment. By prioritizing service reliability and ensuring the safety of workers and the public, the utility strives to maintain a robust infrastructure that meets the evolving needs of its customers.
System Service	***Reliability***	• Toronto Hydro strives to maintain and improve reliability at local, feeder-wide, and system-wide levels by continuously optimizing its system and deploying cost-effective technologies and solutions.
	Capacity Constraints	• Expected load changes can impact service consistency and demand requirements for the system. To address this, Toronto Hydro proactively adjusts and expands its infrastructure to optimize reliability and meet evolving customer needs.
General Plant	***Operational Resilience***	• Toronto Hydro prioritizes the ability to mitigate and recover from disruptions to core business functions. Through robust strategies, contingency plans, and proactive risk management, the utility ensures prompt restoration of operations, minimizing impact and maintaining service continuity.
	System Maintenance and Capital Investment	• Toronto Hydro recognizes the significance of investing in day-to-day operational activities, as doing so enables the utility to prioritize the safety and well-being of its employees while

Category	Driver	Description
	Support	maintaining an environment that fosters efficiency and reliability in delivering essential services.

E2 Capital Expenditure Planning Process Overview

Section E2 explains how Toronto Hydro developed its 2025-2029 Capital Expenditure Plan, including the pacing and prioritization decisions that the utility made to balance price and other outcomes that align with customer needs and preferences. This section is organized into the following three areas:

- **Section E2.1** describes the sequence of business planning activities that produced the Capital Expenditure Plan, and provides an overview of the utility's key considerations and decisions during this process.
- **Section E2.2** describes the results of the utility's planning-specific Customer Engagement and how Toronto Hydro developed a plan that is aligned with and responsive to customer needs, preferences and priorities.
- **Section E2.3** focuses on the outputs of Toronto Hydro's asset management and operational planning processes (described in Section D) and how they influenced the pacing and prioritization of the capital expenditure plan.
- **Section E2.4** focuses on how the outputs of the Asset Needs Assessment are used in the Portfolio Planning process to develop program-level expenditure plan proposals to support the utility's asset management outcome objectives.

Detailed justifications for Toronto Hydro's planned capital program expenditures can be found in the sections in E5 through E8 of this Distribution system Plan ("DSP").

E2.1 Business Planning Process

In developing a multi-year investment plan, Toronto Hydro begins from the principle that the utility is entrusted by customers and stakeholders to prepare a responsible plan that balances both price and service quality outcomes. The 2025-2029 Plan achieved that balance through an integrated and iterative business planning process that considered customer feedback from start to finish.

Toronto Hydro's 2025-2029 Capital Expenditure Plan ("the Plan") is an output of the utility's outcomes-oriented, customer-focused business planning process. The Plan was derived from the utility's distribution system asset management processes and other operational planning activities, including outputs from the Investment Planning & Portfolio Reporting ("IPPR") process described in Sections D1 and D3. Figure 1 below provides a high-level view of the process as it relates to the Capital Expenditure Plan, and the sections that follow provide an overview of how the elements of

the process came together to generate the Plan that forms the basis of Toronto Hydro's 2025-2029 DSP.

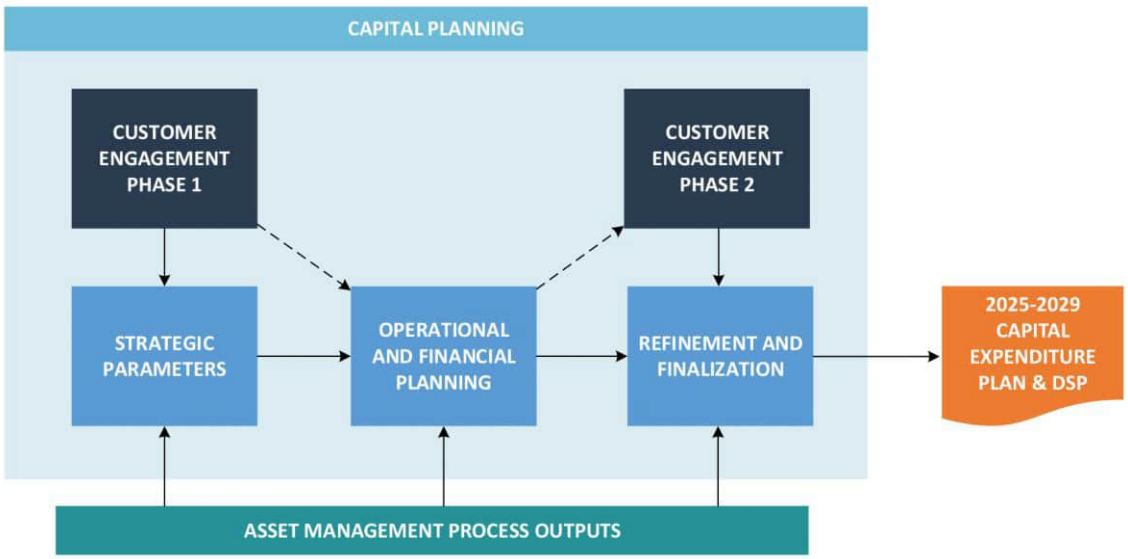


Figure 1: Capital Planning in Business Planning

E2.1.1 Strategic Planning Direction

Toronto Hydro began planning by engaging customers to ascertain their needs and priorities for the 2025-2029 planning period (i.e. Phase 1 of Customer Engagement), and used the customer feedback received to provide strategic direction to the planning process.

Feedback from customers was that price, reliability, and investing in new technology were their top priorities. Relative to price, reliability has become increasingly important to residential customers. When it comes to reliability, customers prioritize reducing the length of outages, with a particular focus on extreme weather events for residential and small business customers. Key Account customers are more sensitive to power interruptions and prioritize reducing the total number of outages. Almost equally to price and reliability, customers expect the utility to invest in new technology that will reduce costs and make the system better in the future.

Customers also expect Toronto Hydro to invest proactively in system capacity to ensure that high growth areas do not experience a decrease in service levels. The majority of Key Account customers surveyed have Net Zero goals to reduce their business' net greenhouse gas emissions to zero, and

expect Toronto Hydro to support them in meeting their electrification objectives by ensuring that the system has capacity for growth and by providing them advisory services.[1]

With consideration for customers' needs, priorities and other inputs (discussed below), Toronto Hydro organized its plan around the following investment priorities.

1) **Sustainment and Stewardship:** Risk-based investments in the renewal of aging, deteriorating and obsolete distribution equipment to maintain the foundations of a safe and reliable gird.
2) **Modernization:** Developing advanced technological and operational capabilities that enhance value and make the system better and more efficient over time.
3) **Growth & City Electrification:** Necessary investments to connect customers (including Distributed Energy Resources ("DERs") and build the capacity to serve a growing and electrified local economy.
4) **General Plant:** Investments in vehicles, work centers and information technology (IT) infrastructure to keep the business running and reduce Toronto Hydro's greenhouse gas emissions.

For each investment priority, Toronto Hydro set performance objectives that provide value for customers and are meaningful to its operations.

Table 1: 2025-2029 Performance Objectives

Investment Priority	Key Performance Objectives
Sustainment and Stewardship	• Maintain recent historical system reliability • Manage asset risk by maintaining overall health demographics of the asset population in 2025-2029 • Adhere to previous commitments for safety and environmental compliance activities (e.g. removal of at-risk PCBs by 2025; complete Box Conversion by 2026) • Optimize the pace of renewal investment from year-to-year using risk-based decision-making tools. • Ensure investment pacing contributes to stable long-term investment requirements for all assets (2030+)

[1] The results of Customer Engagement, Phase 1, are discussed in detail in Exhibit 1B, Tab 5, Schedule 1 – Appendix A.

Investment Priority	Key Performance Objectives
Modernization	• Prioritize investments that will deliver demonstrable benefits to customers, especially enhancements that will improve value-for-money in the long-term (i.e. efficiency) • Improve system reliability through enhanced fault management, leveraging automation and advanced metering through Advanced Metering Infrastructure ("AMI") 2.0 • Enhance system observability across the system, enabling better asset management and operational decision making • Leverage technology to improve customer experience (e.g. reliability, power quality, customer tools, DER integration) • Enhance resiliency and security of the system through advanced grids, targeted undergrounding of critical overhead assets, and enhancements to distribution schemes for critical loads downtown
Growth & City Electrification	• Connect customers efficiently and with consideration for an increase in connections volumes due to electrification • Expand stations capacity to alleviate future load constraints, with consideration for increased EV uptake, decarbonization drivers, and other growth factors (digitization and redevelopment) • Optimize near-term system capacity through load transfers, bus balancing, cable upgrades and the targeted use of non-wires solutions such as demand response and energy efficiency • Alleviate constraints on restricted feeders to accommodate the proliferation of DER connections • Install control and monitoring capabilities for all generators > 50kW • Accommodate relocations for committed third-party developments, including priority transit projects
General Plant	• Replace critical facilities assets in poor condition • Improve stations site conditions and physical security to meet legislative requirements (Ontario's Building Code [2], *Occupational Health and Safety Act*[3], CSF, etc.) • Achieve emissions reduction by implementing Toronto Hydro's NZ40 strategy • Support modernization objectives including grid automation and customer experience. • Minimize cybersecurity risks associated with IT/OT infrastructure • Ensure IT infrastructure is available and reliable with minimal service disruption

[2] Ontario Regulation 332/12: Building Code, under Building Code Act, 1992, S.O. 1992, c. 23.
[3] *Occupational Health and Safety Act,* RSO 1990, c. O.1

In addition to setting these performance objectives, Toronto Hydro adopted top-down financial constraints to ensure that the principle of balancing price and service quality outcomes remained top of mind throughout the planning process.

1. **Price Limit:** Toronto Hydro set an upper limit of approximately 7 percent as a cap on the average annual increase to distribution rates and charges.[4]
2. **Budget Limits**: Toronto Hydro set upper limits of $4,000 million for the capital plan and $1,900 million for the operational plan over the 2025-2029 period.

In developing these strategic parameters, Toronto Hydro considered a number of inputs, including:

- as mentioned above, customer priorities and preferences identified in Phase 1 of the utility's planning-specific Customer Engagement activities;
- customer needs and preferences as understood by the utility through routine and ongoing engagement with customers and community stakeholders;
- historical and forecast system health demographics and performance;
- long-term asset stewardship needs, including pacing considerations related to resourcing, supply chain, execution constraints, project lead-times, etc.;
- forecasted system use profiles and pressures, including capacity constraints in the short-, medium- and long-term amid increasing demand for load and DER connections;
- detailed demand scenarios reflecting the uncertain long-term trajectory (2050) for the energy system within the City of Toronto;
- safety and environmental risk assessments;
- evolving business conditions and the need to strategically deploy new and enhanced technologies to manage performance risk and take advantage of emerging opportunities to generate value for ratepayers;
- resiliency and business continuity risks, including climate change risk;
- evolving regulatory and compliance needs;
- workforce needs and challenges;
- inflationary cost pressures, including significant upward pressure on material and construction costs in Toronto;
- total cost benchmarking; and

[4] As calculated for the monthly bill of a Residential customer using 750 kWh.

- distributor scorecard benchmarking.

To further inform the selection of price and capital budget limits, Toronto Hydro performed a high-level scenario analysis based on preliminary investment strategy options for each capital program. These options generally reflected:

- a cost-constrained "low" option that, depending on the type of program (i.e. sustainment, modernization, growth, or general plant), would involve taking on additional asset risk in the medium-term, delaying or forgoing further modernization or decarbonization benefits, or taking a higher-risk "wait-and-see" approach to investing for growth (i.e. expansion and connections);
- a "high" option, which, depending on the program, would aim to improve system performance and asset risk in the medium-term, strategically accelerate modernization in areas that can deliver long-term reliability and efficiency benefits for customers, or plan for higher growth needs driven by electrification and community energy plans; and
- a middle option, where program-specific trade-offs would be made between costs and benefits, for example by aiming to maintain current levels of asset risk for certain asset classes, or stretching the pace of modernization and associated benefits over a longer time horizon.

Figure 2, below, illustrates what the total capital expenditure plan would look like if Toronto Hydro had selected exclusively from either the low or high options for every investment program as compared to the draft plan for 2025-2029.

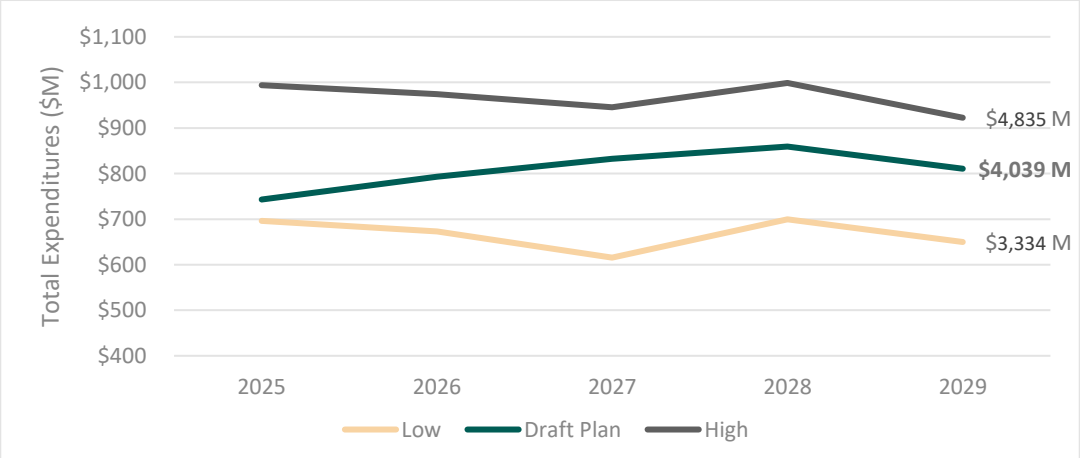


Figure 2: Preliminary High-level 2025-2029 Capital Expenditures Scenarios

Based on the aforementioned inputs, through an iterative process that spanned over a year, Toronto Hydro system planners and experts worked diligently to identify the minimum investments necessary to meet these objectives and balance near-and long-term service quality performance with price impacts for customers, as informed by the feedback in Phase 1. Toronto Hydro selected the $4,000 million capital budget limit to achieve this balance of keeping rates reasonable without compromising performance.

E2.1.2 Focus on Operational and Financial Planning

The strategic parameters guided the operational and financial planning activities that produced the capital expenditure plan for 2025-2029. Over the course of these iterative planning activities, the utility worked to develop and optimize its program-level capital and operational expenditure plans to align with short- and long-term performance objectives, while remaining within the financial constraints and strategic considerations set-out in the strategic parameters.

The utility developed initial capital program expenditure proposals with the aim of fulfilling strategic objectives in the focus areas of Growth, Sustainment, Modernization and General Plant. From this starting point, an iterative process generated multiple versions of the capital expenditure plan, eventually producing a draft plan that formed the basis of Phase 2 of Customer Engagement. The differences between the initial version of the plan – which on an aggregate basis was higher than the $4,000 upper limit on capital expenditures – and the draft version of the plan were as follows:

- **Growth:** Toronto Hydro reduced Growth proposals for the 2025-2029 period by approximately $191 million. This was largely achieved by taking a more balanced approach to the expected demands placed by electrification and refining forecast estimates in the Customer Connections program. Given the uncertainty surrounding the timing of electrification driven pressures and the energy transition, the utility opted to plan for moderate growth within this rate period while making selective, strategic investments to prepare for further growth in the future. Refinements to program cost and volume estimates also drove minor changes to expenditures within other programs.

- **Sustainment:** Toronto Hydro reduced its Sustainment proposals for the 2025-2029 period by approximately $87 million. It scaled back investments in its Area Conversions program, specifically in the Rear Lot Conversion segment, by approximately $37 million by converting customers with rear lot construction at a more moderate pace in alignment with the Ontario

Energy Board ("OEB's") 2020-2024 Decision and Order.[5] It also reduced investments in the Cable Chamber Renewal segment within its Underground Renewal - Downtown program by approximately $25 million by scaling back the number of poor condition assets addressed in the next rate period and managing failure risk by concentrating on asset locations that carry the highest level of potential failure consequences. Finally, the utility reduced investments in the Underground Renewal – Horseshoe program by approximately $48 million in order to balance reliability and cost pressures, reducing the pace of direct buried cable replacement and feeder conversions within the rate period. These reductions were partly offset by refinements to program estimates within other programs. From the onset, the utility worked to constrain the planned pacing of renewal investment to a minimum level at which it expects it can maintain recent levels of system average reliability (with necessary support from complimentary grid modernization investments), while ensuring prudent management of broader long-term asset risk considerations, including: managing longer-term demographic pressures in certain asset classes; addressing obsolescence risks such as the large remaining population of 4 kV feeders and stations, which are inefficient and poorly suited to meet emerging system demands; and ensuring sufficient funding to support the upsizing of neighbourhood level equipment (e.g. pole top transformers) during renewal projects in order to support electrification of consumer energy demand. A description of how the utility leveraged its asset management processes to appropriately pace and prioritize its Sustainment plan is provided in Sections E2.2 and E2.4 below.

- **Modernization:** Toronto Hydro reduced Modernization expenditures by approximately $191 million over the 2025-2029 period. This reduction was driven by the need to ensure progress towards grid modernization objectives while balancing rate impacts for customers. The reductions were primarily achieved within the System Enhancement program. The Downtown Contingency segment was substantially reduced, focusing efforts in a limited way on creating station switchgear ties between Copeland Station and Esplanade Station within this rate period to manage a subset of contingency concerns within the downtown system. Toronto Hydro expects to pilot innovative solutions such as the Automated Primary Closed Loop distribution system which has the capability to provide a more effective and relatively economical solution to establish feeder ties between stations, thereby delivering longer term system benefits at a reduced cost in the future. Toronto Hydro also reduced the Contingency

[5] EB-2018-0165, Decision and Order (December 19, 2019).

Enhancement segment in order optimize the investment profile of the program over the five years and manage resource and other execution risks. Reductions within the System Enhancement program were slightly offset by refinements to cost and volume estimates within other programs.[6]

- **General Plant:** General Plant expenditures decreased by approximately $11 million as result of adopting a more constrained strategy for the Head Office, as described in the utility's Facilities Asset Management strategy at Section D6.

Overall, in an effort to find the balance between price and progress towards outcomes that customer expect, Toronto Hydro constrained its initial capital plan by approximately $480 million from the beginning to the end of the process. The result was a $4,000 million draft capital expenditure plan for 2025-2029,[7] which was subsequently refined and finalized as described in the next section.

E2.1.3 Refinement and Finalization of the Capital Expenditure Plan

Toronto Hydro presented the draft plan to customers in the Phase 2 Customer Engagement survey to validate whether: (i) the plan aligns with customer needs and priorities and (ii) the balance between price and other outcomes aligns with customer preferences. To that end, the Phase 2 survey solicited customer feedback on Toronto Hydro's overall draft plan and the associated price impacts. 84 percent of customers in all customer classes supported the price increase associated with the draft plan or an accelerated version of it. A full analysis of the Phase 1 and Phase 2 Customer Engagement results is provided in Section E2.3 below.

To gain additional insight into the preferences of customers relative to trade-offs between price and other key outcome like system health, reliability and customer service, Toronto Hydro provided customers with the key details of the utility's investment plan, broken down into seven key investment options (described in Section E2.3 below). For each of these investment options, the utility described its draft plan and options to spend more or less for faster or slower progress towards key performance outcomes. In response to being asked to make specific trade-offs between price and other outcomes in each of the seven choices within the plan, customers expressed certain

[6] Exhibit 2B, Section E7.1.
[7] This figure includes inflation and other allocations, and excludes Renewable Enabling Improvement ("REI") expenditures funded through provincial rate relief.

preferences to increase, maintain or reduce the pace of investment. Toronto Hydro considered this feedback in refining and finalizing its 2025-2029 investment plan.

Along with refining planning assumptions to incorporate new and salient information such as the impact of 2022 actuals, the utility leveraged the results of Customer Engagement Phase 2 to calibrate the pace of investment in certain programs. Overall, the adjustments that Toronto Hydro made to programs between the draft plan and the final plan were as follows:

- **Growth:** Toronto Hydro reduced growth-related expenditures by approximately $57 million over the 2025-2029 period. This was due in part to an additional reduction to the load connections forecast, which was partly offset by increased investment needs identified in the Load Demand program due to incremental scope and revised cost estimates. Toronto Hydro also refined the scope of the Battery Energy Storage Systems segment to reflect insights from the procurement process for battery investments in the current rate period, which resulted in further reductions. In light of customer feedback with respect to trade-offs between price and other outcomes in Growth investments, the utility also reduced the Stations Expansion program by $35 million by deferring the second phase of the Basin TS expansion into the next period.

- **Sustainment:** Toronto Hydro increased Sustainment expenditures by approximately $65 million over the 2025-2029 period due to refinements to program cost estimates including updates for inflationary assumptions and incremental investment needs to address legacy infrastructure and associated failure risk. For example, incremental expenditures were required to address legacy switches in the downtown underground system and to complete all Box Construction feeder conversions in the next rate period. In order to partly offset these increased investment requirements and be responsive to customer preferences gleaned in the Phase 2 engagement, Toronto Hydro reduced $20 million from its stations renewal program by deferring switchgear renewal investments.

- **Modernization:** The Modernization plan increased by $8 million. Increases in the Metering program due to cost refinement and inflation pressures were offset by the decision to reallocate funding for various types of modernization pilot projects to the Innovation Fund outlined in Exhibit 1B, Tab 4.

- **General Plant** General Plant expenditures decreased by approximately $48 million over the 2025-2029 period, the Facilities Management and IT Software programs were reduced by approximately $13 million, and the pace of fleet electrification was lowered by $3.5 million in response to customer preferences expressed through the second phase engagement (see E2.3 below). The remaining decrease is due in large part to an administrative correction made to the Fleet Equipment program that resulted in a $31 million reduction.

Overall, Toronto Hydro reprioritized investments to produce an optimized and customer-aligned capital expenditure plan of $4 billion over the 2025-2029 period.[8]

Section E2.2, below, provides an overview of how Toronto Hydro derived the plan from the asset management processes described in Section D of the DSP. Section E2.3 describes the results of the Customer Engagement process and how they informed the DSP. Section E2.4 focuses on how the outputs of the Asset Needs Assessment are used in the Portfolio Planning process.

E2.2 Asset Management in Capital Planning

Toronto Hydro primarily derived its 2025-2029 Capital Expenditure Plan based on its Asset Management System ("AMS") for distribution assets, Information and Operational Technology ("IT/OT") Asset Management, and Facilities Asset Management described in Section D. As discussed in Sections D1 and D3, the utility develops its system investment programs through the annual Investment Planning and Portfolio Reporting ("IPPR") process. This process leverages the various asset lifecycle optimization and risk management methodologies discussed in Section D3 to produce capital programs and expenditure plans that are optimized to support the utility's customer-focused outcome objectives. The scenarios and recommendations developed in IPPR become inputs to business planning (discussed in the previous section), where program expenditure plan proposals are further refined, leveraging the same AMS tools and outputs.

Figure 3 below (originally presented in Section D3.4) is a simplified view of the major program planning elements within the IPPR process. It depicts the cyclical nature of program development and the integration points with customer engagement activities.

[8] This figure includes inflation and other allocations, and excludes Renewable Enabling Improvement ("REI") expenditures funded through provincial rate relief.

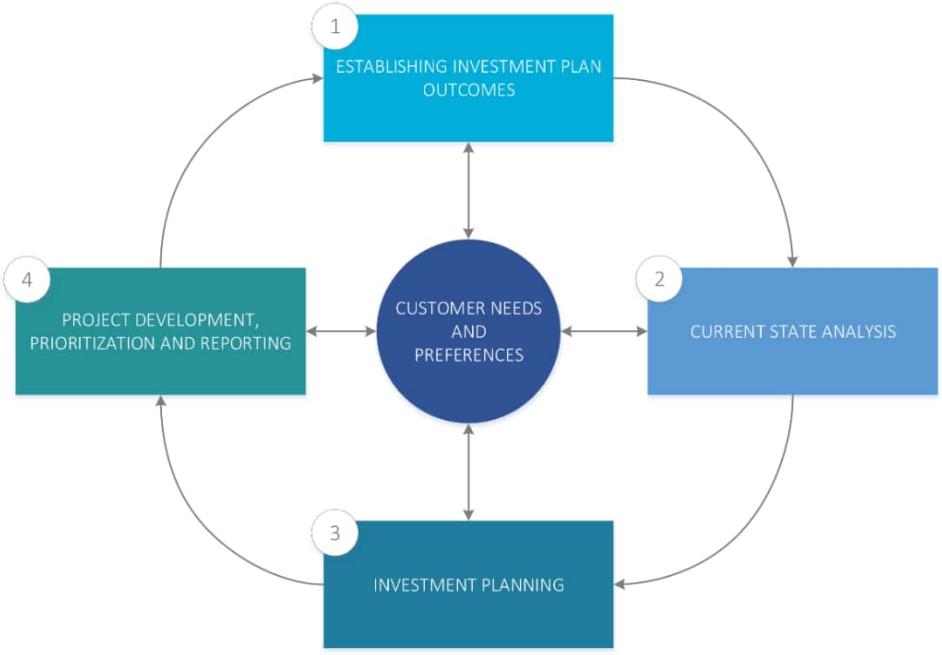


Figure 3: The IPPR Program Development Framework

Step one in the figure above, which involved selecting the desired outcomes and objectives for the 2025-2029 investment plan, was described in the previous section (E2.1). The following sections explain how each of the remaining three elements in this process contributed to the production of the 2025-2029 Capital Expenditure Plan for system-related investments.

E2.2.1 Asset Needs Assessment for 2025-2029

Concurrent with the development of the utility's asset performance objectives (summarized in Table 1 above and also discussed in Section D1.2.1.1), Toronto Hydro performed an Asset Needs Assessment to develop a baseline understanding of the current state of its distribution system. As explained in Section D3, the Asset Needs Assessment includes a Current State Assessment ("CSA") and a System Needs and Challenges Review. The results of these analyses informed the capital budget limit that Toronto Hydro set in the strategic parameters for the business plan.

E2.2.1.1 Current State Analysis Results

The Current State Analysis ("CSA") produced foundational information, including asset demographics (i.e. counts, age and nameplate attributes) and condition demographics. These data points informed program pacing and prioritization decisions throughout business planning.

1. Asset Condition Demographics

The utility examined the current state of its asset condition demographics – derived from its Condition Based Risk Management ("CBRM") methodology – to determine which asset classes were showing the greatest signs of deterioration, and took this into account in establishing planning scenarios. Table 2 below shows the percentage of assets in the worst condition bands (HI4 and HI5) summarized by major system category.

As illustrated by comparing the 2022 Actual condition to 2017 Actual condition, Toronto Hydro managed to improve or approximately maintain the HI4/HI5 condition profiles for major assets on its network and underground systems, as well as within its stations. This was accomplished through sustained capital investment and maintenance activities over the last five years. Over the same period, the utility saw a moderate deterioration in condition on its overhead system, driven largely by deterioration in the wood pole population. As discussed in Section E4.1.2, this decline in overhead system health was driven in part by the decision to restrain renewal expenditures by deferring some work into 2025-2029 in order to balance cost pressures across the overall Capital Expenditure Plan. Toronto Hydro managed this by shifting temporarily to a spot replacement approach focused primarily on PCB removal and delaying larger area rebuilds that are required to address deteriorating poles and switches as well as obsolete 4 kV feeders.[9]

Table 2: CBRM Results by System (% of asset population in HI4/HI5 condition as of year-end)

System Category	2018 CBRM Outputs		2023 CBRM Outputs	
	2017 Actual	2024 Projection (no intervention)	2022 Actual	2029 Projection (no intervention)
Network	5%	23%	4%	16%
Overhead	6%	34%	9%	30%
Stations	8%	44%	3%	28%
Underground	3%	7%	3%	10%

As shown in Table 2 above, Toronto Hydro continues to face asset condition pressures across all parts of its system over the next rate period. For Toronto Hydro's high-volume overhead and underground

[9] Note that Toronto Hydro found that it was necessary to also defer work within the Underground System Renewal – Horseshoe program in favour of PCB at-risk equipment removals. In this case, it has largely been underground cable replacements that the utility has deferred to 2025-2029. Since underground cables do not have a condition model, the effect of cable replacement deferrals on the growing backlog of cables at risk of failure is not captured in Table 2.

asset populations, the rate of asset deterioration expected by the end of the next rate period is projected to be roughly the same as it was in the equivalent analysis performed in 2018. While the network system is exhibiting a slower rate of deterioration compared to 2018, two additional drivers of investment should be noted: (1) the continuing prevalence of non-submersible network units, which are at a higher risk of catastrophic failure due to flooding regardless of their condition; and (2) an anticipated wave of network demographic issues beyond 2029, with over 50 percent of network units projected to be at or beyond end of useful life by 2034 without intervention. As for Toronto Hydro's major stations assets, an observed improvement in the rate of deterioration is the result of the utility's focused effort in recent years to eliminate high risk, obsolete stations assets including oil circuit breakers. Despite these ongoing efforts, the CBRM model projects a 25-percentage-point increase in the share of HI4/HI5 assets for the station asset population by 2029, which equates to hundreds of major stations assets, the vast majority of which are of obsolete technology types.[10]

Toronto Hydro set-out to develop a risk-calibrated plan that would invest the minimum necessary to manage reliability performance in light of condition-related pressures, and prevent the accumulation of a backlog of assets that are at risk of failure or otherwise need to be upgraded. Asset renewal backlogs are problematic not only because they greatly heighten system reliability risk: they also result in rate instability for customers, as well as inefficiencies in work execution. Such inefficiencies stem in part from performing more work reactively – which is typically higher cost – and in part because planned work becomes more expensive due to surges in material and labour needs that could otherwise be smoothed out through proactive investment. This was one of the key considerations in the utility's selection of its capital budget limit for business planning. The Portfolio Planning section below (E2.2.3) provides additional details on how asset condition informed the pacing of investment in Toronto Hydro's 2025-2029 Capital Expenditure Plan.

2. Assets Past Useful Life

As discussed in Section D3.2, to assess the age demographics of its distribution system, Toronto Hydro examines the proportion of assets across the system that are operating at or beyond useful life (the Assets Past Useful Life metric, or APUL). The age demographics of the system as of the beginning of 2023 are summarized in Figure 4 below.

[10] For a detailed discussion of the various drivers for the proposed stations renewal pacing, refer to Exhibit 2B, Section E6.6.

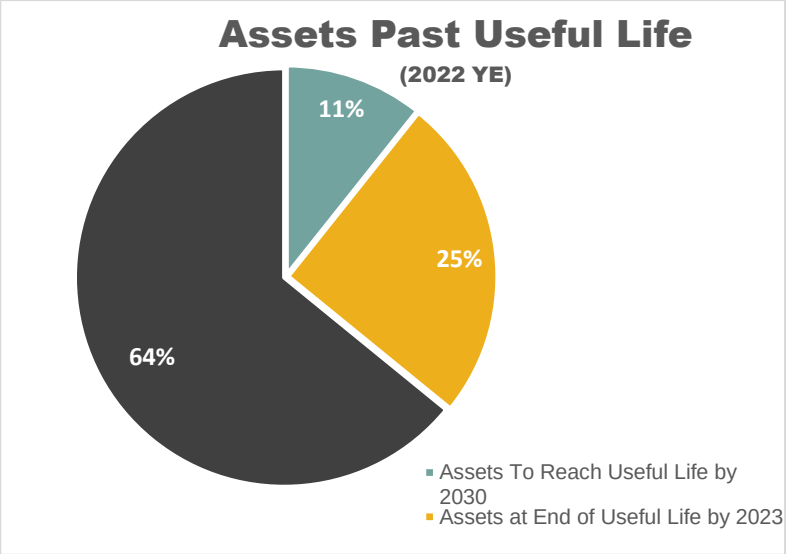


Figure 4: Percentage of Assets Past Useful Life

In 2018, Toronto Hydro's percentage of assets past useful life was 24 percent, with an additional nine percent forecasted to reach expected useful life by 2025. At an aggregate level, and as a direct result of Toronto Hydro's ongoing renewal efforts in recent years, the APUL measure has been relatively stable. However, it should be noted that even a single percentage point in the APUL measure represents future asset replacement needs in the order of hundreds of millions of dollars. Approximately a quarter of the utility's asset base continues to be operating beyond its expected useful life, and an estimated additional 11 percent will reach that point by 2030, which is two percentage points higher than the equivalent rate of deterioration projected in 2018, indicating that a significant proactive renewal program continues to be necessary to sustain overall demographics at current levels and prevent the APUL backlog from increasing.

An overall increase in the APUL backlog would result in a corresponding deterioration in reliability, safety risk, reactive replacement costs, and other outcomes driven by asset failure.

E2.2.1.2 System Needs and Challenges Review

In addition to the information generated by the CSA, Toronto Hydro considered a number of other indicators of system investment need, including system utilization, connection capacity, distributed generation forecasts, legacy asset profiles (e.g. lead cable replacement needs), regional planning considerations, grid modernization objectives, and other factors. The utility developed strategic

investment scenarios for each of these issues, which in turn informed the capital expenditure plan scenarios discussed in Section E2.1.

Section D2 provides an overview of the various considerations resulting from the System Needs and Challenges Review. Section D4 describes Toronto Hydro's strategy to manage growth and development in an uncertain future as a result of electrification and decarbonization of the utility grid. It outlines how additional drivers and enhanced scenario-based load forecasting techniques impacted the 2025-2029 investment plans. Section D5 provides a comprehensive overview of the utility's Grid Modernization Strategy for 2025-2029. Section E2.3.3 provides additional insight into the strategies for addressing these issues in the 2025-2029 Capital Expenditure Plan.

E2.2.1.3 System Reliability Performance and Projection Scenarios

System reliability is an important customer-focused outcome and a lagging indicator of performance, including the effectiveness of the subset of Sustainment and Modernization investments that are primarily directed toward preventing outages and shortening outage duration (e.g. direct-buried cable replacement, Contingency Enhancement, etc.). Although Toronto Hydro's renewal and modernization efforts over the last decade have led to improvements in reliability performance that began in the mid-2000s, more recently this performance has plateaued. As shown in Figures 5 and 6, the rate of improvement in frequency and duration of outages began to slow in the last rate period, prior to a slight deterioration in reliability performance experienced from 2020 to 2022.

During the period of 2020-2022, Toronto Hydro experienced a rise in reliability impacts caused by a range of factors. The increase in SAIFI was driven by factors including Foreign Interference (especially animal contacts), Defective Equipment (including outages attributed to underground cable and cable accessories, overhead switches, overhead conductors, as well as poles and pole hardware failures), and Tree Contacts. The largest individual contributor to the increase in SAIFI was Unknown impacts. Unknown outages are typically short-duration, high-impact outages that are restored through SCADA controlled devices. While Toronto Hydro makes its best effort to investigate these events, it is not always possible to pinpoint the exact cause. The majority of these outages are usually non-permanent and self-clearing, stemming from potential causes including animal contacts, tree contacts, and emerging equipment failures.

With respect to SAIDI, Foreign Interference (including outages attributed to animal contacts, vehicles, and foreign objects) was a substantial contributor to the increase in SAIDI during the aforementioned period. Along with Foreign Interference, Defective Equipment (particularly

underground cable and cable accessories, and overhead switch failures), Unknown impacts, and Tree Contacts have also played a material role in the observed increase in SAIDI. Further information regarding Toronto Hydro's historical reliability performance is available in Exhibit 2B, Section C.

Starting in January 2022, in an effort to improve reporting accuracy, Toronto Hydro began leveraging Oracle's Network Management System ("NMS") – serving as an upgrade to its existing Outage Management System – as part of its reliability audit process to capture improved outage information and address limitations within the Interruption Tracking Information System ("ITIS"). As part of the multi-year NMS upgrade initiative, Toronto Hydro plans to implement a new commercial software solution, Oracle's Utility Analytics ("OUA"), which will serve as the future successor to ITIS for reliability reporting. Further discussion on the impacts of OUA is provided in Exhibit 2B, Section C.

These upgrades continue to improve the data quality and accuracy of Toronto Hydro's interruption tracking and reporting. Some of these changes have resulted in higher reliability trends in 2022 when compared with historical years. This includes an increased number of outages affecting small numbers of customers and a higher number of scheduled outages reported, impacting both SAIFI and SAIDI performance.

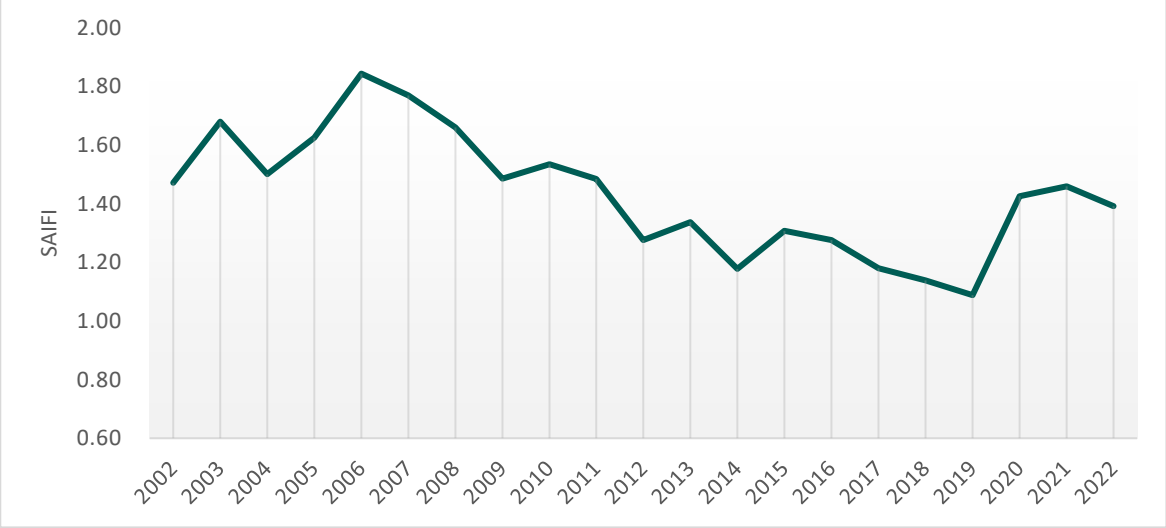


Figure 5: Historical SAIFI (Excluding MEDs and Loss of Supply)

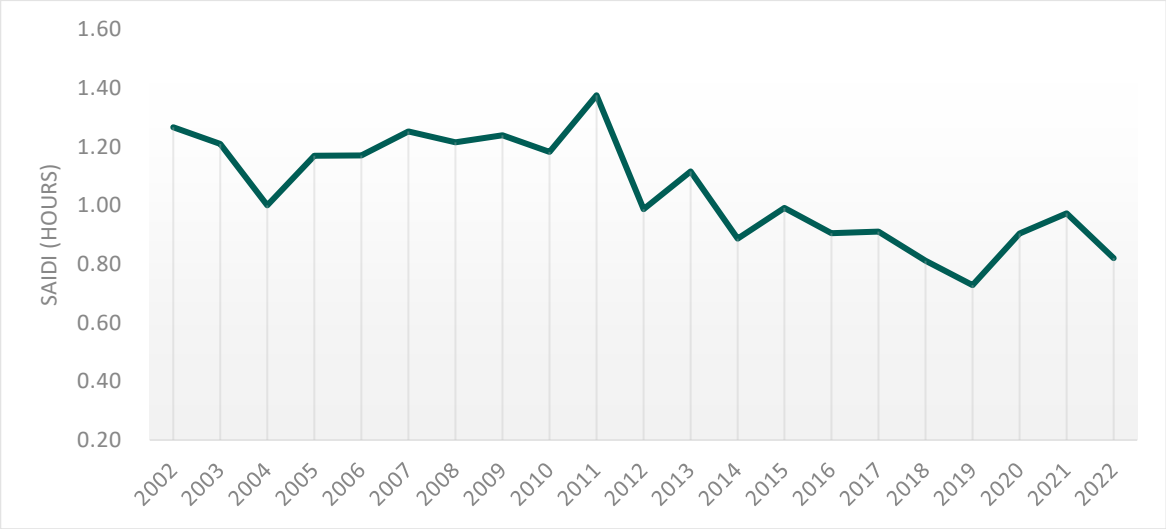


Figure 6: Historical SAIDI (Excluding MEDs and Loss of Supply)

Overall, the utility drew the following key conclusions from recent historical reliability trends and associated asset demographics:

1. **Defective Equipment continues to be the most dominant contributor to reliability performance (SAIDI and SAIFI),** with only Unknown outages having a roughly equivalent impact on SAIFI in the last three years. Asset condition and age demographics are important leading indicators of future Defective Equipment cause code performance. As discussed above (E2.2.2.1), Toronto Hydro's demographic models show that, for the 2023-2029 period, population-level risk accumulation related to asset deterioration will be about as rapid as it was projected to be over the equivalent 2018-2024 period, and in parts of the system where defective equipment has a significant impact on day-to-day reliability (e.g. the underground horseshoe system), the rate of deterioration could in fact be higher. It should be noted that Toronto Hydro's investment plan for the underground and overhead horseshoe systems will continue to be partially skewed toward PCB at-risk equipment replacement activities in 2023, 2024 and 2025, meaning that a full return to primarily reliability-focused sustainment investments will not occur before 2026. With all of these factors in mind, and with the goal of ensuring that sustainment investments are sufficient to maintain reliability over the rate period and the longer-term, the utility concluded that it would be necessary to increase sustainment expenditures in the 2025-2029 period.

2. **General reliability performance has plateaued in recent years following a sustained period of improvement.** From the beginning of the utility's concerted ramp-up in system renewal activities (circa 2007), Toronto Hydro had a focus on eliminating non-standard equipment and system configurations with acute failure risks (e.g. fibre-top network units), and has focused on addressing areas of the system with highly concentrated reliability performance challenges. As a result of the success of these programs, the demographic risk challenges that the utility faces are now more diffuse in nature, meaning that it would likely take a much greater level of sustainment investment (and maintenance expenditures) to drive material year-over-year improvements in Defective Equipment outages in the next decade. At the same time, as discussed in the Grid Modernization Strategy overview (Section D5), there are evolving systemic challenges such as climate change and electrification which Toronto Hydro expects will have the dual effect of (i) increasing reliability risk on the system due to greater system utilization and more frequent impacts from adverse weather, and (ii) increasing the average customer's sensitivity to outages due to an increased reliance on electricity as their primary source of energy. With these broader trends in mind, the utility concluded that the 2025-2029 investment period would demand a greater emphasis on modernizing the grid, leveraging technologies such as SCADA-operated switches and reclosers, distribution sensors, and advanced distribution management tools to not only continue to improve the customer's overall reliability experience within the rate period, but establish the foundation for full-scale grid automation in 2030 and beyond, ensuring the utility is prepared to deliver stable reliability performance as climate change and electrification pressures accelerate.

Based on these conclusions and related observations from Customer Engagement, the utility set-out to develop an investment plan for 2025-2029 that would (1) include the minimum level of sustainment investment required to maintain the recent average historical frequency of outages caused by Defective Equipment (as represented by the SAIFI Defective Equipment measure), and (2) accelerate ongoing investments in the modernization of the grid in order to improve – in both the short and long-term – the overall customer reliability experience (as represented by the SAIDI measure excluding Major Event Days, Loss of Supply, and Scheduled Outages).[11] Toronto Hydro's

[11] As discussed in Exhibit 1B, Tab 3, Schedule 1, Toronto Hydro has temporarily removed the Scheduled Outages cause code from its custom SAIDI performance measure for the 2025-2029 period due to major forecasting uncertainty for this cause code caused by the recent implementation of OUA, coupled with the underlying expectation that Scheduled Outages will increase in the 2025-2029 period as the result of a larger planned work program.

2025-2029 forecasts and targets for both of these measure can be found in Exhibit 1B, Tab 3, Schedule 1.

E2.3 Customer Priorities, Needs and Preferences in Capital Planning

As described in Exhibit 1B, Tab 5, Schedule 1, Toronto Hydro undertook extensive Customer Engagement as part of business planning for this application. The utility augmented its routine, ongoing customer engagement by engaging Innovative Research Group ("Innovative") to design and implement a planning-specific Customer Engagement study, which was structured in two phases:

- In **Phase 1,** Innovative used a range of techniques to assess customers' needs and preferences. This was an iterative process - initial qualitative (exploratory focus groups) informed the questions that were put to customers in subsequent telephone and online surveys. These surveys (directed at residential, small business, commercial & industrial, and Key Accounts customers) provided quantitative statistically-valid results. The results of this phase directly informed the strategic planning direction for the business plan and informed decision-making throughout the planning process that produced the draft capital expenditure plan.
- In **Phase 2**, Innovative took Toronto Hydro's entire draft plan (including capital & OM&A expenditures) back to customers to solicit customer feedback on seven key investment options, including trade-offs between price and other outcomes. The utility used the results of this phase to refine and finalize its plan.

Further details on the engagement process, the methods used, improvements, and the engagement results can be found in Exhibit 1B, Tab 5, Schedule 1 ("Customer Engagement") and in the final report from Innovative ("the Innovative Report"), Appendix A to that schedule. The following sections provide a detailed overview of how the Customer Engagement results are reflected in the 2025-2029 Capital Expenditure Plan.

E2.3.1 Phase 1 Customer Engagement: Needs and Priorities

The Phase 1 Customer Engagement identified customer needs and priorities in relation to Toronto Hydro's programs and services for the 2025-2029 planning period. Based on low-volume (i.e. residential and GS < 50 kW) customer focus groups conducted at the beginning of Phase 1, in conjunction with an audit of Toronto Hydro's past and ongoing customer engagement efforts, the following set of customer priorities was identified:

1) Delivering electricity at reasonable distribution rates
2) Enabling customers access to new electricity services
3) Ensuring reliable electrical service (including power quality for Key Account customers)
4) Ensuring the safety of electrical infrastructure;
5) Expanding the electrical system so that customers can reduce their impact on climate change by using electricity;
6) Helping customers with conservation and cost savings;
7) Investing in new technology that could help either reduce costs or better help withstand the impacts of adverse weather
8) Minimizing Toronto Hydro's impact on the environment
9) Providing quality customer service and enhanced communications
10) Replacing aging infrastructure that is beyond its useful life.[12]

In addition to identifying and categorizing customers' priorities, Innovative gathered feedback on how customers ranked these priorities. While customer preferences varied somewhat across rate classes, the overall feedback centered around the following common themes:

1. **Price and reliability are the top customer priorities:** Relative to price, reliability has become increasingly important to residential customers. When it comes to reliability, customers prioritize reducing the length of outages, with a particular focus on extreme weather events for residential and small business customers. Key Account customer are more sensitive to power interruptions and prioritize reducing the total number outages.
2. **New Technology:** Almost equally to price and reliability, customers expect the utility to invest in new technology that will reduce costs and make the system better, even if the benefits aren't immediate, as along as the costs and benefits are clear.
3. **System Capacity:** Customers expect Toronto Hydro to invest proactively in system capacity to ensure that high growth areas do not experience a decrease in service levels. The majority of Key Account customers surveyed have Net Zero goals to reduce their business' net greenhouse gas emissions to zero—and expect Toronto Hydro to support them in meeting their climate action objectives by ensuring that the system has capacity for growth and by providing them advisory services.

[12] Exhibit 1B, Tab 5, Schedule 1, Appendix A, page 5

This feedback informed Toronto Hydro's strategic planning direction, including the four investment priorities around which Toronto Hydro's plan is organized: **Sustainment, Modernization, Growth and General Plant**. As discussed in Section E2.1 above, the utility sought to deliver on customer needs and expectations by setting an upper capital expenditures limit that established a balance between keeping rate increases low while ensuring reliability performance and preparing the system for key pressures such as electrification and climate change in a prudent manner. Toronto Hydro concluded that a sustainment level of capital expenditures within its system renewal type investments would provide the minimum funding necessary to:

- maintain reliability over the period consistent with historical average;
- maintain long-term performance by preventing asset failure risk from increasing over the period;
- deliver targeted improvements to customers with below average reliability service; and
- maintain or, in targeted situations, improve upon the utility's performance in other priority areas (e.g. Customer Service, Safety, etc.).

Toronto Hydro also identified the need to invest in the system in 2025-2029 to prepare for increased electrification demands and technological changes expected in the near future. As explained in Section E2.2.1, the utility refined these strategic parameters into specific asset management objectives for the 2025-2029 period (see Table 1) and developed a draft business plan to achieve these objectives. The following subsections describe how each of these objectives aligns with specific Phase 1 Customer Engagement results.

E2.3.1.1 Financial Outcomes/Price

When customers were asked to rank their top three priorities, 46 percent of customers chose price, followed by reliability and investing in new technology at 45 percent each.[13] As compared to residential customers, small business customers appear to be more price sensitive. For small business customers, price is still the clear priority by a strong margin at 54 percent – followed by investing in new technology (40 percent) and reliable service (33 percent).

Commercial and Industrial ("C&I") customers (i.e. GS > 50 kW) expressed preferences similar to residential customers and prioritized reasonable rates and reliable services almost equally – at 50

[13] *Ibid.,* at page 5

percent and 48 percent respectively. This was followed by grid capacity expansion for climate action at 33 percent.

As discussed in detail in E2.1 and E2.2, Toronto Hydro developed a capital plan with necessary trade-offs to strike balance between price and performance/service outcomes that align with customer needs and priorities including: the overarching customer priorities of keeping rates reasonable, maintaining average reliability now and in the long-term, improving resiliency (outage duration), and investing in new technology in the 2025-2029 period. Leveraging the outputs of its asset management tools and processes, Toronto Hydro's plan was calibrated to find the right balance between these key objectives.

E2.3.1.2 Reliability

1. Customer Needs and Priorities

Reliability is becoming an increasingly important priority (on par with price) for residential customers, as compared to five-years ago when the utility conducted a similar customer engagement survey in the course of preparing the 2020-2024 Distribution System Plan and rate application.

When asked specifically about different types of reliability investments all customers, with the exception of Key Accounts, prioritized reducing the length of outages over reducing the number of outages. Residential and small business customers were particularly focused on the reliability impacts of extreme weather events, with a particular emphasis on the need to reduce restoration times in extreme weather events (70 percent and 60 percent respectively).[14]

Overall, Key Account customers prioritized reliable service including power quality (69 percent), followed by reducing outage restoration in extreme weather (52 percent). When asked about reliability investments specifically, the focus was on reducing the number of outages (78 percent) and improving power quality (73 percent). This focus on reducing outages reflects the practical reality that for large business customers any interruptions can be costly due to loss of product, or health and safety issues.

2. Plan Alignment

Toronto Hydro's objectives for its 2025-2029 Capital Expenditure Plan are aligned with and responsive to the customer feedback summarized above. When it comes to reliability performance,

[14] *Ibid.* at page 8.

the utility is balancing price with minimum investments to manage, and where appropriate, reduce asset failure risk through sustainment investments in order to maintain overall SAIDI and SAIFI performance over the plan period as discussed in E2.1 and E2.2 above.

Asset failure risk is assessed by leading indicators like asset condition. Section E2.2 describes the various ways in which the goal of either maintaining, or in some cases reducing, the level of asset risk informed the pacing of Toronto Hydro's investment programs. For example, the utility's pacing of pole replacement for the 2025-2029 period is intended to manage the deterioration of condition demographics of wood poles, which is a key issue for the overhead system. Similarly, Toronto Hydro plans to pace direct-buried cable replacement with the intention of preventing the significant reliability risks related to this asset type from increasing to an extent that would result in deteriorating service and high reactive repair costs over the long-term.

Toronto Hydro's plan also includes investments to improve the resiliency (i.e. the ability to handle emergency events) of the system and utility operations, which aligns with feedback received from residential, small business, and C&I customers. These investments are discussed throughout Section E2.2 and include targeted relocation or undergrounding of critical overhead infrastructure (Section E6.5), the renewal of major stations assets in the downtown core (Section E6.6), modernization of the network system (Sections E6.4 and E7.3), and investment in grid intelligence technologies for contingency enhancements and improved system observability (Section E7.1).

Available capacity is another leading indicator of reliability performance and the ability of the system to handle contingency events. This is especially true given accelerating pressures driven by electrification, which may result in higher asset utilization and subsequent degradation. It is also an important indicator of Toronto Hydro's ability to connect customers and carry-out planned capital and maintenance work efficiently. Toronto Hydro plans to maintain current performance for available capacity through investments in the Stations Expansion,[15] and Load Demand programs.[16]

E2.3.1.3 Investments in New Technology

1. Customer Needs and Priorities

Both Residential and Small business customers prioritize investing in new technology among their top three priorities. When asked specifically about different kinds of investments in new technology,

[15] *Supra* note 15.
[16] Exhibit 2B, Section E5.3.

residential, small business and C&I customers all prioritized investments in new technology that can help Toronto Hydro find efficiencies and reduce customer costs over other types of investments.

In addition, customers across all rate classes support:

- Investing in new technology that would make the system better even if there is an increase to customer rates, as long as Toronto Hydro is clear about the cost to customers and the potential benefits; and,
- Investing in technology that might not provide an immediate benefit but will in the future.

2. Plan Alignment

Toronto Hydro's plan includes paced investment in new technology to improve system performance and reduce costs over time. When it comes to the distribution grid, including system planning and operations, Toronto Hydro's 2025-2029 strategy for deploying new technology (i.e. its modernization strategy) is focused primarily on the steady deployment of industry proven technologies (e.g. reclosers, switches, smart meters, analytics) which the utility has prioritized and paced based on the expectation that they will (1) deliver benefits to customers in the near-term (e.g. improved reliability and operational efficiency), while (2) laying the foundation for more advanced use cases that will deliver greater benefits and essential capabilities in 2030 and beyond (e.g. fully automated "self-healing" grid capabilities; more advanced DER management capabilities to optimize DER value to the grid).

The investments that constitute Toronto Hydro's 2025-2029 Grid Modernization Strategy are largely an extension of the continuous modernization efforts which have delivered benefits for customers over the last decade. For example, a key part of Toronto Hydro's *Grid Readiness* portfolio within its 2025-2029 Grid Modernization Strategy (Section D5) is the Flexibility Services program (discussed in detail in Section E7.2.1). For this program, Toronto Hydro plans to build on the historical success of its Local Demand Response initiative by expanding the use of distributed resources for demand response purposes (i.e. flexibility services). Flexibility Services is a type of programmatic Non-Wires Solution which leverages customer-owned flexible assets to provide the utility with tools for managing capacity constraints. The program also provides customers with new revenue mechanisms and opportunities to engage with their distribution company. While Toronto Hydro expects the expansion of this program to have immediate benefits for customers in the 2025-2029 period (e.g., capacity risk mitigation in areas with local constraints; avoidance and deferral of capital investment), the expansion of this program (and implementation of the *Grid Readiness* portfolio plan more

broadly) will also be a crucial and necessary step in accelerating the utility's journey toward leveraging DERs in real-time and at scale – a capability that will be necessary to navigate the energy transition effectively and efficiently for customers in the long-term.

As detailed in Section D5, Toronto Hydro's 2025-2029 Grid Modernization Strategy follows a similar approach for all three major strategic portfolios (*Grid Readiness, Intelligent Grid* and *Asset Analytics & Decision-making*). Toronto Hydro is building on the utility's considerable experience deploying smarter technologies to deliver immediate benefits in 2025-2029, while laying the groundwork for more sophisticated capabilities and benefits that will be essential to maintaining performance and meeting heightened customer and stakeholder expectations for the electricity system beyond 2030.

Toronto Hydro is planning to continue with a similar approach for its corporate service functions and customer-facing service operations in 2025-2029. The utility plans to make paced technology investments to improve data quality, develop new insights and analytics, automate business and customer-facing processes, and deploy digital workforce tools to enhance the efficiency of day-to-day business operations and keep up with evolving customer needs and preferences for services and engagement.

As described in Section D8 ("Information Technology ("IT") Investment Strategy"), Toronto Hydro has a rigorous Enterprise Technology Portfolio ("ETP") framework to ensure consistency in IT investment decisions, establish and maintain governance of investments and achieve alignment with the utility's strategic objectives and target outcomes. Toronto Hydro intends to continue to apply a flexible and agile approach to its IT investments, leveraging the ETP framework and associated technology roadmaps to ensure investments are prioritized with the goal of delivering the appropriate balance of immediate and long-term outcomes for customers. For more details on planned IT/OT investments for the 2025-2029 period, refer to Exhibit 2B, Section E8.4 and Exhibit 4, Tab 2, Schedule 17.

E2.3.1.4 System Capacity Investments

1. Customer Needs and Priorities

Across all rate classes, customers support proactive investment in system capacity to ensure that high growth areas do not experience a decrease in reliability. Key Account and C&I Customers showed particularly strong support for these investments.

When asked to identify their general priorities, 33 percent of C&I customers identified the need to expand the capacity of the grid such that they can reduce their impact on climate change through electrification as one of their top three outcomes.

In fact, the majority (64 percent) of Key Account customers surveyed have Net Zero goals to reduce their business' net greenhouse gas emissions to zero – and expect Toronto Hydro to support them in meeting their climate action objectives by ensuring that the system has capacity for growth and by providing them with advisory services.

2. Plan Alignment

Toronto Hydro's growth-related investments in the 2025-2029 Capital Expenditure Plan are aligned with customers' expectations to proactively invest in system capacity infrastructure in high growth areas to ensure there is sufficient capacity to maintain current service levels. As discussed in detail in Section D4 – Capacity Planning, Growth and Electrification, when it comes to system capacity, the utility is balancing the need to invest proactively in expanding the system to serve the future needs of its customers with the practical reality that there is uncertainty surrounding the pace of the transition due to policy, technology and consumer behavior factors. Toronto Hydro adopted a "least regrets" planning approach to anticipate and minimize regretful outcomes in the light of this uncertainty.

To facilitate this approach, the utility enhanced its System Peak Demand Forecast with additional inputs for electric vehicles ("EVs"), data centers and Municipal Energy Plans, assessment of spare feeder positions, identification of system constraints that impact generation connections, and identification of unique drivers for demand growth. Toronto Hydro also augmented its decision-making process with the results of a long-term scenario modelling tool known as Future Energy Scenarios, which projects what demand would be under various policy, technology and consumer behaviour assumptions that are linked to Net Zero 2040 or 2050 objectives. The Future Energy Scenarios is described in more detail in Exhibit 2B, Section D4, Appendix A.

The resulting growth-related investments are described in Section 2.4.1 and include the connection of load and generation customers,[17] the accommodation of third-party relocations,[18] capacity

[17] Exhibit 2B, Section E5.1.
[18] Exhibit 2B, Section E5.2.

expansion,[19] and non-wires solutions.[20] Note that Toronto Hydro's "least regrets" investment approach is further reinforced by the utility's Grid Modernization strategy outlined in Exhibit 2B, Section D5. The Grid Modernization Strategy recognizes the need to prepare for coming transformations by transitioning towards a more technologically advanced distribution system, and developing advanced capabilities that over time will provide greater flexibility to:

- take a "wait and see" approach to capital investment needs that have a higher degree of uncertainty, and
- implement increasingly cost-effective technology-based solutions to address grid needs and deliver reliability, resilience, system security and other valuable customer outcomes as electrification accelerates in the next decade and beyond.

As part of this strategy, Toronto Hydro is investing in developing a more intelligent grid (e.g. contingency enhancements, and investments in sensors and next generation smart meters that are expected to improve grid observability, and the implementation of grid automation solutions such as FLISR). These modernization investments, once implemented on the grid and integrated into utility operations, provide enhanced capabilities to observe system performance at an asset-level and make real-time (and increasingly automated) operating decisions. Building these capabilities is necessary to improve accuracy and granularity of load forecasting and optimize the capacity and performance of a more heavily utilized grid, including at the neighbourhood level, where consumer technologies such as electric vehicles are expected to increasingly drive the need for low-voltage system expansions on a more rapid timescale.

E2.3.2 Phase 2 Customer Engagement

Toronto Hydro's consultant Innovative presented the draft plan to customers in the Phase 2 customer engagement to solicit feedback on the following:

- pacing and bill impacts for key investments areas in Toronto Hydro's plan;
- the price of the overall draft plan and whether customers are willing to accept it.

In an effort to be more transparent about the plan, its investments priorities, and outcomes including the price impacts, Toronto Hydro put its entire draft plan to customers. To help customers

[19] *Supra* note 15.
[20] Exhibit 2B, Section E7.2.

understand the investment priorities and provide feedback in terms of trade-offs between price and pacing towards outcomes, Toronto Hydro broke down the draft plan into seven key choices:

1. **Modernization**: Investments to build a smarter, more efficient and resilient grid for the future.[21]
2. **Growth**: Investment to increase the grid's capacity to reliably serve customers growing electricity needs.
3. **Sustainment**: Investments to manage reliability risk due to equipment failure.
4. **Sustainment:** Investments in the paced upkeep of equipment at or near end of life.
5. **Sustainment**: Investments to standardize outdated equipment.
6. **General Plant**: Investments in fleet, facilities and IT infrastructure to keep the business running efficiently.
7. **Decarbonization**: Investments to reduce greenhouse gas emissions from Toronto Hydro's operations by electrifying fleet and facilities assets.

E2.3.2.1 Phase 2 Results

For each of these options, Toronto Hydro put forward the draft plan, along with the options to spend more or less for faster or slower progress towards key outcomes such as reliability, system health, customer service, efficiency, and environment. The outcomes for each investment option were set out in a table, and the interactive slider allowed customers to dial the draft plan up or down based on their preferences. These options to spend more or less were grounded in the investment options developed and considered throughout the planning process.

After considering and providing feedback on the pacing and prioritization in the seven key areas noted above, customers were asked whether Toronto Hydro should stick with its proposed plan, accelerate spending to improve system outcomes, or scale back the plan. An average of 84 percent of customers, across all rate classes either supported sticking with the plan or spending more to improve system outcomes.

While a majority of customers supported the plan, or one that does even more to improve system outcomes, when asked to make certain trade-offs between price and pacing, customers expressed certain preferences to increase, maintain or reduce the pace of the investment plan. Through this

[21] For the purpose of Phase 2 Customer Engagement, Toronto Hydro mapped a portion of IT software enhancements including the Advanced Distribution Management System (ADMS) project, and cyber security investments to the Modernization category in order to provide customers a more comprehensive view of the price impact of this priority.

feedback on the investment categories, Toronto Hydro was also able to understand where customers prioritize spending.

Generally, customer preferences in terms of trade-offs between price and progress were in-line with Toronto Hydro draft plan in Modernization, Stewardship and Standardization, and slightly lower than the draft plan on Growth, Reliability and General Plant (including Running the Business and Decarbonization). Toronto Hydro used this feedback, along with other information obtained in the normal course of the planning process, to refine and finalize the Plan.

E2.3.2.2 Final Plan Adjustments

Toronto Hydro concluded from the Phase 2 Customer Engagement process that the draft plan achieved an appropriate balance between keeping prices reasonable and delivering the outcomes that customers need and prioritize. In addition, Toronto Hydro used the Phase 2 results to inform the finalization of the plan, making some adjustments where appropriate to reflect customer preferences. Overall, these customer-feedback driven adjustments yielded a further top-down constraint on the plan of approximately $70 million, as summarized in section E2.1.3 above.

E2.4 Portfolio Planning for 2025-2029

Toronto Hydro's Portfolio Planning process used the outputs of the Asset Needs Assessment to develop program-level expenditure plan proposals that would support the utility's asset management outcome objectives for 2025-2029.

As described in Section D3.4.3, Toronto Hydro developed bottom-up expenditure plan scenarios for each capital program, leveraging the asset lifecycle optimization and risk management practices and methodologies described in Section D3. The proposals were evaluated in relation to their potential contribution to: (i) the utility's outcome objectives and measures; and (ii) alignment with customer needs and preferences. The program proposals were further refined as a result of business inputs and information, as well as feedback received in the second phase of Customer Engagement (discussed in Section E2.3 above).

The following subsections describe how the outputs of the Asset Needs Assessment and the utility's asset lifecycle optimization and risk management practices informed the timing and pacing of the programs in the 2025-2029 Capital Expenditure Plan under the focus areas of Growth, Sustainment, Modernization, and General Plant.

E2.4.1 Growth Expenditures

Toronto Hydro developed a 2025-2029 Growth expenditure plan that is responsive to the utility's need to continuously meet its legally mandated service obligations, including the requirement to safely connect load and generation customers in a timely manner, and requirements to comply with revenue metering and billing standards. The pacing of investments in this category was largely dictated by the anticipated projected demand in these areas over the 2025-2029 period. Toronto Hydro considered the expected impacts of increased electrification demands on the grid in the 2025-2029 period and relied on the Peak Demand Forecast to understand growth drivers and the related investment needs.

Table 3: 2025-2029 Growth Expenditure Plan ($ Millions)

Capital Program	Costs ($M)
Customer Connections (Exhibit 2B, Section E5.1)	$477
Externally Initiated Plant Relocations & Expansions (Exhibit 2B, Section E5.2)	$76
Load Demand (Exhibit 2B, Section E5.3)	$236
Generation Protection, Monitoring, and Control (Exhibit 2B, Section E5.5)	$35
Non-Wires Alternatives (Exhibit 2B, Section E7.2)	$23
Stations Expansion (Exhibit 2B, Section E7.4)	$173
Growth Capital	**$965**

E2.4.1.1 Connecting Load Customers

Toronto Hydro's Customer Connections,[22] and Load Demand programs support the safe, timely, and cost-efficient connection of load customers.[23] Forecast expenditures for load connections are based on historical trends in gross cost and customer contribution amounts for load connection activities. They are also informed by development trends in the City[24] and the adoption of emerging technologies catered towards clean energy and electrification. The utility's 2025-2029 expenditure plan anticipates growth in new services, upgrades, and removals based on current and proposed development. (Refer to Section E5.1 for more details.)

[22] *Supra* note 17.
[23] *Supra* note 16.
[24] As described in Exhibit 2B, Section B2.2, Toronto Hydro's Development Planning team leverages the City of Toronto's development pipeline to engage large customers and developers with upcoming projects.

The Load Demand program addresses near-term system capacity constraints in areas of concentrated load growth. Toronto Hydro's Distribution Capacity and Capability Assessments (summarized in Section D3.3) identified a number of areas in both the Horseshoe and Downtown regions of the system where investments such as load transfers, cable upgrades, and equipment upgrades will likely be required to ensure the utility can continue to connect customers efficiently. These investments are also necessary to maintain sufficient grid flexibility to handle contingency scenarios and optimize planned work schedules, contributing to Toronto Hydro's reliability objectives and improving customer satisfaction by providing large customers with greater scheduling flexibility for planned outages.

Overall, the proposed expenditure plans in these two load-driven Growth programs reflect the investments required to connect customers in accordance with the OEB's service connection targets, while maintaining system performance for existing customers and improving the effects of scheduled outages on the operations of larger customers.

E2.4.1.2 Connecting Generation Customers

Toronto Hydro's Customer Connections,[25] and Generation Protection, Monitoring, and Control programs ("GPMC"),[26] support the safe, timely, and cost-efficient distributed energy resource ("DER") connections to the distribution system, including renewable energy generation ("REG") projects. The utility aligned the planned 2025-2029 expenditures in both programs with its 2023-2029 DER connection and capacity forecasts, illustrated in Figures 2 through 8 in Section E3. These forecasts considered historical connection trends, current pipeline of applications, the economic environment, government and regulatory incentives, and net zero initiatives. The utility currently projects that the total number of DER connections will grow from about 2,700 in 2023 to nearly 4,500 by the end of 2029 – an increase of roughly 67 percent.

Toronto Hydro's Generation Capacity and Capability Assessment (described in Section E3.3) identified a number of challenges to accommodating the forecasted 516.7 MW of DERs on the system by the end of 2029, including short-circuit capacity constraints, islanding risks, and system thermal limits. To address the above challenges and continue to connect all forecasted DERs, Toronto Hydro plans investments in Generation Protection, Monitoring, and Control,[27] and Energy Storage

[25] *Supra* note 17.
[26] Exhibit 2B, Section E5.5.
[27] *Ibid*.

Systems (Non-Wires Solutions Program).[28] Through the GPMC program, the utility aims to install six bus-tie reactors to address short-circuit capacity constraints and 315 monitoring and control systems to monitor system conditions in real time and to ensure all DER sites are de-energized in the event of a system fault. Through the Energy Storage Systems ("ESS"), Toronto Hydro intends to develop a scalable, demand-driven, ESS strategy that enables renewable integration. ESS can act as a load to prevent output curtailment from the renewable assets while ensuring a stable grid through controlling the minimum load to generation ratio. Toronto Hydro plans to deploy nine renewable-enabling ESS projects

E2.4.1.3 Accommodating Third-Party Plant Relocation Requests

The Externally Initiated Plan Relocations and Expansions program funds plant relocations and expansions triggered by third-party requests.[29] In accordance with OEB's Distribution System Code ("DSC") and related legislation (i.e. *Building Transit Faster Act, 2020* and *Public Works and Highways Act, 1998)*, Toronto Hydro is legally obligated to work cooperatively with third parties towards accommodating these requests in a fair and reasonable manner.[30][31] For the 2025-2029 period, the utility developed an expenditure plan to address committed relocation and expansion projects from third-parties, including Road Authorities (e.g. the City of Toronto), Metrolinx, and the TTC. Toronto Hydro gathers information on capital projects through direct consultation with external agencies, participation in the Toronto Public Utilities Coordination Committee, and reviewing governmental and public agency publications.[32] These capital plans and project schedules are subject to change at the discretion of the sponsor agencies, and any such changes typically impact the timing and potential the scope of Toronto Hydro's relocation and expansion work.

E2.4.1.4 Capacity Expansion and Demand Response

Whereas Toronto Hydro's Load Demand investments are driven by the short-term capacity needs of the system, its Stations Expansions investments are driven by long-term capacity needs of the system to renew and expand its stations. The utility's investment plans are informed by its Station Load Forecast (for more details see Section D4), the Regional Planning process, and are aligned with Hydro

[28] *Supra* note 20.
[29] *Supra* note 18.
[30] The Distribution System Code, (August 2, 2023), Section 3.1.10.
[31] *Building Transit Faster Act ("BTFA"), 2020*, S.O. 2020, c. 12 and *Public Works and Highways Act, 1998*, RSO 1990, Ch P.49.
[32] Exhibit 2B, Section B - Coordinated Planning

One's sustainment plans. Given the complexity and size of these individual projects, their expenditures are discrete and not conducive to smoothing over the rate period.

Investments for the 2025-2029 period are driven by anticipated bus-level constraints for stations serving areas of high growth and development, and are fully aligned with the results of regional planning activities conducted in coordination with the Independent Electricity System Operator ("IESO") and Hydro One.[33] The most recent planning document from this process is the Needs Assessment Report for the Toronto Region. Refer to Section B for more information on coordinated system planning with third parties. The proposed projects will add or free up 574 MVA capacity, supporting the sustainment of reliability, operational flexibility, and connections capabilities.

E2.4.2 Sustainment Expenditures

Continued proactive renewal expenditures are required during the 2025-2029 period to manage significant safety, reliability and environmental asset risks and to ensure stable and predictable performance for current and future customers.[34] As described in Section E2.2.1.1. above, approximately one quarter of Toronto Hydro's assets are operating beyond useful life. The system continues to age at a rate comparable to the projected rate of aging in recent rate periods, although a slight increase is expected in the assets at end-of-life by 2030. Condition demographic results continue to indicate substantial asset investment needs for a number of asset classes, and the utility continues to face challenges related to higher-risk, obsolete legacy assets and asset configurations such as rear lot plant and direct-buried cable.

The first phase of Customer Engagement revealed that most low-volume and medium-sized customers were satisfied with average reliability performance while larger users indicated a greater interest in reliability and reduction in restoration times. In light of these results, and leveraging the asset risk assessment and mitigation practices discussed in Section D3, Toronto Hydro developed program expenditure plans for 2025-2029 that ensure the minimum pace necessary to sustain overall asset risk and reliability performance at current levels, while also driving targeted outcome improvements. These outcome improvements include, reducing the risk of PCB contaminated oil spills, reducing the level of failure risk related to a significant backlog of aging and poor condition stations assets, and improving performance on worst performing feeders.

[33] It is also important to note that these investments are aligned with Hydro One's sustainment plans.
[34] See detailed description in Overview of Distribution Assets (Section D2) and in the System Renewal programs (Section E6).

Table 4: 2025-2029 Sustainment Expenditure Plan ($ Millions)

Capital Program/Segment	Costs
Area Conversions (Exhibit 2B, Section E6.1)	$237
Underground Renewal – Horseshoe (Exhibit 2B, Section E6.2)	$476
Underground Renewal – Downtown (Exhibit 2B, Section E6.3)	$165
Network System Renewal (Exhibit 2B, Section E6.4)	$123
Overhead Renewal (Exhibit 2B, Section E6.5)	$273
Stations Renewal (Exhibit 2B, Section E6.6)	$218
Reactive and Corrective Capital (Exhibit 2B, Section E6.7)	$328
Sustainment Capital	**$1,820**

E2.4.2.1 Overhead Asset Renewal Investments

Toronto Hydro's Overhead System Renewal,[35] Area Conversions,[36] and Reactive and Corrective Capital programs address failure and obsolescence risks related to overhead grid system assets.[37] The utility paced the 2025-2029 expenditure plan for these programs to: (i) maintain current system reliability performance; (ii) prevent age and condition related asset risk from accumulating over the period; and (iii) continue to reduce and eliminate safety and environmental risks and other deficiencies associated with legacy assets and asset configurations.

Demographic pressure on wood poles and pole top transformers is the key driver of overhead renewal need during the 2025-2029 period is.[38] Wood poles are critical to the safety and viability of the distribution system.[39] About 9,000 poles, or ten percent of Toronto Hydro's wood pole population, currently show at least material deterioration (i.e. HI4). The utility projects the total number of poles at material deterioration or worse condition could more than triple to an estimated 32,000 by 2030 without intervention (including an increase in poles at "end-of-serviceable life" from approximately 500 to over 7,000). Toronto Hydro's 2025-2029 expenditure plan will manage failure risk by prioritizing replacement of poles near or at "end-of-serviceable life" condition (i.e. HI5). The

[35] Exhibit 2B, Section E6.5.
[36] Exhibit 2B, Section E6.1.
[37] Exhibit 2B, Section E6.7.
[38] See section D2.1.1.
[39] Wood pole replacement is the highest-volume renewal activity out of the subset of assets that are analyzed through Toronto Hydro's ACA methodology. Given the importance of managing the overall condition-informed failure risk for this asset class over the planning period, the utility began tracking the wood pole condition demographics as a Custom Performance Measure starting in 2020 (see Section C for more details).

Overhead System Renewal program budgets for approximately 12,000 pole replacements from 2023 to 2029. In addition, the Area Conversions,[40] and the Reactive Capital programs will also include pole replacements.[41]

The percentage of pole-top transformer units operating beyond their 45-year useful life is projected to increase from 24 percent to 30 percent by the end of 2029. Compounding the reliability dimension of this risk is potential for oils spills, including spills containing PCBs, from pole-top transformer failure. The utility has paced pole-top transformer replacement to align with reliability objectives and to work towards eliminating the risk of PCB contaminated oil spills by 2025.



Figure 7: Rusted Overhead Transformers at Risk of Leaking Oil

The Area Conversions program addresses the obsolete, legacy overhead construction types which are an ongoing challenge for Toronto Hydro, including rear lot construction and box construction. Because of the continuing decline in rear lot plant performance, and the high complexity and duration of rear lot conversion projects, Toronto Hydro determined it is necessary to continue removing rear lot plant proactively at a steady pace, prioritizing areas where customers are experiencing the worst performance. For box construction, Toronto Hydro developed a plan for 2025-2029 that continues the strategy of eliminating all box construction poles by 2026, as first articulated in the 2015-2019 DSP. This is the fastest executable rate at which the utility can eliminate this legacy configuration.

[40] *Supra* note 36.
[40] *Ibid*.
[41] *Supra* note 37.



Figure 8: Box Construction (left). Replacing a transformer on a poor condition Rear Lot pole (right)

E2.4.2.2 Underground Asset Renewal Investments

Failure and obsolescence risks related to underground system assets are addressed by Toronto Hydro's Underground System Renewal – Horseshoe,[42] Underground System Renewal – Downtown,[43] Area Conversions,[44] and Reactive and Corrective Capital programs.[45] As with the overhead asset renewal investments, the 2025-2029 expenditure plan for these programs is paced to maintain system reliability, prevent age and condition related risk from accumulating and reduce and eliminate safety and environmental risks.

Legacy asset performance and risks – particularly the reliability-related failure risks associated with obsolete cables (i.e. direct buried and lead) – continue to be the most significant driver of renewal needs on the underground system. Underground cables have been the single greatest contributor to outages caused by defective equipment, resulting on average in 146,000 customer hours of interruption annually.

The utility's Asset Needs Assessment identified 666 circuit-kilometres of direct-buried cable and direct-buried cable in duct remaining in the Horseshoe area as of 2022. Of this, approximately 370 circuit-kilometres are of the highest-risk cross-linked polyethylene ("XLPE") type. Approximately 61 percent of this cable is currently beyond its useful life and the utility anticipates that 64 percent will be at or beyond useful life by end of 2029. To prevent reliability from degrading, the utility developed

[42] Exhibit 2B, Section E6.2.
[43] Exhibit 2B, Section E6.3.
[44] *Supra* note 36.
[45] *Supra* note 37.

a plan to proactively replace an estimated 182 circuit-kilometres of this cable in the Underground System Renewal – Horseshoe program during the 2025-2029 period, prioritizing the highest-risk neighbourhoods based on cable age, performance, criticality, and adjacency to other assets at risk of failure.[46]

Toronto Hydro's Asset Needs Assessment also resulted in the continuation of a long-term renewal strategy for lead cable in the downtown area. Due to the generally good reliability performance of lead-covered cable, Toronto Hydro has historically managed these assets through reactive and corrective interventions and targeted repairs. However, these cable types have shown signs of aging and declining performance in recent years and are largely considered obsolete in North America due to various safety and environmental risks (see Section E6.3 for more details).[47]



Figure 9: Collapsed cable splice

To manage the significant magnitude of this asset renewal need, Toronto Hydro developed a prioritization model to rank primary feeder cable segments in the system using factors such as historical failures, cable types, number of splices, age and customer base.[48] Based on this prioritization model, Toronto Hydro developed a plan to maintain reliability performance for affected customers by replacing approximately 3.5 percent of the 985 kilometres of paper-insulated lead-covered ("PILC") and 5.2 percent of the 176 kilometres of asbestos-insulated lead-covered PILC cable with modern polymeric cables in the 2025-2029 period.

[46] Given its significant impact on reliability and the fact that this is the utility's largest renewal activity, Toronto Hydro plans to continue reporting its progress on this plan as a 2025-2029 Custom Performance Measure under the Reliability outcome category (see Section C).
[47] There is only one supplier of paper-insulated lead-covered ("PILC") cable remaining in North America and no suppliers of asbestos-insulated lead-covered ("AILC") cable.
[48] The results of this analysis are summarized in Exhibit 2B, Section E6.3, Figures 1 and 2.

Other electrical assets addressed by the Underground System Renewal programs include transformers and switches in the Horseshoe area and on the Underground Residential Distribution ("URD") system, which serves low-volume customers in parts of the downtown area. These assets will be prioritized based on age, condition and historical performance and will largely be addressed in conjunction with underground cable rebuild projects and voltage conversion, except on the URD system and in cases where submersible, pad-mount and vault transformers must be replaced on a spot basis by 2025 to reduce risks of PCB contaminated oil spills.



Figure 10: Corrosion on top of a Submersible Transformer

The Underground System Renewal – Downtown program also continues a proactive cable chamber renewal plan. Managing the condition-related risk of failure of cable chambers is essential to ensuring the safety and long-term viability of the underground system. Toronto Hydro has historically managed these civil assets reactively, however, the latest Asset Needs Assessment identified a significant population of cable chambers with at least material deterioration. There are currently 130 cable chambers currently in "end-of-serviceable life" condition (HI5) and 462 in material deterioration condition (HI4). Toronto Hydro developed a plan to proactively help prevent condition demographics from deteriorating further over the 2025-2029 period by rebuilding approximately 45 cable chambers, replacing approximately 2,800 cable chamber lids, rebuilding over 120 cable chamber roofs and addressing an estimated 25 cable chambers that need to be abandoned.



Figure 11: Cable Chamber roof in HI5 condition (left), Cable chamber roof inside view (right)

Starting in 2025, Toronto Hydro is introducing a planned renewal segment to address underground switchgear in customer-owned vaults that feed apartment buildings, educational facilities and community centres. Previously Toronto Hydro managed the replacement of these assets on a reactive basis, however, these require replacement due to obsolescence. Toronto Hydro plans to target the worst condition and most critical assets to maintain average reliability performance for customers served by these assets.

E2.4.2.3 Network Asset Renewal Investments

Failure and obsolescence risks related to network system assets are addressed by Toronto Hydro's Network System Renewal,[49] and Reactive and Corrective Capital programs.[50] The utility paced the 2025-2029 expenditure plans for these programs to: i) maintain current system reliability performance; ii) improve resiliency and operational efficiency of the network; iii) prevent age, condition and obsolescence related asset risk from accumulating over the period; and iv) continue to reduce and eliminate safety and environmental risks (and other deficiencies) associated with legacy assets and asset configurations.

The network system plays an important strategic role in meeting the reliability expectations of interruption-sensitive customers in the City's core, which contains dense, high-traffic commercial and residential areas. The network system is designed to handle normal failure scenarios better than Toronto Hydro's other system configurations.[51] However, in the case of catastrophic failures such as a vault fire, the entire secondary network grid that is connected to the vault must be de-energized until the situation can be safely remedied, which can take over 24 hours. These types of failures can

[49] Exhibit 2B, Section E6.4.
[50] *Supra* note 37.
[51] Exhibit 2B, Section D2.2.3.

result in risks to public safety and the environment. To minimize these scenarios, Toronto Hydro takes a highly proactive approach to network equipment and vault maintenance and renewal.



Figure 12: Damage from a network vault fire

The risk of flooding continues to be a concern on the network system. As noted in Section D2.1.2, four of the 10 highest rainfall years on record have occurred in the last decade. Toronto Hydro developed a plan for the 2025-2029 period that targets non-submersible network units which are susceptible to water ingress and have elevated failure risks even when in good condition. There are currently 43 network transformers with material deterioration. Condition projections suggest that 149 units will be in HI4 and HI5 condition by 2029 without intervention. Age projections indicate that 50 percent of the system's network units will be at or beyond useful life by 2034. Toronto Hydro is planning to replace 95 units in 2023-2024 and 130 units in 2025-2029. This pace of replacement is expected to reduce failure risk on the network system by improving condition-related asset risk across the network unit population.

To mitigate risks to public and employee safety, the utility also plans to continue proactively renewing network vaults in poor condition. The number of vaults in HI4 and HI5 condition is expected to grow from 91 to over 130 by 2030 without intervention, which would represent 29 percent of the population. The utility is planning to proactively address 38 vaults over the 2025-2029 period. Network vault rebuilds are complex projects in congested areas and require significant planning efforts, making it necessary for the utility to maintain a steady and proactive renewal program over time.

Toronto Hydro plans to reconfigure three networks over the 2025-2029 period as part of its Network Circuit Reconfiguration segment (under Network System Renewal program).[52] This segment involves

[52] *Supra* note 49.

reconfiguring and re-cabling secondary grid networks into more robust spot vaults and enhanced grids. These reconfigurations will help improve outage restoration time and reduce risks associated with second contingency events for downtown network customers.

E2.4.2.4 Stations Renewal Investments

Toronto Hydro's Stations Renewal,[53] and Reactive and Corrective Capital programs address failure and obsolescence risks related to stations assets.[54] Stations assets are highly critical assets that have the potential for causing widespread and lengthy interruptions in the event of failure.[55] Stations asset replacement projects are complex and typically require long lead and execution timelines. In light of these operational constraints and a growing backlog of stations renewal needs, Toronto Hydro developed a plan for the 2025-2029 period that addresses stations equipment at a faster pace than in the 2020-2024 period. This is needed to maintain station asset demographics, as well as to replace obsolete station electromechanical relays with modern digital relays – an important part of Toronto Hydro's Intelligent Grid strategy as discussed in the Grid Modernization Strategy in Section D5.

The Asset Needs Assessment for stations assets continues to identify a significant backlog of aging equipment, with 42 percent of switchgear, 51 percent of power transformers, 48 percent of outdoor breakers, and 55 percent of DC battery systems operating at or beyond their useful life. The need for investment was further underscored by the high proportion of assets in moderate (H3), material (HI4), and end-of-serviceable-life (HI5) condition, as shown in Figure 13 below.

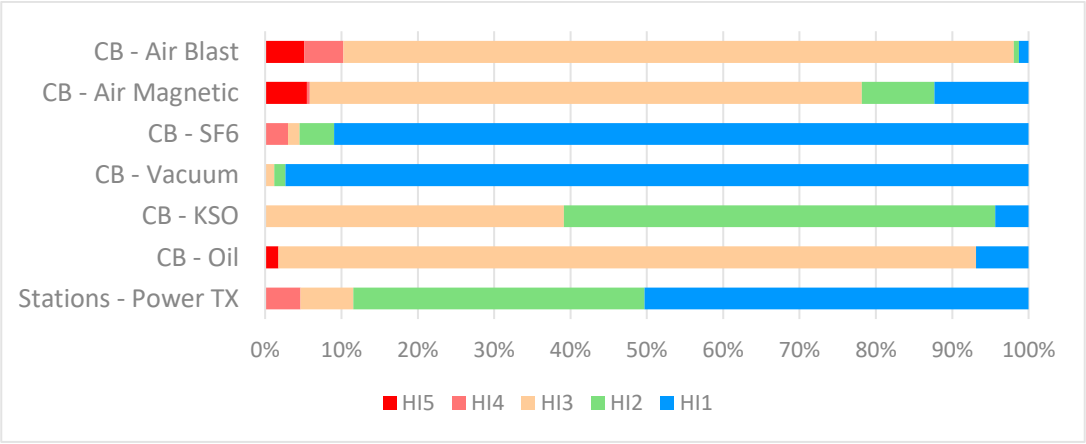


Figure 13: Asset Condition Assessment of Station Assets

[53] Exhibit 2B, Section E6.6.
[54] *Supra* note 37.
[55] *Supra* note 53.

Overall, in support of its objectives to maintain reliability, improve system resiliency, and manage the long-term viability of the distribution system, Toronto Hydro developed plans to execute the following stations work in the 2025-2029 period:

- Replace three TS switchgear units –serving the highest-density areas of Toronto – all of which are beyond their 50-year useful life and feature obsolete circuit breaker designs contained within non-arc resistant enclosures (elevating safety risks for employees);
- Replace 12 TS outdoor circuit breakers prioritized based on condition, age, load served, and at risk of containing PCB;
- Replace 63 TS outdoor switches that are beyond their 50-year useful life, reducing the risk of lengthy interruptions for customers in the North York area of Toronto;
- Remove 12 aging and deteriorating Municipal Station ("MS") switchgear with obsolete circuit breakers;
- Replace 15 power transformers, to mitigate an increased failure rate in this rate period and the next. All power transformers will be between 54 and 66 years of age at the time of replacement and have identified condition concerns such as high-power factor and low insulation resistance;
- Replace 1 end-of-life MS primary supply, which has assets older than 60 years of age at the time of replacement; and
- Renew end-of-life stations battery and ancillary systems.

E2.4.2.5 PCB Risk Reduction Strategy

Toronto Hydro's risk mitigation strategy for PCB contaminated oil spills is a key driver and prioritization consideration for multiple renewal programs. Due to the toxic and persistent nature of PCB, the Government of Canada's PCB Regulations[56] prohibit the use of equipment that contains greater than 50 ppm PCBs, or the release of greater than one gram of PCBs, which could result from an oil leak with significantly less than 50 ppm. The City of Toronto also enforces its own PCB-related bylaws with a near-zero tolerance for the discharge of PCBs into the storm and sanitary sewer systems.

Toronto Hydro is continuing its efforts to eliminate the risk of oil spills containing PCBs on its overhead, underground, and network systems by 2025 through inspection and testing under its

[56] PCB Regulations (SOR/2008-273), under the *Canadian Environmental Protection Act, 1999.*

maintenance programs (discussed in Exhibit 4, Tab 2, Schedules 1-4) and through targeted asset replacement as set out in the programs described above.[57]

E2.4.3 Modernization Program Expenditures

Toronto Hydro developed a 2025-2029 Modernization expenditure plan that targets a select number of system enhancement needs that support the utility's asset management objectives for the period and deliver customer value using technology-driven solutions. Toronto Hydro's modernization investments are aligned with its 2025-2029 Grid Modernization Strategy, discussed in Section D5. This strategy is driven by a confluence of external drivers – including accelerating climate change; emerging decarbonization and energy innovation policy mandates; rapid digitalization of the economy; and potential decentralization of the energy system (i.e. Distributed Energy Resources) – which threatens to overwhelm grid capacities and capabilities in the long-term if not proactively addressed. The Grid Modernization Strategy addresses these emerging challenges and parallel opportunities in a paced manner that leans first and foremost into the deployment of proven technologies (e.g. reclosers, switches, smart meters, analytics), which will deliver benefits to customers in the near-term (e.g. improved reliability), while laying the foundation for more advanced use cases that will be required in 2030 and beyond. Complementing this focus on proven technology is a secondary emphasis on innovation. There are certain challenges – e.g. cost-effectively increasing the amount of distributed generation that can connect to congested feeders – for which the optimal technological and commercial solutions are not yet settled or mature. In these areas, Toronto Hydro is planning to increase its investment in pilot projects and industry partnerships, which the utility believes can contribute to accelerated progress across the entire sector. For a comprehensive overview of the core elements of the Grid Modernization Strategy, refer to Section D5.

Table 5: 2025-2029 Modernization Expenditure Plan ($ Millions)

Capital Program/Segment	Costs ($M)
System Enhancement (Exhibit 2B, Section E7.1)	$151
Network Condition Monitoring and Control (Exhibit 2B, Section E7.3)	$6
Metering (Exhibit 2B, Section E5.4)	$248
Overhead Resiliency (Exhibit 2B, Section E6.5)	$86

[57] Overhead System Renewal (*Supra* note 35.), Underground System Renewal (*Supra* note 42 and 43), Stations Renewal (*Supra* note 52), and Reactive and Corrective Capital (Exhibit 2B, Section E6.7). Refer to each of these programs for a description of how the planned investments address PCB at-risk equipment and potential challenges.

Capital Program/Segment	Costs ($M)
Stations Control and Monitoring (Exhibit 2B, Section E6.6)	$65
IT Cyber Security & Software Enhancements (Exhibit 2B, Section E8.4) [58]	$94
Modernization Capital	**$651**

E2.4.3.1 Metering Investments

Investments in the Metering program (Section E5.4) are triggered by the need to remain in compliance with OEB's minimum standards for billing accuracy and Measurement Canada and IESO requirements related to metering and billing. Based on a needs assessment for its metering assets, Toronto Hydro developed a plan for 2025-2029 that is largely driven by the timing of metering and metering system upgrade cycles. Residential and Small Business (C&I) Meter Replacement activities will continue in order to address end-of-life meters with expiring seals. Toronto Hydro cannot, as a matter of law, bill customers using meters with expired seals. Through these replacements, Toronto Hydro plans to install next generation smart meters (referred to as Advanced Metering Infrastructure 2.0 or AMI 2.0) and upgrade the supporting metering infrastructure. AMI 2.0 will play an important role in establishing a greater level of system observability within Toronto Hydro's Grid Modernization Strategy. For more information on expected use cases for AMI 2.0, please refer to Section D5.2.2 and D5.3.1.

E2.4.3.2 System Design Enhancements and Modernization

Through the Asset Needs Assessment and the Portfolio Planning process, as well as the parallel Grid Modernization Strategy development exercise, Toronto Hydro identified several targeted opportunities to address asset risk and enhance customer value by improving system design and investing in system modernization. The bulk of this planned investment is in the System Enhancements (Section E7.1) and Network Condition Monitoring and Control (Section E7.3) programs. These programs will continue Toronto Hydro's efforts to identify places on the system where asset failure risk can be mitigated, outage restoration capabilities improved, and future operational costs reduced through the installation of protection devices and remote SCADA-enabled switches and sensors.

[58] For the purpose of Phase 2 Customer Engagement, Toronto Hydro mapped a portion of IT software enhancements including the Advanced Distribution Management System (ADMS) project, and cyber security investments to the Modernization category in order to provide customers a more comprehensive view of the price impact of this priority.

The Network Condition Monitoring and Control program was introduced for 2020-2024 and arose out of the need to address performance risks and connection capability challenges on the network system. These issues risk eroding the long-term viability of the network at a time when its compact and reliable design is becoming an increasingly effective option for medium and large customers in developing, high-density areas of the City. Toronto Hydro expects to continue its original objectives of the program to install monitoring and control equipment and fibre optic cable in approximately 920 network vaults by the end of 2026. This will complete Toronto Hydro's first major implementation of an entirely new set of distributed smart grid capabilities since the initial roll-out of AMI. Organizational learnings from this program, including the successful achievement of reliability, and cost reduction and avoidance benefits, will be applied to the implementation of Toronto Hydro's 2025-2029 Grid Modernisation Strategy. Pilot projects to further enhance network monitoring capabilities, such as the installation of fire sensors, analog water sensor, a vault camera, vault hatch open sensor, and secondary cable monitoring with cable sensors will commence after 2025. These improvements will enhance Toronto Hydro's ability to detect emergencies earlier and prevent catastrophic accidents from occurring.

Over the 2025-2029 period, the System Enhancements program is comprised of three investment initiatives that will strategically address critical issues like operational constraints, security-of-supply risks and system operational inefficiencies. The Contingency Enhancement segment will continue to enhance Toronto Hydro's ability to efficiently restore power to customers in the Horseshoe and Downtown areas. By installing 205 new SCADA switches in the Horseshoe, this segment will ensure that at least 90 percent of Horseshoe feeders have the minimum infrastructure (SCADA switches and reclosers) in place to integrate into a "self-healing" network beginning in 2030. It will deploy a total of 298 switches and 220 reclosers more broadly on parts of the system that can benefit materially from improved outage restoration and protections, contributing to Toronto Hydro's objective of improving SAIDI generally, as well as improving reliability for customers on poor performing feeders over the 2025-2029 period, and ensuring the system has appropriate flexibility to maintain reliability and operate efficiently over the long-term in the face of demand growth and potential DER proliferation. The Downtown Contingency segment allows for N-2 (i.e. two station loss-of-supply issues at the same time) operational capability to address serious, high-impact loss-of-supply scenarios for areas of the city with critical institutional and economically significant loads. Copeland Station is the optimal downtown anchor source, and for the 2025-29 period, eligible stations with 3000A feeder positions will receive station-to-station switchgear ties. Lastly, in accordance with Toronto Hydro's grid modernization goals, the System Observability segment will introduce new

equipment that improves reliability and system awareness of the distribution system, contributing to improved operational efficiency, outage response, asset management decision-making, and load and generation forecasting. This will be achieved through the targeted deployment of sensors (such as overhead and underground sensors, online cable monitoring, and transformer monitoring) that will provide the utility's planners and grid operators with real- or near-real time insight into asset performance and operating conditions at critical points on the grid.

In addition to the System Enhancements and the NCMC programs, Toronto Hydro plans to renew and modernize protection, control, monitoring, and communication assets at its Transformer and Municipal Stations. Replacing these deteriorated and obsolete assets enables the utility to sustain reliability, and advance the modernization of Toronto Hydro's substations. During the 2025-2029 period, Toronto Hydro plans to renew 33 existing Remote Terminal Units (RTUs) and replace 251 obsolete relays with modern digital relays.

E2.4.3.3 System Resiliency

Over the 2025-2029 period, Toronto Hydro is reintroducing and expanding the work done through the 2015-2019 Overhead Infrastructure Relocation program[59] to improve the resiliency of the overhead system through targeted relocations and/or undergrounding of overhead assets that are vulnerable to power outages during major storm events. Specifically, Toronto Hydro seeks to (i) underground critical sections of overhead infrastructure that are persistently affected by outages caused by external factors; (ii) relocate overhead sections in areas with limited access; and (iii) reconfigure and, if necessary, underground pole lines exiting stations that carry three or more circuits.

By increasing the resiliency of the system, these investments will reduce the impact of outages due to weather events on customers, and as such are responsive to customer reliability priorities as described in Section E2.3.1.2.

E2.4.3.4 IT Software Enhancements

Modernization efforts with respect to the grid and business operations are supported by various IT software investments during the 2025-2029 period, which includes the Advanced Distribution Management System ("ADMS"). For example, while the System Enhancement program deploys SCADA switches on the distribution network, which are critical for distribution automation, IT

[59] EB-2014-0116, Exhibit 2B, Section E6.5

initiatives, such as the implementation of manual Fault Location, Isolation and Service Restoration (FLISR) technology (as part of the broader ADMS project) in 2025-2029, will apply real-time analytics to the operation of these switches to support further reductions in fault isolation and service restoration duration. These investments are also foundational to Toronto Hydro's goal of preparing the Horseshoe grid for the implementation of a fully automated, self-healing grid operation beginning in 2030. More broadly, Toronto Hydro intends to accelerate investment in data quality and governance, system integrations, data analytics, process automation, customer facing tools, and decision-making platforms in 2025-2029 to enhance value for customers and establish the foundations and capabilities for longer-term efficiency and sustainable performance. For more information on enhancements, refer to the Grid Modernization Strategy in Section D5 and the IT Investment Strategy in Section D8.

Over the 2025-2029 period and as part of its broader Modernization efforts, Toronto Hydro also plans to continue to invest in cybersecurity controls to monitor digital threats and ensure a robust response to intensifying risks in this area. The investment plans were developed such that the utility is able to maintain its cybersecurity posture at current levels while developing future state readiness to adapt to the constantly changing cybersecurity threat landscape.

E2.4.4 General Plant Expenditures

Toronto Hydro developed a General Plant expenditure plan leveraging the asset management principles and strategies outlined in Sections D6 ("Facilities Asset Management"), D8 ("IT Asset Management"), and Section E8.3 ("Fleet and Equipment Services"). This plan also supports Toronto Hydro's Net Zero 2040 strategy as set out in Section D7 ("Net Zero 2040"). Investments in this category are necessary to keep the utility running efficiently and effectively and are generally driven by lifecycle cost management principles, business continuity needs, and emerging customer needs and preferences.

Table 6: 2025-2029 General Plant Expenditure Plan ($ Millions)

Capital Program/Segment	Costs
Enterprise Data Centre (Exhibit 2B, Section E8.1)	$72
Facilities Management and Security (Exhibit 2B, Section E8.2)	$145
Fleet and Equipment Services (Exhibit 2B, Section E8.3)	$44

Capital Program/Segment	Costs
Information and Operational Technology (Exhibit 2B, Section E8.4)[60]	$206
General Plant Capital	**$467**

E2.4.4.1 Fleet and Facilities

Investments in Facilities Management and Security,[61] and Fleet and Equipment needs are primarily driven by asset obsolescence, condition and lifecycle cost analysis for major work centres, stations buildings, physical security systems, and vehicles.[62]

Investments are also driven by the decarbonization goals set out in the utility's Net Zero 2040 strategy (Section D6). In order to meet these goals, the utility plans to electrify fleet and facilities assets. Specifically, Toronto Hydro intends to reduce emissions from its vehicles and work centres by: (i) replacing gasoline and diesel power vehicles with hybrid and electric vehicles, and (ii) converting natural gas boilers and heaters in the work centres to electric boilers and heaters.

E2.4.4.2 Information and Operational Technology (IT/OT)

The utility's planned IT/OT Systems investments[63] for the 2025-2029 period are primarily directed at maintaining current business capabilities, with the remainder directed at expanding existing business capabilities or driving new ones in alignment with outcome objectives and customer needs. The IT/OT program consists of the following key elements:

- **IT Hardware:** Planned expenditure levels were developed to align with asset lifecycles for backend assets (e.g. servers) and endpoint assets (e.g. laptops) that require replacement, and to meet anticipated business needs as forecasted through business planning.
- **IT Software:** Planned expenditure levels were developed in anticipation of upgrade requirements (i.e. security patches, version upgrades to secure vendor support, etc.) for major IT systems such as the utility's Enterprise Resource Planning ("ERP") and other minor applications. Expenditures also include regulatory compliance needs and a portion of software enhancements to improve and expand business functionality.

[60] *Supra.* note 58.
[61] Exhibit 2B, Section E8.2.
[62] Exhibit 2B, Section E8.3.
[63] Exhibit 2B, Section E8.4.

- **Communication Infrastructure:** Planned expenditure levels were developed to address communications infrastructure that is relied upon by core utility operations to maintain and operate the distribution system in a safe and reliable manner. Proposed investments will address functional obsolescence and reliability risk (e.g. upgrading the communications technology that supports the utility's critical SCADA system), safety and operational risks (i.e. underground radio expansion) and support for system modernization investments (e.g. fibre-optic plant replacement and expansion to support Network Condition Monitoring and Control).

To inform the level of overall IT/OT expenditures, Toronto Hydro procured an independent benchmarking study by Gartner Consulting (see Section D8, Appendix A), which concluded that Toronto Hydro's IT expenditures as of 2022 benchmark competitively against industry peers and the increase in Toronto Hydro's 2022 IT spending compared to 2017 is similar to industry peers. Gartner also concluded that, in both years, the distribution of Toronto Hydro's IT investments "by cost category, investment category, and functional area are all comparable to the peer group, with the exception of higher allocations to Applications spending ([…] largely due to the Customer Information System ("CIS") upgrade) and IT Management and Administration ([…] largely due to increased investment in Cyber Security services)."

E2.4.4.3 Enterprise Data Centre

Toronto Hydro's operations are supported by its Enterprise Data Centre ("EDC"), which houses the utility's essential networking, telephony and telecommunications systems, data storage and backup systems and server infrastructure across two distinct locations that collectively support organization-wide ("enterprise") processes. Toronto Hydro will need to store more data within its EDCs as the utility continues to build, maintain, and operate its distribution system in accordance with the evolving needs and nature of load customers, DER owners and operators, and other stakeholders, and as the utility modernizes its systems and practices by introducing new enterprise systems and business processes throughout the 2025-2029 rate period.

Although Toronto Hydro has prudently managed and maintained reliability and operational resilience at its EDC locations through its robust asset management strategy and asset renewal and repair activities,[64] the utility expects that EDC 1 will reach its capacity within the next five years and

[64] Exhibit 2B, Sections D6 (Facilities Asset Management Strategy) and E8.2 (Facilities Management and Security), and Exhibit 4, Tab 2, Schedule 12 (Facilities Management OM&A program).

will no longer be able to accommodate new data and support new systems. As such, Toronto Hydro proposes to relocate EDC 1 to another centre to enhance the overall redundancy and resiliency of the EDC and minimize the risks of an organization-wide outage.

E2.4.4.4 Portfolio Reporting

The Portfolio Reporting element of IPPR directly informed the development of capital program expenditure plans for the 2025-2029 period. In particular, Toronto Hydro analyzed actual project accomplishments and costs in each program to establish the project- and/or volume-based assumptions that would form the basis of the high-level program cost estimates for the 2025-2029 period.[65] Due to the unique nature of work in each capital program (e.g. large discrete assets vs. area rebuilds; like-for-like vs. reconfiguration), Toronto Hydro's planners relied on different estimating approaches for different programs, leveraging both historical information and professional judgement. These assumptions were challenged and refined throughout the IPPR process and business planning.

E2.4.4.5 Capital Program Efficiency and Unit Cost Benchmarking

To assess the actual efficiency with which Toronto Hydro executes its system investment and maintenance programs, the utility retained UMS Group ("UMS") to perform a capital and maintenance unit cost benchmarking exercise. The utility provided UMS with actual, all-in capitalized unit costs for major asset classes for the 2020-2022 period. UMS performed a normalized comparison of these results to those of peer utilities across North America.

Overall, UMS found that Toronto Hydro's unit costs ranged from minus 12.2 percent to plus 1.9 percent relative to the median. These results provide an indication that the utility has delivered its large capital program cost-effectively through rigorous project development, program management, procurement, and execution practices. UMS also noted that if certain qualitative considerations, such as customer density, were statistically normalized for, Toronto Hydro's comparative ranking would be better than shown. The study can be found at Exhibit 1B, Tab 3, Schedule 3, Appendix C.

[65] For many DSP programs, it is practically infeasible to develop project-specific details for a five- to seven-year planning horizon. Planners used a mix of analogous and parametric estimating techniques to create high-level estimates for the programs in these situations. Analogous estimating involves creating a "top-down" estimate of a project's cost and duration using experience with similar projects. Parametric estimating involves identifying volumetric costs and scaling the project or program estimate by the volume of units.

E3 System Capability Assessment for Renewable Energy Generation and Distributed Energy Resources

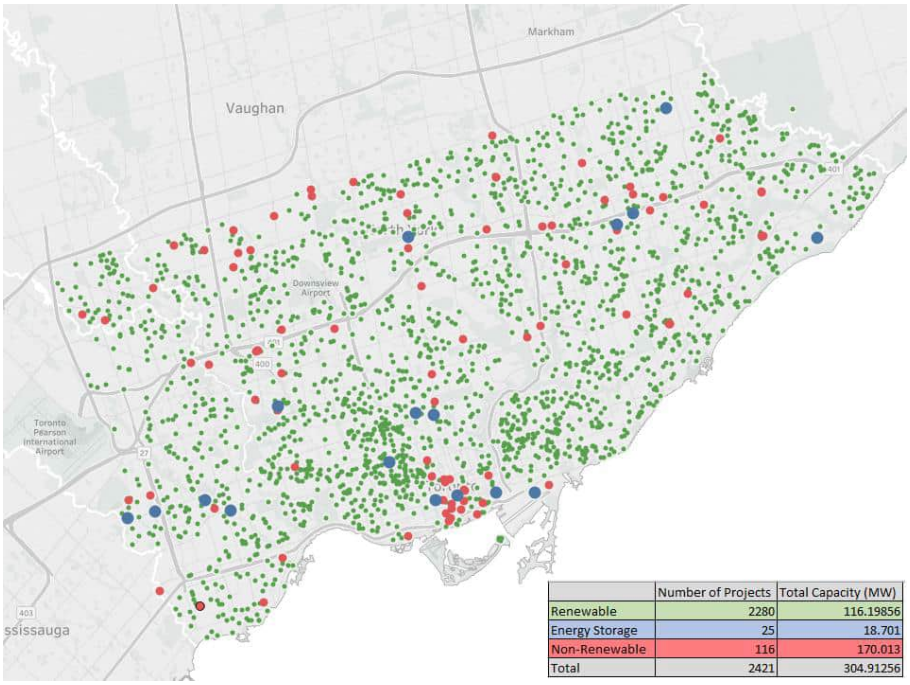
This section provides information on the capability of Toronto Hydro's distribution system to accommodate renewable energy generation and other distributed energy resource ("DER") connections. This information includes renewable DER applications, overall DER connection projections, the distribution system's ability to connect, as well as known constraints on the distribution system.

E3.1 DER Applications

Since the introduction of the *Green Energy and Green Economy Act, 2009*, Toronto Hydro connected over 2400 DERs under various programs including FIT, HCI, PSUI-CDM, RESOP, HESOP,[1] and Net-Metering. In 2018, the FIT and micro FIT programs ended, and the *Green Energy and Green Economy Act, 2009* was repealed on January 1, 2019. Interest in generation projects within Toronto Hydro's service territory saw a greater than anticipated decrease in renewable pre-assessment applications in the years immediately following the conclusion of the FIT program in 2018. However, customers have continued to show an interest in DER projects, and connections continue to grow, albeit at a slower pace. Toronto Hydro continues to receive applications from a wide range of proponents including, but not limited to, individual residential addresses, public transit facilities, housing developments, large grocery stores, educational facilities, and hospitals.

As of the end of 2022, Toronto Hydro has 2,424 unique DER connections to its distribution grid. Figure 1 provides an overview of existing DER connections within Toronto Hydro's service territory. This represents over 304.9 MW of generation capacity across various types of DER technologies.

[1] Feed-in Tariff ("FIT"); Hydroelectric Contract Initiative ("HCI"); Process and Systems Upgrade Initiative – Conservation Demand Management (PSUI-CDM"); Renewable Energy Standard Offer Program ("RESOP"); and Hydroelectric Standard Offer Program ("HESOP");



	Number of Projects	Total Capacity (MW)
Renewable	2280	116.19856
Energy Storage	25	18.701
Non-Renewable	116	170.013
Total	2421	304.91256

Figure 1: Toronto Hydro DG Connections (as of December 31st, 2022)

From 2018 to 2022, Toronto Hydro connected about 93.2 MW of generation to its distribution system, which represents approximately 22.8 percent of the 408.4 MW connected capacity that was projected for the same time period in the 2020-2024 rate application. The lower than expected DER capacity connected during this period can be attributed to various reasons:

- The conclusion of the FIT program in 2018 led to a greater than anticipated decrease with a 71.9 percent decline in renewable DER pre-assessment applications in the years immediately following the cancellation across residential, commercial & industrial segments.
- Changes in the IESO Process Systems & Upgrade program in 2019 made fossil-fuel based CHP projects ineligible for incentives.
- During the COVID-19 pandemic there was a sharp reduction in applications for pre-assessments for DERs by commercial and industrial businesses. Subsequently, connections fell well below pre-pandemic expectations.
- A number of large projects were placed on hold indefinitely by customers or were cancelled, including, but not limited to, a 9.87 MW biogas generator project, a 15 MW energy storage system, and a 10 MW diesel synchronous generator project.

E3.2 Forecasted DER Connections

Toronto Hydro's 2023-2029 DER connection and capacity forecast considers a combination of historical trends, project pipeline, economic environment and the current energy policies at the time of the forecast.[2] Total DER projects are expected to contribute a total increase of 67 percent to total installations, reaching nearly 4,500 connections by the end of 2029, as shown in Figure 2. This represents a total DER installed capacity of approximately 516.7 MW by the end of 2029 in comparison to the 304.9 MW installed as of the end of December 2022, depicted in Figure 3.

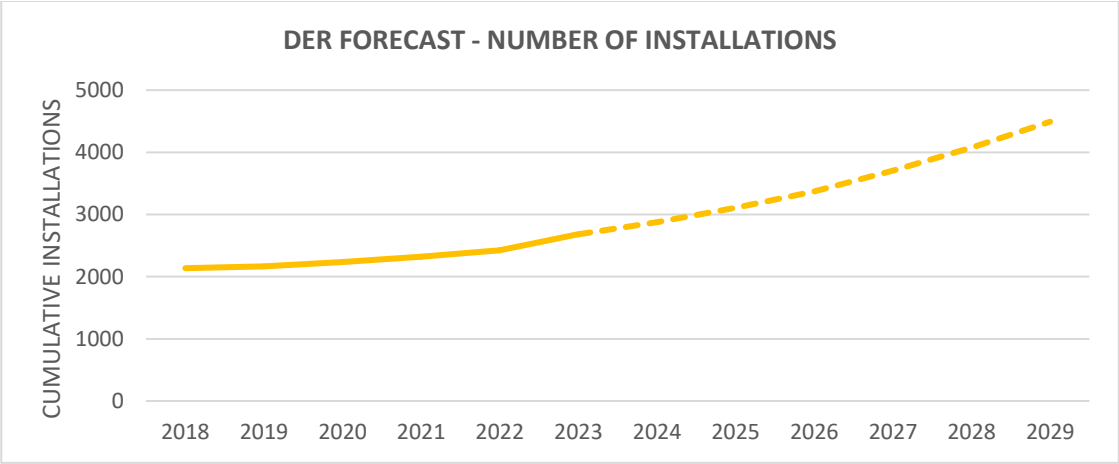


Figure 2: Historical and Forecasted DER Installations

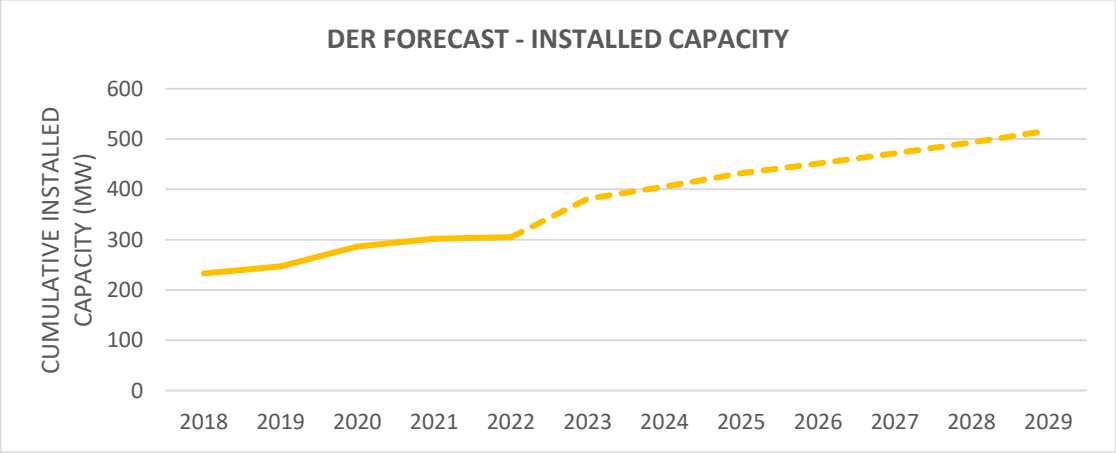


Figure 3: Historical and Forecasted Installed DER Capacity

[2] See Exhibit 2B, Section E5.1.3.2 for further details of Toronto Hydro's DER connection forecast methodology.

Toronto Hydro organizes its DER forecast into renewable, energy storage and non-renewable categories. As of the end of 2022, renewable installations represent the largest category of DER by number of connections while non-renewables represent the largest category by generation capacity. Non-renewable DERs are generally larger capacity connections used to support large commercial or industrial facilities. With more emphasis on decarbonization, it is expected that the combined installed capacity for renewable and energy storage facilities could surpass non-renewables by 2029 as shown in Figure 4.

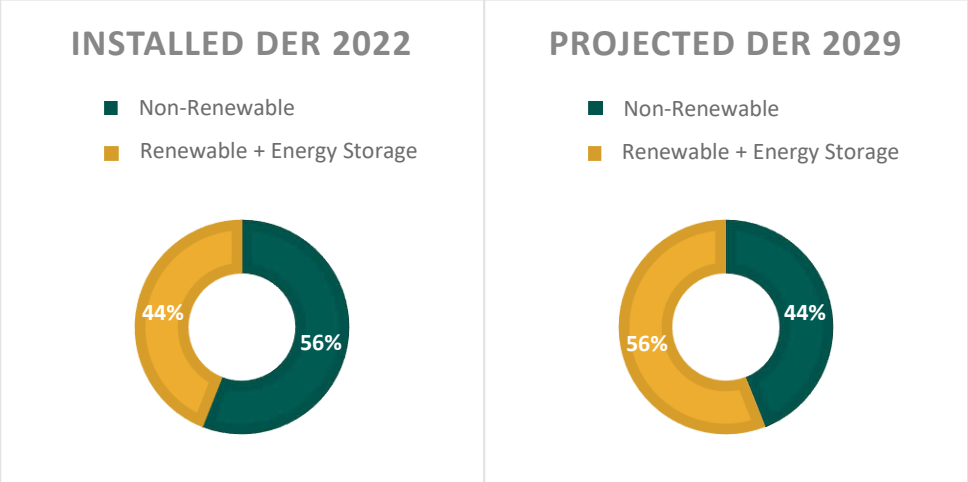


Figure 4: DER Composition by Installed Capacity

E3.2.1 Forecasted Connections for Renewable

Between 2023 and 2029, Toronto Hydro forecasts over 1700 additional renewable connections (totalling over 74 MW) to the distribution system. This would bring total installed capacity to approximately 200 MW as shown in Figure 5. This rate of growth is in alignment with the Ontario Distributed Energy Resources Impact Study conducted by ICF and submitted to the OEB in 2021.[3]

[3] Ontario Energy Board, ICF, Ontario DER Impact Study (January 18, 2021), online, https://www.oeb.ca/sites/default/files/ICF-DER-impact-study-20210118.pdf

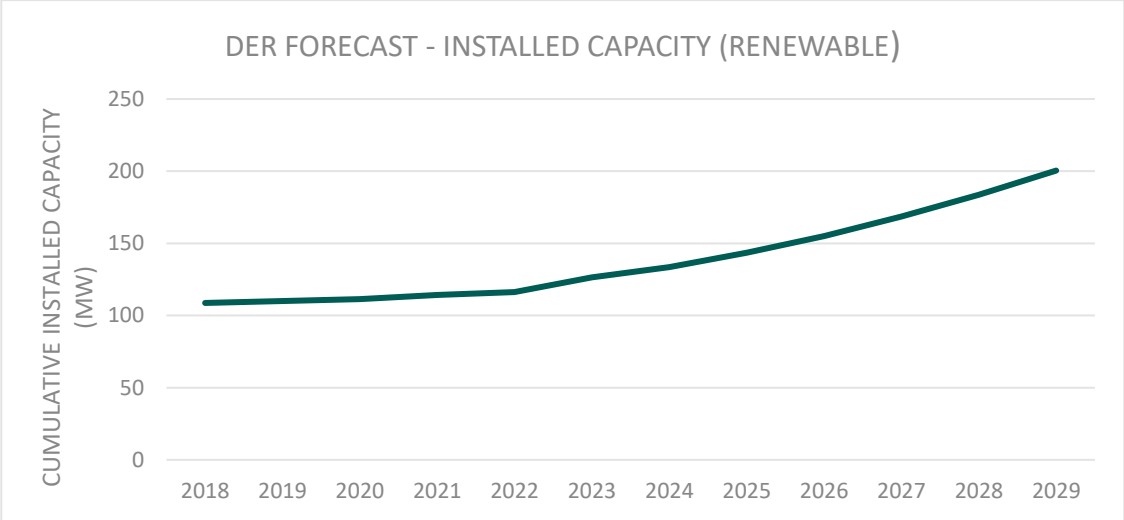


Figure 5: Historical and Forecasted Renewable DER Installed Capacity

E3.2.2 Forecasted Connections for Energy Storage

Although in recent years Toronto Hydro saw a reduced interest in energy storage projects, the utility forecasts a return to high growth by the end of decade. As of the end of 2022, Toronto Hydro connected 28 energy storage projects with total generating capacity of 18.7 MW, the vast majority of which are used in commercial and industrial applications, including for the reduction of global adjustment charges. Toronto Hydro's current energy storage project pipeline anticipates the connection of 12 projects by the end of the year with a combined capacity of 31.9 MW.

Beyond 2025, Toronto Hydro expects that energy storage growth will return to linear growth patterns, similar to pre-pandemic levels. Between 2023 and 2029, Toronto Hydro forecasts over 50 additional energy storage connections (totalling over 70.8 MW) to the distribution system. This would increase the total number of connections to 82 by 2029, and the total installed energy storage capacity to 89.5 MW, as depicted in Figure 6.

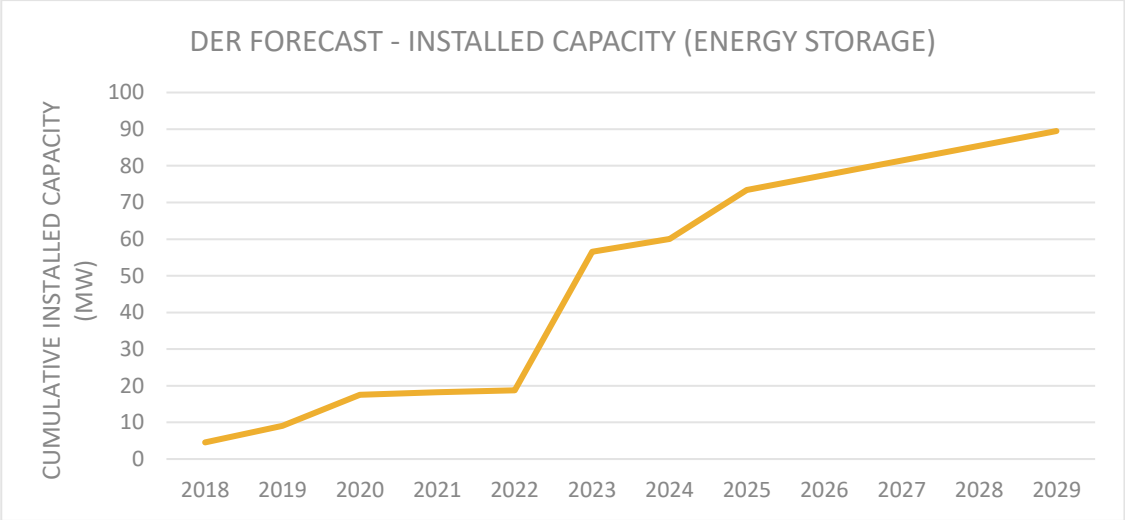


Figure 6: Historical and Forecasted Energy Storage Capacity

E3.2.3 Policy Considerations

Customer choice is the key driver of DER demand, and this driver can be greatly impacted by policy, including the available funding and incentives. The FIT program is a testament to the significant impact that policy and incentives can have on the renewable DER uptake by customers. Between 2009 and 2018 when the FIT program was active, DER installed capacity increased from 1.4 MW to 108.7 MW—a compound annual growth rate of 62.2 percent. When the FIT program ended, the renewable energy annual average growth rate fell to 1.7 percent over 2018 to 2022.

Policies and economic factors that may impact the rate of renewables and energy storage connections include:

- **Green Energy Tax Credit –** Announced by the Federal Government in November 2022, the Green Energy Tax Credit is a refundable credit of up to 30 percent of the capital cost of investments in specific generation systems, including solar PV and battery storage systems.[4]
- **Third Party Ownership of Net Metered Generation Facilities –** On July 1, 2022, the OEB enacted changes to enable third-party ownership of Net Metered generation facilities,

[4] Environment and Climate Change Canada, Clean Investment Tax Credits in Budget 2023, "online", https://www.canada.ca/en/environment-climate-change/news/2023/04/minister-guilbeault-highlights-the-big-five-new-clean-investment-tax-credits-in-budget-2023-to-support-sustainable-made-in-canada-clean-economy.html

opening up access to the program for customers who may not be in a position to own or operate their own behind-the-meter renewable energy generating equipment.[5]

- **Lithium Ion Battery Cost** – Lithium Ion battery prices have decreased by more than 79 percent since 2013 and are expected to continue to decrease.[6] The combination of solar PV and energy storage allows users to maximize the use of solar PV generated energy that can only be captured during the day.
- **Ultra-Low Overnight Price Plan** – In 2023, Ontario launched an "Ultra-Low" (ULO) overnight price plan for residential and small business customers. The ULO plan offers an overnight rate of 2.4 cents per kWh (down from 7.4 cents)[7] providing an incentive for storing energy overnight and discharge it during the day when the price is higher.
- **Industrial Conservation Initiative (ICI) program** – Commercial and industrial customers who opt into the Industrial Conservation Initiative (ICI) program can reduce their global adjustment charges through peak shaving using energy storage systems.

The timing, impact and probability of customer demand is subject to a host of policy, economic and technology factors that are difficult to predict. While Toronto Hydro considered the programs and incentives that are currently available to customers in preparing its DER forecast, actual growth rates could materially differ from what the forecast anticipates if new programs or incentives become available.[8] As such, the utility needs flexibility to adapt its plans in response to external factors which could drive up greater customer demand for renewables or energy storage. To enable this flexibility over the 2025-2029 rate period, Toronto Hydro's Custom Rate Framework proposes a mechanism known as the Demand Related Variance Account (DRVA). For more information about the DRVA, please refer to Exhibit 1B, Tab 2, Schedule 1.

[5] Ontario Energy Board, Forms and Templates: Third-Party Net Metering and Energy Contracts , "online", https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/forms-and-templates-third-party-net
[6] BloombergNEF, Lithium-ion Battery Pack Prices Rise for First Time to an Average of $151/kWh, "online", https://about.bnef.com/blog/lithium-ion-battery-pack-prices-rise-for-first-time-to-an-average-of-151-kwh/#:~:text=LFP%20battery%20pack%20prices%20rose,cell%20prices%20observed%20in%202022
[7] https://news.ontario.ca/en/release/1002916/ontario-launches-new-ultra-low-overnight-electricity-price-plan
[8] See, for example, the Future Energy Scenarios Report where consumer choice modelling of the uptake scenarios for rooftop solar PV showed a range of installed capacity by 2050 of between 400 MW to 1,200 MW; Exhibit 2B, Section D4, Appendix B – *Future Energy Scenarios Report* at pages 67-70.

E3.2.4 Forecasted Connections for Non-Renewable

Toronto Hydro's pipeline for non-renewable DER currently consists of 8 projects, totalling 26.6 MW expected to be connected in 2023. Between 2023 and 2029, Toronto Hydro forecasts 28 additional non-renewable DER connections (totalling over 56.8 MW) to the distribution system. This would bring total installed non-renewable DER capacity to 226.8 MW as shown in Figure 7.

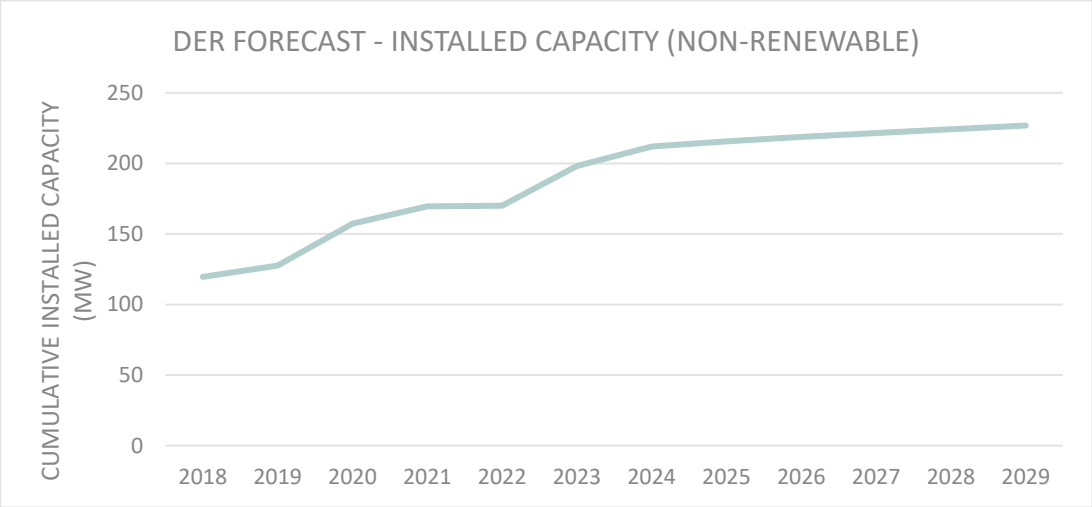


Figure 7: Historical and Forecasted Non-Renewable Capacity

While Toronto Hydro anticipates government policy to gradually reduce the use of non-renewable sources of energy in the journey to reaching net zero goals, the most common applications of non-renewable DER do not yet have viable or technologically mature alternatives. For example, gas generators remain a preferred method of backup generation as they can run for long periods of time in the event of a prolonged outage. Non-renewable generation is also used for Combined Heat and Power (CHP) systems which can generate both heat and electricity.

E3.3 System Capability to Connect DER

Toronto Hydro's system capability to connect renewable DER facilities is subject to a number of considerations, including short-circuit capacity, the risk of islanding, thermal limits, and the inability to transfer loads between feeders during planned work. Each of these considerations is described in greater detail below.

1. Short Circuit Capacity Constraints

To maintain safe and reliable operation of the distribution system, Toronto Hydro cannot connect DERs in situations where short circuit capacity limitations exist. Short circuit capacity is electrical system or component's capacity to withstand without permanent damage, high levels of electrical energy congregating on that point or location. Figure 8 below is a map which shows the areas within Toronto's grid that are approaching, or have reached, short circuit limits at various stations. These stations are supplied by Hydro One Networks Inc. transformers and directly connect to Toronto Hydro feeders.

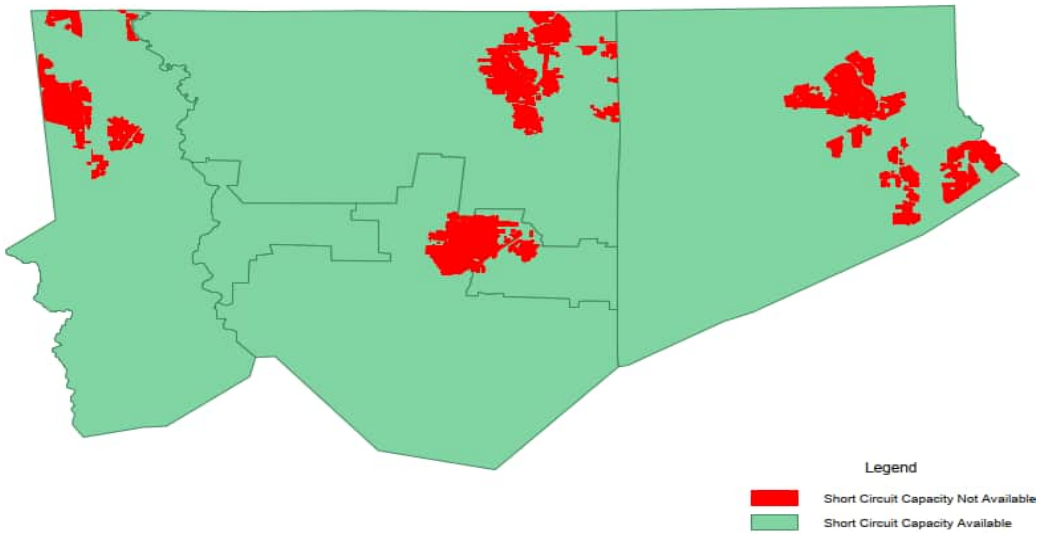


Figure 8: Map of Distribution System Short Circuit Capacity Constraints

Toronto Hydro maintains a list of restricted feeders on its website that is updated every 3 months in accordance with section 6.2.3 (g) of the Distribution System Code. As of July 2023, Toronto Hydro has five transformer station bus pairs that are restricted leading to 48 total restricted feeders due short circuit capacity constraints, as outlined in Table 1 below.

Table 1: Restricted Feeders and Number of Connected Customers

Station Name	Feeder Designation	Restriction	No. of Connected Customers
Sheppard TS, Bus EZ	47-M4	Short Circuit Capacity	0
	47-M6	Short Circuit Capacity	3378
	47-M1	Short Circuit Capacity	3952

Station Name	Feeder Designation	Restriction	No. of Connected Customers
	47-M5	Short Circuit Capacity	0
	47-M2	Short Circuit Capacity	0
	47-M8	Short Circuit Capacity	618
	47-M7	Short Circuit Capacity	1293
	47-M3	Short Circuit Capacity	5909
Woodbridge TS, Bus BY	D6-M1	Short Circuit Capacity	662
	D6-M2	Short Circuit Capacity	0
	D6-M3	Short Circuit Capacity	0
	D6-M4	Short Circuit Capacity	322
	D6-M5	Short Circuit Capacity	0
	D6-M6	Short Circuit Capacity	0
Leslie TS, Bus BY	51-M1	Short Circuit Capacity	0
	51-M3	Short Circuit Capacity	1794
	51-M5	Short Circuit Capacity	1065
	51-M7	Short Circuit Capacity	5663
	51-M2	Short Circuit Capacity	0
	51-M4	Short Circuit Capacity	625
	51-M6	Short Circuit Capacity	2196
	51-M8	Short Circuit Capacity	2582
Leaside TS, Bus AQ	A-5-L	Short Circuit Capacity	54
	A-6-L	Short Circuit Capacity	30
	A-10-L	Short Circuit Capacity	65
	A-12-L	Short Circuit Capacity	1990
	A-13-L	Short Circuit Capacity	1934
	A-16-L	Short Circuit Capacity	5
	A-17-L	Short Circuit Capacity	32
	A-21-L	Short Circuit Capacity	2058
	A-22-L	Short Circuit Capacity	2623
	A-26-L	Short Circuit Capacity	34
	A-1-L	Short Circuit Capacity	0
	A-3-L	Short Circuit Capacity	6

Station Name	Feeder Designation	Restriction	No. of Connected Customers
	A-28-L	Short Circuit Capacity	10
	A-2-L	Short Circuit Capacity	0
	A-4-L	Short Circuit Capacity	12
	A-27-L	Short Circuit Capacity	20
	A-14-L	Short Circuit Capacity	2019
Richview TS, Bus BY	88-M1	Short Circuit Capacity	90
	88-M3	Short Circuit Capacity	127
	88-M5	Short Circuit Capacity	0
	88-M7	Short Circuit Capacity	0
	88-M2	Short Circuit Capacity	1651
	88-M4	Short Circuit Capacity	0
	88-M6	Short Circuit Capacity	0
	88-M8	Short Circuit Capacity	49

Toronto Hydro is working with Hydro One to mitigate these restrictions by re-examining feeder limits and making planned investments in bus tie reactors as part of the Generation Protection Monitoring and Control (GPMC) program at Exhibit 2B, Section E5.5.

2. Anti-Islanding Condition for DER

Islanding occurs when a DER source continues to power a portion of the grid even after the main utility supply source has been disconnected or is no longer available. This situation must be avoided as it can interfere with grid protection systems and pose a serious safety risk to crews who perform work on Toronto Hydro's system. To safeguard against this risk, the connection of photovoltaic solar inverters and other DER sources must prevent unintentional islanding, as per IEEE 1547.2/D6.5, August 2023 (Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces).[9] Toronto Hydro plans to continue to deploy real-time monitoring and control investments at every new DG site to protect against the risk of islanding. For more information please refer to the GPMC program at Exhibit 2B, Section E5.5.

[9] "IEEE Draft Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," in IEEE P1547.2/D6.5, August 2023, vol., no., pp.1-322, 11 Aug. 2023 ("IEEE P1547.2/D6.5").

As the ratio of generation capacity to minimum load on a feeder increases, the amount of time required by inverters to respond to anti-islanding scenarios also increases and the effectiveness of inverter response to anti-islanding scenarios decreases. Based on common industry practice [10] Toronto Hydro aims to ensure that "DR aggregate capacity is less than one-third of the minimum load of the Local Electric Power System (EPS)"[11] – i.e. minimum generation to load ratio (MLGR).

Toronto Hydro conducted an analysis for all feeders in its system to establish MLGR in accordance with applicable guidance found in IEEE-P1547.2/D6.5, August 2023. [12] The results of study, summarized in Table 2 below, show that 23 feeders are below the recommended ratio, and that by 2029 an additional 24 feeders could be below the ratio based on the DER forecast for renewables.

Table 2: MLGR Feeder Analysis

Station	Feeder Name	Nameplate Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Min. Load (MW)	Current MLGR	MLGR Forecast 2029	REG Cx Enabled (MW)
Agincourt TS	63-M6	3.530	100.0%	5.77	7.10	2.011	1.230	2.24
Finch TS	55-M31	1.750	100.0%	2.95	3.52	2.011	1.193	1.20
Fairbank TS	35-M8	1.997	83.0%	2.80	5.50	2.753	1.750	1.15
Rexdale TS	R29-M1	1.115	100.0%	1.94	2.54	2.275	1.305	0.83
Horner TS	R30-M3	0.760	100.0%	1.38	1.91	2.519	1.387	0.62
Scarborough TS	E5-M24	3.712	16.5%	1.15	4.12	1.109	0.969	0.53
Horner TS	R30-M10	4.573	12.5%	1.08	5.12	1.120	1.007	0.51
Bathurst TS	85-M6	6.761	7.5%	0.98	5.56	0.822	0.768	0.47
Bathurst TS	85-M30	5.250	9.5%	0.97	2.83	0.539	0.495	0.47
Finch TS	55-M32	1.508	33.2%	0.97	4.09	2.712	2.069	0.47
Leslie TS	51-M25	1.677	25.5%	0.85	4.88	2.911	2.322	0.43
Finch TS	55-M29	1.914	21.7%	0.83	4.22	2.205	1.809	0.42
Fairchild TS	80-M10	1.300	23.1%	0.65	2.69	2.069	1.629	0.35
Leslie TS	51-M23	2.100	14.3%	0.65	4.58	2.181	1.868	0.35

[10] R. Seguin, et. al., *High-Penetration PV Integration Handbook for Distribution Engineers*, NREL/TP-5D00-63114 (2016), "online", https://www.nrel.gov/docs/fy16osti/63114.pdf
[11] IEEE P1547.2/D6.5.
[12] "IEEE Draft Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," in IEEE P1547.2/D6.5, August 2023 , vol., no., pp.1-322, 11 Aug. 2023.

Station	Feeder Name	Nameplate Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Min. Load (MW)	Current MLGR	MLGR Forecast 2029	REG Cx Enabled (MW)
Bathurst TS	85-M7	6.105	1.7%	0.34	2.62	0.429	0.413	0.24
Bathurst TS	85-M1	6.013	0.2%	0.20	6.86	1.141	1.107	0.18
Finch TS	55-M2	5.300	0.0%	0.18	2.96	0.558	0.541	0.18
Bathurst TS	85-M32	4.750	0.0%	0.18	6.08	1.280	1.234	0.18
Windsor TS	A-61-WR	1.500	0.0%	0.18	2.75	1.835	1.642	0.18
Esplanade TS	A-39-X	7.000	0.0%	0.18	14.50	2.072	2.021	0.18
George Duke TS	A-45-GD	1.050	0.0%	0.18	2.18	2.074	1.776	0.18
Fairchild TS	80-M23	0.900	0.0%	0.18	2.12	2.356	1.970	0.18
Cecil TS	A-41-CE	1.275	0.0%	0.18	3.37	2.646	2.326	0.18

To address islanding concerns and enable safe connection of renewable DERs on feeders with a high generation to load ratio, an energy storage system (ESS) can be installed on the feeder to act as a load to manage MLGR when the minimum load is low. For more information, please refer to the Renewable Battery Energy Storage System segment of the Non-Wires Solutions program at Exhibit 2B, Section E7.2.

3. System Thermal Limits and Load Transfer Capability

For large generation, or aggregated generation, an important operating limit stems from a feeder's continuous load thermal ratings. Exceeding system thermal limits adversely affects the lifespan of distribution equipment and can cause immediate equipment failure. Monitoring and control equipment allows Toronto Hydro to monitor and mitigate feeder thermal loading.

In undertaking feeder planning and operations, Toronto Hydro considers the system impact of the generator being online versus offline. The aforementioned thermal ratings affect the variability of various generation sources, system load growth, and the occurrence of contingencies, as thermal limits are indicative of the grid's equipment withstand capabilities. Since contingencies and feeder planned work occur particularly on feeder load transfers, it is imperative to assess the relative impact DER would impose particularly those larger capacity generators. Real-time monitoring and control would provide this window of information.

E3.3.1 Planned Investments to Eliminate Constraints

In order to connect the forecasted DERs to Toronto Hydro's distribution system, the following solutions have been identified as planned investments for the 2025 to 2029 period:

1) Six bus-tie reactors to alleviate short circuit capacity constraints at stations that cannot be relieved through station expansion work or by increasing station equipment thresholds. Table 3 below identifies the station buses where bus tie reactors are proposed.

Table 3: Locations of Proposed Bus Tie Reactors (2025-2029)

Station Name	Bus	2023 Available Short Circuit Capacity (MVA)	2029 Available Short Circuit Capacity (MVA)
Cecil	CE-A1A2	59.7	-32.7
Esplanade	X-A1A2	58.9	-7.6
Leslie	51-BY	3.2	-46.6
Richview	88-BY	-40.3	-41.2
Runnymede	11-JQ	113.6	-103.3
Woodbridge	D6-BY	-27.3	-28.0

2) Real-time monitoring and control systems must be installed at every site to monitor for islanding and thermal conditions.[13] In accordance with the Distribution System Code, monitoring and control systems for renewables are paid for by the distributor rather than the customer as is the case for non-renewables.
3) Toronto Hydro plans to deploy nine energy storage systems, with an aggregate capacity of 10.2 MW, to enable the connection of forecasted renewable growth on the nine high-priority feeders outlined in Table 3 above. The utility selected these feeders based on their existing high renewable DER penetration, low MLGR ratio and high forecasted renewable DER growth. Please refer to the Non-Wires Solutions program for more information about the feeder selection process and analysis (Exhibit 2B, Section E7.2).
4) Toronto Hydro plans to install a new bus at Sheppard TS which will introduce an estimated 126 MVA of new short circuit capacity at the station to enable new DER growth. The utility selected this option due to the technical limitations of installing a bus-tie reactor on the Gas Insulated Switchgear (GIS) bus at Sheppard TS.[14] /C

[13] Exhibit 2B, Section E5 – Generation Protection and Control, section E5.5.4.2.
[14] Please refer to the Stations Expansion program in Exhibit 2B, Section E7.4 for more details. /C

Table 4 below provides the short circuit capacity constraints forecasted at this station.

Table 4: Current and Forecasted Short Circuit Capacity at Sheppard TS

Station Name	Bus	2023 Available Short Circuit Capacity (MVA)	2029 Available Short Circuit Capacity (MVA)
Sheppard	47-EZ	-57.3	-91.4

E4 Capital Expenditure Summary

This section provides an overview of Toronto Hydro's capital and system maintenance and operational (O&M) expenditures for the 2020-2029 rate period, including explanations of: (i) variances in forecast expenditures from the 2020-2024 capital plan versus actual expenditures during over the 2020-2024 rate period, and (ii) shifts in 2025-2029 forecast expenditures versus 2020-2024 historical expenditures by investment category.

The explanations provided in this section are complimentary to the information presented in OEB Appendices 2-AB,[1] and 2-AA which are appended to this section.[2] Detailed explanations for material variances and trends are also provided within the 'Expenditure Plan' section of each capital program in sections E5 to E8.

Toronto Hydro confirms that there are no expenditures for non-distribution activities included in this application.

Accounting Treatment for CWIP

Expenditures for capital projects that span more than one calendar years are recorded in a Construction Work-in Progress ("CWIP") account until the project work is completed. Given the nature of its capital expenditure programs and projects, at any point in time, Toronto Hydro has a balance in the CWIP account. Initial capital expenditures are recorded in CWIP until the project is complete, and capitalized. Under Modified International Financial Reporting Standards ("MIFRS"), a financing charge, referred to as Allowance for Funds Used During Construction ("AFUDC"), is added to capital projects that exceed six months to complete. AFUDC is part of Other Capital Expenditures as further explained below.

Other Capital Expenditures

Toronto Hydro's capital expenditures under the Other Capital Expenditures category includes Allowances for Funds Used During Construction ("AFUDC") and miscellaneous capital, as described in OEB Appendices 2-AB.[3]

[1] Exhibit 2B, E4, Appendix A
[2] Exhibit 2B, E4, Appendix B
[3] *Supra* note 1.

- AFUDC is capitalized in accordance with the OEB's Accounting Procedures Handbook, Article 410. The AFUDC rate applied by Toronto Hydro under MIFRS for 2020 to 2022 actuals, 2023 to 2024 bridge, and 2025 to 2029 forecast years is based on Toronto Hydro Corporation's weighted average cost of borrowing.
- Miscellaneous capital primarily consists of pre-capitalized inventory and major tools. The value of pre-capitalized inventory results from the change in capitalized inventory levels between years.[4] The utility purchases major tools in the normal course of operations and on an ongoing basis to replace worn or broken tools, as required, and to install, commission and otherwise complete capital activities.

E4.1 Plan versus Actual Variances for 2020-2024

In Toronto Hydro's 2020-2024 rate application, the OEB approved a custom incentive rate-setting mechanism on the basis of a capital expenditure plan of $2,710.7 million.[5]

Due to the imposition of a 0.9% stretch-factor on Toronto Hydro's capital related revenue requirement, along with other drivers such as extraordinary inflation and increases in customer connections and load demand needs, the utility had to manage its 2020-2024 capital plan with a constrained level of funding relative to the needs and the costs of the plan. To do so, the utility reprioritized projects and adjusted program pacing as needed. Where possible, Toronto Hydro balanced the execution of the plan to deliver on high-priority objectives, and manage performance across numerous outcomes. Key objectives and outcomes included:

- Removing assets containing or at risk of containing PCB from the system by 2025 to comply with environmental obligations;
- Removing box construction framed poles from the system by 2026 to advance public and employee safety outcomes;
- Ensuring that the grid has sufficient capacity to serve areas of high-growth and development in the city and to connect customers in a timely and efficient manner;
- Installing monitoring and control equipment in areas like the network system to increase system observability and drive operational productivity.

[4] Ontario Energy Board, *Accounting Procedures Handbook for Electricity Distributors*, (January 1, 2012), Article 410.
[5] EB-2018-0165, Draft Rate Order (Filed: January 21, 2020; Updated: February 23, 2020), Schedule 4 – Capital Expenditures.

- Replacing assets at a pace sufficient to maintain reliability with historical levels of performance and to maintain system health in line with 2017 condition.
- Staying on track to complete Copeland TS – Phase 2 project and the Control Operations Reinforcement program on time within budget.

As described in Section D1, Toronto Hydro goes through an extensive annual business planning process to strike a balance across these objectives. To ensure the utility was able to meet specific needs of the system (including those listed above) and manage within the operating conditions of the current period (including 40-year high inflation), Toronto Hydro had to reduce the pacing of certain system renewal investments: [6]

- the replacement of direct-buried cables as part of its Underground System Renewal – Horseshoe program;[7] and
- the replacement of wood poles in its Overhead System Renewal program.[8]

Reduction in these programs placed additional pressure on reliability performance. Toronto Hydro had to carefully manage these pressures to honour its commitment to maintain reliability performance over this period and meet other key plan objectives noted above. The utility succeeded in this balancing act as it:

- maintained reliability performance relatively consistent over its historical average. The utility's SAIDI performance improved over the last five years (2018-2022), averaging 0.85 hours and exceeding the OEB's distributor target of 0.87 hours. The utility's SAIFI performance is slightly worse than the OEB's distributor target of 1.20, averaging at 1.30 during 2018 to 202, but comparable to the 2013-2022 average of 1.28;
- Connected approximately 10,000 customers through the Customer Connections program, with an increase of $147.5 million (71 percent) in capital expenditures over the forecast to maintain and exceed performance;

[6] As described in detail in Exhibit 1B, Tab 3, Schedule 3, these include COVID-19, extraordinary inflation, and workforce challenges.
[7] Exhibit 2B, Section E6.4.
[8] Exhibit 2B, Section E6.6.

- Continued to support expansion and relocation projects as part of the Externally Initiated Plant Relocations and Expansion program including but not limited to the Metrolinx GO expansion project and the TTC initiated Easier Access Program;
- Reduced constraints on the system through the Load Demand program by alleviating 131 MVA on highly loaded buses, reducing the number of highly loaded feeders by 10, improving the civil infrastructure associated with station expansion of five Terminal Stations as well as civil rebuild at the distribution level, and maintaining the number of feeders subject to switching restrictions during the summer months to under 10;
- Replaced approximately 50,000 residential, small commercial, and industrial meters as part of the AMI 2.0 project in the Metering program over the rate period which improves billing accuracy, faster outage response, improved network range, enhanced cyber security protection, increased grid transparency, data granularity and analytical capabilities;[9]
- Completed installations of radio communication link equipment required to facilitate the two-way communication flow between DER facilities and the Toronto Hydro Control Centre at more than 100 sites during the period of 2020 to 2023;
- Replaced 444 box-framed poles with an additional 236 anticipated over the rate period, enabling the utility to meet its commitment to remove box construction poles from the system by 2026;
- Converted 384 customers from aging rear lot service to safer and more reliable front lot underground during 2020 to 2022, and is on track to convert approximately 299 rear lot customers during 2023 to 2024;
- Addressed approximately 3,500 transformers containing or at risk of containing PCBs with upward pressure on the cost of materials attributed to supply chain issues from the COVID-19 pandemic through a combination of inspection and replacement over the course of 2020-2022;
- Addressed aging and failure risk prone direct-buried cable in the underground system through replacement of 79 kilometers of direct-buried cable over 2020-2023 for an estimated total of 105 kilometers by the end of the rate period;

[9] Exhibit 2B, Section E5.4.

- Continued to address obsolete PILC and AILC cable through the Underground Renewal – Downtown program by replacing an estimated 30 circuit-km of PILC cable and 9 circuit-km of AILC over the 2020-2024 rate period;[10]
- Addressed deteriorated and non-submersible units through the investments in the Network System Renewal program by replacing 82 network units and an additional 95 network units by the end of the rate period;[11]
- Improved flexibility of the system through investments in the System Enhancements program that includes the addition of tie points, sectionalizing points and upgrades to undersized loops, and installation of switchgear ties between Copeland and Windsor stations;[12]
- Continued to advance capabilities and build upon progress from the previous rate period through Local Demand Response initiatives outlined in the Non-Wires Solutions program (E7.2) by targeting Manby TS and Horner TS over the 2020-2024 period;
- Commissioned 379 vaults with an additional 320 over the rate period to modernize just under 90 percent of the secondary network through the Network Condition Monitoring and Control ("NCMC") program, [13] achieving sustained operating expenditure savings and improved network resiliency; and gaining crucial organization grid modernization experience that will be applied to the 2025-2029 rate period;
- Increase the capacity of Copeland Station with a Phase 2 expansion that provides an addition 144MVA to support the growth and development of Central Waterfront area and enhance reliability and resiliency in the downtown core. This project is on time and below budget by approximately $5 million.[14]
- Improving operational resilience and strengthening system security by completing construction of a dual Control Centre by the end of 2023; and
- Improving cyber security and business efficiency and laying the foundation for future customer experience enhancements by upgrading the Customer Information System ("CIS") to a modern, vendor-supported version by Q2 of 2024.

[10] Exhibit 2B, Section E6.3.
[11] *Supra* note 8.
[12] Exhibit 2B, Section E7.1.
[13] Exhibit 2B, Section E7.3.
[14] Copeland Phase 2 savings are derived from continuous improvement in execution based on the utility's experience and lessons learned from Copeland Phase 1. For example, more cost-effective procurement agreements for major equipment.

Toronto Hydro forecasts $2,787.4 million in net capital expenditures over the completion of the 2020-2024 rate period, which is three percent higher than the $2,710.7 million approved by the OEB in the 2020-2024 DSP.

In Table 2 below, Appendix 2-AB, and throughout the remainder of this section, Toronto Hydro refers to the OEB Approved values for 2020-2024 as the "Plan" for 2020-2024. By comparing the 2020-2024 plan to the actual and forecasted bridge year expenditures, the utility is able to provide a complete picture of the management and execution of the current plan.

Table 2 below provides a breakdown of the Plan and of actual plus bridge expenditures by year and by category, and the subsections that follow the table provide explanations for each category:

Table 2: 2020-2024 Capital Expenditure Summary ($ Millions)

OEB Category	Historical									Bridge					
	2020			2021			2022			2023			2024		
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	For.	Var.	Plan	For.	Var.
System Access	164.9	225.2	37%	193.0	240.7	25%	184.7	244.3	32%	197.4	260.5	32%	211.1	289.6	37%
System Renewal	290.5	261.7	(10%)	307.2	247.3	(19%)	304.7	276.6	(9%)	319.4	314.0	(2%)	309.5	358.8	16%
System Service	34.6	33.4	(3%)	60.1	68.0	13%	71.3	67.1	(6%)	33.6	32.8	(2%)	38.5	24.3	(37%)
General Plant	78.8	56.1	(29%)	92.8	72.4	(22%)	88.1	112.9	28%	76.8	96.5	26%	84.4	80.7	(4%)
Other	5.3	17.5	232%	6.5	4.8	(26%)	8.9	12.8	44%	6.3	12.6	100%	5.7	7.7	35%
Total CAPEX	**574.1**	**593.9**	**3%**	**659.6**	**633.3**	**(4%)**	**657.7**	**713.7**	**9%**	**633.5**	**716.4**	**13%**	**649.3**	**761.2**	**17%**
Capital Contributions	(74.8)	(145.8)	95%	(102.7)	(100.1)	(2%)	(93.9)	(115.8)	23%	(94.5)	(133.4)	41%	(97.6)	(135.9)	39%
Net CAPEX	**499.2**	**448.1**	**(10%)**	**556.9**	**533.2**	**(4%)**	**563.8**	**597.9**	**6%**	**539.1**	**582.9**	**8%**	**551.7**	**625.3**	**13%**
System O&M	126.3	117.1	(7%)	-	117.5	-	-	124.1	-	-	127.1	-	-	135.0	-

Note: Capital contributions include contributions made by customers and third-parties.

E4.1.1 System Access 2020-2024 Variance Analysis

From 2020 to 2024, System Access expenditures are forecasted to be approximately 33 percent higher than planned due to the following factors:

- Expenditures in the Customer Connections program are forecasted to be approximately 55 percent higher than the plan on a gross basis and 71 percent higher on a net basis.[15] This program is highly volatile and driven by various external factors (e.g. size and location of connections, available capacity provisions, economic drivers). Toronto Hydro experienced a higher than anticipated increase in system access requests for large projects (greater than 5MVA demand) over this period. The increases in 2021-2022 were attributed to the unforeseen emergence of large connections across a broad spectrum of market segments including: multi-use projects (commercial-condominium), institutional infrastructure, industrial infrastructure, data centres, and transit projects (Finch West LRT). Toronto Hydro factored in these trends in developing its 2025-2029 forecasts. See the Customer Connections program for additional details.
- Expenditures in the Load Demand program are forecasted to be approximately 38 percent higher than planned.[16] This variance was driven by the need for load transfers between stations and feeders to alleviate system constraints. Like Customer Connections, the Load Demand program can vary significantly from one year to the next due to expected new connections, voltage conversions, and an updated station load forecast. To keep up with these drivers, the Load Demand program forecast is re-evaluated annually.
- Expenditures in the Externally Initiated Plant Relocations and Expansions program are forecasted to be approximately 18 percent higher than planned due to an increase in the volume and complexity of third-party relocation and expansion projects.[17]
- Expenditures in the Metering Program are forecasted to be 34 percent lower than planned. Due to procurement delays and funding constraints, Toronto Hydro adjusted the pacing of meter replacements in the current rate period.[18]

E4.1.2 2020-2024 Variances: System Renewal

From 2020 to 2024, System Renewal expenditures are forecasted to be approximately 5 percent lower than planned due to the following factors:

[15] Exhibit 2B, Section E5.1.
[16] Exhibit 2B, Section E5.3.
[17] Exhibit 2B, Section E5.2.
[18] *Supra* note 9.

- Expenditures in the Area Conversions program are forecasted to be approximately 24 percent higher than planned.[19] The net increase in the program is driven by the Box Construction Conversion segment, which saw higher spending due to required shifts in project scheduling as well as incremental cost pressures related to the complexity of the work and various external cost drivers (e.g. coordination with the CafeTO program). For more details, please refer to section E6.1.4.2. The Rear Lot Conversion investments also saw a slight increase of approximately 4 percent.
- Expenditures in the Underground System Renewal – Horseshoe,[20] and Underground System Renewal – Downtown are forecasted to be approximately 24 percent lower than planned.[21] Through its planning and execution process, Toronto Hydro determined that it was necessary to constrain investment in these programs in order to manage funding pressures and balance the attainment of multiple objectives within the plan. The utility temporarily shifted its execution strategy to a target spot replacement approach focused on PCB removals, which meant taking on incremental risk in its aging cable population. That accumulation asset failure risk is driving the need for incremental investment in key underground assets such as cables in 2025-2029. In Downtown program, Toronto Hydro was able to find some savings over the 2020-2024 rate period by engineering an alternative approach to cable renewal work which leverages existing available civil infrastructure to the extent possible.
- Expenditures in the Overhead System Renewal program are forecasted to be approximately 18 percent lower than planned due to the same considerations,[22] as discussed above for the Underground Renewal program. Toronto Hydro managed a reduced pace in this program by temporarily shifting its execution strategy to a spot replacement approach focused on PCB removals, and deferring larger area rebuilds to address deteriorating poles and switches as well as obsolete 4 kV feeders.
- Expenditures in the Network System Renewal program are forecasted to be approximately 26 percent higher than planned.[23] The increase is driven in large part by design and execution complexities that emerged as the projects matured from conceptual to detailed design. This includes additional scope of work (e.g. civil construction and legacy cable removal), material

[19] Exhibit 2B, Section E6.1.
[20] Exhibit 2B, Section E6.2.
[21] *Supra* note 10.
[22] Exhibit 2B, Section E6.5.
[23] *Supra* note 7.

cost increases driven by supply chain disruptions, and work execution challenges related to field conditions (e.g. urban congestion) and operational complexities (e.g. coordination challenges).

- Expenditures in the Stations Renewal program are forecasted to be approximately 23 percent higher than planned due to project complexity, necessary scope increases, and inflationary cost escalations.[24]

E4.1.3 2020-2024 Variances: System Service

From 2020 to 2024, System Service expenditures are forecasted to be approximately five percent lower than planned due to the following factors:

- Expenditures in System Enhancements program are forecasted to be approximately 5 percent lower than planned.[25] Toronto Hydro constrained the pace of investment in this area by deferring work to the 2025-2029 rate period and by leveraging opportunities to carry out some of the planned enhancement work within related renewal programs.
- Expenditures in the Energy Storage Systems (ESS) segment, which has been re-mapped to the Non-Wires Solutions program, are forecast to be 79 percent lower than planned due to challenges in finding a cost-effective site for an ESS installation, as well as supply chain constraints. Faced with these challenges, and further studying the use cases and the regulatory considerations of ESS as a grid-asset Toronto Hydro decided to evolve its ESS investment strategy to focus on enablement of renewables electricity generation resources.[26]

Phase 2 of Copeland TS is expected to be completed in early 2024, therefore, there are no expansion costs forecast for the 2025-2029 rate period. 2020-2024 expenditures are forecast to be about 1 percent higher than planned. For further details, please refer to Stations Expansion program.[27]

[24] *Supra* note 8.
[25] *Supra* note 12.
[26] Exhibit 2B, Section E7.2.
[27] Exhibit 2B, Section E7.4.

E4.1.4 2020-2024 Variances: General Plant

From 2020-2024, General Plant expenditures are forecasted to be aligned with the Plan, as a result of variances in the following programs offsetting each other:

- Expenditures in the Facilities Management and Security program are forecasted to be 41 percent higher than planned due to need for additional unplanned reactive asset replacements, such as the replacement of a failed HVAC unit at the 14 Carlton work centre, the installation of hatchway railings and safety devices, and physical security enhancements in response to security incidents; incremental work to reduce building emissions;, and overall higher costs of materials and labour driven by supply chain disruptions and inflationary pressures in the construction industry.[28]
- Expenditures in the IT/OT program are forecasted to be 8 percent lower than planned. Increases in cybersecurity investments required to reinforce system protection due to an increase in external threats were offset by savings resulting from the prudent decision to defer the Enterprise Resource Planning ("ERP") system upgrade. Toronto Hydro made this decision when it learned that the system vendor, SAP, extended maintenance support for the existing ERP platform until 2027, and extended support until 2030.[29]

The Control Operations Reinforcement Program included in the 2020-2024 Plan is expected to be complete before 2025-2029 on time and within budget.[30]

E4.1.5 2020-2024 Variances: Other Capital

Expenditures in the "Other Capital" investment category are projected to be 69 percent higher than forecast over the 2020-2024 rate period. The primary driver for this increase is a result of a strategic decisions to increase pre-capitalized inventory to mitigate plan execution risks driven by supply chain disruptions (i.e. extended lead times and delivery uncertainty) experienced during the COVID-19 pandemic. This decision enabled Toronto Hydro to ensure equipment availability for its growing capital program, including critical compliance investments in at-risk PCB transformer replacements.[31]

[28] Exhibit 2B, Section E8.2.
[29] Exhibit 2B, Section E8.4.
[30] EB-2018-0165, Exhibit 2B, Section E8.1.
[31] Please refer to Exhibit 4, Tab 2, Schedule 13 for further details on supply chain challenges

E4.1.6 2020-2024 Variances: System O&M

System Operations and Maintenance ("System O&M") expenditures are driven by the need to maintain distribution assets and support the execution of Toronto Hydro's capital, maintenance, system response, and customer-driven work activities. The expenditures include the following activities:

- Preventative and Predictive Maintenance Programs (Exhibit 4, Tab 2, Schedule 1-3);
- Corrective Maintenance (Exhibit 4, Tab 2, Schedule 4)
- Emergency Response (Exhibit 4, Tab 2, Schedule 5);
- Disaster Preparedness Management (Exhibit 4, Tab 2, Schedule 6);
- Control Centre Operations (Exhibit 4, Tab 2, Schedule 7);
- Customer Operations (Exhibit 4, Tab 2, Schedule 8);
- Asset and Program Management (Exhibit 4, Tab 2, Schedule 9);
- Work Program Execution (Exhibit 4, Tab 2, Schedule 10); and
- Supply Chain (Exhibit 4, Tab 2, Schedule 13);

System O&M expenditures are forecast to increase from approximately $117.1 million in 2020 to $135 million in 2024, representing an average annual increase of 4 percent over the period. The primary drivers are asset and system maintenance needs, compliance obligations and resource requirements to support a higher volume and greater complexity of work in Toronto Hydro's service territory as the city of Toronto continues to grow, digitize, and decarbonize its economy. Below is a more detailed list of specific drivers:

- Corrective maintenance to address safety, reliability and environmental risks arising from a higher number of deficiencies identified through inspection programs.
- Compliance with incremental requirements imposed by the Electrical Safety Authority with respect to grounded-wye customer supply points and grounding of unused primary lines.
- The introduction of a Cable Diagnostic Testing program to support a more targeted approach for managing short-term cable systems risks.
- An increase to the Vegetation Management program to mitigate the reliability impacts of Toronto's expanding tree canopy.
- Increased overhead switch maintenance volumes and costs to ensure optimal maintenance cycles and keep pace with a growing population of assets.

- Greater requirements for testing, resealing, and reusing meters.
- The introduction of incremental Storm Guying inspections and corrective action to improve resiliency of poles during high wind events.
- The introduction of inspections for communication infrastructure at DER sites.
- Workforce requirements to support higher volumes and complexity of work, prepare the grid for energy transition and build capabilities required to support grid modernization objectives, including improvements to data quality and additional analytical capacity.
- An increase due to external factors such as weather in Emergency Response and customer demand for services such as vault access, locates and connections in Customer Operations.

The volume of maintenance for an asset class is dictated by asset class maintenance cycles and can vary from year-to-year. Similarly, the extent of maintenance required for inspected assets can vary from year-to-year depending on observed condition and other factors. To manage natural variances and volatility in maintenance programs, Toronto Hydro paces the execution of its maintenance plans where feasible and appropriate. For example, an increase in station battery failure for a particular year may be offset by a deferral of checker plate replacements at submersible vault locations or vault cleaning activities in Network Vaults.

E4.1.6.1 Capital Investment and System O&M

While capital investments can impact System O&M costs in different ways as discussed below, identifying specific impacts for each year is not practical due to the numerous factors involved and the gradual and ongoing nature of many of these impacts. Instead, the following summarizes and provides examples of the various ways System O&M costs are impacted by capital investments.

As discussed in more detail in Section D3.1.1.3, a significant portion of maintenance program costs are for activities which are independent of capital investments, such as cyclical inspections to meet minimum requirements under the Distribution System Code, and, where there is an impact of capital investments, the directional relationship depends on a number of factors, including the type of capital investment. For example, Growth investments are generally expected to put upward pressure on maintenance requirements as the number of assets on the distribution system increases. In addition, Toronto Hydro may introduce new assets, which require the introduction (and over time expansion) of new maintenance and inspection activities. For example, in 2022 Toronto Hydro began annual inspections, testing, and cleaning of its Bulwer Battery Energy Storage System ("BESS") assets

under the Preventative and Predictive Station Maintenance program and expects to expand this to additional Toronto Hydro-owned energy storage systems as they are added under the Non-Wires Solutions capital program. [32,33] While Modernization investments can similarly increase maintenance costs by installing new assets such as SCADA-mate switches, it can also help to reduce some O&M costs. For example, the NCMC program installs sensors in network vaults providing remote monitoring and control, and through this Toronto Hydro expects to reduce the number of planned vault inspections required for each network vault per year, reducing maintenance costs by approximately $275,000 each year in the Preventative and Predictive Underground Line Maintenance program once all vaults are commissioned. [34] While this benefit of the NCMC program is not expected to be realized until 2027, the utility has already avoided costs by reducing the need for crews to visit vaults during outage events or to identify and investigate deficiencies.[35]

For Sustainment investments, typical like-for-like asset replacement is generally expected to have minimal to no impact on maintenance spending. If replacements are done at a high enough pace to materially improve asset health demographics (which is generally not the goal), this could in turn reduce the expected volume of deficiencies requiring corrective intervention (e.g. repair). However, this is complicated by the fact that a younger and healthier asset base may require relatively higher levels of Corrective Maintenance for subsets of assets due to the fact that younger equipment with defects may be better suited to repair (i.e. maintenance) as opposed to full replacement (i.e. reactive capital). Toronto Hydro does anticipate that Sustainment programs targeting legacy assets such as air-blast circuit breakers and the 4.16 kV system (including box construction and rear lot) will contribute to a gradual and modest reduction in costs related to legacy equipment maintenance as the population declines and the assets are replaced with equipment that typically requires lower maintenance costs (including emergency or corrective maintenance) or is maintenance free. For example, air-blast circuit breakers rely on air compressors, which Toronto Hydro inspects and maintains twice a year. As Toronto Hydro removes air-blast circuit breakers from the system through

[32] Exhibit 4, Tab 2, Schedule 3.
[33] *Supra* note 26.
[34] Exhibit 4, Tab 2, Schedule 2.
[35] For example, as of June 2023 Toronto Hydro had saved approximately $120,000 by not deploying crews during outage events. See Exhibit 2B, Section E7.3 for more details on the NCMC program and its benefits.

its Stations Renewal program, it will reduce and eventually eliminate the volume of these inspections under the Preventative and Predictive Station Maintenance program.[36]

As discussed in more detail in Section E4.2.6 below, growth in the overall size of the capital investment program is expected to increase costs in O&M programs that support such investments, including Asset and Program Management,[37] and Supply Chain.[38]

E4.1.7 2020-2024 Construction Work in Progress ("CWIP")

Table 3 below provides the 2020-2024 CWIP. Detailed explanations for capital expenditures are provided above and explanations for trends in In-Service additions are provided in Exhibit 2A, Tab 1, Schedule 1.

Table 3: Historical (2020-2022) and Bridge (2023-2024) CWIP ($ Millions)

	Actual			Bridge	
	2020	**2021**	**2022**	**2023**	**2024**
Opening CWIP	381.2	380.6	427.8	471.2	442.4
Additions (CAPEX)	447.4	532.4	597.8	579.1	620.3
Deductions (In Service Additions)	(447.9)	(485.2)	(554.4)	(607.9)	(606.3)
Closing CWIP	380.6	427.8	471.2	442.4	456.4

Note: Variances due to rounding may exist

[36] Exhibit 2B, Section E6.6 and Exhibit 4, Tab 2, Schedule 3.
[37] Exhibit 4, Tab 2, Schedule 9.
[38] Exhibit 4, Tab 2, Schedule 13.

E4.2 Forecast (2025-2029) vs. Historical (2020-2024) Expenditures

Table 4 below shows the contribution to the total capital program of each investment category for the current and future rate period. Compared to the current 2020-2024 rate period, there is a shift in the 2025-2029 rate period towards System Access and System Service investments to:

- keep pace with the demands of customers in a city that is growing, digitizing and decarbonizing its economy, and
- prepare the grid for the energy transition that is set to unfold over the next two decades by modernizing the utility's infrastructure and operations to improve resiliency, enable DER integration and deliver long-term reliability and efficiency benefits to customers.

Table 4: Historical and Forecast Share of Total by Investment Category

Category	Historical Share of Total (%)						Forecast Share of Total (%)					
	2020	2021	2022	2023	2024	Avg.	2025	2026	2027	2028	2029	Avg.
System Access	18%	26%	21%	22%	25%	**22%**	30%	30%	28%	24%	23%	**27%**
System Renewal	58%	46%	46%	54%	58%	**53%**	49%	48%	48%	51%	53%	**50%**
System Service	7%	13%	11%	6%	4%	**8%**	5%	5%	8%	9%	10%	**8%**
General Plant	13%	14%	19%	17%	13%	**15%**	14%	16%	15%	14%	12%	**14%**
Other CAPEX	4%	1%	2%	2%	1%	**2%**	1%	1%	1%	1%	1%	**1%**
Total	100%	100%	100%	100%	100%	**100%**	100%	100%	100%	100%	100%	**100%**

/C

In the sections that follow, Toronto Hydro provides a summary of key programs and investment priorities that are driving the planned increases in each of these categories in 2025-2029 compared to 2020-2024. Additional details about each of these programs and priorities are found throughout other section of this Distribution System Plan.

E4.2.1 System Access: Historical vs. Forecast Expenditures

Table 5: System Access: 2020-2029 Expenditures ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Access	80.4	140.3	128.4	127.1	153.7	220.1	229.1	224.0	196.6	182.7

/C

Toronto Hydro expects System Access expenditures to continue to increase into the 2025-2029 rate period. As discussed in Section E2.2, this overall increase is driven by two primary considerations:

- continued growth and development in the city of Toronto, including the expected impacts of electrification as more customers turn to electricity for their day to day needs such as transportation and building heating systems;
- necessary replacement of end-of-life revenue meters which will also offer Toronto Hydro the opportunity to modernize this critical part of the system with Advanced Metering Infrastructure (AMI) 2.0.

As discussed in Section D2, the City of Toronto leads North America in new buildings under construction. Toronto Hydro expects continued growth in customer load and generation connections, as well as major infrastructure projects (e.g. transit development) that are externally initiated. Toronto Hydro is also due to renew its sizable population of end-of-life residential and small commercial and industrial (C&I) revenue meters.[39] Inflation for materials, labour and other construction-related costs is also driving increases in certain programs. For more information on the programs in this category, refer to Section E5.

E4.2.2 System Renewal: Historical vs. Forecast Expenditures

Table 6: System Renewal Expenditures: 2020-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Renewal	261.5	247.3	276.5	314.0	358.8	359.7	366.5	391.3	423.7	429.1

Over the 2025-2029 rate period, Toronto Hydro plans to increase its System Renewal investments in the 2025-2029 rate period by approximately 35 percent compared to 2020-2024 rate period. As discussed in Section E2.2, this increase is necessary to manage significant safety, reliability, and environmental asset risks, maintain the system in a state of good repair by managing the overall health demographics of assets, and ensure stable and predictable grid performance for current and future customers.

[39] *Supra* note 9.

As mentioned in Section E4.1.2 above, Toronto Hydro constrained investment in key System Renewal programs to manage funding pressures in the 2020-2024 rate period. This prudent decision, along with other factors, led to increasing investment needs in the 2025-2029 rate period including:[40]

- asset condition demographics (e.g. wood pole condition);
- persistent backlogs of high-risk legacy assets such as direct-buried cable;
- growing asset stewardship risks in the downtown core, including those related to aging lead cable and deteriorating civil assets;
- growing backlog of critical stations-level equipment at risk of failure;
- increasing performance pressures on the system from climate change, necessitating greater investment in resiliency;
- elimination of PCB at-risk assets from the distribution system;
- the increasingly urgent need to convert aging, legacy 4 kV / 13.8 kV parts of the system to higher voltage standards that are capable of handling electrified loads, DERs and automation;
- the need to accelerate replacement of obsolete mechanical stations relays with digital relays capable of supporting advanced operational functions and grid automation; and
- anticipated cost pressures from construction inflation in the City of Toronto which reached a 40-year all time high in the 2020-2024 rate period.

Toronto Hydro expects to eliminate PCB at-risk units from the distribution system by 2025 and box-framed poles by 2026. The winddown of these investment priorities will enable the utility to ramp-up investment in the conversion of legacy 4 kV / 13.8 kV parts of the system. In addition to addressing the reliability risks posed by these aging assets, the conversion of these configurations to higher voltage standard enables the utility to accommodate higher volumes of electrified loads.

E4.2.3 System Service: Historical vs. Forecast Expenditures

Table 7: System Service Expenditures: 2020-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Service	32.8	68.4	67.2	32.8	24.3	38.3	35.0	66.0	78.1	84.3

/C

[40] See Sections D1, E2, and Section E6 for additional details.

Over the 2025-2029 rate period, Toronto Hydro plans to increase its System Service investments by approximately 34 percent compared to 2020-2024 investment levels. Expenditures in this category are central to Toronto Hydro's strategy to expand and modernize its grid and operational capabilities to address key drivers of change within its business, including electrification, DER proliferation, and climate change impacts. For more information about this strategy see Section D4 – Capacity Planning and Electrification Strategy and D5 – Grid Modernization Strategy. /C

Increased investments in this category are largely driven by:

- capacity expansion needs in the Stations Expansion program including investment in a new Transformer Station to support expected load growth in the Downsview areas and Hydro One contribution to expand capacity at existing stations, such as Sheppard TS.[41] /C
- a paced ramp-up in the System Enhancement program to enhance system observability and controllability, and enable the utility to be ready for widescale grid automation in the horseshoe areas of its system in the next decade.[42] These investments are expected to deliver long-term reliability and efficiency benefits to customers.
- investments in Energy Storage systems (ESS) to improve the grid's capacity to connect and integrate Renewable Energy Generation (REG) connections which are expected to play an increasing role in advancing customers' and stakeholders decarbonization objectives.

E4.2.4 General Plant: Historical vs. Forecast Expenditures

Table 8: General Plant Expenditures: 2025-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
General Plant	56.1	72.4	112.9	96.5	80.7	103.9	119.1	124.9	116.1	98.6

Over the 2025-2029 rate period, Toronto Hydro plans to increase its General Plant investments by approximately 34 percent compared to 2020-2024. Expenditures in this category are driven by asset lifecycle management for fleet, facilities, and IT equipment that support the efficient execution and management of Toronto Hydro's capital and operational work programs. In addition, Toronto Hydro plans to continue to invest in paced decarbonization of its facilities and fleet emissions, as well as in

[41] *Supra* note 27.
[42] *Supra* note 12.

the relocation of an enterprise data centre. The latter project is required to enable the utility to expand and reliably operate this critical piece of infrastructure in accordance with the growth of the distribution system, as the significant challenges associated with the data centre's current location preclude such expansion and pose significant business continuity and reliability risks.

This category is also driven by investments in cyber security and enterprise technology software solutions, which are needed to achieve the following outcomes:

- strengthen protection and resilience against increasing digital threats brought on by advancements in technology and changes in geopolitical dynamics;
- support grid modernization efforts detailed in Section D5;
- drive continuous improvement in productivity through process automation;
- leverage technology tools and capabilities to serve customers in a timely and effective manner and deliver good experience as more customers turn to electricity for their day-to day energy need; and
- implement public policy initiatives and maintain compliance with legislative and regulatory requirements.

E4.2.5 Other Capital: Historical vs. Forecast Expenditures

Table 9: Other Capital Expenditures: 2025-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Other Capital	17.4	4.6	12.8	12.6	7.7	6.2	7.0	8.3	9.2	10.2

Other Capital includes forecasted amounts for Allowance for Funds Used during Construction ("AFUDC") which are required during the execution of capital programs in the 2025-2029 rate period.[43]

[43] As discussed in Section E4.1.5, Road Cut Restoration costs and Major Tools are attributed directly to capital program expenditures and are not included in Table 7.

E4.2.6 System O&M: Historical vs. Forecast Expenditures

Table 10: System O&M Expenditures: 2020-2029 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System O&M	117.1	117.5	124.1	127.1	135.0	144.1	148.9	153.0	159.0	164.5

System O&M expenditures are expected to increase at an average annual rate of approximately 3 percent between 2025 and 2029. The increases are driven by a number of factors:

- Toronto Hydro is expanding inspection and maintenance activities in key areas through the Preventative and Predictive maintenance programs, resulting in an 11 percent increase between 2024 and 2025, followed by a moderate 1 percent average annual increase from 2026-2029. Starting in 2025 Toronto Hydro is adjusting inspection cycles for wood poles from ten years to eight years to manage failure risk driven by wood pole age and condition demographics. Toronto Hydro will also begin inspecting concrete and steel poles as part of its Pole inspection program on a ten-year cycle. Toronto Hydro will transition to a minimum six-year maintenance cycle for overhead switches, which represents an increase from the current variable cycle, which is generally greater than six years. Toronto Hydro will continue to ramp up the Cable Diagnostic testing segment in Preventative and Predictive Underground Line Maintenance program, collecting key condition information on a greater number of feeders to inform both short- and long-term investment decisions. The introduction of incremental inspection activities at DER sites and increasing volume of Energy Storage locations within the Preventative and Predictive Stations program also drive cost increases. Toronto Hydro plans to reduce its Network Vault civil inspection program starting in 2027 as a result of the implementation of Network Condition Monitoring and Control resulting in reduced costs in that program. The large majority of Toronto Hydro's inspection and maintenance programs are cyclical in nature, with cycles established to meet regulatory requirements, as discussed in Exhibit 2B, Section D3. As a result, significant reductions to inspection or maintenance programs are not expected in the 2025-2029 period. Differing volumes of work and inflationary impacts will result in year over year fluctuations in expenditures between 2025-2029 within these programs;[44]

[44] Exhibit 4, Tab 2, Schedules 1-3.

- The Corrective Maintenance program expenditures increase by 14 percent between 2024 and 2025, followed by a 3 percent average annual increase from 2026-2029. The increase in the Corrective Maintenance Program is driven by the need to address a growing backlog of P3 deficiencies within the system. Expected expenditures related to increasing spot tree trimming and corrective work for DER sites also drive an increase in this program. For more details, please see Exhibit 4, Tab 2, Schedule 4;
- A 12 percent increase between 2024 and 2025 is forecasted within the Emergency Response program. Inflationary pressures including increased labour and vehicle costs for services and a new contract for external resources that will be effective in 2025 contribute to the increase. From 2026-2029, expenditures align to a 2 percent average annual increase;[45]
- The Supply Chain program is growing by 14 percent between 2024 and 2025 followed by an average annual increase of 6 percent between 2026-2029. The increase in costs is primarily due to higher payroll and contract costs required to support an expanded Capital Program within a more complex global supply chain environment;[46]
- The Asset and Program Management program will have an average annual increase of 6 percent over the 2025-2029 rate period driven primarily by higher payroll and external contract costs to support an expanding capital and maintenance program and the expansion of the Grid Modernization function. This function will allow the utility to forecast, understand, and manage a more complex system as it becomes increasingly decarbonized, decentralized, and digitized. Incremental resources, new skillsets, and third-party support is required within the planning and engineering functions in support of the above needs;[47]
- The Work Execution program will have an average annual increase of 5 percent over the 2025-2029 rate period. The growth in this program is driven directly by the need for additional headcount to support a growing capital and maintenance program with increasing complexity to support the energy transition. The increase in headcount in key Certified and Skilled Trades and Designated & Technical Professional positions is required to enable internal work execution, whereas key resources such as field, project, and contract managers are required to support external work execution. Increases in training costs, tools and safety equipment, and personal protective equipment ("PPE") are also required;

[45] Exhibit 4, Tab 2, Schedule 5.
[46] *Supra* note 38.
[47] *Supra* note 37.

- In addition, increasing resource and skill requirements and capabilities to support grid modernization results in higher costs across various business functions. For example, increasing the workforce of Control Centre Operations will be crucial as Toronto Hydro expands its grid and modernizes system operation through more sophisticated data analysis and automation, which will require more staff both to handle increasing volumes of work and deploy specialized skills and knowledge made necessary by the evolution of operational systems; and
- Inflationary pressures are also a key contributor to increasing expenditures over the forecast period across the various System O&M programs.

E4.2.7 Forecast Construction Work in Progress ("CWIP")

Table 11 below provide the 2025-2029 CWIP. Detailed explanations for capital expenditures are provided above and explanations for variances in In-Service additions are provided in Exhibit 2A, Tab 1, Schedule 1.

Table 11: Forecasted 2025-2029 CWIP ($ Millions)

	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
Opening CWIP	456.4	533.7	589.1	596.4	636.6
Additions (CAPEX)	719.4	747.1	797.2	809.3	786.7
Deductions (In Service Additions)	(642.1)	(691.7)	(789.8)	(769.2)	(859.5)
Closing CWIP	533.7	589.1	596.4	636.6	563.8

/C

Note: Variances due to rounding may exist

E5.1 Customer Connections

E5.1.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 356.2	**2025-2029 Cost ($M):** 476.5
Segments: Load Connections; Generation Connections	
Trigger Driver: Customer Service Requests	
Outcomes: Customer Focus, Public Policy Responsiveness, Operational Effectiveness - Safety, Operational Effectiveness - Reliability	

The Customer Connections program ("the Program") captures system investments that Toronto Hydro is required to make to provide customers with access to its distribution system. This includes enabling new or modified load connections and distributed energy resources ("DER") connections to the distribution system, in accordance with legal and regulatory obligations under various statutes and codes. This Program is a continuation of customer connection activities described in Toronto Hydro's 2020-2024 Distribution System Plan.[1]

Toronto Hydro's primary objective in this Program is to provide new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system. In pursuing this objective, the utility strives to meet, and where possible, exceed, all mandated service obligations. In 2022, Toronto Hydro completed 99.9 percent of low voltage (below 750 V) and 99.1 percent high voltage (750 V or above) connections on time, a performance improvement from 2018 of 1.6 percent for low voltage connections and 0.8 percent for high voltage connections. In 2022, 92.4 percent of DER connections were connected on time.[2]

The Program is comprised of two segments:

- **Load Connections**: This segment involves completing new load connections and upgrades to existing load connections. Customers are connected to one of the various overhead or underground distribution systems in the City. The work also includes any expansion work necessary to address capacity constraints for the purpose of connecting customers; and

[1] EB-2018-0165, Exhibit 2B, Section E5.1
[2] These metrics are published in Toronto Hydro's 2022 Scorecard; See: https://www.oeb.ca/utility-performance-and-monitoring/scorecard/600/view

- **Generation Connections**: This segment involves connecting DER customers to the distribution system.

The investments made by Toronto Hydro in this Program support the ongoing economic growth and development in the City of Toronto.[3] The connection of DER facilities under this Program supports the achievement of the public objectives with respect to facilitating innovation and supporting DER integration within Ontario's electricity system and the Ministerial directive issued by the Minister of Energy on October 21, 2022.

E5.1.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro customer focus objectives by: o Fulfilling customer service requests as mandated by Sections 6.2.4 (generation connections) and 7.2 (customer connections) of the Distribution System Code ("DSC"), Electricity Act, 1998 (Electricity Act), and Ontario Energy Board Act, 1998 (OEB Act); and Toronto Hydro's Conditions of Service and Electricity Distribution License; o Completing low and high voltage connections within five and ten business days respectively at least 90 percent of the time, as measured pursuant to the OEB's connection metrics and section 7.2 of the DSC; o Completing customer appointments in accordance with the OEB's Appointment Scheduling and Appointments Met metrics, 90 percent of the time, as per sections 7.3 and 7.4 of the DSC; and o Responding to inquiries requiring a written response within ten business days at least 80 percent of the time, as measured pursuant to the OEB's Written Response metric and section 7.8 of the DSC. o Connecting DER facilities to the distribution system as mandated by sections 25.36, and section 26 of the Electricity Act, 1998; and; without extensive delays or adverse impacts to existing customers, within 5 business days at least 90 percent of the time on a yearly basis as per section 6.2.7 of the DSC.

[3] City of Toronto, Toronto Official Plan, "online", https://www.toronto.ca/city-government/planning-development/official-plan-guidelines/official-plan/ ; City of Toronto, City Planning Development Pipeline 2021, "online", https://www.toronto.ca/wp-content/uploads/2021/06/963e-Development-Pipeline-2021.pdf; Waterfront Toronto, Integrated Annual Report 2021-2022, June 23, 2022, "online", https://www.waterfrontoronto.ca/sites/default/files/202207/Waterfront%20Toronto%20Integrated%20Annual%20Report%202021-2022.pdf

Public Policy Responsiveness	• Supports the Ministerial directive to facilitate innovation and support DER integration within Ontario's electricity system
Operational Effectiveness - Safety	• Contributes to compliance with Electrical Distribution Safety (O. Reg 22/04) and safety objectives by: o Ensuring service connections are compliant with applicable requirements; and o Ensuring Electrical Safety Authority connection permits are available prior to connecting new or upgraded customers' service entrance equipment.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, System Capacity) by installing assets that meet up-to-date standards and provide sufficient capacity when completing the connection request.

E5.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Customer Service Requests
Secondary Driver(s)	Mandated Service Obligations

E5.1.3.1 Load Connections

The Load Connections segment is driven by customer requests to connect to Toronto Hydro's distribution system and service upgrades for existing customers. Toronto Hydro has seen an increase in the volume and complexity of customer connections due to ongoing growth and development in the city, larger connections (e.g. for data centres, transit etc.) and the energy transition. Densification and growth in the City of Toronto, including increased residential and commercial developments as well as mass transit system growth, are fundamental drivers for the increased volume of work in the Load Connections segment, as many, if not all, new developments will require new or modified connections to Toronto Hydro's distribution system. The energy transition is also an important driver of the Load Connections segment as customers look to the electricity grid to meet more of their energy needs. Toronto Hydro anticipates that the number of customer service requests and the size of the requested connections will continue to trend up to accommodate growing residential and commercial needs. Toronto Hydro has a legal obligation, pursuant to section 28 of the *Electricity Act*,

to fulfill these service connection requests or to make an offer to connect ("OTC") for any customers in its service area.[4]

Toronto continues be one of the fastest growing cities in North America. Serving this growing city, Toronto Hydro receives a high volume of requests for connections and upgrades for residential and commercial developments each year. Toronto currently has 238 construction cranes operating, 4.7 times as many as the next most active city, Seattle.[5] From 2017 to 2022, the city's development pipeline included 2,413 projects in various stages of approval and completion as shown in Figure 1 below.[6] Toronto Hydro anticipates that a large number of projects and proposed loads submitted between 2017 and 2022 are expected to be completed within the 2025-2029 period or shortly thereafter based on the average completion rate and the number of units proposed for the City of Toronto.[7] Thus, Toronto Hydro expects that the current rate of development will continue over the 2025-2029 period. These projects in the development pipeline represent a City record of 717,327 residential units and 14,484,961 square metres of non-residential gross floor area, the highest development volumes for any five-year period the City has reported on to date. The pace of development in Toronto could increase even further with the recent passage of the *More Homes Built Faster Act, 2022*[8] by the Government of Ontario. This act is intended to expedite the approval of development projects and provide new tax incentives and funding mechanisms aimed at encouraging development. Toronto Hydro will continue to monitor the impact of this legislation on the distribution system.

[4] Subject to certain exemptions as set out in the Distribution System Code, including Section 3.1.1 of the Distribution System Code ("DSC")
[5] Rider Levett Bucknall (RLB), Crane Index® for North America, Q1 2023, "online", https://www.rlb.com/americas/insight/rlb-crane-index-north-america-q1-2023/
[6] Including projects that are pending approval, approved, awaiting or holding building permits, or under construction - The 2413 pipeline projects breakdown is 622 built, 879 active and 912 under review: Toronto City Planning, Profile TO, Development Pipeline 2022 Q2, "online", https://www.toronto.ca/wp-content/uploads/2023/02/92b5-CityPlanning-Development-Pipeline-2022-Q2.pdf
[7] Discussed further in the Load Demand program, see Exhibit 2B, Schedule E5.3.
[8] Bill 23, More Homes Built Faster Act, 1st Sess, 43rd Parl, 2022, https://www.ola.org/en/legislative-business/bills/parliament-43/session-1/bill-23

	Built	Active	Under Review	Total in Pipeline	% of Total	% of Growth Areas
City of Toronto	622	879	912	2,413	100.0%	
Growth Areas	394	549	605	1,548	64.1%	100.0%
Downtown and Central Waterfront	142	205	179	526	21.7%	31.5%
Centres	30	48	47	125	5.2%	14.5%
Avenues	149	209	279	637	26.4%	28.3%
Other Mixed Use Areas	73	87	100	260	10.8%	25.6%
All Other Areas	228	330	307	865	35.9%	

Source: City of Toronto, City Planning: Land Use Information System II

Development projects with activity between January 1, 2017 and June 30, 2022. Built projects are those which became ready for occupancy and/or were completed. Active projects are those which have been approved, for which Building Permits have been applied or have been issued, and/or those which are under construction. Projects under review are those which have not yet been approved or refused and those which are under appeal.

Figure 1: Proposed Projects in the City of Toronto (2017-2022)

In addition to volume of projects, Toronto Hydro also anticipates that there will be a greater need for larger and more complex connections. There has a been a substantial increase in larger commercial and multi-use projects requiring greater than 10MVA of demand load per project, and data centres requiring larger loads than previously required from Toronto Hydro. In addition, the city is experiencing a period of unprecedented expansion of electrified public transportation requiring large new load connections to Toronto Hydro's distribution system (e.g. Yonge North Subway Extension, Scarborough Subway Extension, Eglinton Crosstown West Extension, Ontario Line).[9]

Furthermore, the City is experiencing a shift to clean energy, and electrification through the adoption of emerging technologies such as electric vehicle charging, electric heat pumps, and water heaters. As the adoption and demand of such technologies continues to evolve and grow, the demand for access to Toronto Hydro distribution system must be leveraged to support these demands. Immediate growth areas being supported by Toronto Hydro's distribution system include electric vehicle charging for: public streets, City fleet vehicles (including TTC), Toronto Parking Authority parking lots, residential homes, commercial and residential developments. Ongoing and other evolving areas include heating/cooling systems (heat pumps), and complete home electrification at single-family residential home and residential complex levels.

[9] Further details can be found in Exhibit 2B, Schedule E5.2

This pace of development and growth is consistent with the City's projected growth in population, which is over 2.97 million as of July 2021 and is expected to continue to increase into the future.[10] Since the City of Toronto is bounded, accommodations for population growth and needed support systems (residential, retail, commercial, multi-use, institutional, transit developments), including access to Toronto Hydro's distribution system to support population growth, will intensify as the population increases.

As illustrated in Figure 2, from 2012 to 2022, Toronto Hydro connected approximately 76,000 customers, representing a 11 percent increase in its customer base (average of 1.0 percent per year), and approximately 20,000 customers from 2018 to 2022, representing a 2.6 percent increase (average of 0.7 percent per year). Similar levels of growth are expected for the 2025-2029 period, as described in the Customer Forecast Section.[11] These additional customers were connected to Toronto Hydro's distribution system as a result of the investments in the Load Connection segment.

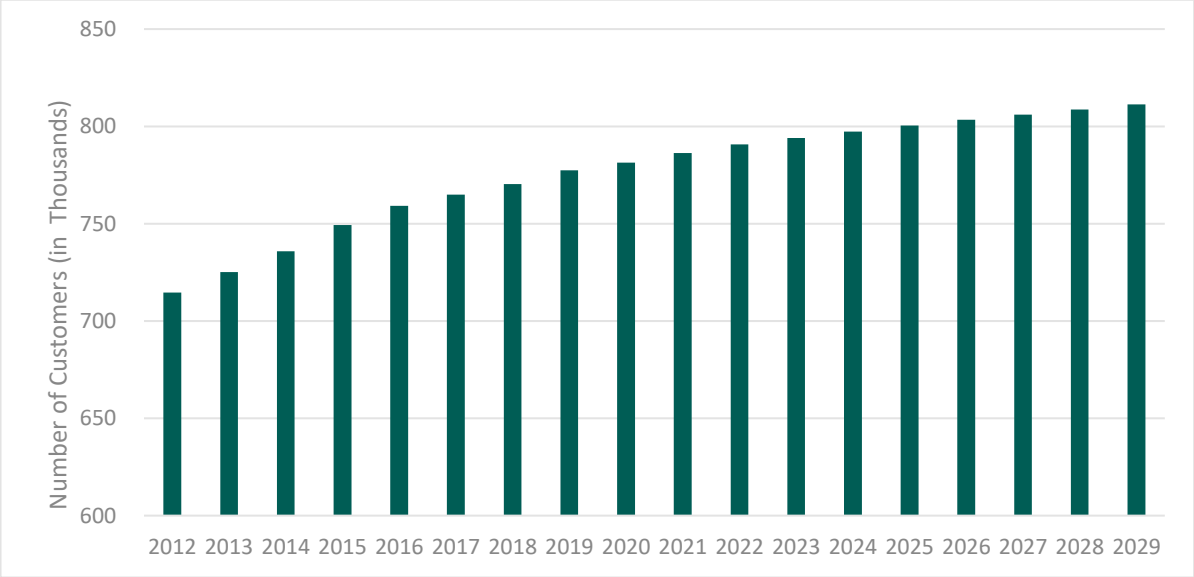


Figure 2: Historical and Forecast Number of Toronto Hydro Customers

10 Province of Ontario, Ontario Population Projections, "online", https://www.ontario.ca/page/ontario-population-projections#chart8;
The greatest growth is expected in the areas of: City of Toronto, 2021 Census, "online", https://www.toronto.ca/wp-content/uploads/2022/02/92e3-City-Planning-2021-Census-Backgrounder-Population-Dwellings-Backgrounder.pdf
For the period 2016 to 2021, the districts of Spadina-Fort York, Toronto Centre, Etobicoke-Lakeshore, and Toronto-St Paul's have shown the greatest growth in population at growth in populations of 17.9%, 15.5%, 9.8%, and 8.4% respectively

11 Exhibit 3, Tab 1, Schedule 1.

Customer connections can be in the form of a basic connection, or a connection requiring expansion work. Each new or upgraded service connection must meet the individual needs of the customer. This includes customer specific type, size, required demand load, geographical location of the customer's site, geographical availability of Toronto Hydro's distribution system in relation to the customer's site, and available distribution system infrastructure and capacity provisions.

The types of connections Toronto Hydro performs can generally be divided into two categories as follows:

- **Low voltage connections (below 750 Volts) ("LV"):** These connections primarily involve residential and small commercial customers (GS<50 rate class) supplied at 750 Volts or less whose average monthly maximum demand is less than, or is forecasted to be less than 50 kW. The number of connections remains high at over 2000 connections per year for the period of 2020-2022. This work is typically seasonal and has a relatively short turnaround time. As part of Toronto Hydro's obligations, the utility works with customers to provide options for a new connection or service upgrade. As per the DSC, section 7.2.1, these service requests must be completed within 5 business days from the day on which all applicable service conditions are satisfied. or at a later date as agreed to by the customer and distributor; and

- **High voltage connections (750 Volts and above) ("HV"):** These connections primarily relate to larger residential and commercial developments. These customers typically engage Toronto Hydro years before service is expected to be required. Figure 3 provides a year-over-year comparison of the volume of new formalized high voltage requests that Toronto Hydro receives on an annual basis. High voltage connections increased by 27.6 percent for the period 2020 to 2022. As per section 7.2.2 of the DSC, these service requests must be completed within ten business days from the day on which all applicable service conditions are satisfied, or at a later date as agreed to by the customer and distributor.

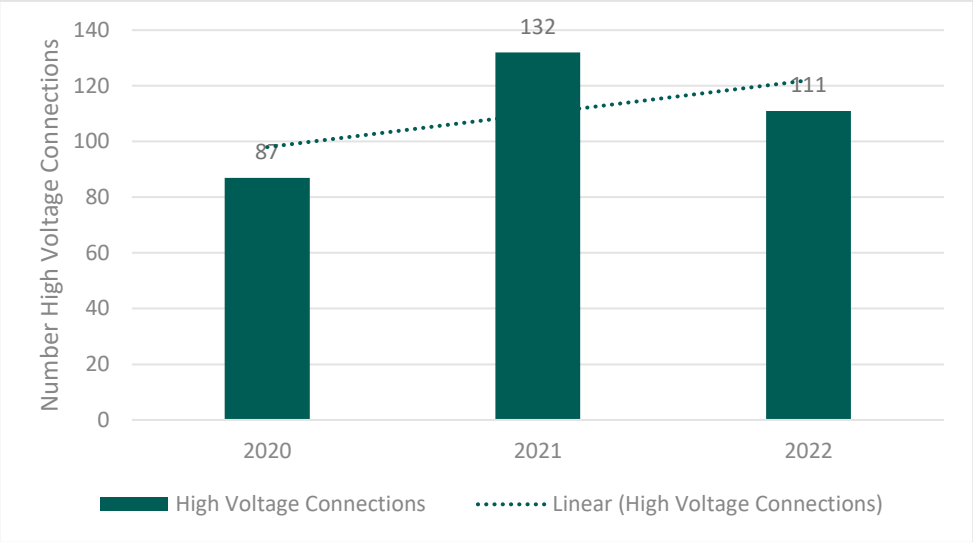


Figure 3: High Voltage Connections 2020-2022

For both low and high voltage service connections, applicable service quality requirement must be met at least 90 percent of the time on a yearly basis.

Toronto Hydro continues to process a high amount of feeder requests[12] at over 800 per year, and has experienced a 29.8 percent increase in feeder requests since 2020. In 2022, Toronto Hydro processed 1055 feeder requests, the highest volume to date. The overall increasing trend in the volume of requests processed from year to year is expected to continue up to and throughout the 2025-2029 period. Following a feeder request, the connection typically materializes within five years, from the day the feeder request was created, excluding any project delays. As a result, the number of feeder requests received between 2021 and 2022 are expected to drive work in the 2025-2029 period.

[12] **Feeder request**: An internal request to determine the appropriate point and method of connecting customers exceeding 50 kW to Toronto Hydro's distribution system. Feeder requests relate to both potential and proposed projects in their preliminary stages.

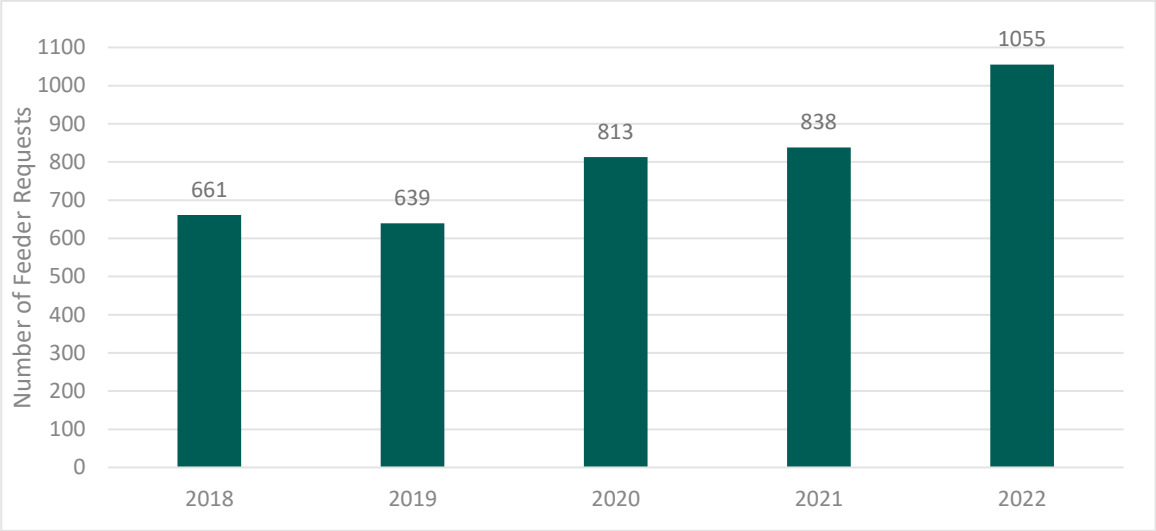


Figure 4: Feeder requests processed (2018-2022)

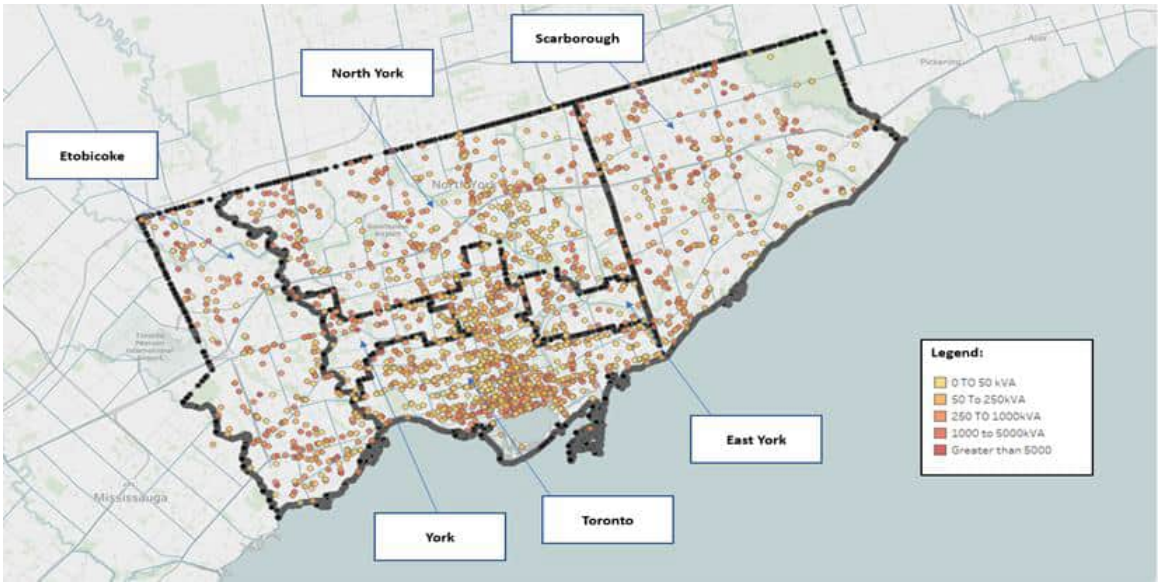


Figure 5: Load Additions in the City of Toronto during the 2018-2022 Period

Similar trends were observed in the overall increasing volumes of Offers to Connect (OTCs) issued requiring expansion work throughout the 2019 to 2022 period, as illustrated in Figure 6**.** The number of Offers to Connect (OTCs) between 2020-2022 has already exceeded 68 percent of the total volume count of OTCs for the five-year period 2015-2019. Expansion work is typically needed for larger connections or requests in areas of the City that are capacity constrained. This involves the installation or upgrade of distribution assets such as new circuits or civil infrastructure required to

accommodate new customer loading. Such work can have a significant cost impact as it typically requires a substantial amount of resources to plan and construct the infrastructure necessary to connect a large customer. The resulting expansion projects are usually large-scale and complex, and thus require weeks or months to complete. Connecting customers to the distribution system without completing the necessary expansions can negatively impact system reliability and safety.

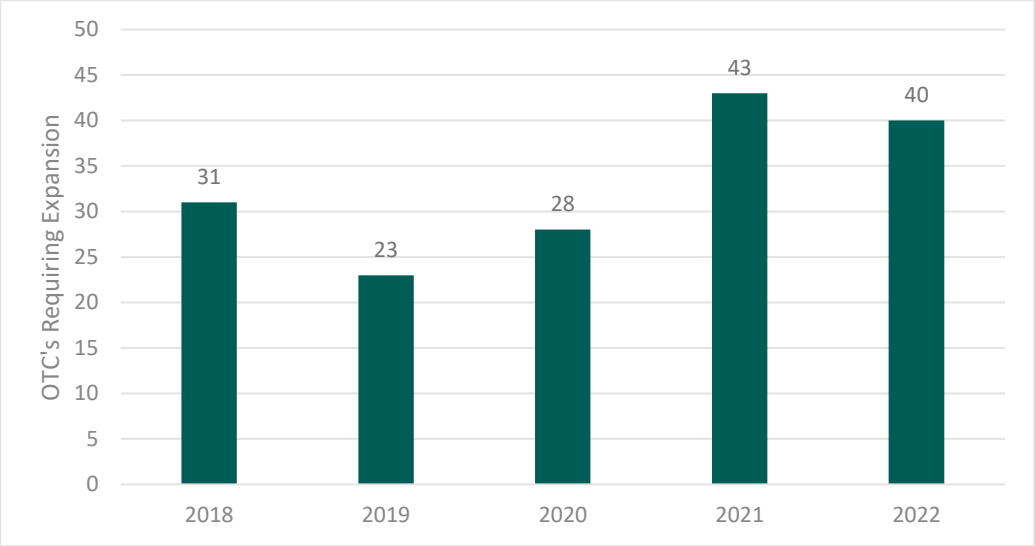


Figure 6: Offers to connect Requiring Expansion

E5.1.3.2 Generation Connections

As per section 25.36 of the *Electricity Act*, Toronto Hydro is mandated to connect renewable DER while maintaining the safety and reliability of the system for existing customers. Toronto Hydro is also obligated under section 6.1 of its Distribution License and section 26 of the *Electricity Act* to provide generators with non-discriminatory access to its distribution system and to provide access for renewable energy generation facilities. Under Section 6.2 of the DSC, for all types of DERs, Toronto Hydro has an obligation to enable and connect the DER. Toronto Hydro must balance its obligations to prospective and existing DER connections with its responsibilities to maintain a safe and reliable distribution system for its load customers. When connecting and assessing DER facilities, Toronto Hydro is also required to meet certain timelines:

- Based on OEB's recently released Distributed Energy Resources Connection Procedures (DERCP) document, the distributor must complete and provide a Connection Impact

Assessment (CIA) with cost estimates within 60 days[13] of receipt of substantially complete application for small and mid-sized DER where no system reinforcement or expansion work is required, and within 90 days where either the DER is large or system reinforcement or expansion work is required; and

- A distributor, as per sections 5.3.13 and 5.3.14 of the DERCP, shall connect an applicant's micro-embedded generation facility to its distribution system within 5 business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to by the customer and distributor 90 percent of the time on a yearly basis.

Toronto Hydro supports connecting DER to the distribution system in alignment with the DERCP and in coordination with Hydro One and the IESO. As of the end of 2022, Toronto Hydro connected 2,424 DER connections from customers and developers under a variety of technologies and applications with a total connected capacity of 304.94 MW. These can be broken down into three (3) different categories as shown in Table 4 below:

- **Renewable:** consists of DER based on renewable technologies, such as solar photovoltaic, wind turbine and bio-gas generators;
- **Energy storage:** refers to DER related to the capture of energy, such as batteries and underwater compressed air; and,
- **Non-renewable:** refers to conventional fossil-fuel based DER, such as natural gas generators and combined heat and power ("CHP").

1. Existing Generation Connections

An overview of the number and total capacity of DERs and their distribution across the city are provided in Table 4, Table 5 and Figure 7.

Table 4: Cumulative Existing Generation Connections by type

Type	2015	2016	2017	2018	2019	2020	2021	2022
Renewable	1296	1547	1749	2072	2094	2126	2185	2280
Energy Storage	1	4	4	10	11	22	24	28
Non-Renewable	35	38	44	54	60	87	112	116
Total	**1332**	**1589**	**1797**	**2136**	**2165**	**2235**	**2321**	**2424**

[13] Ontario Energy Board, Distributed Energy Resources (DER) Connections Review, "online", https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations/distributed-energy-resources-der

Table 5: Cumulative Existing Generation Capacity (in MW) by type

Type	2015	2016	2017	2018	2019	2020	2021	2022
Renewable	71.9	86.6	96.6	108.7	110.0	111.3	114.1	116.2
Energy Storage	0.7	0.7	0.7	4.5	9.1	17.6	18.2	18.7
Non-Renewable	91.9	98.4	114.4	119.6	127.7	157.4	169.5	170.0
Total	**164.5**	**185.6**	**211.6**	**232.8**	**246.8**	**286.3**	**301.8**	**304.9**

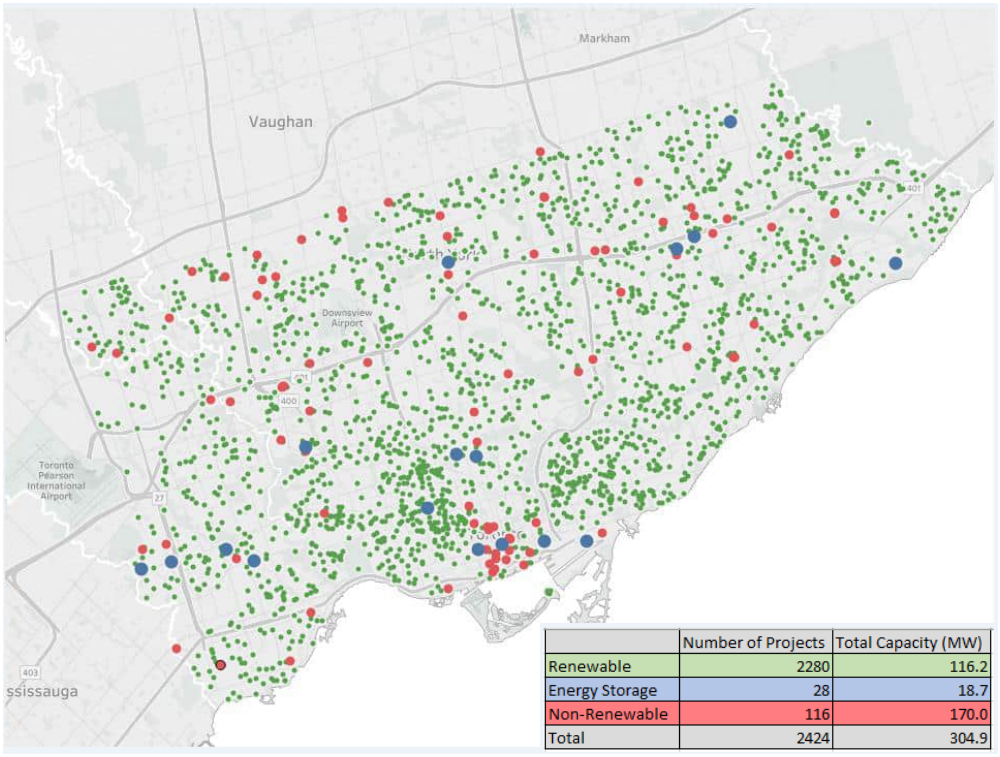


Figure 7: Generation Connections in Toronto Hydro Service Area by Generation Type

Interest in generation projects within Toronto Hydro's service territory saw a greater than anticipated decrease with a 71.9 percent decline in renewable pre-assessment applications in the years immediately following the conclusion of the FIT program in 2018. However, customers have continued to show an interest in DER projects, and connections continue to grow, albeit at a slower pace. Tables 4 and 5 show increases across all categories of DERs. As of the end of 2022, renewable installations represent the largest category of DER by number of connections while non-renewables represent the largest category by generation capacity. Non-renewable DERs are generally larger capacity connections used to support large commercial or industrial facilities. With recent regulatory

and public pressures towards clean energy, it is possible that the combined installed capacity for renewable and energy storage based DER's could surpass non-renewable in this next rate period.

a. Renewable DER Connections

Since the FIT program ended in 2018, Net Metering has become the predominant program choice for connecting renewable generation. Net Metering financially compensates customers through bill credits for any excess electricity generated to the grid at the going rate for electricity. However, the financial benefit is generally less lucrative when compared with the FIT program. While interest in Net Metering continues to grow, pre-assessment and connection applications under this program are lower by comparison to the years when the FIT program was active. Still, since 2018, Net Metering pre-assessments had an average annual growth of 36 percent between 2018 and 2022. In 2022, a total of 362 pre-assessments were completed along with 95 connections, both record highs for this program in the midst of the COVID-19 pandemic.

b. Energy Storage Connections

There has been a relatively low number of energy storage connections in Toronto to date; with only 28 connected projects as of 2022. However, Toronto Hydro's current Energy Storage project pipeline anticipates the connection of an additional 12 projects worth 31.9 MW by the end of 2023. Some of these projects include large battery systems being installed at various Metrolinx and Toronto Transit Commission (TTC) stations used for light-rail transit and hybrid bus charging. The relatively large pipeline in 2023 can be partially attributed to the advancement of projects that had been delayed in earlier years as a result of the COVID-19 pandemic.

c. Non-Renewable DER Connections

In 2018, Toronto Hydro saw significant interest in non-renewable generation with pre-assessment applications increasing to 124 from 61 the previous year. In 2019 however, pre-assessment applications declined to only 35 for non-renewable DER and have continued to fall with only 5 requested in 2021. A similar trend can be observed with CIA applications reducing from 25 to 4 between 2020 and 2021. The timing of this decrease coincides with changes made to the IESO's Process Systems & Upgrade (PSU) program, originally introduced by the IESO in 2011, that offered financial incentives for the implementation of energy efficiency and generation projects that are

capital intensive.[14] As of May 1st, 2019, IESO made fossil-fueled CHP applications ineligible for incentives under this program.[15] This has led to a notable decrease of non-renewable DER applications. In 2022, only four non-renewable projects were connected, compared to 52 in 2020 and 2021. The increased regulatory and public pressures on companies to move towards cleaner sources of energy generation will likely lead to continued decline in new non-renewable installations.

2. Generation Connection Forecast

Toronto Hydro's DER forecast is separated into renewable, energy storage and non-renewable segments. For each segment, forecast DER capacity was approximated using a mathematical model that best represented recent and anticipated growth patterns, considering a combination of historical trends, project pipeline, economic environment and the current energy policies at the time of forecast.

The DER forecast assumes that no major changes to the current regulatory policy or availability of funding and incentives occur within the forecast period. Furthermore, Toronto Hydro compares its forecast results with other third-party studies and research for alignment.

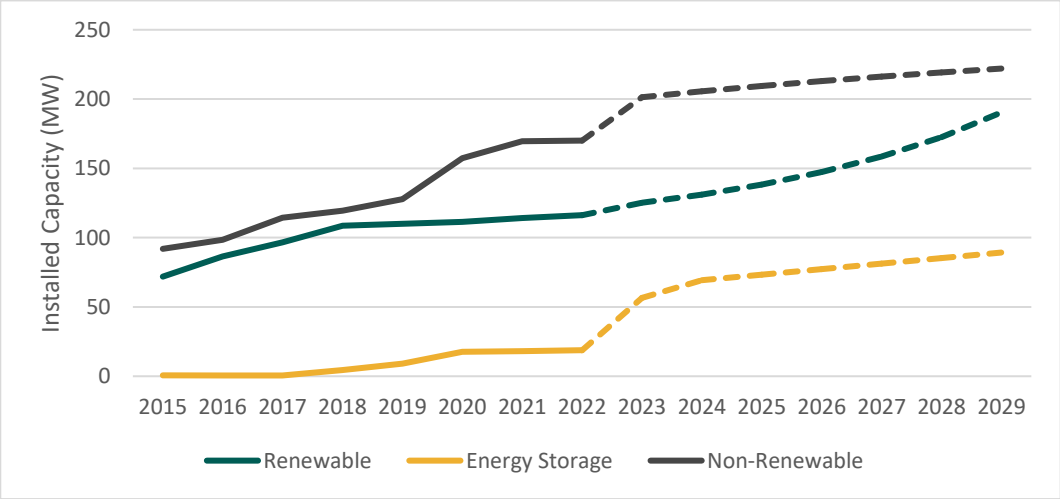


Figure 8: DER Generation Capacity (historical and forecasted) within Toronto Hydro's service territory

[14] Save on Energy, Program Requirements, "online", https://saveonenergy.ca/-/media/Files/SaveOnEnergy/Document-Archive/IF-Documents/PSUP-Program-Requirements-LT.ashx
[15] Independent Electricity System Operator (IESO), New Process and Systems Upgrades Program, "online", https://www.ieso.ca/en/Sector-Participants/Conservation-Delivery-and-Tools/Conservation-E-BLASTs/2019/05/New-Process-and-Systems-Upgrades-Program

a. Overall Forecast

Total DER projects are expected to contribute a total increase of 67 percent to total installations, reaching over 4,400 connections by the end of 2029. This represents a total DER installed capacity of approximately 516.7 MW in comparison to the 304.9 MW installed as of the end of December 2022.

Table 6: Forecast Generation Connections

Generation Type	2023	2024	2025	2026	2027	2028	2029
Renewable	2507	2690	2916	3172	3495	3858	4263
Energy Storage	44	47	53	58	66	73	82
Non- Renewable	132	137	139	141	143	145	147
Total	**2683**	**2874**	**3108**	**3371**	**3704**	**4076**	**4492**

Table *7:* Forecast Generation Capacity (in MW)

Generation Type	2023	2024	2025	2026	2027	2028	2029
Renewable	126.4	133.4	143.4	155.1	168.5	183.6	200.4
Energy Storage	56.6	60.0	73.4	77.4	81.4	85.4	89.5
Non- Renewable	198.2	212.1	215.6	218.7	221.6	224.3	226.8
Total	**381.2**	**405.5**	**432.4**	**451.2**	**471.5**	**493.3**	**516.7**

b. Renewable DER Connections

Between 2023 and 2029, Toronto Hydro forecasts over 1700 additional renewable connections (totalling over 74 MW) to the distribution system. This would bring total installed capacity to 200.41 MW. This rate of growth is in alignment with the Ontario DER Impact Study conducted by ICF in 2021.[16]

c. Energy Storage connections

Between 2023 and 2029, Toronto Hydro forecasts over 50 additional Energy Storage connections (totalling over 70.8 MW) to the distribution system. This would increase the total number of connections to 82 by 2029, and the total installed Energy Storage capacity to 89.5 MW. The pipeline projects indicate aggressive growth in energy storage connections between 2023 and 2025. This growth may be attributed to completion of projects deferred earlier during the COVID-19 pandemic.

[16] ICF Ontario DER Impact Study – January 18, 2021

Beyond 2025, Toronto Hydro believes energy storage growth will return to linear growth patterns, similar to pre-pandemic levels. This rate of growth put this forecast above the high-scenario in the Ontario DER Impact Study conducted by ICF in 2021.[17] However, due to the relatively small existing total capacity of Energy Storage currently installed in Toronto, even the connection of a single large project will lead to large statistical percentage increase in the installed base.

d. Non-Renewable Connections

Toronto Hydro's pipeline for non-renewable DER currently consists of eight projects, totalling 26.6 MW expected to be connected in 2023. Between 2023 and 2029, Toronto Hydro forecasts 28 additional non-renewable DER connections (totalling over 56.8 MW) to the distribution system. This would bring total installed non-renewable DER capacity to 226.8 MW.

While Toronto Hydro anticipates increased pressure from government and regulatory bodies to reduce the use of non-renewable sources of energy as different net zero emissions targets are approached,[18] the most common applications of non-renewable DERs do not yet have viable or technologically mature alternatives. For example, gas generators remain the preferred method of backup generation in the event of an outage for customers as they can run for longer periods of time when compared with energy storage. Renewable generation is not typically suitable for this purpose as they are dependent on the availability of wind (in the case of wind turbines) and sunlight (in the case of solar PV).

Non-renewable generation is also used for Combined Heat and Power (CHP) systems which can generate both heat and electricity. Currently, projects to make fossil fuel-based CHP systems sustainable are still in the pilot phase,[19] and not available to customers.

e. Renewable DERs Policy Considerations

DER demand is driven directly by customer behaviour and choices, which in turn can be greatly impacted by regulatory policy and the availability of funding and incentives. The FIT program is evidence of the rapid impact policy and incentives can have on the renewable DER segment. Between 2009 and 2018 when the FIT program was active, DER installed capacity increased from 1.4 MW to

[17] ICF Ontario DER Impact Study – January 18, 2021
[18] TransformTO's Net Zero 40 and the Net-Zero Emissions Accountability Act achievement of Net Zero by 2050.
[19] Newswire, Cision Canada, "online", https://www.newswire.ca/news-releases/new-combined-heat-and-power-system-will-reduce-greenhouse-gas-emissions-ghg-and-advance-enbridge-gas-hydrogen-hub-in-markham-ontario-886069080.html

108.7 MW, which represents a compound annual growth rate (CAGR) of 62.2 percent. When the FIT program ended, renewable energy growth reduced to 1.7 percent.

Some current policies and economic factors that may impact the rate of renewable DER and energy storage connections include:

- **Green Energy Tax Credit -** This tax credit, announced by the Federal Government in November 2022, allows a tax credit of up to 30 percent of the capital cost of investments in specific generation systems including solar PV and battery storage systems;[20]

- **Third Party Ownership of Net Metered Generation Facilities –** On July 1, 2022, the OEB enacted changes to enable third-party ownership of Net Metered generation facilities.[21] It is expected that this policy will increase customer accessibility to renewable generation facilities, given the high initial cost requirement. This has generally been the case in other jurisdictions where this model is well established.[22] While no third-party Net Metering applications have yet been received by Toronto Hydro, Toronto Hydro anticipates that this policy may play a key role in driving renewable DER growth during this period;

- **Low Lithium Ion Battery Cost -** Lithium Ion battery prices have decreased by more than 79 percent since 2013 and are expected to continue to decrease.[23] The combination of solar PV and energy storage allows users to capitalize on energy that can only be captured during the day, improving the usability of power generated by solar PV. Low battery cost, along with the popularity of the Net Metering program, are likely to result in increased adoption of these technologies;

- **Ultra-Low Overnight Price Plan -** In 2023, the Ontario government launched a new "Ultra-Low" overnight price plan for residential and small business customers. The new ultra-low

[20] Environment and Climate Change Canada, News Release, "online", https://www.canada.ca/en/environment-climate-change/news/2023/04/minister-guilbeault-highlights-the-big-five-new-clean-investment-tax-credits-in-budget-2023-to-support-sustainable-made-in-canada-clean-economy.html
[21] Ontario Energy Board, Forms and Templates: Third-Party Net Metering and Energy Contracts, "online", https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/forms-and-templates-third-party-net
[22] For example, the Solar Energy Industries Association (SEIA) in the US reported that 83% of residential solar systems installed over the last 4 years in New Jersey from 2017 were third-party owned (https://www.seia.org/initiatives/third-party-solar-financing)
[23] BloombergNEF, Lithium-ion Battery Pack Prices Rise for First Time to an Average of $151/kWh, "online", https://about.bnef.com/blog/lithium-ion-battery-pack-prices-rise-for-first-time-to-an-average-of-151-kwh/#:~:text=LFP%20battery%20pack%20prices%20rose,cell%20prices%20observed%20in%202022

overnight rate of 2.4 cents per kWh (down from 7.4 cents)[24] provides further incentive for customers to store energy overnight and discharge during the day and is expected to lead to increased demand for energy storage systems; and

- **Industrial Conservation Initiative (ICI) program -** Large commercial and industrial customers who have opted into the Industrial Conservation Initiative (ICI) program with the IESO can reduce their global adjustment charges through peak shaving or "GA busting" using energy storage systems.

The timing, impact and probability of customer incentives relies on a number of different societal and political considerations and are difficult to predict. While this forecast does not consider future incentives not already announced, it is clear that new incentives can dramatically change the numbers presented here. As different levels of government implement net zero targets, the likelihood of intervention by government and regulatory bodies to support or promote DERs is likely to increase. As such, growth trends of DER could look very different beyond 2029.[25]

E5.1.4 Expenditure Plan

Table 8: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
Program/ Segment	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Customer Connection	36.5	92.5	75.9	71.3	75.7	84.5	90.0	95.4	100.7	106.0
Generation Connection	(0.9)	(0.1)	0.2	-	-	-	-	-	-	-
Total	**35.6**	**92.4**	**76.1**	**76.3**	**75.7**	**84.5**	**90.0**	**95.4**	**100.7**	**106.0**

E5.1.4.1 Customer Connections

Table 9: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**

[24] Province of Ontario, Ontario Launches New Ultra-Low Overnight Electricity Price Plan, "online", https://news.ontario.ca/en/release/1002916/ontario-launches-new-ultra-low-overnight-electricity-price-plan
[25] See, for example, the Future Energy Scenarios whereby the total solar PV uptake by 2025 reaches an installed capacity of approximately 430 MW in the low scenario and more than three times that in the high scenario; Exhibit 2B, Section D4, Appendix B – *Future Energy Scenarios Report* p. 67-70.

Customer Connections Gross	105.6	136.1	139.5	135.1	155.9	167.4	178.9	190.0	201.2	212.3
Customer Connections CC	(69.0)	(43.6)	(63.5)	(63.8)	(80.2)	(82.9)	(89.0)	(94.7)	(100.5)	(106.3)
Net	**35.6**	**92.4**	**76.1**	**76.3**	**75.7**	**84.5**	**90.0**	**95.4**	**100.7**	**106.0**

Expenditure in the Customer Connections segment is driven by a myriad of factors. Year to year variations are due to factors such as economic drivers and changes, the specific type of connection and associated expansion work, provincial and municipal policies regarding infrastructure, community and land revitalization projects, and the energy transition. As described below, Toronto Hydro's 2025-2029 expenditure forecast is based on historical data.

The irregular nature of expenditures in this segment is attributed to externally driven variables, which include:

1) Economic drivers, changes, and policies influence corporations in various industries (such as technology,[26] design,[27] financial services, transportation, etc.) to operate or expand in Toronto, consequently impacting investment needs and expenditures. Factors such as GDP, growth forecasts, inflation, unemployment rates, corporate tax rates, investor protection, purchasing power and credit ratings provide awareness into economic potential and the operating environment. Provincial and municipal policies regarding infrastructure and community revitalization projects (e.g. Toronto Waterfront – Port Lands, Quayside, Parliament Slip, Villiers Island), hospitals, universities, public transit projects (e.g. TTC and Metrolinx - Yonge North Subway Extension, Scarborough Subway Extension, Eglinton Crosstown West Extension, Ontario Line) may give rise to connection work and consequently create further construction and related work in the relevant project sites and surrounding areas;

2) The number, type, size, and location of connection requests received by Toronto Hydro are factors that inform whether an expansion to the distribution system is required. As elaborated in Section 3.1 above, expansion work can significantly impact program

[26] Toronto is a global hub for IT: CBRE, Scoring Top Tech Talent 2022, "online", https://mktgdocs.cbre.com/2299/957e9b99-3410-4f62-b1b1-b4a53147cee1-897668710/2022-Scoring-Tech-Talent.pdf
[27] Toronto employs the largest design workforce in Canada and third largest in North America: CBRE, Tech-30 2022, "online", https://mktgdocs.cbre.com/2299/1d1f0fcb-b1a2-443e-9277-59e1ec6b9cee-609426651/Tech-30-2022.pdf

expenditures as it typically requires a substantial amount of resources to plan and construct the infrastructure necessary to connect a customer; and

3) Capacity relief and additional capacity provisions completed under other System Access and System Renewal programs. For example:
    a) Areas with load constraints may be relieved under the Load Demand program- the resulting capacity relief will allow Toronto Hydro to connect customers more efficiently, reducing expansion requirements to the distribution system and consequently reducing connection costs;
    b) Assets replaced to current standards under the Overhead System Renewal program may indirectly include additional capacity provisions for future purposes, including where:

        (i) poles are replaced with higher or stronger poles to accommodate additional circuits without having to replace the new poles in the future; and

        (ii) additional ducts may be installed when ducts are rebuilt to leverage trenching costs and avoid future costs.

Toronto Hydro's customer charges or allowances associated with connections are established pursuant to the DSC, and Toronto Hydro's Conditions of Service. Connection asset related work, less any allowance, is paid for by the customer. Expansion asset related work is evaluated using the Economic Evaluation Model[28] to determine capital contribution and expansion deposit requirements to be met by the customer.

For the next rate period, Toronto Hydro proposes to increase its Basic Connection Fee allowance for Rate Class 1 to 5 from $1396[29] to $3059. The Basic Connection Fee has not been updated since 2009. The updated Basic Connection Fee reflects the cost of the current connection standards and includes upgraded transformation from 100kVA, to 167KVA. The upgraded transformation standard will reinforce the current overhead system and reduce barriers to electrification by supporting increased load from EV charger installation and/or home electrification. In addition, the increased allowance will also make new service connections more affordable for new residential homes.

[28] As defined in Section 3 and Appendix B of the Distribution System Code ("DSC").
[29] Fees are reviewed annually and updated with notice to customers when Toronto Hydro's Conditions of Service is revised.

The contributions filed in the last application assumed a gross spend (and capital contribution ratio of 48 percent). The average capital contribution rate for years 2020-2022 was 47.7 percent. In order to smooth any cyclical trends and better reflect actual contributions, the 2025-2029 forecast for contributions was developed by considering the average capital contribution experienced during the most recent 5-year period (i.e. 2018 to 2022) and projecting year by year specific contributions for 2025-2029 yielding an average capital contribution rate of 49.8 percent an increase of 3.7 percent above the previous filing rate.

For the 2020-2024 period, the load connection segment is forecasted to be 1.75 times the gross expenditures initially planned. As described above, recovered capital contributions were consistent with the planned ratio of 48 percent. As will be explained below, the increase in expenditures is largely attributed to a substantial increase in projects greater than 5MVA and 10MVA of demand load.

For 2021-2022 Toronto Hydro experienced a higher than anticipated increase in system access requests for large projects (>= 5MVA demand load). In that time, Toronto Hydro connected three times more incremental demand load for >= 5MVA projects than for the entire proceeding five-year rate period 2016-2020 and almost 8.7 times more incremental demand load for projects >=10MVA.

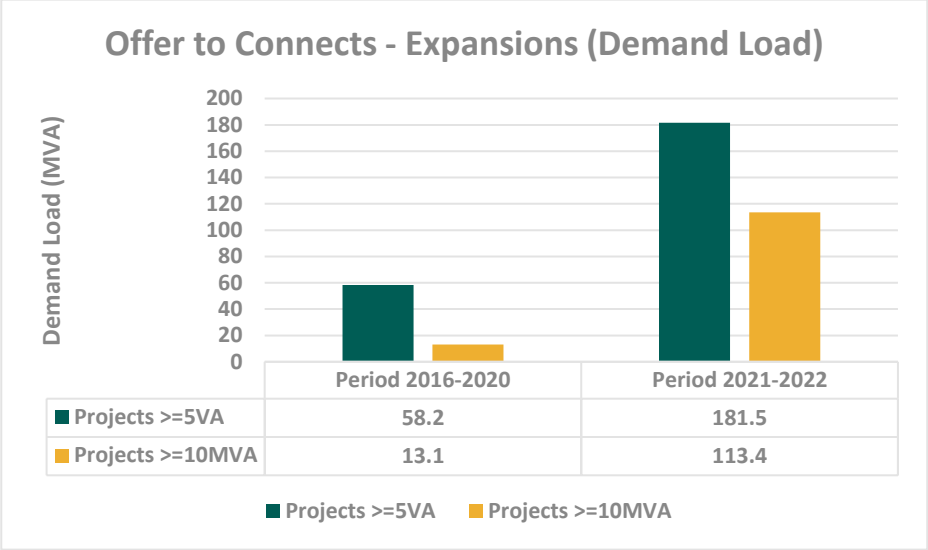


Figure 9: Offers to Connect – Expansions (Demand Load)

The increases in 2020-2021 were attributed to the emergence of unforeseen large connections across a broad spectrum of market segments including: multi-use projects (commercial-

condominium), institutional infrastructure, industrial infrastructure, data centres, and transit projects (Finch West LRT). This market trend towards larger projects seeking system access is expected to continue at 2021-2022 levels through to 2024 based on the current feeder request pipeline, ongoing pre-offer to connect customer design discussions and demand load requirements. Based on Toronto Hydro's early development and Key Accounts initiatives, and direct consultation with customers, Toronto Hydro determined that planned developments for the 2025-2029 timeframe include approximately 17 to 20 projects with greater than 10MVA of demand load. These projects are progressing through the City of Toronto pipeline and development application process, drawing and review phases.

Additionally, the energy transition to clean energy, and electrification has begun creating increased demand for access to the distribution system to support customer adoption of emerging technologies such as electric vehicle charging, electric heat pumps, and electric water heaters. The increasing access requests have developed through numerous channels (Key Accounts relationships, direct customer requests, and consultant/contractors on behalf of customers) and it is expected to grow as energy transitioning matures. Identifiable EV specific projects over the 2022-2024 period include the City of Toronto on street parking project (30 locations with 53 charging ports – 2023), Toronto Parking Authority off street parking (including over 100 EV ground level charging station installed, and 47 pole-mounted stations – 2022, and 225 ground level stations in 2023). This rate of electrification within the City of Toronto is expected to grow and increase rapidly throughout the 2024-2029 period together with ongoing new building construction electrification requirements for commercial, residential and mixed-use developments.

Looking forward to the 2025-2029 period, it is forecasted that the large project (excluding data centres) segment growth will continue to grow at the same or higher levels than the 2020-2024 period. In particular, as discussed above, large projects requiring greater than 10MVA of demand load is expected to grow from one project/year (2020-2024) to approximately three to four projects per year (2025-2029) with an average incremental total demand load of 65MVA per year. Projects during this period are expected to include loading profiles which also encompass compliance with EV charging requirements. These projects are primarily comprised of large multi-use community building developments throughout the City.

Major transit projects for 2025-2029 are also expected to exceed levels experienced and expected for 2020-2024 (one to two projects for the period), and includes projects for the Yonge North Subway Extension, Scarborough Subway Extension, Eglinton Crosstown West Extension, and the Ontario Line

for a total incremental demand load of approximately 150MVA over the 2025-2029 period which is approximately ten times the expected level for 2020-2024.

Based on early development and Key Account initiatives, and direct customer consultations, it is forecasted that the number of data centre service connection for the 2025-2029 period will remain the same as for the 2020-2024 period (total of three for a total incremental demand load of 107MVA), but that the data centres forecasted for 2025-2029 are larger and more complex approximately doubling the incremental demand load expected to approximately 207MVA.

The Customer Connections program is driven by customer service requests and as such, Toronto Hydro ranks and prioritizes jobs in this Program in accordance with the schedules and timelines of individual customers and service requests.

For customers requiring basic connections, prioritization is conducted on a first come, first served basis, considering the in-service date requested by the customer. This prioritization applies where Toronto Hydro has sufficient physical infrastructure, such as through overhead or underground lines, to enable the connection as well as adequate capacity on the relevant distribution feeder cable and station bus. Furthermore, customer timelines are considered to minimize disruptions or allow for efficiencies, whenever possible.

Wherever civil or electrical capacity is constrained or reliability is a concern, the connection is completed once the constraints are addressed by an expansion or system enhancement. For connections that cannot be completed without an expansion, prioritization of the work is determined in accordance with the timelines and requirements stated in the OTC.

E5.1.4.2 Generation Connections

Table 10: Historical & Forecast Program Costs ($ Millions)

	Actual		Bridge			Forecast				
Program/Segment	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Generation Connections Gross	0.8	(1.9)	(0.7)	-	-	-	-	-	-	-
Generation Connections CC	(1.7)	1.8	0.9	-	-	-	-	-	-	-
Net	**(0.9)**	**(0.1)**	**0.2**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

All project expenses and operational costs for Toronto Hydro to facilitate the DER connections are recovered from the customer through capital contributions.[30] The $0.9 million and $ 0.01 million losses incurred between 2020 and 2021 were due to changes in financial bookkeeping practices that led to discrepancy between expenditures and capital contributions in those years.

Toronto Hydro does not propose any net expenditure under this Program for the years 2025 to 2029. If during the course of the project, Toronto Hydro does not use all of the fees collected from the customer to facilitate the DER connection, Toronto Hydro will refund the difference back to the customer.

Table 11 and Table 12 below provide a breakdown of work units and costs associated with the Generation Connection program based on generation type and size.

Table 11: 2020-2024 Volumes (Actual/Bridge)

Generation Type	Actual			Bridge		Total
	2020	2021	2022	2023	2024	
Renewable <50 kW	24	51	85	170	157	**487**
Renewable > 50 kW	8	8	10	57	26	**109**
Micro Energy Storage	-	-	3	2	2	**7**
Small Energy Storage	9	2	1	2	1	**15**
Mid Energy Storage	2	-	-	9	1	**12**
Large Energy Storage	-	-	-	2	1	**3**
Small Non-Renewable	25	22	4	9	1	**61**
Mid Non-Renewable	1	3	-	7	1	**12**
Large Non-Renewable	1	-	-	-	-	**1**

[30] Work and costs associated with additional modifications to the distribution system to incorporate renewable generation into the system are discussed in the Generation Protection, Monitoring, and Control program see Exhibit 2B, Section E5.5.

Table 12: 2025-2029 Volumes (Forecast)

Generation Type	Forecast					Total
	2025	2026	2027	2028	2029	
Renewable <50 kW	179	202	259	293	325	**1258**
Renewable > 50 kW	47	54	64	70	80	**315**
Micro Energy Storage	2	3	4	4	6	**19**
Small Energy Storage	1	1	1	1	1	**5**
Mid Energy Storage	1	2	2	2	2	**9**
Large Energy Storage	-	-	-	-	-	**0**
Small Non-Renewable	1	1	1	1	1	**5**
Mid Non-Renewable	1	1	1	1	1	**5**
Large Non-Renewable	-	-	-	-	-	**0**

Toronto Hydro has a dedicated DER team that supports DER connections. This team works closely with customers to ensure the DER connection process is followed and timelines set by the Ontario Energy Board are met. Generation connections, like customer load connections, are processed and completed on a first come first serve basis.

E5.1.4.3 Cost Management

Toronto Hydro integrates the connection work with its planned construction activities to help ensure that the scope, nature and timing of the connection work does not adversely affect the utility's existing customers and planned work program.

If Toronto Hydro anticipates that load growth will require additional infrastructure upgrades beyond what is required under the expansion work for a customer service connection as set out in an OTC, the utility will include the additional system growth distribution work (which can range from installing larger circuits to rebuilding cable chambers) as a part of the project but not allocate these costs to the customer's OTC for the service connection. Such additional infrastructure upgrade project costs are allocated to the respective programs (e.g. Load Demand, Externally Initiated Plant, Overhead System Renewal, or Underground System Renewal). This coordinated approach is more cost-efficient than returning to the same area at a later date to perform additional upgrades.

An example of this approach can be found in work along Toronto's Waterfront, where the required civil work to connect new condominiums and developments was augmented to include the

additional infrastructure necessary to meet future demands and system requirements that are imminently expected based on the City's Precinct Plans and progress for revitalisation projects such as the Port Lands. The development areas of the Port Lands (e.g. Villiers Island, Polson Quay and South River, McCleary District, Hearn Generating Station, Maritime Hub, Media City, East Port, South Port) includes residential, commercial, retail, and industrial land uses, combined with green space and community-based developments.

Wherever possible, Toronto Hydro also coordinates its connection work with construction activities undertaken by other utilities or municipal provincial, or federal government agencies. For example, Toronto Hydro is coordinating the expansion work for the Port Lands Revitalization Project with the City of Toronto's road allowance infrastructure construction schedule, as well planning for the Downsview park lands (City of Toronto/Canada Lands) development including servicing and infrastructure.

Where an expansion overlaps with a capital work program or another project, Toronto Hydro would connect customers under a temporary arrangement until the project is complete.

For Generation Connections, the cost for Toronto Hydro to facilitate DER connections are recoverable through customer paid fees resulting in zero net expenditures. These fees are regularly re-evaluated by Toronto Hydro to ensure that they recuperate all connection costs considering various factors like equipment cost changes, market inflation, etc.

E5.1.5 Options Analysis

E5.1.5.1 Option 1: Do Nothing

Do nothing is not an option as Toronto Hydro would be violating the DSC as well as its Distributor License.

E5.1.5.2 Option 2 (Selected Option): Customer Connections Program

As customers request access to the distribution system, Toronto Hydro endeavours to connect them in the most efficient and economic means available. Specifically, Toronto Hydro aims to connect customers from the closest access points available; where possible.

Depending on the system and customer conditions (e.g. requirements, size, location, and timelines), capacity or access may not be available. In such cases, Toronto Hydro will consider alternative solutions to connect the customer. Such alternatives may include, but are not limited to, transferring

existing customers to an alternative feeder to free capacity on the feeder in question, or upgrade, extend, or install feeders, transformers, switches or other relevant equipment, as required. Should multiple options exist to connect a customer, options are reviewed with the customer and any differences (financial or technical) are explained to the customer to allow for an informed decision.

The Customer Connections program is an integral program for Toronto Hydro for the purposes of meeting customer service requests in accordance with its mandated service obligations. Without this Program, Toronto Hydro will not be able to serve and connect customers in the manner specified by its Distributor Licence and other applicable regulatory requirements.

E5.1.6 Continuous Improvement

E5.1.6.1 Productivity

In 2022, as part of a continuous improvement initiative to enhance the customer experience, Toronto Hydro created two new teams – the customer intake team and the pre-design team to streamline the customer connection process:[31]

- The customer intake team creates a single point of contact for all customer inquiries related to connections; and,
- The pre-design team acts as a single point of contact for customer to ensure all information required by the design team for large connections is collected before moving forward to the design phase.

At the end of 2023, Toronto Hydro is expected to launch the Service Request Form Enhancements on the Customer Connections portal. These enhancements will improve the customer experience by enhancing the service request form for customers to request new and existing connections from Toronto Hydro. Further details of these initiatives are described in Exhibit 4, Tab 2, Schedule 8.

To improve the customer experience and help customers better understand the availability of different service types and options, Toronto Hydro has prepared a set of public-facing brochures and guidelines. Brochures topics include “How to Power up your Home”, “How to power up your Projects”, pool clearance and underground clearance.

[31] Further details regarding these two teams can be found in Exhibit 4, Tab 2, Schedule 10.

E5.1.7 Execution, Risks & Mitigation

E5.1.7.1 Execution

Customer Connections involves the installation of connection, expansion, and/or enhancement assets, as defined by the DSC. The utility manages the work required under the Customer Connections program for Toronto Hydro. Customers or their representatives are required to consult with Toronto Hydro concerning the availability of supply, supply voltage, service location, metering, and any other details necessary to establish service.

Customers apply for new or upgraded electricity services and temporary power services in writing. Each customer provides Toronto Hydro with sufficient lead-time to ensure the timely provision of adequate electricity supply. Toronto Hydro communicates with the customer in a timely manner in accordance with the DSC and Toronto Hydro's Conditions of Service.

Pursuant to the applicable provisions of the DSC and its Conditions of Service, Toronto Hydro does not connect customers if it has safety concerns or reason to believe that the connection would affect the reliability of its distribution system. A load analysis is performed for each customer request to ensure that the requested connection would not overload Toronto Hydro assets above their rated capacity. For large connections, this analysis also includes protection and coordination studies to ensure the proper protection is in place and to avoid damage to equipment and potential safety risks.

During the consultation and design phase of a customer’s request, if a connection could potentially degrade the reliability of the relevant feeder or station, expansion work is deemed necessary to increase capacity or transfer load so that the current level of reliability is maintained.

Toronto Hydro provides customers with an OTC within 60 days from the day all required information is received. The customer is presented with a job quotation or a “short form” OTC, should the connection not require any expansion. Otherwise, the customer is provided with a “long form” OTC.

Customers are required to accept and make all OTC payments within 60 calendar days of receiving the OTC. Once an OTC is executed, the resulting work is to be carried out by Toronto Hydro resources unless the customer pursues an alternative bid where allowed by the OTC.

E5.1.7.2 Risks & Mitigation

The following are a number of risks that may affect the completion of the Program, and associated actions aimed to eliminate or manage such risks:

- **Capacity upgrade requirements**: Due to the increasing quantity and size of customer service requests, Toronto Hydro anticipates that many future connections will require expansion work to deal with capacity constraints. Typically, these expansions have long lead times that could present a challenge to Toronto Hydro in meeting the customer's required timelines for connection. The increasing complexity of connections, which may require additional capacity/equipment from Hydro One, may not allow Toronto Hydro to deliver an OTC within 60 days. Toronto Hydro will continue to:
    - Use long term forecasting, including analysis of city area and development plans in order to address growth early on and proactively upgrade or install required assets through enhancement work to the system;
    - Engage customers early on in the process to determine needs and assess impact on distribution system; and,
    - Engage with Hydro One as early as possible in order to mitigate capacity constraints which may appear on both the distribution and transmission systems.

- **Customer timelines and requirements**: Customers' changing requirements, load demand, deadlines, and delays in providing information, signing offers to connect, and providing payments present a risk to project timelines. Customers frequently require more complicated connection schemes to ensure their current and future needs are met. In addition, an expedited construction schedule by the customer and/or a strain on Toronto Hydro resources risks the utility's ability to complete the project on time and meet the customer's timeline. Toronto Hydro strives to identify and mitigate these risks early on during the design and consultation phase through early engagement, key accounts interaction, customer intake processes, and pre-design teams. This overall process educates, and prepares both the customer and Toronto Hydro on servicing challenges, finding the best solution from a technical and economic standpoint, and identifying any servicing limitations which may occur prior to the issuance of an offer to connect. Toronto Hydro communicates with the customer in a timely manner in accordance with the DSC and Toronto Hydro's Conditions of Service to ensure requests are continuously progressing. Customers are informed of expectations, timelines, and requirements early on through proper communications. Customers are also required to accept and make all OTC payments within 60 calendar days of receiving the OTC; and

- **Generation Connections:** Toronto Hydro has identified a number of constraints within its system that impact DER connections and interconnection-related decisions: 1) short-circuit capacity; 2) risk of islanding; 3) thermal limits; and 4) the lack of the ability to transfer loads between feeders during planned work. The Generation Protection, Monitoring & Control Program at Exhibit 2B, Section E5.5 describes the steps Toronto Hydro is taking to mitigate these system constraints.

E5.2 Externally Initiated Plant Relocations and Expansion

E5.2.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 54.2	**2025-2029 Forecast ($M):** 76.0
Segment: Externally Initiated Plant Relocations & Expansion	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Focus, Public Policy Responsiveness, Financial Performance, Operational Effectiveness - Reliability	

The Externally Initiated Plant Relocations and Expansion program (the "Program") captures work Toronto Hydro must undertake to relocate its infrastructure in response to third-party relocation requests to resolve conflicts between existing utility infrastructure and third-party capital construction projects. The Program also includes work that increases the capacity of Toronto Hydro's system where, in some instances, efficiencies can be achieved by integrating expansion work of the electrical system with the required relocation work. Relocation requests by third parties are usually received from those required to maintain, upgrade, expand and improve existing public infrastructure such as roads, bridges, highways, transit systems, transmission stations and rail crossings. The governmental third parties include the City of Toronto and the Ministry of Transportation of Ontario. Toronto Hydro also receives relocation requests from other agencies, such as Metrolinx, which it assesses in a fair and reasonable manner.

The City of Toronto is experiencing a period of significant infrastructure renewal, neighbourhood revitalizations, commercial development and large transit expansions. Toronto Hydro seeks to respond to relocation requests received from third parties in a safe, environmentally responsible, reliable, cost-efficient and timely manner. In pursuing this objective, the utility aims to meet its obligations under:

- The *Public Service Works on Highways Act, 1998* ("*PSWHA*");[1]
- The Distribution System Code ("DSC") section 3.1.10;

[1] RSO 1990, Ch P.49.

- The *Building Transit Faster Act, 2020 ("BTFA")*;[2]
- The *Building Broadband Faster Act, 2021* ("*BBFA*"),[3] including requirements under Ontario Regulation 410/22 made under the *Ontario Energy Board Act*, *1998* ("*OEB Act*");[4] and
- Agreements with third parties.

Typically, when relocations are required, Toronto Hydro replaces the existing facilities on a like-for-like basis. This approach represents the minimum investment required to allow Toronto Hydro to continue providing safe and reliable electricity distribution service. However, at times, the nature of the project is such that like-for-like replacements are not the most efficient or desirable option. In these cases, there will be an opportunity for Toronto Hydro to maximize construction efficiencies and increase the existing capacity at the same time a relocation project is completed. In these cases, Toronto Hydro reviews the relocation request in conjunction with its future plans, and, if efficiencies can be achieved, works with the third party to complete system expansion work in conjunction with the required relocation. When Toronto Hydro increases the capacity of its infrastructure driven by future load growth during an externally initiated relocation project, this is known as an "expansion" for the purposes of this Program.[5]

The timing, pace and spending under this Program is driven by third-party requirements outside of Toronto Hydro's control. The circumstances and discretion of third parties can cause schedules and project scopes to change. In order to mitigate against the unpredictable nature of the work in this Program, Toronto Hydro seeks base rate funding for committed capital projects only. Toronto Hydro was approved to record variances in the difference between capital spending embedded in base distribution rates and the actual spending in the Externally Initiated Variance Account.[6] The Externally Initiated Variance Account was continued through to the end of the current rate period.[7] Toronto Hydro now seeks approval to record variances between capital spending embedded in rates and actual spend over the 2025-2029 rate period in the Demand Variance Account. Further details on the Demand Variance Account can be found in Exhibit 1B, Tab 2, Section 1 – Rate Framework and

[2] SO 2020, Ch 12.
[3] SO 2021, Ch 2 Sched 1
[4] SO 1998, Ch 15 Sched B.
[5] Also known as an "enhancement" under the Distribution System Code.
[6] EB-2014-0116, Toronto Hydro-Electric System Limited Decision and Order (December 29, 2015) at p. 50.
[7] EB-2018-0165, Toronto Hydro-Electric System Limited Decision and Order (December 19, 2019) at p. 198.

Exhibit 9, Tab 1, Section 1 – DVA Overview. This approach will allow Toronto Hydro to fund necessary non-discretionary work, while protecting ratepayers from potential over recovery.

E5.2.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by responding to relocation requests and undertaking necessary, timely and cost-efficient system expansion work to accommodate future growth and increase system access, which should reduce the frequency and duration of construction disruptions for local area residents.
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by: ○ Complying with the *PSWHA*, which requires Toronto Hydro to work with prescribed entities to complete the relocation of Toronto Hydro infrastructure, when requested, and subject to the cost responsibility principles established therein; ○ Complying with the *BTFA*, where Metrolinx may require the utility to modify its infrastructure if necessary for a priority transit project; ○ Complying with the *BBFA* and associated regulations, where the Minister may require a distributor to perform work if it deems it necessary for the deployment of a designated broadband project; and, ○ Complying with section 3.1.10 of the DSC by responding to customer requests for the relocation of Toronto Hydro's assets.

Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by: ○ Obtaining, from third parties requesting distribution plant relocations, full or partial funding for newly installed/relocated assets pursuant to applicable cost sharing agreements; and ○ Combining externally initiated relocation work with expansion work where doing so provides a more prudent and cost-effective solution than conducting the expansion work at a later date.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's reliability objectives by: ○ Installing new infrastructure to current standards; and ○ Improving capacity, where required, through expansion work associated with the relocation.

E5.2.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Customer Service Requests, Capacity Constraints

E5.2.3.1 Mandated Service Obligations

The *PSWHA* requires Toronto Hydro to work with public entities requesting relocation of hydro plant in a timely manner to promote the maintenance and improvement of public infrastructure.[8] In addition, Toronto Hydro has obligations under the *BTFA and BBFA* to deliver relocation services to expedite provincial transit and broadband infrastructure projects.

E5.2.3.2 Capacity Constraints

The scope, timing and pacing of these relocation projects are driven by operational decisions of third parties that are beyond Toronto Hydro's control. Toronto Hydro reviews load demand projections in the vicinity of externally initiated relocation work to identify opportunities to increase capacity

[8] These public entities must meet the definition of "road authorities" under the *PSWHA*: "road authority" means the Ministry of Transportation, a municipal corporation, board, commission, or other body having control of the construction, improvement, alteration, maintenance and repair of a highway and responsible therefore.

during a relocation project. When capacity needs are identified, Toronto Hydro integrates expansion work into the relocation project. This offers a more cost-effective solution than conducting the expansion work after the sponsor agency has completed its project.

E5.2.3.3 Customer Service Requests

Responding to relocation requests by customers is part of Toronto Hydro's customer service obligations as set out in section 3.1.10 of the DSC. Undertaking necessary, timely and cost-efficient system expansion work in connection with such relocations allows Toronto Hydro to accommodate future growth and increase system access while reducing the frequency and duration of construction disruptions for local residents.

E5.2.3.4 Program Need

Toronto Hydro undertakes the externally initiated relocations and expansions projects solely in response to capital work initiated by third parties. Any expansion work carried out under this Program is needed to meet anticipated future load growth to allow Toronto Hydro to coordinate projects with construction work being carried out by third parties.

The projects within this Program can be divided into four broad categories:

1. Requests from road authorities governed by the *PSWHA*;
2. Requests from agencies subject to *BTFA* for transit and *BBFA* for broad brand infrastructure;
3. Requests from other agencies and customers; and,
4. Expansion work undertaken in conjunction with the relocation work.

1. Requests from Road Authorities

The *PSWHA* outlines obligations for utilities with infrastructure on roads and those entities, such as the City of Toronto and Ministry of Transportation of Ontario, that have control of the construction, improvement, alteration, maintenance and repair of a highway ("Road Authorities"). For instance, typical relocation work arising from a City of Toronto initiated project includes relocating hydro poles to enable road realignment.

The *PSWHA* establishes a framework for determining cost responsibility between the parties for the relocation work. Under this framework, the Road Authority and the utility may agree upon the apportionment of the cost of the labour employed in the relocation, but, if there is no such

agreement then the equipment and labour costs are divided equally between the Road Authority and the utility, and all other costs of the work (such as material costs) are the responsibility of the utility.

For relocation project components not covered under *PSWHA* but initiated by a Road Authority, such as streetscape improvement projects, or for non-like-for-like replacements (i.e. converting overhead to underground), Toronto Hydro aims to negotiate agreements that provide greater cost recovery than the default cost apportionment provided for under the *PSWHA*.

2. Requests from Agencies Subject to *BTFA* and *BBFA*

Since the previous 2020-2024 rate application two statutes have been passed which create additional obligations on utilities regarding the relocation of utility assets: the *BTFA* and the *BBFA.*

The *BTFA* was passed in 2020 to expedite the delivery of transit projects by removing barriers and streamlining processes that may result in delays. The *BTFA* outlines obligations for utilities regarding relocation of infrastructure related to priority transit projects. The *BTFA* also provides rules for cost allocation, whereby Metrolinx and the utility may agree on the apportionment of the actual cost of the work. However, if there is no agreement, Metrolinx must bear the actual cost of the work. Toronto Hydro successfully negotiated with Metrolinx that all *BTFA* relocations will be 100 percent funded by Metrolinx.

Currently, the *BTFA* designates four projects in Toronto Hydro's service area as priority transit projects:

1. The Ontario Line;
2. The Scarborough Subway Extension;
3. The Yonge North Subway Extension; and,
4. The Eglinton Crosstown West Extension, extending from Mount Dennis.

The *BBFA* was passed in 2021 to expedite the delivery of broadband projects of provincial significance.[9] This Act outlines obligations for distributors and transmitters to complete work

[9] Under the *BBFA*, the proponent and the distributor may agree on the apportionment of the actual cost of the work. If there is no agreement, there is a formula set out in Ontario Regulation 410/22 to determine the proponents share of the costs. For further details on the cost apportionment formula see s. 7 of Ontario Regulation 410/22 made under the *Ontario Energy Board Act,* and the OEB's Guidance on Cost Apportionment for Designated Broadband Projects dated February 9, 2023.

necessary for the deployment of a designated broadband project. There are no projects currently designated under the *BBFA* within Toronto Hydro's service territory.

3. Requests from Other Agencies and Customers

Where the *PSWHA, BTFA* and *BBFA* do not apply, the initiating third-party typically funds 100 percent of the relocation costs while Toronto Hydro funds any expansion work conducted in conjunction with the relocation work. Large scale projects such as the Toronto Transit Commission ("TTC") Yonge and Bloor Station Capacity Improvement Project and Easier Access Program, are examples of major projects not subject to the *PSWHA* provisions. In these cases, the third-party funds 100 percent of the relocation work.

Metrolinx is also currently working on transit projects that are not designated under the *BTFA.* The GO Expansion project will enable electric trains on several corridors. This requires adding new tracks, new stations and overhead catenary lines.[10] This includes expanding existing electrified transit through subways and Light Rail Transit ("LRT").

Work with Metrolinx is subject to a number of crossing agreements which govern cost sharing. Toronto Hydro is working with Metrolinx to negotiate cost responsibility for the additional relocation work. If, as a result of these negotiations, Toronto Hydro must bear some of the relocation costs, these costs will be recorded in the Demand Variance Account.

4. Expansion Work in Conjunction with Relocation Projects

Expansion work carried out under this Program is needed to meet anticipated future load growth. Pursuing expansion work in conjunction with the externally initiated relocation work allows required infrastructure to be installed where future construction may be restricted due to City streetscaping, commercial developments, City-imposed road work moratoriums or conflicts with other below grade utilities such as water, sewer, gas, and telecommunications.

Incorporating expansion work into the relocation work may result in significant cost savings compared to undertaking expansion work at a later date. Expansion work completed in conjunction with relocation projects may eliminate future third-party utility relocation and coordination work, avoid additional restoration work and minimize disturbance to the general public. Further,

[10]Metrolinx, GO Expansion, "online", https://www.metrolinx.com/en/projects-and-programs/go-expansion

undertaking expansion work in conjunction with relocation work ensures that Toronto Hydro infrastructure is installed in already congested rights of way without triggering the need for City approval of encroachment exemptions under the municipal consent requirements for infrastructure clearances. For instance, within the transit corridors of the Ontario Line and Eglinton Crosstown West Extension, Eglinton LRT and Finch West LRT, Toronto Hydro is taking the opportunity afforded by these relocations to expand its existing infrastructure in preparation for the expected load growth along the LRT lines. The expansion work is scheduled to occur between 2024 and 2030.

E5.2.4 Expenditure Plan

Toronto Hydro's projected spending in this Program is based on committed capital plans from third-parties including Road Authorities, Metrolinx and the TTC. Toronto Hydro gathers information on capital projects through direct consultation with external agencies, participation in the Toronto Public Utilities Coordination Committee, and reviewing governmental and public agency publications. These capital plans and project schedules are subject to change at the sole discretion of the sponsor agencies. Any such changes could impact the timing and execution of Toronto Hydro's relocation and expansion work. The projected quantum and timing of spending shown in Table 4, below, is based on the most current information available from third parties.

Table 4: Historical, Bridge and Projected Program Spending ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Total Project Cost	82.8	67.6	66.1	84.8	63.9	103.7	78.5	58.0	58.8	61.2
Capital Contributions	74.1	58.3	53.2	69.6	55.7	81.1	61.8	46.1	46.7	48.6
Net Cost	**8.7**	**9.3**	**12.9**	**15.2**	**8.2**	**22.6**	**16.7**	**12.0**	**12.1**	**12.6**

Given the uncertainty associated with the projects in this Program, Toronto Hydro sought rate funding for committed capital projects only (e.g. Eglinton Crosstown LRT and Finch West LRT) in its 2020-2024 rate application in the amount of $46.1 million. Any changes to these major projects or any new projects that emerged during the rate period would increase spending under this Program. Toronto Hydro requested and received a continuation of the Variance Account for Externally Driven capital to record the difference between the capital spending embedded in base distribution rates and the actual spending in the Program over the rate period.

Toronto Hydro's incurred capital expenditure costs in the 2020-2024 rate period were approximately $54.2 million, approximately $8 million over the planned amount. During the 2020-2024 rate period, there was an increase in the number and size of relocation projects. As well, there were increased costs to complete some of the work in the 2020-2024 rate period. For example, site conditions on the John Street project necessitated the use of more costly tunnelling and shaft construction than what was previously planned to accommodate the deeper elevation of new infrastructure design in order to clear other utility conflicts.

Toronto Hydro identified a number of major projects below in section E5.2.4.1 that are to commence or continue in the 2025-2029 rate period. Given the uncertainty associated with these projects, in order to mitigate against the unpredictable nature of the work in this Program, Toronto Hydro seeks base rate funding for committed capital projects only. Toronto Hydro also requests approval to capture the difference between the capital spending embedded in base distribution rates and the actual spending over the 2025-2029 rate period in the Demand Variance Account. This approach will allow Toronto Hydro to fund necessary non-discretionary work, while protecting ratepayers.

E5.2.4.1 Major Projects

Key projects with anticipated completion in the 2025-2029 rate period, including projects which have carried over from the 2020-2024 rate period, are described below.

1. Building Transit Faster Act

Metrolinx has issued notices to relocate all existing Toronto Hydro assets to accommodate construction activities and planned infrastructure for four priority transit projects designated under the *BTFA*: the (i) Ontario Line, (ii) Scarborough Subway Extension, (iii) Yonge North Subway Extension and (iv) Eglinton Crosstown West. Additional information on the four priority transit projects designated for execution are as follows:

i. Ontario Line Subway

The Ontario Line is an estimated $17 billion investment by the Province of Ontario to expand transit in Toronto with 15 stations. As shown in Figure 1 the 15.6 km Ontario Line will run between Exhibition/Ontario Place through downtown Toronto to the Ontario Science Centre.[11]

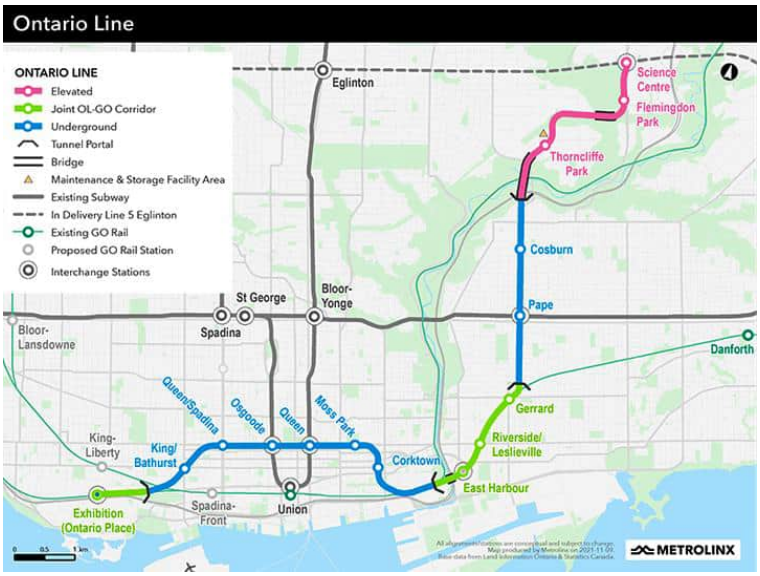


Figure 1: Proposed Map of Ontario Line

The project provides an opportunity for Toronto Hydro to undertake needed expansion work in the area. The City expects the Ontario Line corridor to experience significant growth in terms of population density and real estate developments.[12] Construction of new underground assets by Toronto Hydro within the construction zone will relieve existing area capacity constraints and meet this future growth. Completing expansion work in conjunction with the proposed construction allows Toronto Hydro to take advantage of construction efficiencies eliminating extensive future relocation work involving complex utility coordination, potential deviation on municipal consent requirements on infrastructure clearances, and disturbances to the public. Construction efficiencies may also be gained by using the same trench for multiple utilities and avoiding additional restoration

[11] Metrolinx, Ontario Line – Projects, *"online"*. https://www.metrolinx.com/en/projects-and-programs/ontario-line.
[12] City of Toronto, 2021 Census: Population and Dwelling Counts, "online", https://www.toronto.ca/wp-content/uploads/2022/02/92e3-City-Planning-2021-Census-Backgrounder-Population-Dwellings-Backgrounder.pdf.

work. The timing of the relocation and expansion work is primarily based on project timelines set by Metrolinx and its contractors. The project has a current estimated completion date of 2031.

ii. Scarborough Subway Extension

The Metrolinx Scarborough Subway Extension (SSE) is an estimated $5.5 billion project and will bring the TTC's Line 2 subway service nearly eight kilometres further into Scarborough, from the existing Kennedy Station northeast to McCowan Road and Sheppard Avenue (see Figure 2). The extension is set to replace Line 3 with three new stations at Lawrence Avenue and McCowan Road, Scarborough Centre, and a terminal station at McCowan Road and Sheppard Avenue. Toronto Hydro has also planned to construct new underground assets within the construction zone to relieve existing area capacity constraints and meet future growth. The timing of the relocation and expansion work is primarily based on project timelines set by Metrolinx and its contractors. The project has an estimated completion date of 2030.

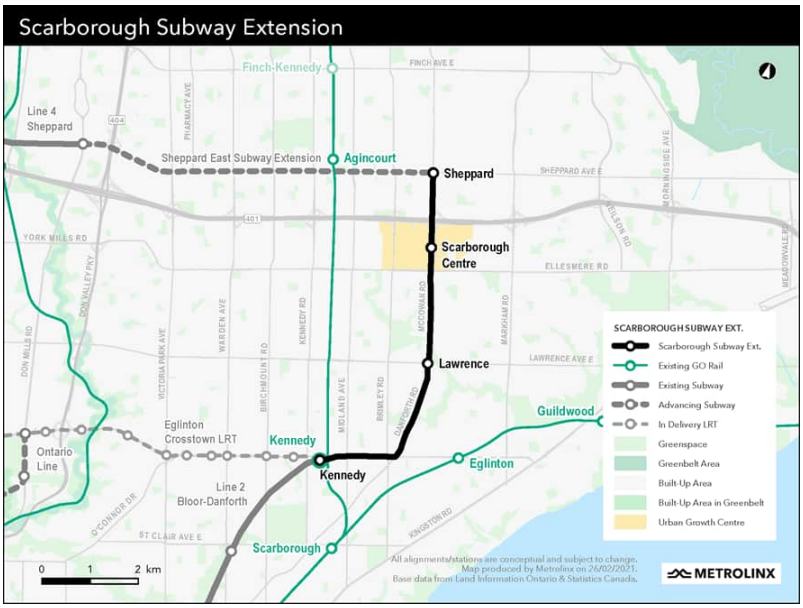


Figure 2: Proposed map of Scarborough Subway Extension

iii. Yonge North Subway Extension

The Yonge North Subway Extension is an estimated $5.6 billion project by the Province of Ontario. It will extend the TTC's Line 1 service north from Finch Station to Vaughan, Markham and

Richmond Hill. The 7.4km line will add approximately five stations. The project provides an opportunity for Toronto Hydro to undertake needed expansion work in the area up to Steeles Avenue, the limit of its service territory. The City expects the Yonge North Subway Extension corridor to experience significant growth in terms of population density and real estate developments. Construction of new underground assets by Toronto Hydro within the construction zone will relieve existing area capacity constraints and meet this future growth. The timing of the relocation and expansion work is primarily based on project timelines set by Metrolinx and its contractors. Construction started in February of 2023 and there is an estimated completion date of 2030.[13]

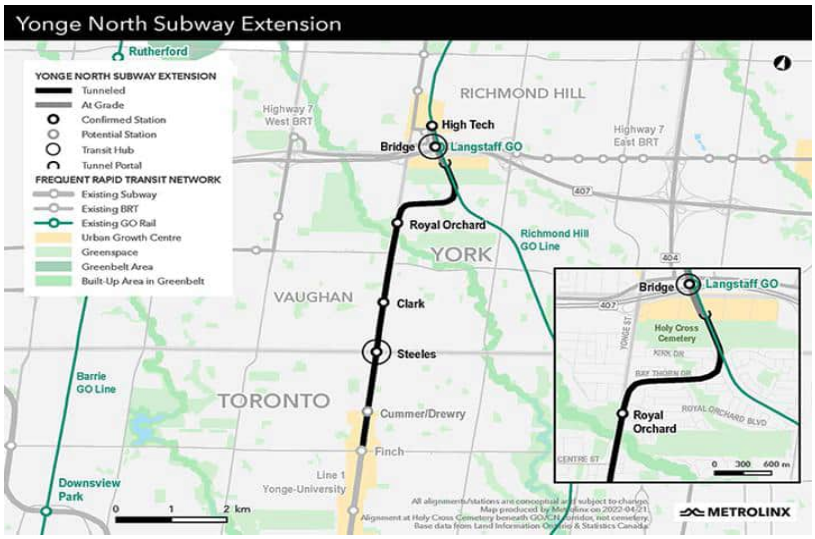


Figure 3: Proposed map of Yonge North Subway Extension

iv. Eglinton Crosstown West Extension

The Eglinton Crosstown West Extension ("ECWE") is an estimated $4.6 billion investment by the Province of Ontario that will bring rapid transit to Etobicoke and Mississauga. The western extension of the Eglinton Crosstown LRT will run approximately 9.2 km from Mount Dennis Station, west towards Renforth Drive and will operate mainly underground. Upon delivery of the ECWE, it

[13] Metrolinx, Yonge North Subway Extension, "online", https://www.metrolinx.com/en/projects-and-programs/yonge-north-subway-extension.

will create a continuous rapid transit system that spans from Scarborough, through midtown Toronto and into Mississauga.

With the new LRT, the Eglinton West LRT corridor will be more densely populated as the transit services will allow for increased growth and development. Toronto Hydro will be taking advantage of the relocation work to construct new infrastructure within the Eglinton West LRT corridor to alleviate capacity constraints and meet the anticipated load growth in the area. Expansion work will be completed in conjunction with the required relocation work causing less disruption to customers and enabling cost savings due to the elimination of road cut restoration costs. These savings are achieved through cost efficiencies in design and construction including savings in trenching costs, bulk concrete purchase savings, insurance, and digital mapping. The timing of the relocation and expansion work is primarily based on project timelines set by Metrolinx and its contractors. Tunneling commenced in April 2022, and the project is expected to reach completion in 2030.[14]



Figure 4: Proposed map of the Eglinton Crosstown West Extension

[14]Metrolinx, Eglinton Crosstown West Extension, "online", https://www.metrolinx.com/en/projects-and-programs/eglinton-crosstown-west-extension

2. Metrolinx GO Expansion

The Go Expansion is a $13.5 billion investment by the Province of Ontario, to be carried out by Metrolinx, to enhance and update GO Transit infrastructure across the Greater Toronto and Hamilton Area to support more frequent, two-way, uninterrupted service via electric trains.

This initiative is a multi-year project on the GO rail network that will require extensive relocation of underground and overhead assets along the GO rail corridor in four project categories:

- **GO Electrification**: utilizing an overhead catenary system at 25 kV to operate electric motor trains and phase out diesel trains;
- **Grade Separation**: elevating the rail corridor to separate rail crossings from other modes of transportation;
- **GO Expansion**: expansion of rail tracks and associated infrastructure (i.e. tracks, rails and signals) to facilitate improved uninterrupted service; and
- **GO Station**: construction of new platforms, buildings, stations, traction power stations, parking and maintenance storage facilities to build a connected transit network.

As part of this project, Metrolinx requires the relocation of Toronto Hydro assets to meet infrastructure clearance requirements and to facilitate infrastructure, equipment and construction activities over the course of the proposed 10-year program. Figure 5 shows a typical GO Transit grade separation.



Figure 5: Grade Separation at Davenport Diamond

During the 2020-2024 rate period, Toronto Hydro has and will continue to execute Utility Preparatory Activities for the early and complementary works phase. In 2023, Toronto Hydro began investigating approximately 100 conflicts related to the development phase and scoped out approximately 35 relocation projects expected to be completed between 2023 and 2030.

Toronto Hydro is also developing a number of projects to take advantage of efficiencies in carrying out necessary expansion work in parallel with the required relocation work. The expansion work involves the construction of new infrastructure within the construction zone of the GO rail corridor and stations. The timing of the proposed work is dependent on the priority and construction of the grade separation, track expansion, electrification and station work determined by Metrolinx.

3. TTC Easier Access Program

The TTC initiated the Easier Access Program with the goal of making all of its services and facilities, including key subway and Scarborough Rapid Transit stations, fully accessible to persons with disabilities. The *Accessibility for Ontarians with Disabilities Act*, *2005* ("*AODA*") requires that all public facilities and services are accessible by 2025.[15]

Significant subway station infrastructure is impacted by the need for *AODA* compliance, including the requirement that subway stations be constructed in a tiered configuration, similar to the one set out in Figure 6. In total, 13 stations were originally included in the program. Since the last rate application, the program has expanded to include a total of 16 stations. Many of the impacted stations are located in the downtown area necessitating relocation of Toronto Hydro's infrastructure. Toronto Hydro has already completed relocation work for five stations. Although these projects were initially scheduled to be completed entirely during the 2020-2024 rate period, there will be some carry over into the 2025-2029 rate period. Toronto Hydro is also evaluating opportunities for expansion.

[15] SO 2005, Ch 11.

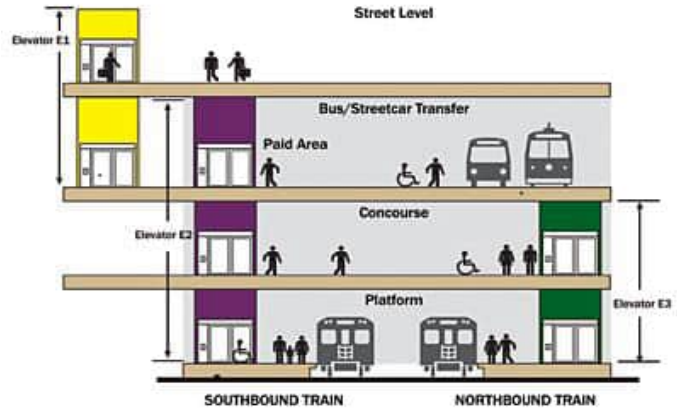


Figure 6: TTC Easier Access Station Concept

4. TTC Bloor-Yonge Station Capacity Improvements

The TTC is planning to modify and expand the existing Bloor-Yonge Station, the busiest station on the TTC. The project will increase and reconfigure existing below-grade subway platforms and add a new platform to address current congestion and accommodate future TTC ridership and neighbourhood density. This project will require the relocation of existing Toronto Hydro infrastructure. Early works are underway, and the project is expected to continue into the 2025-2029 rate period. Toronto Hydro will be reviewing the project for expansion opportunities.

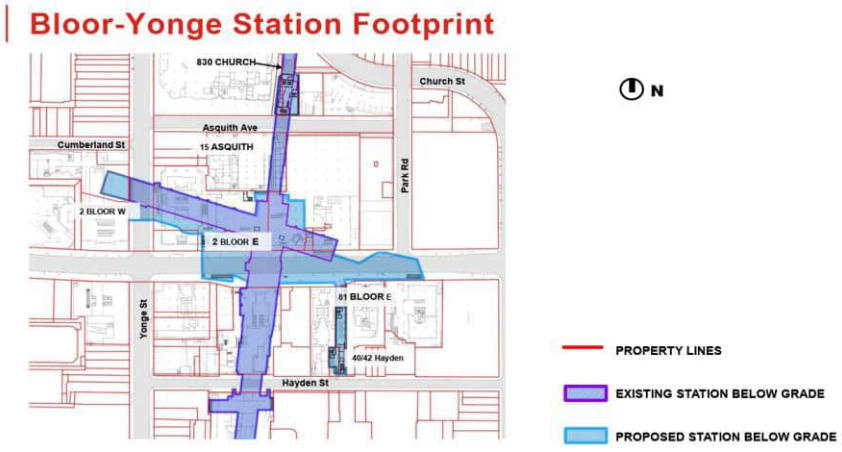


Figure 7: TTC Bloor-Yonge Station Capacity Improvements Concept-Footprint

5. City of Toronto Projects

The City of Toronto has approved a 10-year capital budget and plan of $49.26 billion for 2023-2032 which includes a variety of local and City-wide projects dedicated to the modernization, transformation and renewal of the City. [16] The City has approached Toronto Hydro to relocate the utility's infrastructure in conflict with a number of these projects. There are currently 42 active relocation projects, including those in connection with major development initiatives such as:

- **Basement Flood Protection Program ("BFPP"):** The City's BFPP is a multi-year program to reduce the risk of flooding by making improvements to the sewer system and overland drainage routes, increasing the resilience of the City to climate change including hazards such as flooding and heat.[17] The capital budget for the program is $2.1 Billion between 2023-2032.[18] The City of Toronto has requested that Toronto Hydro relocate its assets in order to accommodate sewer and watermain installations. The applications received to date are for relocations in Toronto's midtown. It is expected that there will be requests related to the program in other parts of the city.
- **City Bridge Rehabilitation Program:** The City of Toronto has over 900 bridges and culverts. The City's 2023-2031 Capital Plan has increased funding by $75.3 million over 2023-2031 to maintain the state of good repair of bridge and culvert infrastructure.[19] Repairs to city bridges typically include repairs to the concrete structure, removal and replacement of deteriorated expansion joints, cleaning and coating of steel girders, bearing replacement, and removal and replacement of barrier walls. Toronto Hydro has underground and overhead civil and electrical infrastructure situated within or upon the City's bridges and culverts that conflict with bridge rehabilitation work requiring relocation. In response to requests from the City, Toronto Hydro will temporarily or permanently relocate its infrastructure to accommodate City work.

[16] City of Toronto, 2023 Budget Launch Presentation https://www.toronto.ca/legdocs/mmis/2023/bu/bgrd/backgroundfile-230875.pdf
[17] City of Toronto, Basement Flooding Protection Program, https://www.toronto.ca/services-payments/water-environment/managing-rain-melted-snow/basement-flooding/basement-flooding-protection-program/
[18] City of Toronto, 2023 Program Summary Toronto Water https://www.toronto.ca/wp-content/uploads/2023/04/94eb-2023-Public-Book-TW-V1.pdf
[19] City of Toronto, 2023 Program Summary Transportation Services https://www.toronto.ca/wp-content/uploads/2023/04/94ec-2023-Public-Book-TS-V1.pdf

A number of projects are put forward every year by the City in connection with its capital plan. With continued City building initiatives and population growth projections, Toronto Hydro anticipates that third-party relocation activity will remain high during the 2025-2029 rate period as a result of City council budgetary approvals.

6. Waterfront Toronto

The Waterfront Secretariat leads the Toronto Waterfront Revitalization Initiative on behalf of the City of Toronto, as well as federal and provincial partners. There are number of projects run by Waterfront Toronto, including the Quayside development. Quayside is a 4.9-hectare (12-acre) area at the foot of Parliament Street, comprising about 3.2 hectares (8 acres) of developable land across five development blocks, as well as parkland, open space and future roads. Quayside will act as a hub, linking nearby neighbourhoods like St. Lawrence, the West Don Lands, the Distillery District, Bayside, and the future Villiers Island.[20]

As part of this development, Waterfront Toronto is proposing utility relocations, streetlighting, streetscape and development along Queens Quay between Bonny Castle and Parliament Street. The relocation work is expected to be completed in the 2025-2029 rate period. Toronto Hydro will be exploring expansion opportunities provided by this project.

E5.2.4.2 Upcoming Projects

Additional projects that are still in preliminary stages may emerge in the current or next rate period. Government and public agencies such as Metrolinx, TTC, and the City of Toronto have approached Toronto Hydro regarding their initiatives to expand and improve transit and to revitalize public space including, but not limited to, the following projects:

- **Metrolinx**: On Corridor Works project will transform the GO Transit rail network in the Greater Toronto and Hamilton Area over the next decade into a system that will deliver two-way all-day service every 15 minutes over core segments of the Go Rail network.
- **TTC/Waterfront Toronto**: Expansion of Union LRT and Queens Quay LRT stations to accommodate additional streetcar lines and passengers, including construction of a high order streetcar line in a dedicated transit right-of-way.

[20] Waterfront Toronto, Quayside https://www.waterfrontoronto.ca/our-projects/quayside

E5.2.5 Options Analysis

E5.2.5.1 Option 1: Completing Externally Driven Relocation Work Only

Toronto Hydro is obligated to relocate its electricity distribution equipment in response to road authorities defined under the *PSWHA* and for projects subject to *BTFA* and *BBFA*, as well as respond to relocation requests by third parties in a fair and reasonable manner. In general, when relocations are required, Toronto Hydro replaces the pre-existing facilities on a like-for-like basis. This approach constitutes the minimum investment on the part of Toronto Hydro to continue providing safe and reliable electricity.

E5.2.5.2 Option 2 (Selected Option): Completing Externally Driven Relocation Work and Expansion Work

Sometimes the nature of a project is such that it is not the most efficient or beneficial option to undertake only relocation work. Upon receipt of a relocation request, Toronto Hydro reviews the future capacity needs in the area and evaluates whether there are opportunities for construction efficiencies available to support undertaking expansion work along with the relocation work. An example of how expansion and relocation work may be combined to maximize efficiencies is the Port Lands Flood Protection Initiative (PLFP).

Upon being advised of the project by the Waterfront Toronto, and the need to relocate its infrastructure, Toronto Hydro reviewed its capital plan to identify expansion work opportunities that could be executed along with the relocation work. Toronto Hydro performed a system analysis to determine expected load growth on the feeders in the area. In reviewing the current feeder loading conditions and approved loads through customer connections and factoring in contingency scenario loading, Toronto Hydro determined that by 2027, local feeders would be heavily loaded, requiring relief. To accommodate this anticipated growth, expansion work was integrated into the work plan to be executed during plant relocation initiatives.

Executing expansion work in coordination with the Waterfront Toronto's capital work was determined to be preferable to just undertaking the relocation work for the following reasons:

- It often is less expensive to construct new civil infrastructure to support the expected load growth in the area if such work is undertaken in conjunction with the relocation work required by the Waterfront Toronto's project. If the expansion work is undertaken in the

future there would be a need for increased coordination initiatives with third-party utilities, more potential for deviation from municipal consent requirements on infrastructure clearances and additional civil construction and restoration work in the area.

- The City's road cut moratorium could prevent Toronto Hydro from installing additional infrastructure when needed to address the expected load growth. The City of Toronto imposes a five-year moratorium on road cuts in an area after road resurfacing is completed. Breaking the moratorium requires City approval and payment of a fee. Failing to complete expansion work during the relocation phase of a project could lead to Toronto Hydro having to install costlier and less optimally located facilities to meet the anticipated demand.

- Completing the expansion work and the relocation work together avoids prolonged disturbances to the residents and businesses in the neighbourhood.

E5.2.6 Distribution Grid Operations Consultation

Consultation with Toronto Hydro's Distribution Grid Operations ("DGO") Department, which coordinates all work on the distribution system, early in the design process improves outcomes for third parties and customers more broadly. Early consultation allows the DGO to sequence work on feeders to accommodate third-party relocation work more quickly while minimizing disruptions to customers in the area. The DGO also provides an operational perspective during design review. DGO is able to identify design modifications to improve system reliability early on, thereby avoiding any delay to the overall project.

E5.2.7 Execution Risks & Mitigation

Toronto Hydro's projected spending in this Program is based on a combination of deferred projects from the last rate period, future committed projects and anticipated projects. There is risk that projects in these categories or their timing may be modified or may not materialize as anticipated. In addition, new projects can emerge, adding to program costs. To mitigate the effects of these risks for ratepayers, Toronto Hydro requests approval to record variances in the Demand Variance Account.

The projects proposed under this Program are largely dictated by the schedule and plans of third parties. Third parties often face their own constraints with respect to the execution and completion timelines for their projects. To accommodate work on projects, and ensure that projects are

completed within the timelines requested by customers, Toronto Hydro may undertake work during off-peak hours on evenings and weekends, as necessary. Toronto Hydro constantly monitors changes to codes, bylaws and Legislation which impacts its relocation operations to ensure that its processes and standards align with requirements.

E5.3 Load Demand

E5.3.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 120.9	**2025-2029 Cost ($M):** 217.1
Segments: N/A	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Operational Effectiveness - Safety	

/C

With increasing land development and growth in Toronto Hydro's service territory, the Load Demand program (the "Program") aims to alleviate emerging capacity constraints to ensure the availability of sufficient capacity to efficiently connect customers to Toronto Hydro's distribution system. In doing so, the Program also seeks to minimize the effect of load growth on existing customers. Toronto Hydro's investments in this Program enable the operation of its distribution system under first contingency scenarios, as well as the minimization of potential switching restrictions during summer peak conditions (which can impede the utility's ability to execute maintenance and capital work during summer months).[1] This Program is a continuation of the activities described in the Load Demand program in Toronto Hydro's 2020-2024 rate application.[2]

More specifically, the Program alleviates overloaded equipment and capacity constraints on the distribution system through:

- Load transfers to relieve station bus overloads;
- Feeder cable upgrades and load transfers to improve capacity and asset utilization;
- Equipment upgrades to increase available capacity and reduce the number of switching restrictions experienced during the summer peak; and
- Civil enhancements to remove system bottlenecks and support additional electrical capacity.

[1] " First contingency" occurs when any one primary feeder, transformer, or other critical equipment is lost, either due to a fault or planned outage.
[2] EB-2018-0165, Toronto Hydro-Electric System Limited Application (filed August 15, 2018, updated April 30, 2019), Exhibit 2B, Section E5.3.

E5.3.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Customer Focus	• Contributes to the sustainment of service connection targets established by the OEB (i.e. the Electricity Service Quality Requirements) for new residential, small business services, and high voltage services by undertaking targeted capacity upgrades in areas of high load growth in the downtown and Horseshoe area. • Contributes to customer satisfaction results by providing large customers flexibility in scheduling substation maintenance by reducing summer peak switching restrictions.
Operational Effectiveness - Reliability	• Contributes to maintaining Toronto Hydro's System Capacity measure, and reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Improving restoration capabilities and reducing customer interruptions by providing additional capacity or maintaining spare capacity through cable upgrades and load transfers; ○ Improving restoration capabilities in the downtown or Horseshoe systems by offloading highly loaded feeders; ○ Improving system reliability by reducing the risk of failures due to highly overloaded equipment through mitigation of expected bus overloads; and ○ Improving downtown reliability by maintaining or reducing the number of heat restricted feeders.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety performance objectives (as measured through measures like Total Recordable Injury Frequency) by reducing the failure risk of overloaded infrastructure to Toronto Hydro workers and members of the public.

E5.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Customer Service Requests, Reliability, System Efficiency

E5.3.3.1 Mandated Service Obligations

As per sections 3.3.1 and 4.4.1 of the Distribution System Code ("DSC"), Toronto Hydro is required to ensure its distribution system can support projected load growth while maintaining reliability and quality of service for customers on both a short-term and long-term basis. The utility must also connect new customers within the timelines prescribed by the OEB's service quality standards without adversely affecting the quality of distribution services for existing customers.[3] The OEB requires 90 percent of connections to be completed on time. Toronto Hydro achieved 99.9 percent of new residential and small business services completed within the prescribed timelines, and 99.1 percent of new high voltage connections completed within the prescribed timelines. The investments in this Program are specifically targeted to meet the OEB's service quality standards.

To satisfy these requirements, Toronto Hydro must maintain sufficient capacity on its system to keep pace with load growth and to ensure that its assets are not overloaded (i.e. an overloaded bus is defined as reaching 95 percent of its firm capacity under normal and emergency operating conditions). Highly loaded feeders in the downtown are defined as feeders that exceed cable ratings under contingency, assuming peak customer loads and a coincidence factor of 1 (i.e. all customers peak at the same time). In the Horseshoe, highly loaded feeders are defined as those with peaks of 400A, which is the standard planning practice as it leaves at least one third of a feeder's capacity available to support tie feeders under contingency.

The rapid influx of dense load in the downtown core and Horseshoe areas (see section E5.3.3.2 for more details) poses a challenge to Toronto Hydro's ability to meet its service requirements. Over the 2025-2029 rate period, Toronto Hydro expects that rapid growth will cause multiple buses to reach their rated capacity. The forecasted growth in the distribution system is based on the Toronto Hydro's Station Load Forecast. The actual demand will vary based on the actual realization of load on the system. This can depend on multiple factors and emerging trends such as electric vehicle

[3] Section 7.2 of the *Distribution System Code* requires Connection of New Services: low voltage (<750 Volts) within 5 business days and high voltage (>750 Volts) within 10 business days. Ontario Energy Board, *Distribution System Code* (August 2, 2023).

("EV") uptake and pacing of heating electrification. Section E5.3.5 Options Analysis explores how future energy scenarios can impact the requirements of this Program.

As discussed in greater detail below, critical parts of Toronto Hydro's distribution system (such as the Downtown and Central Waterfront Area in Table 4), which service a large amount of load or are experiencing high growth, are serviced by feeders that are already highly loaded and at risk of overloading in the upcoming years. Growth in these areas has been driven in large part by multiple storey residential condominiums, mixed use buildings and large commercial developments. If no action is taken to alleviate constraints, load shedding will be required during the summer peak period to mitigate the risk of failure from overloaded equipment. This involves dropping customer loads when the feeders or the equipment that supply them are overloaded so that a tolerable loading level can be maintained. Supplying customers through highly loaded feeders reduces the level of reliability, thereby causing Toronto Hydro to fail in meeting a top priority of these customers as identified through customer engagement.

E5.3.3.2 Customer Service Requests

Toronto Hydro receives customer requests for service connections every time there is a new residential, industrial, or commercial development, or when upgrades are required for an existing connection. Applications for Service are processed as part of the Customer Operations program.[4] In most cases, system planner input is required to determine how to service the customer in the most efficient manner. In constrained areas of the system, the utility's ability to respond to customer service requests within the OEB-prescribed timelines, without affecting the quality of service for existing customers, is largely dependent on the investments made in this Program.[5] Toronto Hydro utilizes the City of Toronto's land planning information to help assess which areas of the system are in most urgent need of additional capacity to accommodate customer service requests in a timely and cost-effective manner.[6]

Figure 1 shows the load additions (connection applications involving new or increased load) submitted to Toronto Hydro from 2018 to 2022 by geographical region. Figure 2 shows the resulting load impact in each region of the City.

[4] Exhibit 4, Tab 2, Schedule 8.
[5] *Supra* note 3.
[6] City of Toronto, *Development Pipeline 2022 Q2* (February 2023), « online », https://www.toronto.ca/wp-content/uploads/2023/02/92b5-CityPlanning-Development-Pipeline-2022-Q2.pdf

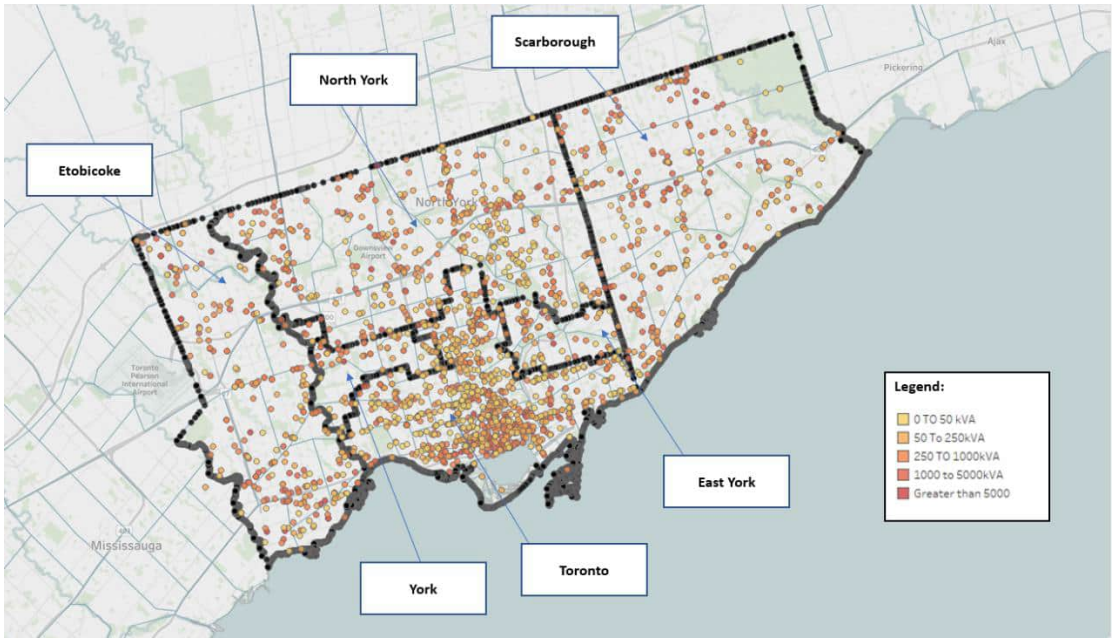


Figure 1: Load Additions in the City of Toronto during the 2018-2022 Period

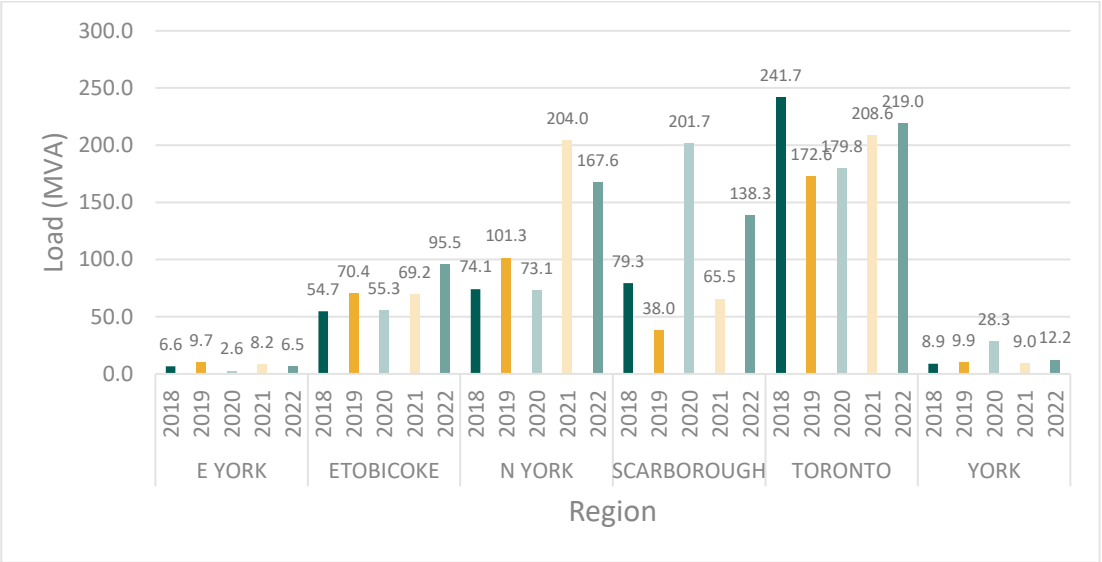


Figure 2: Load Additions by Region during the 2018-2022 Period

The City of Toronto is experiencing an increase in development which is expected to continue throughout the 2025-2029 rate period. Table 4 below provides a summary of the projects submitted to the City of Toronto's Planning Division between 2017 and 2022 Q2, and Figure 3 is a map of the residential units proposed over this period.

Table 4: Proposed Projects in the City of Toronto (2017-2022 Q2)[7]

	Built	Active	Under Review	Total in Pipeline	% of Total	% of Growth Areas
City of Toronto	**622**	**879**	**912**	**2,413**	**100.0%**	
Growth Areas	**394**	**549**	**605**	**1,548**	**64.1%**	**100.0%**
Downtown and Central Waterfront	142	205	179	**526**	21.7%	31.5%
Centres	30	48	47	**125**	5.2%	14.5%
Avenues	149	209	279	**637**	26.4%	28.3%
Other Mixed Use Areas	73	87	100	**260**	10.8%	25.6%
All Other Areas	228	330	307	**865**	**35.9%**	

Source: City of Toronto, City Planning: Land Use Information System II

Development projects with activity between January 1, 2017 and June 30, 2022. Built projects are those which became ready for occupancy and/or were completed. Active projects are those which have been approved, for which Building Permits have been applied or have been issued, and/or those which are under construction. Projects under review are those which have not yet been approved or refused and those which are under appeal.

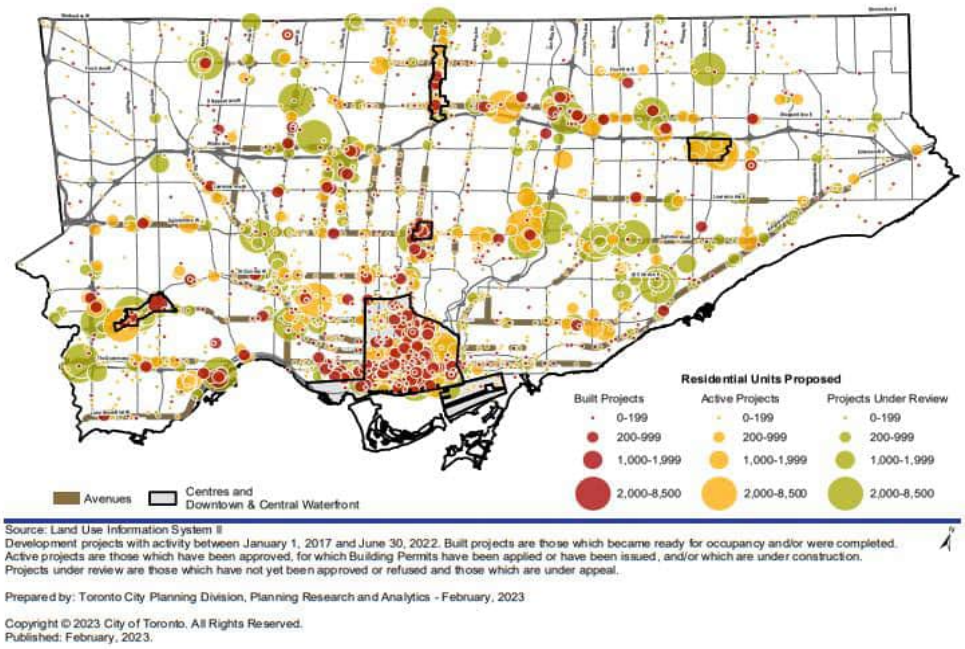


Figure 3: Residential units proposed (2017-2022 Q2)

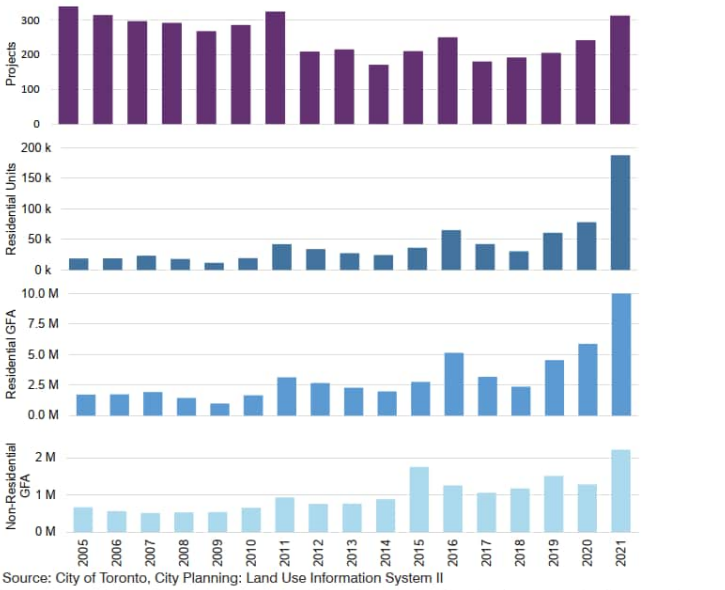
As illustrated in Figure 3, the majority of the growth is focused on the downtown system, particularly the Downtown and Central Waterfront area, where 43,513 residential units have been built as of the end of 2022 Q2 and 180,652 units are in the pipeline for future development. Another area

[7] *Supra* note 6.

experiencing strong growth in the downtown system is the Yonge-Eglinton Centre, with 38,361 units in the pipeline.

In the Horseshoe area, Sheppard East Subway Corridor, Etobicoke Centre, North York Centre, and Scarborough Centre have experienced development growth which is expected to continue: (i) in the Sheppard East Subway Corridor area, 22,699 units are in the development pipeline; (ii) in the Etobicoke Centre area, 17,575 are in the development pipeline; (iii) in the North York Centre area, 12,330 are in the pipeline; and (iv) in the Scarborough Centre area, 29,260 are in the pipeline.[8]

The number of projects submitted to the City of Toronto have remained relatively consistent over the years, ensuring a steady influx of projects and a healthy pipeline of projects. However, the number of residential units proposed and overall Gross Floor Area ("GFA") of the projects have increased substantially over the years, indicating each project has become larger and more complex overall. Figure 4 shows the trend of applications over the years. For Toronto Hydro, these large projects create single points of concentrated load that require detailed analysis and consideration when planning for their connections and managing system load overall.



Source: City of Toronto, City Planning: Land Use Information System II

Development projects submitted each year from 2005 to 2021, and the total number of residential units, residential GFA, and non-residential GFA proposed. Residential and non-residential GFA is in square metres.

Figure 4: Trend of Projects, Residential Units and GFA by Application Intake Year, 2005 to 2021

[8] *Supra* note 7.

Therefore, Toronto Hydro expects a steady stream of customer service requests for new connections over the 2025-2029 rate period and beyond. To meet these requests in a timely and cost-effective manner, and maintain reliability and quality of service for existing customers, Toronto Hydro must invest in infrastructure upgrades and load transfers to alleviate capacity constraints. In particular, Toronto Hydro must focus its efforts in the downtown and Horseshoe areas where concentrated growth is straining the distribution system by overloading station buses, feeders, and transformers.

E5.3.3.3 System Reliability and Efficiency

This Program aims to ensure that the system has enough capacity to restore customers during contingency events and that asset failure and loss of supply due to overloading are prevented. Operating assets above their rated capacity for prolonged durations increases the risk of failure and corresponding loss of supply to customers. These conditions can lead to the premature failure of primary overhead conductors and undersized legacy assets (e.g. underground paper insulated lead-covered "PILC" cables), that were installed over 35 years ago when standard trunk cables were approximately 30 percent smaller and had a 25 percent lower current capacity. Since 2012, Toronto Hydro's distribution system has experienced 293 cable and splice failures on legacy PILC cable. Where cables are at the largest standard size, instead of cable upgrades to alleviate overloads on the feeders, load transfers to other feeders with capacity will be considered.

Overloaded assets pose reliability and public safety risks. For example, the temperature of conductors and cables increases when they are overloaded which reduces the conductor's tensile strength.[9] Loss of the rated tensile strength can cause significant sagging of an overhead feeder line, which makes it more susceptible to external contacts and safety requirement violations.[10,11] Similarly, underground cables, such as the cross-linked polyethylene ("XLPE") cable used in the downtown system, soften as their temperature increases, particularly in areas where the insulation is under

[9] K. Adomah, Y. Mizuno and K. Naito. "Probabilistic assessment of the reduction in tensile strength of an overhead transmission line's conductor with reference to climatic data." *IEEE Transactions on Power Delivery*, vol.15, pp.1221-1224, 2000.
[10] F. Jakl and A. Jakl. "Effect of Elevated Temperatures on Mechanical Properties of Overhead Conductors under Steady State and Short-Circuit Conditions." *IEEE Transactions on Power Delivery*, vol. 15, pp. 242-246, Jan. 2000.
[11] Minimum Safety Clearance as in Toronto Hydro standard 03-2000 Overhead – Minimum Vertical Separations, where the exact clearance depends on the configuration of the pole, the type of attachments on it, and primary voltage.

mechanical stress (e.g. bends in the route), leading to deformation of the cable. This in turn can lead to electrical failures resulting in outages.[12]

E5.3.3.4 Addressing Drivers and Need

To meet the increasing need for capacity, ensure system reliability and efficiency, and meet the mandated service obligations, four types of work are carried out under this Program:

- **Bus Level Load Transfers**: load transfers between station buses to alleviate overloaded buses. [13]
- **Feeder Level Load Transfers and Upgrades**: transferring loads between feeders to alleviate overloaded feeders or upgrading undersized feeder trunks to the current standard.[14]
- **Equipment Upgrades**: carried out in areas like network vaults to increase unit size and associated capacity, which may reduce the number of switching restrictions experienced during summer peaks.
- **Civil Enhancements**: carried out in duct banks and egress cable chambers to enable capacity upgrade by allowing for more feeders to be installed.

1. Bus Level Load Transfers

Toronto Hydro plans to execute targeted load transfers on station buses that are expected to become overloaded based on Toronto Hydro's Station Load Forecast and those where opportunities will arise to redistribute load with adjacent station buses.[15]

Table 5 lists the specific station buses planned for bus level load relief during the 2025-2029 rate period, and Figure 5 shows the stations' locations. The station bus can be relieved by expanding the capacity of the bus through bus expansion, or by relieving the load of the bus through bus transfers. Bus transfers can be performed by transferring load between buses within the same station or to another station in the area. Additionally, bus balancing can be achieved during transfers to ensure that the bus capacity within transformer stations is optimized.

[12] S. H. Alwan, et al. "Factors Affecting Current Ratings for Underground and Air Cables." *International Journal of Energy and Power Engineering,* vol. 10, pp. 1422-1428, 2016.
[13] **Bus** – A rigid, large conductor usually in substations, to provide a quick and convenient means of rearranging circuit connections to keep power flowing or to restore power after an outage.
[14] **Feeder** – A distribution circuit carrying power from a substation to customers. Feeders consist of circuits and other electrical equipment supported by civil infrastructure like poles and ducts.
[15] Exhibit 2B, Section E7.4.

The completion of Copeland TS Phase 2 under the Stations Expansion program will have the potential to enable load relief at Esplanade TS, Strachan TS, Windsor TS, Cecil TS, and Terauley TS. [16,17] For these stations, civil and cabling work to enable the transfers is planned to be undertaken before Copeland TS Phase 2 is energized, so that the full benefits of Phase 2 can be realized immediately upon its energization. Relief for Horner TS and Manby TS will follow in the 2025-2029 rate period after the expansion of Horner TS is completed during the 2020-2024 rate period.

Table 5: Station Buses Planned for Relief within 2025-2029

Station	Bus	Estimated Load to Transfer (MVA)	Area
Cecil	*A1-2CE*	10 - 20	Downtown
Copeland	*A1-2CX*	10 - 20	Downtown
Dufferin	*Note 1*	4 - 14	Downtown
Esplanade	*Note 2*	10 - 20	Downtown
Finch	*J-Q*	35 - 50	Downtown
Horner	*B&Y*	25 - 40	Horseshoe
Leslie	*B&Y*	15 - 30	Horseshoe
Manby	*Q-Z*	20 - 35	Horseshoe
Strachan	*A9-10T*	10 - 20	Downtown
Terauley	*Note 2*	10 - 20	Downtown
Windsor	*Note 2*	10 - 20	Downtown

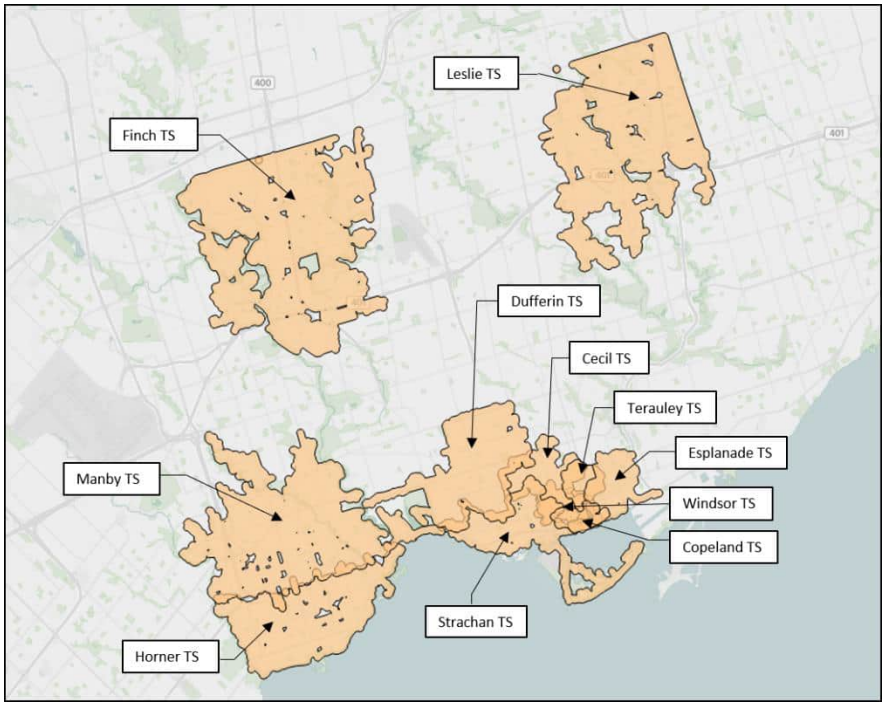
/C

Note 1: Targeting bus supplying feeders in area bounded by St. Clair Ave, Queen Street W, Bathurst Street, and Keele St.

Note 2: Stations that are scheduled for Relief as part of Copeland Phase II expansion.

[16] *Ibid.* Copeland TS Phase 2 is expected to be completed by 2023/2024.

[17] Not all stations listed are addressed through the Load Demand program.



/C

Figure 5: Stations Targeted for Relief during the 2025-2029 Rate Period

If the buses outlined in Table 5 above are not relieved, it may not be possible to connect new customers to these station areas. As a result, Toronto Hydro may need to supply new service requests in the areas serviced by these stations from adjacent buses or stations, potentially resulting in system inefficiencies, materially higher connection costs, and longer timelines to complete the work. For example, capital contributions from connecting customers are required when revenue from their demand does not cover the cost of expansion work, as determined by the Economic Evaluation Model.[18] This may occur when significant expansion work is required for smaller loads.

Station bus load forecasts are re-evaluated annually.[19] Based on updated results, it may be necessary and prudent for Toronto Hydro to reprioritize load transfers. Some of the buses that Toronto Hydro plans to address in the 2025-2029 rate period originally appeared in plans for relief during the 2020-2024 rate period. For the reasons summarized in Table 6 below, these investments were reprioritized, with portions of the projects completed in the 2020-2024 rate period, and remaining portions to be addressed during the 2025-2029 rate period.

[18] Exhibit 2B, Section E5.1.3.1.
[19] Exhibit 2B, Sections D2.3, D3.3.1, and C3.3

When reviewing work to be targeted within the Program, Toronto Hydro will also consider work that can potentially be deferred using Non-Wire Solutions (NWS).[20] In the case of Manby TS and Horner TS in Table 6, the short-to-medium term capacity constraints of the buses due for load transfers were mitigated by identifying opportunities where local demand response ("DR") could be leveraged to reduce peak loads. The NWS program enables efficient and cost-effective load management, and can be leveraged in the 2025-2029 rate period in the prioritization of load transfers.

Table 6: Load Transfers projects continuing from 2020-2024 to 2025-2029

Station	Bus	Reasoning
Horner	*B&Y*	Based on regular re-evaluation of the proposed work in this Program, load transfers between Fairbank TS and Runnymede TS were prioritized ahead of these stations for the 2020-2024 period. The Horner TS and Manby TS load transfers were re-prioritized, and only the portions of the load transfers that required immediate attention were addressed in the 2020-2024 rate period. The remaining transfers are scheduled to be completed in the 2025-2029 rate period.
Manby	*Q&Z*	

/C

In order to transfer load from one station to another, Toronto Hydro often needs to install new feeders at stations with spare capacity. These stations are either existing ones with switchgear that have available capacity and feeder positions, or new stations where switchgear will be installed to create additional capacity. New civil infrastructure will be required if the existing infrastructure is in poor condition and requires rebuilding or if there are insufficient ducts to accommodate the new feeder installations. Extensive cable pulling and splices are then required to complete the transfer of customer loads from the existing feeders to the new feeders.[21] Load can also be transferred from one station to another by extending existing feeders to feeders with available capacity. In the Horseshoe distribution area, loads can alternatively be transferred by installing new switches or relocating existing switches. Therefore, the scope of work required when performing Load Transfer

[20] Exhibit 2B, Sections E7.2
[21] A splice is a joint created to maintain the connectivity between two cable sections or cable types. It is typically carried out when a longer cable is required, a branch is required or part of an old cable is replaced with a new cable.

projects vary depending on how much upgrades are required on existing civil and electrical infrastructure as mentioned above.

2. Feeder Level Load Transfers and Upgrades

Asset failures (overhead conductors, underground cables, and civil infrastructure) can lead to outages that last for hours due to the time it takes for crews to switch customers from faulted feeders to standby supplies. In first contingency scenarios, the distribution system is designed to continue operating at or below rated capacity in order to facilitate the transfer of load from feeders under a faulted condition to standby feeders. This allows for the restoration of power to affected customers from the standby feeder while the faulted feeder is being repaired. If feeder capacity is constrained, the number of customers the system can be served by the standby supply may be limited. Those customers that cannot be served by the standby supply would experience lengthy service interruptions, which would adversely impact reliability. Having available capacity on additional tie feeders allows for quicker restoration during more catastrophic events where cascading load transfers are required, because more operational options will be available to restore customers.

When the load on a faulted feeder exceeds the available rated capacity of standby feeders, restoration of power to affected customers is not possible until repairs are completed and, as a result, such customers would be at risk of prolonged interruptions. For example, in the overhead system, when a feeder faults and its standby feeder ties cannot be used due to the risk of overloading, the affected customers on the faulted feeder would remain without power until the failure is completely addressed.

In addition to the expected reliability improvement, having the flexibility (in the form of switching equipment) to de-energize feeders improves Toronto Hydro's ability to execute planned capital and maintenance work by enabling the utility to switch customers onto their standby feeders.

When processing new customer connection requests, Toronto Hydro conducts an analysis to evaluate how customers are supplied, optimize the use of existing capacity, and accommodate new customers efficiently. This analysis helps to determine areas requiring feeder level transfers to enable available capacity. In some instances, Toronto Hydro may decide to perform feeder level load transfers if the assets are already at the maximum standard cable size, or if the bus that supplies the feeder has available capacity but feeder loading is not balanced.

Performing a load transfer between feeders to accommodate a new customer is often the preferred alternative when possible as it can be carried out at a lower cost than upgrading the feeder. Similar to bus level load transfers, feeder level upgrades and load transfers provide value to current and future customers by ensuring that the system can support rapid growth in a timely and cost-efficient manner, without adversely affecting the quality of service for existing customers.

The sections that follow describe the Feeder Level Load Transfers and Upgrades planned on the 27.6 kV system, which serves the area of the system commonly known as the Horseshoe and the work planned for the 13.8 kV system, which serves the downtown core.

a. The Horseshoe System

To manage load growth in the Horseshoe area, Toronto Hydro plans to undertake capital investments in feeder level load transfers and feeder upgrades in the Scarborough, Etobicoke, and North York areas. Load transfers are preferred over feeder upgrades because the overhead system, which serves the majority of the Horseshoe area, has multiple tie switches making it easier and more cost-effective to transfer load between adjacent feeders. Cable upgrades are also performed in the Horseshoe when segments along the cable are undersized and limit the overall carrying current capability along the feeder. Such undersized segments along feeders are typically legacy aluminum cables which are upgraded to standardized copper cables to raise the maximum current carrying capacity to 600 A, which is an increase of up to 100 A in capacity, or about the equivalent of 2300 customers.[22] There are 111 Horseshoe feeders forecasted to be highly loaded by 2029 and Toronto Hydro plans to relieve 15 of the highest priority feeders (i.e. those with the highest level of overloading) through feeder transfers or cable upgrades in order to manage the forecasted growth over the 2025-2029 rate period. Toronto Hydro will continuously assess actual feeder conditions before investing in any upgrades or transfers. /C /C

b. The Downtown System

The majority of the underground 13.8 kV system in downtown Toronto is configured as a dual radial scheme. Customers are supplied by two feeders: one that provides their normal supply and the other that operates as standby supply. In areas that have experienced rapid load growth, customers now have an overloaded standby supply, with additional overloaded feeders expected during the 2025-

[22] Exhibit 2B, Section E7.1.

2029 rate period. If there is a loss of supply in these areas, overloaded standby supply means that there are less options available to restore customers.

Toronto Hydro analyzed all downtown feeders to determine which feeders are projected to be highly loaded during the 2025-2029 rate period based on the Toronto Hydro's Station Load Forecast. By the end of 2029, there is projected to be 178 highly loaded feeders in the downtown system (representing approximately 27 percent of downtown feeders) if no work is done to address them. /C /C

As a result, in the 2025-2029 rate period, Toronto Hydro plans to relieve 64 of the highest priority feeders in the downtown area to manage load growth and continuously meet system reliability goals through feeder upgrades and feeder load transfers. By comparison, in the 2020-2024 rate period, Toronto Hydro relieved 18 highly loaded feeders through cable upgrades and transfers. This increase in the number of highly loaded feeders planned for relief is due to the rapid growth of the number of highly loaded feeders. Toronto Hydro will continue to prioritize the feeder transfer and upgrade projects based on the latest information on how load is materializing on the system and regular re-forecasting efforts. /C

Toronto Hydro plans to upgrade undersized feeder trunks to the current standard (500 kcmil TRXLPE) to maximize previously stranded capacity for feeders that are becoming highly loaded. For example, feeder A62A supplies 16 customers in and around the downtown core along Dundas St. E. to Jarvis St., and along Yonge St. from Dundas St. to Richmond St. Many of these customers are key account customers operating commercial complexes, outdoor public and event spaces, university campus services and government locations. This feeder is at capacity due to the presence of undersized 2/0 trunk cable. An upgrade to 500 kcmil TRXLPE cable will more than double the capacity on the feeder, allowing for 5 MVA of customer load to be added.

In the downtown area, because of congested civil infrastructure nearing end of life or built to older civil standards (therefore unable to accommodate the latest cable standards), it is often necessary to rebuild or expand the existing civil infrastructure when upgrading underground cables. Figure 6 below shows a congested legacy square duct unable to accommodate the current standard trunk cable, therefore limiting the overall capacity of feeders using this civil route. In addition to capacity constraints, the clay duct tile is typically collapsed, and in need of rebuild. Such legacy square ducts span over 4.6 kilometres and contain feeders supplying in the downtown area including hospitals, as well as other large customers.

Toronto Hydro plans to complete upgrades or rebuilds of this existing civil plant as part of this Program. It is estimated that 50 percent of the length of the civil route for each planned feeder upgrade will need to be upgraded as well to accommodate the new electrical. This includes cable chamber and duct bank rebuilds.



Figure 6: Example of a Legacy Square Clay Tile Duct

New feeder installations are also required when an area requires greater capacity than is available with existing feeders. These new feeders are then utilized to relieve the existing load and service any upcoming demand in the area. In cases where bus expansion is not possible at the station, the feasibility of expanding the bus with new feeder positions at nearby stations are explored. The new feeders from nearby stations will supply the load from the station that has reached or exceeded its capacity. One instance where new feeders from a station are required to offload a nearby station is Richview TS offloading existing feeders from Finch TS. The area which Finch TS services, spanning from Hwy 27 to Jane St, and Steeles to South of Hwy 401, have feeders that are highly loaded and require support and relief to accommodate upcoming load growth in the area. With Finch TS already highly loaded at the bus as well, new feeders from Richview TS, which is a nearby station south west of Finch TS, will support by offloading the highly loaded feeders from Finch TS.

3. Equipment Upgrades

Due to capacity constraints, Toronto Hydro is forced to impose summer switching restrictions during peak load conditions, such that certain feeders cannot be taken out of service during those periods.

If restricted feeders are taken out of service, their corresponding standby infrastructure (standby feeders, adjacent network units) will be overloaded. This practice constrains Toronto Hydro's ability to complete new customer connections and hinders its ability to plan and execute other capital maintenance work in a timely and efficient manner.

Heat restricted feeders are feeders flagged as at-risk of overloading their standby feeders or network equipment during a contingency situation during peak hours or summer days. This means that these feeders should not be taken out of service (at a certain temperature) in the summer months in order to avoid overloading other infrastructure under contingency. Toronto Hydro is seeking to maintain or reduce the number of restrictions on its system so as to enhance its ability to take feeders out of service for maintenance or capital work. Cable upgrades and load transfers may be used as strategies to relieve summer switching restrictions on the primary feeder level. The equipment upgrades as part of this Program aim to upgrade undersized network units that are at-risk of overloading and may create summer switching restrictions. An example of a network unit is shown in Figure 7. A network unit consists of a primary switch, network transformer, and network protector.



Figure 7: An Example 500 kVA Network Unit

In the downtown core, network units are fed from various primary feeders, and are interconnected on the secondary side (i.e. low voltage) of the distribution transformer in order to provide a redundant and highly reliable supply to customers. This configuration reduces the risk of customers experiencing interruptions during single contingency events. The network system supports reliability for customers in the downtown area, highlighted as a priority through customer engagement. Current key customers on the network system include hospitals, hotels, telecommunication and government buildings.

Through network equipment upgrades, Toronto Hydro will improve reliability for downtown customers on the network, highlighted as a priority in customer engagement. This will be done by reducing the number of potential network unit failures due to overloads; increasing the robustness of the network units by introducing the submersible design; and improving the amount of first contingency scenarios supported by reducing feeder restrictions. Network equipment that is at or over capacity must be upgraded to ensure that the network system operates without overloading. Overloading the network equipment can result in premature deterioration and failure of the assets, which in turn drives the need to impose restrictions during peak summer months. An additional benefit of upgrading existing overloaded network equipment is the introduction of a more robust submersible design that is capable of operating under flooded conditions. In locations where an upgrade is not possible because the network units are already at the highest size or if there are civil limitations, an additional transformer in a new vault may be installed or additional secondary cables may be added to support the highly loaded vaults.

In the 2020-2024 rate application, Toronto Hydro indicated its goal of reducing the number of summer switching restriction feeders to under 10, and has been doing so accordingly as seen in its progress presented in Table 7 below.

Table 7: Summer Restrictions by Year

Summer Restrictions	Year					
	2017	2018	2019	2020	2021	2022
Number of Feeders Restricted	21	9	6	4	4	5

To address the growth in demand of the number of network units under contingency, Toronto Hydro plans to upgrade 5 network units during the 2025-2029 rate period.[23] Toronto Hydro's goal is to continue maintaining the total number of restrictions to below 10 by during the 2025 to 2029 rate period. To achieve this goal, Toronto Hydro will also mitigate any potential primary feeder restrictions via cable upgrades and load transfers.

Where other equipment upgrades are required due to capacity needs based on forecasted growth on the feeders and not due to asset end of life, this Program will also upgrade capacity in order to manage growth and mitigate overloading assets.

4. Civil Enhancements

When certain stations are expanded or their switchgear is upgraded, Toronto Hydro must undertake supporting civil enhancement work in the egress cable chambers to enable additional capacity at the station. Table summarizes the expected station upgrades within the 2025-2029 rate period that may require civil egress rebuilds in order to optimally serve customers. These areas are shown geographically in Figure 8.

Table 8: Stations Requiring Civil Egress Rebuilds

Station	Switchgear Unit	Associated Work	Target Completion Year
Bridgman TS	*A1-2H, A7-8H*	*Switchgear Renewal*[24]	2026, 2029
Danforth MS	*A1-2DA*	*Switchgear Renewal*[25]	2028
Downsview TS	*New TS*[26]	*New TS*[27]	2029+
Duplex TS	*A1-2DX*	*Switchgear Renewal*[28]	2026
Manby TS	*B-Y, V-F, T3/T4, T13/T14*	*Switchgear Renewal and Transformer Renewal*	2027, 2029
Wiltshire TS	*A5-6WA*	*Switchgear Renewal*[29]	2029
Windsor	*A5-6WR, A3-4WR*	*Switchgear Renewal*[30]	2027, 2029

[23] The peak load reading of each network unit in the system was taken over the last 5 years and a growth consistent with the Metro Toronto Regional Infrastructure Plan was added to forecast the future overloads.
[24] See Exhibit 2B, Schedule E6.6 – Stations Renewal
[25] *Supra* note 24.
[26] See Exhibit 2B, Schedule E7.4 – Stations Expansion
[27] *Ibid.*
[28] *Supra* note 24.
[29] *Ibid.*
[30] *Ibid*.

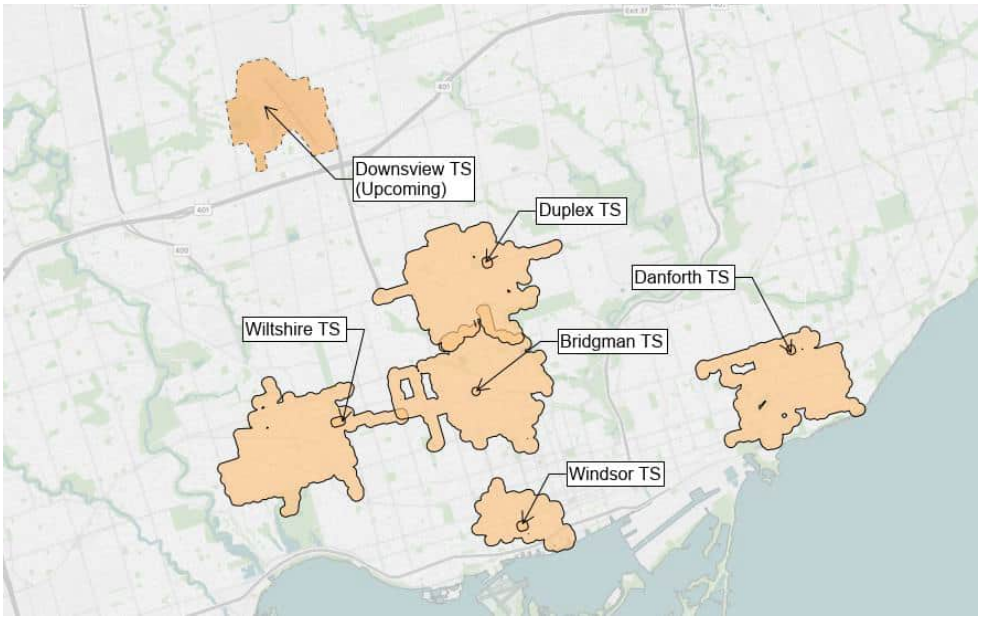


Figure 8: Stations Targeted for Civil Enhancements during the 2025-2029 Rate Period

Civil work can vary depending on the location of the asset expansion or renewal within the station, as well as the existing civil infrastructure in and around the station. For example, the Carlaw TS switchgear renewal scheduled for 2023 and 2024 will have new switchgear at the northeast corner of the station, egressing through the north cable pit. The majority of the Carlaw feeders already run north and northeast and those that are needed to the south must utilize cable chambers around the station to run south. This creates additional civil work around the station with added cable chambers and ducts being required. Another example during the 2020-2024 rate period is planned relief of Basin TS to the south to Carlaw TS due to the rapid growth around Basin TS including Ashbridge's Bay, GO Transit and the Port Lands developments. Additional feeders will need to be pulled south and the civil infrastructure must be upgraded and arranged in order to accommodate these plans.

In addition to supporting station renewal or expansion, civil infrastructure throughout the distribution system is required to be expanded or upgraded in areas that limit growth and electrical capacity. An example of infrastructure upgrade and expansion during the 2020-2024 rate period is along John Street between Front Street and Stephanie Street. The rebuilding of John Street addressed existing failing infrastructure and installed additional infrastructure required for growth. The scope consisted of rebuilding cable chambers, cable chamber roofs, vault roofs, vault rebuilds, collapsed ducts, and the expansion of ducts required for communication cables and contingency tie cables between stations. This rebuild ensured that existing key account customers fed from Windsor

TS would not be impacted by civil failure, enabled the connection of new customers in a timely manner, ensured that duct system can accommodate the fiber communication system, and enabled the ability to tie Cecil TS to Windsor TS to further mitigate against station contingency events. This was of great importance to the city because John Street connects many of Toronto's key cultural institutions to the waterfront. In the 2025-2029 rate period, Toronto Hydro is planning to invest in similar civil upgrades along Victoria Street, between Dundas Street and Lombard Street to rebuild legacy duct banks (i.e., square clay tile ducts) and undersized cable chambers that contain feeders supplying key account customers such as hospitals.

Apart from the capacity limitations, congested cable chambers increase the potential impact of chamber collapse on multiple feeders (and the significant customer load they supply in aggregate). For example, a cable chamber of 15 feeders can account for up to 75 MVA of customer load. Congested cable chambers also significantly impede the ability of crews to perform work safely.

E5.3.4 Expenditure Plan

Table 9: Historical & Forecast Program Costs ($ Millions)

	Actuals			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Load Demand	24.0	29.7	30.8	22.6	13.8	43.5	46.4	38.1	42.7	46.4

/C

Table 10: Cost Breakdown by Type of Work ($ Millions)

	Actuals			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Load Transfer (Bus)	8.7	13.6	15.3	16.5	4.9	22.59	15.11	17.81	15.97	8.69
Load Transfer (Feeder)	0.82	0.87	1.3	0.85	2.9	8.19	7.16	7.25	7.32	6.95
Cable Upgrades	7.3	5.9	8.3	4.7	2.4	7.72	12.04	12.20	12.31	2.57
Equipment Upgrades	0.32	0.10	0.42	0.23	0.0	-	0.39	0.79	0.40	0.42
Civil Enhancements	6.9	9.3	5.5	0.05	3.6	5.04	11.72	-	6.66	27.79

/C

The 2025-2029 expenditure plan is based on the specific work that is planned in each year. As is true with the 2020-2024 rate period, expenditures vary considerably from one year to the next due to the volume of work associated with the different activities undertaken by the Load Demand program (i.e. load transfers, cable and equipment upgrades, and civil enhancements).

During 2020-2022, Toronto Hydro has relieved capacity constraints on the system through the:

- Alleviation of 131 MVA on highly loaded buses through bus level load transfers or bus expansion;
- Reduction in the amount of highly loaded feeders by 10 through feeder level transfers and feeder upgrades;
- Improvement to the civil infrastructure associated with station expansion of Carlaw TS, Horner TS, Runnymede TS, Strachan TS, Terauley TS, as well as the upgrade to John street civil infrastructure between Front Street and Stephanie Street; and
- Maintaining the number of summer switching feeder restrictions to under 10.

These forecasts are re-evaluated annually, as described in the DSP – Capacity Planning, driven by information on expected new connections, on expected load transfers and voltage conversions, re-evaluated growth rate, and the previous years' weather corrected peak which is used as base for load growth.[31] Based on the annual re-evaluation of station bus load forecasts, Toronto Hydro fully expects that project scheduling will change. This is natural for a program such as Load Demand. For example, Toronto Hydro planned to address 28 highly loaded feeders through cable upgrades and load transfers. However, with the changing load growth needs of the system and reprioritization, 18 highly loaded feeders have now been planned to be addressed. Instead, additional investments were allocated to bus level load transfers with the following stations undergoing transfers that were not originally planned for: Runnymede, Carlaw, Leaside, George & Duke, Dufferin, and Terauley stations. This resulted in approximately an additional 100 MVA of bus level load transfers.

Investments in the 2025-2029 rate period aim to continue to relieve capacity strained areas in the City of Toronto. The plans are based on Toronto Hydro's Station Load Forecast. As described in section E5.3.3, this Program is made up of investments in station bus load transfer, feeder level load transfers and upgrades, network equipment upgrades and civil egress enhancements.

[31] Exhibit 2B, Sections D2.3, 3.2.1, and C3.3.

E5.3.4.1 Station Bus Load Transfers

The proposed work aims to provide load relief to the station buses that are expected to become overloaded in the next rate period due to growth, and which are located in areas where capacity is available at an adjacent station. Some of the planned bus load transfers are dependent on the completion of station expansions projects, such as the Copeland TS Phase 2 project. /C

The costs for bus level load transfers were forecasted using a cost per MVA transferred value, based on evaluations of historic project actuals. The cost per MVA can vary greatly for a bus level load transfer, depending on distance between stations involved in the transfer, location of feeders, and geographical constraints, such as the presence of bridges and highways, and civil conditions.

Load transfers in the Horseshoe area, which is generally served by the overhead system, can vary in /C cost depending whether the transfer requires tie switches between feeders, or whether expansion work as well is required. The cost would be considerably lower in areas where only a switch is required for a transfer compared to when expansion work would be required. Additional expansion work can include civil and electrical work in order to transfer load which can significantly increase the cost of the project.

E5.3.4.2 Feeder Level Load Transfers and Upgrades

As noted above, Toronto Hydro plans to undertake 64 feeders in the downtown area and **15** feeders in the Horseshoe area for relief through feeder upgrades and feeder load transfers during the 2025-2029 rate period. /C

Any cable upgrade to the trunk of a feeder is estimated to upgrade approximately 1,000 meters of cable in the downtown and 2,000 meters of cable in the Horseshoe, which will include civil upgrades for half of the distance. Civil upgrades include duct banks, cable chambers, and splices along the feeder route. The unit cost assumes 1,000 meters of upgrades per targeted downtown feeder because this is the average length of a feeder trunk, with each downtown feeder having a maximum spread of approximately 3,000 meters. In the Horseshoe, the average length of undersized aluminum cable egress that is targeted for upgrades to standardized copper cable is approximately 2,000 meters.

E5.3.4.3 Equipment Upgrades

Toronto Hydro plans to complete five network equipment upgrades during the 2025-2029 rate period in order to maintain its target of limiting summer switching restrictions under contingency scenarios to under 10.

For network equipment upgrades, the per unit cost was based on the cost to remove and install a new 750 kVA network unit, which was the most common upgrade seen in the 2020-2024 rate period.

E5.3.4.4 Civil Enhancements

Toronto Hydro plans to increase capacity and add new feeder cell positions at the following stations in the 2025-2029 rate period: Bridgman TS (downtown), Danforth TS (downtown), Downsview TS (Horseshoe), Duplex TS (downtown), Manby (Horseshoe) Wiltshire TS (downtown), and Windsor TS (downtown). Often, when station capacity is expanded and new cell positions are installed, additional feeders need new or expanded routes outside of the station via new or upgraded egress cable chambers and duct banks.

Toronto Hydro also plans to enhance its civil infrastructure in capacity constrained areas within the City of Toronto. The civil enhancement plan will address cable chambers and ducts in need of rebuild, and legacy infrastructure including square ducts which span over 4.6 kilometers, which limit the size of feeders to smaller diameter cables causing bottlenecks in capacity.

E5.3.4.5 Project Prioritization

Toronto Hydro considers a combination of several factors when prioritizing projects within the Load Demand program, including:

- **Load growth:** Toronto Hydro addresses areas of the system that are at capacity and that require significant investments to allow the connection of new customers. Forecasting of highly loaded areas is used to determine which projects should be prioritized.
- **Contingency operation:** Current limitations on the system prevent overloading during contingency operations. Projects that introduce additional capacity to allow the operators to remove these limitations will receive a higher priority.
- **Reliability:** For load transfer projects, sections of cable that require upgrading and that are on feeders with poor reliability or adjacent feeders will be given higher priority in order to improve future outage restoration times.

E5.3.4.6 Cost Management

Load Demand projects are continuously evaluated to ensure that the spending is in the appropriate areas. For example, the need for each bus level load transfer is re-evaluated annually to see if forecasts still hold true or if they should be modified. Load forecasts are the basis for determining if buses require relief. As seen in Table 6 above, two buses that were expected to be overloaded in the 2020-2024 rate period are being deferred to the 2025-2029 rate period. This allowed for other Load Demand work to be completed in their place since the transfers identified in Table 6 were no longer immediately required.

Additionally, Toronto Hydro enables cost savings through NWS. Peak shaving through Local DR can reduce immediate needs for bus level load transfers in this Program. During annual reviews of load growth forecasts, NWS may be deployed, if available, to temporarily defer bus level load transfer projects. In the 2025-2029 rate period, Toronto Hydro will aim to procure up to 30 MW of demand response capacity across three stations in the Horseshoe area and three stations downtown, which could help defer or avoid about 25% of the total load planned to be transferred. For further details, please refer to Section E7.2 Non-Wires Solutions. /C /C

By making capacity available by both electrical relief (via bus transfers, feeder transfers, feeder upgrades and equipment upgrades), and civil relief (via station enhancements), customers are able to be connected in an efficient manner. Without available capacity, infrastructure may have to be built using a suboptimal station (i.e. not in the area of the customer(s)) and using suboptimal and lengthy routes. Avoiding this work reduces the overall cost of connecting customers.

E5.3.5 Options Analysis

E5.3.5.1 Option 1: Do Nothing

Option 1 entails not planning any load transfers, equipment upgrades, or civil enhancements. This option allows Toronto Hydro to defer capital spending. Toronto Hydro anticipates that this option would reduce reliability and increase failure risk. Increasing loading stress on existing electrical infrastructure in heavily loaded areas under first contingency would shorten the operational life time of the electrical infrastructure. Rolling blackouts may be required during the summer to ensure that the peak loading remains under the capacity for the system, since no investments are being made to resolve the overloads during summer peaks. Areas of heavy loading will continue to experience increased loading, with the capacity to transfer loads under contingency decreasing. Following this

option would impair the utility's ability to expedite upgrades to relieve heavily loaded infrastructure effectively and efficiently.

The addition of new high load customers in identified heavily loaded areas may exceed first contingency capacity, making system upgrades increasingly difficult and lengthy as Toronto Hydro would be unable to take feeders out of service for planned work if there is no viable standby feeder to accept the load. Finally, the exposure risk of customers in highly loaded areas to lengthy outages due to equipment failures or severe weather will be higher because of the inability to transfer load to standby or alternate supplies if capacity constraints are violated.

This is not a feasible option as it would give rise to a risk of non-compliance with DSC sections 3.3.1 and 4.4.1, which require Toronto Hydro to prudently and efficiently manage its distribution system, and address forecast load growth.

E5.3.5.2 Option 2 (Selected Option): System Investments Aligned with Toronto Hydro's Station Load Forecast

Option 2 aligns with the Toronto Hydro's Stations Load Forecast which applies a probabilistic approach to forecast the peak loads of all the buses of the stations within the city of Toronto. The output of the forecast is arranged to reflect summer and winter peaks due to the different characteristics between the two peaking seasons. The primary drivers for load growth for the 2025-2029 rate period are Customer Connections, commercial transportation electrification, EVs and hyperscale data centres.

This investment option would relieve station capacity by transferring load away from heavily loaded areas. This option also invests in cable upgrade, feeder transfers, equipment upgrades and civil enhancements in highly loaded areas with a focus of relieve overloads under a first contingency basis. As part of this option, Toronto Hydro will also consider utilizing NWS as a mitigating tool to defer bus-level load transfers where applicable.

Efforts under this option will provide capacity to expedite future upgrades and balance system loading, makes use of existing system assets by performing load transfers between highly loaded buses and feeders to lightly loaded alternatives, and allows Toronto Hydro to maintain full compliance with sections 3.3.1 and 4.4.1 of the DSC with regard to prudent and efficient distribution system management.

This is the preferred option since it addresses the capacity needs of the distribution system that are arising in the short to medium term, as well as considering expected electrification needs that have a significant impact to Toronto Hydro's distribution system. With this option, Toronto Hydro can comply with the DSC and improve customer service, reliability, and safety of the system.

E5.3.5.3 Option 3: System Investments Aligned with Future Energy Scenarios High Electrification Scenario (Customer Transformation Low)

This option looks to invest in accordance with the Future Energy Scenarios model Consumer Transformation Low ("CT Low") Scenario which accounts for high electrification needs while assuming low efficiency.[32] Based on the CT Low scenario, the amount of bus-level load transfers will increase by 217 percent when compared to Option 2. Additionally, compared Option 2, the number of highly loaded feeders will increase by 40 percent, the number of network equipment upgrades will increase by 120 percent and the expected stations requiring additional civil egress work will increase by 50 percent. Based on these increases, this will result in an increase cost of approximately $230 million when compared to Option 2. /C /C /C

This option would allow for extensive relief in line with a more aggressive load growth. However, there is a higher risk of overbuilding the system if aligning with this option. While it is not recommended to proceed with this option, this analysis does provide insight into the degree of variability in load growth depending on how electrification trends and customer behaviours materialize in the 2025-2029 rate period.

E5.3.6 Execution Risks & Mitigation

Several issues can present risks to the execution of the Load Demand program.

1. Uncertainty of Future Load Growth

Based on studies and analysis, the Station Load Forecast considered factors with a probabilistic approach when forecasting for peak loads of all Toronto Hydro buses of the station within the City of Toronto. Potential risks could arise based on future city planning changes or changes to redevelopment areas which could impact the load growth for the area. Such uncertainties can be mitigated by monitoring trends and updating forecasting accordingly and increasing flexibility when prioritizing and deploying work under the Load Demand program. Another strategy for managing

[32] Exhibit 2B, Section D4.

unexpected growth is the use of NWS such as local DR to shave peak loads. NWS can be implemented to incentivize customers to help reduce bus peaks. This type of NWS provides temporary relief, to provide flexibility to allow the time to implement more permanent solutions such as equipment upgrades or load transfers. Therefore, capital investments will still need to be made in the Load Demand program to support this growth.

2. Increasing Complexity of Projects

In order to complete load transfers and cable upgrades, feeders may need to be pulled or upgraded over long distances, utilizing several cable chambers and duct banks along the route. Records provide an indication of what civil costs can be expected for a Load Demand project; however, there can be unexpected rebuilding or expansion of civil infrastructure that is required. Civil inspections performed earlier in the project cycle can help mitigate any unforeseen project costs. Toronto Hydro has included preliminary inspections and design during up-front project creation in order to better scope out each project, leading to less variation in scope, costs and timelines as projects progress from planning to execution and construction.

3. Challenges Coordinating with Third Party Utilities

Moratoriums and third-party construction can limit and dictate the civil routes used in load transfers. Costlier solutions to bring capacity into an area may be required because we are unable to utilize more optimal routes where moratoriums exist or third-party construction is taking place. In these cases, potential impacts must be identified at the early stages of project planning and coordination must be sought and achieved.

5.4 Metering

E5.4.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 87.4	**2025-2029 Cost ($M)**: 247.9
Segments: Revenue Metering Compliance; and Wholesale Metering Compliance	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Focus, Public Policy Responsiveness, Financial Performance, Operational Effectiveness	

The Metering program (the "Program") funds investments in the utility's metering technology to ensure the reliable measurement of electricity acquired by the utility through the provincial transmission system and distributed to its customers. The Program consists of two segments: Wholesale Meter Compliance and Revenue Meter Compliance.

The Wholesale Meter Compliance ("WMC") segment involves the planned upgrades of wholesale meters at transmission supply points.

The Revenue Meter Compliance ("RMC") segment involves the installation of meters for new customers, the replacement of meters approaching seal expiry, the planned replacement of residential and small commercial smart meters with next generation smart meters (commonly referred to as Advanced Metering Infrastructure ("AMI") 2.0, and upgrades for supporting metering infrastructure. The segment is comprised of specific initiatives that impact all of Toronto Hydro's customers. A substantial part of this segment involves the planned replacement of Toronto Hydro's population of AMI, including residential and small commercial smart meters under the AMI 2.0 deployment.

The Program and its constituent segments are a continuation of the activities described in the Metering program in Toronto Hydro's 2020-2024 rate application.[1]

The Program's primary objectives are to maintain compliance with legal and regulatory metering requirements under the *Electricity and Gas Inspection Act* ("*EGIA*")*, Weights and Measures Act*

[1] EB-2018-0165, Exhibit 2B, Section E5.4.

("*WMA*"),[2] and the *Independent Electricity System Operator's ("IESO") Market Rules* (which Toronto Hydro must abide by as a Market Participant), while facilitating accurate customer billing and supporting utility's financial obligations.[3] In addition, as summarized in Section 1.6.1.1 of Grid Modernization, the deployment of AMI 2.0 is in line with Toronto Hydro's grid modernization objectives, as it lays a strong foundation for advanced and intelligent grid infrastructure. The abundance of data that accompanies the deployment of AMI 2.0 opens up opportunities for enhanced grid observability and situational awareness. The increased granularity of data collected through advanced meters will enable more robust data analytics, unlock new possibilities for grid optimization, and promote proactive asset management, customer engagement, and the implementation of non-wire solutions ("NWS") such as flexibility services. AMI 2.0 will also play an important role in enhancing outage management and grid reliability by introducing new functionalities like "last gasp", which enables grid operators to identify outage locations and dispatch repair crews to more precise locations.

E5.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: ○ Maintaining billing accuracy of at least 98 percent by: (a) upgrading and replacing metering infrastructure and limiting the percentage of meters past their useful life and (b) completing metering system upgrade initiatives that reduce estimated bills and bill corrections; and ○ Installing ION meters for large industrial and commercial customers to enable customers to monitor energy consumption and power quality in real-time.

[2] R.S.C., 1985, c. E-4 ["*Electricity and Gas Inspection* Act"]. and R.S.C., 1985, c. W-6 ["*Weights and Measures Act"].*

[3] Independent Electricity System Operator, *IESO's Market Rules & Manuals*, Chapter 6 and Chapter 4, 6 Appendices.

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's reliability objectives by: ○ Installing meters with last gasp functionality which enables grid operators to identify outage locations and dispatch repair crews to more precise locations, which reduces operational costs and results in a quicker and more accurate response. ○ Enhancing data granularity (e.g. demand data, asset health data) which improves grid reliability by enabling the development of analytical tools that serve to proactively monitor asset health and identify maintenance needs and ultimately, reduce likelihood of unexpected equipment failure.
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by: ○ Maintaining compliance with various requirements such as Measurement Canada's *Electricity and Gas Inspection Act* and Regulations, the *Weights and Measures Act,*[4] and the *IESO's Market Rules* to enable accurate and timely meter reading, billing and market settlements.[5]
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by ensuring energy consumption, and purchase of wholesale energy is measured accurately and in a timely manner. • Enhanced measurement capabilities will allow for the development of enhanced analytical insights, including new types of predictive and prescriptive analytics, providing opportunities to improve the cost-effectiveness of planning and operational decisions.

E5.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Failure Risk, Business Operations Efficiency, Reliability

[4] *Supra* note 2
[5] *Supra* note 3

E5.4.3.1 Mandated Service Obligations

Metering in Canada is governed by the *Weights and Measures Act* ("*WMA*") and the *Electricity and Gas Inspection Act* ("*EGIA*").[6] Measurement Canada has jurisdiction over the administration and enforcement of these Acts.

1. Wholesale Meter Compliance

Toronto Hydro plans to upgrade its wholesale revenue meters to comply with the metering standards mandated by *IESO's Market Rules*[7] and Measurement Canada. Wholesale revenue metering upgrades require approved instrument transformers, de-registering the existing wholesale revenue metering points, preparing the site for new compliant wholesale metering equipment, overseeing the wholesale revenue metering installation work, and completing the registration process with the IESO. In 2020, Toronto Hydro completed its Wholesale Metering conversion on its existing grid supply points to comply with *IESO's Market Rules*.[8] For the 2025-2029 rate period, Toronto Hydro plans to continue its work on all new applicable wholesale metering points.

2. Revenue Metering Compliance

The *WMA* and *EGIA* and related regulations govern Toronto Hydro's ability to bill its customers for electricity usage, and require that all meters must be resealed at specified intervals to ensure that a customer's electricity usage is metered accurately.[9] Once a seal expires, the meter cannot legally be used for billing purposes and must either have its seal period extended (via compliance testing), or be replaced.

For large homogenous batches of meters, Measurement Canada permits a sampling protocol to verify the accuracy of the meters. If the statistical accuracy results from the sample testing are within acceptable levels, all the meters in the meter group will receive a seal extension.

The regulatory framework also requires certain meters that do not fall under the sampling program to be removed for individual testing (reverification) and replaced with new meters.

[6] *Supra* note 2.
[7] *Supra* note 3
[8] *Ibid.*
[9] *Supra* note 2.

Once the seals of a meter sample group have expired, Toronto Hydro cannot use the meters in the group to bill its customers. Also, in the event that the meters with expired seals remain in use, Toronto Hydro could face financial penalties, as contemplated by *EGIA*.[10]

All categories of meters (residential, commercial and industrial, large users, suite meters, wholesale meters) will either need to have their seals extended or be replaced throughout the 2025-2029 rate period. The bulk of residential and small commercial and industrial meters (which make up the significant majority of meters in Toronto Hydro's system) will have their seals expire between 2024 and 2026. Please see Figure 1 for a breakdown of the number of meters with seals expiring by year.

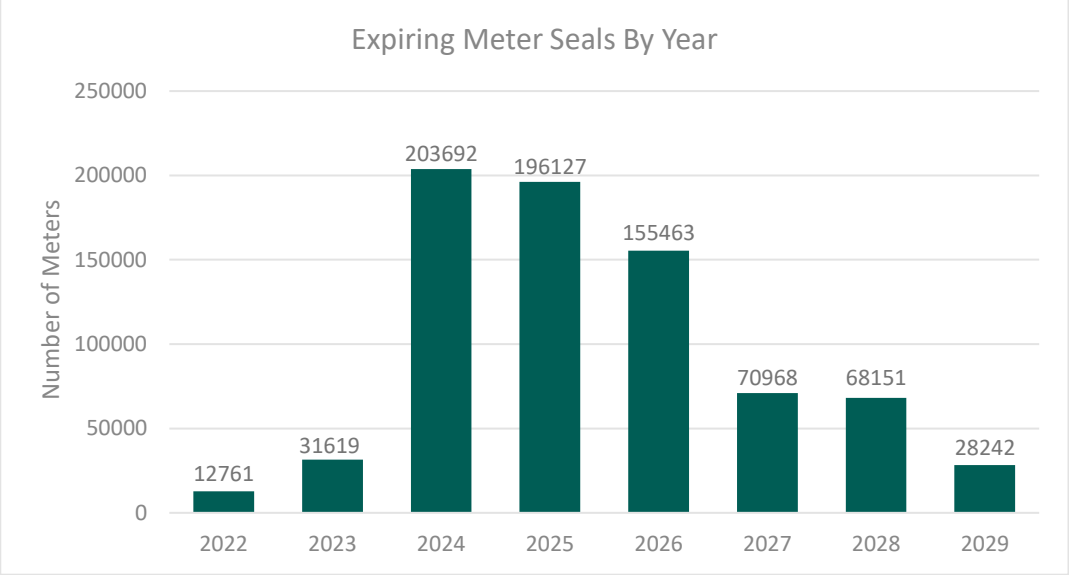


Figure 1: Expiring Meter Seals by Year

Customers in the General Service 1,000 to 4,999 kW and Large Use Customers above 5,000 kW classes represent only 0.06 percent of Toronto Hydro's customers, yet they generate approximately 12 percent of the utility's total yearly revenue. These customers are typically key contributors to the economy of Toronto and Ontario, and can have loads that are sensitive to power quality issues. Examples of such customers may include auto manufacturers, office towers, entertainment complexes that host national and international audiences and sporting events, hospitals, and industrial manufacturing plants.

[10] *Ibid.*

Replacing meters currently in use by customers in the General Service 1,000 to 4,999 kW and Large Use Customers above 5,000 kW classes at the time of meter reverification from non-ION to ION meters that have added functionality will allow for the diagnosis of customer power quality issues and may lead to a reduction in customer specific power interruptions. In addition, these meters provide three-phase power quality information that Toronto Hydro can use to investigate distribution system issues related to power quality, in order to take preventative actions to rectify system issues. These meters also provide direct benefits to the customers themselves by allowing them to monitor their energy consumption and power quality in real-time.



Figure 2: ION 8650 Meter Installed at Large User Sites

As existing meters for customers in the General Service 1,000 to 4,999 kW and Large Use Customers above 5,000 kW classes reach seal expiry, Toronto Hydro will upgrade them from non-ION meters to ION meters. Toronto Hydro must also replace and reverify these meters as their meter seals expire. The planned ION installation schedule for the 2025 to 2029 rate period is outlined in Figure 3, below.

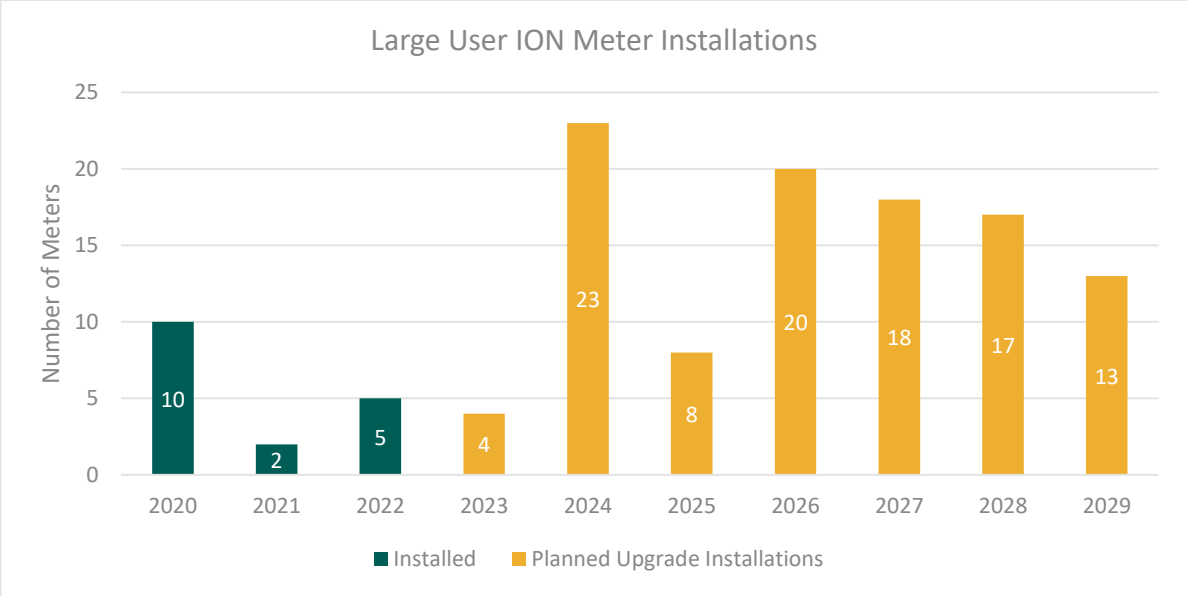


Figure 3: Large User ION Meter Installations by Year

a. Suite Meter Installations

Toronto Hydro is legally obligated to offer suite meter installation service. Utilities like Toronto Hydro offer this service in a competitive environment, and are also the provider of last resort in the event that the condominium chooses not to secure a third-party meter service provider.

Currently, Toronto Hydro meters approximately 94,000 individual suites using suite meters, while also metering about 3,000 multi-residential buildings using bulk meters.

Throughout the 2025-2029 rate period, Toronto Hydro will continue to offer its suite metering services to new customers and retrofit upgrades with an expected average of approximately 2,000 new units every year. Toronto Hydro will also maintain the existing population of installed suite meters by reverifying and re-sealing the meters, as required.

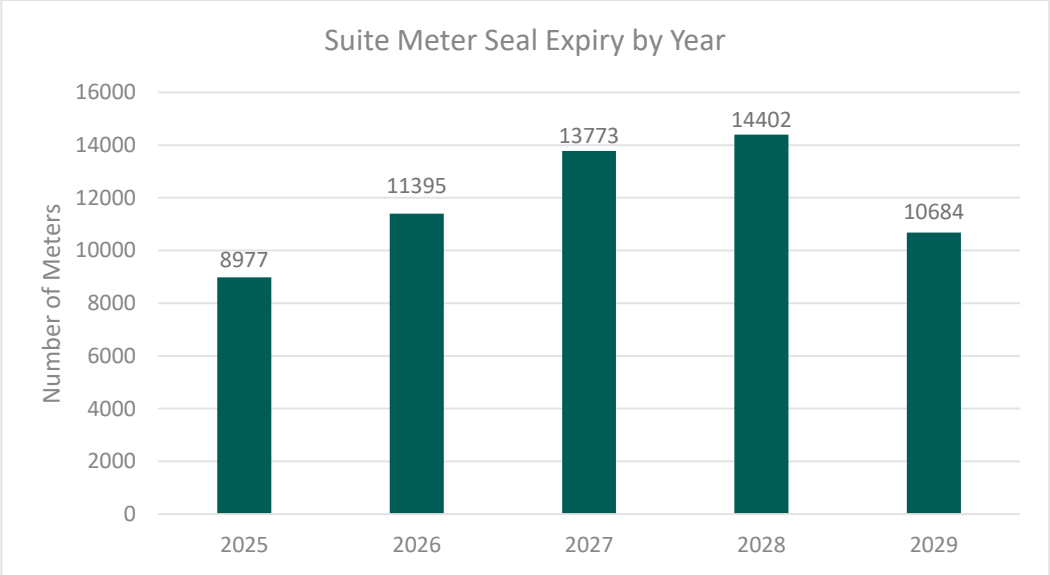


Figure 4: Suite Meter Seal Expiry by Year 2025-2029

b. Continued Provincial Meter Data Management Repository ("MDM/R") Integration

Toronto Hydro's billing systems were fully integrated with the provincial Meter Data Management Repository ("MDM/R") by the end of 2018. During the 2025-2029 rate period, Toronto Hydro expects the IESO, in its capacity as the Smart Metering Entity ("SME"), to perform upgrades and annual enhancements to the MDM/R. For example, following recent amendments to Ontario Regulation 393/07, distributors will be required to transmit smart metering data relating to electricity conveyed into the distribution system as of January 1, 2025, which may drive further system modifications.[11] Toronto Hydro will need to ensure that its internal metering systems and Customer Care and Billing System ("CC&B") continue to communicate successfully and uninterruptedly with the MDM/R.

E5.4.3.2 Growth in Interval Meters

Efficient metering system is essential to manage Toronto Hydro's billing data in order to meet Ontario Energy Board ("OEB")'s prescribed billing accuracy targets and applicable metering requirements as per the Distribution System Code ("DSC"),[12] and ensure continuous vendor support.

[11] Ontario Regulation 393/07: Smart Metering Entity, made under *Electricity Act, 1998,* SO 1998, Ch 15, Sched A.
[12] Ontario Energy Board, *Distribution System Code* (August 2, 2023).

As the industry shifts towards electrification and decarbonization, the rise in the adoption of electric vehicles ("EVs") and distributed energy resources ("DERs") will increase customers' and stakeholders' expectations with respect to access to precise, hourly interval metering data to enable demand management, participation in the Industrial Conservation Initiative, and similar activities.[13] To facilitate this transition, Toronto Hydro will need to ensure it has adequate capacity to respond to the higher volumes of new metering installations and continue to comply with the applicable metering requirements as per *WMA*, *EGIA,*[14] and DSC in the 2025-2029 rate period.[15]

E5.4.3.3 Failure Risk

Toronto Hydro was among the first utilities to implement smart meters in support of provincial policy objectives, installing the bulk of its residential and small commercial meters between 2006 and 2008. As the meter population ages, the probability of meter failures increases. The rate of increase in failure risk accelerates as meters approach and surpass their expected lifespan, which is typically 15 years.[16] In 2021, segments of Toronto Hydro's meter population began to surpass the 15-year lifespan. By 2025, approximately 70 percent of Toronto Hydro's residential and small commercial meters will have surpassed their expected useful life as shown in Figure 5 below. Without proactive intervention, Toronto Hydro expects this trend to lead to accelerating rates of meter failure.

[13] Under the *Industrial Conservation Initiative*, Class A consumers can reduce the Global Adjustment portion of their bill if they are able to reduce or avoid consuming electricity from the provincial electricity grid during the top coincident peak hours of the year.
[14] *Supra* note 2.
[15] *Supra* note 11.
[16] Exhibit 2A, Tab 2, Schedule 1, Appendix D.

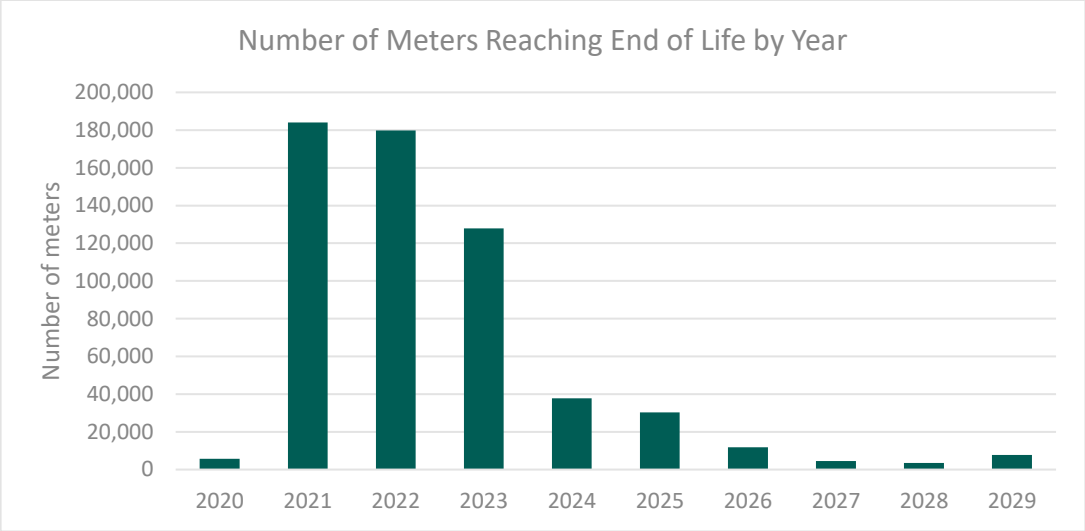


Figure 5: Residential and General Service <50 kW meters reaching end of life at 15-year lifespan

Failed meters have several negative consequences for utility operations and outcomes. When a meter fails, Toronto Hydro must estimate the customer's bill. Estimated billing decreases performance on OEB-prescribed billing accuracy targets, decreases customer satisfaction due to subsequent billing corrections, and undermines the utility's financial stability. Furthermore, replacing meters reactively is generally less cost-effective than doing so as part of a higher-volume planned program.

To address the growing population-wide risk of failure, Toronto Hydro intends to replace approximately 680,000 meters between 2023 to 2028. Meters will be replaced at or shortly following the end of their useful life of 15 years. In the process of renewing this significant population of end-of-life meters, the utility plans to introduce next generation smart meters and supporting network infrastructure, which – as discussed in the following section – will allow Toronto Hydro to increase the customer value derived from these assets through expanded capabilities.

E5.4.3.4 Business Operations Efficiency & Reliability

1. AMI 2.0

Metering technology plays a vital role in facilitating the efficient and effective operations of Toronto Hydro's system. A significant portion of Toronto Hydro's residential and small commercial meters were installed between 2006 and 2008, and rapid advancements in technology have rendered these first-generation smart meters outdated and obsolete. While the replacement of these meters is

primarily driven by failure risk, advancements in metering technology have allowed for the adoption of incremental functionalities that directly align with Toronto Hydro's Grid Modernization strategy.

As shown in Figure 6, below, Toronto Hydro expects AMI 2.0 to deliver new capabilities beyond AMI 1.0, which was predominantly focused on meter-to-cash efficiencies. These new benefits include improved billing accuracy, faster outage response, improved network range, enhanced security against cyber-threats, increased grid transparency (e.g. system observability), and improved data granularity and analytical capabilities. In the longer term, Toronto Hydro intends to leverage the monitoring and control capabilities associated with AMI 2.0 to develop additional functionalities that could prove valuable in the management of an electrified and decarbonized energy system, including load disaggregation (e.g. tracking consumption by type of home appliance) and the potential integration of smart meters within the utility's DER management system ("DERMS" or "Energy Centre"). These evolving features are dependent on further technological developments.

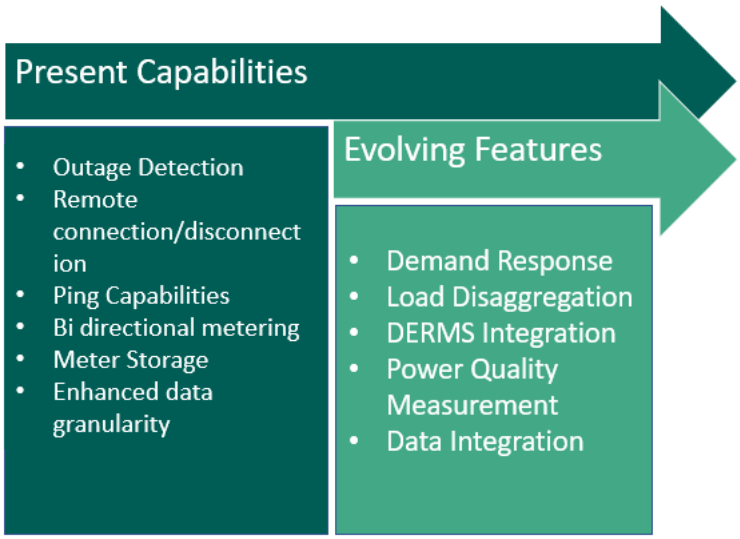


Figure 6: AMI 2.0 Use Cases: Expanded Capabilities

For a comprehensive overview of the role and expected benefits of AMI 2.0 in Toronto Hydro's modernization strategy, please refer to Section 1.6.1.1 of *Grid Modernization*. Three of the primary "out of the box" capabilities – last gasp, improved transmitting, and remote disconnect and reconnect – are highlighted below.

a. Last Gasp Functionality

Currently, Toronto Hydro is typically dependent on phone or service calls to define the location and boundaries of an outage. The utility's next generation smart meters will enable automatic outage and restoration notification (called "last gasp"). This capability will serve to reduce outage response times by deploying crews to the specified location sooner. See Figure 7, below, for a depiction of the operation of the "Last Gasp" functionality.

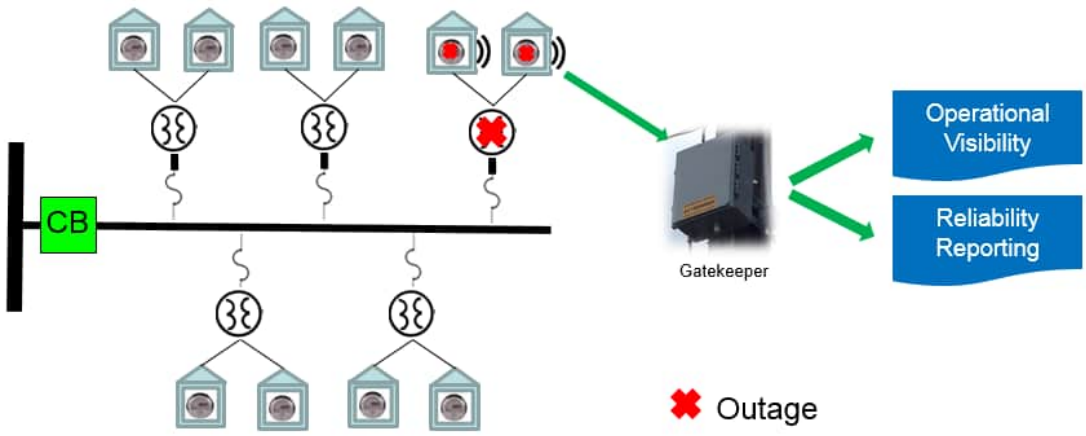


Figure 7: Last Gasp Function

b. Improved Transmitting

Another key feature of next generation meters is the presence of a more effective transmitter that will drastically increase the range and penetration of the meter signal. This is expected to increase the number of meters successfully read, reducing "orphaned" meters and the number of manual reads required, and further reducing the number of estimated bills issued, increasing Toronto Hydro's performance on OEB's bill accuracy metrics.

c. Remote Connection/Disconnection

Additionally, the introduction of meters with remote connection and disconnection capabilities allows Toronto Hydro to reduce the cost of performing disconnections and reconnections, due to the reduced need to dispatch field crew to a customer's property. This feature also enables customers to be reconnected soon after receiving payment, and allows for a more efficient and flexible

implementation of OEB-prescribed reconnection standards. Toronto Hydro already completes all reconnections within two business days at least 90 percent of the time, as required by the OEB.[17] However, remote reconnection technology will significantly reduce reconnection timelines, which is more convenient to customers, therefore improving customer satisfaction.

2. Interval Metering system

Currently, Toronto Hydro uses the Interval Metering system, ITRON Enterprise Edition ("IEE" - the data processing system) and MV-90 (data collection system) to ensure efficient metering and support the interval data collection process for Toronto Hydro's interval metered customers (i.e. General Service at least 50 kW and above customers), respectively. Efficient metering is essential to manage Toronto Hydro's billing data in order to meet OEB prescribed billing accuracy targets and applicable metering requirements as per the DSC, and ensure continuous vendor support.

The utility will upgrade both systems to maintain vendor support. The IEE system is scheduled for an upgrade during 2023-2025 and again during 2028-2029. The MV-90 data collection system is also scheduled for upgrades during 2026-2027 to support better design, functionality and enhance the interval data collection process.

3. Residential Metering

Currently, Toronto Hydro's residential metering head-end system ("Connexo") is responsible for collecting and submitting measurement data and meter events to the meter data management ("MDM") systems. This system consists of two components, Connexo NetSense and Connexo FieldSense. Connexo FieldSense was implemented in 2022 and incorporates the software and hardware for field service management. The utility must continually upgrade its residential metering head-end system to maintain vendor support and the capability to enable features available on newer generation meters. By end of 2023, Toronto Hydro plans to implement a new version of Connexo NetSense, the residential metering head-end system which will be required to support the next generation meters (AMI 2.0). This upgraded version will allow for improved functionality – enabling enhanced communication features available in newer advanced meters and implementing a Gatekeeper (Collector) replacement program. More importantly, the new generation of meters will reduce the number of manual meter reads and estimated bills. This will also allow Toronto Hydro to

[17] *Supra* note 11, Section 7.10.1.

continue to meet OEB-prescribed bill accuracy targets and improve customer satisfaction by limiting billing errors.

4. Suite Metering

The City of Toronto is experiencing significant development of condominiums and other high-density buildings. As a result of this customer growth, by the 2025-2029 rate period Toronto Hydro's current suite meter AMI system ("Primeread") will no longer be able to retrieve and process the suite meter data fast enough on a daily basis to meet meter reading and billing performance targets mandated by Measurement Canada and the IESO. As a result, Toronto Hydro intends to upgrade its data collection system, Suite Meter Advanced Metering Infrastructure ("AMI") to i) ensure continuous vendor support, ii) improve Toronto Hydro's operations, including timely and accurate billing resulting in higher customer satisfaction, ability to meet OEB-prescribed bill accuracy metric (by reducing estimated billing and manual reads); and iii) improve financial stability. The lifecycle of the Suite Metering AMI has a scheduled upgrade roughly every three years to keep up with the influx of new suite metered customers. Primeread was initially brought online in 2012, the first upgrade took place in 2015, followed by 2017. The next upgrade is scheduled in 2023 and then again during 2027-2028.

5. Operational Data Storage Upgrade ("ODS")

Presently, ODS is used for framing consumption data for billing and for automated validation, editing and estimating meter data. ODS transfers consumption data from meters into Toronto Hydro's CC&B for billing and ensures timely and accurate billing for customers. The transfer of consumption data from ODS to CC&B is crucial to complete the annual rate reclassification process, as mandated by OEB Distribution System Code. The upgrade scheduled for 2024-2026 will enhance the ODS to better manage Toronto Hydro's billing data to meet OEB prescribed billing accuracy targets and ensure continuous vendor support. The subsequent upgrade for ODS is scheduled for 2029. These upgrades would also accommodate any new price plan introduced by OEB.

E5.4.4 Expenditure Plan

Toronto Hydro's historic and forecast spending in the Program is shown in Table 4, below. Expenditures in the Program are largely driven by the timing of metering and metering system upgrade cycles.

Table 4: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Metering	11.2	8.1	8.4	9.0	50.7	63.7	69.9	72.4	34.7	7.4

The majority of costs in 2020 is attributed to work related to wholesale metering compliance. The bulk of spending over 2021-2023 has been driven by upgrades to meter data and related field services systems to retain vendor support, meter replacements and reverification related to revenue metering compliance, and suite metering costs. To address funding constraints over the 2020-2024 rate period, Toronto Hydro deferred the majority of meter replacements to the 2025-2029 rate period, when it plans to replace meters at their seal expiry year. In addition, delays in procuring AMI 2.0 meters required the utility to adjust the pace of replacements through its sampling and reverification program by extending the seal life for meters with seals expiring in 2023 by six years. During the 2020-2024 rate period, Toronto Hydro plans to replace approximately 50,000 residential, small commercial, and industrial meters, as part of the AMI 2.0 project. Starting in 2024, program costs are forecasted to increase, primarily driven by the resumption of deferred meter replacements for residential, small commercial, and industrial meters, including the installation of next generation meters as part of AMI 2.0. During the 2025-2029 period, Toronto Hydro plans to replace approximately 630,000 meters.

Although the replacement of these meters is primarily driven by failure risk, the advancements in technology have allowed for the adoption of advanced functionalities. These meters will allow Toronto Hydro to expand the functionality of its metering population, through wider interoperability using a standards-based solution, greater options for remote meter disconnect and reconnect, distributed intelligence, cloud and data analytics, advanced outage detection, integrated distribution automation network support, remote power quality monitoring, and personalized customer communication.

Table 5, below shows the detailed breakdown of Program spending over the 2020-2024 rate period.

Table 5: Actual & Bridge Program Costs 2020-2024 ($ Millions)

	2020	2021	2022	2023	2024	Total
Residential and Small C&I Meter Replacement	0.44	0.05	1.74	3.39	43.63	**49.24**
Suite Metering	1.84	1.80	1.02	1.21	1.19	**7.06**
Large Customer and Interval Metering	0.12	0.02	0.03	0.05	0.34	**0.55**
Remote Disconnect	0.78	0.76	0.33	0.31	0.31	**2.50**
Sampling/Meter Replacement	4.19	3.58	2.88	1.53	2.92	**15.10**
Wholesale Metering	1.66	-0.02	0.14	0.30	0.70	**2.79**
System Upgrades	2.19	1.89	2.31	2.20	1.60	**10.19**
Total	**11.2**	**8.1**	**8.4**	**9.0**	**50.7**	**87.4**

Table 6, below, provides a breakdown of Toronto Hydro's forecast expenditures over the 2025-2029 rate period. This forecast is based on the number of meters that will need to be resealed or replaced in each year to ensure compliance with Measurement Canada and *EGIA* requirements.[18] In addition, Toronto Hydro must continuously monitor and manage the risk of asset failures associated with meters past their end-of-life by replacing meters at or shortly following their useful life of 15 years with next generation smart meters and supporting network infrastructure, as part of AMI 2.0. Lastly, the forecasted plan allows Toronto Hydro to increase the customer value derived from these assets through expanded capabilities that can be leveraged to meet future changes in customers' needs and preferences. Costs for metering system upgrade initiatives are based on a paced installation schedule using currently available cost estimates.

As shown below, the greatest increase in Toronto Hydro's forecast spending over the 2025-2029 rate period compared to historical spending over the 2020-2024 rate period is seen in the residential and small commercial meter replacement category. This increase is primarily attributed to the meter replacement initiative under the AMI 2.0 deployment (See Options Analysis section for additional details). With respect to suite metering, although the total cost is decreasing over the five-year period, the total cost is higher than for the 2020-2024 rate period to support the expected average growth of approximately 2,000 new units every year. With respect to Wholesale Metering, initially, the wholesale metering upgrade at Charles TS was scheduled within the 2020-2024 rate period. However, based on a cost benefit analysis, Toronto Hydro made the decision to move this upgrade

[18] *Supra* note 2

to the 2025-2029 rate period, as part of the scope of Hydro One's planned power transformer replacements.

Table 6: Forecast Program Costs 2025-2029 ($ Millions)

	2025	2026	2027	2028	2029	Total
Residential and Small C&I Meter Replacement	54.5	58.9	62.2	26.0	0.0	**201.6**
Suite Metering	2.1	1.9	1.8	1.7	1.6	**9.1**
Large Customer and Interval Metering	0.2	0.7	0.3	0.3	0.2	**1.7**
Sampling/Meter Replacement	4.9	4.2	5.0	3.9	3.2	**21.2**
Wholesale Metering	0.0	1.5	0.0	0.0	0.0	**1.5**
System Upgrades	2.0	2.6	3.0	2.9	2.4	**12.8**
Total	**63.7**	**69.9**	**72.4**	**34.7**	**7.4**	**248.1**

E5.4.5 Options Analysis

E5.4.5.1 Options for Revenue Meter Compliance

The Revenue Meter Compliance segment includes many tasks that must be completed in order to remain in compliance with Measurement Canada requirements. This includes the meter replacements for residential, suite meters, interval meters, and large users and metering system upgrades. These projects must be completed to ensure continued compliance with Measurement Canada and OEB requirements. For example, for the interval and suite metering projects, Toronto Hydro must maintain the meter seals to ensure continued compliance with requirements contained in the *WMA* and the *EGIA*.[19]

The major project for the Revenue Meter Compliance segment over the 2025-2029 rate period is the residential and small commercial meter replacement under the AMI 2.0 deployment. The AMI 2.0 project is slated to commence in the 2020-2024 rate period, and will continue throughout the 2025-2029 rate period. The options for the 2025-2029 rate period revolve primarily around the pace of meter replacements under the AMI 2.0 project, and only consider the costs associated with residential and small commercial meter replacement. If meters with expired seals are not replaced before their seal expiry, their seals will be extended through the sampling and reverification program under each option. This project has four options for completion, which are discussed in detail below.

[19] *Supra* note 2.

1. Option 1: Replacement of meters beyond their 15-year useful life

This option replaces meters in their second seal period, which is generally beyond their 15-year useful life. This option is the least capital intensive of the four, as it defers the meter replacement to a future period. Although this option is the most financially feasible, meters would remain in operation for the longest period of time, and beyond the useful life, posing considerable operational, regulatory and financial risks. As well, this option does not replace the entire population of AMI-included models by the end of 2029.

As most of the meters are replaced past their end of useful life under this option, it poses a risk of failure for these aging meters. Substantial meter failures would have a significant negative impact on Toronto Hydro's operations, including lack of timely and accurate billing resulting in lower customer satisfaction, inability to meet OEB-prescribed bill accuracy metric and financial instability. A reactive approach to replace the meters that have failed would result in an increase in Toronto Hydro's operational costs which would need to be addressed through the redirection process, thereby placing other forecasted investments at risk.

The total cost of this option for the 2025-2029 rate period is $163.0 million.

2. Option 2: Replacement of meters beyond their 15-year useful life while mitigating risk of asset failure

Option 2 has a greater emphasis on mitigating the risk of asset failures associated with meters past their end-of-life. Under Option 2, meters would be replaced earlier than Option 1, resulting in the replacement of more meters in the 2025-2029 rate period than under Option 1. Under Option 2, however, a portion of the original AMI meters would remain in the field delaying the achievement of Last Gasp functionality. Last Gasp functionality cannot be enabled until the majority of meters are replaced with newer models. Also, Toronto Hydro will not be able to capture the entire benefits of AMI 2.0 meters until the majority of the current meters are replaced.

The total cost of this option for the 2025-2029 rate period is $182.7 million.

3. Option 3: Replacement of meters as they reach seal expiry

The primary focus of this option is to replace meters as they reach seal expiry, regardless of their age or seal period. This option will pose a greater risk for resource balancing as it requires a large number of meters to be replaced in 2025.

As this option does not prioritise meter replacements based on meters past their end-of-life, this will pose a greater risk of failure for meters past end-of-life which may result in additional operational cost for field activities and manual billing of the customer. A reactive or ad hoc approach to meter replacement also requires more operational costs, compared to a planned replacement.

The total cost of this option for the 2025-2029 rate period is $199.0 million.

4. Option 4: Replacement of the entire fleet of meters (Preferred Option)

Under option 4, the entire fleet of AMI meters would be replaced during over 2023-2029. The replacement schedule would be identical to Option 2 for meters that have reached their end-of-life by 2029 plus those that have an end-of-life beyond 2029 would be added in.

This pacing option adequately achieves all of the intended objectives of the replacement such as the seal expiry issue and potential risk of meter failure beyond end-of-life, while mitigating any operational, regulatory and financial risks. This option also aligns with Toronto Hydro's grid modernization and customer experience strategic objectives as it enables the earliest attainment of out-of-the-box benefits compared to all other options. Benefits include remote disconnect and reconnect and the earliest achievement of Last Gasp functionality. Option 4 also lays the groundwork for the implementation of other advanced capabilities that will require further investments in technology (e.g. DERMS), development of organizational capabilities (e.g. advanced analytics and data governance) and alignment across multiple organizational stakeholders to be realized (See Figure 6 above – AMI 2.0 Use Cases: Expanded Capabilities for more details).

Given these considerations, Toronto Hydro has selected Option 4 as its approach.

The total cost of this option for the 2025-2029 rate period is $201.6 million.

5. Options Comparison

Option 4 is selected based on the following criteria as summarized in Table 7:

- **Lowest number of projected meter failures associated with assets past end-of-life**: The proposed replacement strategy in Option 4 and Option 2 is expected to have the lowest number of meters past their life expectancy in the 2025-2029 rate period. Delaying the replacement of meters beyond their useful life of 15 years can lead to an increased risk of

meters failure. As a result, there is an increased risk of non-compliance with the *EGIA*,[20] the OEB-prescribed performance metric pertaining to bill accuracy and *IESO's Market Rules* regarding market settlements.[21] In addition, responding to meter failures that occur before their scheduled replacement can result in increased operational costs (e.g. billing exceptions that require manual intervention and additional field activities to investigate the failures). Additionally, a reactive or ad hoc approach to replacing meters that have failed can result in higher operational costs that would need to be redirected, placing other forecasted investments at risk.

- **Earliest achievement of Last Gasp functionality**: Next generation meters are equipped with this capability. This feature enables grid operators to identify outage locations and dispatch repair crews to more precise location, resulting quicker and more accurate response. It also enables emergency response and outage restoration activities that require customer level outage information. It is expected that this option will provide the fastest achievement of Last gasp capability.
- **Replacing entire fleet of meter models included in the AMI 2.0 project**: By replacing the entire fleet of AMI 2.0-included models, this option is expected to lay the groundwork to realize future advanced capabilities of AMI 2.0 meters. These advanced capabilities will serve to equip Toronto Hydro and its customers with new functionalities that are well-aligned with Toronto Hydro's Grid Modernization and Customer Experience objective and lay the foundation for the development of an intelligent grid (i.e. two-way interactive capabilities) and enhancing customer service (i.e. omni-channel view of the customer). The advanced capabilities of the AMI 2.0 meters will require further investment in technology (such as DERMS), development of organizational capabilities (such as advanced analytics and data governance) and alignment across multiple organizational stakeholders to be realized. (See above Figure 6 –AMI 2.0 Use Cases: Expanded Capabilities).

[20] *Supra* note 2.
[21] *Supra* note 3.

Table 7: Options Comparison

Option	Emphasis	Risk of asset failures past EOL	Investment Level	Replacing all AMI2.0 models by 2029
Replacement of meters beyond their 15-yr useful life	Minimize capital investment in the 2025-2029 period	Medium	Lowest	No
Replacement of meters beyond their 15-yr useful life while mitigating risk of asset failure	Minimize meters past EOL	Low	Medium	No
Replacement of meters as they reach seal expiry	Align replacement with seal expiry	High	High	Yes
Replacement of the entire fleet of meters (Preferred Option)	Minimize meters past EOL	Low	High	Yes

E5.4.5.2 Options for Wholesale Metering Compliance

For the Wholesale Metering Compliance segment, Toronto does not have any alternative options as the utility is required to complete the remaining Meter Service Provider ("MSP") conversions, in accordance with IESO's mandated requirements.

Toronto Hydro seeks new opportunities, through close collaboration with Hydro One Networks Inc., to 'bundle' any proposed Wholesale Metering Compliance initiatives with planned capital improvements. This includes replacements of any Hydro One power transformers and distribution equipment within the joint-use terminal stations.

E5.4.6 Execution Risks & Mitigation

The table below illustrates the major program risks that may occur while executing the Program.

Table 8: Meter Risks, Impact, Probability, and Mitigation

Project Segment	Risk	Impact	Probability	Mitigation
Revenue Meter Compliance	Execution/ Supply chain Risk for AMI 2.0 deployment	The Mass deployment plan for AMI 2.0 meters would have to be modified and timelines stretched. This would force Toronto Hydro to reseal meters past useful life, increasing capital expenditures and risk of failure	Low	• Ensure that enough lead time is provided to the vendor to ensure delivery of equipment as required. • Toronto Hydro will adopt the following mitigation measures to ensure contractual mechanisms are available as well as to oversee and enforce contract terms and conditions: ○ Clearly state expected timelines and have resolution clauses to address delays. ○ Identify an escalation path to quickly resolve conflicts and discrepancies. ○ Enforce short interval control through vendor project status updates and reports.
Wholesale Metering	Hydro One projects enabling Toronto Hydro's required meter replacements are delayed.	Compliance with *IESO Market Rules* is affected or delayed.	Low – projects are complicated and subject to equipment delays and resource availability.	Work closely with Hydro One to schedule work and to allocate appropriate resources to metering compliance projects.

E5.5 Generation Protection, Monitoring, and Control

E5.5.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 11.2	**2025-2029 Cost ($M):** 35.0
Segments: Generation Protection, Monitoring, and Control	
Trigger Driver: Mandated Service Obligations	
Outcomes: Customer Focus, Public Policy Responsiveness, Operational Effectiveness - Safety, Operational Effectiveness - Reliability	

The Generation Protection, Monitoring, and Control program (the "Program") allows Toronto Hydro to fulfill its regulatory obligations under section 6.2.4 of the Distribution System Code ("DSC") and section 25.36 of the *Electricity Act, 1998* to connect Distributed Energy Resource ("DER") projects to its distribution system, which includes renewables like solar photovoltaic, wind and biogas.[1] It also allows Toronto Hydro to meet its obligations under section 6.1 of its Distribution License and section 26 of the *Electricity Act, 1998* to provide generators with non-discriminatory access to its distribution system. Toronto Hydro's investments in this Program consist of "renewable-enabling improvements".[2]

As of 2022, Toronto Hydro has connected 2,421 DERs totalling 304.9 MW in capacity. The utility is forecasting an increase in DER connections (including energy storage), reaching an estimated 516.7 MW by the end of 2029. To safely connect and monitor these DERs, Toronto Hydro plans to make the following investments in the 2025-2029 rate period:

- Generation protection measures, including the installation of bus-tie reactors at six station busses to alleviate short circuit capacity constraints; and
- Installation of 315 monitoring and control systems ("MCS") for renewable DER facilities greater than 50 kW to provide situational awareness and control of DER facilities on the distribution system.

[1] SO 1998, Ch 15 Sched A.
[2] Sections 1.2 and 3.3.2 of the DSC.

E5.5.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Customer Focus	• Contributes to Customer Service objectives by: ○ Enabling the connection of new generation customers without extensive delays or adverse impacts to existing and new customers; ○ Complying with sections 25.36, 25.37 and section 26 of the *Electricity Act, 1998* by connecting DER customers to its distribution system; ○ Providing Toronto Hydro with the ability to observe larger DERs in real-time and enable the maximum allowable amount of generation to be connected to the grid.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Ensuring the operation of the distribution system remains within safe and allowable designed short circuit current limits by installing six bus-tie reactors on station buses; ○ Avoiding unintentional islanding and reducing the islanding risk of DER sources; and ○ Ensuring bi-directional flows remain within distribution system design parameters including thermal and short-circuit capability by installing MCSs at existing and new DER facilities.
Operational Effectiveness - Safety	• Contributes to maintaining Toronto Hydro's Total Recorded Injury Frequency (TRIF) measure and employee safety by: ○ Enabling automatic disconnection of DER from the grid in adherence to OESC Rule 84-008 ○ Provide the ability to both remotely and automatically isolate DER connections under specified conditions as part of work protection and EUSR rule requirements
Public Policy Responsiveness	• Supports the Ministerial directive to facilitate innovation and support DER integration within Ontario's electricity system

E5.5.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Mandated Service Obligations
Secondary Driver(s)	Reliability, Customer Service Requests

Toronto Hydro is legally mandated to connect DER customers and provide generators non-discriminatory access to its distribution system.[3] The planned investments in this program qualify as Renewable Enabling Improvements in the DSC and will address certain barriers to connecting DERs, including short-circuit capacity constraints, increased risks of islanding, overloading the system and increased thermal ratings. Furthermore, by investing in real-time monitoring and control at customer DER sites, Toronto Hydro is continuing to lay the foundation for more advanced DER management use cases in the longer-term.

The Program is fundamentally customer-driven. The proposed work will allow Toronto Hydro to connect customer DER projects to the distribution system through the Customer and Generation Connections program.

The planned investments are also critical renewable enabling improvements that Toronto Hydro must carry-out in order to safely and reliably respond to the increasing demand of renewable DER facilities across the City of Toronto.

Figure 1 below shows typical DER installations on the Toronto Hydro distribution system, as enabled by investments in this Program.



Figure 1: Residential (left) and Commercial (right) DER Installation

[3] See: Sections 25.36, 25.37 and 26 of the Electricity Act, 1998; Section 6.2.4 of the Distribution System Code; Section 6.1 of Toronto Hydro's Distribution License.

E5.5.3.1 Proliferation of Distributed Energy Resource Facilities

As of 2022, Toronto Hydro has connected 2,421 DERs totalling 304.9 MW in capacity. The utility is forecasting a continued increase in DER connections (including energy storage), reaching an estimated 516.7 MW by the end of 2029.[4]

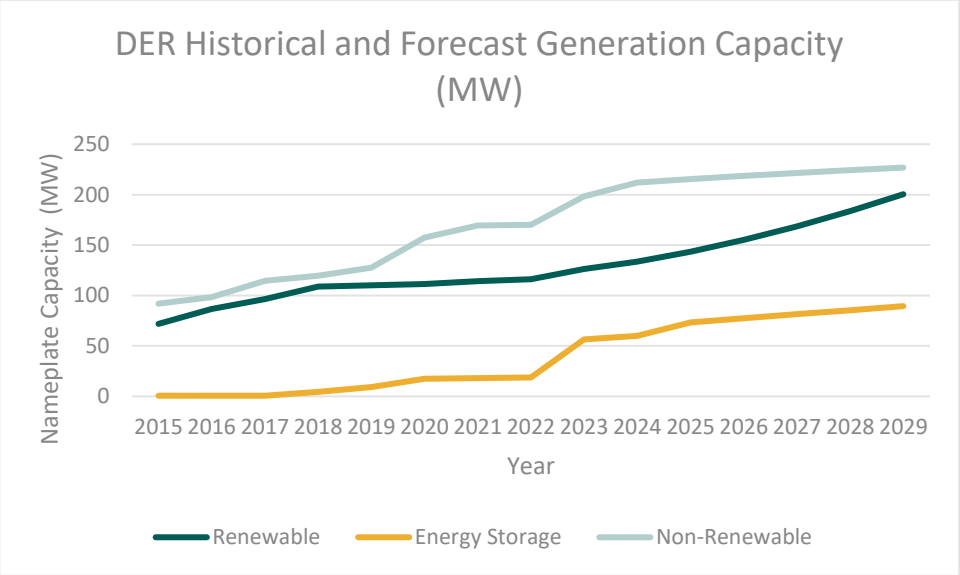


Figure 2: Historic and Forecasted Generation Capacity 2015-2029

As discussed in detail in the Generation Connection segment at section E5.1.3.2, this forecast is subject to uncertainty. As a customer-driven program, the uptake of DERs is affected by customer behaviour and other external factors, including policy and technology developments. For example, the cancellation of the Feed-in-Tariff ("FIT") program in 2018 resulted in a sharp decrease in renewable DER applications after a period of high year-over-year increases. Between 2009 to 2018, Toronto Hydro saw a compound annual growth rate of 33.93 percent, peaking in 2011 with a more than 89.9 percent increase in generation installed compared to 2010. From 2019 to 2022 the compound annual growth rate fell to 1.84 percent.

Looking ahead, the results of Toronto Hydro's Future Energy Scenarios modelling effort depict a wide range of DER uptake scenarios for the next decade and beyond. For example, at the very high end, the Future Energy Scenarios model shows that achieving Net Zero by 2040 in accordance with the City of Toronto's current strategy could involve increasing renewable penetration on Toronto

[4] See EB-2023-0195, Exhibit 2B, Sections E3 and E5.1 for a discussion of the DER forecasting methodology.

Hydro's grid to an estimated 1,249 MW by 2029. This would represent an increase of 974.9 percent of DER capacity on the grid. Hosting this level of DERs while also facilitating the full realization of coordinated DER benefits for the grid could require significant investment in hosting capacity expansion, grid modernization, and innovation.

In order to manage the inherent uncertainty of forecasting these connections, Toronto Hydro regularly reviews DER connection trends to evaluate where system constraints will emerge.

E5.5.3.2 System Capability to Connect and Control Distributed Generation

Toronto Hydro supports connecting DERs to the distribution system in alignment with the DSC and in coordination with Hydro One and the Independent Electricity System Operator ("IESO"). The utility has identified a number of constraints within its system that impact DER connections and interconnection-related decisions: 1) short-circuit capacity; 2) risk of islanding; 3) thermal limits; and 4) the lack of the ability to transfer loads between feeders during planned work.

Asset failure can occur when distribution equipment exceeds system short circuit levels, equipment thermal ratings and nominal voltage ratings. Failures due to distribution system stresses from DER sources can cause transformer equipment failure, surge arrester failure, nuisance outages from sympathetic tripping and other similar effects.

Toronto Hydro must manage the capacity and type of generation connected to both feeders and stations to ensure reliable operation and prevent damage to existing infrastructure. Introducing increased levels of bi-directional flows from DER will require protection, monitoring, and control to prevent such occurrences during normal operation, planned work and emergency situations.

At this time, there is a limited set of options for addressing DER constraints. As part of its Grid Modernization Roadmap and in anticipation of a high-DER future, Toronto Hydro is investigating and pursuing technologies and solutions that can provide for incremental flexibility in DER integration, including through more predictive and dynamic forms of DER management within grid operations.[5] For example, the energy storage systems (ESS) program is expanding to deploy grid-side batteries to (1) relieve system constraints thereby enabling more renewable hosting capacity on the grid; and (2) respond to the dynamic output of renewable energy sources by acting as a load-generation buffer in periods of mismatch. Furthermore, advances in the Advanced Distribution Management System

[5] See EB-2023-0195, Exhibit 2B, Section D5 for Grid Modernization Roadmap.

("ADMS") and Distributed Energy Resource Management System ("DERMS"), which are systems designed to provide a holistic view of the grid and optimize operations through real-time telemetry and control algorithms, can also enable DER utilization at a higher capacity factor and in turn, allow DERs to participate in grid services at more dynamic and granular levels.

1. Short Circuit Capacity Limitations

Short circuit limits on both the Toronto Hydro and Hydro One system are important factors in determining how much DER can be connected to Toronto Hydro's distribution system. This is because short circuit capacity is the measure that ensures certain power distribution assets are within their recommended withstand thresholds. The primary limiting element for short circuit capacity is substation equipment (where fault current levels are highest) and, more specifically, substation load side breakers.

Currently, three station buses have reached short circuit capacity limits and are not able to connect additional DERs. Toronto Hydro anticipates that a total of eight station busses will exceed short circuit capacity by 2029.

Table 4: Current and Forecasted Short Circuit Capacity

Station Name	Bus	2023 Available Short Circuit Capacity (MVA)	2029 Available Short Circuit Capacity (MVA)
Cecil	CE-A1A2	59.7	-32.7
Ellesmere	H9-J	81.0	-5.4
Esplanade	X-A1A2	58.9	-7.6
Leslie	51-BY	3.2	-46.6
Richview	88-BY	-40.3	-41.2
Runnymede	11-JQ	113.6	-103.3
Sheppard	47-EZ	-57.3	-91.4
Woodbridge	D6-BY	-27.3	-28.0

To arrive at the projected constraints in Table 4, Toronto Hydro mapped its overall forecast of 2029 DER capacity onto station busses by assuming that the geospatial distribution of DERs will continue to follow existing load connection patterns.

Toronto Hydro manages short circuit capacity limitations through two methods: 1) bus-tie reactors; and 2) increased fault levels. Each of these is described in further detail below.

Note that traditional station expansions investments can also relieve short circuit capacity limitations by introducing distribution equipment with higher capacity or greater short circuit withstand limits. However, given the significant cost and time involved, it is not economical to expand a station solely for the benefit of connecting DERs. Rather, increased DER connection capacity can be considered a secondary benefit of planned station expansions, which will be required in the normal course to accommodate increasing load demand in specific regions of the city. For example, the planned expansion of Sheppard TS will have the secondary benefit of helping to alleviate the existing short circuit constraint. The remaining station busses forecasted to require relief as described above will not, however, be addressed through stations expansion investments.

a. Bus-Tie Reactors

To facilitate DER connections, bus-tie reactors can be installed on the bus to mitigate high fault current levels. This technology lowers short circuit current on the station bus and distribution system by inserting impedance at the bus-tie point. This limits the fault contribution of the two transformer windings in a typical Dual Element Spot Network ("DESN") type station arrangement. A reactor of 0.5 ohms installed at a bus-tie could allow up to an additional 15 MW of DER capacity. The actual

size of a reactor depends on site specific constraints such as space, etc. Since they are essentially a linear inductive reactance, their cumulative impedance will add to the system's impedance which will result in a reduction of the fault currents. The main advantage of series reactors is that they allow the use of existing equipment without costly modifications or replacements.

Toronto Hydro has engaged Hydro One to coordinate bus-tie reactor installations at stations where fault current constraints have become or are likely to be an issue in the near future. Based on current forecasts, of the eight stations requiring relief by 2029, Toronto Hydro anticipates installing six bus-tie reactors over the 2025-2029 rate period to alleviate short circuit capacity constraints, as summarized in Table 5: Bus Tie Reactor Installations below.

Of the remaining two stations, Sheppard TS would not be a good candidate for a bus-tie reactor due to its use of a gas-insulated bus but has potential upcoming station expansion work that could also increase short circuit limits at the station. For Ellesmere TS, the short circuit constraint may be addressed using an alternative measure described below.

Table 5: Bus Tie Reactor Installations

Station Name	Bus	Year
Richview	88-BY	2025
Runnymede	11-JQ	2026
Cecil	CE-A1A2	2027
Esplanade	X-A1A2	2028
Leslie	51-BY	2029
Woodbridge	D6-BY	2029

b. Increased Fault Level for 27.6 kV Stations

Another solution to short circuit capacity constraints, in some limited circumstances, is operating at an increased fault level. There is no cost associated with operating at the increased fault level, but it is deemed to be a temporary solution due to the minimal short circuit capacity it relieves. Currently, Toronto Hydro operates at 16.7 kA fault level for stations operating at 27.6 kV. The Transmission System Code provides that 27.6 kV stations may operate at a fault level up to 17 kA, creating additional short circuit capacity.[6] Hydro One must approve an application from a distributor to

[6] Appendix 2 of the TSC.

operate at a higher fault level. The solution is only available where customers' equipment fault withstand ratings are verified to be within safe limits, particularly for those customers closest to the station.

Toronto Hydro determined that of the eight stations expected to experience short circuit constraints by 2029, only one bus, Ellesmere TS J bus, met the criteria for operating at the increased fault level without impacting the reliability of connected customers.

E5.5.3.3 System Monitoring to Control Distributed Generation

Lack of monitoring and control over distributed generation on the grid can lead to increased risks of islanding, overloading the system, and increased thermal ratings. These can be addressed through the installation of MCSs.

Currently, Toronto Hydro requires MCSs for DER installations that are equal to or greater than 50 kW. This accounts for almost 95 percent of the total DER capacity connected to Toronto Hydro's grid. This threshold ensures that Toronto Hydro has enough visibility and management of DERs to achieve the objectives of the Program at a reasonable cost.

1. Anti-Islanding Condition for Distributed Energy Resources

Islanding occurs when a DER source continues to power a portion of the grid even after the main utility supply source has been disconnected or is no longer available due to a fault condition. This can create dangerous back-feed on the distribution system, exposing workers to live circuits that they believe are de-energized. This can also interfere with grid protection systems and damage equipment after utility power is restored.

Monitoring and control can mitigate the risks associated with DER for the public and Toronto Hydro field personnel. Rule 84-008 of the *Ontario Electricity Safety Code* ("OESC") requires that DERs have back-feed protection so that in the absence of electrical power (potential) on the utility's supply, DERs cannot energize the utility's supply. If the anti-islanding feature of a DER were to fail, it would back-feed into the local distribution system. The possibility of electric shock due to this scenario would pose a safety risk to the public, Toronto Hydro field personnel, and the system in general. Active monitoring and control systems help avoid this situation by automatically issuing a remote electronic trip or shutdown command when the feeder breaker is opened.

The connection of PV solar inverters and other DER sources must be accomplished in a manner that ensures that unintentional islanding of DER sources cannot occur. Through the MCS equipment logic that reverts the Remote Terminal Unit ("RTU") contact of the remote disconnect device after loss of power from the UPS, islanding conditions are averted. Toronto Hydro plans to continue to deploy real-time monitoring and control investments proposed within this Program at new DER sites greater or equal to 50 kW as per section 3.3.3 of the DSC to provide the needed ability to address anti-islanding concerns.

One of the anti-islanding measures in the IEEE 1547 Standard for Interconnecting Distributed Resources (DR) with Electric Power Systems, section 4.4.1, recommends that a distributor ensure that "*DR aggregate capacity [be] less than one-third of the minimum load of the Local Electric Power System (EPS).*"[7] As the ratio of generation capacity to minimum load increases, the amount of time required by inverters to respond to anti-islanding scenarios also increases and the likelihood of inverters responding to anti-islanding scenarios decreases.

With the proliferation of DER in Toronto in recent years, several feeder circuits have already surpassed the generation to minimum load ratio of one-third. A total of eleven distribution feeders have ratios ranging from 0.30 to 11.51 (refer to Table 6: Existing Feeders with Generation to Load Ratio Greater Than One-Third below). These feeders currently present an increased risk of unintentional islanding conditions to the distribution system.

Table 6: Existing Feeders with Generation to Load Ratio Greater Than One-Third

Feeder Name	TS Station Name	TS Bus	DER Connected (MW) as of Dec. 2022	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
63-M6	Agincourt	Y	3.6	7.6	0.47
53-M3	Bermondsey	B	0.6	2.1	0.30
80-M10	Fairchild	Y	1.4	2.2	0.63
55-M31	Finch	J	1.8	3.6	0.48
R30-M3	Horner	B	0.8	1.7	0.45
38-M4	Manby	F	0.6	0.0	11.51
R29-M5	Rexdale	B	0.9	2.5	0.36
A-35-T	Strachan	A7A8	1.0	0.5	1.99

[7] Institute of Electrical and Electronics Engineers.

Feeder Name	TS Station Name	TS Bus	DER Connected (MW) as of Dec. 2022	Minimum Feeder Load (MW)	Generation to Minimum Load Ratio
R43-M31	Warden	J	0.8	2.4	0.35

The forecasted 516.7 MW cumulative of DER capacity anticipated by the year 2029 will further exacerbate the existing islanding risks and adversely affect Toronto Hydro's ability to safely and reliably connect additional DER to the distribution system. Monitoring and Control Systems allow Toronto Hydro to prevent concerns of anti-islanding as these give the utility the ability to remotely turn off the DER if they unintentionally island. If the generation to minimum load ratios are not addressed by proactive investments in control and monitoring capabilities, they could ultimately limit the number of DERs Toronto Hydro is able to connect to the system. These systems also provide greater visibility into the grid and allow the utility to enable more DERs to connect, as explained in section E5.5.3.3.

2. System Thermal Limits and Load Transfer Capability

Protection, monitoring and control upgrades also provide the ability to connect additional DER by ensuring system loading thresholds are satisfied. Exceeding system loading limits, as seen in Table 6: Existing Feeders with Generation to Load Ratio Greater Than One-Third, sacrifices the life of distribution equipment and can cause immediate equipment failure as mentioned earlier.

For large sized generation connections or the aggregation of small and medium sized generation connections, limiting a feeder's continuous load thermal ratings is an important operating condition. Feeder planning and operation account for the system impact when the generator is up and running as well as when the units go off-line. These thermal levels come into play with factors such as the variability of various generation sources, system load growth and the occurrence of contingencies. Simply put, the MCS equipment helps ensure that the generation is within the level that will not strain the distribution system equipment under certain conditions.

The ability to provide monitoring and control allows Toronto Hydro to monitor and mitigate the impact of thermal loading by, for example, transferring load between feeders. This enables the utility to have more visibility into actual impact and variability of DER on the system and will therefore enable Toronto Hydro to be better equipped to make more accurate planning and operations decisions regarding thermal levels.

3. Monitoring and Control Systems

Since the 2015-2019 rate period, Toronto Hydro has required and facilitated the installation of monitoring and control systems for all new DER connections greater than 50 kW. This has provided the visibility required to monitor system conditions in real time and to ensure all DER sites are de-energized in the event of a system fault. With the continued implementation of the Program, Toronto Hydro will be able to actively monitor and control DERs in real time to ensure operation within acceptable levels and that the anti-islanding feature of the DERs have properly operated in the event of a distribution system fault.

Figure three depicts the required real-time monitoring and control via utility communication networks and the supervisory control and data acquisition ("SCADA") system.

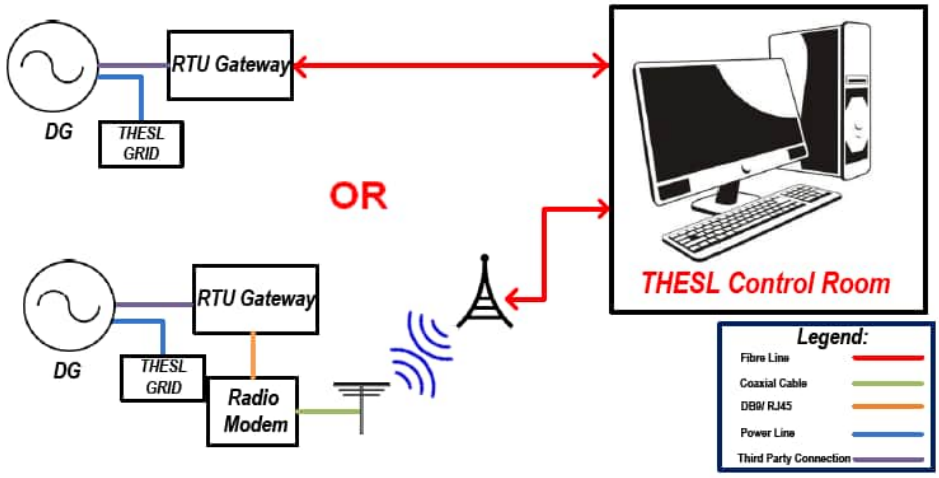


Figure 3: Monitoring and Control Interface to Toronto Hydro SCADA System

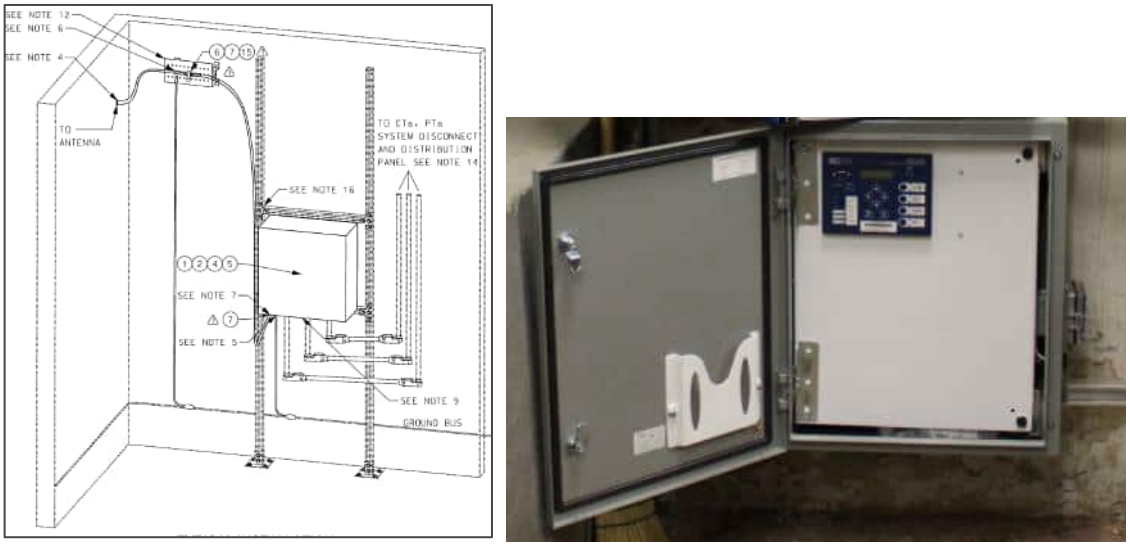
Monitoring and control also enables greater real-time visibility into the operating conditions of DER sites located in Toronto Hydro's service territory. Power system controllers need to know the aggregate generation connected to the system during planned or emergency load transfers. A power system controller must account for all DER during a load transfer because the increase in generation connected to the alternate feeder may cause short circuit capacity to be exceeded. The ability to remotely and automatically disconnect all DER sites on a feeder during planned or emergency load transfers is expected to simplify these operations as it would allow power system controllers to focus on restoration of customers' electricity rather than each individual DER site connected to a feeder.

Monitoring and control provide situational awareness into the operating conditions of all DER connected to the distribution system, which will give Toronto Hydro the ability to collect data for planning purposes and to connect additional DER sites to the distribution system. This will have additional long-term value with respect to planning for future DER connections. Currently, Toronto Hydro assesses the potential to connect a DER site to the distribution system based on estimated thermal loading values. This approach assumes that a DER site will continuously generate 100 percent of its rated capacity. This inherently limits the number of DER sites that can be connected to the system, because the conservative estimated value assumes that the thermal loading of the DER site is greater than it likely is at any given time. Monitoring and control will provide Toronto Hydro actual performance data from in-service connections for thermal loading values which will give a more precise view of existing conditions. This, in turn, will feed into DER hosting capacity analyses to automate visualization of estimated available capacity and facilitate cost-effective integration of additional DER on the distribution system. Real-time data will also serve as building blocks for expanding DER connection types through the Flexible Connections pilot concept under the Innovation Fund segment.[8]

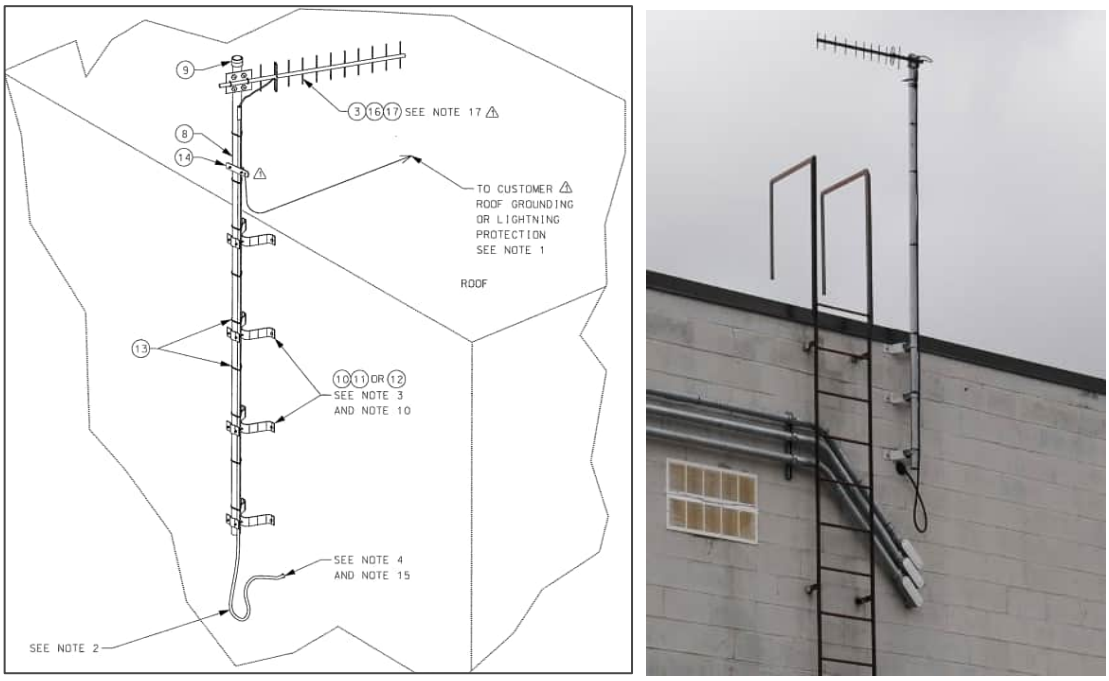
Toronto Hydro's requirement for monitoring and control is modeled after requirements developed by the IESO. The IESO has developed DER monitoring and control guidelines with a focus on visibility, dispatch and forecasting capabilities for DER sites over 5 MW. Because of the volume and capacity of DER sites in Toronto Hydro's service territory (over 304.9 MW in aggregate as of the end of 2022), monitoring and control is required to connect additional DER projects and for grid management. This is also consistent with the requirements and practices of other distributors.

Toronto Hydro's current monitoring and control process allows for the connection of DER sites through a Toronto Hydro communication interface as shown in Figure 4 below along with the standards it adheres to. Figure 5 shows a customer installation, which also adheres to Toronto Hydro standards.

[8] See EB-2023-0195, Exhibit 1B, Tab 04, Schedule 02 for Innovation Fund.



1 **Figure 4: Toronto Hydro Communication Standard for DER Connections (left) and Communication**
2 **Gateway Installed at Customer DER Site**



3 **Figure 5: Toronto Hydro Communication Antenna Setup Standard (left) and at a Customer Site**
4 **(right)**

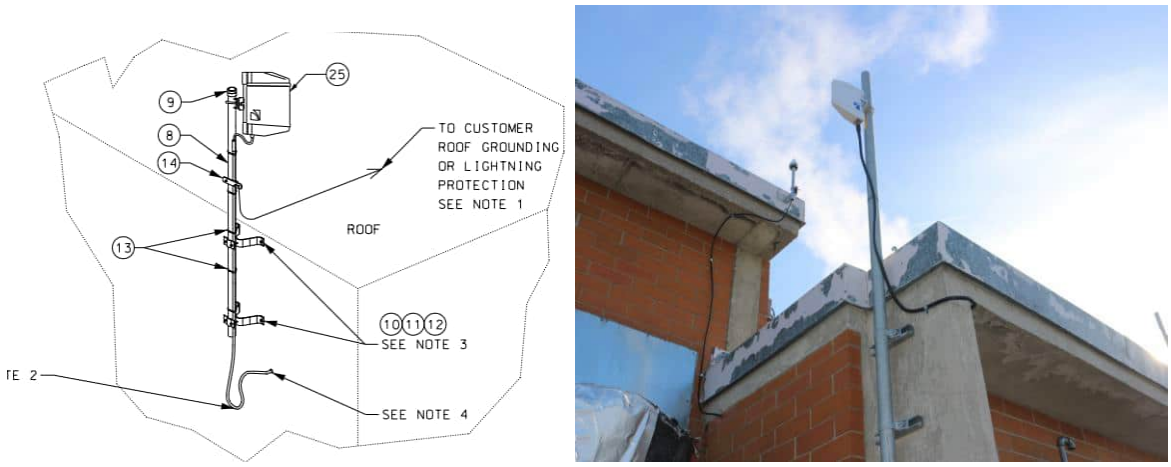


Figure 6: Toronto Hydro Alternative Type Communication Antenna Setup Standard (left) and at a Customer Site (right)

E5.5.4 Expenditure Plan

Table 4: Historical, Bridge & Forecast Program Costs ($ Millions)

	Actual		Bridge			Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Generation Protection, Monitoring, and Control	0.8	0.8	0.1	4.1	5.3	5.9	6.1	6.3	6.5	10.3

E5.5.4.1 2020-2024 Variance

1. Generation Protection

The plan for the 2020-2024 rate period was to install bus-tie reactors at five Hydro One owned and operated transformer substations (Ellesmere TS J bus, Esplanade TS A1A2 bus, Fairbank TS YZ bus, Horner TS BY bus and Sheppard TS BY bus) which Toronto Hydro anticipated would reach short circuit capacity by 2024. As of June 2023, three station busses currently need relief, and of those stations, only Sheppard TS is from the 2020-2024 forecast. These variances can be attributed to both the challenge of accurately predicting where customers will choose to install DERs, as well as a slower rate of DER renewable applications, particularly after the conclusion of the Feed-In-Tariff program and other government incentive driven DER programs (Process and System Upgrade Incentive, etc.).

After consultation with Hydro One, Toronto Hydro ruled-out Sheppard TS for a bus-tie reactor in the 2020-2024 rate period due to technical limitations imposed by the Gas Insulated Switchgear (GIS) bus. This is in addition to a proposed station expansion initiative planned in the near future.

Hydro One and Toronto Hydro carried-out a further study of various bus-tie reactor candidates, which ultimately resulted in the elimination or deferral of a number of potential projects due to technical, physical, or logistical constraints. Richview TS currently stands as the only immediate candidate for a bus-tie reactor installation in the 2020-2024 rate period as its 88-BY bus currently exceeds short circuit capacity limits and the project appears to meet Hydro One's short term feasibility criteria. Toronto Hydro will continue to collaborate with Hydro One to pursue a reactor installation at Richview in the 2020-2024 rate period. The cost associated with the procurement and installation of a bus-tie reactor is roughly estimated at approximately $3 million with actual project cost expected to differ between sites depending on location specific factors such as spacing constraints and electrical configuration, in addition to the current supply chain environment. In the event that the Richview TS station bus-tie reactor installation does not materialize in the current rate period, Toronto Hydro is forecasting it to be implemented early on the next 2025-2029 rate period.

2. Monitoring and Control

For 2020-2024 rate period, the monitoring and control segment was split into three initiatives:

a. MCS Buyback Program;
b. Antenna Installation Program; and
c. New DER Meter and RTU Issuance.

a. MCS Buyback Program

Between 2012 and 2017, there were over 400 renewable generation connections where the customer purchased and installed MCS for their facilities. Sections 3.3.2(g) and 3.3.3 of the DSC provide that utility is responsible for costs incurred related to SCADA system design, construction and connection for renewable energy generation facilities. In compliance with this obligation, Toronto Hydro undertook to reimburse those customers that had directly purchased their MCS. This process involves the negotiation of agreements to purchase the MCS and assign necessary access rights, warranties, etc., in order to facilitate Toronto Hydro's ongoing management of the MCS.

At the start of 2020, there was a total of 135 MCSs that Toronto Hydro needed to buy back from customers at an estimated cost of $135,000. Out of that total number:

- 19 have completed the buyback process;
- 18 are in the purchase agreement sign off stage; and
- the remaining 98 are in audit or deficiency rectification stages, with target completion by the end of 2024.

Note that Covid-19 pandemic related restrictions and limitations temporarily prohibited access to sites, primarily affecting site audit procedures and causing delays to program execution.

b. Antenna Installation Program

In addition to the purchase of 400+ MCS from past customers, Toronto Hydro is installing the radio communication link equipment required to facilitate the two-way communication flow between these DER facilities and the Toronto Hydro Control Centre. Installation began in 2020 and, to date, Toronto Hydro has completed installations at more than 100 sites. The program experienced some delays due to needed updates on the software security and performance settings for these assets. Revisions to installation standards were also required in order to allow new optimal equipment to be installed and connected based on site specific requirements (Antenna type, Modem type, Mounting provision changes, etc.). In addition, the hardware has been updated to LTE technology which is the 3rd iteration from the former GE SD9 and GE Orbit radio modems. Toronto Hydro is mitigating the risk of scope ambiguity going forward by developing a new RFP that provides greater clarity on scope of work requirements. This program is expected to continue past the 2020-2024 rate period and into the 2025-2029 rate period which would cover newer installations as well.

c. New DER Meter and RTU Issuance

The forecast for new M&C equipment for 2020 to 2022 was 31. There were 26 units ordered.

E5.5.4.2 2025-2029 Forecast

Based on current DER forecasts, the Program is projected to cost $35.0 million over the 2025 to 2029 period.

Table 8: Forecast Program Costs ($ Millions)

	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
Generation Protection - Bus Tie Reactor	3.2	3.3	3.4	3.5	7.1
Generation Protection - Monitoring and Control	2.6	2.8	2.9	3.0	3.2
Total	**5.9**	**6.1**	**6.3**	**6.5**	**10.3**

1. Bus-Tie Reactors

Toronto Hydro regularly monitors short circuit capacity trends to identify where constraints may emerge. Based on current information, Toronto Hydro anticipates that eight stations will require relief by the end of 2029. Ellesmere TS can be addressed at no cost by increasing fault limits. Sheppard TS will be addressed through planned expansion work. Bus tie reactors will be required to mitigate short circuit capacity limitations at the remaining six transformer stations at a cost of $20.4 million.

Toronto Hydro plans to begin the design and construction of the first reactor in 2025 and complete installations of six reactor by 2029.

Table 9: Bus Tie Reactor Installations Cost and Installation Schedule ($M)

Station Name	Bus	2025	2026	2027	2028	2029	2025-2029
Richview	88-BY	3.2					
Runnymede	11-JQ		3.3				
Cecil	CE-A1A2			3.4			
Esplanade	X-A1A2				3.5		
Leslie	51-BY					3.5	
Woodbridge	D6-BY					3.6	
Total		**3.2**	**3.3**	**3.4**	**3.5**	**7.1**	**20.4**

Bus-tie reactor installations will occur in accordance with Hydro One feasibility studies. Hydro One will assess station space constraints, station operation disruption, and overall project viability for each site.

2. Monitoring & Control ("MCS")

Pursuant to sections 3.3.2(g) and 3.3.3 of the DSC, Toronto Hydro is required to bear the costs related to communication systems (i.e. MCS) to accommodate the connection of renewable energy

generation facilities. For all non-renewable energy generation facilities, the customer is responsible for costs relating to the MCS.

The timing and pacing of the installation of MCSs is driven by customer requests to connect DER to the distribution system. The estimated costs of the installation of MCSs over the 2025 to 2029 period at $14.5 million is based on forecasted DER connections as discussed above in section 5.5.3.1. The equipment and installation costs associated with the integration of a DER site into Toronto Hydro's SCADA system is approximately $25,000 and is based on historical DER MCS installations**.**

E5.5.4.3 Project Prioritization

The Program is driven by customer requests to connect DER to the distribution system and as such, are prioritized on a first come, first served basis. DER customer timelines and deadlines are considered to minimize disruptions and allow for efficiencies, whenever possible.

E5.5.4.4 Cost Management

Toronto Hydro continuously evaluates the selection of bus tie reactor projects to ensure investment is in the appropriate areas. For example, the utility re-evaluates station bus short circuit levels after each new connection application is received for that bus. Connection Impact Assessments ("CIA") are performed for each new DER and are the basis for determining if buses require short circuit relief.

Toronto Hydro is also regularly engaging with Hydro One and is made aware of future station transformer upgrades that could relieve short capacity constraints.

For both segments, variance analyses will also be performed to identify areas for improvement and future cost management.

E5.5.5 Options Analysis

E5.5.5.1 Option 1: Do Nothing

Under this option, Toronto Hydro does not install any bus tie reactors or MCSs. DER connections would continue to occur on parts of the distribution system where they could be accommodated, up until the point where technical limitations are reached. This option will increase the number of DER application rejections and reduce reliability as Toronto Hydro would reach its operational and system

design limits which would potentially make the distribution system sensitive to fault conditions with a reduced safety buffer.

Additionally, the inability to have situational awareness and a more precise view into the operating conditions of DER that could impact the grid (through the installation of MCSs), would reduce the utility's capacity to connect additional DER facilities to the distribution system in the future. Failure to connect renewable DER facilities to the Toronto Hydro distribution system would result in non-compliance with the requirements of Toronto Hydro's distribution license, the DSC and *the Electricity Act*, *1998*. As mentioned per Section 6.2.4 of the DSC, and sections 25.36 and 25.37 of the *Electricity Act, 1998* Toronto Hydro is obligated to connect DER customers to its distribution system. Toronto Hydro is also obligated under section 6.1 of its Distribution License and section 26 of the *Electricity Act, 1998* to provide generators with non-discriminatory access to its distribution system. To comply with these obligations, Toronto Hydro evaluated two alternatives (major asset upgrades and the Generation Protection, Monitoring, and Control program) for addressing the system constraints that currently limit the utility's ability to connect the growing demand for DER on the system and safely and reliably manage DER connected to the distribution system.

Without active monitoring of DER facilities, there is an increased risk of unintentional islanding and unintentional back-feed that could have an adverse effect to the grid from DER sources thus reducing reliability on the system. This presents an increased risk to Toronto Hydro linespersons as they will be exposed to back-feed situations. Therefore, Toronto Hydro does not recommend this option.

E5.5.5.2 Option 2 (Selected Option): GPMC Program

The GPMC Program is the preferred alternative, as it is a much more timely and cost-effective solution and would allow for the continued integration, expanded visibility, and monitoring and control of DER connected to the Toronto Hydro distribution system.

In addition, Toronto Hydro expects that the program's solutions will enable prediction of the amount of generation produced by DER connected to the distribution system, a capability that is not currently available to system planners. With performance data gathered through the Generation Protection, Monitoring, and Control program, Toronto Hydro will be able to make better informed decisions on the design and operation of the distribution system. The program would better prepare Toronto Hydro to deliver on commitments to help customers electrify quicker and easier by optimizing use of existing infrastructure.

The program would further advance the Toronto Hydro mandate to facilitate DER connections by directly alleviating technical barriers to connecting DERs, particularly renewable energy sources and energy storage systems, by investing in additional hosting capacity through the installation of bus-tie reactors on Toronto Hydro TSs identified to have short circuit constraints.

The overall cost of this option is $35.0 million over the 2025-2029 rate period.

E5.5.5.3 Option 3: Major Asset Upgrades

As an alternative to the work planned within the Program, Toronto Hydro could address DER requirements via major asset upgrades at transformer stations where short circuit capacity constraints exist. Assets to be upgraded include power transformers and switchgear. Monitoring and control equipment would also be installed as part of this option. However, with a cost of roughly $19M per switchgear upgrade, not to mention complex coordination of outage and feeder transfers, this would be an uneconomical and impractical approach to enabling incremental DER hosting capacity on the system.

E5.5.6 Continuous Improvement and Productivity

With the implementation of MCS, Toronto Hydro will have access to real time data for all generation sites greater than 50 kW. The information obtained from the MCS and the Energy Monitoring and Control Capabilities can be integrated with distribution system analysis software to produce simulations and reports in a more timely, accurate and efficient manner. This would result in CIA's being completed within the prescribed time at a higher rate. In addition, cellular communication would be the communication medium to be utilized long term using similar architecture of the current radio antenna. This would increase the communication bandwidth for DER telemetry for more precise readings through an increase in communication frequency.

For the bus-tie reactor program, continued emphasis to find the most optimal approach for implementing the reactor installation to increase DER enablement is to be performed. This would be done through fault analysis studies within the on-going coordination initiatives with Hydro One.

MCS assets have the added benefit of integrating with Toronto Hydro's DERMS platform, Energy Centre, to perform real-time coordination and control of DER assets to capitalize on resource management. The RTU embedded within the MCS plays a key role in the integration of other smart grid assets such as smart inverters and microgrids that are detailed in the Non-Wires Alternatives

program. Finally, as DER penetration begins to densify on parts of the grid, the communication infrastructure will be crucial to enable aggregation and scalability of DER control from feeder to bus level and beyond.

E5.5.7 Execution Risks & Mitigation

The forthcoming HONI feasibility study for bus-tie reactors could reveal station limitations that deem the reactor installation implausible in certain locations. In these cases, Toronto Hydro will explore other potential short circuit constraint mitigation interventions (e.g. split-bus configuration schemes) before ruling out the possibility of station-level hosting capacity relief in the near-term.

With respect to the Monitoring and Control segment, communication infrastructure (i.e. radio network) may need to be expanded or upgraded to handle a high volume of DER connections. Toronto Hydro is in the process of migrating most of its communication infrastructure to IP based equipment. This would bring about changes to hardware in place and an upgrade program has to be implemented to accommodate such.

Global supply chain shortage would also be another factor that might affect the timeline for execution of both the MCS and bus-tie reactor segments. Engaging vendors early and often to provide the necessary equipment would be key to managing the current delay from manufacturers.

E6.1 Area Conversions

E6.1.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 207.6	**2025-2029 Cost ($M):** 236.7
Segments: Rear Lot Conversion, Box Construction Conversion	
Trigger Driver: Functional Obsolescence	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Customer Focus	

The Area Conversions program ("the Program") funds the replacement of legacy 4.16 kV distribution system designs with updated standard 13.8 kV and 27.6 kV lines, focusing on two unique functionally obsolete 4.16 kV systems known as Rear Lot Construction and Box Construction. These systems serve residential customers in the Horseshoe region, and small commercial and residential customers in the downtown area. The Program is designed to address below-average customer reliability outcomes, mitigate public and employee safety risks, and overcome other operational and customer service deficiencies posed by these legacy and aging systems.

This Program is grouped into the following segments and it is a continuation of the renewal activities described in Toronto Hydro's 2020-2024 Distribution System Plan ("DSP").[1]

- **Rear Lot Conversion:** this segment continues the replacement of functionally obsolete distribution system designs, installed in the backyard, or rear lot, with standard front lot underground supply. Typically installed over 50 years ago, these assets serving residential customers in the Horseshoe region of Toronto feature below-average reliability outcomes for customers, safety concerns for crews and the public, and other operational and customer service deficiencies. Toronto Hydro is on track to successfully upgrade approximately 683 rear lot customers to front lot 27.6 kV underground services during the 2020-2024 rate period. Toronto Hydro's overall objective for this segment is to prevent rear lot equipment failure risk from worsening, as failures are likely to result in long duration outages and ongoing safety risks to customers and crews from rear lot plant. To this end, Toronto Hydro plans to invest $120.6 million to convert 1,467 customers between 2025-2029, an increase

[1] EB-2018-0165, Exhibit 2B, Section E6.1.

in pacing that reflects an observed increase in the number of assets past useful life on the rear lot system since 2014.

- **Box Construction Conversion:** a continuation of Toronto Hydro's plan to eliminate aging 4.16 kV box construction feeders from the pre-amalgamation City of Toronto. These overhead feeders are located along main streets in the downtown area and serve residential and small commercial customers. Toronto Hydro no longer builds the system to this standard due to safety compliance, reliability, access, equipment, capacity, and procurement issues. The congested box-like framing of the circuits prevents crews from establishing safe limits of approach to live conductors, which in turn restrict operations and leads to longer power restoration times when compared to modern overhead standards. During the 2020-2024 rate period, Toronto Hydro expects to convert a total of approximately 3,368 poles from the legacy 4.16 kV to the standard 13.8 kV overhead system, which will remove an estimated 680 box-framed poles from the system. Toronto Hydro is planning to spend $116.1 million to continue conversion of the remaining box construction areas over the 2025-2029 rate period, prioritizing the removal of the last 344 box-framed poles by 2026 to eliminate the various safety and reliability risks these assets present to employees and the public.

Toronto Hydro plans to invest $236.7 million in the program in the 2025-2029 rate period, which is a 14 percent increase over projected 2020-2024 spending (including forecasted inflation). This pace of investment is necessary to mitigate the reliability and the safety risks of these functionally obsolete systems.

E6.1.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Eliminating the risk of long (i.e. 5 to 24+ hours) rear lot outages for an estimated 1,467 residential customers in the worst performing rear lot areas. ○ Improving average outage restoration times for 15,246 residential and small business customers downtown by eliminating the remaining 344 box-framed poles from the system.

Operational Effectiveness - Safety	• Contributes to public safety performance and employee safety by mitigating safety risks that are unique to obsolete rear lot and box construction systems. Specifically: ○ Eliminate safety risks to address compliance issues (i.e. relating to Electric Utility Safety Rule 129 - safe limits of approach, Canadian Standards Association and Electrical Safety Authority) associated with legacy box construction feeders by replacing remaining box construction assets. ○ Increase the pace of rear lot conversion investment in order to better manage the increasing risk of equipment failure and subsequent safety issues arising from crew access and public exposure to rear lot access.
Customer Focus	• Contributes to Toronto Hydro's customer service performance and customer satisfaction by: ○ Minimizing the need for unplanned crew access to customer property by converting approximately 1,467 residential rear lot customers to front lot service. ○ Improving the speed and cost-efficiency of customer grid access (including for generation and electric vehicles) in high-growth areas of downtown Toronto by converting approximately 1,681 poles from 4.16 kV to 13.6 kV. ○ Reducing public traffic disruptions on main city streets from an operational and maintenance perspective (i.e. less frequent repairs and visits) once the box construction is converted.

E6.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Functional Obsolescence
Secondary Driver(s)	Reliability, Safety, Capacity

This Program addresses distribution assets with legacy design features that result in substandard reliability performance for customers, safety risks for crews and the public, capacity constraints for the system and other undesirable outcomes. For these reasons, Toronto Hydro consider these assets to be functionally obsolete.

The risk of failure increases as these assets age and deteriorate. Hence, Toronto Hydro prioritizes these assets for replacement in order to maintain acceptable reliability outcomes and mitigate exposure to safety risks.

Rebuilding these systems on a like-for-like basis is not a viable option due to the substandard performance, material availability, compatibility issues and safety risks inherent to the existing designs. Furthermore, Toronto Hydro is gradually phasing out its 4.16 kV distribution system in favour of the more efficient 13.8 kV and 27.6 kV systems, which are also better suited to efficiently handle urban growth and development in the City of Toronto.

The following sections provide more detailed information about the drivers of work in the Rear Lot Conversion and Box Construction Conversion segments.

E6.1.3.1 Rear Lot Conversion

The Rear Lot Conversion segment is a continuation of Toronto Hydro's plan to convert and re-supply rear lot customers with underground front lot services. As illustrated in Figure 1 below, the replacement front lot design supplies customers through lateral underground 27.6 kV primary circuits along the roadways with predominantly padmounted transformers. Once customers are connected to the improved configuration, all former rear lot assets are removed to eliminate any existing safety risks.



Figure 1: Legacy Rear Lot Supply vs. Replacement Front Lot Supply.

Rear Lot Conversion is necessary to address reliability and safety risks that are caused or exacerbated by poor accessibility and physical encroachments inherent to the existing rear lot plant location.

1. Rear Lot Reliability Issues

Rear lot plant was generally built in the 1960s and a large portion of these assets are operating beyond their useful lives. As the plant ages, the risk of outages caused by equipment failure increases. Notably, rear lot plant consistently experiences longer duration outages than the average Toronto Hydro feeder (as illustrated in Figure 2 below), primarily due to the difficulty crews face in locating faults and safely accessing and repairing equipment.

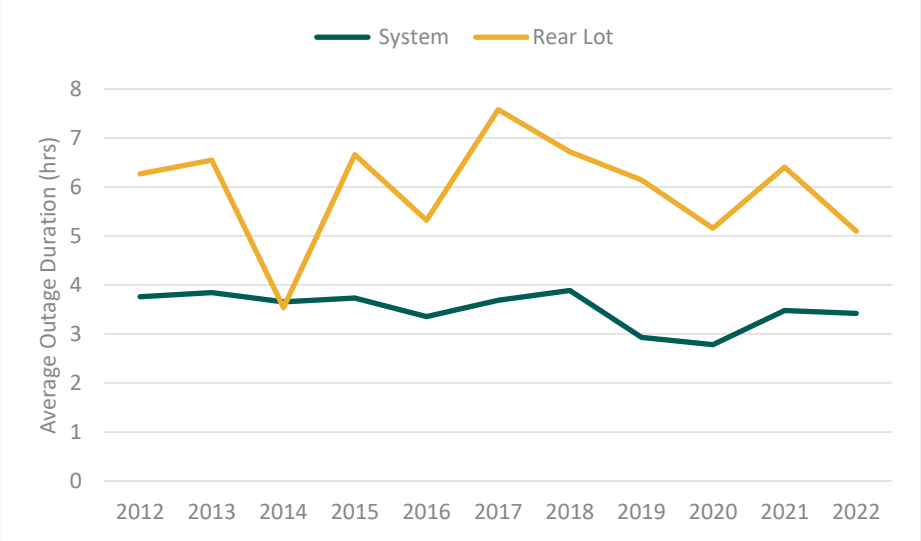


Figure 2: Average Outage Duration Excluding Major Event Days ("MEDs"): Rear Lot vs. All Feeders

On average, over the 2012-2022 period, outages on rear lot feeders were 2.5 hours longer than outages on the system as a whole.

Over the long term, by limiting and reducing the volume of end-of-life rear lot assets, Toronto Hydro aims to prudently manage the safety and reliability risks associated with their failure. The average age of the rear lot distribution is already higher than the useful life expectancy of 50 years for most assets. This average age continues to grow rapidly when compared to the rate of conversion, increasing failure risk. It is estimated that by 2029 the average age of the remaining rear lot system will surpass 60 years.

Figure 3 below shows the growing number of customers that will be served by increasingly aged rear lot plant if not addressed.

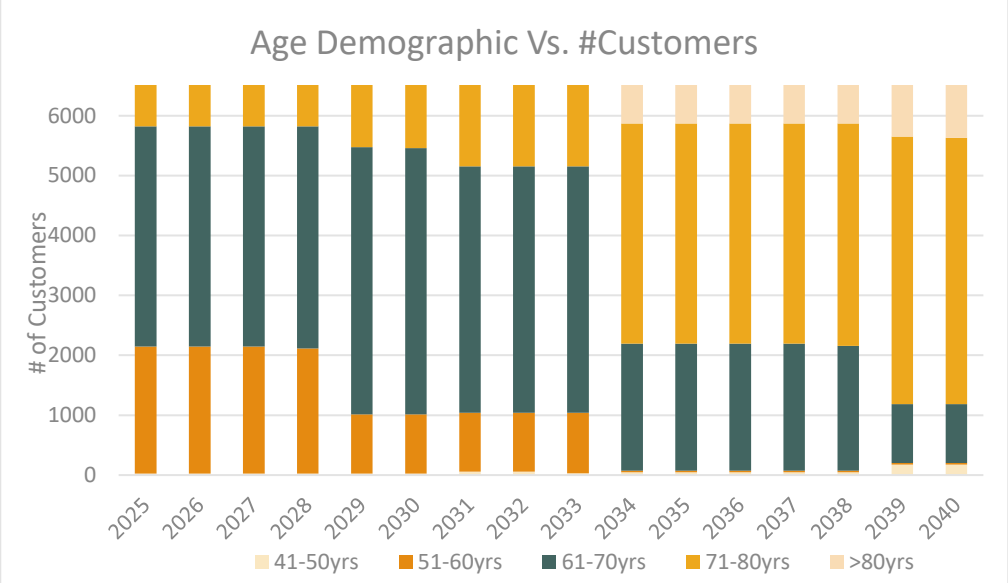


Figure 3: Rear Lot Age Demographic and Number of Customers Supplied

The relatively poor performance of Toronto Hydro's rear lot distribution system is further demonstrated by the number of incidents resulting in loss of service to rear lot customers for at least one day. The location of the infrastructure (i.e. in backyards, often in close proximity to trees, swimming pools and vegetation), and its deteriorating condition make rear lot distribution plant particularly vulnerable during storms and other severe weather events. Furthermore, Toronto Hydro's primary assets in rear lot areas are attached to poles that are predominantly owned by a third-party company, i.e. Bell, making it more difficult for Toronto Hydro to perform maintenance and reactive work to maintain these assets in good condition. Table 4 below contains examples of outages longer than 24 hours in duration that have occurred in rear lot areas. In all cases, accessibility challenges contributed to prolonged outage durations. Many outages on rear lot feeders greatly exceed five hours, as shown in Table 4 below. Toronto Hydro's recent customer engagement demonstrated that reliability, in particular reducing restoration time in extreme weather, is a top priority for residential customers.

Table 4: Long Duration (at least 24hrs) Events on Rear Lot Areas

Date	Station	Feeder	Cause	Duration (hrs)	MED[2] (Y/N)
01-Jun-12	*SCARBOROUGH WEST TS*	NAE5-2M3	WIND EXTREME / ADVERSE WEATHER	25.4	N
19-Jul-13	*BLACKFRIARS MS*	VCF1	WIND EXTREME / ADVERSE WEATHER	44.6	N
19-Dec-13	*LONGFIELD MS*	BHF1	WIND EXTREME / ADVERSE WEATHER	34.5	N
28-Aug-13	*SCARBOROUGH WEST TS*	NAE5-2M3	FREEZING RAIN EXTREME / ADVERSE WEATHER	26.6	N
05-May-17	*ALBION MS*	MGF1	CABLE - PRIMARY / DEFECTIVE EQUIPMENT	26.3	N
04-May-18	*LONGFIELD MS*	BHF1	WIND EXTREME / ADVERSE WEATHER	72.2	Y
05-May-18	*OBERON MS*	UEF3	WIND EXTREME / ADVERSE WEATHER	25.0	N
06-Nov-18	*DELAMERE MS*	PFF3	CABLE - PRIMARY / DEFECTIVE EQUIPMENT	24.4	N
11-Jan-20	*MILL MS*	LFF2	RAIN EXTREME / ADVERSE WEATHER	28.2	N
08-Jul-20	*CHAPMAN MS*	EBF1	RAIN EXTREME / ADVERSE WEATHER	24.0	Y
21-May-22	*WARDEN TS*	NAR43M23	ADVERSE WEATHER / TREE CONTACTS	53.1	Y
21-May-22	*OBERON MS*	UEF2	ADVERSE WEATHER / TREE CONTACTS	49.1	Y
21-May-22	*DALEGROVE MS*	RCF1	ADVERSE WEATHER / TREE CONTACTS	49.1	Y

Rear lot reliability issues are caused by the obsolete design of the plant and the challenging environment in which it operates. As an example, Figure 4 below shows the Jamestown residential rear lot area which Toronto Hydro is upgrading over the 2020-2024 rate period. The primary lateral, shown in red, branches off of the main feeder circuit, enters the neighbourhood in between two

[22] Major Event Day.

houses, and is subsequently routed between the rear of residential properties. The secondary circuit, shown in green, branches off and crosses customer properties to the meter base supplying each residence.



Figure 4: Lateral Circuit Configuration - Jamestown former Rear Lot Neighbourhood

Outage restoration issues stem from the following factors, which are common to rear lot areas such as the one depicted in Figure 4:

- **Manual fault detection:** the vast majority of rear lot feeders operate at 4.16 kV and therefore lack fault detection and isolation technologies such as Supervisory Control and Data Acquisition ("SCADA")-mate switches that are standard in up-to-date distribution systems.

- **Accessibility/Visibility:** in a typical rear lot area, poor access and visibility exacerbate a fault situation, contributing to prolonged outages and inefficient use of resources during fault location and outage restoration. Limited access can restrict the use of standard equipment such as bucket trucks, drilling machines and other machinery and implements. This means that heavy materials such as poles and transformers must be manually carried or even hoisted over the residence by crane. For overhead feeders, specialized reactive crews are needed to physically climb the poles during repairs. For underground feeders, crews must manually dig trenches to repair direct-buried cables.

- **Obstructions:** spatial constraints like trees and fences may prevent crews from walking on an uninterrupted path along the feeder to locate the fault, forcing them to enter multiple residential backyards along the circuit. Once the fault is located, crews often face the difficult task of repairing the fault and restoring service while being mindful of a customer's private property and compliance with electrical safety regulations. For instance, Figure 4 shows the presence of mature trees and swimming pools in the vicinity of Toronto Hydro plant.

- **Non-standard equipment:** the top left area of Figure 4 shows the location of obsolete T-splices (used to split underground distribution circuits). Any outage downstream of a T-splice will affect all customers on the main branch circuit. This is not the case in modern power system design where fuses prevent this undesirable outcome.

The Jamestown area further demonstrates the extent to which reliability can be an issue for rear lots with 23 outages over 2012-2021, the majority of which lasted longer than five hours. This level of service would be considered unacceptable to most customers. Toronto Hydro is rebuilding and upgrading the Jamestown area over the current rate period and reliability has already showed some improvement, with no outages in the areas already converted in 2021 and 2022. Figure 5 below shows the number and duration of outages in the Jamestown area from 2012 to 2022 along with progress made in converting customers (i.e. decrease in rear lot customer count) in the area.

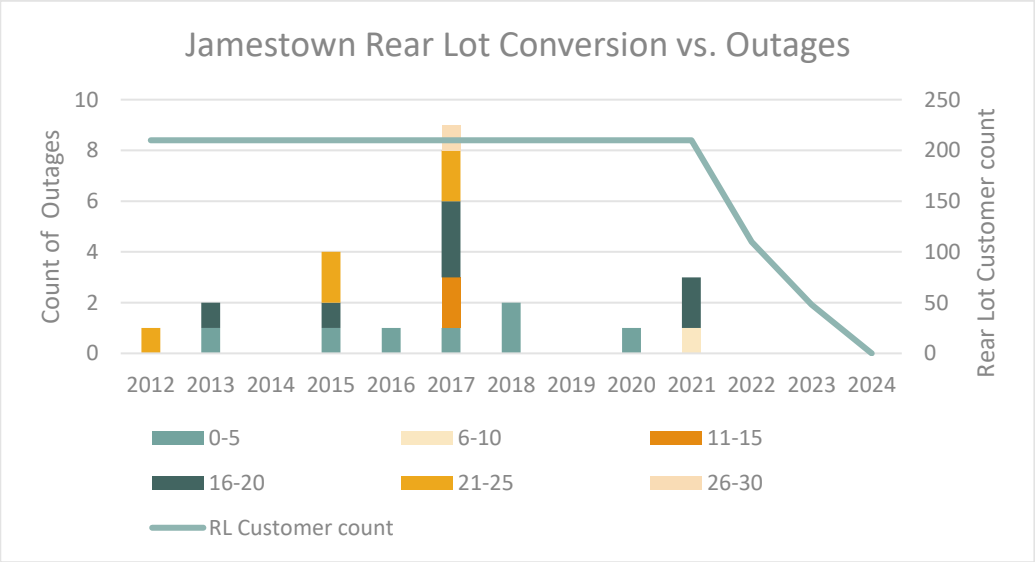


Figure 5: Jamestown Neighbourhood Rear Lot Customer Count and Outage Frequency by Duration

In rear lot areas, 82 percent of the poles have surpassed their useful life and 64 percent of the poles with available asset condition assessment information are showing moderate to material deterioration. Furthermore, 59 percent of the poles in rear lot areas are owned by a third-party company, for which Toronto Hydro has no condition data and it is more difficult for Toronto Hydro to access to perform maintenance and reactive work when required. Table 6 shows the breakdown of Toronto Hydro-owned rear lot poles by asset condition category.

Table 6: ACA Comparison of Toronto Hydro-Owned Rear Lot Poles

Pole Asset Condition Class	% of Assets per Class (2022)
HI1 – Good Condition	28%
HI2 – Minor Deterioration	4%
HI3 – Moderate Deterioration	30%
HI4 – Material Deterioration	27%
HI5 – End of Life	7%
ACA Data Unavailable	3%

Converting an entire rear lot area is a complex and lengthy undertaking that must be carefully sequenced and executed over multiple years. Given the amount and age of the remaining plant, it is necessary for Toronto Hydro to start increasing its pace of proactive Rear Lot Conversion, while prioritizing those areas that are experiencing the worst reliability performance.[3]

Toronto Hydro has ranked feeders according to their reliability performance. The following 'heat map' (Figure 6) shows all rear lot outages from 2012-2022 with dots representing a recorded outage in the rear lot area. The circles overlapping the dots in the chart indicate feeders which have been targeted for conversion in the 2025-2029 rate period. The proposed Rear Lot Conversion plan will continue to address those areas where customers are experiencing the worst service.

[3] Note that Toronto Hydro must ensure that areas that have already been started are fully completed before moving to a new neighborhood, even when those areas are showing temporary reliability improvements due to the partial conversion.

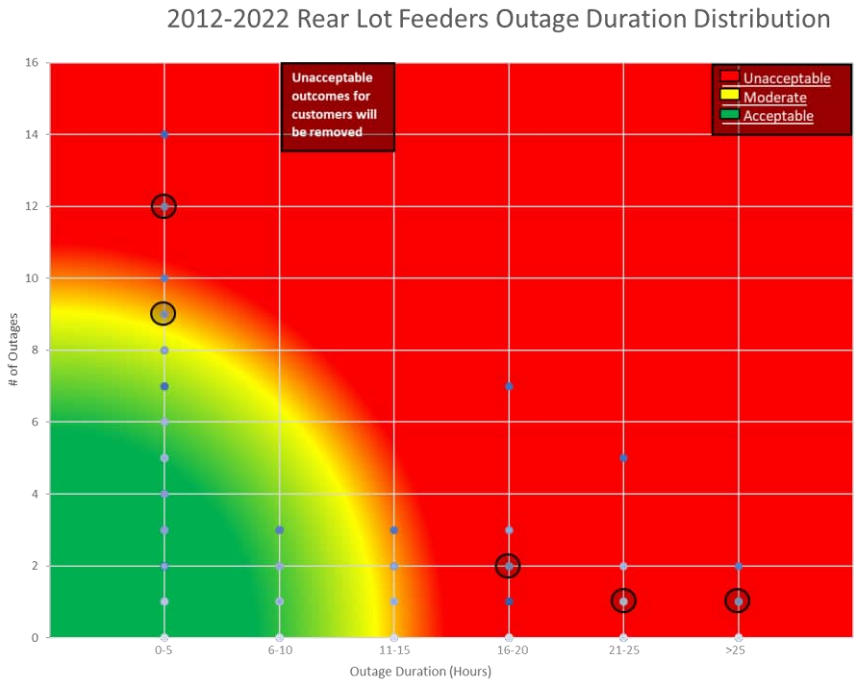


Figure 6: Heat Map of All 2012-2022 Rear Lot Outages

2. Rear Lot Safety Issues

Equally important in the Rear Lot Conversion segment is the need to prudently manage safety risks to crews and the public. These risks are generally caused by the same operational factors and field conditions that contribute to long-duration outages on the rear lot system.

As mentioned above, as assets age and deteriorate, the risk of failure increases along with the likelihood that Toronto Hydro crews will need to access and repair rear lot equipment on a reactive basis. The congested nature and location of rear lot poles means that most cannot be accessed safely using bucket trucks. Workers must instead climb these poles, increasing the risk of potential injury from the additional physical exertion and falling hazard compared to when using a bucket truck, as well as an increased risk of electrical contact due to lack of bucket truck safety mechanisms (insulated aerial boom and bucket liner). Other potential safety risks associated with rear lot plant are:

- tight work spaces and reduced clearances for worker to operate equipment;
- poor visibility at night;
- poor footing in the winter;

- the need to manually transport equipment to poorly accessible job sites;
- the need to climb poles that may be in poor condition due to rot, animal damage, or other environmental factors and may require additional stabilization; and
- obstacles (e.g. fences, sheds, and swimming pools) and clearances between Toronto Hydro's distribution equipment and customer property that do not meet minimum requirements.

An incident demonstrating these safety risks occurred in 2014. Toronto Hydro dispatched a two-member crew following notification of a fallen tree at the rear of a house that had a steep slope covered with snow and ice. One crew member walked up the slope to locate the cable attachment and slipped and injured his right elbow and hip. The following pictures (Figure 7) show similar examples of safety challenges faced by Toronto Hydro crews.



Figure 7a: Field crews replacing failed transformer on pole in poor condition



Figure 7b: Poor condition pole in close proximity to swimming pool

In addition to access issues, mature tree canopy cover (which sometimes requires immediate trimming on site) and poorly constructed landscapes can cause visibility issues in rear lots. Other than contributing to extended outage durations, reduced visibility is a safety concern for crews executing electrical work in locations that do not comply with (e.g. clearances defined in) the Electrical Utilities Safety Rules ("EUSR") rule 129, and applicable standards of the Canadian Standards Association ("CSA"), Toronto Hydro, and the Electrical Safety Authority ("ESA") (e.g. ESA Rule 75-708). The need to manage crew safety risk is one of the primary reasons that Toronto Hydro needs to minimize the aggregate risk of rear lot asset failure.

Public safety is also a key consideration in respect of the Rear Lot Conversion segment. Rear lot assets installed in the 1960s do not adequately account for access needs related to modern growth of neighbourhoods, expansions of homes and live line clearances. Locations have been identified where live wires are in close proximity to customer homes, sheds, fences, and swimming pools. Exposed wires have also been found at riser poles that have been deteriorating or moved over time due to direct contact. Furthermore, when a pole deteriorates or leans, a transformer leaks oil or catches fire, or porcelain insulators break, the safety risk to the public increases when installations are in proximity to those structures. Figures 8 and 9 illustrate some of these issues.



Limits of Approach

1. Rear lot overhead poles, transformers, and live conductors in close proximity to physical properties
2. Obsolete 4.16kV transformers
3. Aged and tilted cross arms and leaning poles
4. Mature vegetation. trees and vines present risk of contact
5. Transformers are typically mounted lower on the poles, in line with windows. If a transformer were to catastrophically fail it may be a hazard to the public or protrude into windows

Figure 8: Energized transformer and pole line close to home and covered in vegetation



Figure 9: Primary conductor and assets near swimming pools

3. Other Rear Lot Issues

The majority of feeders with rear lot areas are operating at 4.16 kV. Toronto Hydro is gradually converting all of these feeders to the standard 27.6 kV and rear lot conversion is an important component of this plan. In many cases, the rear lot area of a feeder must be converted before any other renewal conversion is possible, therefore it essential that the rear lot conversion is paced at a sufficiently rapid rate to enable conversions.

In addition to enabling the introduction of fault detection and isolation technologies like SCADA-mate switches, which are lacking on 4.16 kV feeders, converting to 27.6 kV is expected to:

- enhance power quality with less voltage drop for customers at the end of distribution lines;
- reduce line losses, improving the efficiency of the distribution system;
- modernize the system in order to prepare for the demands of electrification, growth, and the proliferation of distributed energy resources ("DERs") that 4.16 kV feeders cannot accommodate; and
- enable the eventual decommissioning of Municipal Stations, avoiding operating and maintenance expenditures that would otherwise be incurred.

Box Construction Conversion

The Box Construction Conversion segment is a continuation of Toronto Hydro's plan to convert functionally obsolete 4.16 kV feeders with box-framed poles to the latest standard 13.8 kV armless construction. Box construction is a legacy 4.16 kV overhead design. Due to safety, reliability, access, equipment, capacity, and procurement issues, Toronto Hydro no longer builds the system to this standard. As discussed in detail below, safety compliance issues drive the need to eliminate box construction from the system as quickly as practical. Figure 10 below shows the prior, during, and post-construction pictures of two converted box construction locations on Gerrard Street East.



Figure 10: Actual box construction conversion project on Gerrard Street East at two locations. Photographs on the left show 4.16 kV box construction poles prior to conversion. Photographs in the middle are demonstrating the in-construction stage. The completed project is shown in the photographs on the right, where all 4.16 kV box construction has been removed.

4. Box Construction Safety Issues

The industry-wide practice for overhead pole maintenance is to access circuits using bucket trucks. However, the congested nature of obsolete box construction design means that most box construction circuits cannot be accessed safely in this manner. Instead, workers must climb these poles, which increases the safety risks they face. Such risks include potential injury from the additional physical exertion from climbing, an elevated falling hazard when compared to the use of a bucket truck, and an increased risk of electrical contact due to the inability to use the insulated aerial boom and bucket liner found on the bucket trucks.

Furthermore, Toronto Hydro crews working in close proximity to box construction lines can have difficulty conforming to the working clearances defined in EUSR Rule 129.[4] The required 15-centimeter air gap between people (or tools) and energized conductors cannot always be achieved. Compliance with these safety rules requires adjustments to normal work operations, such as maneuvering around poles in a bucket truck and closing off road access to multiple poles. This in turn contributes to the lengthy outage restoration times discussed below.

Similar to rear lot lines, some box construction lines also fail to comply with applicable clearance requirements resulting in potential safety risks to the public. Live wires have been found in close proximity to customer homes, windows and balconies. Some buildings are within two to three metres of live lines due to the legacy design parameters of box construction. This issue must be addressed by replacing box construction with updated standard 13.8 kV construction as part of plant renewal. As a visual example, Figure 11 below illustrates some box construction clearance issues.



Limits of Approach

Box Construction poles house conductors with wide cross-arms which cause conductors to be spaced further away from poles and closer to buildings and windows compared to armless construction standards. This photo shows a few of the many issues associated with the obsolete design of box construction:

1. Close proximity of live lines to public and public structures due to the physical properties of the box frame.
2. Aged and tilted cross arms and leaning pole.
3. Transformers are typically mounted lower on the box poles, in line with windows. If transformers were to catastrophically fail, it may cause the windows to break and endanger the public.

Figure 11: Example of Box Construction clearance issues

5. Box Construction Reliability Issues

The existing box construction plant is on average 39 years old and is a poor reliability performer relative to the system as a whole. Despite a steady decrease in the total box construction plant

[4] Electric Utility Safety Rule 129 - safe limits of approach, Canadian Standards Association and Electrical Safety Authority, Page 34, "online", https://www.ihsa.ca/PDFs/Products/Id/RB-ELEC.pdf.

remaining over the last 10 years, there has not been a corresponding decrease in the total number of outages on box construction feeders (87 outages over 2013-2017 versus 88 over 2018-2022, excluding MEDs). The top causes of these outages include defective equipment, tree contacts, and adverse weather. Box construction assets are less capable of withstanding strong winds than new 13.8 kV overhead feeders in the downtown area as these assets are aging and deteriorating.

Box construction feeders also tend to require longer restoration times than feeders built to current standards, as shown in Figure 12. The reasons are similar to those that result in longer outages in the rear lot, including: the need for manual fault location; clearance, access and safety issues that slow down operations; and during reactive equipment replacement, the need to integrate newer standard equipment in a unique configuration that is compatible with the existing box construction design.

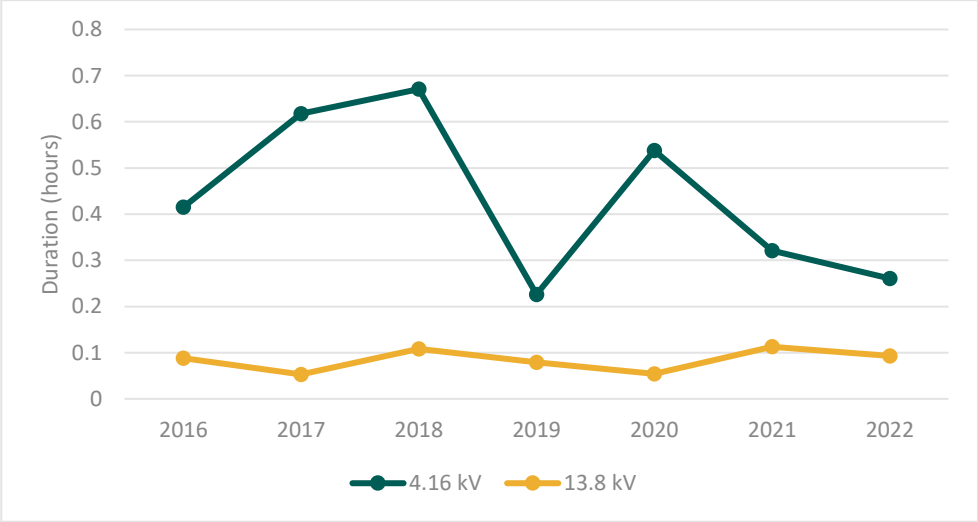


Figure 12: Average Outage Duration per Customer for 4.16 kV (Box Construction) and 13.8 kV Systems Excluding MEDs

Toronto Hydro expects reliability to worsen further as assets continue to deteriorate. Table 7 below shows the percentages of conductors, poles and switches that have already reached or exceeded their useful life. While the proportion of poles at or past useful life is fairly modest at 13 percent (as of 2022), by the end of 2023 another 17 percent will have also reached useful life. Furthermore, when considering the subset of poles that pose the most risk – i.e. those that are box framed – the percent at or past useful life has already reached 60 percent.

Table 7: Percentage of Box Construction Assets at or Past Useful Life

Asset Type	Percentage (%)
Overhead Primary Conductors	56%
Switches	36%
Poles	13%
Secondary Conductors	<1%

Based on asset condition assessment, 9 percent of the wood poles have material deterioration and are in poor condition and this percentage is expected to increase to approximately 35 percent by 2029 without any investments. As with age, when considering box-framed poles on their own, these percentages increase: to 15 percent HI4 or HI5 as of 2022 and 61 percent by 2029 (without investment).

Table 8: Condition Assessment of Box Construction Assets

Asset Class: Wood Poles	% of Assets per Class (2022)	% of Assets per Class (2029)
HI1 – Good Condition	60%	42%
HI2 – Minor Deterioration	5%	18%
HI3 – Moderate Deterioration	26%	4%
HI4 – Material Deterioration	8%	27%
HI5 – End of Life	1%	8%

6. Other Box Construction Issues: Capacity, Efficiency and Grid Modernization

Box construction feeders are part of the 4.16 kV legacy system. Crew members with expertise in legacy assets are needed to trouble shoot and address defective equipment when needed. The inability to acquire legacy assets often force them to repair the system using temporary and non-standard solutions. Workforce retirements are diminishing the pool of employees who are experienced in trouble shooting and repairing box construction feeders, which further underscores the need to eliminate box construction on a firm timeline.

Toronto Hydro is gradually phasing out 4.16 kV in favour of 13.8 kV and 27.6 kV standards. Lower voltage 4.16 kV feeders have significantly lower capacity and are less flexible in accommodating new loads than 13.8 kV feeders. Upgrading feeders to 13.8 kV system will allow Toronto Hydro to more

efficiently accommodate new loads, renewable generation connections, and electric vehicle charging stations in high-growth areas of downtown Toronto. Without these upgrades, Toronto Hydro may need to connect new loads using alternative means, such as installing new feeders or extending existing feeders. This requires additional time and resources and may increase the connection costs for customers and developers. As noted above, upgrading feeders to a higher voltage will also reduce line losses and will help prepare the system for activities related to Grid Modernization (such as enhancing restoration capability of the system by adding switching points on the feeders and possibility of introducing self restoration schemes like Fault Location Isolation and Service Restoration ("FLISR")) which cannot be implemented on these legacy assets.

E6.1.4 Expenditure Plan

Table 9 below summarizes the historical, bridge and forecast spending for this Program. After examining program needs and establishing pacing strategies for each segment, Toronto Hydro developed the expenditure plan for the 2025-2029 rate period and applied volume and cost assumptions based on historical accomplishments. The cost estimates were created using the historical average cost per customer (for Rear Lot Conversion) and average cost per pole (for Box Construction Conversion) to extrapolate long-term program costs based on high-level project attributes. The forecast Rear Lot Conversion spending is higher over the 2025-2029 rate period when compared to 2020-2024 levels due to the deterioration of the assets in the rear lot areas due to age, as well as the need to modernize the system to enable growth and electrification. Toronto Hydro plans to eliminate all box-framed poles from the system by 2026 and continue converting the remaining box construction areas. The forecast spending is slightly lower compared to 2020-2024 levels due to the pace of work slowing as the utility gets closer to completing all box construction conversion.

Table 9: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Rear-Lot Conversion	9.2	9.9	12.8	18.3	11.7	19.8	21.2	23.4	28.5	27.7
Box Construction Conversion	26.5	29.6	21.0	19.6	49.1	44.5	39.9	10.2	10.6	10.9
Total	**35.6**	**39.5**	**33.8**	**37.9**	**60.8**	**64.4**	**61.1**	**33.6**	**39.0**	**38.6**

Rear Lot Conversion Expenditure Plan

Toronto Hydro invested $31.9 million in rear lot conversion projects between 2020 and 2022, resulting in the conversion of 384 customers from aging rear lot service to safer and more reliable front lot underground service. The utility plans to invest a total of $61.9 million by the end of 2024 to convert approximately 683 customers over the 2020-2024 rate period, a 71 percent reduction from Toronto Hydro's proposed conversion pace in the 2020-2024 DSP.

In accordance with the OEB Decision and Order on Toronto Hydro's 2020-2024 plan, which reduced the approved Rear Lot budget by $54 million to approximately $60 million, the utility significantly reduced its plan for Rear Lot Conversion and a number of projects (or project phases) and their corresponding customers conversions were deferred as shown in Table 10, below.[5] However, due to external pressures driving up costs and the significant reliability and safety risks associated with rear lot, especially during storm events and as assets continues to age and deteriorate, Toronto Hydro determined that it could not reasonably reduce the level of investment by the full amount prescribed by the OEB in its decision.

Table 10: Status of 2020-2024 DSP Planned Projects

Rear Lot Area	Phases	Number of Customers (2020-2024 DSP[6])	Number of Customers (updated)	Conversion Status
Thorncrest	Phase 9	618	89	Completed
	Phase 10		130	Completed
	Phase 11		114	2024
	Phase 12		147	Deferred
Jamestown	Phase 1	258	100	Completed
	Phase 2		62	Completed
	Phase 3		48	2023
Markland Woods	Phase 6	300	167	Deferred
	Phase 7		118	Deferred
Martin Grove Gardens	Phases 1 to 5	452	137	2024
	Phases 6 to 9		170	Deferred

[5] EB-2018-0165, Decision and Order (December 19, 2019) at page 93.
[6] Note that the number of customers in areas planned for 2020-2024 under the 2020-2024 DSP were high-level estimates and have since been updated based on more detailed information.

Mount Olive	Phases 1 to 3	83	61	Deferred
Kingsview	To be determined	173	156	Deferred
Richview Park	To be determined	263	263	Deferred
Willowridge	Phases 1 to 7	201	201	Deferred

Toronto Hydro plans to invest $120.6 million over the 2025-2029 rate period to convert approximately 1,467 rear lot customers in the worst performing areas to mitigate the various risks that have been discussed (including the risk of prolonged outages, ranging from 5 to more than 24 hours). Figure 13 shows the estimated rate of customers conversion from 2016 to the current estimated completion year of 2052.



Figure 13: Rate of Conversion of Rear Lot Customers (2015-2029)

Rear Lot Conversion is not a like-for-like replacement activity. Projects are therefore difficult to estimate on an installed asset basis without first completing a preliminary design of the new front lot underground feeder, which does not take place until closer to project execution. As such, Toronto Hydro has used an historical average cost per customer to parametrically estimate 2025-2029 costs for the prioritized project areas. To develop the cost per customer, Toronto Hydro continued to use

the methodology from the 2020-2024 DSP and examined two rear lot areas, consisting of four projects completed in recent years.

Toronto Hydro applied an average cost of $0.058 million per customer in developing the segment cost forecasts for the 2025-2029 rate period. This is a significant increase over the previous cost per customer estimated in the 2020-2024 DSP due to externally-driven escalations of labour, material, and other (e.g. vehicle) costs over recent years having a particularly high impact on the costs to plan and execute this complex conversion work.

The amount required per annum will vary year-over-year based on the timing of each project over multiple calendar years. Toronto Hydro designs and plans projects using a phased approach based on feeder configuration and customer count (e.g. Project Martin Grove Gardens with over 400 customers involved eight phases with multiple customers each) and ensures that civil construction is completed in one year and then followed in the next year by electrical construction. Civil work costs approximately twice as much as electrical and therefore annual costs (total and per customer conversion completed) will vary depending on the balance of civil and electrical work completed each year.

The average duration of a full 100-customer phase rear lot conversion construction project is approximately 24 months. By completing projects in a staggered fashion instead of addressing all the customers at one time, Toronto Hydro can improve reliability by reducing the time until the first customers will start benefitting from the conversion. For example, if Project Martin Grove Gardens were to be done as single-phase project it would take about 60 months for 400 customers to be fully converted and during that time all those customers would continue to experience a higher risk of outages on the legacy equipment. However, when done in phases, the first 50-70 customers would be converted after only 24 months. This way only a portion of the customers would be at higher risk of outages throughout the full project period. Minimizing the risk of outages minimizes the risk of added costs and long duration outages as crews can spend less time restoring power on legacy equipment.

Rear Lot Conversion projects are prioritized based on asset reliability, equipment condition, and coordination with planned city road work. Generally, the worst performing feeders are targeted for completion first, however rear lot areas where projects have started must be fully completed before moving to a new area despite any changes in reliability performance. To reduce costs, Toronto Hydro also strategically aligns and coordinates rear-lot projects with other conversion projects that share

the same feeder. Figure 14 identifies rear lot areas, including those that Toronto Hydro has recently converted and those prioritized for conversion over 2025-2029, with additional details on latter areas in Table 10.

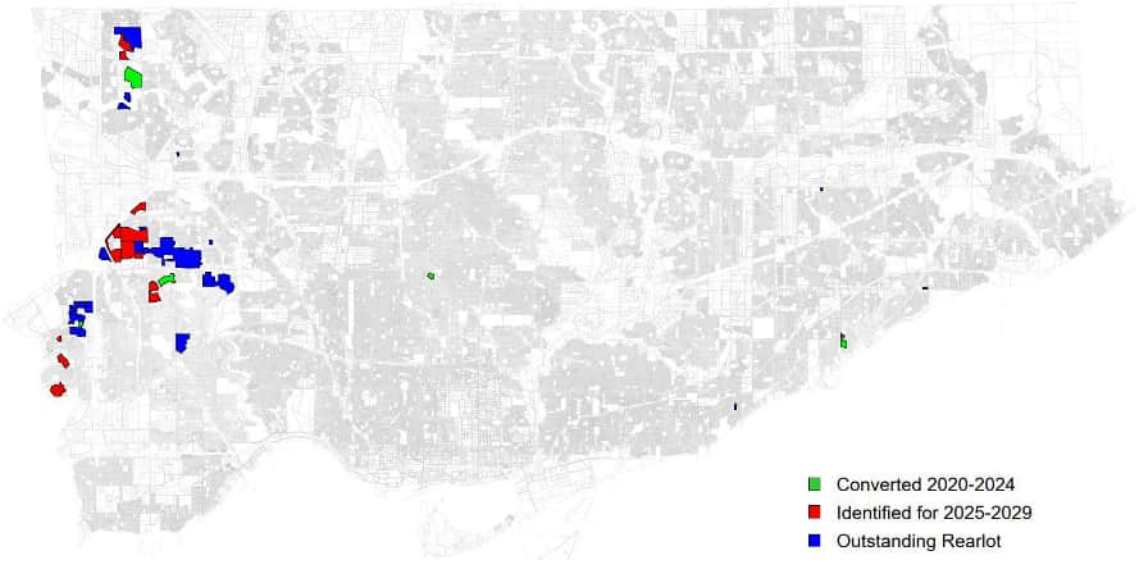


Figure 14: Outstanding Rear Lot Areas to be completed during 2025-2029 and beyond

Table 11: Planned Rear Lot Projects for 2025-2029

Rear Lot Area	Number of Customers	Expected Date of Completion	Number of Outages (2012-2022)	Number of Outages Greater than 5 Hours (2012-2022)
Thorncrest Phase 12	147	2025	1	0
Markland Woods	285	2025-2026	17	8
Martin Grove Gardens	307	2025-2027	7	2
Willowridge	201	2027-2028	11	3
Mount Olive	61	2027-2028	2	2
Kingsview	156	2028-2029	11	2
Eringate Centennial-West Deane	130	2028-2029	18	2
Richview Park	263	2028-2029	1	0

For the 2025-2029 rate period, Toronto Hydro has planned the conversion of seven rear lot areas, the majority of which the utility deferred from the 2020-2024 rate period as discussed above:

Thorncrest, Markland Woods, Martin Grove Gardens, Kingsview, Willowridge, Mount Olive and Richview Park. One new rear lot area is also planned for conversion towards the end of the rate period, which has been preliminarily identified as Eringate Centennial-West Deane, but may change based on the latest reliability data and any other considerations closer to the time of planning.

Box Construction Conversion Expenditure Plan

Toronto Hydro invested $77.0 million in Box Construction Conversion projects over 2020-2022, removing 444 box frames and converting a total of 1,889 poles to safer, more reliable, and operationally flexible 13.8 kV feeders. The utility plans to invest $68.7 million over 2023-2024 to eliminate approximately 236 additional box frames and convert 1,479 poles. This will leave approximately 344 box frames and an estimated total of 1,681 poles to be addressed in the 2025-2029 period. Toronto Hydro expects to spend about 36 percent ($38.4 million) more than the $107.3 million initially forecast for the 2020-2024 period. The cost variance is driven by changes to the project schedule, including a number of projects that carried over from the 2015-2019 rate period (as shown in Table 11 below), as project phases were deferred or moved up to accommodate internal and external dependencies. Other drivers include externally driven price escalations, coordination and accommodation of third-party initiatives such Metrolinx's Ontario Line and the City of Toronto's CafeTO, and the differences between high level estimates used for the forecasts and the detailed estimates and actual costs following detailed design and construction.

Table 12: Box Construction Projects 2020-2029

	Conversion	Construction Attainment	Projected/ Actual Costs ($M)[7]
Carlaw	2019-2021	Complete	7.3
Dupont	2018-2022	Complete	8.1
Danforth	2018-2024	2024	22.6
Hammersmith	2017-2021	Complete	14.1
Junction	2018-2022	Complete	11.3
Runnymede	2019-2021	Complete	5.0
Wiltshire[8]	2024	2024	0.3
Highlevel	2021-2026	2026	70.5

[7] Excludes inflation and other allocations.
[8] MS Decommissioning.

Sherbourne	2021-2026	2026	21.7
Spadina-Chaplin	2022-2026	2026	37.45
University	2021-2029	2029	25.1
Defoe-Strachan[9]	2017-2026	2026	21.0

Toronto Hydro estimates that $116.1 million will be required over the 2025-2029 rate period to complete full conversion of all except one (Defoe-Strachan, see footnote 8 below) of the remaining box construction areas, which will improve average outage restoration time for 15,246 customers. Other anticipated benefits of this work include (1) addressing safety risks related to EUSR, CSA and ESA compliance issues, (2) improving speed and cost-efficiency of customer grid access in high-growth areas of downtown Toronto, and (3) reduced traffic disruptions due to less frequent repairs and maintenance. Figure 15 below shows the actual and anticipated rate of removing box frames from the system. As discussed further below, Toronto Hydro must complete some conversion work after all the box-framed poles have been removed.

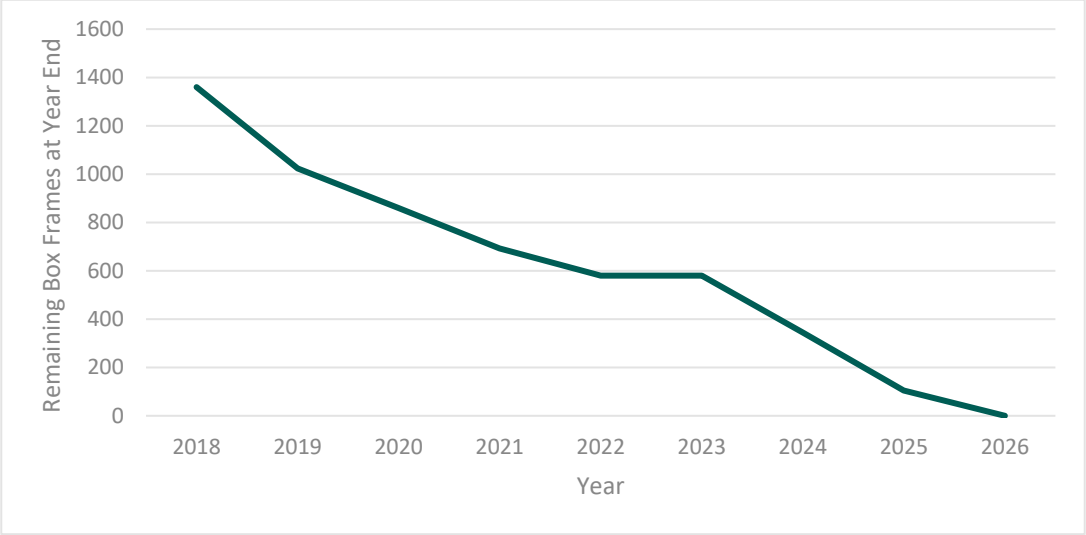


Figure 15: Remaining Box-Framed Poles in the System (2018-2026)

[9] For the Defoe-Strachan area, while all box-framed poles will be removed, full voltage conversion will not be completed until after 2029 due to a number of internal and external dependencies and those costs are not included in the table.

Toronto Hydro examined a number of completed box construction projects to develop an average cost of conversion per pole. This analysis concluded that cost of conversion fluctuates from one project to the next or from one year to other due to area specific characteristics. For example:

- Some areas have lessor number of poles but have coordination and execution challenges while other areas have higher concentration of poles but are relatively easier to construct.
- Some areas have overhead supply directly feeding customers on a quiet side street without trees and underground risers while other areas have box construction assets on a main downtown artery, such as Queen Street, with both primary and secondary distribution and risers going from overhead to underground and vice versa.
- Some areas may have road access issues, moratoriums, work time restrictions, heavy vegetation, or third-party attachments such as TTC street cars that require coordination while other areas may not have these issues.
- Some projects, based on their location and box construction framing density, require different techniques for the safe removal of the legacy equipment.

In order to minimize the cost fluctuations, Toronto Hydro established an average cost of $0.039 million per pole using various projects completed in 2018 to 2022. This average cost of conversion per pole was used to derive the forecast costs for projects for 2025-2026. The increase in this unit cost over the cost per pole in the 2020-2024 DSP reflects inflationary pressures and the fact that the last box construction areas to be completed are the most complex and challenging to design and execute.

Box construction projects planned for the 2025-2029 rate period will convert all remaining box construction on the system, except for part of the Defoe-Strachan area. These phases are interdependent, have to be coordinated with Hydro One, transit authorities including the TTC and Metrolinx, customer connection and third-party development projects, and have to be executed in a particular order. Therefore, Toronto Hydro will continue to manage to the current schedule, prioritizing removal of all remaining box-framed poles by the end of 2026 in alignment with the utility's previously established commitment to eliminate the public and employee safety risks associated with these poles. However, as discussed further in section E6.1.6.2, while it will remove all remaining box-framed poles by 2026, conversion work will be executed in two-phases with only partial voltage conversion at Defoe-Strachan and University completed by 2026. While Toronto Hydro expects to complete full conversion of University by the end of the 2025-2029 rate period, the

remaining conversion for Defoe-Strachan cannot be continued until after 2029 due to a number of factors, including conflicts with Metrolinx's Ontario Line work.

E6.1.5 Options Analysis

Options for Rear-Lot Conversion

1. Option 1: Continue Converting Rear Lot Customers at Current (2020-2024) Pace

Under this option, Toronto Hydro would maintain the current pace of rear lot conversion over the 2025-2029 rate period. Areas not planned for conversion would continue to pose higher safety risk and be prone to prolonged outages, especially in extreme weather. It would also lead to more reactive replacements of assets, which tend to cost more and do not achieve any of the benefits, such as increased efficiencies and capacity to enable customers to connect new services, related to converting to 27.6 kV. At this pace, it would take until the mid 2050s to convert all remaining rear lot customers, at which point the reliability impact on customers and safety risk would be completely unacceptable given the extreme age and expected deterioration of the remaining assets. Given the current age and condition of these assets, the current pace of conversion is not sustainable and would require a much higher level of investment beyond 2029 to mitigate the increasing risk and deteriorating performance. Especially in light of recent customer feedback that indicates that timely restoration during extreme weather events is a top priority, this option is not recommended.

2. Option 2 (Selected Option): Convert Rear Lot Customers at Moderately Increased Pace

Under this option, Toronto Hydro plans to moderately increase its pace of rear lot conversion in the 2025-2029 rate period. This will support mitigation of safety risks and reduce the frequency of prolonged outages, as well as support modernization of the grid through voltage conversion. At this pace, it will still take until after 2050 to convert all rear lot customers and the remaining rear lot areas will continue to pose increasing reliability and safety risks. Toronto Hydro also expects that it will need to increase the pace of investment beyond 2029 to address this escalating risk as these assets age and deteriorate, but not as dramatically as it would need to under Option 1. Toronto Hydro finds this option to be a reasonable balance between residential customers' top two priorities of price and reliability.

3. Option 3: Convert Rear Lot Customers at Accelerated Pace

Under this option, Toronto Hydro would further increase the pace of rear lot conversion over the 2025-2029 rate period. At this pace, Toronto Hydro would eliminate all rear lot plant and its associated risk by the mid 2040s. This would also enable faster progress in converting the system to 27.6 kV and realizing the associated benefits, including lower costs associated with maintaining and renewing municipal stations and improved service levels for customers connecting new services or choosing new technologies such as solar panels. This is the best option for managing rear lot risk and standardizing the grid, but the additional cost cannot be justified at this time given Toronto Hydro's other investment priorities and the need to limit rate increases.

Options for Box Construction Conversion

1. Option 1: Full Voltage Conversion and Box-Framed Pole Removal beyond 2026

In this scenario, Toronto Hydro would delay the removal of the last box-framed poles from the system beyond 2026, when it could be incorporated into full voltage conversion projects. Station constraints (see section E6.1.6.2 for more detail) and other considerations have resulted in certain areas being unfeasible to fully convert to 13.8 kV by the end of 2026 as previously planned. Delaying the removal of some box-framed poles beyond 2026 presents unacceptably high safety risks to Toronto Hydro employees. The utility is committed to meeting its previously established 2026 target for box-framed pole removal. Therefore, this option is not recommended.

2. Option 2 (Selected Option): Removal of Remaining Box-Framed Poles by 2026

This option will eliminate the significant safety risks associated with box construction assets for crews and the public by the end of 2026. It will also remove capacity constraints, renew aging and deteriorating assets, improve reliability for customers, and enable the retirement of station assets that will be otherwise costly to renew or maintain. This option involves removing all box-framed poles by the established deadline of 2026, but full voltage conversion and station decommissioning for two areas will be completed later due to station constraints.

This option is recommended as it enables the fastest possible elimination of the safety risks associated with box-framed poles, while providing short and long-term benefits to customers and the utility.

E6.1.6 Execution Risks & Mitigation

Rear-Lot Conversion

Timely third-party project coordination: One program risk is the potential for a minimum five-year moratorium on new road work in areas where Toronto Hydro intends to do rear lot conversion work. Toronto Hydro will mitigate this risk by working closely with the City of Toronto on planned road work (i.e. through utility coordination council meetings). In the event that planned City of Toronto work puts program completion at risk, Toronto Hydro will negotiate with the city to coordinate a construction schedule that is acceptable to all parties and stakeholders involved.

Customer Engagement: Customer care is a significant aspect of risk mitigation during the planning and execution phases of rear lot conversion, which by nature are relatively intrusive and involve construction on multiple sides of each customer property. To determine asset locations that best align to customer preferences, Toronto Hydro maintains extensive and proactive customer communication and provides an opportunity for customers to voice their concerns and to work with the designer and constructor. In most cases, community meetings are held to proactively introduce residents to the project plans and educate them on construction implementation. City Ward councillors are informed of the project and often are invited to community meetings and pre-construction meetings to assist with constituent inquiries. Written letters are sent in advance to customers' homes to inform them of the project, new equipment installations and line of sight to new equipment as per applicable municipal notice requirements.

Conversion coordination: The remaining rear lot configurations feature multiple feeders that provide service across the same easement, making conversion activities relatively complex. These feeders depend on one another for load transfers, especially during contingency scenarios (i.e. during outages on any of the feeders). Feeders tie with one another and can be used to resupply each other if a feeder's primary source of power from a substation is disrupted due to a fault or work being done. Therefore, it is important that alternative sources of power remain available during conversion in the event of an emergency. These interconnections require careful staging of conversion jobs over several years.

Box Construction Conversion

Station Constraints: In order to do the voltage conversion work, affected 13.8 kV stations need to have spare cell positions and 4 wire capability. If these are lacking in an area, Toronto Hydro works

with stakeholders to implement them where needed. However, this can take time and may be dependent on external factors, such as Hydro One work. For two of the remaining box construction areas, Defoe-Strachan and University, this is an issue that Toronto Hydro cannot address in time to complete full box construction conversion of these areas by 2026 as was previously intended. Therefore, Toronto Hydro's strategy in these areas is to perform box-framed pole removals with and without voltage conversion, i.e. partial conversion of these areas. Where feasible, Toronto Hydro will rebuild portions of the feeders to remove box-framed poles while the system remains energized at 4.16 kV, with a provision to add 13.8 kV lines on the renewed poles in the future, once constraints are resolved. For the remaining box-framed poles that cannot be removed without conversion, the utility will transfer load to open up a few cell positions and enable some voltage conversion.[10]

Project Interdependencies: Projects in this segment have highly interdependent phases that have to be executed in a particular order. Delays in any particular phase cascade to the later phases of the project. In order to remove box frames within the established timeline, Toronto Hydro regularly reviews the execution plan to identify and resolve any emerging issues.

Customer Coordination: For the majority of the commercial customers serviced on 4.16 kV system, there is underground equipment, risers, and terminations connected to the pole. Transferring a riser and termination requires an outage to the customer to conduct work safely. Coordinating power interruptions and access with customers could delay projects. Toronto Hydro is mitigating this risk through proactive and early customer engagement.

Construction Coordination: Many of the remaining box construction assets are within high pedestrian and vehicle traffic areas which also include TTC bus or streetcar routes (see example shown in Figure 16). In this regard, mitigation involves proactive coordination and engagement with the City to create a traffic plan, especially at major intersections. Most pole installations require a single lane to be occupied by trucks and equipment and as such, inadequate coordination would jeopardize project completion in a timely manner.

[10] Note that some of this load transfer relies on energization of Copeland Station (Phase 2).



Figure 16: Area with High Pedestrian and Vehicle Traffic, including TTC Routes.

Third-Party Assets: Third-party assets attached to the utility poles, such as Rogers, Bell, and City assets, can interfere with full conversion and pole removal work. Toronto Hydro will engage owners of these assets as soon as possible to coordinate and plan their transfer to avoid delays.

E6.2 Underground System Renewal – Horseshoe

E6.2.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 359.8	**2025-2029 Cost ($M):** 475.7
Segments: Underground System Renewal Horseshoe	
Trigger Driver: Failure Risk	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Environment	

The Underground System Renewal – Horseshoe program ("the Program") manages failure risk on major underground distribution assets serving customers in the Horseshoe area of Toronto. The Program invests in proactive asset renewal and focuses on maintaining the reliability, safety, and environmental risk levels of major underground distribution assets. This program is a continuation of the activities described in the Underground System Renewal – Horseshoe program in Toronto Hydro's 2020-2024 Distribution System Plan ("DSP").[1]

The Program addresses three major underground asset classes: cables, transformers, and switches. These assets deteriorate over time due to usage, aging, and exposure to harsh environments which increases the risk of failure. Legacy asset design issues exacerbate the probability of failure for certain asset types targeted by this program.

Outages caused by asset failure on the underground system take approximately 34 percent longer to restore than outages on the overhead system, resulting in lengthy interruptions that may last up to 24 hours or longer. The failure characteristics of legacy underground cables are such that customers can experience multiple cable-related outages in a short period, leading to potentially significant declines in customer satisfaction in affected neighborhoods.

The program consists of both rebuild and spot replacement projects. Rebuild projects are ideal when a confluence of conditions within a concentrated geographical area make it necessary and/or economically prudent to rebuild an entire section of the system. For example, areas of the system with a high concentration of assets at risk of failure (e.g. due to deteriorated condition) and a history of poor reliability are typically addressed through rebuild projects. Voltage conversion is another

[1] EB-2018-0165, Exhibit 2B, Section E6.2

important consideration for rebuilds. For example, Toronto Hydro has a population of legacy 4.16 kV feeders in the Horseshoe that it is gradually converting to modernized 27.6 kV standards in order to improve operational performance and efficiency and prepare for the demands of electrification, growth, and the proliferation of distributed energy resources ("DERs"). As 4.16 kV is no longer an accepted system standard, when 4.16 kV asset condition and performance within an area deteriorate, Toronto Hydro will generally rebuild the area to current standards rather than replace individual assets on a like-for-like basis.

The Program's investments in the three major underground asset classes are summarized as follows:

- **Cables**: Cables are the greatest contributor to outages caused by defective equipment on Toronto Hydro's system in the Horseshoe, resulting on average in 146,000 customer hours of interruption per year. Through prioritized neighbourhood rebuild projects focused on replacement of high-risk direct-buried cross-linked polyethylene ("XLPE") cables, Toronto Hydro previously had success reducing the number of customer interruptions due to cable failure, from over 200,000 per year in 2013 to approximately 105,000 in 2019. However, more recently Toronto Hydro shifted focus away from rebuild projects addressing direct-buried cables in order to address the urgent environmental risk associated with PCBs. As a result, customer interruptions (and other reliability indicators) have started trending back up, reaching 199,000 in 2022. As of 2022, there are 666 circuit-kilometres of direct-buried cable in the underground system, of which 286 circuit-kilometres are direct-buried cable in dirt, and 380 circuit-kilometres are direct-buried cable in PVC ducts. While direct-buried XLPE cable (not in duct) was previously considered the highest failure risk, direct-buried cable in PVC ducts is now also a priority as it can get clogged with dirt and get sheared due to the movement of earth, making it difficult to replace the cable inside the PVC duct. Toronto Hydro expects the entire direct-buried cable population to be a significant source of failure risk and driver of reliability outcomes as the cables continue to age over the 2025-2029 period. Over half of this cable has reached or passed its useful life as of 2022. Toronto Hydro plans to replace an estimated 340 circuit-kilometers of underground cable, including 182 circuit-kilometres of direct-buried cable over the 2025-2029 period to maintain current average reliability performance on the underground system and to help sustain improvements in the number of feeders experiencing seven or more interruptions per year ("FESI-7").

- **Transformers:** Underground transformers are typically exposed to harsh environmental conditions, and defective transformers cause approximately 17,700 hours of customer interruption per year and contribute to 21 percent of failures on the underground system. As of 2022, 26 percent of underground transformers have reached or surpassed useful life, and over 600 units have at least material deterioration. Without proactive investment, Toronto Hydro expects the number of units past useful life to increase to 39 percent (over 10,000 units) and the number with at least material deterioration to increase to 2,400 by 2029. Toronto Hydro replaces aging and deteriorated underground transformers proactively as part of rebuild projects, and will continue to do so in the 2025-2029 period. Over the 2020-2024 period, Toronto Hydro has shifted towards doing more spot replacements to support the utility's objective of reducing the number of potentially high-consequence PCB leaks. In 2025, Toronto Hydro plans to continue the replacement of the remaining underground transformers that are known to contain, or are at risk of containing, PCB-contaminated oil. Over 2026-2029, the utility will shift back towards a more rebuild-focused approach, using spot replacements for only the worst condition transformers not addressed through rebuilds. Overall, the utility plans to replace an estimated 2,478 underground transformers during the 2025-2029 period through a combination of area rebuilds and spot replacement, with the objective of maintaining average system reliability, eliminating the risk of PCB leaks, and supporting long-term risk management of the underground transformer population.

- **Switches**: Underground switches are continuously exposed to harsh environmental conditions, and their failure typically leads to prolonged outages, ranging from approximately two to 35 hours, affecting an average of 1,350 customers at a time. On average, switches have contributed to approximately 20,000 hours of customer interruption annually. Failure of these assets can also pose employee and public safety risks due to the potential for arc flashing, a risk that is higher with Toronto Hydro's remaining population of legacy air-insulated switches. The number of air-insulated padmounted switches in end-of-serviceable life condition ("HI5") is anticipated to rise from 29 in 2022 to 104 by 2029, which aligns with the accelerated rate of degradation that Toronto Hydro has seen for this type of switch in the field.[2] During the 2025-2029 period, the utility plans to proactively replace an estimated 116 underground padmounted switches in conjunction with area rebuild projects,

[2] Over 90 percent of the failed switches that the utility analyzed in the last five years failed prior to reaching their expected useful life of 40 years, with the highest rate of failure occurring in the 10-14 years range.)

prioritizing higher-risk air-insulated switches operating beyond useful life and/or exhibiting material degradation.

Toronto Hydro plans to invest $475.7 million in the Underground System Renewal program in 2025-2029, which is a 32 percent increase over projected 2020-2024 spending in this Program (including forecasted inflation). This pace of investment is necessary to maintain current average reliability on the underground system, sustain improvements in the number of feeders experiencing seven or more interruptions a year, and prevent asset-related risk on the underground system from increasing in an unsustainable manner over the long-term.

E6.2.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's objectives and obligations to connect low and high voltage customers within 5 and 10 business days respectively at least 90 percent of the time (pursuant to the OEB's new connection metrics and section 7.2 of the Distribution System Code ("DSC"), by upgrading 106 circuit kilometres of low capacity 4.16 kV or 13.8 kV distribution lines to higher voltage capacity of 27.6 kV distribution lines.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, Direct Buried Cable replacement measure) by ○ Replacing approximately 340 circuit-kilometers of underground cable that includes 182 circuit-kilometres of direct buried underground cable that poses elevated risks to reliability; and ○ Replacing assets at and beyond useful life or showing signs of at least material deterioration (i.e. HI4 and HI5) at the end of 2029[3]

[3] For many of its major assets, Toronto Hydro performs asset condition assessment ("ACA"), in which the condition of each asset is assigned a health index ("HI") band from HI1 to HI5, where HI5 indicates the worst condition. For these same assets, the utility can then also project future condition (i.e. HI band) assuming no intervention. See Exhibit 2B, Section D, Appendix A for more details on Toronto Hydro's ACA methodology

Environment	• Contributes to improving Toronto Hydro's performance in relation to the Spills of Oil Containing PCBs measure, and reducing the environmental impact and risks associated with Toronto Hydro's distribution system by removing the remaining underground assets at or beyond useful life that contain or are at risk of containing PCBs by 2025, pursuant to PCB regulations (PCB Regulations4 made under the Canadian Environmental Protection Act, 19995, the Environmental Protection Act6 and the City of Toronto's Sewer Use By-Law7)

E6.2.3 Drivers and Need

Table 3: Drivers and Need

Trigger Driver	Failure Risk
Secondary Driver(s)	Environmental Risk, Safety, Reliability, Capacity Constraints/Growth

The Underground System Renewal – Horseshoe program focuses on replacing three types of assets: cables, transformers, and switches. These assets are the primary components of the underground distribution system, and will typically be replaced in accordance with current standards, generally on a like-for-like basis, unless part of a voltage conversion project.

The proposed renewal is driven by the risk and impacts of asset failures on system reliability, the environment, and public and employee safety. These risks are primarily due to two factors. The first is accelerated degradation of asset condition due to exposure to external elements, such as dirt, salt, dust, moisture, and humidity. This contributes to a loss of integrity of the physical asset, which can in turn lead to failure. Secondly, assets that are at or approaching their end of useful life have a higher probability of failure.

Table 4 provides the useful life of the underground assets in the Horseshoe area. Asset failures may lead to: (1) reliability risks, which can cause outages and directly impact customers; (2) environmental risks, such as oil spills (which may contain PCBs) that harm the environment; and (3) safety risks, resulting from arcing and catastrophic failures.

[4] SOR/2008-273
[5] SC 1999, c. 33
[6] RSO 1990, c. E.19
[7] City of Toronto, by-law No 681, Sewers, (May 15, 2023).

Table 4: Useful Life of Underground Assets by Type in the Horseshoe

Type		Useful Life (Years)
Direct Buried Cable	*Installed in PVC Duct*	40
	Not Installed in PVC Duct	20
Cable in Concrete Encased Duct		50
Transformers	*Submersible*	30
	Padmounted	
	Building Vault	
Switches	*Padmounted*	40
	Vault	

The number of outages due to underground defective equipment has been a major contributor to overall system outages over the last 10 years, constituting almost 56 percent as shown in Figure 1. Historical investments in the Program have driven some reduction in outages due to underground defective equipment, reaching a low in 2019, but this has since started trending up again. A similar pattern has emerged for Customers Interrupted ("CI") and Customers Hours Interrupted ("CHI"), which indicate the impact of these outages on customers, as shown in Figures 2 and 3. This recent deterioration in underground defective equipment driven reliability is largely driven by cable-related outages and is at least partly attributed to Toronto Hydro's prioritization of the removal of PCB at-risk underground transformers during the current rate period. This has shifted work in the Program towards more spot replacements of transformers based on PCB-risk and away from direct-buried cable renewal. As the remaining PCB at-risk transformers are removed from the system, Toronto Hydro plans to shift back to a more balanced distribution of work that will better mitigate reliability risk.

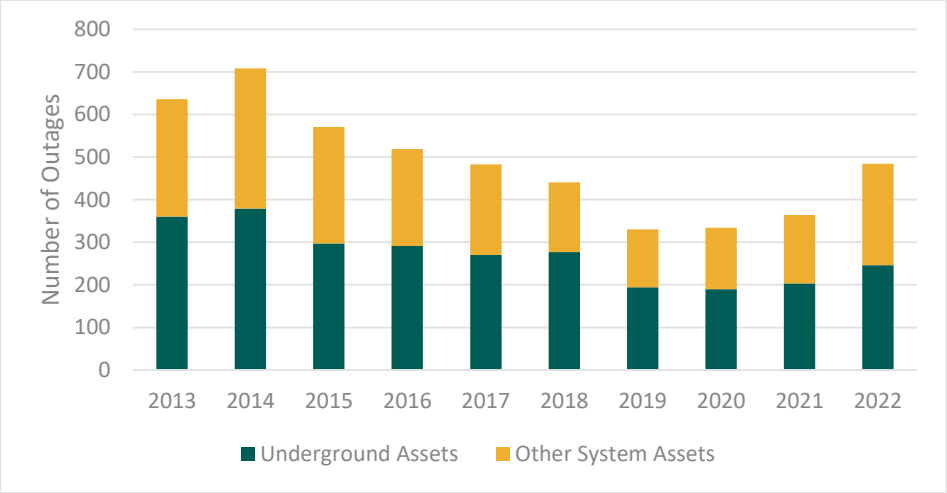


Figure 1: Ten-year Trend of Underground System Contribution to Overall System Outages

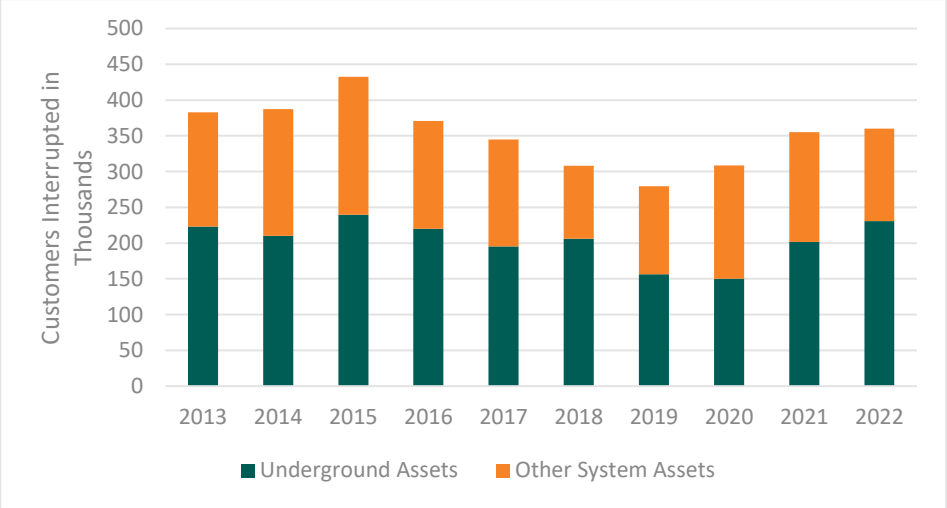


Figure 2: Ten-year Trend of Underground System Contribution to Overall System Customers Interrupted ("CI")

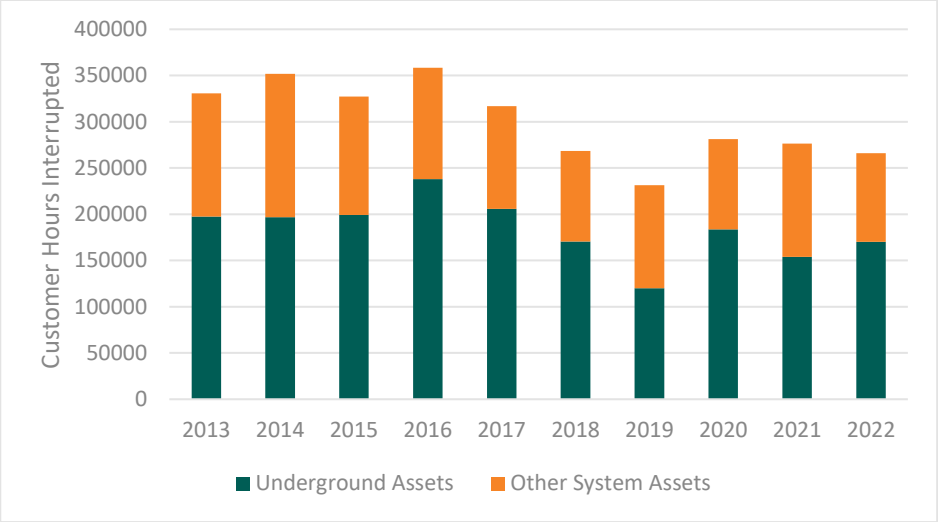


Figure 3: Ten-year Trend of Underground System Contribution to Overall System Customer Hours Interrupted (CHI)

While historical investments improved underground reliability in the Horseshoe area over 2015-2019, performance has started to backslide more recently and Toronto Hydro must increase the pace of renewal to prevent further deterioration. A significant number of assets (e.g. cables) are already past their useful life as of 2022 and the population continues to age. This increases the risk of failure, requiring Toronto Hydro to reactively replace faulted underground equipment. In general, underground assets are more difficult to replace compared to those in the overhead system, mainly because they are installed below-grade and not readily visible or accessible for fault locating.

When an underground fault occurs, controllers first check SCADA devices to determine which section of the feeder is affected. Next, crews look at fault indicators installed on various points on a feeder to locate the component that has faulted, a process that can take hours. Fault locating of direct buried cable is particularly challenging, as crews first need to perform tests to identify the general location of a fault, then dig up that location to confirm and pinpoint the actual cable fault. In some cases, crews need to dig multiple pits to identify the exact location before they can make repairs, prolonging the outage and inconveniencing customers. Operational outages to repair these assets can also expand the outage to surrounding areas thus affecting more customers.

Additionally, the nature of the work leads to significant unplanned disruptions and inconveniences for the neighbourhood and community as a whole, and often requires last minute coordination with third parties under emergency situations and tight timelines. For underground assets, this is

particularly difficult where customers own the assets (such as vaults), as coordination can delay the repair work and extend the outage. In contrast, proactive replacement allows Toronto Hydro to coordinate work with third parties well ahead of the scheduled repair work.

Through a combination of spot replacements and complete rebuilds of areas with poor reliability and large concentrations of high-risk assets, Toronto Hydro plans to replace approximately 340 circuit-kilometers of underground cable, 2,478 underground transformers, and 116 switches over the 2025-2029 period.

Outages on assets at 4.16 kV and 13.8 kV voltages continue to be responsible for a significant number of outages despite more than a decade of work converting to 27.6 kV. In 2013, areas fed by 4.16 kV and 13.8 kV feeders contributed to over 35 percent of the total outages on the underground system and this has increased to over 43 percent on average over the last five years (2018-2022). Any targeted underground areas that still utilize 4.16 kV or 13.8 kV systems will be converted to 27.6 kV. These are legacy assets which cannot be easily replaced and their configurations do not allow for expansion and provide limited options for system restoration during contingency. The overhead portion of these feeders are addressed by the Overhead Renewal program as well as the Area Conversions program.[8] Converting to 27.6 kV is expected to:

- enhance power quality with less voltage drop for customers at the end of distribution lines;
- reduce line losses, improving the efficiency of the distribution system;
- modernize the system in order to prepare for the demands of electrification, growth, and the proliferation of DERs that 4kV cannot accommodate; and,
- enable the eventual decommissioning of Municipal Stations, avoiding operating and maintenance expenditures that would otherwise be incurred.

There are approximately 170 4.16 kV and 13.8 kV feeders remaining to be converted throughout both the underground and overhead system in the Horseshoe. Toronto Hydro is planning to convert both the overhead portion and the underground portion of 29 of these feeders by 2029. At this pacing Toronto Hydro expects it could complete the underground voltage conversion portion of the entire system by 2055-2060.

[8] Exhibit 2B, Section E6.5; Exhibit 2B, Section E6.1.

E6.2.3.1 Replacement of Underground Cable

Toronto Hydro plans to replace underground cable that is past its useful life along with high-risk direct-buried cable that causes poor reliability in the Horseshoe area.

Generally, two types of cables exist in the Horseshoe underground distribution system: (i) XLPE; and (ii) tree-retardant cross-linked polyethylene ("TRXLPE"). These can be installed in three ways: (i) direct buried; (ii) in direct-buried Polyvinyl Chloride ("PVC") ducts; or (iii) in concrete-encased ducts. The majority of direct-buried XLPE cables in Toronto Hydro's system were installed before 1990 and were fabricated using manufacturing processes that are now considered inferior. These assets were installed using a legacy type of construction methodology where cables were laid directly in underground trenches without a protective barrier.

These cables are susceptible to outages due to direct exposure to environmental conditions. Moisture is the most destructive element that affects direct-buried XLPE cable. Water ingress into the cable insulation in the presence of an electrical field causes microscopic tears called "water treeing". Over time, continued moisture penetration and the presence of electrical stresses causes these water trees to become electrical trees (whereby the tears become carbonized and can conduct electricity). This causes the cable to internally short circuit and fail.[9] Additionally, direct-buried XLPE cables in PVC ducts can get clogged with dirt and get sheared by the movement of earth or other external factors, making it difficult to replace the cable inside the PVC duct as shown in Figure 4 below.

Based on Toronto Hydro's experience with direct buried cables, following an initial failure (which is typically a sign of deteriorated insulation and electrical and thermal stresses along the entire segment), subsequent failures in the cable segment occur with greater frequency. Additionally, voltage stress applied to the cable during the fault locating process further degrades the cable insulation.

[9] Exhibit 2B, Section D2 for more details



Figure 4: Clogged PVC Ducts

Underground cable system failures that include underground cables, terminations, and other cable accessories account for approximately 73 percent of the defective equipment-related outages in the underground Horseshoe system as shown in Figure 5 below. The ten-year reliability impact of the underground cable system discussed in this Program is shown in Figures 6 to 8. After reaching a low (improved reliability performance) in 2019, the reliability impact of underground cable systems has started to trend higher again and proactive replacement of underground cable systems is required from 2025-2029.

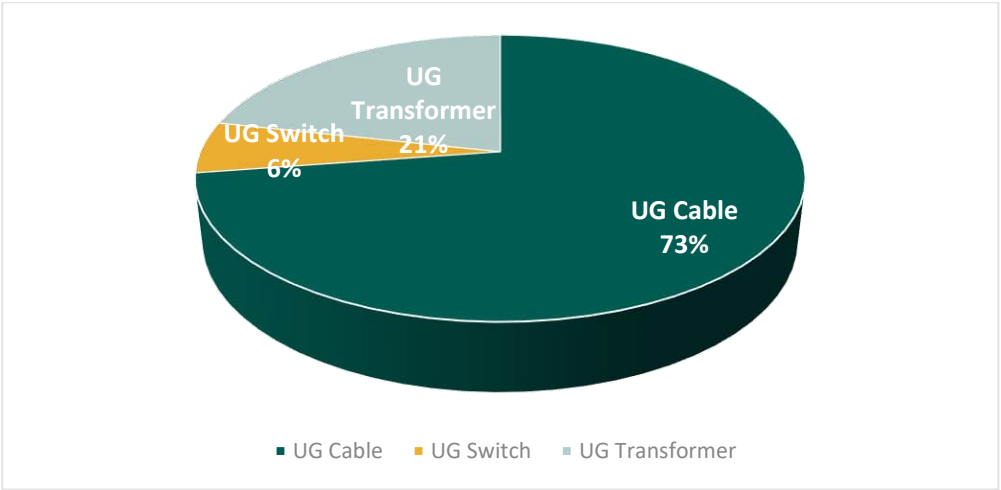


Figure 5: Underground ("UG") Equipment Failures in Underground Horseshoe System by Asset Type from 2013 to 2022

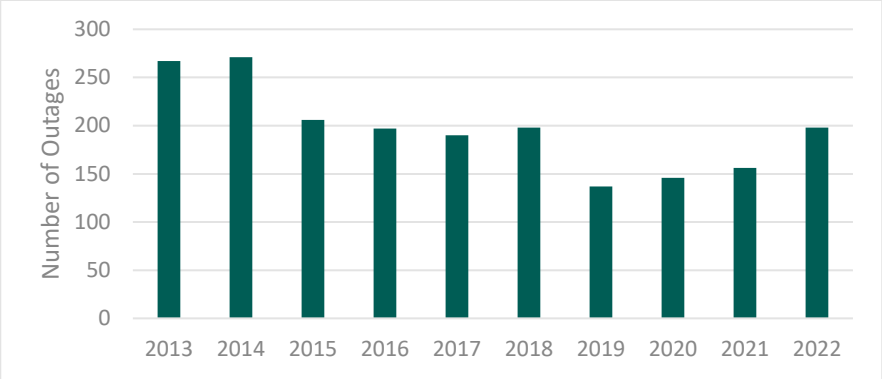


Figure 6: Ten-Year Trend of Outages due to Underground Cable Failure

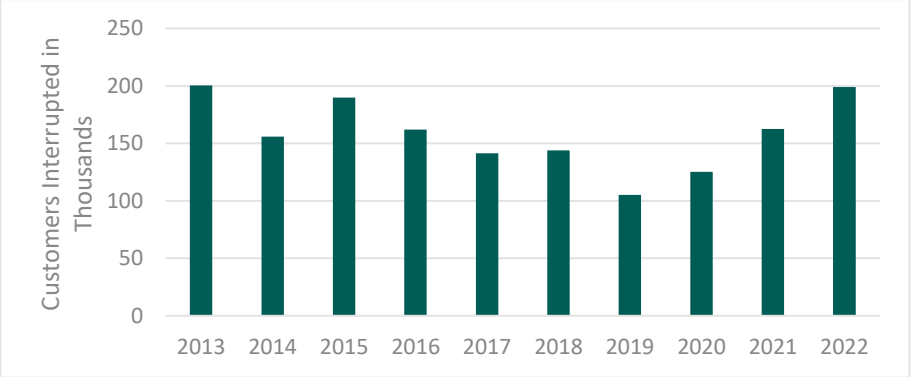


Figure 7: Ten-Year Trend of Total Customers Interrupted (CI) due to Underground Cable Failures

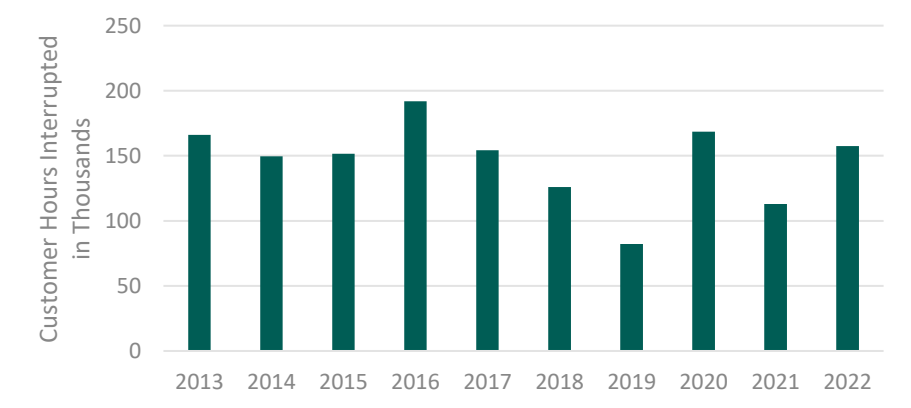


Figure 8: Ten-Year Trend of Total Customer Hours Interrupted (CHI) due to Underground Cable Failures

In addition to the type of cable, age is an important indicator of failure risk. Figures 9 depicts the age distribution of direct-buried XLPE cable (not in duct) in the Horseshoe in 2022 and 2029 (without investment). As of 2022, 73 percent of this direct-buried XLPE cable in Toronto Hydro's distribution system in the Horseshoe has reached or exceeded its useful life (i.e. 20 years). Without replacement, the length of this type of cable at or beyond useful life will reach 215 circuit-kilometres by 2029, which represents 75 percent of the direct-buried XLPE cable in Toronto Hydro's underground Horseshoe distribution system. This increased percentage of direct buried XLPE cable at or beyond useful life will heighten the risk of cable failure and further erode the reliability improvements made prior to 2020.

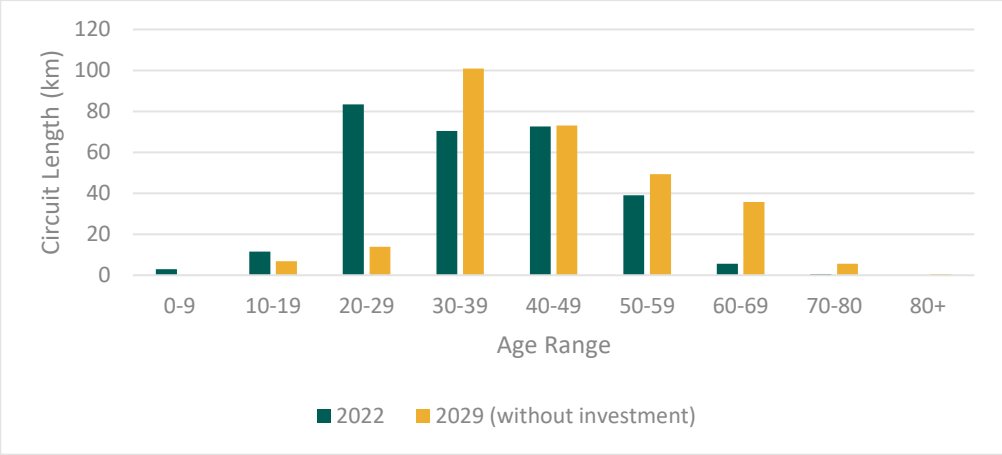


Figure 9: Age Demographics of Direct-Buried ("DB") Cable XLPE in Underground Horseshoe System as of 2022 and by 2029 (without Investment)

Figure 10 depicts the age distribution of the direct-buried cable in duct in the Horseshoe in 2022 and 2029 (without investment). As of 2022, 35 percent of this direct-buried cable in duct in Toronto Hydro's distribution system in the Horseshoe has reached or exceeded its useful life (i.e. 40 years). Without replacement, the length of this cable at or beyond useful life will reach 144 circuit-kilometres by 2029, which represents 38 percent of the direct-buried cable in duct in Toronto Hydro's underground Horseshoe distribution system. As with the direct-buried XLPE cable (not in duct), the increased percentage of direct buried XLPE cable at or beyond useful life will heighten the risk of cable failure

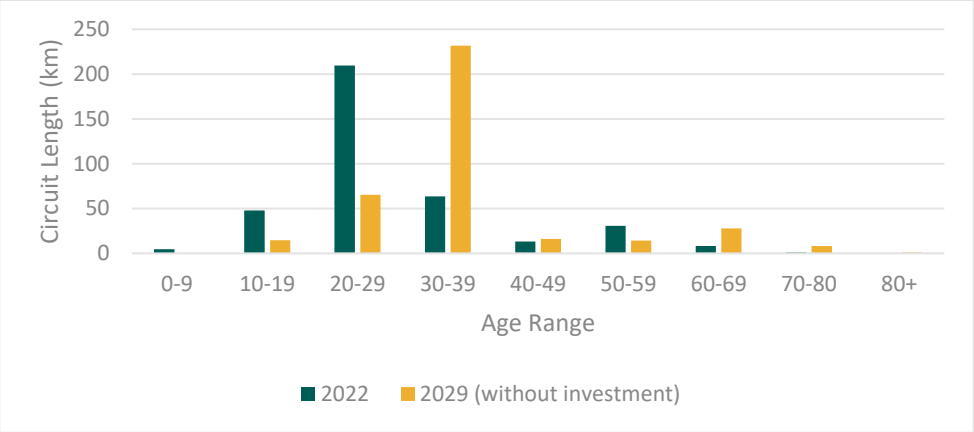


Figure 10: Age Demographics of Direct-Buried Cable in-Duct in Underground Horseshoe System as of 2022 and by 2029 (without Investment)

Although cables installed in concrete-encased ducts are more protected from environmental changes and mechanical damage, failures can still be caused by age and a variety of factors such as insulation breakdown, moisture ingress, and overload. Figure 11 shows the current age distribution of cable inside concrete-encased ducts in the Horseshoe in 2022 and in 2029 without investment. As of 2022, 9 percent of the cable inside concrete-encased ducts in the Horseshoe is at or beyond its useful life of 50 years. Without replacement, the length of cable at or beyond useful life will reach 357 circuit-kilometres by 2029, which represents 12 percent of cable installed in concrete-encased ducts. Proactive replacement of these cables is required to reduce failures and help maintain reliability on the underground system.

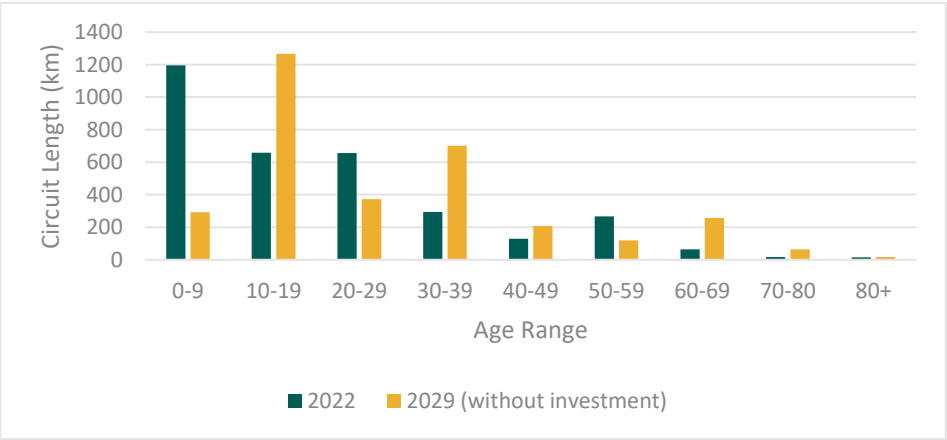


Figure 11: Age Demographic of Cable in in Concrete-Encased Ducts as of 2022 and by 2029 (without Investment)

Toronto Hydro is taking proactive measures to address the risks associated with deteriorating and legacy direct-buried cable as well as concrete-encased cable past useful life. The utility plans to replace approximately 340 circuit kilometres of underground cable, including 182 circuit kilometres of direct-buried cable (out of total of 666 circuit kilometres), through underground rebuild projects over the 2025-2029 period.

To improve reliability and public safety, Toronto Hydro plans to install new TRXLPE cable in concrete-encased ducts instead of burying cable directly into the soil or in PVC duct. This approach protects the cable from dig-ins, reducing the risk of damage and improving public safety. Additionally, installing cables in concrete-encased ducts significantly reduces the time needed to replace faulty cables, as new cables can be pulled into existing ducts. This approach will improve reliability and reduce outage times.

Toronto Hydro has also started performing cable diagnostic testing[10] on prioritized underground cables to provide a more accurate assessment of the condition of underground cables, splices, joints and terminations using a combination of very low frequency tan-delta ("VLF TD") and/or partial discharge testing on Horseshoe feeders/segments. This is executed in two phases:

- Phase 1 consists of visual inspections, Online Partial Discharge, and infrared ("IR") scanning of the end point locations to identify any immediate deficiencies.
- Phase 2 consists of monitored withstand cable testing (Time Domain Reflectometer or "TDR", as well as either online/offline Partial Discharge and/or VLF TD testing). In some cases, Phase 2 testing can only be performed after corrective actions from Phase 1 have been addressed.

In the past, factors such as age, historical failures, and number of joints were used to determine appropriate replacement strategies for these cables. However, under this program, select subdivisions in the Horseshoe area are chosen for testing to assist with making capital investment decisions using more condition-based data and to address areas with poor reliability. During 2021 and 2022, this program provided a more accurate assessment of the condition of underground cables, splices, joints, and terminations. As shown in Figure 12, this initiative has identified a number of deficiencies and generated corrective work that has helped the utility to mitigate cable failures and associated reliability risks. As this program continues to mature, the diagnostic data available on

[10] See Exhibit 4, Tab 2, Schedule 2.

cables will continue to grow and will help Toronto Hydro predict cables at risk of degradation and identify problematic locations in the system with a higher degree of accuracy. While Toronto Hydro is currently ramping up this program, it will require a significant amount of time to test the entire underground cable population and the utility will continue to lack this additional information for a large amount of cable.

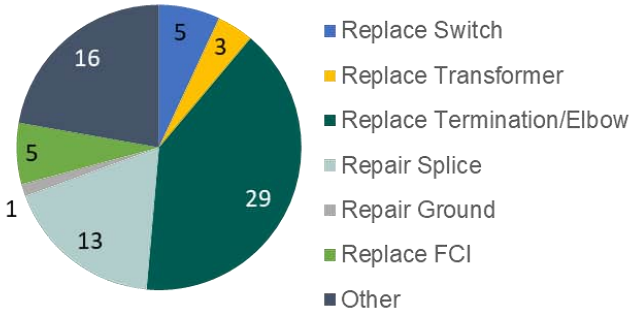


Figure 12: Type and Number of Deficiencies Identified from Cable Testing Program 2021-2022

E6.2.3.2 Replacement of Underground Transformers

Toronto Hydro plans to replace transformers that are at risk of failing and pose an environmental risk due to potential oil leaks (potentially containing PCBs). There are currently 25,753 underground transformers in Toronto Hydro's Horseshoe distribution system, with three main types: (i) submersible; (ii) padmount; and (iii) building vault. Toronto Hydro owns approximately 8,847 submersible transformers, 6,345 padmount transformers, and 10,561 vault transformers, all of which are vulnerable to deterioration from exposure to harsh environmental conditions.

Submersible transformers are located below-grade in small structures such as vaults and can be found on public road allowances or private properties. Padmounted transformers are metal-clad enclosures with lockable cabinet doors that are located on top of concrete pads, often within road allowances or on private properties. Vault transformers, on the other hand, are located above ground level in civil structures and, like padmounted transformers, supply residential areas or commercial buildings.

The harsh environmental conditions to which transformers are exposed cause them to deteriorate over time. Moisture, particularly groundwater and moisture ingress, is the most destructive element leading to the corrosion of the enclosures. Over time, precipitation and humidity can cause tank

perforation, which can result in oil leakage into the environment. The oil leakage reduces transformer oil levels, causing the paper insulation to dry up. When this is combined with the heat generated due to loading, arcing can occur with the potential for a catastrophic failure of the unit. These failures pose significant risks to the public and Toronto Hydro employees as these transformers are located next to sidewalks and on private properties. A summary of the 10-year reliability of the underground transformers is shown in Figures 13 to 15. There has been an overall downward trend in the number of system outages since 2017, which is also reflected in the customer impact reliability indicators, Customers Interrupted and Customer Hours Interrupted. This improvement can be attributed to the recent focus on proactive replacement of underground transformers containing, or at risk of containing PCBs. However, in 2022 there was some worsening of transformer-related reliability and, without continuous investment in this segment, Toronto Hydro expects the reliability improvements made in recent years to be eroded and eventually reversed.

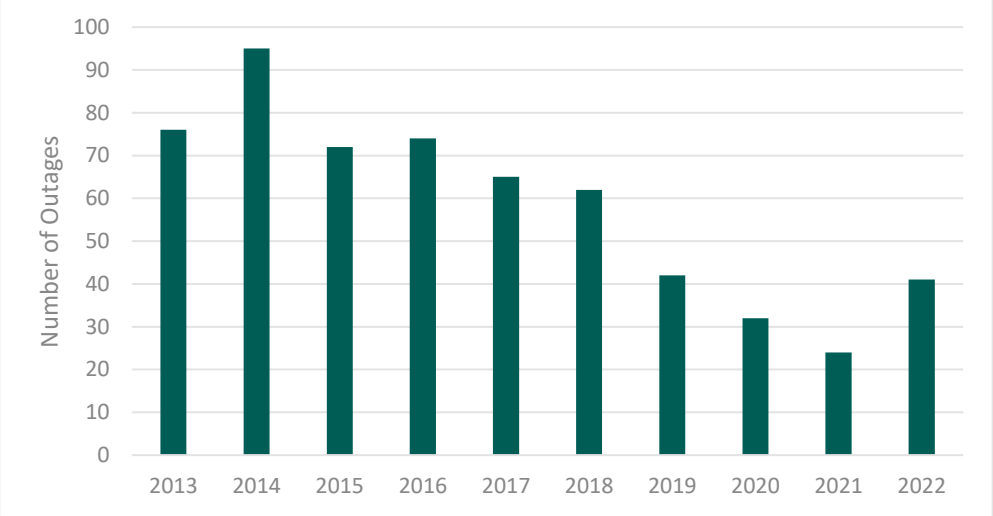


Figure 13: Ten-Year trend of Outages Due to Underground Transformer Failures

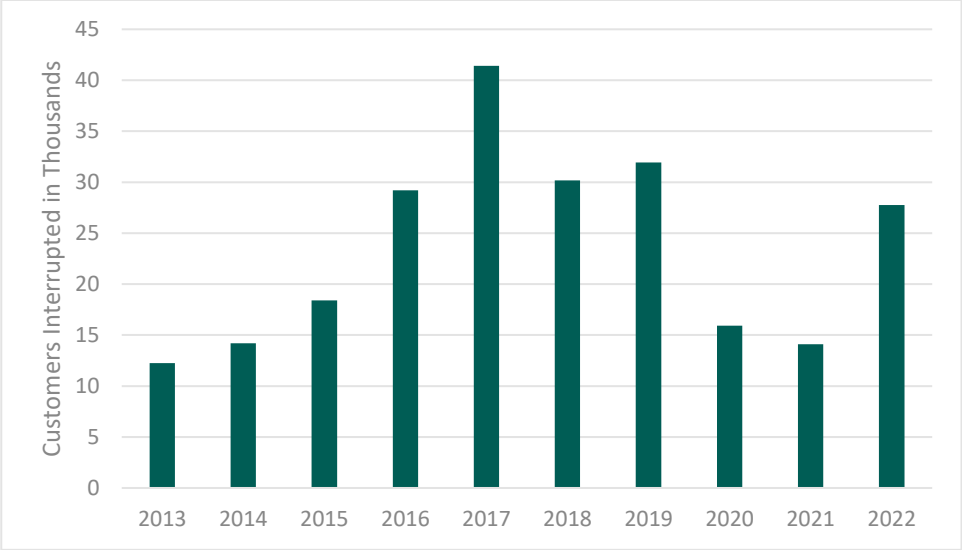


Figure 14: Ten-Year Trend of Total Customers Interrupted (CI) Due to Underground Transformer Failures

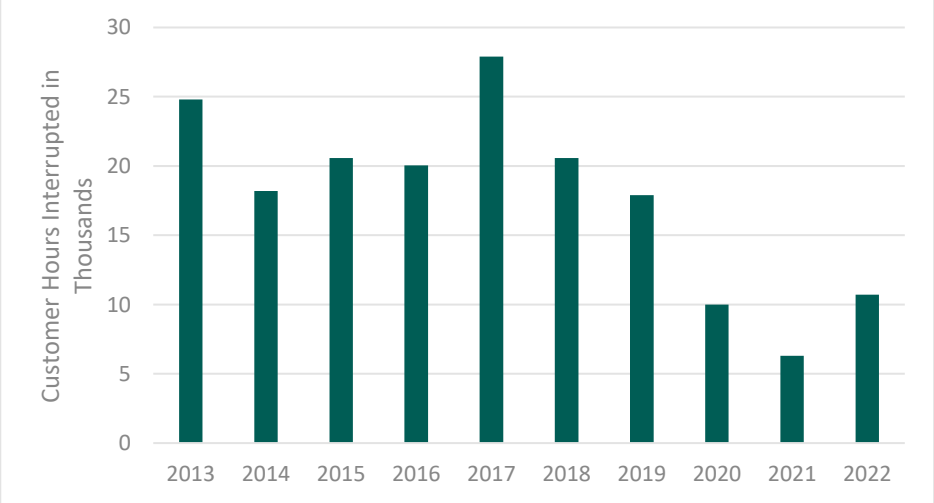


Figure 15: Ten-Year Trend of Customer Hours Interrupted (CHI) Due to Underground Transformer Failures

A number of underground transformer failures in the Horseshoe area have also resulted in oil leaks into the environment. The risk of oil leaks is particularly high for older transformers, which may contain oil with PCBs. Releasing oil, including oil containing PCBs into the environment may breach

the City of Toronto's Sewer Use By-Law[11], Ontario's *Environmental Protection Act*[12] and, the federal *Canadian Environmental Protection Act, 1999*[13] potentially resulting in penalties, or orders to perform remediation work or to otherwise address non-compliance. Toronto Hydro has been targeting underground transformers at risk of containing PCBs, which are all also past their useful life, and estimates that there will be 492 underground transformers that contain or are at-risk of containing PCBs remaining at the end of the current rate period. Toronto Hydro intends to replace all of these units by the end of 2025.

Figure 16 illustrates the number of externally-reported oil spill incidents from 2018 to 2022. The increase in reported spills from 2018-2020 is attributed to a modification of the inspection process in 2018 to improve the reporting of transformers with the potential to leak (i.e. are heavily corroded). During this time, the frequency of inspections for select submersible transformers was also increased based on the condition of the transformer from its most recent inspection. The additional inspections for the more at-risk transformers enabled Toronto Hydro to identify more oil spills, resulting in a higher number of incidents reported in accordance with Ontario's *Environmental Protection Act*[14] at Part X (Spills), and the City of Toronto's Sewer Bylaw, Chapter 681.[15]

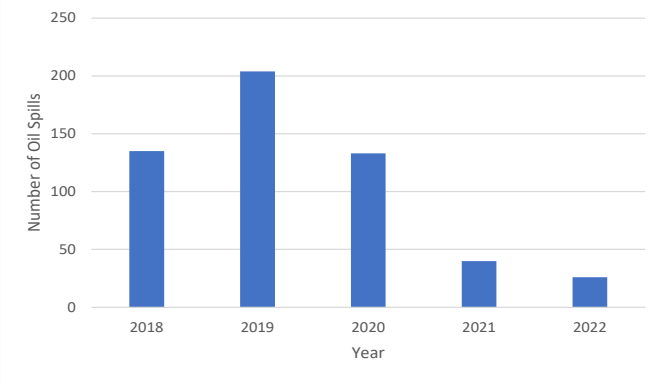


Figure 16: Number of Externally-Reported Oil Spills on Underground Transformers in Underground Horseshoe System

[11] City of Toronto, by-law No 681, Sewers, (May 15, 2023).
[12] RSO 1990, c. E.19
[13] SC 1999, c. 33
[14] RSO 1990, c. E.19
[15] City of Toronto, by-law No 681, Sewers, (May 15, 2023).

Toronto Hydro investigated 2,555 underground transformer failures that occurred between 2013 and 2022. The results of this analysis (see Figure 17 and Figure 18) show that 27 percent of the failed underground transformers failed at or beyond useful life and the number of failed units increases with transformer age. Therefore, if not proactively replaced, transformers on Toronto Hydro's distribution system, which are at or beyond their useful life of 30 years, are at an increased risk of failing.

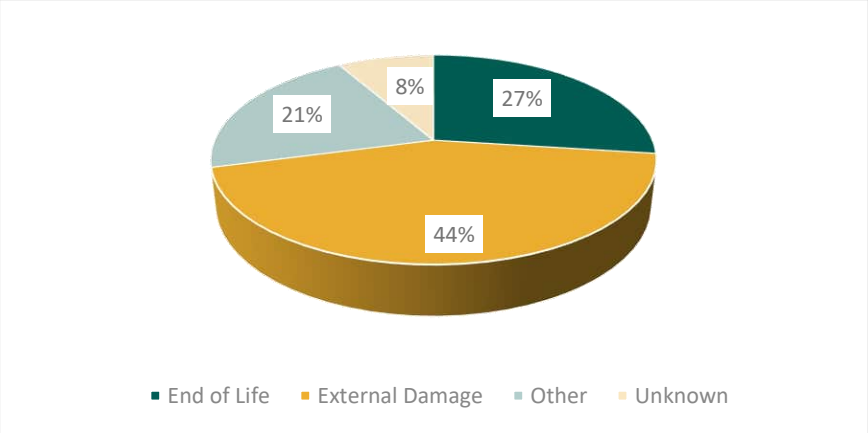


Figure 17: Root Cause Distribution for Failed Underground Transformers from 2013 to 2022[16]

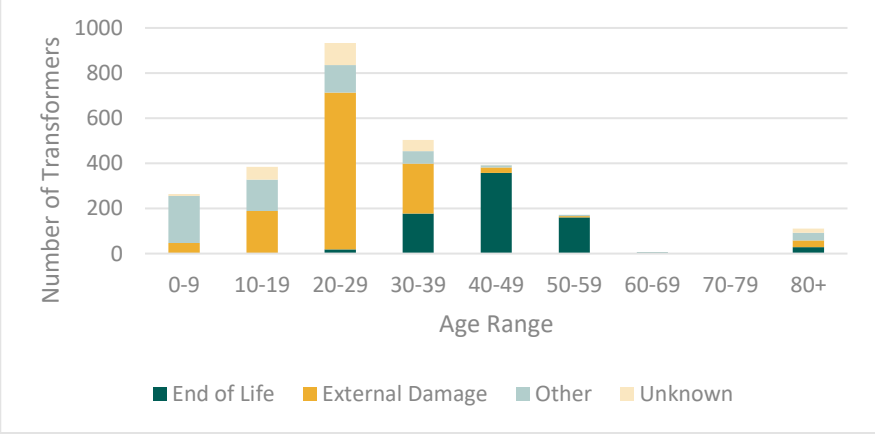


Figure 18: Age at the Time of Failure for Failed Underground Transformers from 2013 to 2022

[16] Others, represent 44 percent which include failures such as supplier quality, lighting strikes, corrosion, overvoltage, contamination etc.

Figure 19 shows the current age distribution of underground transformers in the Horseshoe area in 2022 compared to what it will be in 2029 without investment. As of 2022, 26 percent of underground transformers in the Horseshoe area (i.e. 6,727 units) were at or beyond useful life (i.e. 30 years for padmount, submersible, and vault transformers). Without any replacement, the percentage of transformers at or beyond their useful life will reach 39 percent (i.e. 10,001 units) by 2029. An increase in the number of transformers at or beyond their useful life will increase the risk of units failing, and will erode and eventually reverse the improvements in reliability made in recent years. Additionally, without sufficient replacement, Toronto Hydro will face a backlog of transformers requiring replacement beyond 2029.

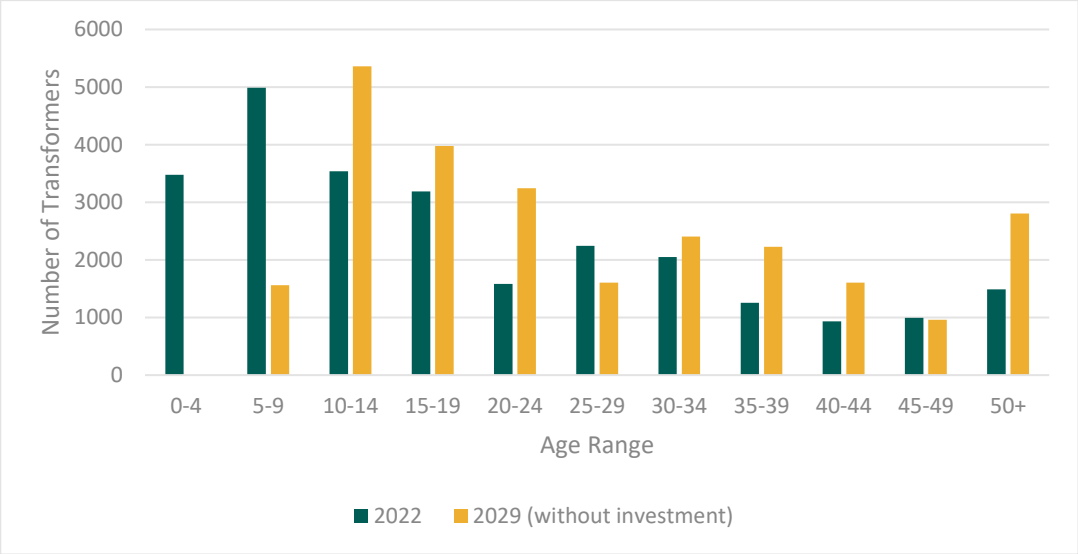


Figure 19: Age Distribution of All Transformers in Underground Horseshoe System as of 2022 and 2029 Without Investment

While age can be a good indicator of a population's current and future failure risk, asset condition assessment provides a more accurate indication of asset failure risk and the need to replace underground transformers (where PCBs are not a factor). As of the end of 2022, 639 transformers exhibit at least material deterioration (i.e. HI4 and HI5) as shown in **Error! Reference source not found.**Table 5 below. Without any capital investment, this number is expected to reach 2,400 by the end of 2029. Not investing in asset renewal will increase reliability risks on the distribution system and run the risk of negative environmental impacts from asset failure as the transformers continue

to deteriorate. The asset condition profiles of the transformers as of 2022 and in 2029 (forecasted) without investment are shown in Table 5 and Figure 20.

Table 5: Asset Condition Assessment for Underground Transformers in Underground Horseshoe System in 2022 and 2029 without Investment

Condition	UG TX - Padmounted		UG TX - Submersible		UG TX - Vault		Total	Total
	2022	2029	2022	2029	2022	2029	2022	2029
HI1 – New or Good Condition	4521	3920	7666	6939	6108	4625	18295	15484
HI2 – Minor Deterioration	1009	469	548	585	3618	1533	5175	2587
HI3 – Moderate Deterioration	476	804	130	534	494	3400	1100	4738
HI4 – Material Deterioration	215	561	120	178	225	506	560	1245
HI5 – End-of-Serviceable Life	22	489	46	274	11	392	79	1155
Grand Total	**6243**	**6243**	**8510**	**8510**	**10456**	**10456**	**25209**	**25209**

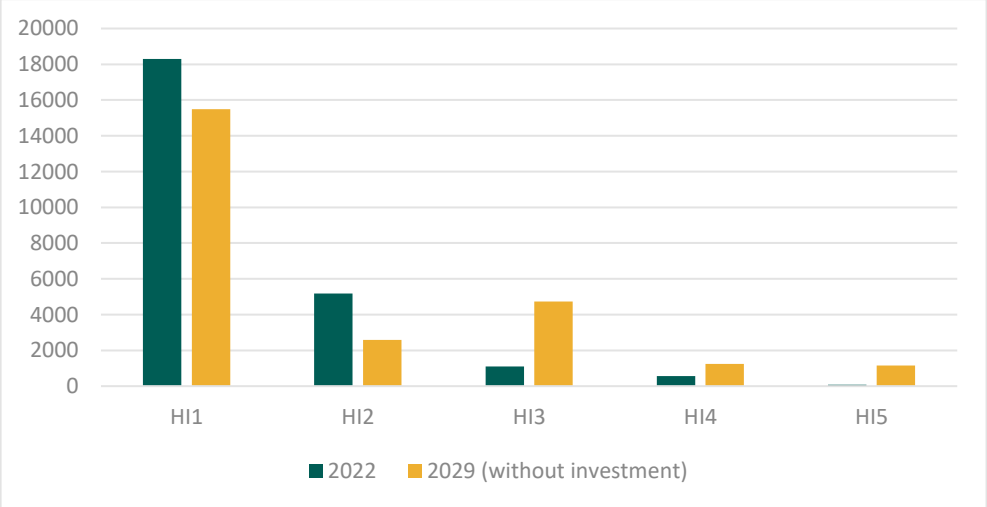


Figure 20: Asset Condition of Underground Transformers in 2022 and 2029 (without investment)

Toronto Hydro plans to replace approximately 2,500 underground transformers under this program over 2025-2029. This will be achieved through area rebuilds on 27.6 kV feeders and voltage conversions of 4.16 kV and 13.8 kV feeders, along with spot replacements of PCB transformers and transformers that are projected to be in HI4 and HI5 condition at the end of 2029 and which are not part of any rebuild project.

E6.2.3.3 Replacement of Underground Switches

Toronto Hydro also plans to replace switches as part of area rebuild projects. There are approximately 3,138 switches in service in the Horseshoe area.

Switches are critical components of Toronto Hydro's distribution system and are used for load switching, isolation, and emergency power restoration procedures. There are two types of switches used in the underground Horseshoe system: (1) padmounted switches (either air vented or sealed with SF_6 insulation) primarily installed next to boulevards for feeder switching; and (2) vault installed switches (either air vented or sealed with SF_6 insulation) used for switching and transformer isolation within a vault. The useful life of these switches is 40 years.

Switches in Toronto Hydro's underground system are exposed to harsh environmental conditions such as contamination and moisture, which can reduce their useful life. Air-vented padmounted switches, for instance, are designed to be vented naturally through louvers under the hood of the enclosure. However, this is also a route for dust and road salt to enter the switching compartments and accumulate within the switch. Although scheduled preventive maintenance, such as inspections followed by corrective CO_2 washing, can remove excessive buildup of contaminants for a limited time, repeated CO_2 washing can contribute to the degradation of the switch's insulation strength, eventually leading to failure.

As the ambient temperature changes, the trapped moisture in the enclosure condenses into water, dampening the dirt and other contaminants that are already present on the insulation surface. The surface then becomes conductive and may result in a flashover of the unit, potentially leading to failure.

A flashover in a padmounted switch can lead to a near simultaneous ignition of all combustible material within the compartment. This discharge of electrical energy can then spread to the other compartments of the switch, causing additional flashovers and combustion, ultimately resulting in

the total failure of the unit. Figure 21 provides an illustration of how contaminants build up on a typical air-vented padmounted switch that could lead to a potential flashover.

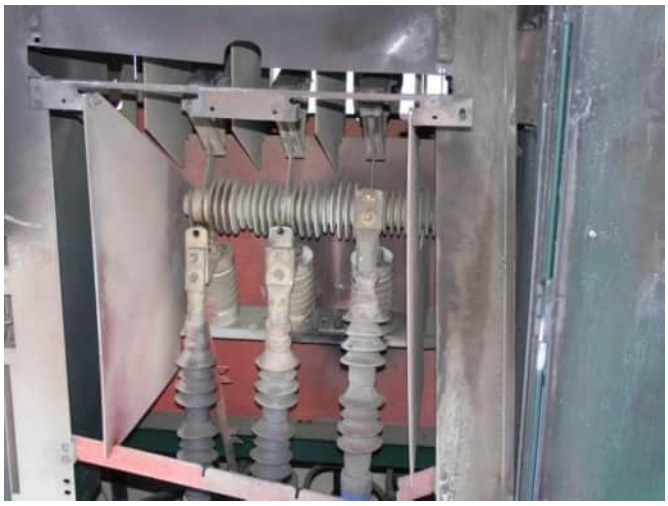


Figure 21: Padmounted switch with contaminant build-up

In Toronto Hydro's underground distribution system in the Horseshoe area, 5.8 percent of the underground outages between 2013 and 2022 were caused by switch failure. Depending upon the location of the switch, whether on the trunk or lateral portion of a feeder, a failure can lead to significant public safety risks and extensive disruption to service for an extended period of time. For example, padmounted switches are commonly connected to the trunk portion of a feeder for load distribution and switching and can lead to significant negative effect on system reliability by causing an outage, or extending a feeder outage to the bus level.

A summary of the ten-year reliability of the underground switches discussed in this Program is shown in Figures 22 to 24. Proactive replacement of switches has helped moderate the frequency of outages caused by switch failures. However, the population of switches in service is aging and if Toronto Hydro does not continue to renew them proactively, the utility expects that the current level of reliability performance will not be sustained as failure rates increase.

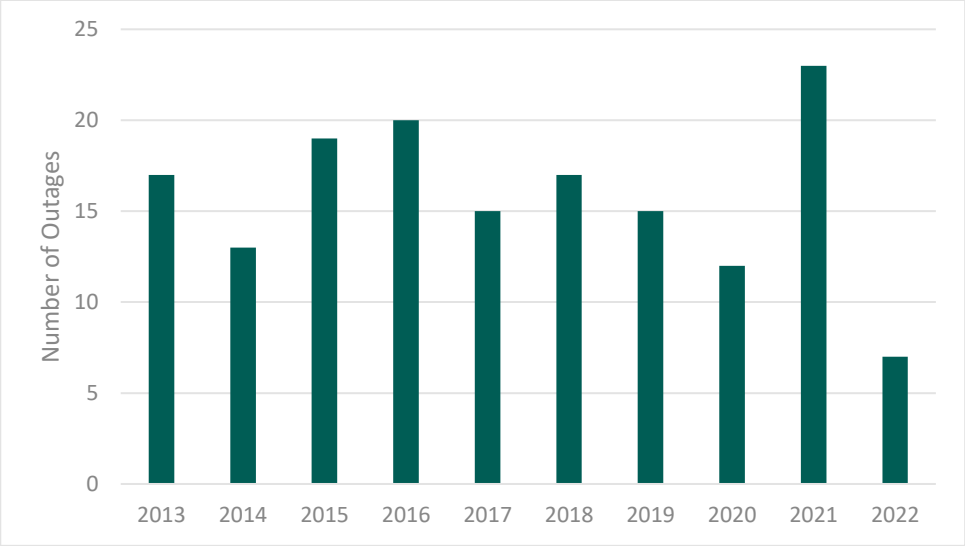


Figure 22: Ten-Year Trend of Outages due to Underground Switch Failures

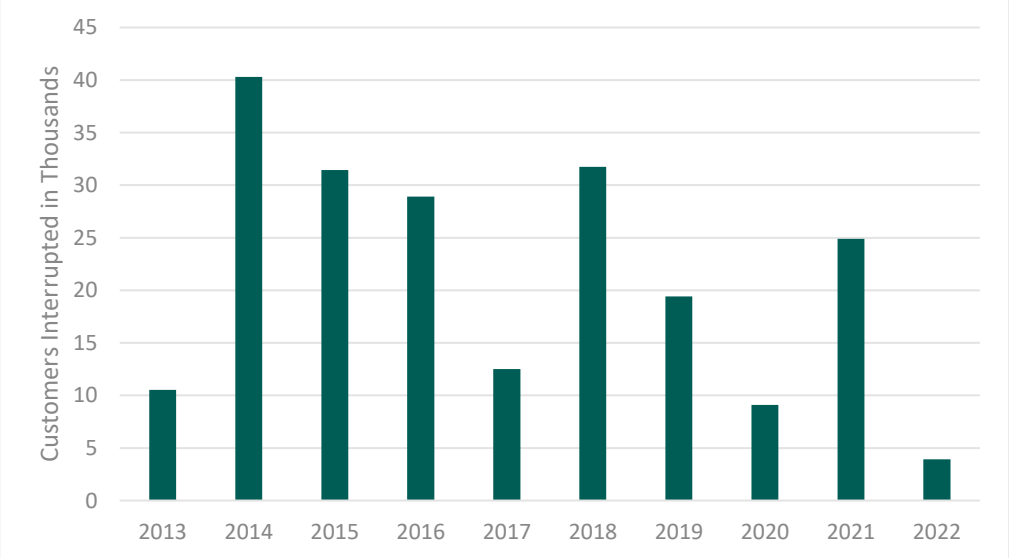


Figure 23: Ten-Year Trend of Total CI due to Underground Switch Failures

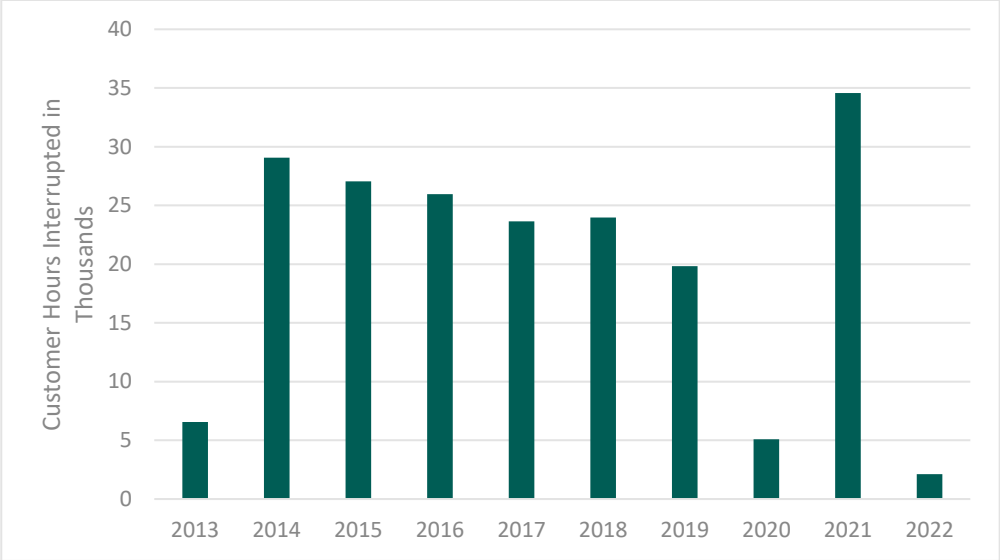


Figure 24: Ten-Year Trend of Total CHI due to Underground Switch Failure

Figure 25 and Figure 26 show the age demographics of all padmount and vault switches, which both have a useful life of 40 years. As of 2029, 86 padmount switches and 595 vault switches will be beyond useful life without investment.

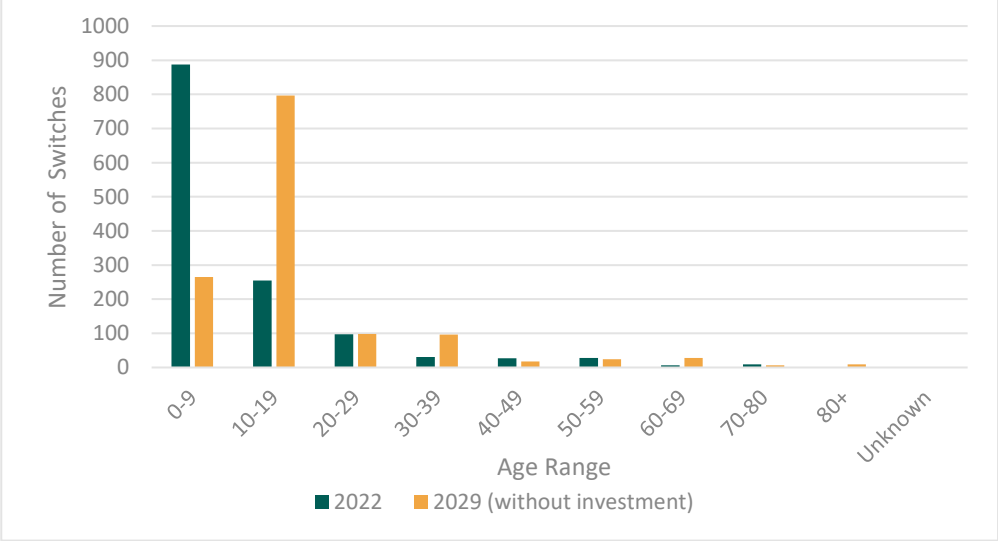


Figure 25: Age Distribution of Padmount Switches in Underground Horseshoe System

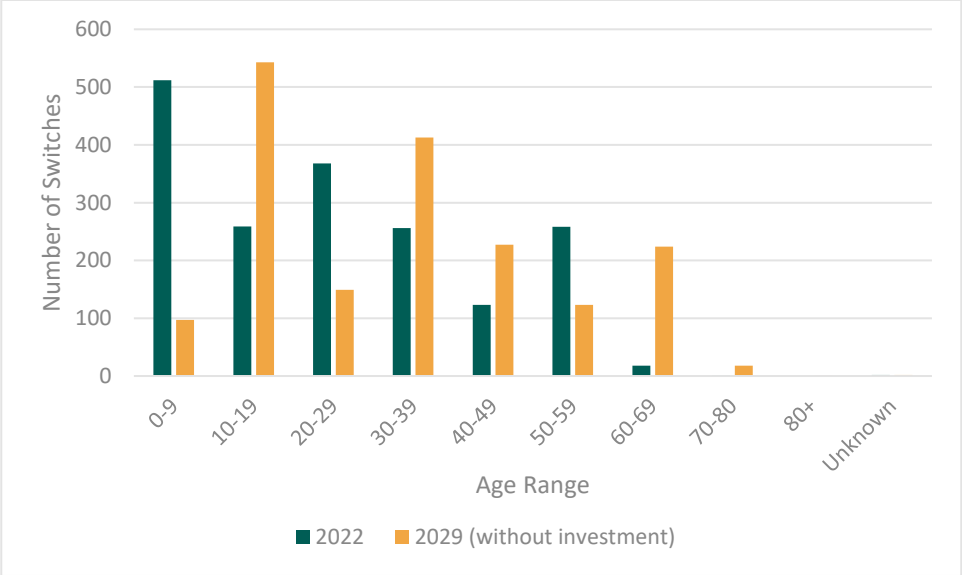


Figure 26: Age Distribution of Vault Switches in Underground Horseshoe System

Toronto Hydro's experience with padmount switches indicates that the majority of these units fail before their expected useful life. Toronto Hydro investigated 359 padmount switch failures that occurred between 2013 and 2022. The results of this analysis (see Figure 27) show that majority of padmount switches failed before the end useful life (40 years) and typical failures are attributed to external factors such as weather, contamination, and corrosion.

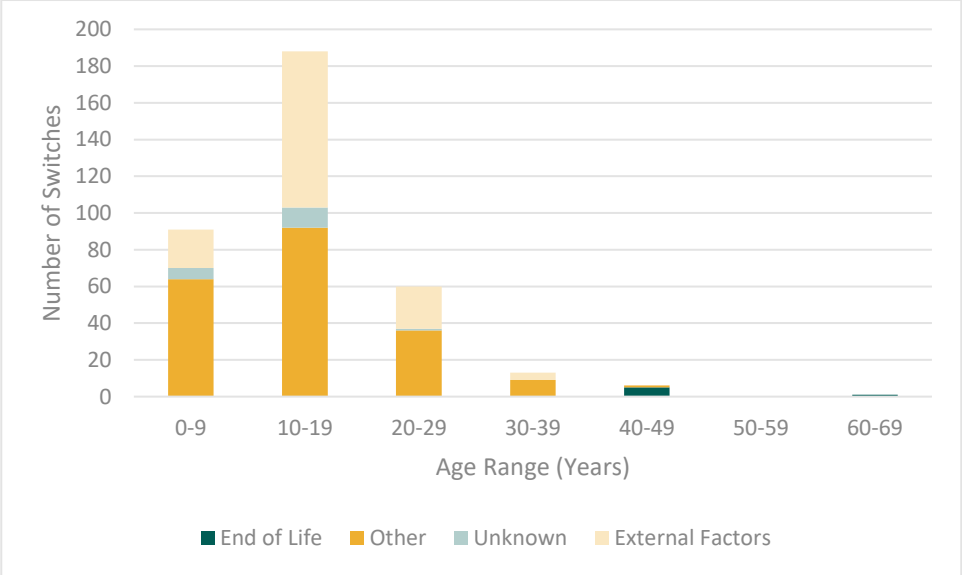


Figure 27: Age and Cause of Failure for Failed Padmount Switches from 2013 to 2022

Condition data for Air and SF6 type underground padmounted switches are shown in Table 6 and Figure 28. There are 70 padmounted switches in HI4 and HI5 as of the end of 2022 and, without investment, that number will almost double to 134 by 2029. An increased number of padmount switches with at least material deterioration will elevate the risks of units failing and therefore, without investment the recent improvements in switch-related reliability will likely erode and eventually reverse.

Table 6: Asset Conditioning for Underground Padmounted Switches – Air and SF_6 Type

Condition	UG Switch Padmounted Air		UG Switch Padmounted SF6		Total 2022	Total 2029
	2022	2029	2022	2029		
HI1 – New or Good Condition	355	346	635	635	**990**	**981**
HI2 – Minor Deterioration	4	11	0	0	**4**	**11**
HI3 – Moderate Deterioration	64	2	0	0	**64**	**2**
HI4 – Material Deterioration	24	13	1	0	**25**	**13**
HI5 – End-of-Serviceable Life	29	104	16	17	**45**	**121**
Grand Total	**476**	**476**	**652**	**652**	**1128**	**1128**

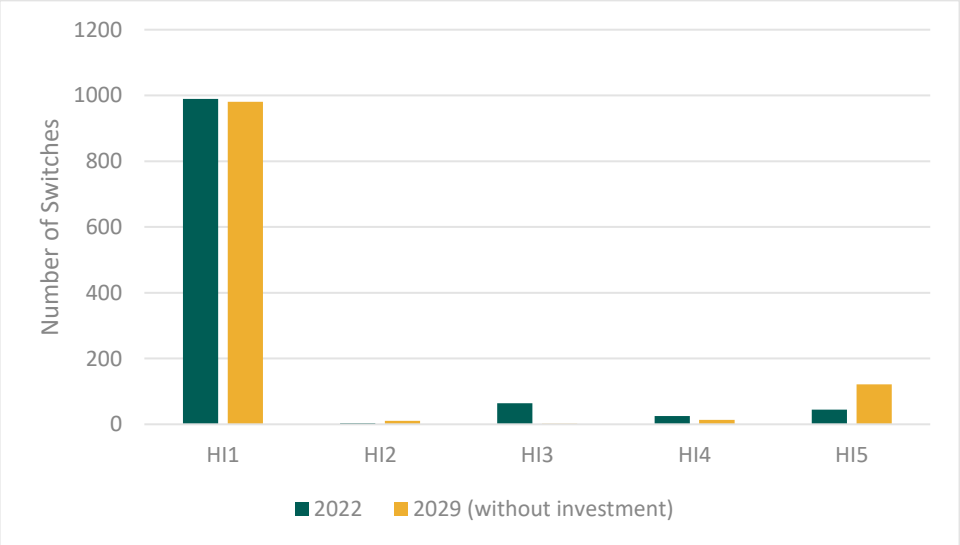


Figure 28: Asset Condition of Underground Switches in 2022 and 2029 (without investment)

To address the risks associated with air vented padmounted switches, Toronto Hydro plans to replace them with the new generation of SF_6-insulated switches. These new switches feature a stainless-steel enclosure to prevent premature rusting and degradation of the cabinet. The unit includes welded viewing windows that mitigate SF_6 gas leakage into the environment. Programmable relays are also used for downstream circuit protection, eliminating the need for on-site switch re-fusing after a fault on the branch circuit. The units have internal grounding provisions making grounding easier and safer for crews in comparison to the external grounding elbows on the existing switches.

The new SF_6 switches also enable SCADA capability for remote sensing, leading to increased system efficiency and improving restoration time in the event of a power failure, while avoiding costs associated with crews physically operating the switch on site. Another advantage of padmounted SF_6 insulated switches is that they have the same circuit configuration and footprint as the existing air insulated padmounted units, thereby avoiding unnecessary cable and civil construction work. Additionally, all external components of the SF_6 insulated switches are sealed and do not require routine CO_2 washing to remove accumulated contaminants.

To mitigate environmental risks related to SF6 insulated gear, Solid Dielectric ("SD") switchgear is being trialed as an alternative. The SD gear shall have the same SCADA capability as the SF6 gear and shall maintain the same circuit configuration and foundation design to avoid unnecessary cable and civil construction work.

Toronto Hydro plans to replace approximately 116 padmount switches over 2025-2029 as part of area rebuild projects under this Program. The remaining padmounted switches and vault switches that have at-least material deterioration and are not part of the rebuild scope will be replaced through the Reactive and Corrective Capital program[17] upon failure as they do not present environmental risks.

E6.2.4 Expenditure Plan

Table 7: Historical & Forecast Program Cost ($ Millions)

	Actuals			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Underground System Renewal Horseshoe	73.5	50.9	64.4	92.3	78.7	92.6	82.3	93.8	101.1	105.9

[17] Exhibit 2B, Section E6.7.

E6.2.4.1 2020-2024 Variance Analysis

Over the 2020-2024 period, Toronto Hydro forecasts total spending of $351.8 million in the Underground System Renewal program, which is approximately $108 million lower than planned in the 2020-2024 Distribution System Plan. Toronto Hydro reduced the Program budget to support meeting the utility's capital funding limits while managing overall risk on the distribution system. In particular, this involved shifting away from direct-buried cable replacement, while still prioritizing underground transformers at risk of containing PCBs.

Over the 2020-2022 period, Toronto Hydro spent $188.8 million and installed 325 kilometres of underground cable in duct, 1,013 transformers, and 127 underground switches, as shown in Table below. Toronto Hydro plans to invest another $163 million in 2023-2024.

Table 8: 2020-2024 Volumes (Actual/Bridge) – Underground Circuit Renewal Horseshoe Program (Primary Electrical Assets)

Asset Class		Actuals			Bridge		Total
		2020	2021	2022	2023	2024	
Total Cable	*km*	114	83	128	175	63	563
Direct-Buried Cable[18]	*km*	29	32	18	13	13	105
Transformers	*Units*	307	425	281	406	361	1677
Switches	*Units*	55	20	52	18	17	162

As noted above, the utility has been prioritizing replacement of underground transformers with PCBs (i.e. through spot replacements) in order to eliminate them by 2025. However, challenges acquiring transformers has reduced Toronto Hydro's ability to ramp up the pace of replacements as intended, resulting in a notable decrease in units completed in 2022. The utility has been working diligently to mitigate the impacts of supply chain issues (see Exhibit 4, Tab 2, Schedule 15) and while the utility expects to increase the pacing in 2023, it is still on track to replace fewer transformers than originally planned. In addition, with the reduced budget and focus on PCB transformers, Toronto Hydro invested less in area rebuilds, resulting in less direct-buried cable and fewer switches replaced than proposed in the 2020-2024 DSP.

[18] Note that the Direct-Buried Cable amounts in this table are a subset of the Total Cable amounts in the row above.

More broadly, unit volume and cost variances can be attributed in part to changes in the scope of work as projects moved from high-level estimates to detailed designs. These changes are anticipated for complex construction projects and typically result from a more detailed review of the scope of work and execution needs during the design phase. For example, designers may identify additional or fewer assets that should be included in a project, interference with other utilities and a resultant need to adjust the scope, additional restoration costs, etc., that influence the final cost of a project.

E6.2.4.2 2025-2029 Forecasts

Toronto Hydro plans to spend $475.7 million in this Program over the 2025-2029 period. The 2025-2029 forecast expenditures are based on Toronto Hydro's historical unit costs trends and experience with executing this type of work over recent years. The estimated volumes for major underground asset replacements during the 2025-2029 period are shown in Table 9.

Table 9: 2025-2029 Estimated Volumes (Forecast) – Underground System Renewal (Primary Electrical Assets)

Asset Class		Forecast					
		2025	2026	2027	2028	2029	Total
Total Cable	*km*	30	72	84	79	75	**340**
Direct-Buried Cable	*km*	25	38	45	35	39	**182**
Transformers	*Units*	870	352	346	429	481	**2,478**
Switches	*Units*	12	22	28	26	28	**116**

The forecasted volumes are estimates based on a preliminary selection of areas targeted for complete rebuilds on 27.6 kV feeders, rebuilds with voltage conversion, and spot replacements.

- **Area Rebuilds on 27.6 kV Feeders:** Area rebuild projects involve the prioritization and replacement of major assets such as cable, switches, and transformers, in areas where historical failures and deteriorated asset conditions pose particularly high risk to reliability. Area rebuilds ensures Toronto Hydro is able to coordinate work in an area and efficiently mobilize crews to minimize customer outages. By replacing entire sections on the distribution system on the feeders selected for rebuild, Toronto Hydro can ensure that customers only undergo one planned outage as opposed to numerous outages resulting from reactive work or spot replacements.

- **Area Rebuilds with Voltage Conversion:** Where a feeder identified for renewal through area rebuilds is operating on 4.16 kV and 13.8 kV voltages, it will be converted to 27.6 kV. Similar to area rebuilds, Toronto Hydro plans to select 4.16 kV and 13.8 kV for conversion based on historical performance, the number of assets that are in deteriorated condition or at or beyond useful life, and potential impact on customers supplied by the feeder for area conversion.

- **Spot replacement:** Transformers that need replacement but are not part of area rebuild projects will be addressed on a case by case basis through spot replacement projects. These projects will focus on replacing assets that are identified as having at-least material deterioration or pose environmental risks due to oil leaks. Spot replacement projects aim to reduce the likelihood of failures and mitigate the risk of negative environment impacts from oil leaks.

Once Toronto Hydro has removed all underground transformers containing PCBs, it will shift back towards an approach that includes more rebuilds focused on direct-buried cable and limiting spot replacements to only the worst condition transformers not addressed elsewhere.

Whenever possible, work under this Program is combined or coordinated with projects from other programs (such as overhead renewal and rear lot conversion) in the same area. Underground renewal projects are broken into civil and electrical phases, and those with significant amounts of civil work are broken down further into sub-phases for better manageability and coordination of resources.

Equipment in the same area and fed from the same Toronto Hydro feeders is coordinated in terms of replacement schedule and sequencing. This approach reduces disruption of supply and requires less mobilization of resources to the same area. Reduced disruption to feeders translates into fewer outages for customers, and improves project efficiencies. In addition, any voltage conversion underground work is coordinated with stations maintenance and capital work. This allows Toronto Hydro to eventually decommission Municipal Stations prior to any major maintenance or renewal investments.

Once projects are scoped at a high level, they undergo a field inspection in order to validate the scope of work, identify third party conflicts, and refine estimates before design finalization. Through

this process, projects identified for renewal may be subject to change, and poorly performing feeders that demonstrate higher risks may take priority.

E6.2.5 Options Analysis

Toronto Hydro considered the following options for the Underground System Renewal program. Under each of these options Toronto Hydro would seek to replace all remaining underground transformers containing, or at risk of containing, PCBs by the end of 2025 and will only replace switches proactively through area rebuilds (i.e. no spot replacement of underground switches).

E6.2.5.1 Option 1: Limited Area Rebuilds (15 feeders), Voltage Conversion (14 feeders) and Spot Replacements of PCB Transformers Only

Under this option, Toronto Hydro would rebuild 29 feeders, including the conversion of 14 feeders operating on 4.16 kV and 13.8 kV voltages to 27.6 kV. With this approach, Toronto Hydro would replace 140 km of cable, of which 98 km is direct-buried (15 percent of total direct-buried cable remaining as of 2022) and 42 km is cable in concrete-encased ducts beyond useful life. At this pace, it would take 30-35 years to eliminate all the direct-buried cable from the system, during which time customers would be exposed to increasing reliability risk as the cables continue to age. There would also be 237 km of cable in concrete-ducts beyond useful life remaining in the system by 2029 compared to 121 km under Option 2.

This option will lead to minimal improvement in cable failures wherein only limited sections of direct-buried cable and cables beyond useful life will be replaced. Given the significant contribution of cables to underground outages and the 542 km of direct-buried cable remaining and 7.6 percent of cables in concrete-encased ducts beyond useful life by 2029 under this option, the utility expects there would be higher costs and disruptions to the public and customers for reactive work.

This option also includes spot replacements of the remaining transformers containing PCBs. Although planned rebuilds will address some transformers past useful life and/or with at least material deterioration, there will continue to be a significant number remaining on the system, increasing the risks of failures and reversing recent improvements in transformer-related reliability and oil spills.

While this option's pace of investment would reduce program costs significantly, the resulting increases to reliability risk and expected impact on customers is not aligned with customer preferences, which includes reliability as a top priority.

E6.2.5.2 Option 2 (Selected Option): Area rebuilds (29 feeders), Voltage Conversion (29 feeders), Spot Replacement of Both PCB and Materially Deteriorated Transformers

Under this option, Toronto Hydro plans to rebuild 58 feeders, including 29 feeders converted to 27.6 kV. With this approach, Toronto Hydro will replace 340 km of total underground cable in the Horseshoe, out of which 182 km will be direct-buried cable (21 percent of total direct buried cable as of 2022) and 158 km will be cable in concrete-encase ducts beyond useful life. At this pace, it will take 20-25 years to eliminate all of the direct-buried cable from the system and there will be an estimated 121 km of cable inside concrete-encased ducts that is beyond useful life by 2029.

Toronto Hydro projects that under this option there will be 458 km of direct-buried cable remaining on the system and 3.8 percent of cables in concrete encased ducts will beyond useful life by 2029. Although, this is still a significant amount of direct-buried cable and end-of-life cable left in the system, it is an improvement over Option 1 and would mitigate the expected reliability impacts of that option. Toronto Hydro finds this pace of cable renewal to be the most reasonable balance between outcomes such as reliability and costs.

Under this option, Toronto Hydro plans to replace approximately 2,500 underground transformers through area rebuilds and through spot replacements of transformers that are projected to be in HI4 and HI5 condition at the end of 2029 and are not part of any rebuild project. This will also include the remaining 492 underground transformers in the Horseshoe area that contain (or are at-risk of containing) PCBs. This option will mitigate the potential accumulation of a large backlog of transformers that are at a high risk of failure and in need of replacement beyond 2029 as well as mitigate the environmental risks associated with leaking oil.

E6.2.5.3 Option 3: Area rebuilds (30 feeders), Voltage Conversion (38 feeders), more DB cable replacement, spot replacement of remaining transformers containing PCB along with assets with at-least material deterioration at the end of 2029

Under this option, Toronto Hydro would fully rebuild a total of 68 feeders, 38 of which would be converted to 27.6 kV. With this approach, Toronto Hydro would replace 375 km of total cable, out of which 215 km is direct-buried cable (32 percent of total direct-buried cable remaining as of 2022) and 160 km is cable in concrete-encased ducts beyond useful life. At this pace Toronto Hydro would eliminate all direct-buried cable within 15-20 years and would reduce the cable inside concrete ducts beyond useful life to 119 km by 2029.

Under this option, the amount of direct-buried cable remaining in the system would be reduced to 425 km by 2029, improving expected reliability relative to the other options.

This option also includes the spot replacement of any remaining underground transformers containing PCBs along with any additional transformers remaining in the system that are projected to be HI4 or HI5 by 2029 without investment and that are not part of any rebuild project. The replacement of these remaining transformers not addressed through the rebuilds would help to reduce the risk of failures as well as to mitigate the environmental risks associated with leaking oil.

This option would ensure that Toronto Hydro would have substantially less backlog of deteriorated and end of life assets by 2029 and less areas in the underground system that are supplied by 4.16 kV and 13.8 kV. While this option is the best one for mitigating reliability and environmental risk, the cost is much higher and it does not represent a balanced trade-off between risk mitigation and price.

E6.2.6 Execution Risks & Mitigation

Project execution begins with the civil phase of the underground renewal project. Electrical construction commences upon completion of the civil work. The risks associated with the Underground System Renewal program include, but are not limited to:

- Unforeseen updates and changes to existing road moratoriums imposed by the City of Toronto in areas where Toronto Hydro intends to perform underground renewal work. To mitigate this risk, Toronto Hydro will coordinate closely with the City of Toronto and its representatives, i.e. Ward Councillor, Business Improvement Area delegates.

- Unforeseen weather conditions that may affect Toronto Hydro's ability to carry out planned outages. Extreme weather conditions such as heat restrictions during summer or harsh winter storms, can also impact construction schedules. Toronto Hydro addresses this risk by closely monitoring weather forecasts and making necessary adjustments to the construction schedule to minimize the impact of adverse weather conditions.

- Third-party conflicts may require Toronto Hydro to modify its trench route due to underground space limitations, resulting in higher than estimated project costs. Toronto Hydro mitigates this risk by engaging with third parties in the design phase to ensure close coordination and alignment. This involves participation in the Toronto Public Utility Coordinating Committee meetings to identify and avoid third party conflicts.

- Some projects require work within customer owned civil structures or consent on easements from customers to install distribution assets on private property. In the case of customer-owned civil structure, the customer may have to perform civil rebuild work prior to Toronto Hydro commencing its activities, causing project delays. Toronto Hydro mitigates this risk by inspecting customer owned assets during the design phase and communicating to the customer by issuing Customer Advice Form ("CAF") for any deficiency identified. This ensures that customers are given advanced notice and have an opportunity to raise their concerns and address the civil work in a timely manner. For permits and easements, Toronto Hydro will reach out and engage customers early in the design phase of the project to account for the possibility of delays. This gives customers the opportunity to meet with the utility to discuss the details of the project and any concerns. This proactive customer engagement approach has been successful in minimizing construction delays.

- All underground projects are designed and constructed in accordance with approved Toronto Hydro's standards and specifications. However, in certain cases, deviations or special considerations are needed during design. Toronto Hydro will follow its established process for all deviation requests so that they can be assessed and approved by the standards department in a timely manner during the design phase. This process helps to prevent delay or costly rework due to operational issues during the execution of the projects.

- Longer lead time for material, especially underground transformers, can seriously impact project execution, resulting in delays or deferrals into future years. This is mitigated through proactive internal engagement and coordination and Toronto Hydro's procurement strategy. For more details on this procurement strategy and what Toronto Hydro has been doing to address this issue please see Exhibit 4, Tab 2, Schedule 15 (Supply Chain).

E6.3 Underground System Renewal – Downtown

E6.3.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 80.6	**2025-2029 Cost ($M):** 165.1
Segments: Cable Chamber Renewal, Underground Cable Renewal, Underground Residential Distribution Renewal, Underground Switchgear Renewal	
Trigger Driver: Failure Risk	
Outcomes: Operational Effectiveness - Reliability, Environment, Operational Effectiveness - Safety	

The Underground System Renewal – Downtown program (the "Program") addresses aging, deteriorating and poor performing underground distribution assets in the downtown core area of pre-amalgamation City of Toronto.[1] This Program continues rebuild and replacement activities for deteriorating and functionally obsolete underground assets in the City's core. Starting in 2020, most of these assets have been managed through a combination of preventative maintenance, targeted refurbishment, planned system renewal and in the event of asset failure, reactive and corrective capital and maintenance programs.[2][3][4] The average condition of these assets (in addition to other pressures discussed below) necessitates a targeted renewal strategy; targeting worst performing and highest risk areas.

The Program is designed to maintain reliability, mitigate asset failure and public safety risks within the downtown core by: (1) replacing obsolete underground lead covered cables with standard tree retardant cross-linked polyethylene ("TRXLPE") cables, (2) reconstructing cable chambers (or components; e.g. roofs, duct banks) at risk of failure due to poor structural conditions, (3) proactively replacing end-of-life and obsolete underground residential distribution ("URD") assets, and (4) proactively replacing end-of-life and obsolete underground switchgear.

The Program is grouped into the four segments summarized below:

[1] This Program does not address network units or network vaults. Network equipment is addressed within the Network System Renewal program (Exhibit 2B, Section E6.4)
[2] See Exhibit 4, Tab 2, Schedules 1, 2, and 3 Preventative and Predictive Maintenance programs
[3] See Exhibit 2B, Section E6.7
[4] See Exhibit 4, Tab 2, Schedule 4 Corrective Maintenance

- **Underground Cable Renewal:** The Underground Cable Renewal segment is a continuation of the activities identified in Toronto Hydro's 2020-2024 Distribution System Plan ("DSP"). This segment replaces obsolete underground lead covered cables with standard tree retardant cross-linked polyethylene cables. Based on the age and condition of Toronto Hydro's population of lead cables, the utility anticipates a decline in reliability performance and an increase in operational and safety risks. Toronto Hydro recognizes the customer value stemming from the removal of these high risk, lead based cables, and plans to invest $61 million over the 2025-2029 period to replace approximately 3.5 percent of 985 km paper-insulated lead-covered ("PILC") cable and 5.3 percent of 176 km asbestos-insulated lead-covered ("AILC") cable. Replacement of legacy PILC and AILC cables will allow Toronto Hydro to maintain reliability performance by proactive replacement of high risk cables. This will also decrease the presence of designated substances (i.e. lead and asbestos) on the grid. These cables are a critical part of the distribution infrastructure serving large customers (e.g. major financial institutions) and other reliability-sensitive customers (e.g. multi-residential high-rises) in the downtown core. Toronto Hydro uses risk-based prioritization, which considers historical failures, age, feeder uniformity based on cable type, and the magnitude and criticality of the load served by each feeder, to direct expenditures to the projects with the greatest customer value. In addition to removing lead-based cable, Toronto Hydro plans to install approximately 5 km of fiber optic cable to enable on line cable monitoring. On line cable monitoring will provide real-time thermal profile of cables and loading data which could be used for cable risk assessment and replacement prioritization in the future.

- **Cable Chamber Renewal:** This segment involves the reconstruction of cable chambers or cable chamber components (e.g. roofs, duct banks) that are at risk of failure due to their poor structural condition. Prior to 2020, Toronto Hydro managed the reconstruction of cable chambers reactively. However, due to the growing number of failing chambers and the complexity of chamber reconstruction work, Toronto Hydro introduced a planned renewal segment in 2020. The vast majority of chambers in Health Index ("HI") band 4 (material deterioration) and HI5 (end of serviceable life) condition are located in the downtown core, where there is heavy vehicular and foot traffic and a high density of circuits running through each chamber.[5] These chambers can hold up to 29 circuits, supplying up to 3,500 customers

[5] For many of its major assets, Toronto Hydro performs asset condition assessment ("ACA"), in which the condition of each asset is assigned a health index ("HI") band from HI1 to HI5, where HI5 indicates the worst condition. For these

per chamber. Typically, these are chambers that supply large condominiums with many suite-metered residential customers. Chambers can also supply one or several large industrial or commercial customers. As of 2022, 592 cable chambers were in HI4 or HI5 condition and this is projected to grow to 1,113 by 2029 without investment. To mitigate this growing backlog and associated safety and reliability risk, Toronto Hydro plans to address 199 cable chambers or cable chamber components. Toronto Hydro also plans to replace 2,800 cable chamber lids to address the public safety risks in high traffic areas. The total forecast cost for this segment is $96.5 million.

- **Underground Residential Distribution ("URD") Renewal:** This segment is focused on the URD system – a unique looped distribution design serving primarily low-rise residential customers in limited areas of the pre-amalgamation City of Toronto. Prior to 2020, Toronto Hydro managed the replacement of URD assets on a reactive basis. However, due to the growing number of failing URD vault roofs, severe corrosion, deteriorating and obsolete equipment, Toronto Hydro introduced a planned renewal segment in 2020. The utility plans to invest approximately $4.8 million over 2025-2029 to proactively replace end-of-life and obsolete URD assets that contribute to the deterioration of URD system reliability, namely switching and non-switching vaults, switches, and transformers. In addition, Toronto Hydro plans to install new Faulted Circuit Indicators ("FCIs") on URD feeders that experience the most outages. Toronto Hydro's objective for 2025-2029 is to invest the amount needed to maintain average reliability performance for the customers served by this system. The utility aims to achieve this by targeting the worst condition, obsolete, and most critical URD assets.

- **Underground Switchgear Renewal:** This segment replaces underground switchgear in customer owned vaults that feed apartment buildings, educational facilities and community centres. To date, Toronto Hydro has managed the replacement of this type of assets on a reactive basis. However, due to the growing number of deficiencies of underground switchgear where repairs are not an option and require replacement due to obsolescence, Toronto Hydro is introducing a planned renewal segment starting in 2025. The utility plans to invest approximately $2.9 million over 2025-2029 to proactively replace end-of-life and obsolete underground switchgear. Toronto Hydro's objective for 2025-2029 is to invest the amount needed to maintain average reliability performance for the customers served by

same assets, the utility can then also project future condition (i.e. HI band) assuming no intervention. See Exhibit 2B, Section D, Appendix A for more details on Toronto Hydro's ACA methodology

these assets. The utility aims to achieve this by targeting the worst condition and most critical assets.

The Underground System Renewal – Downtown program for the 2025-2029 rate period is also aligned with the objectives of addressing environmental and safety risks associated with distribution assets containing PCB, lead, or asbestos. The total proposed investment for the Program in 2025-2029 is $165.1 million.

E6.3.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Operational Effectiveness – Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) and reduces the risk of lengthy outages on feeders serving thousands of downtown customers, including large, critical customers in the core while improving long-term system health by: o Replacing an estimated 35 kilometres of PILC cable that is subject to a high risk of failure. o Rebuilding/repairing/abandoning 199 cable chambers known to be in HI4 and HI5 condition. o Reducing the average number of transition joints on downtown feeders. o Replacing FCIs at end of service life on select URD feeders, enabling crews to quickly find faults and reduce restoration time. o Replacing 20 end of life and obsolete underground switchgear
Environment	• Contributes to Toronto Hydro's environmental objectives and reducing the risk of toxic exposure to the environment by: o Eliminating PILC cable containing oil and potentially PCBs; o Eliminating AILC cable containing asbestos; o Eliminating PILC and AILC cable containing lead; and o Replacing URD transformers containing oil. • Contributes to the utility's commitment to reduce greenhouse gas emissions by replacing URD switches containing SF6 gas.
Operational Effectiveness - Safety	• Contributes to the utility's public and employee safety objectives and performance by: o Replacing 2,800 chamber lids to reduce the risk of injury or property damage from cable chambers lid ejections;

	○ Eliminating safety hazards such as poor structural integrity and cable congestion; ○ Reducing the safety hazards related to the structural failure of cable chambers and URD vaults roofs in high-traffic areas by replacing or abandoning HI4/HI5 condition chambers, and chambers / vaults roof rebuild; and ○ Reducing the potential exposure to lead and asbestos (which are classified as Designated Substances under the Occupational Health and Safety Act6 (Ontario Regulation 490/09 Sections 5 and 10). ○ Safely handle and dispose of asbestos (and lead) as prescribed in the Ontario Occupational Health and Safety Act 7(Reg. 8338) and the Canadian Environmental Protection Act. ○ Replacing an estimated 4,000 cable splices thus reducing the risk of cable chamber lid ejections ○ Reducing the safety hazards related to arc flash incidents due to maloperation of underground switches by replacing HI4/HI5 underground switchgear.

E6.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Functional Obsolescence, Safety, Environmental Risk

The Underground System Renewal – Downtown program is driven by the failure risk of key assets that negatively impact reliability and safe operation within the downtown core. Historically, these assets had shown high reliability but have now become obsolete or pose a risk to the public and the environment. Many of these assets are vital to supply critical customers in the downtown district. These are of particular concern for both residential and large commercial customers who identify reliability as one of their top needs and the majority support investments that reduces outages as demonstrated through the customer engagement surveys.[9]

[6] RSO 1990, c. O.1
[7] *Ibid.*
[8] Control of Exposure to Biological or Chemical Agents, RRO 1990, Reg 833
[9] Exhibit 1B, Tab 5, Schedule 1

E6.3.3.1 Underground Cable Renewal

The Underground Cable Renewal segment is a continuation of the activities identified in Toronto Hydro's 2020-2024 DSP. This segment will focus on replacing obsolete primary PILC and secondary AILC underground cables at a high risk of failure with primary TRXLPE and secondary XLPE cable. These cables are typically found in the pre-amalgamation City of Toronto, especially throughout the downtown core.

PILC and AILC cables were initially installed in the downtown system due to their high reliability and long-life span. However, they are obsolete across the industry due to environmental and health and safety concerns (which includes the challenge of safely and skillfully working with lead). Major utilities are proactively eliminating lead cable, and only one PILC supplier remains (there are no longer any suppliers of AILC cables). Approximately 58 percent of all PILC cables and 93 percent of all AILC cables in the system are more than 30 years old. Aged cables are showing signs of deterioration, including pin holes, cracks, and leaks.

Toronto Hydro is planning to remove approximately 3.5 percent of PILC cable (34.9 circuit kilometres of 985 kilometres) and 5.3 percent of AILC cable (9.3 circuit kilometres of 176 kilometres) between 2025 and 2029. The cables will be replaced based on the risk level associated with each feeder. A prioritization model has been developed by Toronto Hydro to rank primary feeder cable segments based on various factors, including historical failures, cable types, number of transition splices on feeders, age and customer base. In addition, as primary cables and cable segments are being tested or replaced, Toronto Hydro will re-prioritize at-risk feeders. Where at-risk primary cable sections are identified, this will drive the replacement of the legacy type AILC cable that is connected downstream of these cable sections.

PILC cable consists of a conductor surrounded by oil-impregnated paper insulation, lead sheath and an optional linear low-density polyethylene jacket. There are approximately 985 circuit-kilometres of 13.8 kV PILC underground cable on the system. These cables were used as the primary service cable in the downtown core, connecting transformer stations to customers or Toronto Hydro owned distribution transformers (these transformers step down voltage and supply residential customers). Approximately 51 percent of all primary cable in the downtown core is PILC cable and approximately 49 percent is XLPE cable.

Figure 1 shows the distribution of PILC cable in the City of Toronto and the level of risk associated with them based on the type of cable, age, number of splices and reliability record. The highest risk

cable segments (15 percent of total PILC cable length) are found both within and around the downtown core, while the medium risk cable segments (41 percent of total) are heavily concentrated within the core, and the Financial District in particular.

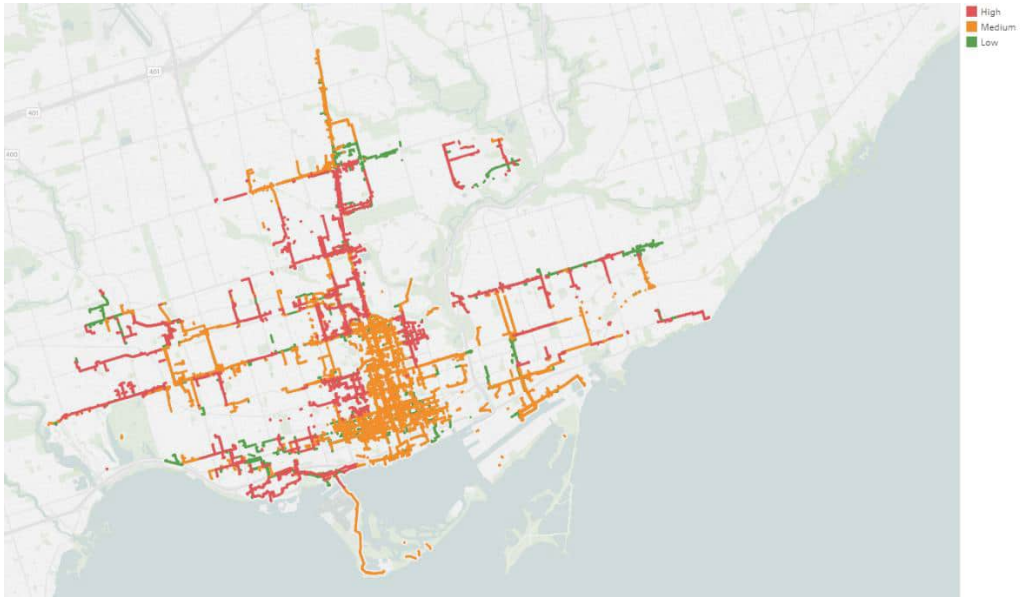


Figure 1: PILC Cable Distribution

AILC cables are found downstream of these PILC cables. They consist of a conductor (typically copper) surrounded by asbestos-based insulation and covered in a ductile lead sheath. These cables account for 40 percent of the secondary voltage connections within the secondary network system.[10]

Figure 2 represents the general distribution of all AILC cables in the city of Toronto and their level of risk based on the associated age and condition of primary assets. The majority of the AILC cable population is located in the core, whereas a small proportion is located north of the core.

[10] For more information on the Secondary Network System, please refer to Exhibit 2B, Section D2.2.3 of the Distribution System Plan.

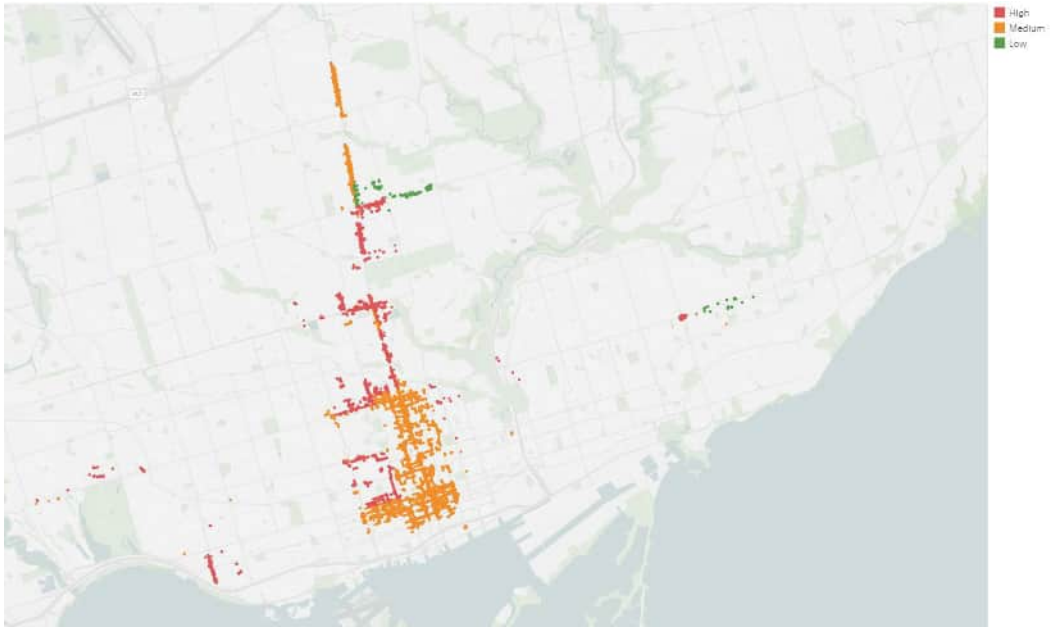


Figure 2: AILC Cable Distribution

Historically, PILC cable was used as it has good reliability record with a typical useful life of 65 years. However, the risk of failure for PILC cable increases if the PILC cable is modified. Due to the obsolescence of PILC and AILC cables, the necessary interventions and modifications to downtown feeders have unavoidably resulted in the splicing of XLPE cable into sections of PILC and AILC cable. Splicing is the process used to maintain the connectivity between two cable sections using joints for similar cable types and transition joints for different cable types. It is typically carried out when a longer cable is required, a branch is required, or part of an old cable is replaced with a new cable. This introduces non-uniformity of cable types and thus increases the risk of failure on the system as the majority of Toronto Hydro feeders with PILC and AILC cables do not consist of 100 percent PILC or AILC; instead, a mixture of cable types is common (e.g. PILC and XLPE, or AILC and XLPE).

Table 4 summarizes the programs and types of work that lead to a mix of cable types on Toronto Hydro feeders.

Table 4: Work conducted on Toronto Hydro feeders that lead to mixed cable types

Programs	Description of Work
Customer Connections (Exhibit 2B, Section E5.1)	• Customers are connected with new XLPE type cable spliced to existing PILC cable. • This also includes the addition of XLPE cable for secondary network type connections (replacement of AILC cable).
Reactive Capital (Exhibit 2B, Section E6.7)	• Cable faults or leaking cables are repaired by cutting or piecing-out faulty sections, and replaced with new XLPE cable, using splices.
Load Demand (Exhibit 2B, Section E5.3)	• Cable sections that require upgrades due to capacity limitations are replaced with new XLPE cable.
Network System Renewal (Exhibit 2B, Section E6.4)	• Circuit reconfigurations, required to achieve network stability and improved reliability, involve splicing new secondary and primary XLPE cable into existing AILC and PILC cables. • Network unit replacements include the replacement of critical AILC or PILC type cables that are connected to these units. • Cables to the most upstream cable chamber are replaced resulting in the introduction of splices.

As a result of the work noted in Table 4, lead cables become more brittle and prone to cracking, and the number of transition joints or splices increases over time. These splices create and add weak points along the cable and introduce additional failure risk to already aging cables serving many large and critical loads. Consequently, feeder life expectancy and probability of failure worsen. As the weakest point on a feeder, a cable joint may fail primarily due to mechanical stress or water ingress.[11] A fault in the joints may also impact the conductor, insulation, or sheath. For instance, the sheath of the joints can develop corrosion due to thermal stresses of the feeder, which increases the chance for moisture to seep into the joint and consequently cause a failure.

The introduction of mixed insulation types also introduces different dielectric strengths or inconsistent magnetic fields at the joints which would result in higher losses or insulation breakdown. These transition joints (splices) are critical to the continuity of the dielectric properties and magnetic field across cable sections. They require a lead sleeve for the cable section to maintain the insulation

[11] Nemati, H.M., Sant'Anna, A., & Nowaczyk, S. (2015). Reliability Evaluation of Underground Power Cables with Probabilistic Models, *The 2015 International Conference on Data Mining,* p. 37-43.

properties of PILC cable. This is to hold the oil from oil-impregnated paper and protect insulation as much as possible. If these sleeves are compromised, this can result in drying out of the impregnated paper and compromise the insulation properties. Furthermore, as cable sections age, they begin to experience thermal, environmental, or mechanical stresses. Since XLPE and lead cables have different properties, the transition joint on any given feeder experiences the most stress. For example, the Windsor TS feeder A-81-WR supplies seven large customers, and includes five transition splices and 25 lead joints, as shown in Figure 3 below. Failure at any of these splices or joints will result in an outage while crews switch customers to backup supply, which typically takes 2 to 4 hours and subsequently about 8 to 10 hours until full power is restored.

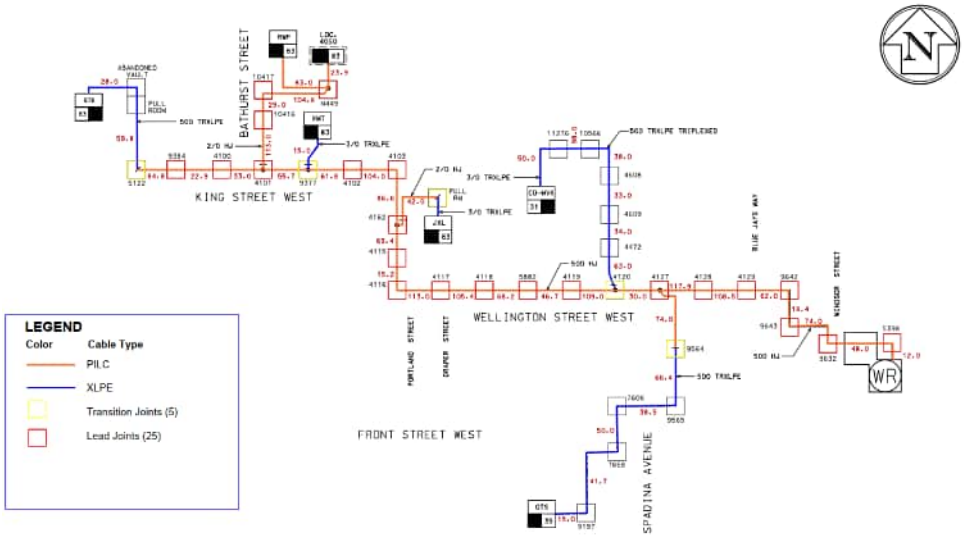


Figure 3: Schematic Feeder A-81-WR that depicts Transitional and Joint Splices

Figure 4 below illustrates examples of splices with deficiencies.



Figure 4: Sample PILC Joint with a Split Sleeve, i.e. Leaker (Left) and Collapsed Cable Splice (Right)

In addition to increased failure risk due to cable splicing, there is the risk of oil leakage from the insulation on PILC cables. Over time, due to load fluctuations and physical stresses on feeder cables, the outer covers of lead cables develop cracks, causing oil from the paper insulation to leak from the cable and pool on the cable chamber floor. On average, Toronto Hydro had to repair 30 such leaks per year between 2019 to 2022, a significant increase from the average of eight per year reported in the 2020-2024 DSP.

As shown in Figure 5 below, the failure rate of lead splices and transition joints per kilometre increases with the age of the feeder sections, i.e. the older the feeder cable and its splices, the higher the number of outages. The majority of these failures are due to moisture ingress, reduction in dielectric strength due to oil leaking from cracks and pinholes, as well as thermal stress.

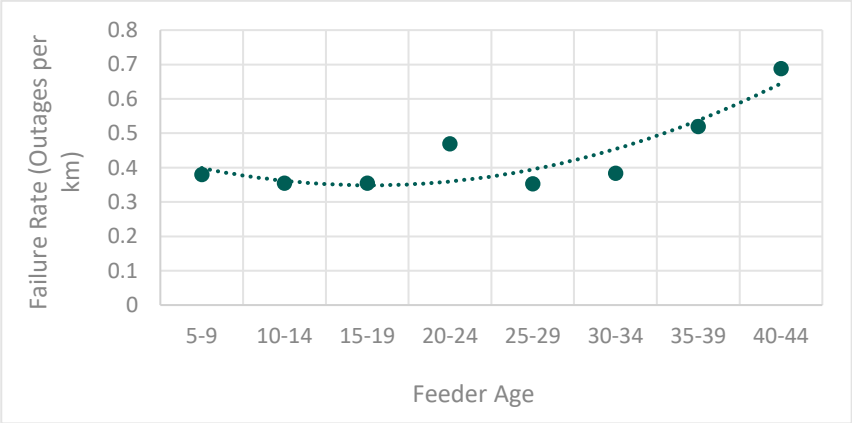


Figure 5: Failure rate of cable splices with PILC[12]

On average, there are 4 transition joints and 27 lead joints per primary feeder in downtown Toronto. By the end of 2029, given the PILC cable planned for replacement, Toronto Hydro expects to maintain the average number of transition joints at 4 and reduce the average number of lead joints to 24. Figure 6 and Figure 7 illustrate the current state of transition joints and lead joints in the system on feeders (though not all feeders are labelled therein). Figure 8 shows the comparison in number of transition splices per feeder between 2017 and 2023 for select feeders targeted for renewal over 2020-2024. The number of transition splices decreased for the four feeders already completed, while

[12] It is important to note that Toronto Hydro keeps a limited quantity of PILC cables on hand for extreme circumstances where reactive repair is required.

the fifth feeder, which has not yet been renewed, saw an increase due to work such as that listed in Table 4.

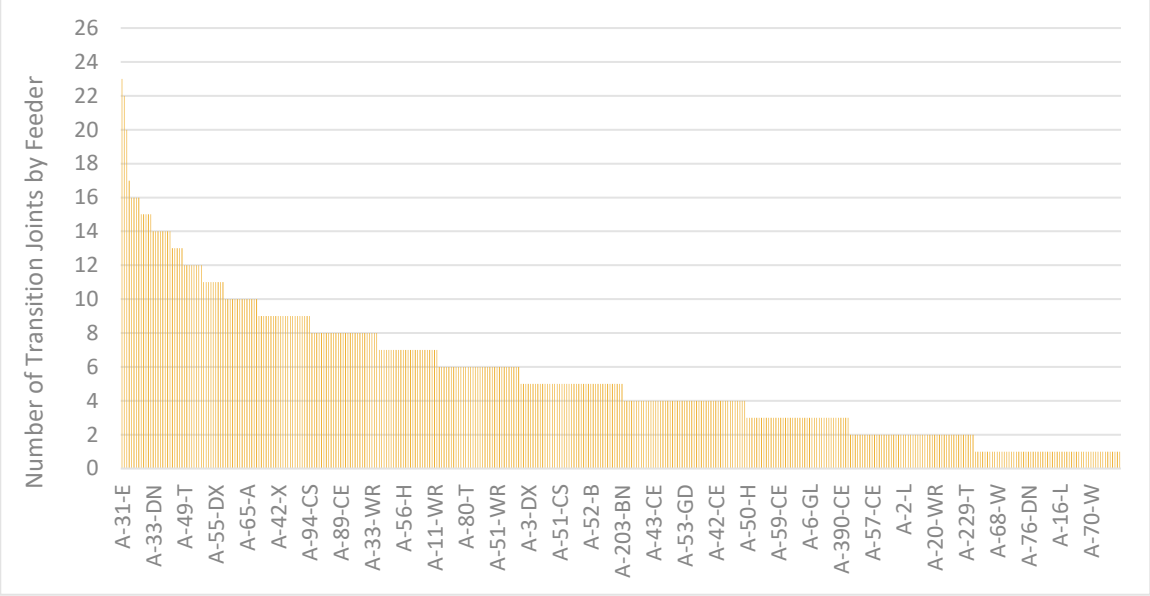


Figure 6: Transition Joints by Feeder

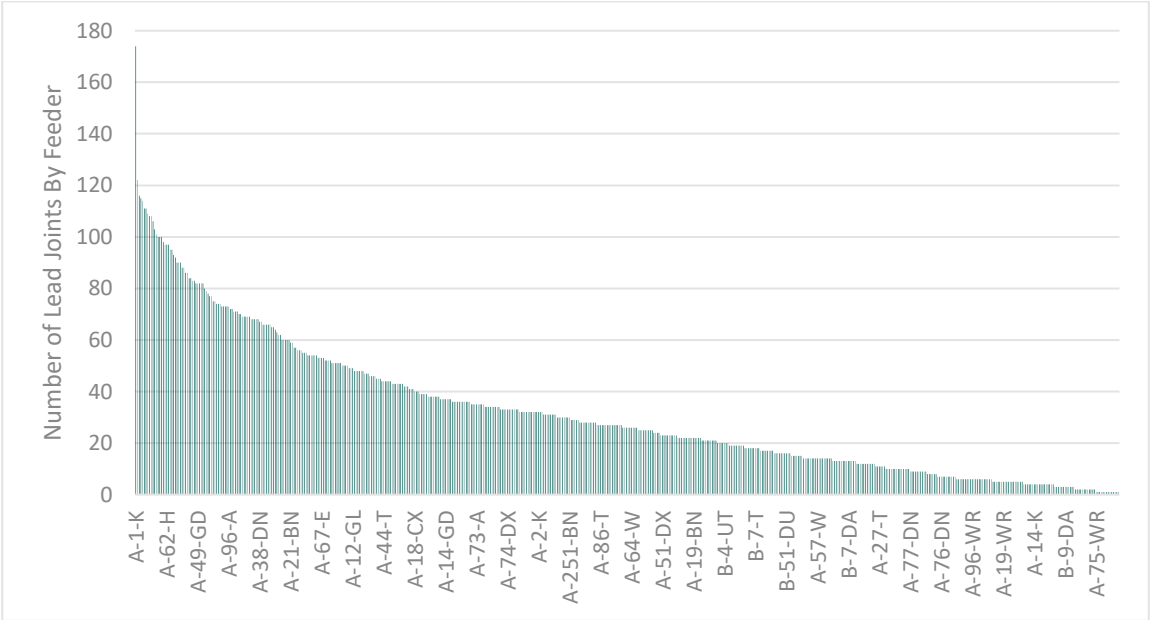


Figure 7: Lead Joints by Feeder

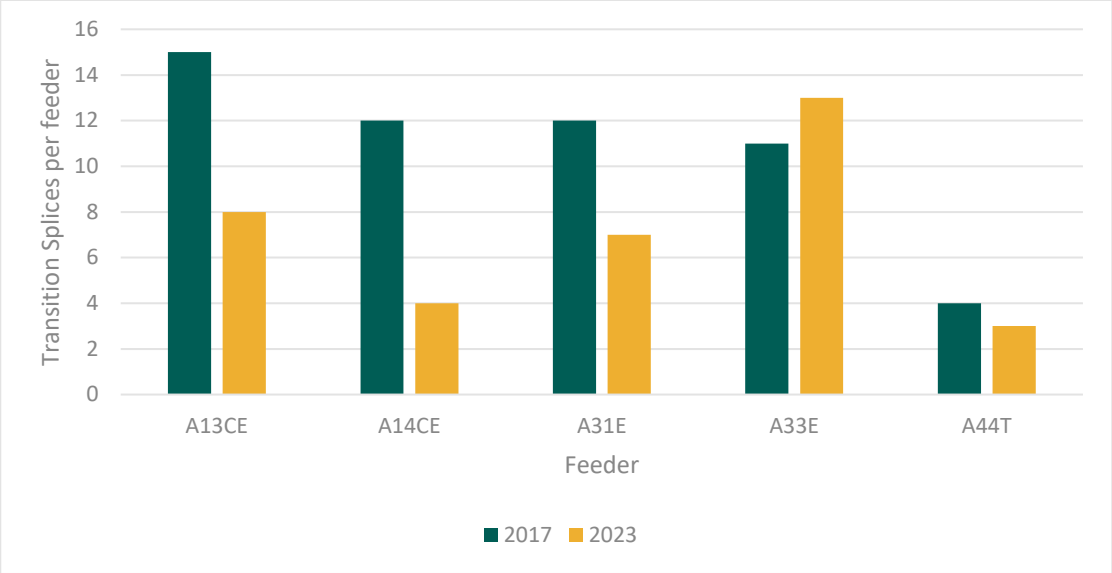


Figure 8: 2017 vs. 2023 Comparison of Transition Splices on feeders targeted for renewal over 2020-2024, with all except A33E now completed (A33E planned for 2024).

As shown in Figure 9, there are on average 44 reported cable or splice related failures per year, including on average 22 failures per year related to splices.

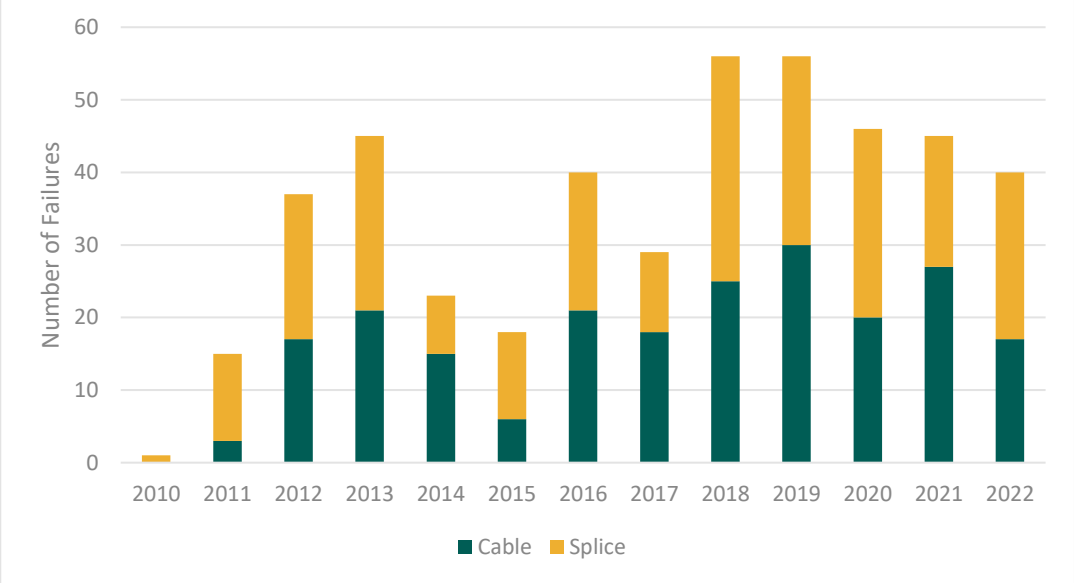


Figure 9: Number of PILC Cable/Splice Failures per Year

There were a total of 312 cable and splice failure incidents reported between 2016 to 2022 with an increasing trend of 55 incidents per year in years 2018 and 2019. The number of incidents per year has gradually reduced between 2019 and 2022 to 40 incidents per year. As per Figure 5, the number of failures per km rises with cable age. Quantitatively, this trend aligns with the qualitative observation by field personnel of the rise of failures as more splices are introduced while cable sections age.

Cable failures affect a wide range of customers, whose configuration of connection to the system depends on the feeder and the supply location and not necessarily customer type. Figure 10 below illustrates this using seven sample feeders. This segment aims to target feeders with large loads, such as A-81-WR, and introduce uniformity of cable by proactively replacing a large section of cable especially in the downtown core. This aligns with the customer engagement results where customers (especially large customers) prioritize reliability. Large multi-residential buildings are considered as large commercial customers here since minimal cable renewal investments will impact many end use customers.

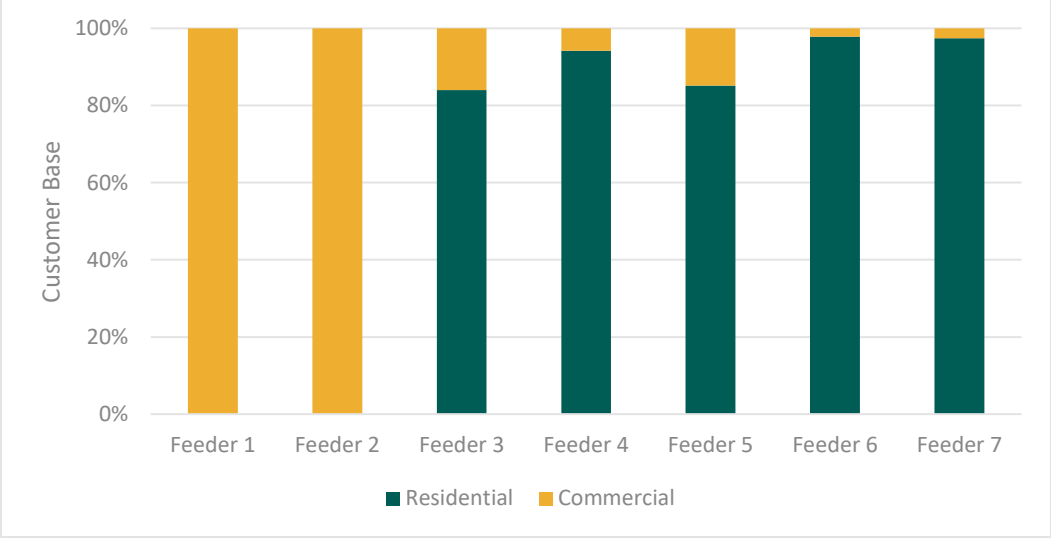


Figure 10: Composition of Customer Type of Circuits with PILC Cable

Lead-based cables (e.g. AILC and PILC) also need to be removed from the system due to a large functional obsolescence factor. Lead splicing typically requires highly qualified and trained individuals. Many utilities are facing a challenge training personnel with respect to lead splicing techniques. The skillset in the workforce is diminishing as lead cable is not actively introduced into the system. Furthermore, PILC cable is only supplied by one North American manufacturer at this

time and a procurement problem may arise in the near future, while AILC cables are currently obsolete and are no longer supported by any manufacturers. Although Toronto Hydro stocks minimal PILC cable, it is not actively introduced into the system and primarily used for reactive replacements. There is also a risk in maintaining a large population of PILC cable in the long term if PILC cable becomes unavailable. This is because some segments of PILC cable cannot be replaced reactively with XLPE and TRXLPE cable due to duct or cable chamber size limitations or the condition of the underlying civil infrastructure. In recent years, due to lack of manufacturers it has been challenging to source splicing materials required for PILC joints and transition joints and as such, construction standards has been revised to limit PILC cable installation and use polymeric XLPE and TRXLPE cables where feasible. As noted above, this increases failure risk if these non-homogenous feeder types are not minimized.

These cables present both safety and environmental risks. Lead is a designated substance as per Ontario Regulation 490/09 (see section 10) and exposure should be minimized to mitigate the health risks. The risks of working with this substance alone is a potential safety hazard as lead needs to be exposed to high temperatures to complete a lead splice. This can create airborne fumes increasing the occupational and environmental exposure. Further, PILC cables manufactured prior to 1986 may contain PCBs within the oil. Toronto Hydro is committed to mitigating the risks of oil leaks containing PCBs. Leaking PILC cables also present risks to crew and public safety as the likelihood of arc flashes due to the deterioration of the insulation is high. Arc flashes are dangerous to crews and pose a safety risk to the public if leaking oil becomes ignited. Leaking oil is a sign of pending cable failure.

In addition to removing obsolete, lead-based cable, Toronto Hydro plans to install fiber optic cables in support of an online cable monitoring program. The program will utilize distributed temperature sensing technology ("DTS") to obtain a continuous temperature profile of the fiber optic cables that are placed alongside underground cables. It will also provide partial discharge information of underground cables. Partial discharge is a common sign of insulation breakdown on underground cables and connections or weak spots in cables which eventually result in cost-intensive repairs and prolonged outages. The benefits of this technology are the following:

1. Increased observability on feeders by providing real time thermal loading of cable segments and thus allow operations and planners to assess feeder loading and available capacity for enhanced optimization of in-service assets.
2. Improved reliability as it would allow for proactive measures to be taken on cables such as identifying and replacement of at-risk cables before failure.

3. Reduce operating costs and planned outage times as it could defer offline cable testing activities.

The online cable monitoring technology depends on the presence of fiber optic cables along the cable route for monitoring and currently not all feeder routes have fiber optic cable. Through this segment, Toronto Hydro proposes installing 5 km of fiber optic cable over the 2025-2029 period in addition to the PILC cable replacement in routes where there is no existing fiber optic cable present. This would expand the fiber optic cable network and enable deployment of online cable monitoring to additional sections of the distribution system. The information provided by online cable monitoring technology could be used to enhance cable risk assessment and replacement prioritization processes in the future.

E6.3.3.2 Cable Chamber Renewal

The Cable Chamber Renewal segment will invest in the structural integrity of Toronto Hydro's high risk, poor condition (HI4 and HI5), and aging population of cable chambers by rebuilding the whole chamber or roof, or abandoning the chamber. Cable chambers house, protect, and provide access to underground electrical equipment across the city. There are approximately 10,657 cable chambers in Toronto Hydro's underground distribution system, of which approximately 74 percent are in the downtown area. These chambers hold up to 29 circuits each, supplying anywhere from 3,500 customers of different types and sizes, down to a few large industrial or commercial customers (e.g. financial institutions, hospitals).

Cable chambers have a useful life of 65 years, while chamber roofs have a useful life of 25 years, meaning that the roof will require a rebuild at least once during the useful life of the chamber as cable chambers are impacted by deterioration drivers such as road salts and vehicle loading. Figure 11 shows the cable chambers age demographic, as of 2022, for all cable chambers and roofs. Approximately 2,208 cable chambers are past their useful life and 6,643 cable chamber roofs are past their useful life.

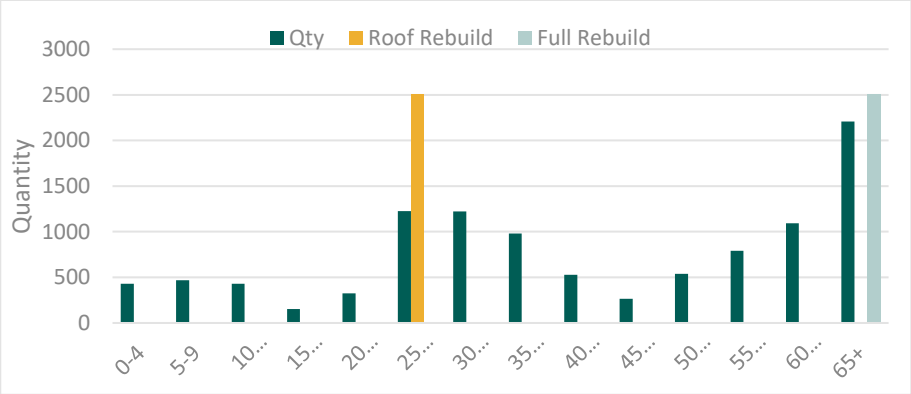


Figure 11: Cable Chambers Age Demographic

Toronto Hydro inspects cable chambers and cable chambers roofs on a planned 10-year cycle. The growing backlog of aging cable chambers is reflected in the observed condition of the assets. For many of its major assets, including cable chambers, Toronto Hydro performs asset condition assessment ("ACA"), in which the condition of each asset is assigned a health index ("HI") band from HI1 to HI5, where HI5 indicates the worst condition. For these same assets, the utility can then also project future condition (i.e. HI band) assuming no intervention.[13] Figure 12 below shows the asset condition of the 10,657 cable chambers in Toronto Hydro's distribution system as of 2022 and the projection for 2029. The data indicates that 592 cable chambers have condition classified as HI4 or HI5 and will require rebuild in the near-term. Furthermore, Toronto Hydro projects that there will be 1,113 cable chambers in HI4/HI5 band by end of 2029 without investment.

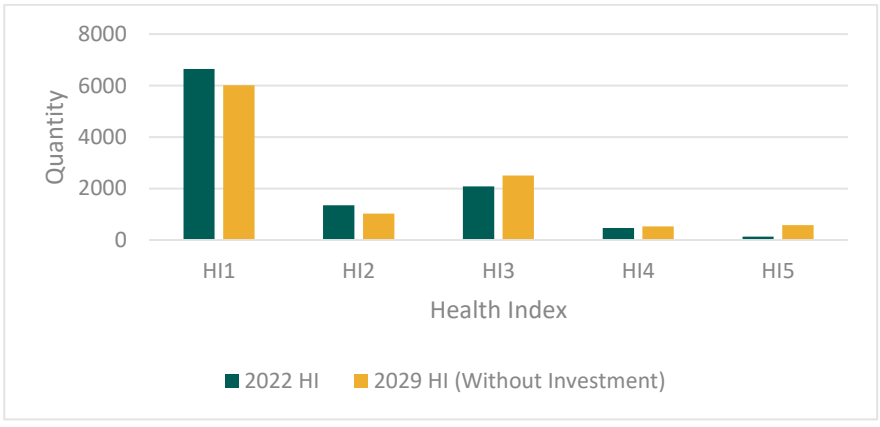


Figure 12: Cable Chamber HI Distribution (Actual and 2029 Forecast)

[13] See Exhibit 2B, Section D3, Appendix A for more details on Toronto Hydro's ACA methodology.

Depending on the severity of issues, Toronto Hydro ensures the time of rebuild is determined based on a holistic review of the structural condition of the chamber (even if it is classified as HI5). This means a cable chamber may require a reactive rebuild or temporary repairs to mitigate safety risks which would allow for a planned rebuild in the future.

Figure 13 below shows the high concentration of HI4 and HI5 condition chambers in the downtown core, where, as mentioned above, the chambers tend to carry a high concentration of circuits serving thousands of customers, or large customer loads. Should a chamber or chamber roof collapse to any extent, the equipment in the chamber could be damaged, leading to a potentially lengthy outage for the aforementioned customers.

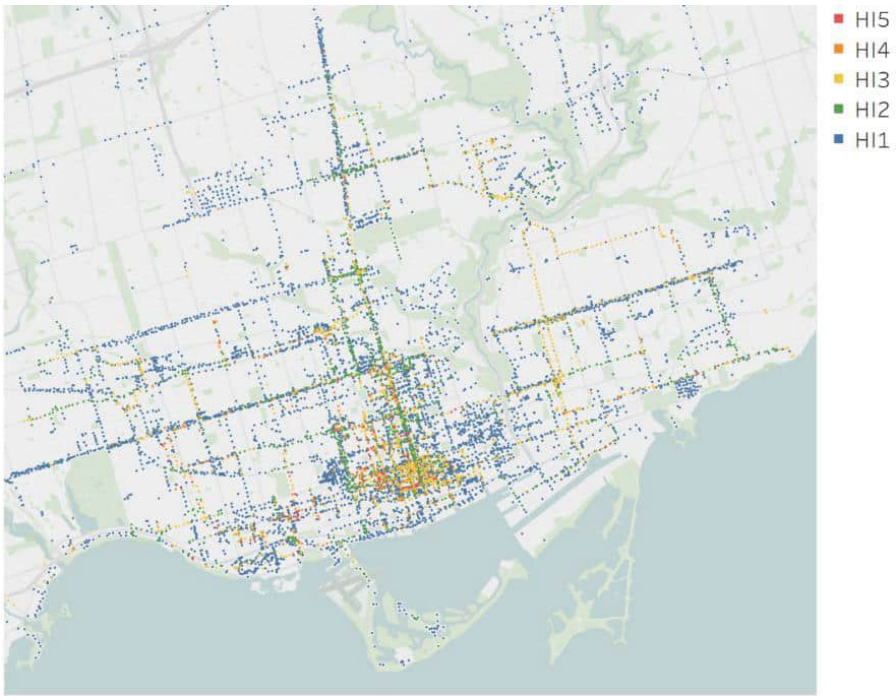


Figure 13: Cable Chamber Locations and Conditions

Of equal or greater concern is the risk to crew and public safety posed by a failing cable chamber. In areas of high vehicular or foot-traffic especially, a structurally unsound chamber or roof can create hazards to the public. The collapse of a chamber or chamber roof could have more severe consequences for the public or for crews working in the chamber. Figure 14 below shows an example of a severely deteriorated cable chamber roof.



Figure 14: Cable Chamber Roof in HI5 Condition (Left), and Roof Inside View (Right)

The images shown in Figure 14 are an example of a cable chamber with a reduced neck which is common when the City rebuilds or regrades roads. In this situation, when the asphalt was removed, a hole was discovered. This is very dangerous especially if the hole or deteriorated structure is covered by newly paved road.

Depending on the specific site, addressing a HI4 or HI5 condition chamber will include:

- **Full rebuild:** rebuilding the cable chamber civil structure, including its roof and duct banks, and involves some cable replacement; or
- **Roof rebuild:** rebuilding only the roof.
- **Cable Chamber Abandonment:** if the cable chamber is in a condition such that it cannot be brought to the current standard, it will be abandoned and a new chamber will be rebuilt beside it.

In addition to rebuilds, Toronto Hydro also plans to continue proactively replacing potentially hazardous cable chamber lids. Deteriorated cables running through cable chambers can fail, potentially causing arcing and igniting gases, which then can create a powerful shock wave. These shock waves can dislodge a chamber lid in a violent manner, ejecting it into the air and creating a serious public safety hazard. Since 2018, Toronto Hydro has recorded 26 incidents related to cable chamber lids, as shown in Figure 15. The utility is proactively replacing lids on cable chambers with an energy mitigating lid design to mitigate this ejection risk. Since 2020, Toronto Hydro has replaced 470 cable chamber lids with energy mitigating lids and plans to replace another 2,800 cable chamber lids over 2025-2029. The increased pace is required to address the safety hazard associated with the higher risk locations in a timely manner.

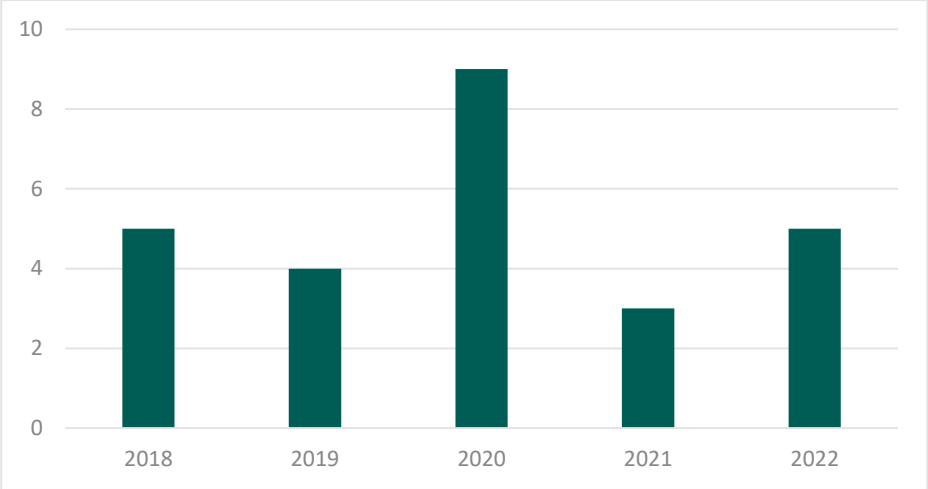


Figure 15: Number of Lid incidents

E6.3.3.3 Underground Residential Distribution ("URD") Renewal

This segment aims to replace deteriorating and obsolete URD assets that could negatively impact system reliability. These assets include: vaults, switches (including FCIs), and transformers that form part of the URD system. As per Toronto Hydro's customer engagement results, residential customers indicated that reliability is a top priority.[14] As such, specific areas of the URD system will be targeted for renewal in this segment to support maintaining the reliability performance of the URD system.

Introduced in the 1990s, the URD system was intended to replace the 4 kV overhead system supplying residential customers in the downtown area. The URD system is comprised of redundancies via main loops and sub-loops to add a level of robustness by isolating sections of the feeder.

The main underground system configurations are either radial or looped. However, system types and configurations are sometimes mixed to provide improved reliability or flexibility when repairs are required, as is the case with URD. In the URD system, primary cables, switches, and distribution transformers are placed underground while most secondary voltage connections remain overhead. This system only appears in limited areas throughout the pre-amalgamation City of Toronto, as seen in Figure 16 below.

[14] *Supra* note 9

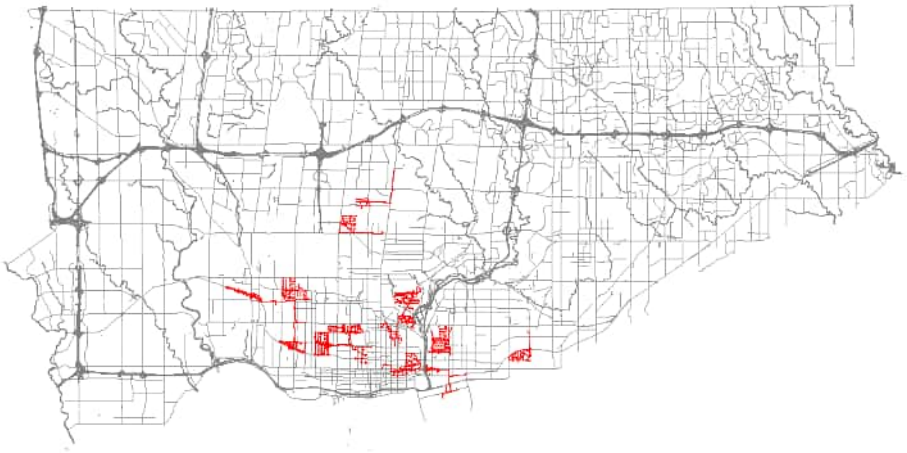


Figure 16: Map of Toronto with URD Feeders

The URD has three distinct feeder sections: (i) a main-loop; (ii) sub-loops; and (iii) branch circuits (or sub-sub-loops). Figure 17 below provides a simplified example of the configuration of a downtown URD feeder. The main loop is fed by the main feeder or standby feeder from the stations and interconnects the 600A switching vaults supplying an area, allowing for the isolation of the sub-loops and branch circuits in the event of a fault. The sub-loops start at the 600A switching vaults on the load side and end at the 200A switching vaults, where the branch circuits split off in multiple directions. URD transformers are connected to the primary feeder sub-loops or branch circuits, which feed individual or groups of customers.

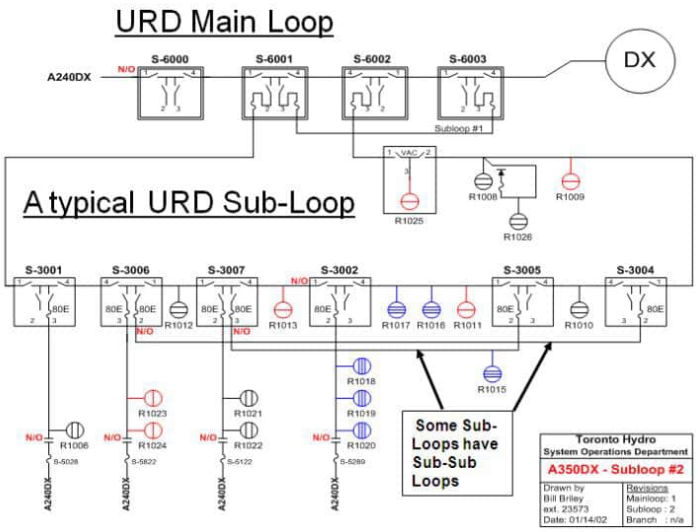


Figure 17: Typical URD Feeder Configuration

The reliability performance of URD system have been relatively stable over the last 5 years as shown in Figure 18 and Figure 19. Defective equipment was the largest contributor to annual customer reliability representing about 70 percent and 80 percent of CI and CHI, respectively. Targeted renewal of URD assets is required to support a stable reliability trend (i.e. maintain reliability performance).

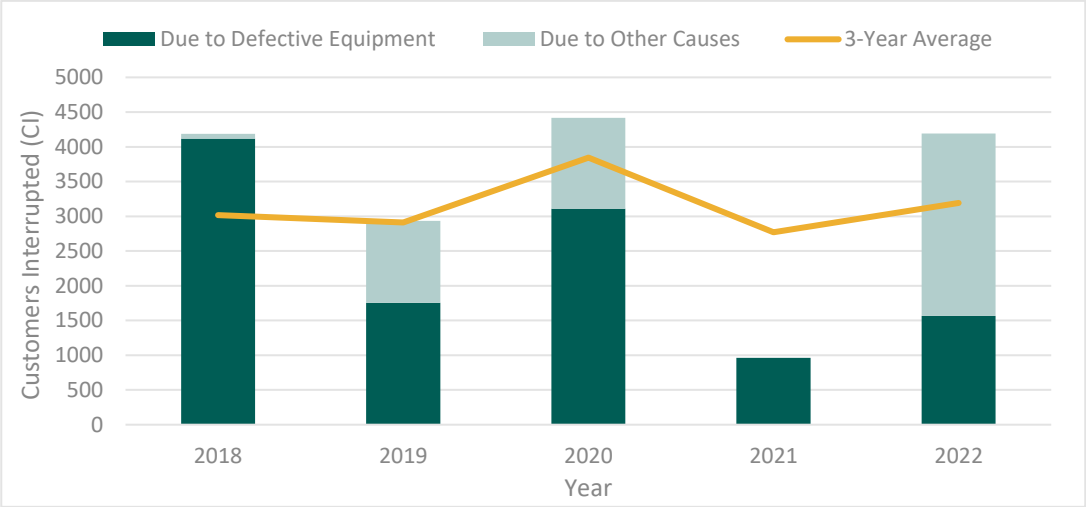


Figure 18: Customers Interrupted — URD System

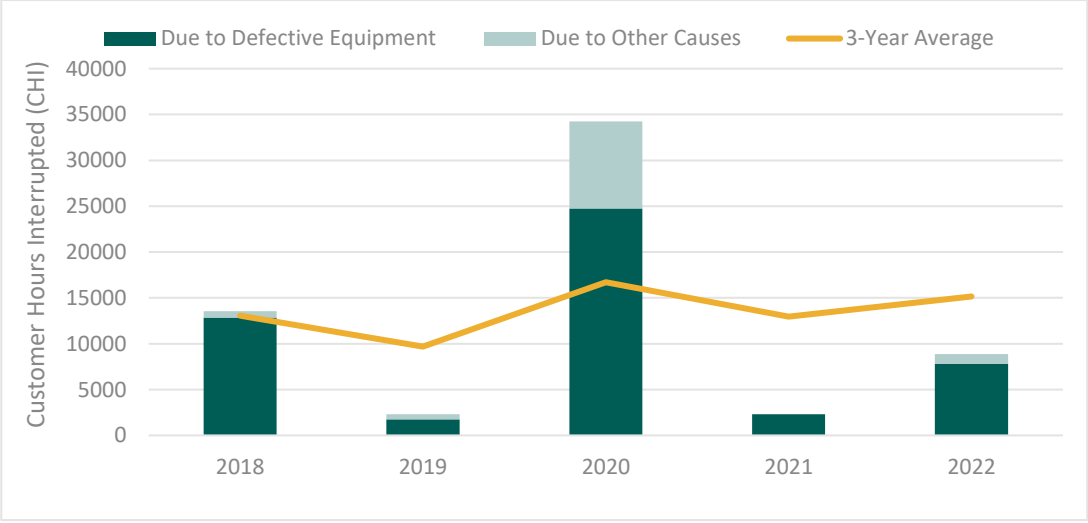


Figure 19: Customer Hours Interrupted — URD System

Figure 20 below compares the average CAIDI of URD system with 13.8 kV underground radial system over the last 5 years.[15] As can be seen from the figure, the average time to restore service in URD is

[15] Customer Average Interruption Duration Index

higher than underground radial system. This is mainly due to the fact that determining the source of an outage in the URD system can be time consuming due to the complex set-up of loops. The design of the URD includes FCIs, which help find the locations of faults in this complicated configuration so that customers can be restored in a timely manner. Of note, the average outage duration in URD system are on slightly increasing trend over the last five years. This is due to the corrosive environment in the switching vaults, where most of these FCIs are located leading to mechanical failure, and associated incorrect readings from the FCIs while fault locating.

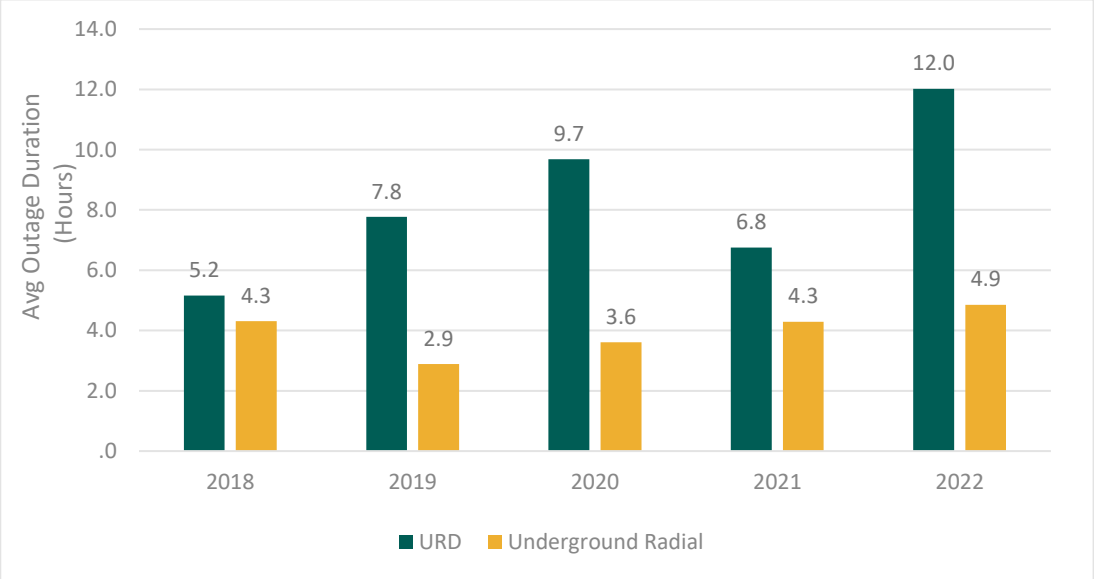


Figure 20: Average Outage Duration – URD vs Underground Radial System

Maintenance and inspection of the URD vaults are performed twice a year, one inspection for the civil condition and the other for the electrical condition. As part of this work, the vaults are inspected to ensure the integrity of the electrical equipment, structure, and security. This includes a thermograph of all electrical assets, cleaning the entire vault and reporting any vaults that require follow-up repairs. The results of the inspections show that URD switching vault equipment tends to be in poor condition due to rust on the cabinet and corrosion on the connectors. Figures 21 and 22 below provide the URD electrical and civil inspections results, highlighting the most common types of deficiencies identified and found over the past three years (i.e. 2020 to 2022).

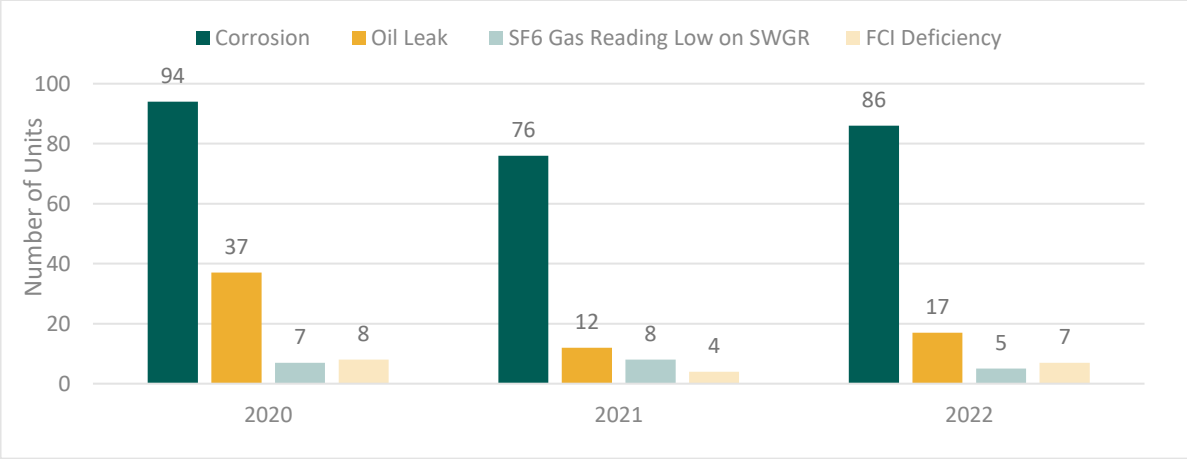


Figure 21: URD Electrical Deficiencies

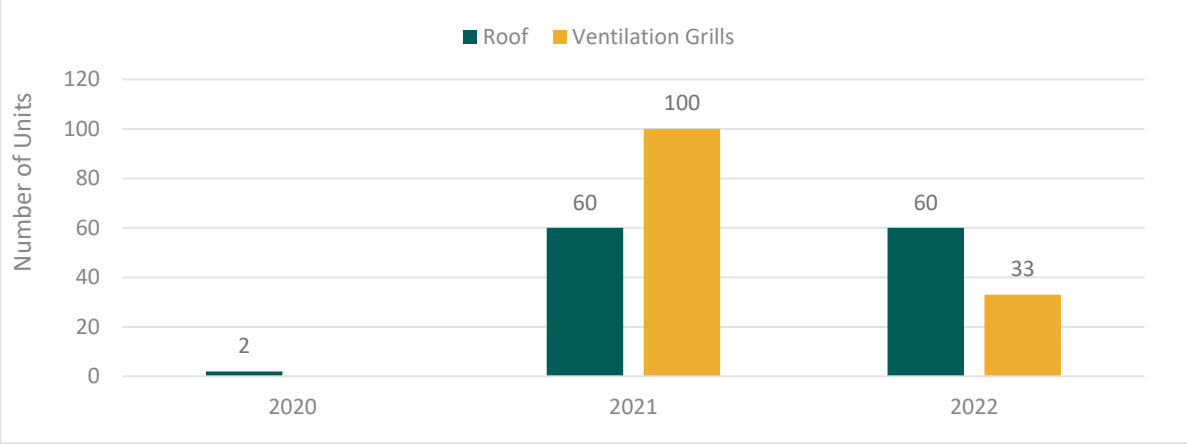


Figure 22: URD Civil Deficiencies

As per the URD electrical inspection data in Figure 21, the main issues are the recent rising number of deficient switchgears with low SF6 readings and malfunctioning FCIs, as well as corrosion of electrical equipment. As per the civil inspection data in Figure 22, URD civil deficiencies have been steadily increasing. These deficiencies increase the risk of failure of URD assets and as a result, the renewal process is driven by failure risk. The following sections describe the state of three main assets of the URD system: URD vault roofs, URD switches (including FCIs), and URD transformers while considering the above-mentioned deficiencies.

1. URD Vault Roof

Civil conditions of URD vaults deteriorate over time due to exposure to harsh environments as a result of severe weather, salt, or road construction. Some commonly found structural deficiencies

caused by asset aging and environmental factors are exposed roof and wall rebar, corroded I-beams and cracked roof and walls. Such deterioration includes corrosion, spalling of concrete, and cover rusting which pose a potential safety hazard for the public and field crews. Compounding this situation, the ventilation design and equipment layout inside the vault have allowed dirt to accumulate on top of switching equipment, causing corrosion of components such as elbow terminations. This degradation of the URD vaults increases the failure risk of the assets within it. Illustrative examples of the aforementioned types of roof cracks are shown in Figure 23 and Figure 24 below.



Figure 23: URD Vault with Deficient Roof



Figure 24: URD Vault Deficient Roof Temporarily Repaired with Asphalt

The useful life of a URD vault is 60 years while the roof is 25 years. Therefore, the roof is typically rebuilt at least once during the life of the vault. Figure 25 below shows the age distribution of URD vaults. The majority of vault roofs of the URD vaults have reached or passed their useful life, and as such are considered for rebuild.

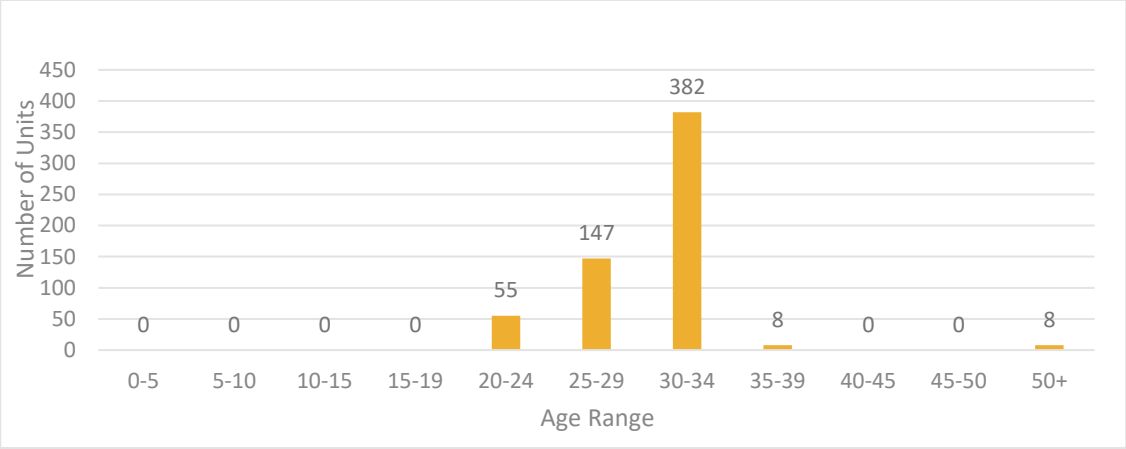


Figure 25: URD Vaults Age Distribution

Figure 26 presents the HI distribution (current and 2029 forecast) of the URD vaults. At the end of 2022, 8 of the URD vaults exhibit at least material deterioration (HI4/HI5 condition). The HI4/HI5 volume is forecasted to grow to 13 in 2029 without investment. It is important to note that the ACA model is a measure of the health of the entire vault asset, and that even vaults in HI1 or HI2 condition may have roof deterioration that needs to be addressed. To alleviate the risks posed by deteriorated vault roofs, Toronto Hydro plans to address 4 URD vault roofs between 2025 and 2029.

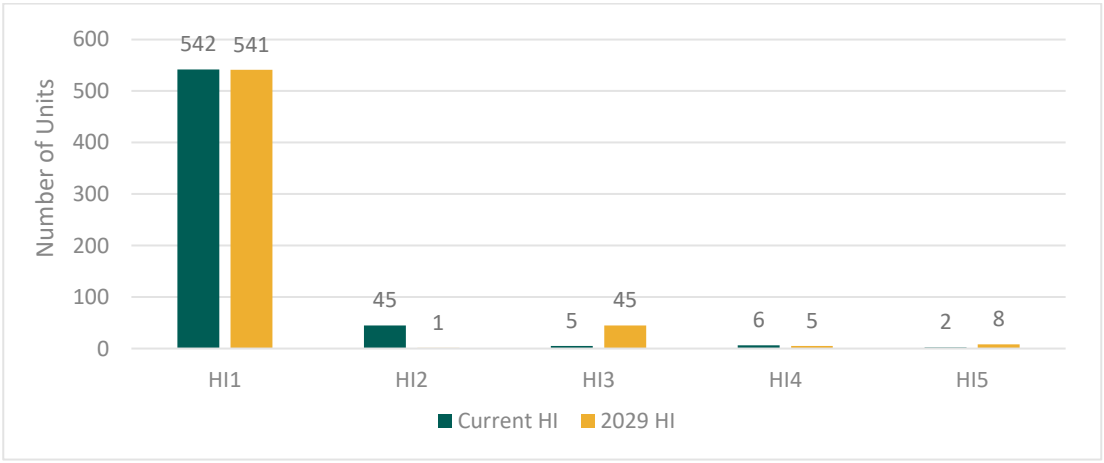


Figure 26: URD Vaults HI Distribution (Actual and 2029 Forecast)

Given the deficiencies being identified, Toronto Hydro is developing a new roof design that minimizes the amount of dirt, debris, and water that accumulate directly on electrical equipment. The new design will be similar to the compact radial distribution ("CRD") underground vault, which typically

supply small retail, apartment, and commercial office buildings. In addition, the new design will improve safety by reducing the potential of tripping incidents, and create a larger opening for the replacement of electrical equipment. When rebuilding a vault roof, the electrical equipment will be assessed and upgraded to the latest standards if existing equipment is in poor condition or obsolete.

2. URD Switches

Switches used in URD are submersible, 200A and 600A, SF6-insulated switches which are operable from above grade. SF6 load break switches are designed and constructed to provide safe and reliable switching. Using SF6 for insulation and arc interruption eliminates space, weight and maintenance costs. The switch provides improved interrupting and open gap performance, while at the same time eliminating most hazards associated with vacuum or oil filled equipment. In the URD system, the switches are mounted on stands close to the vault wall for ease of operation, cabling, and space utilization.

As of the end of 2022, these switches are deteriorating in condition. A large portion do not have stainless steel enclosures and are experiencing gas leakage inherent to the former design of the bolted viewing window, as shown in Figure 27 below.



Figure 27: Example of a SF6 Switch with a "Low SF6" Reading

Due to the design and equipment specification of URD 200A and 600A switching vaults, they do not contain an available heat source, such as a transformer, that would promote air circulation. As a result, non-stainless steel switching equipment installed in those vaults are experiencing accelerated corrosion due to exposure to stagnant moisture. Compounding this situation, the ventilation design and equipment layout inside the vault have allowed dirt to accumulate on top of switching equipment, causing corrosion of components such as elbow terminations and supports or support beams. An example of a corroded support beam can be seen in Figure 28.



Figure 28: Example of Switch Supports that have rusted

The 200A SF6 switches are used to switch load as part of the sub-loop system. They also support 80E SF6 power fuses, which are used for the protection of branch circuits in the URD and are no longer manufactured. As such, there are limited 80E power fuses in Toronto Hydro inventory. A picture of the 80E power fuse is provided in Figure 29. In this regard, the switches are functionally obsolete, as they are no longer supported by the original manufacturer and no spare parts are manufactured or available. Replacement of both the fuse and switchgear is required to provide the adequate protection for branch circuits.



Figure 29: 80E Power Fuse

Figure 30 presents the HI distribution (current and 2029 forecast) of the URD submersible switches. At the end of 2022, five of the URD submersible switches were exhibiting at least material deterioration (HI4/HI5 condition) and this is forecasted to grow to eight in 2029 without investment. To reduce the risks posed by deteriorated and obsolete submersible switches, Toronto Hydro plans to address four units between 2025 and 2029.

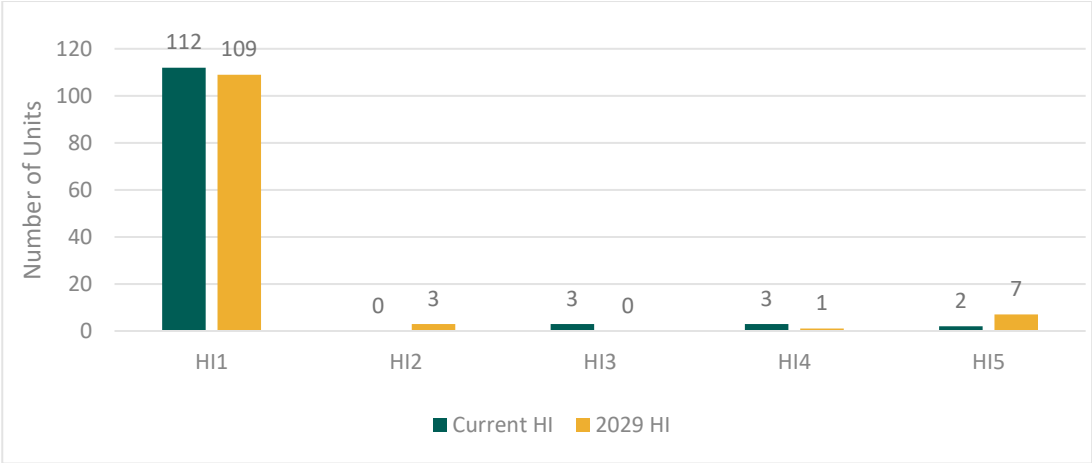


Figure 30: URD Submersible Switches HI distribution (Actual and 2029 Forecast)

In addition, several FCIs used in the URD system and manufactured as recently as 2017 are showing severe signs of corrosion. Some of the units failed to reset upon normal current restoration, giving misleading indications. Recent investigation showed broken internal wiring caused by corrosion and corroded current transformer ("CT") laminations due to water ingress (See Figure 31 below)

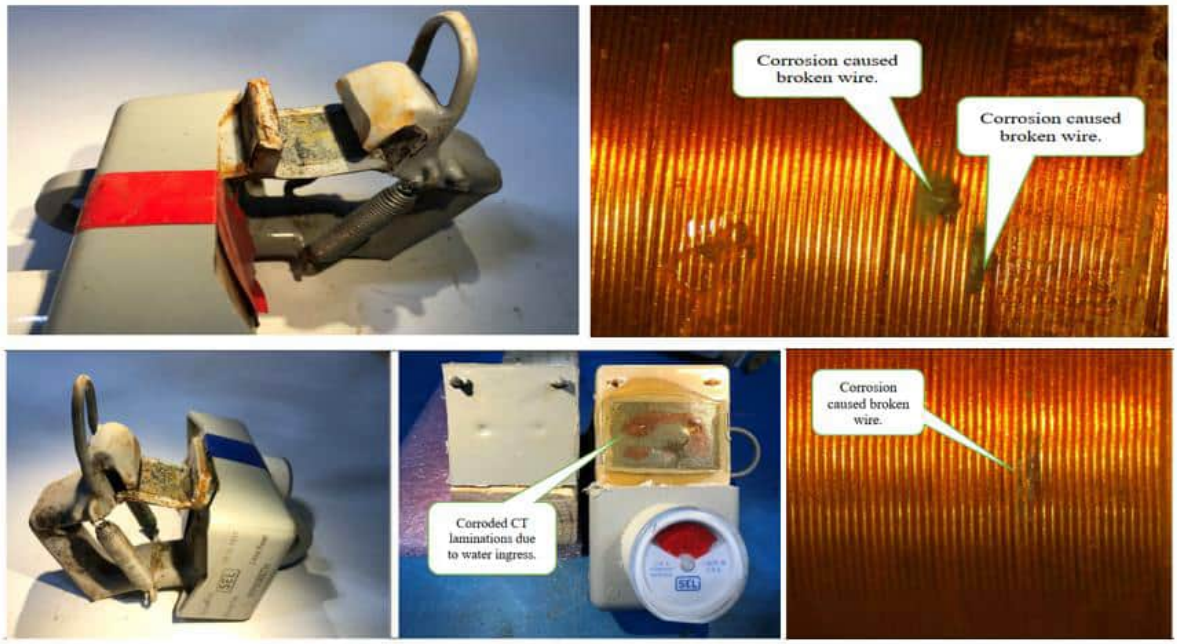


Figure 31: Teardown of the FCI units revealed water ingress caused corrosion in the CT resulting in broken wires

Given malfunctioning FCI is a contributing factor to long duration outages on the URD system, over 2025-2029 Toronto Hydro plans to replace 375 deteriorating and obsolete FCIs with the latest standards, targeting URD feeders with poor reliability performance.

3. URD Transformers

The main type of transformers used in the URD system are submersible transformers in URD vaults. The standard rating for a single phase URD transformer is 167 kVA while the three phase URD transformers range from 150 kVA to 750 kVA. URD transformers are connected to primary feeder sub-loops or branch circuits, which feed individual or groups of customers.

URD transformers are exposed to harsh environments causing deterioration, with moisture being the most destructive element as it can lead to corrosion (see Figure 32). Corrosion of the transformer tank can lead to oil leaks into the environment and low transformer oil levels, which can lead to catastrophic failure. This presents a safety risk to the public and Toronto Hydro employees, in addition to reliability and environmental impacts.



Figure 32: Examples of URD Transformers Exhibiting Corrosion on Lids and Oil Leaks

Figure 33 shows the current and forecast (without investment) HI distribution of Toronto Hydro's URD transformers. As of the end of 2022, 12 URD transformers exhibit at least material deterioration (i.e. HI4 and HI5) and, without investment, this number is expected to increase to 92 by the end of 2029. In order to mitigate the expected increase in environmental, safety, and reliability risk of this asset population, Toronto Hydro plans to replace 17 URD transformers over 2025-2029.

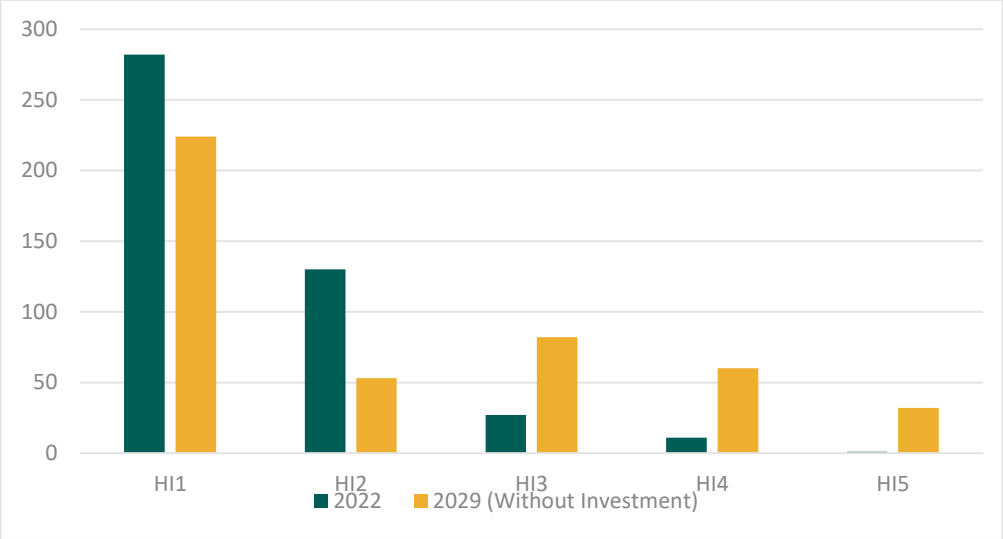


Figure 33: URD Transformer Asset Condition as of 2022 and 2029 (without investment)

As the URD vaults, transformers, and switches approach the end of their useful life, related equipment and civil infrastructure need to be updated to mitigate failure risk. Toronto Hydro will replace the roof vaults with a newer design that reduces the dirt, debris, and water entering the vaults, improves safety by reducing tripping incidents and creates a larger opening for replacing old switches. Along with roof rebuilds, the utility will replace electrical equipment such as transformers or switches within the vault with the equivalent latest standard. Toronto Hydro will also replace submersible with the new generation of SF6-insulated switches which have stainless steel enclosure to prevent premature rusting and degradation of the cabinet. Finally, the utility will replace FCIs prone to malfunctioning with new FCIs to speed up the outage restoration process.

E6.3.3.4 Underground Switchgear Renewal

The Underground Switchgear segment is driven by the failure risk of key assets that negatively impact reliability and safe operation within the downtown core. Historically, these assets have shown high reliability but have now become obsolete or pose a risk to the public. This segment aims to reduce failure and safety risks associated with legacy underground switchgear (see Figure 33) that are obsolete, past their useful life, in poor condition, and prone to failure. Failure can occur due to various factors such as age or repeated use over time, which results in breakage or failure to operate.



Figure 34: Example of Legacy Switchgear

In the 1960s and 1970s Toronto Hydro installed large transformers with underground switchgear in customer-owned vaults. Toronto Hydro owns this equipment, which feeds apartment buildings, educational facilities, and community centres. This underground switchgear is air insulated and used to provide primary supply to transformer vaults from two incoming primary feeders (one normal and one standby). Toronto Hydro has stopped installing this type of switchgear and considers them to be functionally obsolete equipment designs as they are no longer produced or supported by the manufacturer. The existing switchgear population is aging and becoming harder to maintain as spare parts for equipment repairs are not available, making it a challenge for Toronto Hydro to achieve alignment with current maintenance and inspection practices. Going forward, the lack of spare parts precludes long term maintenance as a viable option to extend the service life of these assets.

As of 2023, there are 484 underground switchgear installed in the system. Figure 35 shows the current (2022) and forecast (2029, without investment) ACA for this asset group. The data indicates that six underground switchgear are categorized as having HI4/HI5 conditions and will require replacement in the near-term. While this is a relatively small number of assets (about one percent of these switchgear) with at least material deterioration, this is expected to grow significantly to 89 units (18 percent) by the end of 2029 without investment.

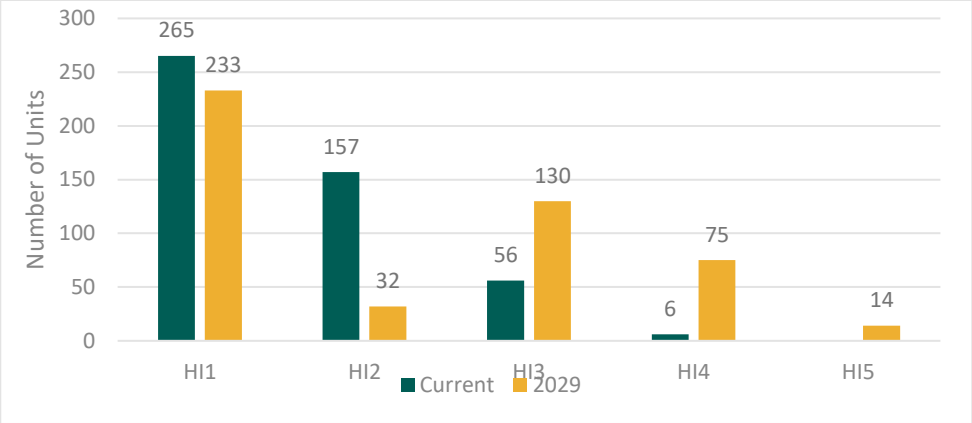


Figure 35: Underground Switchgear ACA distribution

Over the past five years from 2018-2022 work requests related to legacy switchgear have risen from 75 in 2018 to 257 in 2022. While much of this increase is due to the lowest priority work requests (P4), which require monitoring to ensure the issue does not worsen, higher priority work requests (PI and P2) have also been higher in recent years, as shown in Figure 36 below.

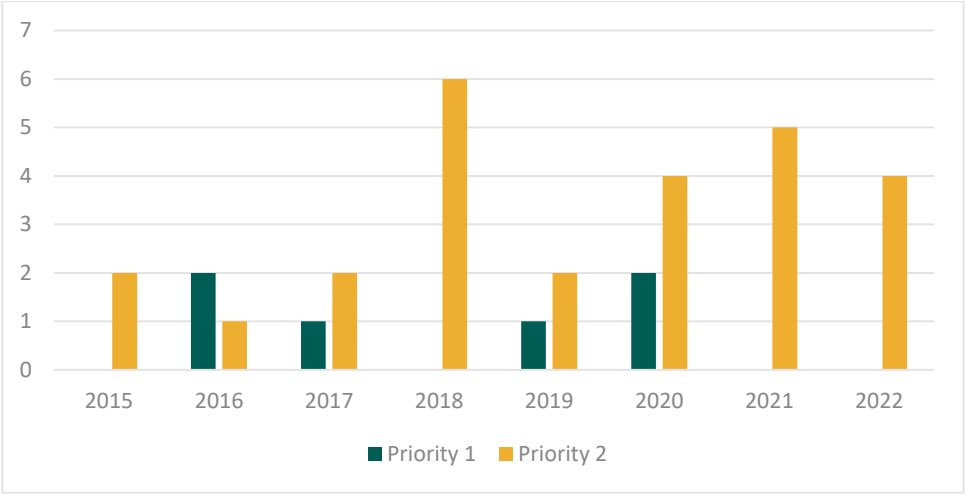


Figure 36: Underground Switchgear related Work Requests (High priority requests)

In the event where switching is required to isolate a customer or move the customer from one feeder to its standby, failed or defective legacy switchgear units may not operate as intended. This failure will result in either the delay of planned work until the switchgear is repaired or, in the event of a failure of the normal feeder, the customer will be without power for a prolonged duration as the switches are not useable. Customers supplied from the transformer vault with underground

switchgear will be affected with the longest outage, but other customers on the feeder will be impacted as well due to the additional time required to isolate the faulted switchgear.

Failing legacy switchgear assets can potentially put the safety of customers and Toronto Hydro employees at risk. The inherent safety risk of switches not properly opening or failing to close entirely create an arc safety risk. Although no arc safety incidents have yet to be reported, as these switchgear age and further work request desk issues are recorded, the likelihood of having an arc safety incident will increase. Some of these legacy underground switchgears are non-submersible and could be damaged by water ingress into the vault as recorded by two incidents in 2018 and 2019. Since 2017, there have been three incidents related to underground switchgear failure, with the worst incident resulting in over 10 hours of interruption on average per customer. Even though the frequency of these events is low, the impact can be long duration outages for all customers on the feeder. Toronto Hydro plans to replace 20 of these switchgear over 2025-2029 to mitigate these risks.

E6.3.4 Expenditure Plan

To address the needs of the underground assets in downtown Toronto, Toronto Hydro plans to invest $165.1 million over the 2025-2029 period. Each segment entails a unique investment strategy as discussed in the following subsections.

Table 5: Forecast Program Costs ($ Millions)[16]

Segments	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Underground Cable Renewal	3.1	5.2	10.2	10.7	7.8	8.6	10.8	11.7	13.4	16.5
Cable Chamber Renewal	4.0	2.9	9.4	18.3	5.4	10.4	13.6	19.1	26.3	27.1
URD Renewal	-	0.4	0.6	0.4	2.1	1.0	1.0	0.9	1.0	0.8
Underground Switchgear Renewal	-	-	-	-	0.1	0.5	0.6	0.6	0.6	0.7
Total	**7.1**	**8.5**	**20.2**	**29.4**	**15.3**	**20.5**	**26.0**	**32.3**	**41.3**	**45.0**

[16] Note that costs associated with former streetlighting assets are embedded in the costs of the segments.

E6.3.4.1 Underground Cable Renewal Expenditure Plan

Over the 2020-2024 period, Toronto Hydro forecasts total spending of $36.9 million in the Underground Cable Renewal segment as shown is Table 6, which is approximately $52.8 million lower than planned in the 2020-2024 DSP. Over the 2025-2029 period, Toronto Hydro plans to spend $61.0 million to replace legacy PILC and AILC cable, an increase of 65 percent over the 2020-2024 period.

Table 6: Underground Cable Renewal 2020-2029 Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Underground Cable Renewal	3.1	5.2	10.2	10.7	7.8	8.6	10.8	11.7	13.4	16.5

Over 2020-2022, Toronto Hydro spent $18.5 million and installed 14 circuit-km of primary TRXLPE cable in duct and approximately 6 circuit-km of secondary cable in duct, as shown in Table 7. Toronto Hydro plans to invest another $18.4 million in 2023-2024 to install 16 circuit-km of primary TRXLPE cable in duct and 1.4 circuit-km of secondary XLPE cable in duct. The expected total PILC cable replacement for the 2020-2024 period exceeds the 2020-2024 DSP planned volume of 27 circuit-km by 3 km, while the expected AILC cable replacement is 44 circuit-km less than the planned volume of 53 circuit-km.

The variance in AILC cable is attributed to the prioritization of PILC over AILC cable replacement and a lack of colocation between the two. Toronto Hydro plans projects according to the priority of primary PILC feeder cables and any AILC cable along the route are identified for replacement at the same time for efficiency. This segment was a new segment for the 2020-2024 period and as project areas were selected, the utility discovered that there was lower than expected colocation between AILC cable and high priority primary PILC cables. AILC cable is mainly present in the secondary network system and some segments of AILC cable are being replaced through the Network System Renewal program.[17] Toronto Hydro has adjusted the forecast AILC volume for 2025-2029 based on this experience it has gained over the 2020-2024 period.

[17] See Exhibit 2B, Section E6.4.

The total expected 2020-2024 spending for this segment of $36.9 million is less than half of the $89.7 million forecast in the 2020-2024 DSP. Toronto Hydro reduced the segment budget significantly to support meeting the utility's capital funding limits,[18] but was still able to meet and slightly exceed the planned PILC cable replacement volume. The unit cost for PILC cable replacement over 2020-2022 was lower than the estimated unit cost in the 2020-2024 DSP due to the following:

- Civil work is costly and challenging to execute due to congested underground infrastructure, the City of Toronto's own infrastructure renewal plans, and other development projects. Therefore, as projects are developed from high level scoping to project development to detailed design, Toronto Hydro evaluates alternate options such as utilizing available civil infrastructure on the other side of the road or another parallel road to defer costly civil work and ensure the executability of projects. Over 2020-2022, Toronto Hydro successfully leveraged these alternatives to limit the amount of civil work needed and keep the average unit costs below the original estimates from the 2020-2024 DSP.
- Projects requiring more civil work require longer lead-up time due to additional design and permitting requirements. Since this was a new segment in 2020, the majority of the projects that the utility has been able to execute so far have not had significant civil work as they could move more quickly to the execution stage. Therefore, the historical unit costs for from 2020-2022 are not expected to be fully representative of future costs as they include mostly electrical costs only. As more projects are executed in future years, the average unit cost is expected to be closer to the estimated unit cost in the 2020-2024 DSP.

Toronto Hydro plans to invest $61 million in 2025-2029 to replace 35 circuit-km of primary PILC cable in duct, 9.3 circuit-km of secondary AILC cable in duct and 5 kilometers of fiber optic cable.

Table 7: 2020-2029 Volumes (Actual/Bridge/Forecast) – Underground Cable Renewal

Asset Class	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PILC Cable (km)	0.8	2.9	10.4	12.4	3.8	5.2	6.4	6.8	7.5	9.0
AILC Cable (km)	0.0	1.6	4.3	1.4	0.0	1.4	1.7	1.8	2.0	2.4
Fiber Optic Cable (km)	0.0	0.0	0.0	0.0	0.0	5.0[1]				

[18] See Exhibit 2B, Section E4 for more details.

Note 1: Toronto Hydro plans to install a total of 5 km of fiber optic cable units over the 5 year period and will determine the yearly allocation during project scoping based on infrastructure criticality and accessibility, feeder loading, and the feasibility of connecting to the existing fiber network.

The Underground System Renewal – Downtown program prioritizes at-risk cable segments based on historical failures, the number of splices on feeders, age, and customer base. Toronto Hydro will use this in conjunction with complementary cable testing data to validate the volume of cable replacement required. This is considered to be a best practice in the industry and is used by utilities such as Consolidated Edison (ConEd) in New York City for their PILC cable replacement program.[19] For cables where inspection and maintenance information is limited, studies have shown that this method is condition driven and a reliable alternative to traditional methods for asset ranking based on asset age, failure history, or asset 'health indices' .[20]

Toronto Hydro has determined that approximately 4.6 percent of the PILC population is in a critical state and should be addressed through proactive replacement during the 2025-2029 period. This 4.6 percent amounts to 44 circuit-km of PILC, and will trigger replacement of approximately 5.3 percent of the existing AILC population (9.3 circuit-km) connected downstream of PILC cable.

Toronto Hydro plans to install 5 km of fiber optic cables to enable on line cable monitoring in locations where no fiber optic cables currently exist. It should be noted that fiber optic cable network already exists on some sections of the downtown core and could be used to deploy online cable monitoring where applicable. Toronto Hydro will select locations to expand this fiber optic cable network based on the existing fiber optic network, the criticality of the route (e.g. number of feeders and key account customers served by the feeders), the difficulty in accessing or maintaining cables on those sections (e.g. rail crossings or under water tunnels), and colocation with a feeder identified for underground cable renewal work in the 2025-2029 plan.

Based on actual and forecast costs for 2020-2024 projects, Toronto Hydro estimates that PILC cable replacement projects will cost, on average, approximately $1.2 million per circuit-km, while AILC replacement will cost approximately $0.5 million per circuit-km. Toronto Hydro has applied these volumetric costs to the forecast population of critical cables to develop the 2025-2029 segment cost of $61 million.

[19] M. Olearczyk et. al., *Notes from Underground – Cable Fleet Management*, "online", http://www.neetrac.gatech.edu/publications/Note_from_Underground_Nov2010.pdf
[20] M. Buhari, V. Levi and S. K. E. Awadallah, "Modelling of Ageing Distribution Cable for Replacement Planning," in *IEEE Transactions on Power Systems*, vol. 31, no. 5, pp. 3996-4004, Sept. 2016.

E6.3.4.2 Cable Chamber Renewal Expenditure Plan

Over the 2020-2024 period, Toronto Hydro expects to invest a total of $40.1 million in the Cable Chamber Renewal segment as shown is Table 8 below, which is approximately $11 million higher than forecast in the 2020-2024 DSP. The higher spending is primarily due to a higher volume of lid replacement and higher than estimated unit costs.

Over 2025-2029, Toronto Hydro plans to increase spending in this segment to $96.5 million to address 199 cable chambers at risk of failure and 2,800 potentially hazardous cable chamber lids, as shown in Tables 8 and 9 below.

Table 8: Cable Chamber Renewal 2020-2029 Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Cable Chamber Renewal	4.0	2.9	9.4	18.3	5.4	10.4	13.6	19.1	26.3	27.1

Over the 2020-2022 period, Toronto Hydro spent $16.4 million to rebuild 10 cable chambers, complete 15 roof rebuilds, and replace 459 cable chamber lids with energy mitigation lids. Toronto Hydro plans to invest $23.7 million in 2023-2024 to replace 830 cable chamber lids, rebuild 22 roofs and 17 cable chambers, and complete 2 cable chamber abandonments. The total number of cable chambers addressed (excluding lids) is less than the proposed volumes in the 2020-2024 DSP as the average cost for cable chamber rebuilds, lid replacements and roof rebuilds has significantly increased compared to what was originally estimated in 2018.

When Toronto Hydro originally estimated the costs in this segment for 2020-2024, it had no actual costs or experience executing this work proactively to base its estimates on, as it was a new segment starting in 2020. Therefore, the estimates did not fully account for certain factors such as the need to replace obsolete PILC and AILC cables, the requirement to take outages to do full rebuilds in certain circumstances, and the full impact of working in congested areas downtow and requirements from the City that some of this work be performed only during weekends and at night. These factors were further exacerbated by the COVID-19 pandemic and unusually high escalation in labour and material costs over this period.

Table 9: Cable Chamber Planned Replacement Volume — Historical and Bridge Period

Asset Class	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Cable Chamber	4	1	5	9	8	3	4	9	15	15
Cable Chamber Roof	7	3	5	19	3	14	26	28	30	30
Cable Chamber Abandonment	0	0	0	1	1	3	5	5	6	6
Cable Chamber Lid	105	162	192	650	180	400	450	550	700	700

Toronto Hydro's spending plan for this segment for the 2025-2029 period includes the following breakdown:

- 2,800 cable chamber lid replacement (approximately $14,350 per unit)
- 46 cable chamber rebuilds (approximately $450,000 a unit)
- 128 cable chamber roof rebuilds (approximately $80,000 each unit)
- 25 cable chamber abandonments (approximately $25,000 each unit).

Toronto Hydro has applied these unit costs to planned unit volumes to develop the 2025-2029 segment cost of $96.5 million. Unit costs are based on recent experience planning and executing cable chamber renewal projects.

Reconstructing a cable chamber requires breaking into or reconstructing portions of duct bank. As such, the cable chamber renewal segment includes the cost of reconstructing a portion of a duct bank along with cable replacement within the cable chamber. Required electrical work within a cable chamber, road or sidewalk repair, and road restoration are also incorporated into the cost. In developing the cable chamber renewal segment costs for 2025-2029, Toronto Hydro now assumes that outages are not required for cable chamber roof rebuilds, but are required for full rebuilds of cable chamber when there are non-standard cables in the chamber which needs to be changed. If the cable chamber does not meet standard requirements, the civil structure will be rebuilt to meet current standards.

Based on inspection records, 592 cable chambers have been identified to be in HI4 and HI5 condition and another 521 are projected to become HI4 or HI5 by 2029 without investment. Toronto Hydro is increasing its investment in this segment to address 199 cable chambers and mitigate this increasing backlog and the associated safety and reliability risk. Cable chamber rebuilds are highly complex

projects, as they require not only civil resources but also electrical resources, permits from the City to dig into streets, management of the high volume of downtown vehicular and pedestrian traffic, and extensive coordination between various stakeholders. The new chamber has to conform to current standards and the size may have to be enlarged to minimize congestion of the cables inside and to accommodate more cables for future needs. In light of these needs, a cable chamber rebuild requires a detailed design. The proposed pace is moderate and accounts for the above challenges and resourcing considerations, as well as the length of time civil deficiencies can be managed before renewal is required

Toronto Hydro mainly prioritizes cable chambers based on the condition of the civil infrastructure as well as the types of customers and thermal loading of feeders. As Toronto Hydro has gained experience planning and executing these projects and has a better understanding of the required costs, it expects to be able to ramp up the pace of investment over 2025-2029. Also based on recent project experience, when planning a cable chamber, the utility will also inspect adjacent chambers in the area and consider any intervention in tandem such that all required work can be completed together. Toronto Hydro will also review the location for possible challenges, such as interference with TTC or other utility infrastructure.

E6.3.4.3 URD Renewal

The URD Renewal segment aims to replace end-of-life and obsolete URD assets that contribute to the deterioration of system reliability. These assets include: vaults, switches, and transformers that form part of the URD system. In addition, THESL plans to install FCIs on select URD feeders that will be prioritized based on reliability performance in order to mitigate the risk of long duration outages.

Table 10 below provides the year over year breakdown of URD Renewal investment including the actuals (2020-2022), bridge (2023-2024), and forecast (2025-2029).

Table 10: URD Renewal 2025-2029 Segment Costs ($ Millions) — URD Renewal

Actual			Bridge		Forecast				
2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
-	0.4	0.6	0.4	2.1	1.0	1.0	0.9	1.0	0.8

The total (actual and bridge) 2020-2024 expenditure of $3.5 million is slightly higher than the 2020-2024 DSP forecast of $3.3 million. Over the 2020-2022 period, Toronto Hydro spent approximately

$1 million and completed three roofs rebuilds and replaced two submersible switches and one URD transformer. Toronto Hydro plans to spend approximately $2.6 million over 2023-2024 to renew seven submersible switches, five transformers, and seven vault roofs.

Table 11: URD Assets Planned Replacement Volume — Historical and Bridge Period

Asset Class	Actual			Bridge		Total
	2020	2021	2022	2023	2024	
URD Submersible Switches	0	0	2	1	6	9
URD Transformers	0	0	1	0	5	6
URD Vault Roof	0	1	2	1	6	10

Toronto Hydro spent slightly more than planned, while completing fewer roof rebuilds and switch replacements (but additional transformer replacements) due to the following reasons:

- Installation of new 200A switch was a pilot initiative, which also required a new vault roof design. As such, there was a significant learning curve in completing designs and obtaining approvals. Pilot projects related to new technologies are susceptible to risk due to uncertainties. The COVID-19 pandemic added another layer of complexity, for example increasing the lead time of the new 200A submersible switches, which affected project execution and timing.
- The unit cost of URD assets was higher than the originally estimated cost, which were estimated using comparable standards as Toronto Hydro had no previous experience with this work and the actual standards had yet to be developed at the time. This was further exacerbated by externally-driven escalations of labour and material costs over the 2020-2022 period. The higher units costs contributed to fewer units completed in order to limit overspending.

Toronto Hydro plans to invest $4.8 million over 2025-2029 to support maintaining URD system reliability and long-term asset risk levels. With this level of funding, the utility estimates that it can renew four submersible switches, 17 transformers, and four vault roofs, and replace 375 old and obsolete FCIs with the latest standard, as shown in Table 12. However, the number and mix of assets addressed are subject to change as Toronto Hydro prioritizes projects and develops detailed scopes. For example, the utility will prioritize projects based on the condition of civil roofs, as deficient roofs pose an immediate risk to the public and employees. Assets such as URD switches and transformers

within these vaults will be replaced on an as-needed basis according to the latest available inspection records.

Table 12: URD Renewal 2025-2029 Volume Forecast

Asset Class	2025	2026	2027	2028	2029	Total
URD Submersible Switches	1	1	1	1	0	**4**
URD Transformers	3	3	3	3	5	**17**
URD Vaults (Roof Rebuild)	2	1	1	0	0	**4**
FCIs	0	100	100	100	75	**375**

E6.3.4.4 Underground Switchgear Renewal Expenditure Plan

The underground switchgear renewal segment aims to replace end-of-life and obsolete underground switchgear assets that contribute to the deterioration of system reliability and pose safety risks. Table 13 below provides Toronto Hydro's annual forecast 2025-2029 expenditures to address the critical underlying issues of the underground switchgear assets in Toronto downtown.

Table 13: Underground Switchgear Renewal 2020-2029 Segment Costs ($ Millions)

	Actual		Bridge			Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Legacy Switchgear	-	-	-	-	0.1	0.5	0.6	0.6	0.6	0.7

There are no historical expenditures associated with this program. Toronto Hydro plans to spend $0.1 million in 2024 for design work related to projects to be executed starting in 2025. Over 2025-2029, the utility proposes investing $2.9 million to replace four switchgears per year. The forecast costs are based on bottom-up estimates (i.e. labour and material requirements) to install a compact radial design standard, which is used in new building vaults.

Switchgear replacement projects may also include replacing transformers depending on the condition of the existing transformer and the feasibility of connecting it to the new standard switchgear. The planned pacing is the practical rate that Toronto Hydro is realistically able to achieve given available resources, while benefiting customers through reduced interruptions and safety risks. The utility will prioritize switchgear based on the condition (current and future HI), inspection and maintenance history, and historical reliability.

Table 14: Underground Switchgear Renewal 2025-2029 Volume Forecast

Asset Class	2025	2026	2027	2028	2029	Total
Underground Switches	4	4	4	4	4	**20**

E6.3.5 Options Analysis

E6.3.5.1 Underground Cable Renewal

1. Option 1: Reduced Pace

Under this option, Toronto Hydro would replace 3.2 percent of PILC cable (31.7 circuit km of 985 km) and 1.7 percent of AILC cable (3 km of 176 km) cables. This reduced pace is aligned with a 35-year timeline for removal of all remaining PILC and AILC cable (when considering cable replacement work done in other programs).

As mentioned in section 3.1, PILC and AILC cables are becoming obsolete across the industry due to environmental, health, and safety concerns. The longer it takes to remove these legacy cables from the distribution system, the greater the risk that Toronto Hydro will not be able to properly maintain the remaining population due to a lack of manufacturer support. In addition, approximately 58 percent of all PILC cables and 93 percent of all AILC cables in the system are more than 30 years old and these aged cables are showing signs of deterioration. Cable splices as a result of reactive replacement of failed PILC and AILC cable, which also increase failure risk, will also increase if these cables are not proactively replaced. This will negatively impact reliability for customers in the downtown area and drive up reactive spending.

Under this option, Toronto Hydro would also not invest in any installation of fiber optic cable, limiting the implementation of on line cable monitoring in the downtown area and the associated benefits described in section E6.3.3.1.

2. Option 2 (Selected Option): Sustainment pacing of PILC and AILC Cables

Under this option, Toronto Hydro is planning to remove approximately 3.5 percent of PILC cable (34.9 circuit kilometres of 985 kilometres) and 5 percent of AILC cable (9.3 circuit kilometres of 176 kilometres) and install 5 km of fiber optic cable over 2025-2029. This option will replace PILC cable at a pace aligned with a 30-year timeline to remove all PILC cable when considering the cable replacement work done in other programs.

Under this option, Toronto Hydro would mitigate the failure risk on the downtown distribution system and maintain reliability. As mentioned above, non-uniformity (i.e. cable splicing) increases the risk of failure. Therefore, by replacing the highest risk cables, the utility will increase the uniformity of cable types in the system (i.e. by replacing the non-uniform cable with XLPE cable), which will help maintain reliability on the system. The installation of fiber optic cable would enable Toronto Hydro to extend the reliability and asset optimization benefits from online cable monitoring.

In addition to maintaining reliability, this option will reduce the risk of oil leakage from the insulation on PILC cables and therefore reduce the need for service interruptions on customers to address these leaks.

3. Option 3: Accelerated Replacement of all PILC and AILC cable over 25 years

Under this option, Toronto Hydro would replace PILC and AILC cables in its distribution system at a pace aligned with a 25-year timeline for full removal when considering the cable replacement work done in other programs.

This would allow the utility to more proactively address the environmental and safety issues associated with the continued use of PILC and AILC cables. It would also mitigate the risks associated with a single supplier (i.e. procurement risk). Furthermore, it would address reliability risks and provide downtown customers with improved reliability.

However, this option is estimated to cost approximately 1.5 times the cost of the proposed plan and does not represent a reasonable balance between price and other outcomes such as reliability. It would also require that additional resources be allocated to this segment, which may be a challenge given other priorities.

E6.3.5.2 Cable Chamber Renewal

1. Option 1: Reduced Pace (Lid Replacements)

Under this option, Toronto Hydro would proactively address 199 cable chambers that represent approximately 35 percent of the projected HI4 and HI5 population by 2029 (without investment), which is consistent with Option 2. Toronto Hydro considers this to be the lowest reasonable number of cable chambers that should be addressed over 2025-2029 to address safety and reliability risks. It is also a pace that realistically accounts for the challenges in planning and executing this work and the required resources.

However, under this option Toronto Hydro would only replace 1,400 chamber lids at risk of ejection (approximately 12 percent of the population) with energy mitigation lids. Toronto Hydro finds that the safety risk due to the significant number of potentially hazardous cable chamber lids that would remain in the system is too high and therefore this option is not recommended.

2. Option 2 (Selected Option): Sustainment Pace

Similar to Option 1, under this option Toronto Hydro plans to proactively address 199 cable chambers that represents approximately 35 percent of projected HI4 and HI5 population by 2029 (without investment). The utility considers this to be the minimum number of cable chambers that should be addressed to sustainably manage the asset population and mitigate the growing backlog of deteriorated structures and associated safety and reliability risk. The proposed pace is moderate and accounts for the challenges and resourcing considerations associated with this work as well as the length of time civil deficiencies can be managed before renewal is required.

However, compared to Option 1, the proposed plan also includes the replacement of twice as many (2,800) potentially hazardous cable chamber lids (approximately 25 percent of the population) with energy mitigation lids. This would address all of the high risk locations and most of those considered a medium risk for lid ejection, mitigating the safety risk to a much more acceptable level.

3. Option 3: Accelerated Pace

Under this option, Toronto Hydro would address all at-risk (i.e. HI4/HI5) cable chambers and replace 5,000 cable chamber lids with energy mitigating lids. Although, this would significantly reduce safety and reliability risks associated with deteriorated cable chambers, this pace would require significantly more spending and resources and could pose execution challenges. Road moratoriums within Toronto's downtown core may further challenge Toronto Hydro's ability to execute the work at an accelerated pace in the short- to medium-term. Toronto Hydro finds that this is not an appropriate balance of benefits and costs and would potentially be infeasible to execute and therefore this option is not recommended.

E6.3.5.3 URD Renewal

1. Option 1: Reduced Pace

Under this option, Toronto Hydro would address select deteriorating URD assets at a reduced pace to manage deterioration. The investments would target the following:

- Replace approximately 25 percent of URD switches and 15 percent of URD transformers projected to be HI4/HI5 by 2029 (without investment);
- Rebuild vault roofs on approximately 25 percent of URD vaults projected to be HI4/HI5 by 2029 (without investment); and
- Install 150 FCIs on the URD feeders with the most outages.

Although this option would be cheaper and mitigate asset failure risk to some extent, it could still negatively impact URD reliability performance and increase safety [and environmental] risk and the deterioration of asset health. Reactive replacement and rebuild of URD assets would likely increase. Deteriorated civil condition of URD vault roofs can potentially compromise the electrical equipment within the vault and also increase the safety risk for Toronto Hydro employees when they enter the vault. Failing or deteriorated switches and transformers can release harmful environmental contaminants such as oil and SF6 gas and pose safety risks, in addition to impacting reliability performance. Finally, faulty FCIs can lead to prolonged outages, which customers have indicated a are a priority.

2. Option 2: (Selected Option) Sustainment Pace

Under this option, Toronto Hydro plans to proactively rebuild URD vault roofs and replace deteriorating and obsolete submersible switches and poor condition transformer at a modest pace. The investments would target the following (subject to detailed prioritization and planning of projects):

- Replace approximately 50 percent of URD switches and 40 percent of URD transformers projected to be HI4/HI5 by 2029 (without investment);
- Rebuild vault roofs on approximately 30 percent of URD vaults projected to be HI4/HI5 by 2029 (without investment); and
- Install 375 FCIs on the URD feeders with the most outages.

As URD vaults, transformers, and switches deteriorate, they need to be addressed proactively to reduce failure risk and mitigate the associated. Under this option, Toronto Hydro would invest a moderate incremental amount over Option 1 that better supports maintaining the reliability, environmental, and safety risks and longer-term sustainability of the URD system. This option is recommended because it provides the best balance between risk and cost compared to the other options.

3. Option 3: Accelerated Replacement of URD Assets

Under this option, Toronto Hydro would replace a larger population of the obsolete 200A switches and install FCIs across all URD feeders. Toronto Hydro anticipates that while this pacing option would better address reliability risk in the URD system, this strategy would also require significantly higher spending and does not represent an appropriate balance of price and reliability aligned with customer priorities. Therefore, this option is not recommended.

E6.3.5.4 Underground Switchgear Renewal

1. Option 1: Reactive Replacement Approach

This option entails continuing to operate the legacy underground switchgear units as is and replacing them only reactively upon failure. Failure rates have slowly increased in recent years and would likely continue to increase, which poses a challenge as there is no longer manufacturer support and spare parts are not available. Accordingly, maintaining the status quo will negatively affect system reliability and will pose potential safety risks to customers as well as Toronto Hydro personnel. As such, this option is not recommended.

2. Option 2 (Selected Option): Replacement of Underground Switchgear at Proposed Pace

Toronto Hydro's plan addresses safety risks associated with deteriorating legacy switchgear units and would improve reliability and safety of the system. The utility expects the replacement of legacy switchgear units to avoid some of the customer impacts and costs associated with in-service asset failures, such as customer interruptions and emergency repairs and replacement. At the proposed pace of 4 units per year, 20 of the 89 units forecast to have at least material deterioration by 2029 would be replaced and their associated safety and reliability risks addressed. Those remaining units not replaced by 2029 or ones not replaced in a timely manner will continue to pose a higher risk of failure until they are replaced. However, this is the recommended option as it is expected to result in an acceptable, but not ideal, reduction in the number of at-risk units at a reasonable level of spending.

3. Option 2: Replacement of Underground Switchgear at Accelerated Pace

Under this option Toronto Hydro would replace legacy switchgear units at an accelerated rate of 8 units per year to achieve faster reduction of safety and reliability risks associated with deteriorating legacy switchgear units. At this pace, Toronto Hydro would replace almost half of the 85 units

projected to have at least material deterioration by 2029. This would reduce the number of legacy switchgear units operating at elevated risk of failure, however, it would also cost twice as much as Option 2 and is therefore not the recommended option.

E6.3.6 Execution Risks & Mitigation

A key execution risk affecting the Underground System Renewal – Downtown program is external dependencies. In the downtown area, coordination with third parties (e.g. City of Toronto, TTC) has been an on-going requirement. Toronto Hydro invests substantial efforts to ensure effective inter-agency coordination.

Toronto Hydro ensures that optimal routes are chosen based on criteria, such as the avoidance of busy intersections and paths where utilities reside. Often, projects require construction of new civil assets such as duct banks or cable chambers. It is expected that these projects may be delayed without effective coordination. To mitigate risks, these projects will be planned well in advance.

Additionally, road moratoriums have the potential to delay projects in the downtown core. To mitigate this risk, Toronto Hydro will plan and schedule work accordingly.

Underground Cable Renewal will prioritize at-risk cables dynamically as testing data, and cable replacement data become available. This means cables that are deemed low-risk one year, may be high risk in another year. As such, dynamic planning will be required, targeting the highest risk assets based on the best available information, i.e. feeders that are statistically more likely to fail. However, this approach may result in disruptions to project scheduling and planning. Efforts will be made well in advance to coordinate multiple projects at the same time so projects are deferred or advanced accordingly.

The successful roll out of new URD assets, including URD submersible switches will depend on the results of a field trial that is currently underway. The plan is to incorporate lesson learned and make any changes before standardizing the product. In addition, since all URD assets are located in residential neighbourhoods in the downtown core, coordination with the relevant customers is critical. Toronto Hydro will abide by residential community by-laws such as noise levels placed by the City of Toronto and coordinate with all stakeholders as necessary.

There may be unforeseen conditions or access problems with some customer-owned civil structures. In these situations, the customer may have to perform civil rebuild work before Toronto Hydro's

work can commence, thereby causing project delays. This risk can be mitigated by fully inspecting all civil plant prior to finalizing project design, and introducing sufficient lead times for customer civil design and construction activities in the project schedule.

Finally, as has become evident over recent years, supply chain pressures and disruptions can drive up material costs and impact timelines. This is mitigated through proactive internal engagement and coordination and Toronto Hydro's procurement strategy. For more details on what Toronto Hydro has been doing to address this issue please see Exhibit 4, Tab 2, Schedule 15 (Supply Chain).

E6.4 Network System Renewal

E6.4.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 116.1	**2025-2029 Cost ($M):** 123.4
Segments: Network Unit Renewal; Network Vault Renewal; Network Circuit Reconfiguration	
Trigger Driver: Failure Risk	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Environment, Financial Performance	

The Network System Renewal program (the "Program") addresses deteriorating and functionally obsolete underground network system assets serving primarily small to medium-sized customers in the pre-amalgamation City of Toronto. These customers reside in the City's core and are often sensitive to outages.[1] For example, sensitive customers that are served by this part of the system include commercial businesses, GO Transit, and hospitals. The Program is designed to maintain reliability and mitigate public safety risks by: (1) replacing non-submersible and deteriorated network units, (2) replacing network vaults in deteriorated condition, and (3) reconfiguring and re-cabling sub-optimal grid networks.

The Program is grouped into the three (3) segments summarized below and is a continuation of the network renewal activities described in Toronto Hydro's 2020-2024 Distribution System Plan, with the exception of Legacy Network Equipment Renewal which was completed in the current rate period.[2]

- **Network Unit Renewal:** This is a continuation of planned replacement of network units at risk of failure. As network unit condition deteriorates, the risk of failure increases, and with it the likelihood of consequences such as lengthy customer outages and vault fires. This segment will target deteriorated units, predominantly non-submersible units. The non-submersible units are susceptible to water ingress and elevated failure risks even when in

[1] As discussed in Exhibit 2B Section D2.2.2, the underground network system is the most reliable configuration available among Toronto Hydro's distribution schemes, and is therefore an ideal option for customers who are sensitive to outages and concerned about reliability.
[2] EB-2018-0165, Exhibit 2B, Section E6.4. Over 2020-2024 Toronto Hydro successfully completed the Legacy Network Equipment Renewal segment by replacing all of the remaining Automatic Transfer Switches ("ATS") and Reverse Power Breakers ("RPB").

good condition. Toronto Hydro will prioritize the replacement of high failure risk units as indicated by condition inspections and health index scores. Without intervention, the utility projects that 149 units will be materially deteriorated ("HI4") or at end-of-serviceable life ("HI5") by 2029 and that 50 percent of its network units will be at or beyond useful life by 2034. The utility plans to replace 130 network units between 2025 and 2029. This rate of replacement is expected to reduce failure risk on the network system by improving condition-related asset risk across the network unit population. Toronto Hydro plans to install new network units that are submersible and equipped with sensors to monitor transformer, protector, and vault conditions, resulting in the cost-effective reduction of reliability, environmental, and safety risks associated with network assets.

- **Network Vault Renewal:** This is a continuation of Toronto Hydro's efforts to rebuild or decommission poor condition network vaults. These civil structures were generally built in the 1950s and 1960s, mainly beneath the sidewalks in the busy downtown core. Toronto Hydro must proactively address structurally deficient vaults in order to mitigate risks to public safety, employee safety, and system reliability, and to maintain the long-term viability of the distribution system. If the proposed work is not completed, the number of network vaults in HI4/HI5 condition is forecasted to increase from 91 to 137, or approximately 29 percent of the vault population, by 2029. During the 2025-2029 period, Toronto Hydro plans to eliminate immediate structural deficiencies of 38 high-risk vaults identified through the Asset Condition Assessment ("ACA") process as having at least material deterioration ("HI4"). Due to the complexity of this mostly downtown work, the rate of planned replacement is less than optimal. However, at the pace of renewal, Toronto Hydro will see a slight increase in the assets in material deterioration or end-of-serviceable-life (HI4 or HI5 condition by the end of 2029, relative to 2022.

- **Network Circuit Reconfiguration:** This is a continuation of Toronto Hydro's plan to mitigate the impact of multiple contingency failures on the network system. This segment involves reconfiguring and re-cabling secondary grid networks into more robust spot vaults and enhanced grids. The result will be minimized customer interruptions, improved planning, modeling, and operational flexibility, and enhanced ability of the network system to operate under extreme events (e.g. multiple contingency outages). Toronto Hydro plans to reconfigure the parts of three secondary networks over the 2025-2029 rate period, an

investment that is expected to deliver long-term reliability and resiliency benefits for network customers in the downtown area.

Toronto Hydro plans to invest $123.4 million in the Network System Renewal program over the 2025-2029 rate period, which is approximately a 6 percent increase over projected 2020-2024 spending on this Program (including forecasted inflation). This level of investment is necessary to maintain public and Toronto Hydro employee safety, and the service levels that downtown customers rely on and expect from the network system.

E6.4.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's Network Units Modernization measure and system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by: ○ Replacing 130 network units at highest risk of failure due to poor condition or vulnerability to flooding; ○ Eliminating structural deficiencies of 38 high-risk vaults that are placing enclosed equipment at risk; ○ Replacing older non-submersible or submersible network units with those equipped with sensors to monitor vault conditions and enable quicker response to adverse network conditions; ○ Reducing average restoration time during a full network outage by reconfiguring networks to support all or most of the load; ○ Reducing customer interruptions by a third during second contingency events, by reconfiguring networks to improve operability under multiple contingency events.
Environment	• Contributes to Toronto Hydro's environmental objectives by eliminating network units at high risk of failure and vulnerable to vault fires or oil spills.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's modernization and safety objectives by: ○ Minimizing the risk of catastrophic transformer failures by replacing network units most at risk due to deteriorated condition or exposure to higher-risk environmental factors; ○ Eliminating potential trip and falling debris hazards at 38 vaults with significant civil deterioration.

Financial Performance	• Contributes to Toronto Hydro's financial objectives by: ○ Reducing the need to dispatch crews in multiple contingency scenarios by reconfiguring the network to support all or most of the network load; and ○ Supporting reduction in summer peak reading inspections by enabling monitoring and control of network units (see Network Condition Monitoring and Control program).[3]

E6.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Safety, Environmental Risk, Reliability, System Efficiency

Toronto Hydro's network system plays an important strategic role in meeting the reliability expectations of interruption-sensitive downtown customers. The Network System Renewal program aims to replace network assets at risk of failure due to deteriorating conditions. The failure of these assets negatively impacts reliability and the effective operation of the network system and potentially increases the risk to public safety and Toronto Hydro's crews.

Toronto Hydro's low voltage secondary network distribution system includes the following assets:

- Network Units that consist of primary switches, network transformers, and secondary network protectors, which are assembled into a single unit;
- Network Vaults, which contain the aforementioned equipment; and
- Secondary Cables, which connect the aforementioned equipment and provide service connections to customers.

The Network System Renewal program is needed to replace those assets that are at risk of failure in order to mitigate the associated safety, environmental, and reliability risks and to maintain the service levels that downtown customers rely on and expect from the network system.

[3] Exhibit 2B, Section E7.3

E6.4.3.1 Network Unit Renewal

The Network Unit Renewal segment is a continuation of the activities identified in Toronto Hydro's 2020-2024 rate application. This segment aims to reduce failure risks associated with network units that are obsolete, in poor condition, and prone to failure. The goal of the segment is to replace the most at-risk units, as indicated by the above criteria, before they fail and potentially cause safety or environmental incidents such as fires or oil leaks.

Although replacements are prioritized based on condition, the network units that are replaced are typically legacy "non-submersible" designs characterized by "ventilated" (see Figure 1) or "semi-dust-tight" protectors. These units are susceptible to water ingress and elevated failure risks even when in good condition. These units also typically contain electro-mechanical relays that are not capable of remote condition monitoring or control. They are replaced with units that are of a submersible design (see Figure 1), containing microprocessor relays, and are capable of meeting the requirements for Toronto Hydro's Network Condition Monitoring and Control program.



Figure 1: Snapshot of a Ventilated Network Unit (L) and Submersible Network Unit (R). The black protector is of a submersible design, which prevents water ingress.

1. Failure Risk and System Efficiency

Two main failure modes can impact a network unit. The first is flooding of the network vault that may damage the protector mechanism causing the unit to short, or fail to operate. The second is an internal transformer failure that is typically caused by low oil, moisture ingress, or age-related insulation deterioration. To maintain network system reliability, network units need to be both

routinely maintained and proactively replaced when they are at an increased risk of failing. Maintenance of network units is summarized in Exhibit 4, Tab 2, Schedule 2. Not replacing deteriorated network units in a timely manner can lead to equipment failures, and in turn cause interruptions to customers, oil leaks of 1,000 litres and more, and potential vault fires that may impact (including by expelling smoke) busy arterial roads in the downtown core of Toronto.

Replacing deteriorated or non-submersible units located in areas prone to flooding with submersible protectors that feature watertight cases can help address failure risks. Toronto Hydro will prioritize the replacement of high failure risk units as indicated by condition inspections and health index information. Toronto Hydro has over 1,900 network units of which roughly 30 percent have non-submersible protectors, which are legacy designs used prior to the installation of the first submersible units in 2003. As a result, virtually all units older than 20 years are ventilated or semi-dust-tight.

Figure 2 shows the current age distribution of submersible and non-submersible network units. With a useful life 35 years, as of the end of 2022, approximately 22 percent of the network unit population is at or beyond useful life. Without any capital investment, this number is projected to increase to 27 percent by 2029 and to 56 percent by the end of 2034. Not investing at a steady pace of asset renewal will not only increase reliability risks on the distribution system but also increase the need to ramp investments in the future and associated complexity involved in replacing a large number of units over a short period. This could result in more outages and higher safety risks due to failure.

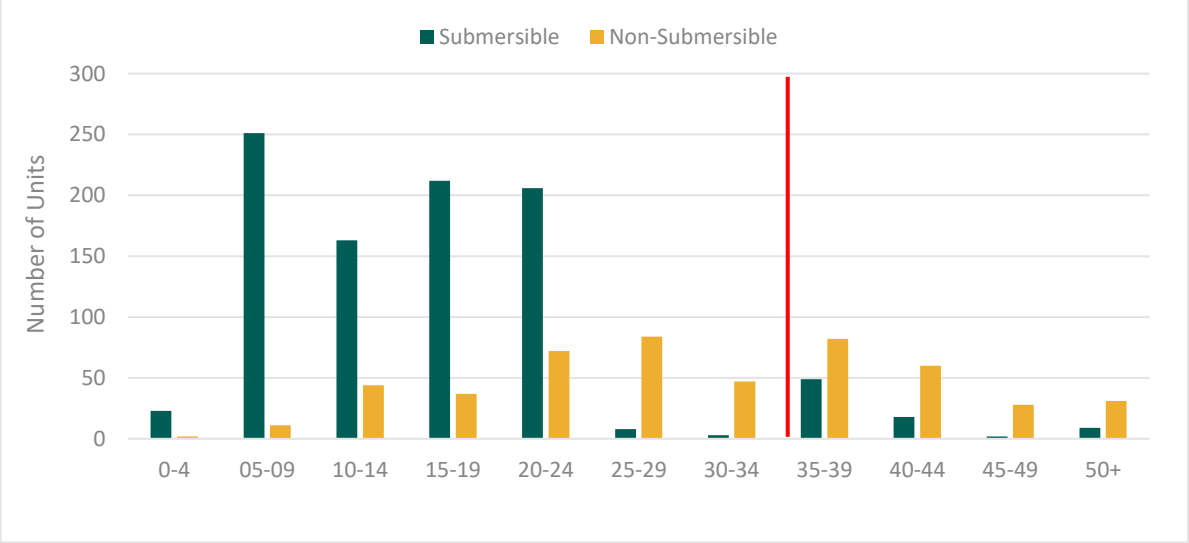


Figure 2: Network Unit Age Demographics

Based on 2022 ACA data, the current and estimated 2029 health index distribution (without proposed work) for network units is shown in Figure 3. HI4 means "material deterioration" and HI5 means "end of serviceable life". It is expected that HI4/HI5 numbers will increase from 43 units (in 2022) to 149 units in 2029. The network unit renewal segment plans to replace 130 units at an average rate of about 26 per year over the 2025-2029 rate period to address deteriorating and high failure risk units.

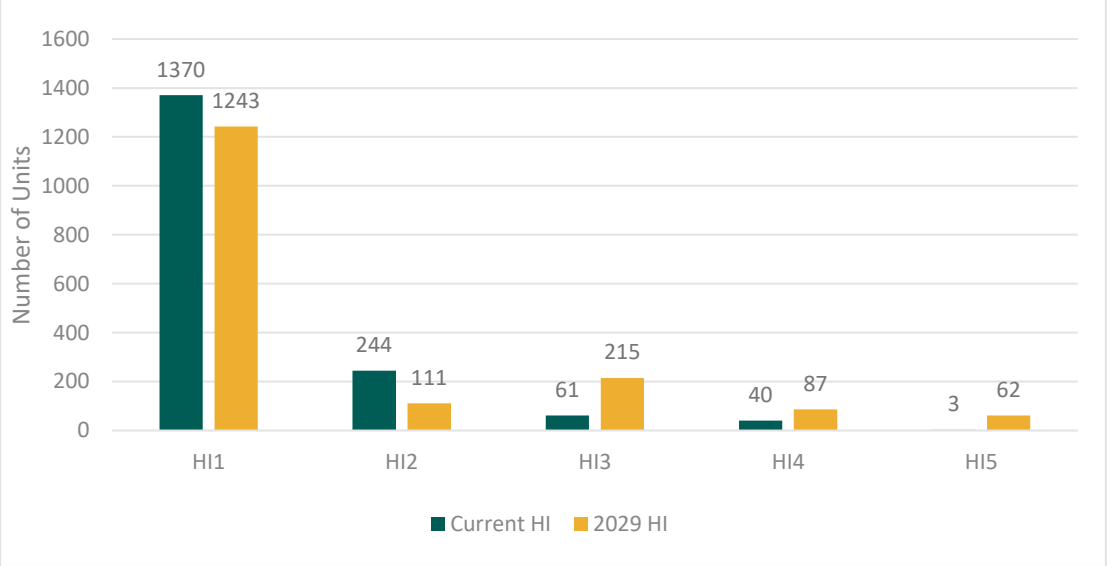


Figure 3: Network Transformers Condition Demographics – Current and Forecasted HI (without Renewal)

2. Safety and Environment

Failure of deteriorated network units can result in both safety and environmental incidents. From a safety perspective, catastrophic failures may cause damage to surrounding property and put the public at risk of injury, especially given that network vaults are typically installed under sidewalks with significant pedestrian traffic. From an environmental perspective, corroded and deteriorated network units may result in oil leaking within a vault, and the possibility of oil escaping through vault drainage systems into the environment. Between 2020 and 2022, Toronto Hydro has experienced 82 oil leaks from network transformers. As network transformers typically contain more than 1,000 litres of oil, oil leaks have the potential to lead to serious environmental consequences. Figure 4 shows the distribution of the 82 network transformer oil leaks experienced by volume of oil leaked.

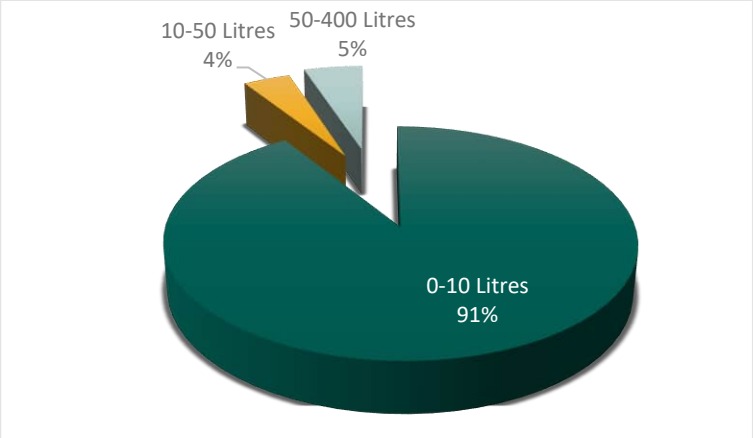


Figure 4: Network Transformer Oil Leaks (2020-2022)

Oil leaks are mitigated by replacing deteriorated units and units operating in environments which place them at elevated risk.

E6.4.3.2 Network Vault Renewal

The Network Vault Renewal segment is a continuation of the network vault rebuild and decommissioning activities detailed in Toronto Hydro's 2020-2024 rate application. Many network vaults associated with the secondary network system were constructed in the 1950s and 1960s, mainly beneath the sidewalks in Toronto's busy downtown core. Today, these assets have many critical structural issues and Toronto Hydro plans to address the worst of them based on condition data. The aim of this segment is to reduce failure risks resulting from vault structural deficiencies that can negatively impact the reliability and effective operation of the utility's distribution system as well as safety risks to the public and Toronto Hydro crews.

3. Failure Risk

Vault structural deficiencies are mainly caused by old age and exposure to adverse environmental factors. Currently, Toronto Hydro has about 470 network vaults, predominantly in the downtown core, supplying the network system. Figure 5 shows the age distribution of all network vaults with reference to the useful life of both the overall vault (60 years) and the roof (25 years).

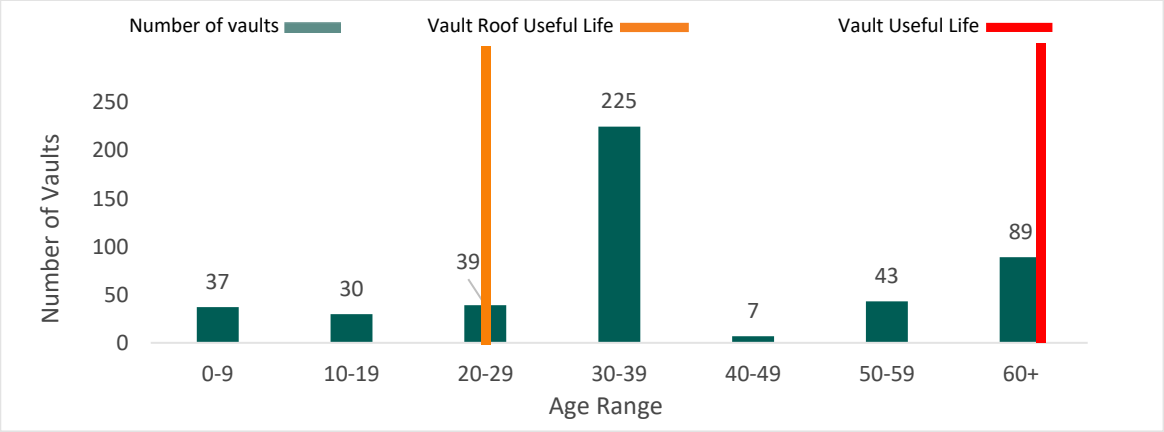


Figure 5: Age Distribution of Network Vaults

The vast majority of vault roofs have reached the end of their expected useful life of 25 years. Additionally, over 28 percent of the vault civil structures will reach the end of their expected useful lifespan (of 60 years) within 10 years. ACA results show that some vaults are deteriorating at an accelerated pace and require repairs even though they have yet to reach their expected lifespan. The increased use of de-icing salts in recent years is contributing to this accelerated aging. Figure 6 shows that as at the end of 2022, 91 (19 percent) of Toronto Hydro-owned network vaults exhibit at least material deterioration (HI4/HI5) and are clear candidates for work under this renewal segment. This number is forecasted to grow to 137 (29 percent) in 2029 if the proposed work is not completed. In addition to the 23 network vaults planned for renewal in 2023-2024, Toronto Hydro plans to address 38 network vaults between 2025 and 2029 to alleviate the risks posed by deteriorating vaults.

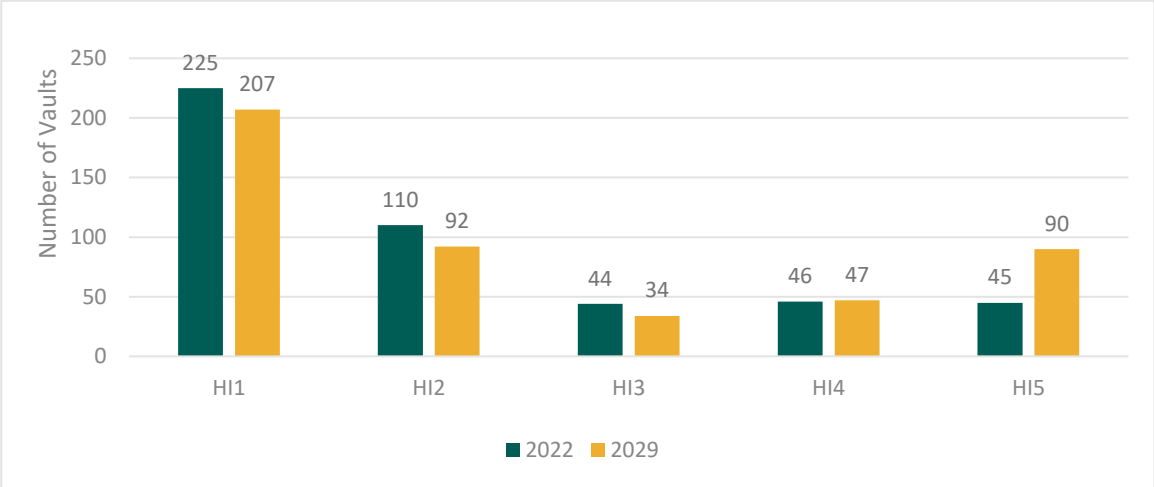


Figure 6: Current, 2025 and 2029 Health Scores for TH-owned Network Vaults

Some commonly found structural deficiencies caused by asset aging and environmental factors are described in Table 4.

Table 4: Vault Structural Deficiencies and Impacts

Deficiency	Impact
Exposed Roof Rebar	Failure risk that can lead to roof collapse, damage to equipment and safety hazard to the public and Toronto Hydro crews.
Exposed Wall Rebar	Failure risk may result in collapse of the vault walls, potentially leading to damaged equipment, costly repairs, safety hazards, and power outages.
Corroded I-Beams	Failure risk due to age and environmental factors can lead to collapse of the roof structure.
Cracked Roof	Exposes electrical equipment to leaking water and accelerated corrosion which may result in catastrophic failure.
Cracked Walls and Floor	Increases risk of failure causing flooding and damage to equipment which may result in large outage.

Examples of these deficiencies are shown in Figure 7, Figure 8, Figure 9, and Figure 10 below.



Figure 7: Roof and Wall with Exposed Rebar



Figure 8: Corroded I-beams



Figure 9: Cracked Roof and Wall



Figure 10: Deteriorated Vault Floor

4. Reliability and System Efficiency

As discussed above, there are several failure modes and deficiencies that may lead to structural failure within a vault. Such damage to the network vaults is likely to negatively affect the performance of the electrical equipment contained inside, potentially contributing to a catastrophic failure of the network assets within the vaults, thereby causing a power outage in the downtown core. Such a power outage could impact between 500 customers (5 MVA) for smaller network grids and up to 3,000 customers (50 MVA) for the large network grids in the downtown core. The outage can last from several hours to a few days, depending on the location, the severity of the fault and, the network distribution system being impacted.

If a vault roof is not replaced on time, removing it later to replace faulty equipment can cause it to collapse, making it more dangerous and challenging for the crew to replace the equipment. In this scenario, the feeder providing power supply to the failed equipment will be turned off for longer periods of time, which will increase the risk of an outage to the customers fed by that feeder. To

maintain reliable service to interruption-sensitive downtown customers, it is imperative that these assets be renewed before they fail.

5. Safety

Table 5 highlights different safety risks to the public and Toronto Hydro crews resulting from deteriorated network vaults. There are two main types of risks to the public. First, the risks of slips, trips, and falls stem from cracking and structural shifting of vault roof structures. Second, complete failure of roof elements can expose the public to energized electrical equipment.

Table 5: Safety Risk & Descriptions

Safety Risk	Description
Slips, Trips & Falls	A deteriorated vault roof may result in uneven grading on sidewalks or walkways and lead to slips, trips, or falls, which could cause injury to members of the public or Toronto Hydro crews.
Falling Debris	Toronto Hydro crews working inside the vault may encounter falling debris from the deteriorated roof or walls of the vault. This could lead to serious injury, especially when working near live equipment.
Fire	Poor condition of vaults can be a contributing factor to catastrophic failures such as vault fires.

The risk posed by cracking and structural shifting can be controlled by a maintenance program that patches or grinds down hazardous structural elements as needed. However, once a vault reaches the point where major structural deficiencies cannot be addressed by maintenance, three different options are available:

- **Decommissioning vaults** (see Figure 11) that are no longer needed as a result of load displacement. The typical cost to decommission a vault is approximately $150,000 to $180,000 and it takes approximately one month to perform the work;
- **Rebuilding the vault roofs** (see Figure 12) where severe structural deficiencies have been identified, but which are located on network vaults that are otherwise structurally sound. The typical cost of rebuilding a vault roof is up to approximately $360,000 and it can take approximately three months to perform the work;
- **Rebuilding entire vaults** (see Figure 13) that have been identified as having severe structural deficiencies requiring a complete reconstruction. These vaults cannot be decommissioned but require more extensive repairs beyond a vault roof replacement. The typical cost for

rebuilding a vault is up to approximately $1.8 million, which includes the average costs for both civil and electrical work. This work can take between 18 and 24 months to complete.

Toronto Hydro also considers evolving customer needs and system requirements when choosing the best course of intervention for any given vault location.



Figure 11: In-Progress Vault Decommissioning



Figure 12: Temporary Roof during a Roof Rebuild





Figure 13: Completely Rebuilt Vault

For the 2025-2029 Network Vault Renewal segment, Toronto Hydro plans to address the immediate structural vault deficiencies of 38 high risk vaults identified through Toronto Hydro's ACA process as having at least material deterioration. In addition to the ACA process, Toronto Hydro carries out civil assessments wherein a civil engineer visually inspects the network vault roof and walls to recommend whether a roof or whole vault rebuild is required.

E6.4.3.3 Network Circuit Reconfiguration

Toronto Hydro plans to reconfigure large network grids so that either: (i) sufficient grid flexibility is introduced to enable the sustainment of second contingency events; or (ii) sufficient customer loads are automatically dropped during second contingency events to allow the remainder of the grids to continue operating reliably.

A reconfigured network should, by design, shed sufficient load under second contingency conditions to allow the remainder of the grid to continue to operate. The network grids targeted for reconfiguration between 2025 and 2029 have six feeders on average and an average of 30 MVA. This segment is a continuation of the work under the same program, as described in the 2020-2024 rate application. In a second contingency event, instead of losing all 30 MVA, the reconfigured networks would only lose about 10 MVA. This equates to a 67 percent reduction in interrupted load.

The Network Circuit Reconfiguration segment uses a number of different methods to address the problems and risks associated with multiple contingency events. The methods used depend on the configuration of the network and the requirements needed to reconfigure it into a robust system that supports second contingency. A single reconfiguration project may utilize multiple methods including:

- **Splitting grid into spot vaults:** This option solves overload problems under second contingency events that could result in equipment failure, and eliminates the need for power system controller intervention during these events.
- **Splitting grid into enhanced mini-grids:** This option is able to better sustain customer loads under multiple contingency events than what is possible using the first option. However, a third contingency would still result in a serious transformer overload and require prompt action by the power system controllers to identify the problem and shed load accordingly.
- **Upsizing transformers:** The option allows all customer loads to be sustained during any second contingency condition; however, a third contingency would still result in a serious transformer overload and would require prompt action by the power system controllers to identify the problem and shed load accordingly.
- **Changing primary feeder connections to network transformers:** This option improves diversity in the feeders supplying the network, thereby making it more resilient to multiple contingency events.

- **Reinforcing existing secondary network grid cabling:** This option ensures secondary cabling is not overloaded during multiple contingency events.

6. Failure Risk

Network Circuit Reconfiguration mitigates the impact of failures. The risk of network system outages has increased over time due to:

- **Evolving Operating Practices:** The secondary network system was originally designed to burn clear faults and self-isolate damaged equipment so that most failures of network transformers and primary and secondary cabling do not result in customer interruptions. However, a small number of transformer failures resulted in vault fires. The fire department's current practice is to require that Toronto Hydro immediately cut all power supplies into the vault as a first step in fighting the fire. As a consequence, multiple network primary feeders must be tripped, which may leave insufficient remaining contingency capacity to sustain the network grid.
- **Multiple Contingency Events:** Operation of the network system under multiple contingency scenarios imposes challenging requirements on operating personnel. First, a network expert must analyze the grid to identify critical overload conditions and propose customer load reductions and necessary reactive tasks, all within restrictive time limits. If an expert is not immediately available at the control center, power system controllers may be forced to drop the entire grid in order to prevent a network cascade failure. Second, once the necessary reactive switching and load reduction tasks are identified, system response crews must perform this work, and customers need to reduce their loads within the identified time limitations.
- **Reach of the Secondary Network Distribution System:** The secondary network distribution system represents approximately 10-15 percent of downtown Toronto's peak load. Although it is Toronto's most reliable distribution system, when a major secondary network equipment failure occurs, the impact is widespread, including many radial supply loads on the same feeders. Often major portions of station switchgear, with up to about 50 MVA of customer load (equivalent to approximately 25,000 residential customers), must be interrupted following such events.

For a typical network with no more than six primary feeders, a widespread forced outage due to a second contingency event would cause about 30 MVA of load to be dropped for four hours to prevent

equipment overload. In recent years, these events have occurred approximately once every three years. A reconfigured network grid should be able to sustain a second contingency incident without requiring the entire network to be dropped. This should typically result in a two-thirds reduction in interrupted load.

7. Reliability and System Efficiency

The network system in Toronto was designed for first contingency operation. Under any first contingency event, power system controllers do not need to take any action to ensure continued reliable supply to network customers. On the other hand, multiple contingency events would require immediate action by power system controllers and system response crews. Often, only minutes are available to take effective action in order to prevent a network cascade failure. As previously mentioned, Network Circuit Reconfiguration enables a network to sustain a second contingency incident without requiring the entire network to be dropped. Since almost all network emergencies involve only first and second contingency outages, this will result in an efficiency improvement in terms of system control.

In addition, most multiple contingency network emergencies require the power system controllers and system response crews to spend hours conducting switching operations to stabilize the network and restore as many customers as possible. As a result, isolation and repair of failed equipment may be delayed until this work is completed. Network Circuit Reconfiguration is expected to reduce the workload required to stabilize the network and restore customers, allowing for restoration work to begin at the earliest opportunity, thereby minimizing the time required to restore the network to normal operation.

Table 6 below identifies the networks targeted for reconfiguration in the 2025-2029 rate period. Over 2025-2029, Toronto Hydro will complete reconfiguration for the parts of three networks that are carried over from the 2020-2024 and 2015-2019 rate periods. All networks targeted will be reconfigured after they have been updated with monitoring and control through the Network Condition Monitoring and Control program.[4] Through Network Condition Monitoring and Control alone, it is expected that around one-third of total network load will be preserved during second contingency events. A reconfigured network will typically preserve approximately two-thirds of the total load during these events (representing an additional one-third savings during second

[4] Exhibit 2B Section E7.3

contingency events on networks already updated with condition monitoring and control). The synergies between these two programs are expected to allow many customers to be sustained even during rare third contingency events.

Table 6: 2025-2029 Targeted Networks for Reconfiguration

Network	Network Feeders	Total Load on Feeders (MVA)	Network Load (MVA)	Proposed Reconfiguration Year
A-North Phase 2	9	22	15	2025
GD Phase 2	9	25	20	2026
CE-South South Ph2	8	16	7	2027

The networks to be reconfigured during this filing period represent around 10 percent of the major network system load. Multiple contingency events occur approximately once each year and the existing network system can successfully manage approximately two-thirds of these events.

8. Functional Obsolescence

The existing secondary grid network distribution system was initially designed for pure network loads and not the mixed network and radial loads that exist today. Network feeders are designed such that they can be highly loaded since loads are automatically redistributed across all other network feeders in case of an outage. However, because radial feeders cannot be loaded as highly, due to the need for them to pick up load during contingency scenarios affecting adjacent feeders, the overall utilization of a mixed feeder is reduced. Furthermore, because of the presence of radial loads on a mixed feeder, the capacity to operate the network under multiple contingencies becomes insufficient. Enhancement of secondary network grid flexibility is necessary to adapt to this new reality.

E6.4.4 Expenditure Plan

To address the critical underlying issues of the network assets in downtown Toronto, the utility plans to invest $123.4 million in the Network System Renewal program during the 2025-2029 rate period. Table 7 below provides Toronto Hydro's annual Historical Years (2020-2022), Bridge Years (2023-2024) and forecasted 2025-2029 expenditures for each of the Program segments.

Table 7: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Legacy Network Equipment Renewal (ATS & RPB) [5]	1.9	1.3	0.8	0.3	-	-	-	-	-	-
Network Unit Renewal	5.9	8.7	12.3	17.2	9.1	6.2	6.4	11.7	12.7	14.2
Network Vault Renewal	6.1	9.1	15.7	10.4	8.6	6.7	6.9	18.0	18.5	19.0
Network Circuit Reconfiguration	1.2	3.1	3.3	0.7	0.8	0.8	1.5	0.8	-	-
Total	**15.0**	**22.1**	**32.0**	**28.6**	**18.4**	**13.7**	**14.8**	**30.5**	**31.2**	**33.2**

E6.4.4.1 Network Unit Renewal

Table 8 below provides the year over year breakdown of Network Unit Renewal investment spending including the actual historical spending from 2020-2022, the bridge years from 2023-2024, and forecasts for 2025-2029.

Table 8: Historical and Proposed Investment Spending ($ Millions) — Network Unit Renewal

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Network Unit Renewal	5.9	8.7	12.3	17.2	9.1	6.2	6.4	11.7	12.7	14.2

Toronto Hydro invested $26.9 million in network unit renewal between 2020 and 2022, replacing 82 deteriorated and non-submersible units as shown in Table 9. An additional 84 network units were replaced reactively. The utility plans to invest a total of $53.2 million by the end of 2024 to proactively replace an additional 95 network units over 2023 and 2024 to minimize failure risks.

Table 9: Network Units Replaced — Actual/Bridge vs Planned

	Actual	Bridge	Total

[5] Over 2020-2024, Toronto Hydro successfully completed the Legacy Network Equipment Renewal segment by replacing all of the remaining ATSs and RPBs.

	2020	2021	2022	2023	2024	2020-2024
Actual / Planned	20	30	32	44	51	177

The higher segment cost, while completing fewer units was mainly driven by:

- Increased amount of legacy cable removal and upgrade work completed while changing out network units. Many of the targeted units are in vaults where Asbestos-Insultated Lead-Covered ("AILC") secondary cable containing asbestos and lead are present and/or have primary Paper-Insutated Lead-Covered ("PILC") cable that terminates at the network units. While the Underground System Renewal – Downtown targets the proactive replacement of AILC and PILC cables, Toronto Hydro replaces these legacy cables as part of network unit renewal projects to improve work execution efficiency. [6]

- Similarly, where appropriate, Toronto Hydro spent more than expected to install certain Network Condition Monitoring & Control ("NCMC") equipment and perform the necessary wiring while replacing network units to improve overall efficiency.

- Material cost increases driven by raw material price increases.

- Project execution challenges including constraints related to moratoriums, coordination issues between stakeholders, and scheduling feeder outages resulted in delay in work execution for some projects. In some instances, civil work was needed to be completed prior to unit renewals.

Over the 2025-2029 rate period, Toronto Hydro plans to spend a total of approximately $51.2 million on this segment to replace deteriorating and high failure risk units. The utility forecasts 149 network units will have at least material deterioration (HI4/HI5) by 2029 and that 27 percent of the total population is expected to be at or beyond useful life. Of these, Toronto Hydro plans to replace 130; an average rate of 26 units replaced per year between 2025 and 2029. While the pace of renewal over the DSP period is lower relative to 2020-2024 pacing, Toronto Hydro forecasts that the proposed pace of renewal is required to mitigate further increases in risk. In addition, THESL has incorporated the results of customer engagement to pace the Network Unit renewal investment.

[6] Exhibit 2B, Section E6.3.

The replacement of units with the highest failure risk is projected to maintain downtown reliability and reduce the safety and environmental risk associated with those units. In addition, newer units will be equipped with new features (e.g. monitoring capabilities to enable faster response to developing problems and submersible protectors).

To minimize costs and use resources efficiently, Network Unit Renewal projects will be combined with other Network System Renewal projects, where possible. In addition, work on at-risk units fed from a common feeder will be planned to be executed in the same year. The asset condition data collected from inspections will be leveraged to prioritize the high failure risk units within the asset class. Severely deteriorated and non-submersible units located in areas prone to flooding will be given the highest priority. Projects can be reprioritized if an urgent need is discovered.

E6.4.4.2 Network Vault Renewal

The Network Vault Renewal segment rebuilds vaults and vault roofs. From 2020 to 2022, Toronto Hydro spent $30.9 million to rehabilitate (or decommission) 20 vaults. Toronto Hydro expects to spend $19.0 million to address 23 vaults. Table 10 below provides the year over year breakdown of Network Vault Renewal investment spending including the actual historical spending from 2020-2022 and the bridge year estimates for 2023-2024. Table 11 provides a breakdown of the number of units attained in 2020-2022 and planned to be completed in the bridge years from 2023-2024.

Table 10: Network Vaults Renewals - Actual/Bridge ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Network Vault Renewal	6.1	9.1	15.7	10.4	8.6	6.7	6.9	18.0	18.5	19.0

Table 11: Volumes Actual/Bridge

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	
Vault Rebuild	9	3	4	8	9	43
Roof Rebuild	0	0	3	5	1	
Vault Decommission	0	1	0	0	0	

First, it should be noted that year-over-year fluctuations are primarily due to costs associated with particular vaults. Costs for civil work tend to vary significantly between projects as such projects tend to impact third-party infrastructure in close proximity. Furthermore, civil construction projects are impacted by timing and constraints imposed by other major City work, such as the Eglinton Crosstown LRT.

Between 2020-2024, Toronto Hydro has increased pacing and will proactively rebuild 10 additional network vaults than planned in 2024 in order to further reduce safety risks to Toronto Hydro employees and the public. Related to this, the costs for vault rebuilds have increased. This can be attributed to certain factors such as City permits only allowing more expensive nighttime work to be completed at certain locations, as well as the costs of civil work tending to vary greatly as projects are heavily impacted by the City and other utility infrastructure in the vicinity.

Furthermore, over the 2020-24 rate period, Toronto Hydro has completed an increased amount of legacy cable removal and upgrade work that was completed in the course of building new network vaults. A number of the targeted vaults contained AILC secondary cable, containing asbestos and lead, and/or have PILC cable that terminates at the network units. In the same vein, additional civil work was completed at certain locations to replace existing two units network vault by building two single unit vaults. This approach helps to save one network unit from catastrophic failure in case of a vault fire; only one network unit will be impacted rather than both units.

Moreover, the supply chain issues originating from the beginning of the pandemic proved to be a significant challenge for Toronto Hydro. As a result of factory closures in early 2020, freight costs and delivery times were heavily impacted and increased significantly. Furthermore, lockdowns worldwide, labour shortages, strong demand for tradeable commodities, interruptions to logistics networks, capacity issues, and material cost increases driven by raw material price increases were are all present throughout the 2020-2024 rate period.

Without intervention, Toronto Hydro forecasts that 137 network vaults will have at least material deterioration (HI4 and HI5) by 2029. Toronto Hydro therefore plans to spend $69.0 million to address 38 of the highest risk vaults during the 2025-2029 rate period (i.e. approximately seven vaults per year), which is in line with the 2020-2024 pace of renewal for these assets. A focust on replacement of units with the highest failure risk is expected to maintain downtown reliability and reduce the safety and environmental risk associated with those units. Table 12 below provides the proposed year over year breakdown of units to be addressed from 2025-2029.

Table 12: Proposed Number of Units - Network Vault Renewal

Year	2025	2026	2027	2028	2029
Vault Rebuild	3	3	7	7	7
Roof Rebuild	0	0	3	2	3
Vault Decommission	0	0	1	1	1

Through this work, Toronto Hydro expects to improve safety and maintain reliability by removing potential trip and falling debris hazards and reducing the risk that any structural deficiencies could lead to damaged equipment. Where applicable, Network Vault Renewal work is combined with overlapping work in the other Network System segments to minimize resource requirements and costs. In addition, projects requiring civil construction work are coordinated with planned City road work to reduce costs associated with routing civil infrastructure around road moratoriums and road cut repairs.

E6.4.4.3 Network Circuit Reconfiguration

The Network Circuit Reconfiguration segment mitigates the impact of multiple contingency events on Toronto Hydro's network system. Throughout 2020-2022, Toronto Hydro spent $7.6 million on this segment and expects to spend $1.4 million over 2023-2024. Table 14 below provides the status of planned network circuit reconfiguration work for 2020-2024. This also includes the carryover work from the 2015-2019 rate period.

Table 13: Historical & Forecast Network Circuit Reconfiguration Expenditures ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Network Circuit Reconfiguration	1.2	3.1	3.3	0.7	0.8	0.8	1.5	0.8	-	-

Table 14: Summary Status of Planned Projects 2020-2024

Network	Completion Year	CapEx ($ Millions)	Comments
Hammersmith Network Preparation	2021-2022	6.5	Carry Over Projects form 2015-2019 Rate Filing Period
Hammersmith Loc 4141 Ci			

Hammersmith Network Conv			
LOC 4174 Vault Rebuild to CC			
Carlaw E Network			
GD Phase 1	2021	0.88	Actuals: 2020-2022
A-North Phase-1	2023	1.7	Bridge Years: 2023-2024
CE-North (Carry Over)	2024		
CE-South Phase 1	2024		
GD Phase 2	2026	3.2	Forecast: 2025-2029
A-North Phase 2	2025		
CE-South Phase2	2027		
WR-West Phase 1	Beyond 2029		
WR-West Phase 2			
CS-West Phase1			
CS-West Phase2			

The variances between planned vs actual historical work, or planned vs forecast bridge years work for this segment has been due the following reasons:

- A large portion of the capital expenditures were dedicated to the completion of the carryover work from the 2015-2019 rate period including Hammersmith and Carlaw East Networks (approximately $6.5 Million).
- Material costs have increased significantly due to the COVID-19 pandemic and related supply chain issues, which resulted in increased raw material prices.
- Additional labour costs incurred due to overtime work mandated by the City's work zone coordinator, additional splicing work required on GD Phase-1 due to complexity of network and for handling of TTC cables and gas main found in the proximity of the cable chambers involved in reconfiguration process.
- Increased amount of legacy cable removal and upgrade work completed while reconfiguring the network secondary, as explained in Exhibit 2B, Section E6.3.
- At certain locations unanticipated civil work was completed during project execution due to location requirements.

Toronto Hydro plans to spend $3.2 million to reconfigure parts of three networks over the 2025-2029 rate period. Table 15 below lists the targeted networks for 2025-2029, these three networks

are carried over from 2020-2024 rate period. These phases correspond to parts of the five largest networks and Toronto Hydro expects that the reconfigurations will help to improve outage restoration times and reduce the risks associated with second contingency events for downtown network customers.

Table 15: Planned Network circuit reconfiguration Projects for 2025-2029

Network	Network Feeders	Total Load on Feeders (MVA)	Network Load (MVA)	Proposed Reconfiguration Year	CapEx ($ Million)
A-North Phase 2	9	22	15	2025	3.2
GD Phase 2	9	25	20	2026	
CE-South Phase2	8	16	7	2027	

To minimize costs and resource requirements, Network Circuit Reconfiguration projects are combined with overlapping work in the other Network System Renewal segments, where applicable. Reconfiguration work can vary significantly from one network to another and this continues to hold true during the 2025-2029 rate period, where the four targeted networks service some of the largest loads with complex configurations.

E6.4.5 Options Analysis

E6.4.5.1 Options for Network Unit Renewal

Toronto Hydro considered the following options for addressing high failure risk network units.

9. Option 1: Reduced Pace

Under this option, Toronto Hydro would only target the 42 network units expected to be in at least "material deterioration" (HI4/5) by the end of 2029. While this option would mitigate reliability risks over the 2025-2029 rate period, with over 50 percent of network units expected to be at or beyond useful life by 2034, a reduced pace of asset renewal would result in a higher risk of power outages due to failure risk in the next decade. Therefore, to manage failure risk in the long term, Toronto Hydro would need to invest more to replace higher volumes of work in the next period at a higher cost. This would also reduce efficiency as it may require higher amounts of reactice and emergency work. As such, this option is not viable given the risks posed by these assets which include

catastrophic failure due to poor condition; flooding; employee and public safety risks as well as environmental risks (e.g. oil leaks).

10. Option 2: Moderate Pace (Selected Option)

This option would address safety risks associated with deteriorating network units that would deliver reliability and efficiency benefits for the network system. At a pace of 26 units per year, 130 network units would be replaced and their associated safety, environmental and reliability risks addressed. These would address some legacy, non-submersible units in at least material deterioration thus minimizing the risk of failure due to flooding. Under this option, the utility expects the replacement of network units would result in avoided direct and indirect costs associated with asset failures across both periods, including but not limited to the cost of customer interruptions, emergency repair and replacement across the 2025-2029 rate period and beyond.

With over 50 percent of the network units expected to reach or go beyond useful life by 2034, the pace under this option would be expected to mitigate the risks associated with deteriorating and non-submersible network units and improve efficiency of the network system. However, units not replaced by 2029 or in a timely manner would continue to pose a higher risk of failure with the potential to cause fires or oil leaks until they are replaced. Some legacy, non-submersible units without material deterioration at an elevated risk of failure due to flooding, would also remain unaddressed.

This option is recommended as it reflects an appropriate trade-off between mitigating safety and environmental risks, reliability impacts, resource constraints, and program cost both in the short-term and in the future.

11. Option 3: Accelerated Pace

Under this option Toronto Hydro would replace network units at an accelerated rate of 40 units per year to achieve faster reduction of safety and reliability risks associated with deteriorating and high failure risk network units. At this pace, Toronto Hydro would replace all of the 149 units forecast to have material deterioration (by 2029) and address an additional 51 units forecast to be at or beyond useful life in the next decade. While this option would minimize the number of network units at elevated risk of failure and would enable the utility to balance the number of units replaced across the 2025-2029 and 2030-2034 rate periods, it would cost roughly 1.5 times more than the proposed plan. As Customer Engagement results note that customers are supportive of Toronto Hydro's

current pacing, this option cannot be justified. Additionally, this pace would not align with the utility's resources and system constraints. For these reasons, Option 3 is not a feasible strategy.

E6.4.5.2 Options for Network Vault Renewal

Toronto Hydro considered the following options for addressing network vaults in poor condition.

12. Option 1: Reduced Pace

In this option, Toronto Hydro would address immediate structural deficiencies of high-risk network vaults identified through the ACA process as having at least material deterioration ("HI4") at a reduced pace. The investment would only target about 22 network vaults (approximately 52 % of network vaults projected to reach HI4/HI5 from 2025 to 2029) thus it will significantly increase the backlog of HI4/HI5 vaults in the system that exists at the start of the 2025-2029 rate period. This option would not replace vaults at either the rate at which the HI4/HI5 population grow by each year, or the rate at which vaults on average reach normal lifespan.

This option is not viable as the multitude of issues discussed throughout the narrative, including structural failure may lead to failure of the equipment housed inside the vaults. Furthermore, safety risks (e.g. tripping, falling debris and fire hazards) for both the public and Toronto Hydro crews would be elevated. Major structural issues cannot be addressed through maintenance work.

13. Option 2 : Moderate Pace (Selected Option)

In this option, Toronto Hydro would proactively address the 38 network vaults which have at least material deterioration (HI4) at a modest pace to reduce the risk of injury to the public and Toronto Hydro crews and the risk to system performance due to asset failure. At a pace of approximately 7 network vaults per year, this option would maintain the number of network vaults projected to reach HI4/HI5 at the level expected for 2025 but would not eliminate the backlog of HI4/HI5 vaults expected at the start of 2025. Based on historical experience, Toronto Hydro projects this pace to be achievable and would help mitigate the forecasted rise in the number of network vaults with material deterioration over the 2025-2029 rate period. Although Toronto Hydro would address the highest risk vaults, there would still be over 85 network vaults that have at least material deterioration (HI4) at the end of 2029. The backlog of these vaults would continue to pose elevated safety and reliability risks. However, this option would be expected to mitigate risks to an acceptable degree at a pace of work that would be realistic to achieve and at a reasonable cost.

14. Option 3: Accelerated Pace

By accelerating the pace of network vault renewal, Toronto Hydro would address the network vaults at an accelerated rate of 9 vaults per year to achieve faster reduction of safety and reliability risks associated with deteriorated and high failure risk network vaults. At this pace, Toronto Hydro would address more than the 42 network vaults forecast to have at least material deterioration (from 2025 to 2029) and would also slightly reduce the backlog of HI4/HI5 vaults discussed in above options. Reliability and safety risks of deteriorated network vaults would be reduced faster and to a greater degree than option 2 above but it would cost approximately 1.3 times more than the proposed pace for this segment. As Customer Engagement results note that customers are generally supportive of Toronto Hydro's current plan pacing, this would not be justifiable. In addition, this pace poses issues with resource and outage management resulting in delays of other planned work needed for the system. Therefore, this is not a recommended option.

E6.4.5.3 Options for Network Circuit Reconfiguration

15. Option 1: Reduced Pace (Selected Option)

This option for the 2025-2029 rate period would address three networks with reduced pace at a cost of $3.2 million. This would include completion of the GD Phase-2, A-North Phase-2, CE-South Phase-2. It would reduce the workload required to stabilize the networks and restore customers following multiple contingency events and reduce the time required to restore the networks to normal operation. The networks targeted under this option service large loads and have complex configurations, which means that they would benefit the most from reconfiguration.

There would be no additional network circuit reconfigurations work planned other than the carryover work from the last rate filing, detailed in Section E6.4.4.3. This will carry the risks of dropping other entire networks under 2nd contingency events into future years. It is the lowest cost option to complete the specified portion of carry-over work and improve the operability of three major networks under 2nd contingency events.

16. Option 2 : Moderate Pace

Under this option, Toronto Hydro would require $4.1 million to complete the projects mentioned in Option 1 plus CE-South Phase-2 network addition. This strategy would attain a total of 4 networks reconfigured rather than partially completed. Historically, network circuit reconfiguration projects

have taken a long time to design and execute due to complexity of the secondary system in the downtown core. This can be attributed to the fact that a lot of civil infrastructure may need to be inspected to ensure that the proposed secondary cable reinforcements can be accomplished. Furthermore, as civil deficiencies are discovered, costs to rebuild civil may cause the cost of the projects to increase significantly. External to the program budget, Toronto Hydro spent $6.5 million to address carryover of work from the 2015-2019 rate period (See: Section E6.4.4.3). While this option would reconfigure two additional networks, it would cost roughly 1.5 times more than the proposed pace as well as not aligning with the utility's resources and system constraints. For these reasons, Option 2 is not recommended.

17. Option 3: Accelerated Pace

The improvement option would require $5.22 million to complete all five major networks. These networks are George & Duke, Windsor-West, Terauley-North, Charles-West, Cecil-South and Terauley-East. As reconfiguration projects have historically taken a long time to design, attempting to fit more projects within this 5-year period poses a feasibility risk. All major networks, covering large geographic areas of the downtown core, reside in areas of the city with aging infrastructure. As civil deficiencies are discovered, costs to rebuild civil may cause the cost of the projects to increase significantly, outside the budget of the program. Toronto Hydro estimates that this would require approximately double the financial and labour resources per year compared to the selected option and is therefore not recommended.

E6.4.6 Execution Risks & Mitigation

The Network System Renewal program is subject to the risks facing downtown underground programs and projects. For all segments, these risks include summer feeder restrictions. More specifically, many downtown network feeders have summer feeder switching restrictions imposed to prevent overloading cables and equipment during peak loading periods. To mitigate this risk, projects are scheduled to avoid the summer period if the feeders involved are restricted (i.e. do not have capacity). If a feeder is newly restricted in the project year, the project timeslot could potentially be exchanged with another project. If a restricted feeder supplies a vault being planned for rebuild, then the work may only be conducted during off-peak hours, and this may hinder project execution. Toronto Hydro's Load Demand program for the 2025-2029 rate application(see Exhibit 2B, Section E5.4 of the Distribution System Plan) is intended to help mitigate these risks by enhancing the grid so that feeder restrictions during summer peak times are minimized.

Each segment may also be subject to its own set of additional risks as discussed below:

- The City and Toronto Hydro's customers often have special events scheduled that can be negatively impacted by a major construction project. Toronto Hydro communicates with stakeholders and customers to establish an agreeable timeline in accordance with system priorities. Should a conflict arise, the project timeslot could potentially be exchanged with another project to allow the overall Program to proceed without negative impact.

- As part of Network safety enhancements, the unit cost of Network units will likely increase in the next few years. Some of the safety enhancements under consideration are:
    - External upper link boxes on protectors
    - New style antlers on protectors
    - Ethernet ready protector relay
    - Pro link style disconnect switches

- The removal of a network unit may cause the remaining network units to experience overloads. Toronto Hydro manages this risk by scheduling the replacement of problematic network units outside of the peak loading periods of the particular vault. For example, work on vaults supplying schools or buildings with electric heat may best be scheduled during the summer.

- City moratoriums and the Metrolinx subway expansion may impact execution timelines. Although existing City moratoriums are considered when planning vault renewal projects, it is possible that new moratoriums may be subsequently introduced. To mitigate this risk, Toronto Hydro reviews all new moratoriums and adjusts its work plans accordingly. Projects, such as the expansion of the transit system in Toronto, pose unique challenges. When such projects are in the execution phase, the City or Metrolinx may impose moratoriums that suspend all other work until critical phases of transit projects are completed. In addition, transit construction may require relocation of Toronto Hydro assets that impacts the Vault Renewal program. To mitigate this risk, Toronto Hydro communicates with Metrolinx on a continual basis to identify, monitor, and resolve conflicts.

- For the Network Circuit Reconfiguration segment, additional risks are posed by structures at the end of their useful lives and customer-owned civil structures. Projects in this segment typically involve the installation of new cabling within existing cable chambers and duct

structures. There is a risk that the required structures will be at the end of their useful lives and may require replacement before the planned work can be executed. This would necessitate scope and timing changes to some projects. However, there are usually multiple options to reconfigure a network. Should the optimal design require civil structure replacement, an alternative that still provides the required reliability and operational benefits, but that does not require civil structure replacement, can likely be found. The design would be revised accordingly to mitigate the cost and timing impacts.

- There also may be unforeseen condition or access problems with some customer-owned civil structures. In these situations, the customer may have to perform civil rebuild work before Toronto Hydro's work can commence, thereby causing project delays. This risk can be mitigated by fully inspecting all civil plants prior to finalizing project design, and introducing sufficient lead times for customer civil design and construction activities in the project schedule.

Since the pandemic's beginning, supply chain disruptions have grown to be a significant challenge for Toronto Hydro. Freight costs and delivery times have significantly increased as a result of factory closures in early 2020, lockdowns in various nations across the world, labour shortages, strong demand for tradeable commodities, interruptions to logistics networks, and capacity issues. It is expected that by 2025-2029, capacity constraints and labor shortages should ease, taking some of the pressure off supply chains and delivery times. To mitigate this risk, Toronto Hydro's procurement department will work closely with our suppliers and monitor manufacturing and delivery times closely to maintain project completion dates.

E6.5 Overhead System Renewal

E6.5.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 218.9	**2025-2029 Cost ($M):** 358.4
Segments: Overhead System Renewal, Overhead Infrastructure Resiliency	
Trigger Driver: Failure Risk	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Environment, Operational Effectiveness – Safety, Financial Performance	

The Overhead System Renewal program (the "Program") manages failure risk on Toronto Hydro's overhead system through the replacement of end-of-life and functionally obsolete assets that are in poor condition or otherwise require replacement to mitigate safety and environmental risks.

Additionally, the 2025-2029 iteration of this Program reintroduces the undergrounding or relocation of parts of Toronto Hydro's overhead system that are particularly vulnerable to external causes of failure or hard to access.

The Program is grouped into the two segments summarized below:

- **Overhead System Renewal:** This segment is a continuation of the Overhead System Renewal program outlined in Toronto Hydro's 2020-2024 Distribution System Plan ("DSP").[1] This segment addresses three major asset classes that are sufficiently critical as to require proactive lifecycle management strategies: (1) pole-top transformers; (2) poles and pole accessories; and (3) overhead switches. The probability that these assets will fail – causing negative impacts to safety, reliability, and the environment – increases as these assets age and deteriorate.

  The Overhead System Renewal segment consists of both rebuild and spot replacement projects. Rebuild projects are ideal when a confluence of conditions within a concentrated geographical area make it necessary and/or economically prudent to rebuild an entire section of the system. For example, areas of the system with a high concentration of assets at risk of failure (e.g. due to deteriorated condition) and a history of poor reliability are

[1] EB-2018-0165, Exhibit 2B, Section E6.5

typically addressed through rebuild projects. Voltage conversion is another important consideration for rebuilds. For example, Toronto Hydro has a significant population of deteriorating, legacy 4 kV overhead lines that it will gradually convert to modernized 13.8 kV or 27.6 kV standards in order to improve operational performance and efficiency and prepare for the demands of electrification, growth, and the proliferation of distributed energy resources ("DERs"). As 4 kV is no longer an accepted system standard, the deterioration of 4 kV asset condition and performance within an area will generally trigger a rebuild of the area to current standards.

Outside of rebuild project areas, any transformers at risk of containing PCBs greater than 2 ppm, will be addressed through targeted spot replacement projects. These projects do not involve the replacement of all assets in a continuous area.

A summary of this segment's investments in the three major overhead asset classes is as follows:

- **Pole-top Transformers:** One of the main drivers of poor performance in the overhead system is defective equipment. Through the focused renewal of PCB containing transformers (which are also past useful life and therefore at higher risk of failure) in recent years, Toronto Hydro has reduced the number of transformer-related customers interrupted and customer hours interrupted from over 10,000 customers interrupted and 6,000 customer hours interrupted and per year on average to 4,133 customers and 4,360 customer-hours interrupted per year on average over the last five years (2018-2022). This focused renewal has also reduced the proportion of overhead transformers past useful life from approximately 14 percent in 2017 to approximately 8 percent at the end of 2022. However, without further intervention, that number will return to 17 percent by 2029. By replacing all remaining PCB transformers by the end of 2025 and then shifting to steady transformer replacement through rebuilds of high-risk and poor performing areas, Toronto Hydro can ensure that the overhead transformers past useful life and the associated reliability and environmental risks remain within a reasonable range over 2025-2029 and beyond.
- **Poles and Accessories**: Pole failures can lead to extensive and prolonged service disruptions, as well as pose safety risks for utility crews and the public. Poles and pole accessories have contributed to over 30,700 customer interruptions and 18,000

customer hours interrupted per year on average over the past five years. Poles are frequently exposed to various severe weather conditions, and may become vulnerable to internal rot, decay, and infestation. These conditions, combined with the fact that approximately 23 percent of Toronto Hydro's wood poles are beyond their useful life as of 2022, make these poles more susceptible to failure. Approximately 9 percent of wood poles are already showing signs of material deterioration (as of 2022) and, without intervention, this proportion is forecast to increase to 30 percent by 2029. Toronto Hydro plans to replace a total of approximately 8,300 wood poles and associated accessories over the 2025-2029 period to reduce the aforementioned failure and safety risks.

- **Overhead Switches**: Overhead switches are constantly exposed to harsh environmental conditions. Their failure often leads to prolonged outages and can pose significant safety risks to utility workers if an arc flash happens during the switch failure. On average, overhead switches contributed to 37,070 customer interruptions and 20,263 customer hours interrupted annually between 2018 and 2022. Approximately 18 percent of gang operated switches and 33 percent of inline disconnect switches have reached the end of their useful life as of 2022. Toronto Hydro plans to replace a total of 510 overhead switches through rebuilds of areas with high concentrations of high-risk assets and poor reliability.

- **Overhead Infrastructure Resiliency**: This segment is a reintroduction and expansion of the work done through the Overhead Infrastructure Relocation program in Toronto Hydro's 2015-2019 DSP[2] to improve the resiliency of the overhead system through targeted relocation and undergrounding of overhead assets as summarized below:

  - Undergrounding critical sections of overhead infrastructure that are persistently affected by outages caused by external factors, such as adverse weather events and tree contacts, to reduce the frequency and impact of these types of outages for affected customers;

  - Relocating overhead sections in areas with limited access, such as heavily treed ravines, valleys, rail corridors, Hydro One rights-of-way ("ROW"), and certain trunk sections running along inaccessible rear lot locations.[3] These sections can be especially vulnerable

[2] EB-2014-0116, Exhibit 2B, Section E6.5.
[3] Note most rear lot assets are being addressed through the Area Conversion program, see Exhibit 2B, Section E6.1.

during major storm events such as heavy rainfall, floods, and ice storms and restoration following major storms is extremely challenging; and

- Reconfiguring and, if necessary, undergrounding pole lines exiting stations that carry three or more circuits (referred to as congested egresses), which pose an unacceptable reliability risk due to vulnerability to factors such as adverse weather and the high number of customers connected to a single physical location.

The objectives of the Overhead System Renewal program for the 2025-2029 rate period are to:

- Renew deteriorated assets at a pace that aims to generally maintain asset condition and failure risk on the overhead system at current levels;
- Maintain overall system reliability and improve reliability for certain poorly performing areas of the overhead distribution system;
- Address the environmental risks of potential PCB oil spills by replacing all remaining transformers containing or at risk of containing PCBs; and
- Improve resiliency through targeted undergrounding or relocation of overhead assets that are at risk of adverse weather, tree contacts, animal contact, foreign interference and/or in areas that are difficult to access.

E6.5.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's objectives and obligations to connect low and high voltage customers within 5 and 10 business days respectively at least 90 percent of the time (pursuant to the OEB's new connection metrics and section 7.2 of the Distribution System Code ("DSC")), by increasing overhead system capacity through voltage conversion from 4 kV and/or 13.8 kV to 27.6 kV in specified areas.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (as measured via metrics like SAIFI, SAIDI, FESI-7, System Health (poles)) by: ○ controlling the population of HI4 and HI5 condition[4] poles over the 2025-2029 period;

[4] For many of its major assets, Toronto Hydro performs asset condition assessment ("ACA"), in which the condition of each asset is assigned a health index ("HI") band from HI1 to HI5, where HI5 indicates the worst condition. For these same assets, the utility can then also project future condition (i.e. HI band) assuming no intervention. See Exhibit 2B, Section D, Appendix A for more details on Toronto Hydro's ACA methodology

	○ replacing pole-top transformers at higher risk of failure through area rebuild and spot replacement; and ○ Relocating and/or undergrounding assets in hard to access or vulnerable locations.
Environment	• Contributes to improving Toronto Hydro's Spills of Oil Containing PCBs measure, and environmental objectives and obligations by eliminating all equipment containing, or at risk of containing, PCBs from the overhead distribution system by the end of 2025 pursuant to PCB regulations (PCB Regulations,[5] made under the federal *Canadian Environmental Protection Act, 1999 and* Ontario's *Environmental Protection Act, 1990*[6] and, City of Toronto's Sewer Use By-Law.[7]
Operational Effectiveness - Safety	• Toronto Hydro and contractor crew safety improved by relocating assets to improve accessibility
Financial Performance	• Voltage conversions enables a reduction in line losses which in turn leads to savings for our customers. • Once an MS Station's feeders have been fully voltage converted; the Station is decommissioned which results in reduced need for capital and maintenance investment. • Improve maintenance costs incurred on assets located at inaccessible locations by relocating assets to areas of better access

[5] PCB Regulations (SOR /2008-273), under the *Canadian Environmental Protection Act,* 1999.
[6] *Environmental Protection Act,* RSO 1990, c E. 19.
[7] City of Toronto, by-law No 681, *Sewers,* (May 15, 2023).

E6.5.3 Drivers and Need

Table 3: Drivers and Need

Trigger Driver	Failure risk
Secondary Driver(s)	Environmental Risk, Reliability, Safety, Functional Obsolescence, System Efficiency

The Overhead System Renewal program is driven by failure risk of assets on the Overhead System due to age, condition, obsolete design or location, which can negatively impact reliability, safety, and the environment. The Program replaces at-risk assets and, where appropriate, will relocate or underground them to address location-specific vulnerabilities.

E6.5.3.1 Overhead System Renewal

The Overhead System Renewal segment focuses on replacing three types of assets: (i) pole-top transformers; (ii) poles and accessories; and (iii) overhead switches. This renewal segment is driven by the risk and impact of overhead distribution asset failures on system reliability and safety due to accelerated asset condition degradation resulting from factors such as: sustained exposure to dirt, salt, dust, moisture and humidity, and assets approaching end of their useful life. Customer Engagement results have shown that reliability is a top priority for all types of customers.[8]

Asset failures on Toronto Hydro's distribution system present reliability risks (which can lead to outages and directly impact customers), environmental risks (e.g. oil spills into the environment), and safety risks (e.g. stemming from electrical contacts, arc flashes, and potentially catastrophic fires). Timely replacements are required to avoid the distribution system being operated under contingency conditions (i.e. with interrupted feeders or assets that cannot provide backup supply in the event of a subsequent outage).

Over the last five years the main known cause of outages in the overhead system is defective equipment as shown in Figure 1. Foreign interference is the second main known cause of outages and these are addressed primarily through the Worst Performing Feeder segment.[9] Without renewal, the risk of overhead asset deterioration and failures would increase, resulting in more frequent and longer outages which would result in an increase in reactive replacement work.

[8] Exhibit 1B, Tab 3, Schedule 1
[9] Exhibit 2B, Section E6.7

Figure 2 shows the volume of reactive capital work requests generated to address overhead system related deficiencies between 2019 and 2022. On average, about 463 such work requests were initiated annually over that period, which is an improvement compared to the 2013-2017 average of 550 per year. Timely replacement of aged and deteriorated equipment before failure can effectively mitigate the frequency and duration of interruptions experienced by customers due to failing overhead assets.

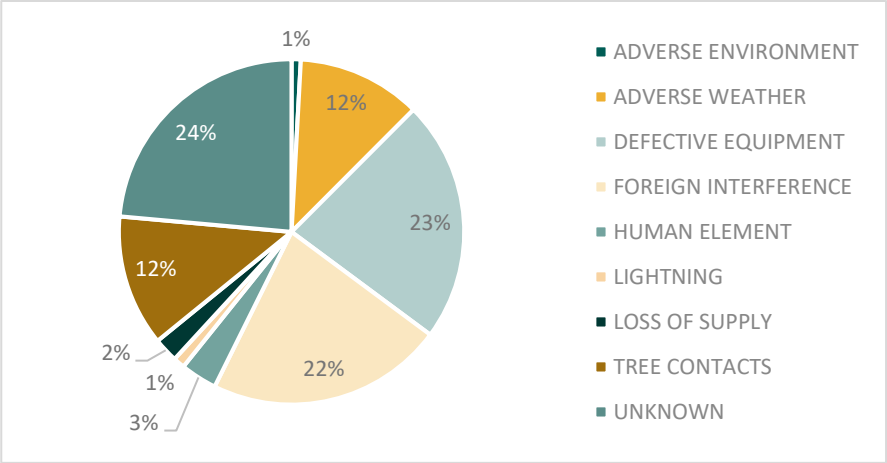


Figure 1: Overhead System Outages by Cause Code 2018-2022 (Excluding MEDs and Planned Outages)

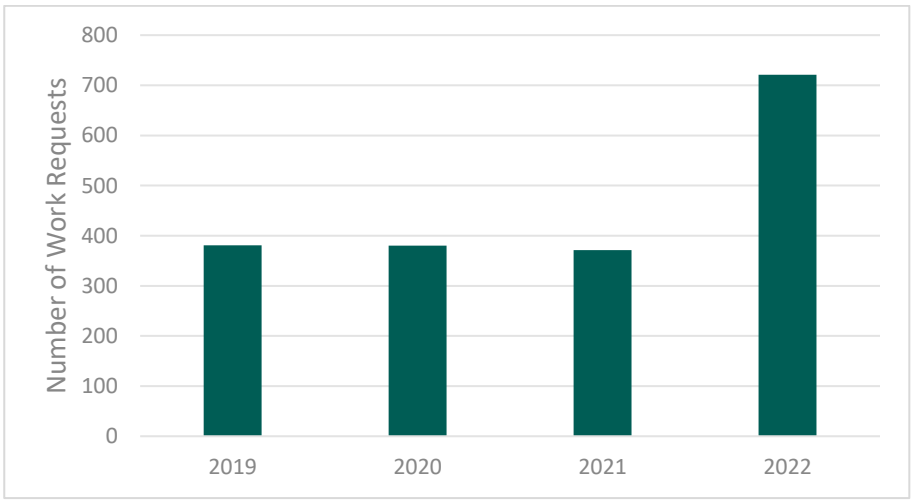


Figure 2: Reactive Work Requests to replace Overhead Assets from 2019-2022[10]

[10] 2018 data is excluded due to the transition to SAP that occurred during that year

The reliability outcome of historical investments in the Overhead System Renewal program is illustrated in Figures 3 and 4, which illustrate the effects of outages on customers; customers interrupted ("CI") and customer hours interrupted ("CHI"). Compared to 2013-2017, on average system wide reliability measures have remained steady. This result is consistent with the objectives that Toronto Hydro set out to achieve in the previous rate application, which was to maintain overall reliability.

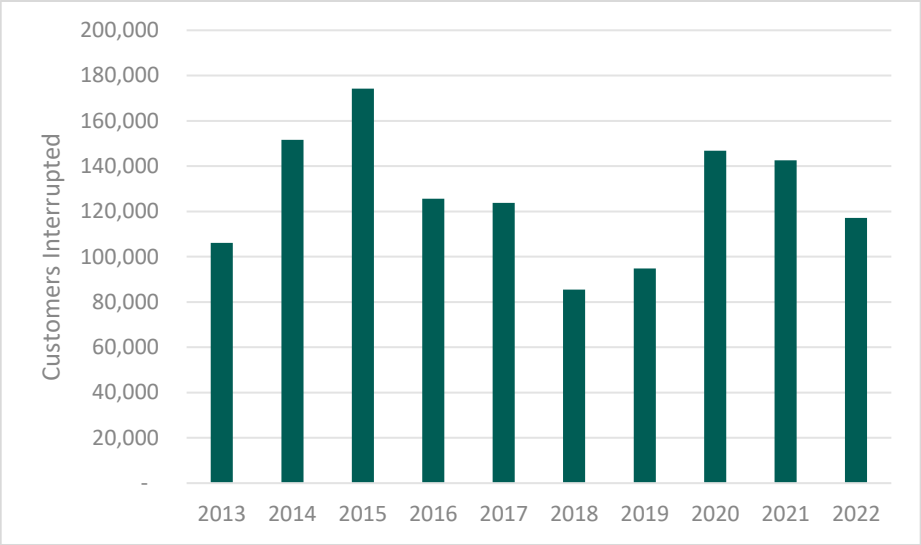


Figure 3: Customers Interrupted ("CI") on the Overhead System (2013-2022)

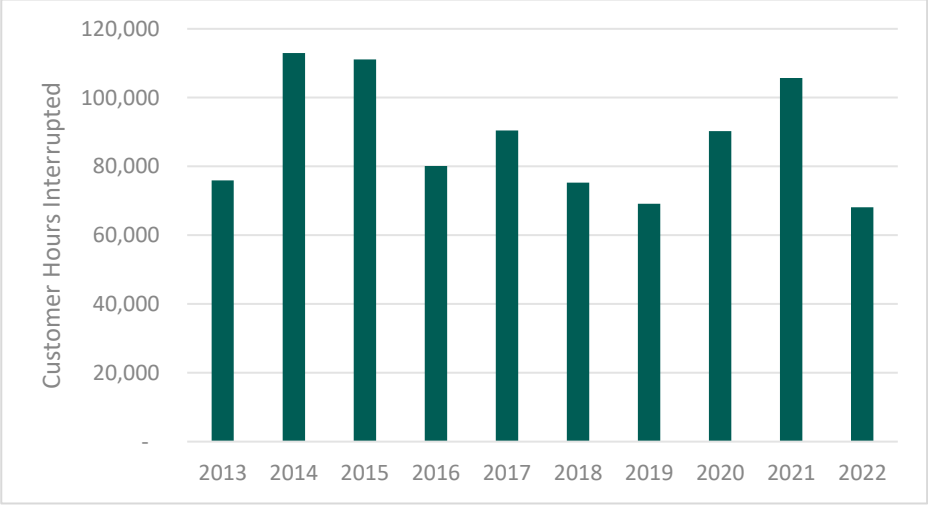


Figure 4: Customer Hours Interrupted ("CHI") on the Overhead System (2013-2022)

Toronto Hydro must slightly increase its pace of investment in the Overhead System Renewal segment in order to prevent reliability risk from increasing. Asset investment is necessary to address the large number of overhead assets that are expected to deteriorate in the coming years as they approach the end of their useful life or remain in service well beyond it.

Table 3 summarizes the age demographics for poles, transformers and switches in 2022 and by 2029 (without investment).

Table 3: Asset Demographics

	Population	Typical Useful Life (Years)	Assets Past Useful Life as of 2022 (%)	Assets Past Useful Life in 2029 without Investment (%)
Wood Poles	108,988	45	23	29
Concrete Poles	49,059	55	13	22
Overhead Transformers	27,690	35	8	17
Overhead Load Break Gang Operated Switches	3,015	30	18	26
Overhead Disconnect Switches	4,425	30	33	54

Table 4 shows the condition of Toronto Hydro's poles in 2022 and by 2029 (without investment).

Table 4: Condition Data for Wood Pole

Asset Condition Index	2022	2029 (Without Investment)
HI1 – New or Good Condition	68,193	60,253
HI2 – Minor Deterioration	7,536	8,310
HI3 – Moderate Deterioration	21,015	5,544
HI4 – Material Deterioration	8,918	24,404
HI5 – End-of-serviceable Life	504	7,655

Through a combination of spot replacements and complete rebuilds of areas with poor reliability and large concentrations of high-risk assets, Toronto Hydro plans to replace approximately 4,848 overhead transformers, 8,338 poles, and 510 switches over the 2025-2029 period.

Any targeted overhead areas that still utilize 4.16 kV or 13.8 kV systems will be converted to 27.6 kV. The underground portion of these feeders is addressed by the Underground System Renewal - Horseshoe program.[11] Likewise, there are 4.16 kV systems in the rear lot, or the backyards, of customers that are addressed by the Area Conversions program.[12] There is a growing number of 4 kV and 13.8 kV feeders where customers have sustained outages (sometimes multiple) of ten hours or more. These are legacy assets which cannot be easily replaced, and their configurations do not allow for expansion or provide many options for system restoration contingency. Converting to 27.6 kV is expected to:

- enhance power quality with less voltage drop for customers at the ends of distribution lines;
- reduce line losses, improving the efficiency of the distribution system;
- modernize the system to prepare for the demands of electrification, growth, and the proliferation of DERs that the 4kV cannot accommodate; and
- enable the eventual decommissioning of Municipal Stations, thereby avoiding operating and maintenance expenditures that would otherwise need to be incurred.

There are approximately 170 4.16 kV and 13.8 kV feeders remaining to be converted throughout both the underground and overhead system in the Horseshoe. Toronto Hydro is planning to convert the overhead portions of 48 of these feeders and the underground portions of 29 of these feeders by 2029. At this pacing Toronto Hydro expects to complete the overhead voltage conversion portion of the entire system by 2049.

1. Replacement of Overhead Transformers

Through the Overhead System Renewal segment, Toronto Hydro replaces overhead transformers beyond useful life, which are at risk of failing and potentially posing an environmental risk due to oil leaks that may contain PCBs. There are currently 27,690 overhead transformers in Toronto Hydro's distribution system. As a critical component of Toronto Hydro's overhead system, transformers are used to step down primary distribution voltage to levels required to supply residential and commercial customers. They are mounted on poles and consistently exposed to external elements that cause degradation (e.g. weather conditions, dust, salt, moisture, cyclical loading, faults and humidity). In particular, exposure to precipitation and humidity over time causes corrosion (tank perforation) which can lead to oil leakage into the environment. Figure 5 shows the reactive work

[11] Exhibit 2B, Section E6.2.
[12] Exhibit 2B, Section E6.1.

requests to replace failed or severely deteriorated pole-top transformers during the 2019-2022 period. Figure 6 shows the forced pole-top outages during the 2018-2022 period (note not all reactive work is tied to an outage).

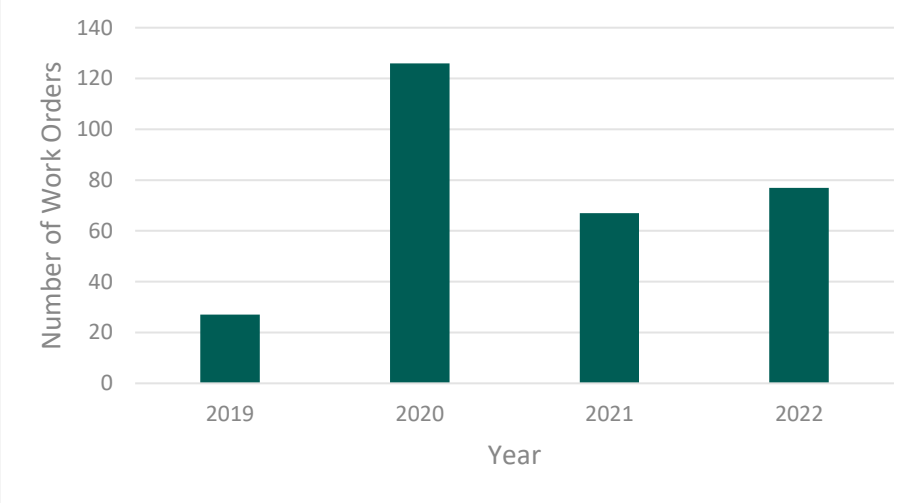


Figure 5: Reactive Work Requests for Pole-top Transformer Replacement[13]

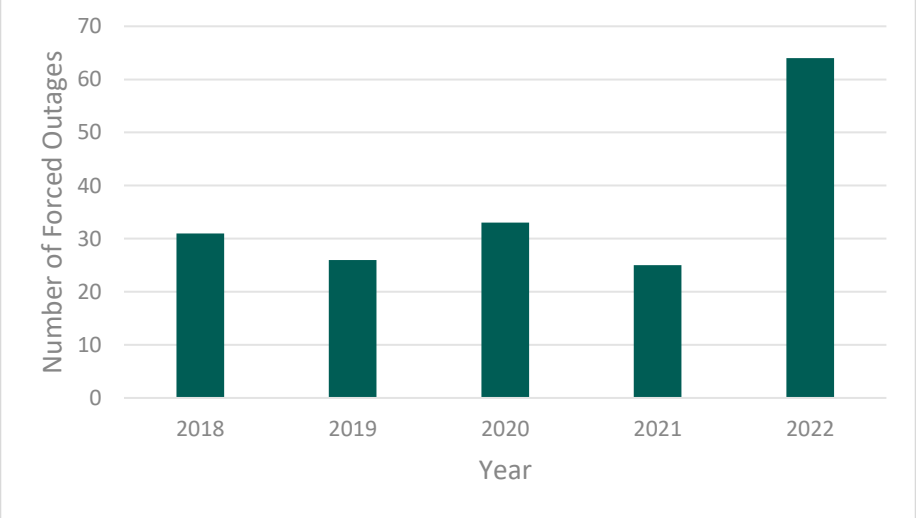


Figure 6: Forced Outages for Pole-top Transformers

On-going renewal work has contributed to an overall average decline in reactive work requests, however in 2022 there was a spike of 64 outages (versus an average of 35 outages over the five-year

[13] 2018 data is excluded due to the transition to SAP that occurred during that year

period). The vast majority of outages relate to transformer failures (approximately 31 to 64 failures per year), contributing to over 4,133 CI and 4,360 CHI over the same period on average (see Figures 7 and 8). In 2022, consistent with the number of outages, both CI and CHI have noticeably increased compared to recent averages – to 7,643 customers and 8,588 hours, respectively. This can be explained in part by the fact that Toronto Hydro has recently implemented more granular automated outage reporting as discussed in Exhibit 2B, Section C. There was also an abnormal number of customers interrupted because of one individual incident. Similarly, the increase of CI in 2020 is attributed to a single outage impacting a relatively large number of customers.

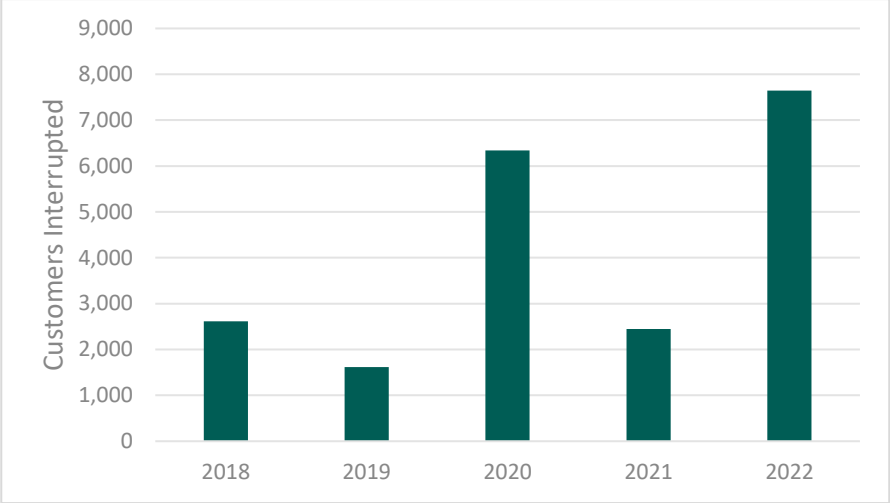


Figure 7: Customers Interrupted ("CI") for Pole-top Transformers

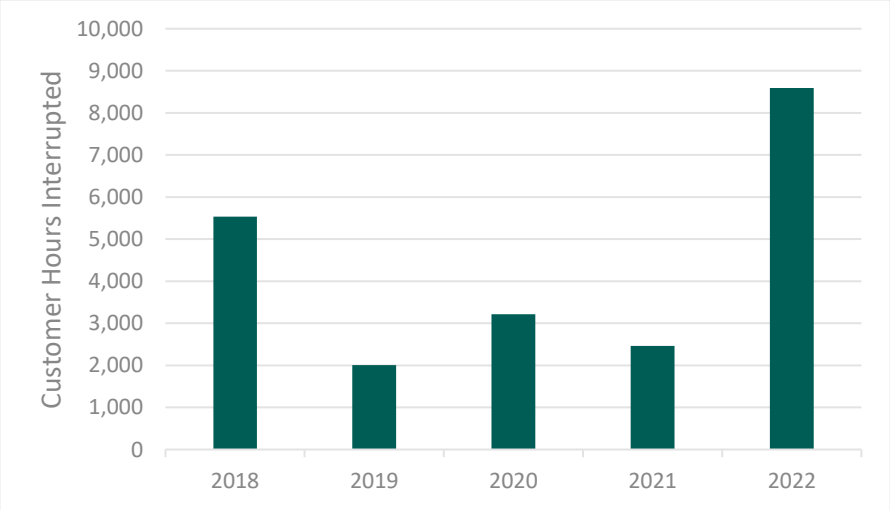


Figure 8: Customer Hours Interrupted ("CHI") for Pole-top Transformers

A number of overhead transformer failures have resulted in oil leaks into the environment. Figure 9 shows the total number of reported oil spill incidents for pole-top transformers during the 2018-2022 period. In recent years the number of spills has declined as Toronto Hydro has targeted the most at-risk transformers for replacement, aiming to replace these transformers prior to failure or before spills can occur. Specifically, older transformers are at an especially high risk of having oil containing PCBs. Releasing oil containing PCBs (or oil on its own) into the environment may be a breach of the federal *Canadian Environmental Protection Act, 1999*[14] (including the PCB Regulations made thereunder),[15] Ontario's *Environmental Protection Act, 1990*[16] and the City of Toronto's Sewer Use By-Law.[17] Toronto Hydro has been targeting overhead transformers at risk of containing PCBs, which are all also past their useful life, and estimates there will be 223 overhead transformers that contain or are at-risk of containing PCBs remaining by the end of 2024.[18] Toronto Hydro intends to replace all of these units by the end of 2025.

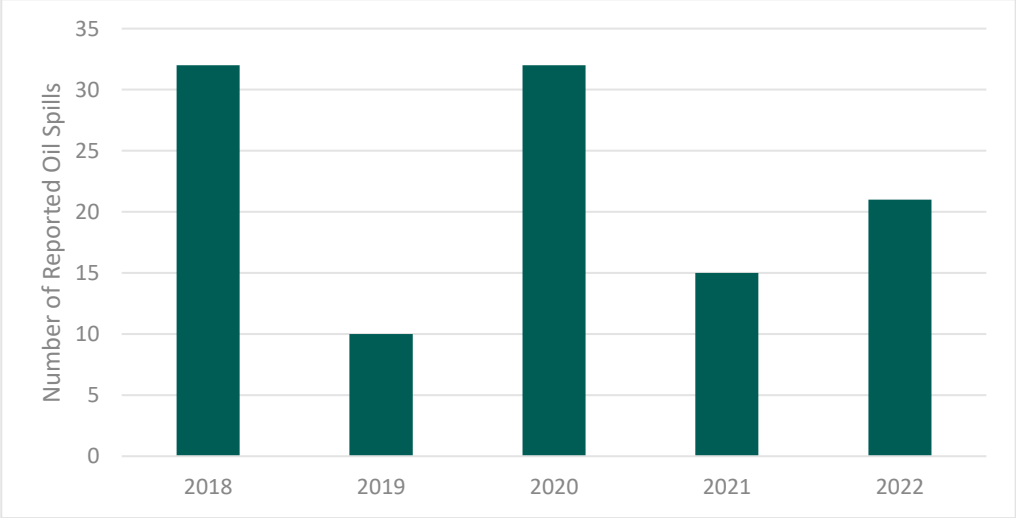


Figure 9: Number of Reported Pole-top Transformer Oil Spills

The utility investigated 547 failed overhead transformers between 2018 and 2022 to identify root causes of failure. The investigations found that 44 percent of the failed overhead transformers failed at or past the end of their useful life and that the number of failures increased with transformer age (see Figures 10 and 11). This is consistent with the expectation that transformers which are at or past

[14] *Supra* note 6.
[15] *Supra* note 5.
[16] *Supra* note 7.
[17] *Supra* note 8.
[18] Compared to approximately 6,400 at the end of 2017.

their useful life of 35 years are subject to an increased risk of failure. Most of the 4kV or 13.6kV system's transformers are also past their useful life, so by converting the system to 27.6kV these potentially failing transformers are removed from the population. In addition, Toronto Hydro, while conducting line patrols, identifies any transformers that show visual signs of deterioration for replacement.

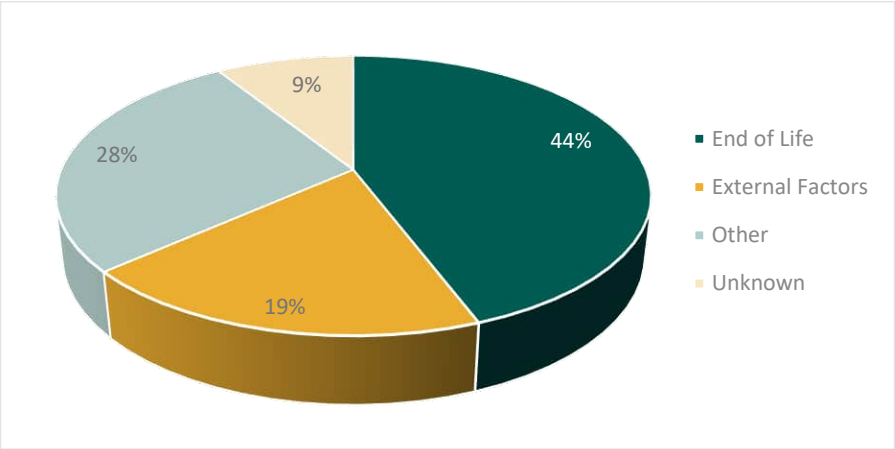


Figure 10: Root Cause Distribution for Failed Overhead Transformers from 2018-2022

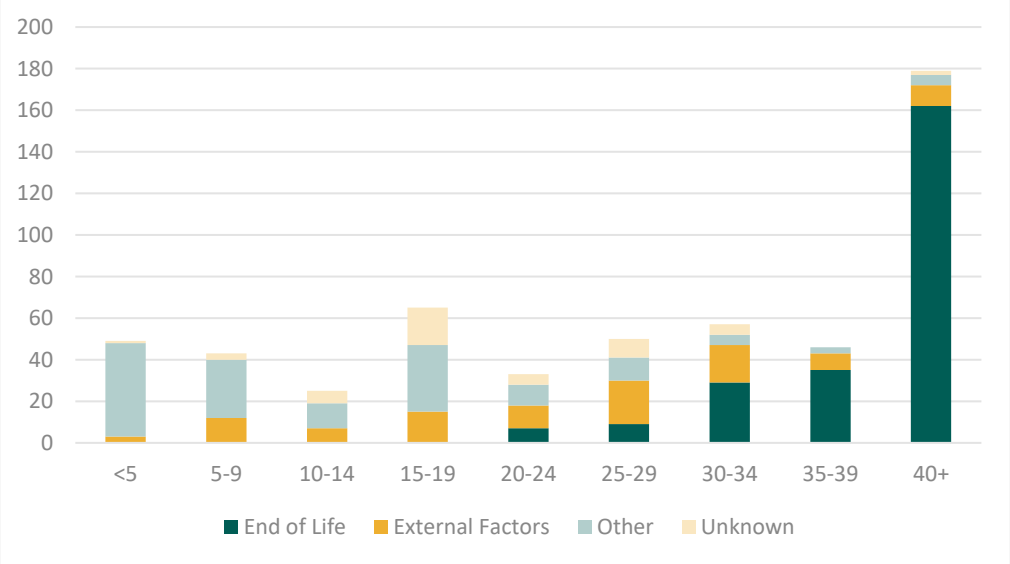


Figure 11: Age and Cause Distribution for Failed Overhead Transformers 2018-2022

Figure 12 shows the age distribution of overhead transformers in 2022 and in 2029 without investment. As of 2022, 2,245 transformers (8 percent) have surpassed their useful life of 35 years.

This is a significant improvement over 2017, when 14 percent were past useful life, and is expected to continue to improve due to the ongoing work to remove all the remaining overhead transformer at risk of containing PCBs. However, by 2029, without investment, the number of transformers past useful life will more than double to 4,747, and an additional 6,866 transformers will be within five years of end of life. Once all of the transformers at risk of containing PCBs have been removed, Toronto Hydro will shift away from spot replacements of transformers, and proactively replace them at a steadier pace through area rebuilds only. Using this approach, Toronto Hydro can ensure that the overhead transformers past useful life and associated reliability and environmental risks remains within a reasonable range over 2025-2029 and beyond, while taking advantage of the efficiencies (and other benefits such as reduced customer disruption) associated with area rebuild work.

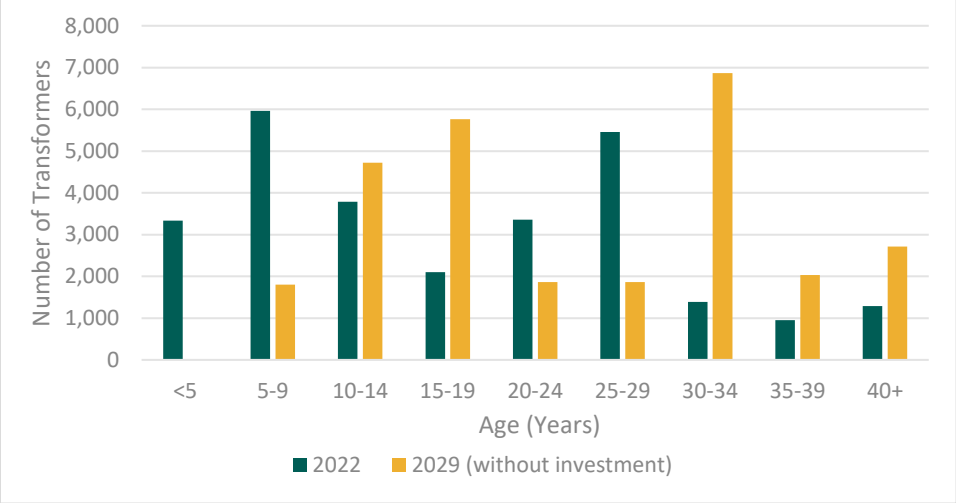


Figure 12: Age Distribution of Overhead Transformers in 2022 and 2029 (without investment)

Toronto Hydro will generally replace overhead transformers like-for-like unless undertaken as part of voltage conversion. However, one of the factors considered is whether the transformer in question is adequately satisfying design and policy requirements. In some cases, existing transformers are overloaded because they are oversupplying the total demand of secondary customers so they need to be upsized or a new transformer needs to be installed along with the one being replaced. Toronto Hydro also considers the City of Toronto's development pipeline[19] and future growth drivers, such as EV penetration when determining if upsizing or adding an additional transformer is required.

[19] Exhibit 2B, Section B2.2

2. Replacement of Poles and Accessories

Through the Overhead System Renewal segment, Toronto Hydro also replaces wood and concrete poles showing material deterioration as well as deteriorating or obsolete overhead accessories such as porcelain insulators and non-standard animal guards.

Toronto Hydro has approximately 108,988 wood poles and 49,059 concrete poles in service. Poles are exposed to environmental conditions that reduce pole strength, including internal rot and decay at the ground line, shell rot, and infestation. In most cases, pole failures can lead to significant public safety risks and prolonged service disruptions. Figures 13 and 14 show the contribution of poles and pole accessory related outages towards CI and CHI over 2018-2022. Poles contributed on average 6,627 customer interruptions and 4,700 customer hours of interruption per year over the last five years and these increase to 30,740 customers and 18,018 customer hours interrupted per year when also considering pole accessories. For the years 2019 and 2021, there were two lighting arrestor outages on the main trunk portion of a feeder that contributed to approximately 13,750 and 9,125 customers out of service respectively. Toronto Hydro has generally been successful in maintaining pole-related reliability and needs to continue proactively investing in pole renewal to manage pole failure risks.

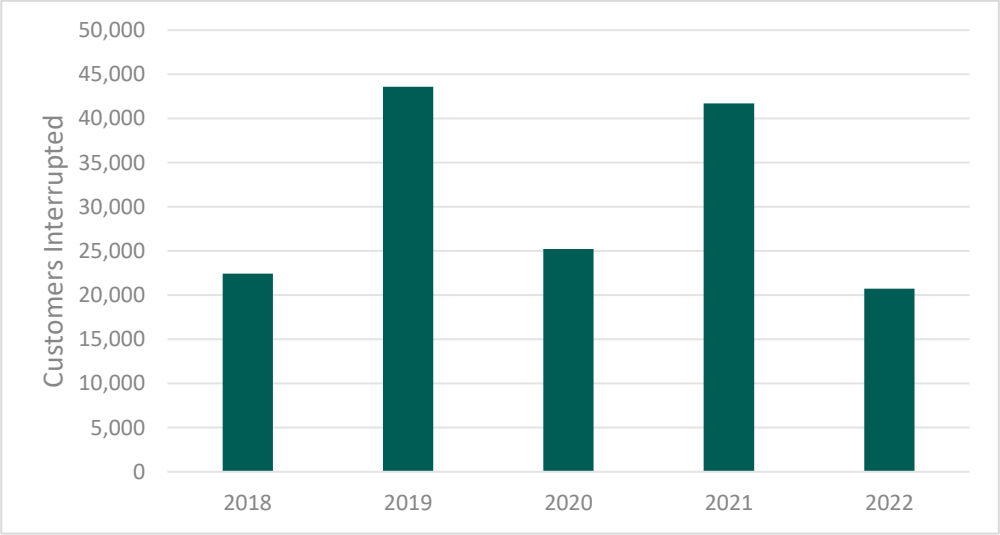


Figure 13: Customers Interrupted ("CI") for Poles and Pole Accessories

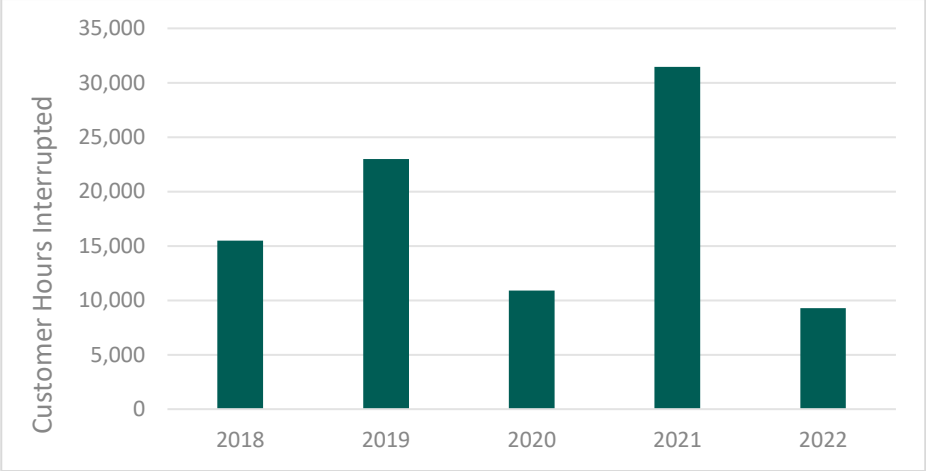


Figure 14: Customer Hours Interrupted ("CHI") for Poles and Pole Accessories

Poles with reduced strength present operational risks to Toronto Hydro crews, safety risks to the public, and reliability risks to the overhead distribution system. The combination of severe weather and poles with reduced strength can lead to catastrophic failure scenarios where one failure can trigger cascading failures on a pole line (i.e. drop of multiple poles and associated equipment, hardware and conductor to the ground). Figure 15 illustrates that, despite ongoing renewal, approximately 287 poles on average had to be replaced reactively per year between 2019 and 2022. Reactive work is variable by its nature and the number of reactive pole replacements can vary year-to-year due to a number of factors, including the number of condemned poles replaced reactively versus through proactive renewal projects and the condition of the poles. However, as discussed below, pole age and condition demographics indicate a continued need to invest in proactive pole renewal to avoid a sustained increase in the need for reactive replacements and related reliability and safety risks.

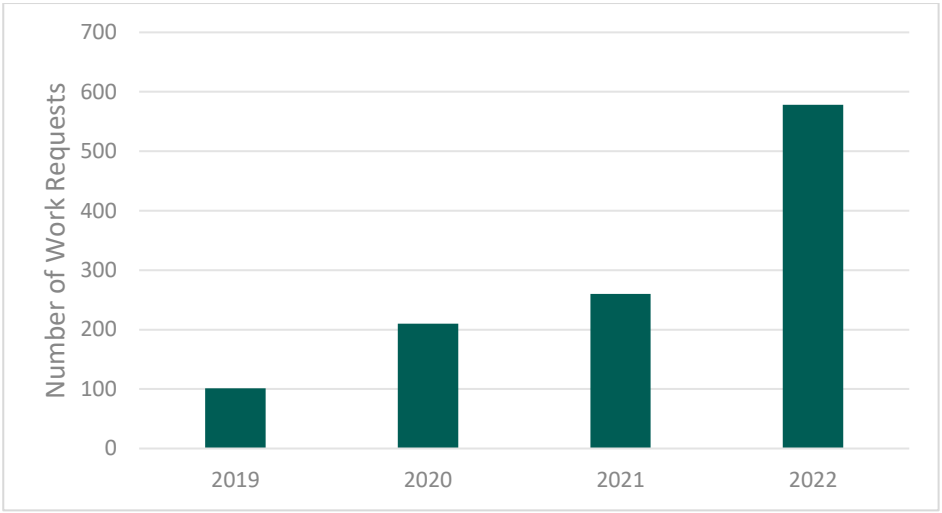


Figure 15: Reactive Work Requests for Pole replacement

In most cases, pole failures can lead to significant public safety risks and prolonged service disruptions. It is imperative that Toronto Hydro remains diligent and proactive in managing pole failure risks through pole replacements either through spot replacements or rebuilds.

Figures 16 and 17 show the age demographics of Toronto Hydro's wood and concrete poles (which have a typical useful life of 45 years and 55 years, respectively) as of 2022. A significant number of poles on Toronto Hydro's distribution system have already passed their useful life.

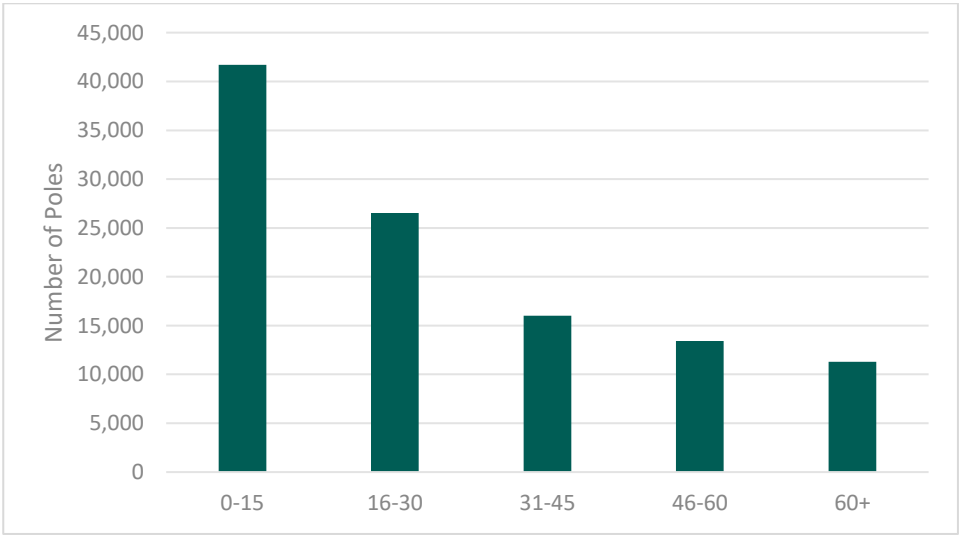


Figure 16: Age Distribution of Wood Poles (2022)

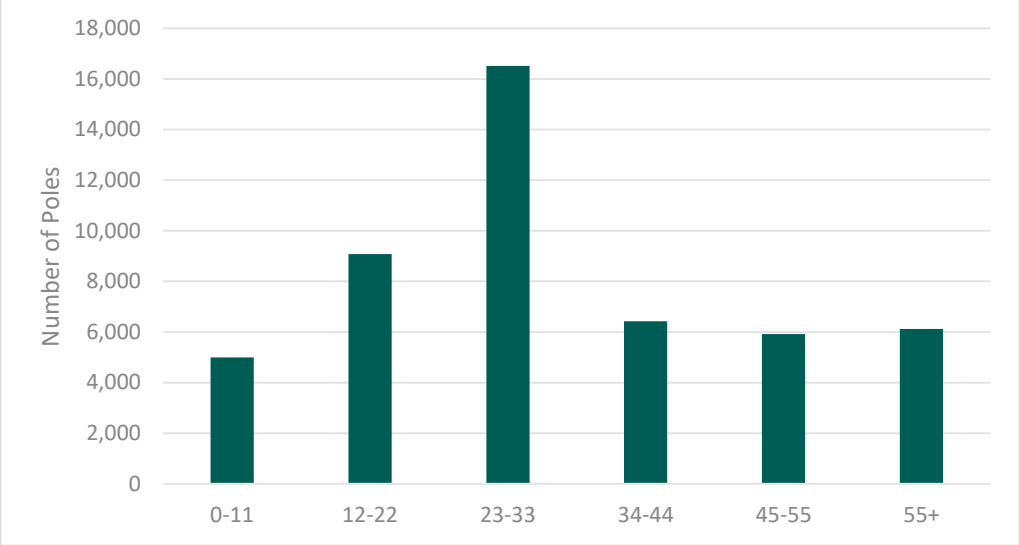


Figure 17: Age Distribution of Concrete Poles (2022)

Based solely on age, an estimated 23 percent or 24,958 wood poles and 13 percent or 6,505 concrete poles require immediate intervention to mitigate failure risk. However, Toronto Hydro plans to replace only aged poles in the worst condition.

The overall condition of poles is assessed through Toronto Hydro's pole inspection program.[20] The results of inspections from this program support Toronto Hydro's Asset Condition Assessment ("ACA") for wood poles. Toronto Hydro's current ACA methodology was first established in 2017; the methodology assigns a health score for condition (summarized into "Health Index (HI)" bands) to a pole based on predetermined criteria (as detailed in Exhibit 2B, Section D, Appendix A). Wood poles are vital assets to the overall overhead system and serve as an indication of overall distribution system health. The ACA results as of the end of 2022 indicate: approximately 9 percent of Toronto Hydro's wood poles (9,422) show signs of material deterioration and or are at end of serviceable life (classified as HI4 and HI5, respectively), and 20 percent of wood poles (21,015) show signs of moderate deterioration (classified as HI3), as shown in Figure 18. Toronto Hydro includes the System Health (Asset Condition) – Wood Poles measure in its 2020-2024 CIR Custom scorecard.[21] System Health is defined as the percentage of HI4 and HI5 poles over the entire pole population. Toronto Hydro's performance on this measure since 2018 is shown in Figure 19. While the Overhead System

[20] Exhibit 4, Tab 2, Schedule 1.
[21] EB-2018-0165, Exhibit 2B, Section C2.

Renewal segment is the biggest contributor to Toronto Hydro's performance on this metric, other programs, such as Area Conversions and Reactive and Corrective Capital,[22] also contribute.

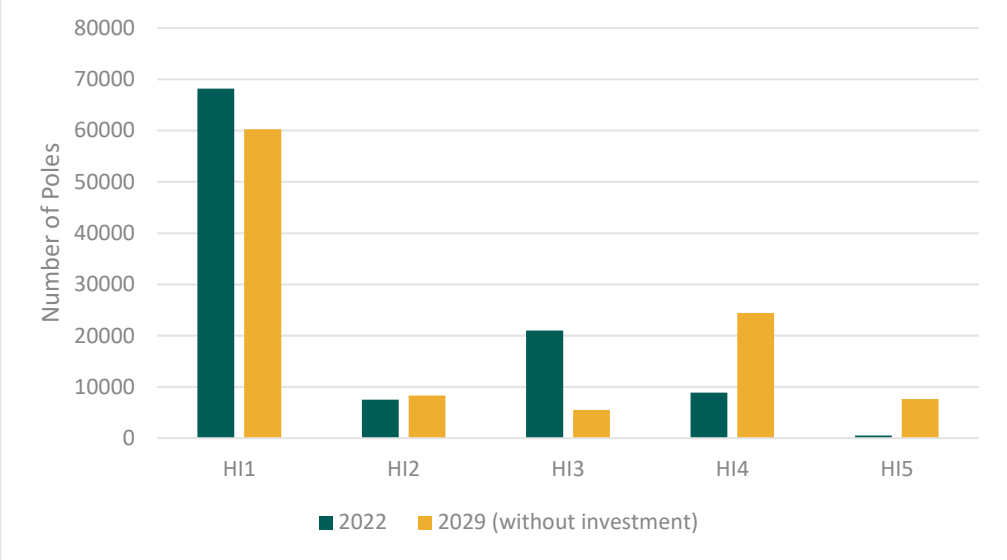


Figure 18: Condition of Wood Poles in 2022 and 2029 (without investment)

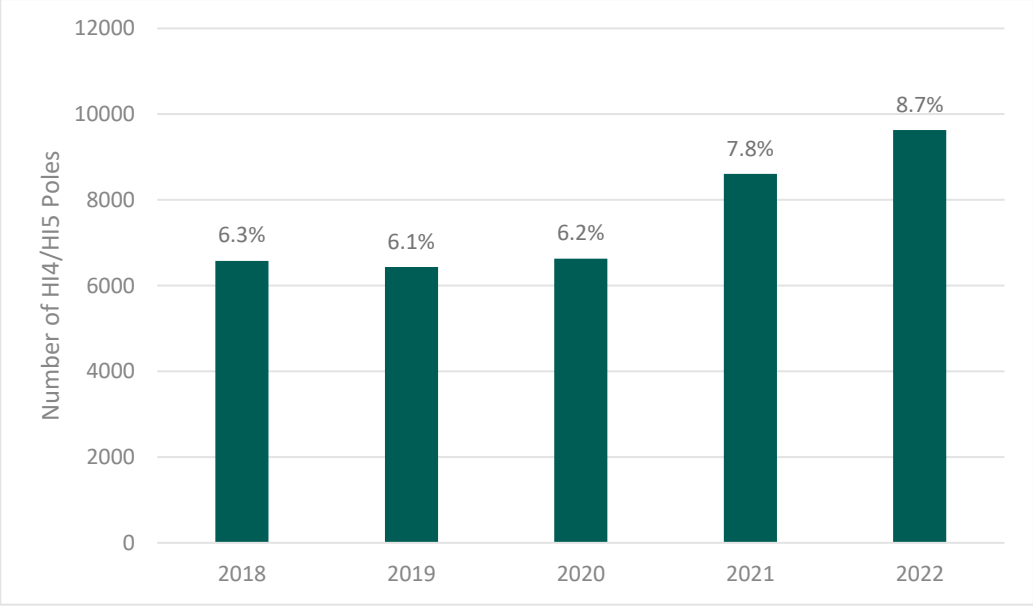


Figure 19: System Health (Asset Condition) – Wood Poles (2018-2022)

[22] Exhibit 2B, Section E6.1 and E6.7

The system health of wood poles has worsened over the past two years (as shown in Figure 19). This is attributed in part to the recent focus of capital renewal work on removing overhead transformers at risk of containing PCBs rather than rebuilds and conversions. Toronto Hydro is planning to replace 8,338 poles in HI4 and HI5 condition by the end of 2029 through overhead rebuild and conversion projects in areas with poor reliability and high concentrations of assets beyond useful life as well as through spot replacements.

In addition to replacing poles with material deterioration, the Overhead System Renewal segment replaces deteriorating and obsolete overhead accessories such as porcelain insulators, porcelain lightning arrestors, and non-standard animal guards. Pole accessories were the single largest contributor to forced outages on the overhead system in 2018-2022. Toronto Hydro's legacy insulators are predominantly porcelain, which has been used in insulation for switches, lightning arrestors, terminators, and line post insulators. Porcelain insulators possess high dielectric strength and good mechanical properties, including hardness and resistance to chemical erosion and thermal shock. However, it is susceptible to contamination build-up, and the accumulation of dirt and salt combined with moisture can lead to insulator tracking, flashover, cracks, insulator shattering and pole fires.

Table 5 shows the total number of pole fire incidents on Toronto Hydro's distribution system from 2015 to 2022. The number of pole fires from one year to the next can vary significantly as risks are related to weather conditions and the presence of contaminants (such as road salts and brines). The impact of a high number of pole fires in 2015 demonstrated how disruptive such incidents can be for the distribution system. The significant reduction in pole fire incidents after 2015 is due to the replacement of porcelain insulators with polymer insulators under a targeted replacement initiative in conjunction with increased insulator washing under the maintenance programs.[23] Toronto Hydro continues to perform regular insulator washing and replaces porcelain insulators as part of pole replacements to mitigate the risk of pole fire incidents.

[23] Exhibit 4, Tab 2, Schedule 1-4.

Table 5: Pole Fire Incidents

Year	Number of Pole Fire Incidents
2015	121
2016	39
2017	27
2018	8
2019	4
2020	17
2021	15
2022	28

3. Replacement of Overhead Switches

The last category of assets replaced through the Overhead System Renewal program is overhead switches. Overhead switches are a critical component of the distribution system that facilitate the isolation of feeder sections or equipment for maintenance during interruptions for load shifting and other operating requirements. They also allow workers to operate safely by isolating feeder sections and creating zones that are free of energized equipment. Toronto Hydro uses two types of switches in its overhead system: in-line disconnect switches and gang operated load break switches, each of which includes both manual load break switches and SCADA controlled switches. Currently there are 3,015 gang operated load switches and 4,425 in-line disconnect overhead switches in the overhead system.

Overhead switches are constantly exposed to harsh environmental conditions such as wind loading and salt spray. These switches can suffer either mechanical failure during operation or electrical failure via a flashover. Failed switches often lead to prolonged outages and pose significant safety risks to utility workers if an arc flash happens during switch failure. Gang operated and SCADA controlled switches were all inspected over 2020-2022 and, on average, 17 percent where found to have a defect such as corrosion. Figure 20 illustrates that 75 reactive work requests were initiated to address the defects found on switches in the overhead system between 2019 and 2022. Figures 21 and 22 show that, especially in recent years, overhead switches continue to contribute significantly to overhead customer outage frequency and duration. Gang Operated type switches, mostly SCADA-Mate, have contributed the most to reliability metrics since 2020 due to these types of switches operating on the trunk part of the feeder. When there is a failure on these types of switches, the

impact is severe, affecting a large number of customers. On average over the past five years, overhead switches contributed to 37,070 customers interrupted and 20,264 customer hours of interruption per year.

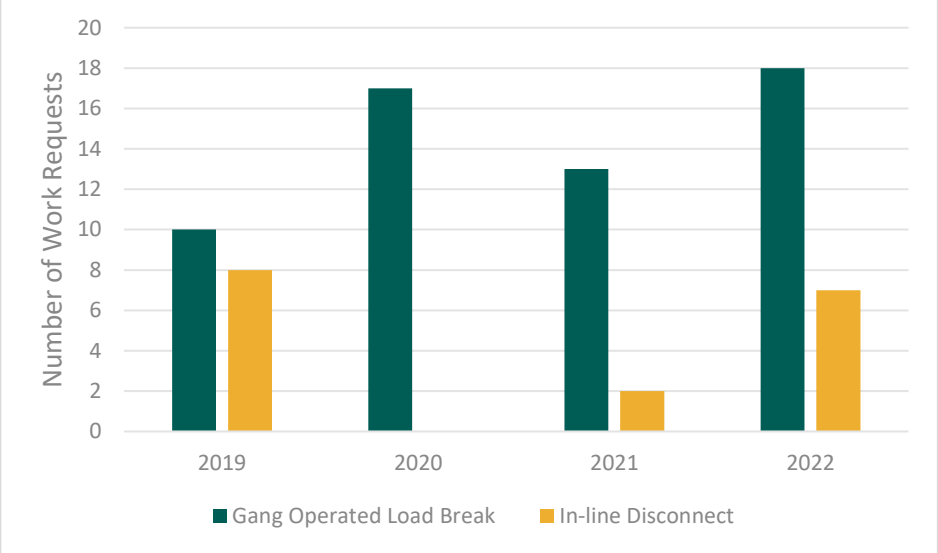


Figure 20: Reactive Work Requests for Overhead Switches

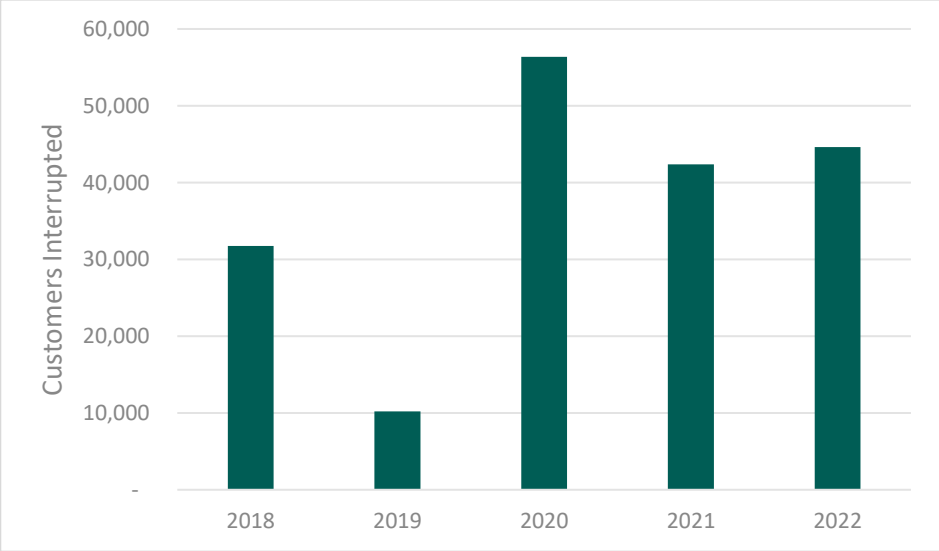


Figure 21: Customers Interrupted ("CI") for Overhead Switches

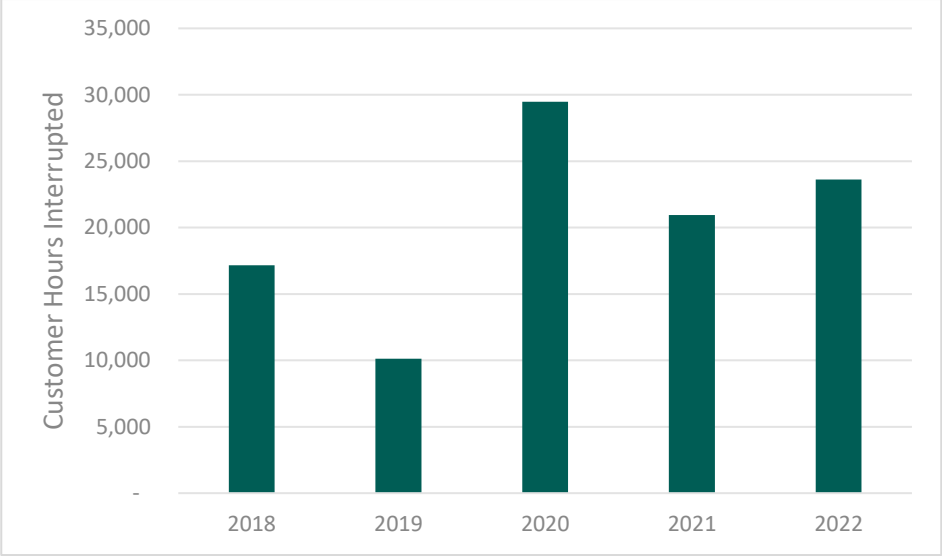


Figure 22: Customer Hours Interrupted ("CHI") for Overhead Switches

Gang operated load break overhead switches and in-line disconnect switches both have a useful life of 30 years.[24] Approximately 18 percent of gang operated switches and 33 percent of in-line disconnect switches have reached the end of their useful life as of 2022. Figure 23 shows the age demographics of Toronto Hydro's overhead switches in 2022. To support maintaining reliability risk, Toronto Hydro needs to continue its steady renewal of overhead switches to keep pace with the aging asset population and prevent an increase in failure rates. Figures 24 and 25 show the asset conditions of overhead gang operated and SCADA-Mate switches. While historically these types of switches have been in relatively good condition compared to the other overhead assets, the population of switches showing at least material deterioration (classified as HI4 and HI5) is expected to increase without proactive renewal.

[24] Previously Gang operated load break overhead switches had a useful life of 40 years while inline disconnect switches had a useful life of 45 years, but these have been reduced to 30 years based on review and insights gained from participation in the utility's latest Depreciation Study filed at EB-2023-0195, Exhibit 2A, Tab 2, Schedule 1, Appendix D

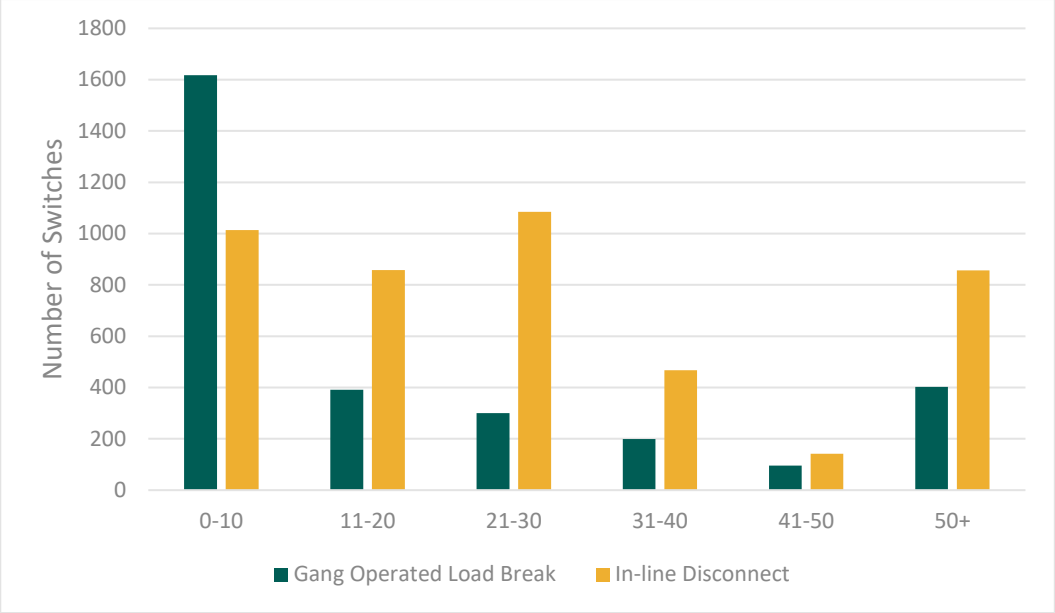


Figure 23: Overhead Switch Age Demographics (2022)

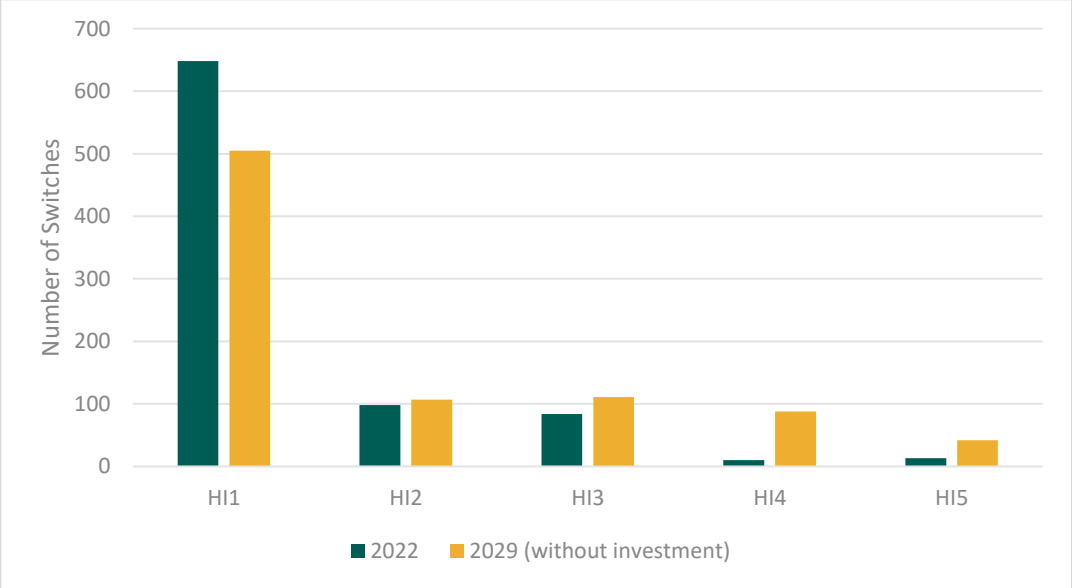


Figure 24: Condition of Overhead Gang Operated Load Break Switches in 2022 and 2029 (without investment).

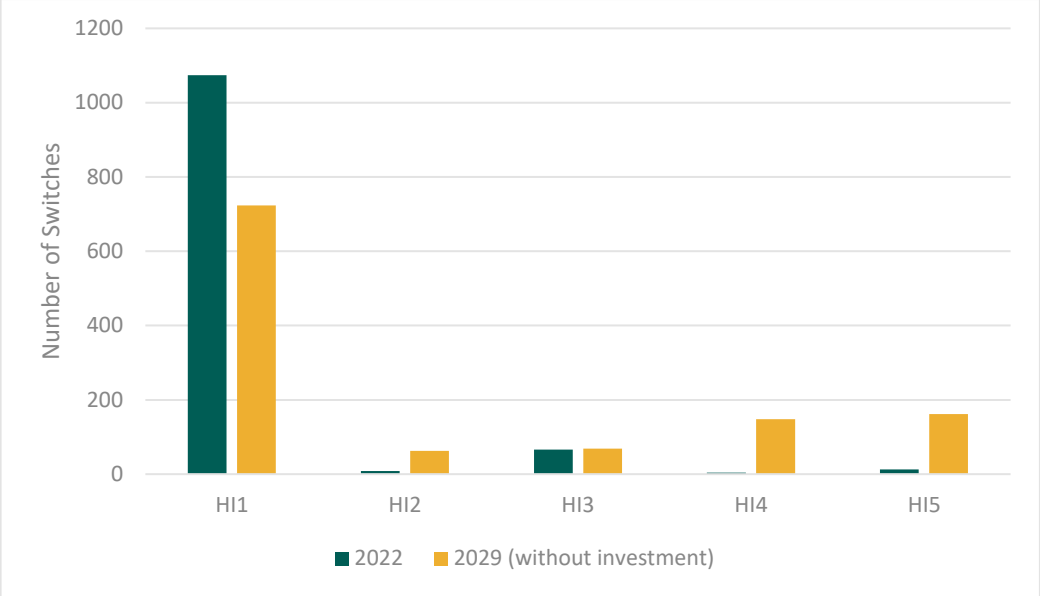


Figure 25: Condition of Overhead SCADA-Mate Switches in 2022 and 2029 (without investment).

E6.5.3.2 Overhead Infrastructure Resiliency

The objective of the Overhead Infrastructure Resiliency segment is to mitigate reliability and safety risks by targeting overhead infrastructure assets that are particularly vulnerable to outages and/or challenging to access due to their location or design. The Overhead Infrastructure Resiliency segment is directly responsive to customer priorities indicated in Phase 1 of Toronto Hydro's Customer Engagement by supporting reductions in the number of outages and restoration time in extreme weather.[25]

Targeted assets include overhead feeders with a history of outages due to weather-related events, tree and animal contacts, and foreign interference. They also include overhead infrastructure assets that are part of functionally obsolete designs, which are no longer aligned with Toronto Hydro's current planning and work practices, but which are not currently addressed through other capital programs. Toronto Hydro plans to mitigate safety and reliability risks associated with these feeders by relocating the existing overhead infrastructure to locations that are more accessible to Toronto Hydro crews and that lower the likelihood and impact of failure.

The primary activities in this segment are:

[25] *Supra* note 8.

1. Undergrounding of overhead assets that have a history of poor reliability (in the form of sustained or momentary outages) due to weather, tree, animal, or foreign interference related outages.
2. Relocation of overhead assets that are in areas with limited or difficult access, and along main arterial rail corridors.
3. Relocation of congested station egress assets with three or more circuits on the same pole.

This segment will mainly target the trunks of feeders as outages on trunks have a higher impact on customers. Trunks are the main sections of feeders exiting from the transformer station and laterals are the branches that come off the trunks and are protected by fuses. Figures 26 and 27 show the CI and customer minutes out ("CMO") impacts of outages due to adverse weather, tree contacts, and foreign interference over the last 5 years, broken down between trunks and laterals of feeders targeted in this segment.

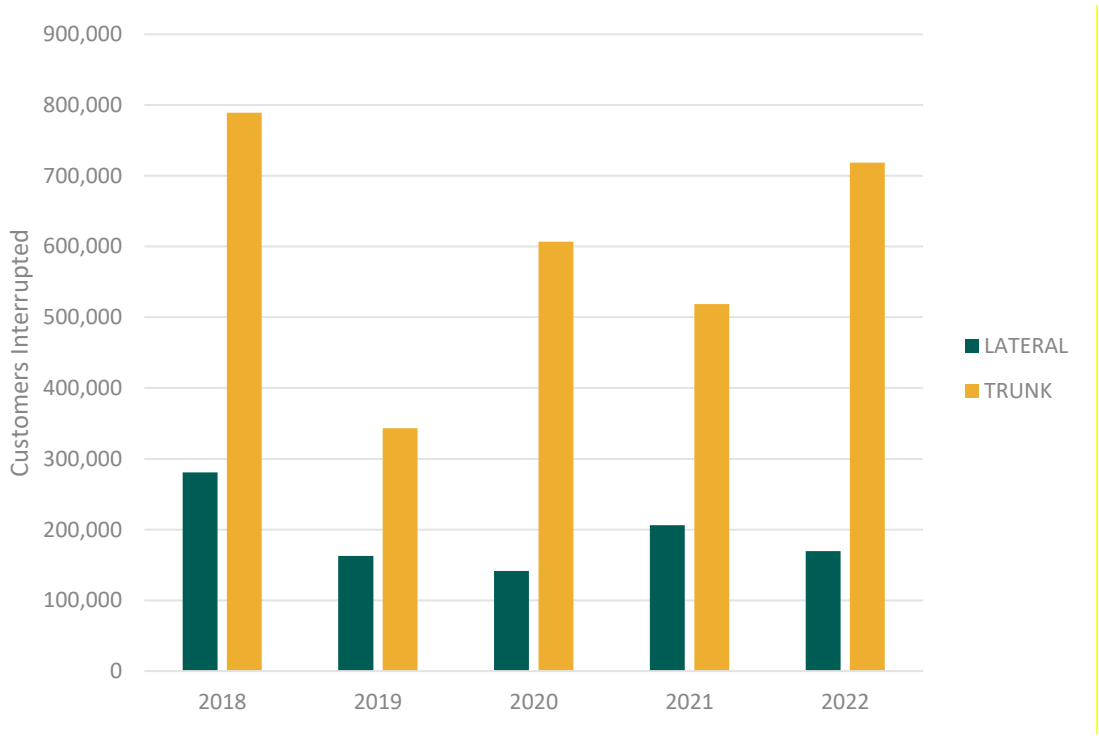


Figure 26: Total Customers Interrupted (CI) – Trunk Versus Lateral

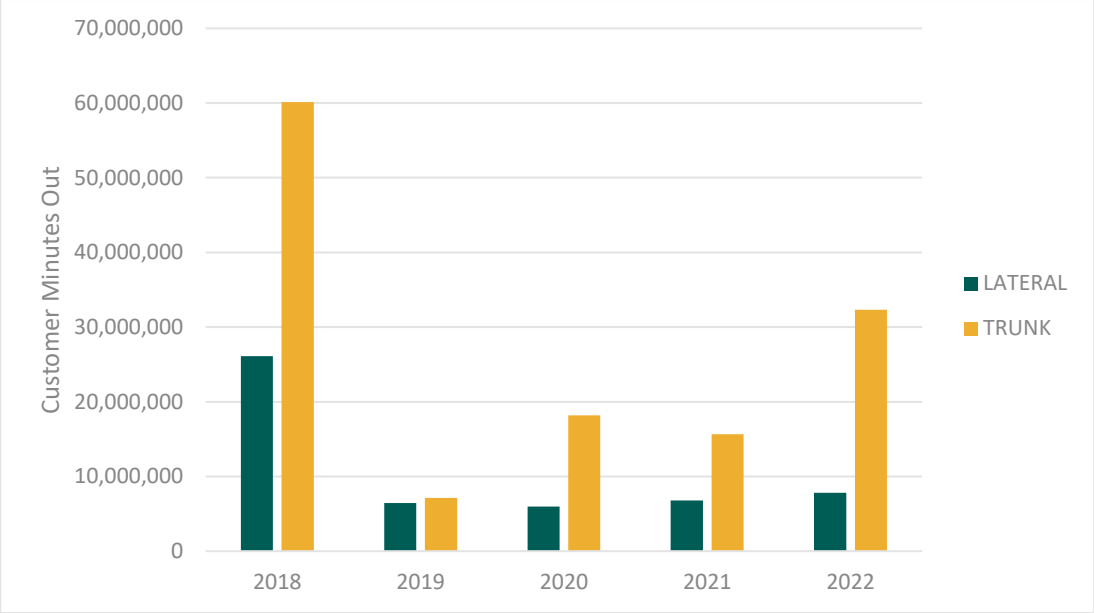


Figure 27: Total Customer Minutes Out – Trunk Versus Lateral

Additional details on the specific types of work and assets targeted in this program are provided below.

1. Overhead Feeders Based on Reliability History

The first category targeted through this segment is overhead feeders which are particularly susceptible to outages due to tree contacts, extreme/adverse environmental or weather factors, and foreign interference. Adverse weather factors include rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions. Adverse environmental factors refer to distribution assets being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, or fire.

Toronto Hydro has identified vulnerable overhead feeders based on the number and duration of outages related to these external factors, as shown in Figure 28 below. Toronto Hydro will target feeders with the greatest number of outages and highest customer hours interrupted as they are likely to benefit the most from being moved underground. By strategically undergrounding overhead sections of these feeders the utility will mitigate the frequency and impact of outages on affected customers, especially as adverse and extreme weather events become more frequent due to climate change.

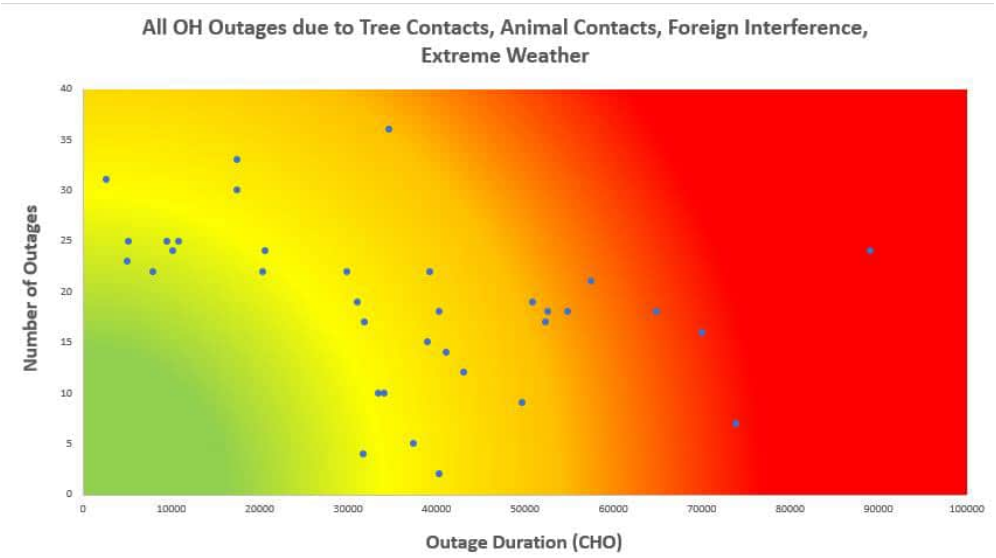


Figure 28: Overhead Outages due to Tree Contacts, Animal Contracts, Foreign Interference and Extreme Weather

2. Overhead Assets in Difficult to Access Locations

Overhead assets in certain parts of the city are located in areas that are difficult for Toronto Hydro employees to access for regular maintenance or for reactive repair or replacement. Figure 29 shows the locations of such assets. These locations can be especially vulnerable during major storm events such as heavy rainfall, floods, and ice storms and make restoration efforts following such events extremely challenging.



Figure 29: Overhead Assets in Inaccessible locations

Figures 30 and 31 show an example of difficult-to-reach assets. The red line in Figure 30 traces the path of three in-service feeders running through the Humber River in Etobicoke across Kipling Avenue, where access is limited. The poles carry one 27.6kV circuit feeder from Rexdale TS and two 4.16kV circuits from Watercliffe MS.



Figure 30: Difficult-to-Access Overhead Circuits on Humber River across Kipling Avenue



Figure 31: Difficult-to-Access Overhead Circuits on Humber River across Kipling Avenue

Another example is shown in Figures 32-33 where the two major circuits (traced in red) from Horner Transformer Station are on the Hydro One right of way ("ROW") and in a rail corridor. Access to these assets requires coordination with CN/CP Rail at all times, even in emergency conditions due to the safety requirement for a flag person from CN/CP authorities. Therefore, these circuits are deemed difficult to access and hence will be targeted for relocation and/or storm hardening.



Figure 32: Overhead Assets in Rail Corridor

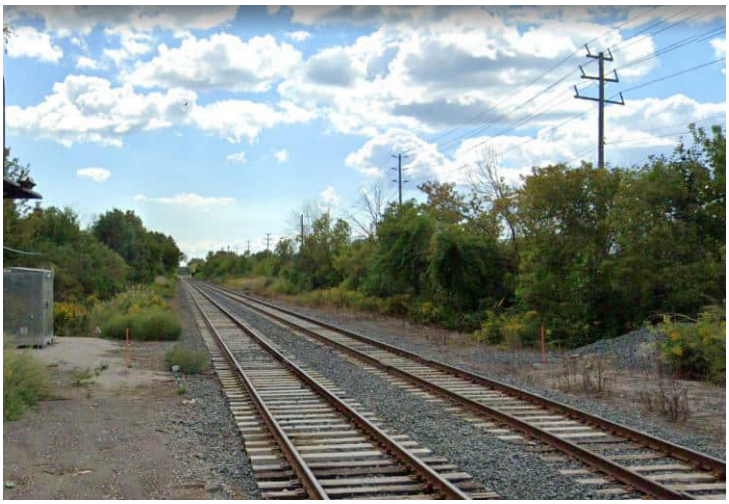


Figure 33: Overhead Assets in Rail Corridor

Toronto Hydro plans to reconfigure the feeders and relocate these assets away from the ravines and right of ways to improve accessibility for Toronto Hydro crew members and reduce vulnerability to outages in adverse weather conditions. This will reduce safety risks, such as slips, trips, or fall hazards due to uneven terrain and by enabling the use of bucket trucks instead of having to climb poles to perform certain activities. When climbing poles to work on energized lines, crews may not have bucket truck and equipment access, increasing the risk of coming into contact with live lines. The use of a bucket trucks is the most secure way for crews to reach the assets located on poles since the crews will be working on a stable and insulated aerial device. In general, the reconfiguration and relocation will reduce restoration times in the event of an outage.

Toronto Hydro will relocate these hard to access pole lines, including primary conductors, poles, insulators, transformers, switches and other associated overhead assets and replace them with new construction located in more accessible areas, e.g. overhead distribution on nearby roadways, underground distribution on boulevards, or ducts on bridges.

3. Congestion of Overhead Circuits Exiting from Transformer Stations

The initial section of a feeder exiting a transformer station extends to the first switching point or switchgear. This section is the 'egress' and it is a critical portion of the feeder because it carries the entire feeder load. Hence any failure or fault on an egress will result in an interruption to all of the customers on that feeder. If these egress sections are overhead, then they are also exposed to a wide variety of external factors that can cause interruptions, such as adverse weather, tree contacts, and foreign interference.

Toronto Hydro has determined that a single pole carrying three or more feeder egresses (three or more circuits) represents an unacceptably high level of risk to reliability due to the amount of load connected in a single physical location. Should a failure occur that impacts the pole line, three or more feeders could experience an outage, resulting in an unacceptably high number of customer interruptions. The risks are further exacerbated where the circuits on the same pole line are back ups to each other and hence a failure will result in a lengthy outage as restoration may not be possible immediately due to the coincident failure of the back-up feeders.

Through this segment, Toronto Hydro plans to reconfigure these assets such that there are no more than two feeders on a pole line. In some cases, this will involve replacing overhead egress with new underground tree-retardant cross-linked polyethylene ("TR-XLPE") cable in concrete-encased

conduit. The circuit will be underground from the circuit breaker to a point where it can return to overhead.

Figure 34 identifies the transformer stations with pole lines containing three or more circuits that Toronto Hydro will begin to target over the 2025-2029 period.



Figure 34: Transformer stations identified with 3 or more circuits

E6.5.4 Expenditure Plan

Table 6 provides the actual (2020-2021), Bridge (2022-2024) and Forecast (2025-2029) expenditures for the Overhead System Renewal program.

Table 6: Historical & Forecast Program Cost ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Overhead System Renewal	36.1	38.2	38.2	32.5	73.9	50.5	49.4	53.3	60.3	58.9
Overhead Infrastructure Resiliency	-	-	-	-	-	-	11.4	24.1	24.8	25.6
Total	36.1	38.2	38.2	32.5	73.9	50.5	60.8	77.4	85.2	84.5

E6.5.4.1 Overhead System Renewal Expenditure Plan

Table 7 below provides the actual, bridge, and forecast costs for the Overhead System Renewal segment. Toronto Hydro invested $112.6 million in the Overhead System Renewal segment between 2020 and 2022, and expects to invest another $106.3 million by the end of 2024. Tables 8 below shows the actual and forecast volumes of assets replaced over 2020-2024. The level of spending and overall unit volumes are both lower than forecast in the 2020-2024 DSP ($265.7 million and e.g. over 11,000 poles) as Toronto Hydro reduced the segment budget to support meeting overall capital funding limits[26] and faced supply chain challenges and other pressures impacting pacing and costs. The utility has been prioritizing replacement of overhead transformers with PCBs (i.e. through spot replacements) in order to eliminate them by 2025. However, supply chain challenges in acquiring sufficient transformers have reduced Toronto Hydro's ability to ramp up the pace of replacements as intended. The utility has been working diligently to mitigate the impacts of supply chain issues[27] and expects to increase the pacing towards the end of the rate period.

Table 7: Historical & Forecast Segment Cost ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Overhead System Renewal	36.1	38.2	38.2	32.5	73.9	50.5	49.4	53.3	60.3	58.9

Table 8: 2020 – 2024 Overhead Asset Replacement Volumes

Asset Class	Actual			Bridge		Total
	2020	**2021**	**2022**	**2023**	**2024**	
Poles	1,418	1,263	1,137	790	2,674	7,282
Transformers	401	584	579	215	1,892	3,671
OH Switches	185	290	71	43	114	703
Conductors* (km)	53.0	60.0	76.0	4.8	45.1	238.8

*Primary cables only

Other factors that can impact project timelines and costs include changes in scope requiring additional work, for example a collapsed duct needing to be repaired.

[26] Exhibit 2B, Section E4.
[27] Exhibit 4, Tab 2, Schedule 15.

Toronto Hydro forecasts spending $272.5 million on the Overhead System Renewal segment over the 2025-2029 period to achieve its goal to generally maintain asset condition and failure risk on the overhead system at current levels and eliminate the last of the overhead transformers at risk of containing PCBs. This includes the cost of replacing end-of-life assets and converting the 4.16 kV or 13.8 kV distribution system to standard 27.6 kV lines. In determining the appropriate pacing, Toronto Hydro carefully considered feedback from customers through the Customer Engagement process to ensure a balanced investment approach to the overhead system renewal portfolio: ensuring reasonable rates but also maintaining reliability. The 2025-2029 forecast expenditures are based on the historical unit cost trends of major asset classes and the forecast volumes of major overhead asset replacements for the same period, as shown in Table 9.

Table 9: 2025-2029 Volumes (Forecast): Overhead System Renewal

Asset Class	2025	2026	2027	2028	2029	Total
Poles	2,113	1,556	1,556	1,556	1,556	8,337
Transformers	1,232	907	911	908	889	4,847
OH Switches	123	91	91	104	102	511
Conductors* (km)	66	49	49	45	44	253

**Primary cables only*

The 2025-2029 forecast volumes are high level estimates based on a preliminary selection and scoping of areas targeted for complete rebuilds and spot replacements. Complete rebuilds include: replacing pole lines, overhead transformers and switches; upgrading associated overhead accessories; and re-stringing new conductor. Some of these areas are currently supplied by 4.16 kV and 13.8 kV systems, which will be converted to 27.6 kV through these projects. Once high-level project scopes are produced, Toronto Hydro performs field inspections to validate the scope of work, identify third party conflicts and refine estimates before final design is completed. Through this process, projects identified for renewal are subject to change. For instance, poorly performing feeders that demonstrate higher risks than originally anticipated may take priority.

The 2025-2029 program incorporates the three approaches described below.

- **Feeder Rebuild:** Rebuild of 27.6kV feeders in areas with poor reliability and high concentrations of assets in deteriorated condition that do not require voltage conversion.
- **Voltage Conversion Rebuild:** Voltage conversion of 4kV or 13.8kV to 27.6kV feeders in areas with poor reliability and high concentrations of HI4 and HI5 condition poles. Voltage

conversion requires that all poles, transformers, switches and conductor in each conversion area be replaced.

- **Spot Replacement**: Spot replacement of transformers containing (or at risk of containing) PCBs and the worst condition poles not targeted through the first two approaches.

Once Toronto Hydro has removed all transformers containing PCBs, it will shift towards a more rebuild-focused approach to overhead asset renewal, limiting spot replacements to only the worst condition poles not addressed elsewhere. The rebuild approach is intended to minimize supply disruptions to customers where possible. Reduced disruption to feeders translates into fewer outages for customers and improved project efficiencies. Another way Toronto Hydro maximizes efficiency and cost savings during project planning is by breaking large overhead rebuild projects into smaller phases for enhanced manageability and coordination, providing greater flexibility for scheduling and assigning resources. This approach also reduces the number of scheduled outages and disruptions that customers will experience.

In addition, Toronto Hydro will coordinate any voltage conversion overhead work with related Municipal Stations renewal work. This allows Toronto Hydro to eventually decommission Municipal Stations prior to any major renewal investments at those stations. Furthermore, the utility needs to strategically and systematically plan conversion work to ensure that the overall 4 kV or 13.8 kV system is still fully functional while the conversion is ongoing. There are additional cost savings and functional benefits from voltage conversions, including that the 27.6 kV distribution system transports more power over longer distances at lower losses (i.e. lower voltage drop at greater distances and improved power quality and distribution efficiency) than the existing 4.16 kV or 13.8 kV systems. This also results in fewer required Municipal Stations, leading to fewer assets to maintain, lower expenditures and greater reliability.

E6.5.4.2 Overhead Infrastructure Resiliency Expenditure Plan

Table 10 below provides the forecast costs for the Overhead Infrastructure Resiliency segment. There are no historical (2020-2022) or bridge (2023-2024) expenditures associated with this segment.

Table 10: Forecast Segment Cost ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Overhead Infrastructure Resiliency	-	-	-	-	-	-	11.4	24.1	24.8	25.6

Over 2025-2029, Toronto Hydro plans to spend $85.9 million to target overhead assets for relocation or undergrounding to mitigate reliability and safety risks and improve resilience. The focus of this segment is on very specific and particularly vulnerable sections of the overhead system only, such as those identified in Figure 35 below.



Figure 35: Potential Locations Targeted for Overhead Resiliency Investments

Toronto Hydro plans to target overhead areas which fall under the criteria described in Section E6.5.3.2: i) feeders with history of outages caused by external factors such as adverse weather; ii) feeders in hard to access locations; and iii) egress pole lines with three or more circuits. The utility

will prioritize the highest risk areas based on the number of circuits, number and types of customers (e.g. whether includes key account customers), and potential impact to reliability.

The total number and timing of the areas targeted will depend on the specific locations and required scope and level of investment for projects selected (which have not yet been determined). Toronto Hydro has experience completing similar projects in the past, which it has used to inform the planned expenditures in this segment.

For example, in 2019-2020, the utility executed a project along Carlingview Drive between Dixon Road and Meteor Drive. The objective was the targeted undergrounding of two overhead 27.6kv circuits and two 13.8kv circuits, which were experiencing conductor galloping from the wind caused by airplanes landing at Pearson airport. This project undergrounded approximately 1 circuit-km of overhead feeders, installing 7 overhead switches, 5 padmount switches, 2 overhead transformers, approximately 16 km of cables (primary and secondary), 14 poles, and 9 cable chambers. The civil work cost $2.3 million and the electrical $3.5 million, which would be equivalent to approximately $3.1 million and $4.3 million in 2026.

E6.5.5 Options Analysis

E6.5.5.1 Options for Overhead System Renewal

Toronto Hydro considered the following options for the Overhead System Renewal segment. Under each of these options Toronto Hydro would seek to replace all remaining overhead transformers containing, or at risk of containing, PCBs by the end of 2025.

1. **Option 1: Limited rebuild/renewal of extremely poor reliability segments, voltage conversion of 36 Feeders and spot replacement of transformers, poles & switches in deteriorated condition, at or beyond their useful life**

Under this option, Toronto Hydro would prioritize and replace only overhead transformers, poles and switches in deteriorated condition that are at or past useful life. The utility would only rebuild or renew limited overhead assets (transformers, poles and switches) on the worst performing feeder segments and do voltage conversion of select areas that meet poor reliability criteria.

This option would provide minimal improvement in limited circumstances where only a limited number of assets on feeder segments that are in poor condition are replaced and eliminating these assets improves overall feeder performance. Under this option, the utility projects that the System

Health (percent of wood poles in HI4 or HI5) of the wood pole population would increase to 20.5 percent by 2029, even when considering the estimated impact of reactive replacements at a rate of 200 poles per year. The reduced pace of renewal in this option would expose the overhead distribution system to a higher risk of asset failure leading to deteriorating reliability and safety to utility workers and the public. As a result of this approach, Toronto Hydro would likely incur higher reactive repair costs, potentially with greater disruptions to the public and customers in the course of reactive repair work and could face a growing backlog of overhead assets at high risk of failure beyond 2029. Therefore, this option is not recommended.

2. **Option 2 (Selected Option): Proactive rebuild/renewal of priority areas exhibiting degradation or poor reliability, voltage conversion of 48 Feeders, and spot replacement of higher risk transformers (PCB only) and poles.**

This option proposes a rebuild or renewal of assets on feeders or geographical areas showing signs of degradation or progressively deteriorating reliability, and voltage conversion of functionally obsolete 4.16 kV or 13.8 kV primary voltage designs to 27.6 kV. Specifically, this option will include:

- Full rebuild of areas with poor reliability and a high volume of deteriorated assets beyond their useful life;
- Full rebuild and voltage conversion of 48 select feeders supplied by 4.16 kV or 13.8 kV primary voltage; with a history of poor reliability and a high concentration of assets beyond their useful life; and
- Like-for-like spot replacement of poles and associated overhead accessories showing material deterioration.

Toronto Hydro projects that under this option the System Health of the wood pole population would increase to 18.4 percent by 2029, assuming 200 HI4 and HI5 poles are replaced reactively each year (average over recent years). This is worse than the current system health, but an improvement over Option 1. In selecting this option, Toronto Hydro considered the need to strike a balance between maintaining acceptable safety and reliability on its overhead system, while providing electricity distribution services to customers at reasonable costs. This strategy is in line with Customer Engagement results, which indicate almost equal priority for rates and reliability. Through this option, Toronto Hydro would be best able to manage and mitigate the failure risk of overhead assets (i.e. by removing aged and unreliable assets to address deteriorating reliability), while improving efficiency and capacity of the system (through conversion of 4.16 kV feeders). Furthermore, this

option will mitigate the potential accumulation of a large backlog of overhead assets at a high risk of failure and in need of replacement beyond 2029 (which would reduce reliability and increase costs for customers over the long term).

3. Option 3: Replace all assets in deteriorated condition (or beyond useful life) through 27.6kV rebuilds and convert 60 Feeders of 4.16 kV service areas to 27.6 kV

Under this option, Option 2 would be expanded in the following ways:

- Complete a higher number of targeted rebuilds, replacing approximately 12,000 poles, 7,000 transformers and 740 switches.
- Convert 60 4.16/13.8 kV feeders to 27.6 kV supply.

The above would provide additional reliability and other benefits such as improving system efficiency. This option would also ensure Toronto Hydro would have substantially less backlog of deteriorated and end of life assets by 2029 and less areas in the overhead system that are supplied by 4.16 kV. This is expected to reduce the number of failures on the overhead system, improve reliability and reduce the spending and resources required for reactive replacements. This option is projected to result in the System Health of the pole population reaching 15.0 percent by 2029. Additional voltage conversion would improve power quality and efficiency, reduce line losses, and accelerate decommissioning of certain municipal stations. However, the financial burden of this option increases dramatically at an estimated total cost of over $350 million.

E6.5.5.2 Options for Overhead Infrastructure Resiliency

1. Option 1: Do Nothing

Under this option, Toronto Hydro would not do any targeted undergrounding or relocation of overhead assets based on historical reliability, location, or design. The distribution system would continue to be prone to increased and prolonged outages on certain feeders due to overhead disturbances and accessibility issues for crews. The safety and operational issues discussed in Section E6.5.3.2, including challenges performing maintenance activities on inaccessible assets, would continue. In some cases, due to the hazards of accessing these locations, feeder outages will be deemed necessary to perform maintenance activities including tree trimming. Additionally, customers on affected feeders would continue to experience longer restoration times than those connected to standard and more accessible feeders.

2. Option 2: Like-for-Like Replacement

Like-for-like replacement would involve the replacement of assets characterized above at their existing locations. Under this option, the probability of failure related to asset age and condition would be reduced, but safety risks related to location would remain. In addition, limited accessibility would continue to impact power restoration times. The overall resiliency of the system would not improve and customers would continue to experience longer than necessary outages. In addition, for most of these cases, a like-for-like option may not be feasible due to the functional obsolescence and non-standard designs of these assets.

3. Option 3: Execute Overhead Infrastructure Resiliency Segment as Proposed

The Overhead Infrastructure Resiliency segment as proposed will directly address the source of specific vulnerabilities on the overhead system, including susceptibility to external factors, such as adverse weather and tree contacts, and functionally obsolete designs, which no longer align with Toronto Hydro's current planning and work practices. This will improve the resiliency of the system and result in improvements to safety and outage frequency and duration.

E6.5.6 Execution Risks & Mitigation

E6.5.6.1 Overhead System Renewal

Large overhead renewal projects can be complicated given that third parties could also be doing work in the same area, resulting in potential conflicts and leading to incremental costs and delays. To ensure effective coordination with the City and other utilities, Toronto Hydro participates in the Toronto Public Utilities Coordinating Committee forum.

Other execution risks associated with large overhead rebuild projects include:

- **Third Party Attachments**: Where third party attachments to Toronto Hydro assets will be affected as part of the project, the relevant owners must be contacted to explore alternative attachment options which may delay the execution timeline. To mitigate this risk, Toronto Hydro will engage owners of these third-party attachment assets as soon as possible to coordinate and plan the required transfer.
- **Permitting**: Delays in obtaining permits from applicable authorities (e.g. the City of Toronto, Ministry of Transportation, CN railways and Hydro One) may require extra design time. To mitigate this risk, additional design time will be built into the schedule to ensure the

necessary permits are obtained without material effect on project schedule. Also, Toronto Hydro will work closely with the City of Toronto on planned road work through meetings of the Public Utilities Coordinating Committee. If work planned by the City puts Program completion at risk, Toronto Hydro will negotiate with the City to coordinate a construction schedule that is acceptable to all parties involved.

- **Operational risks**: Load transfers can be restricted in certain months of the year due to high usage of electricity (e.g. during the summer months). Toronto Hydro will mitigate this risk by scheduling work to avoid periods of loading restrictions.
- **Resource availability**: Insufficient resources and materials can seriously impact project execution, resulting in delays or deferrals into future years. Most recently, there has been an increased risk to the supply chain for acquiring overhead transformers. To address this risk, engineering work plan meetings are held each year to ensure sufficient resources are procured and available to complete the approved projects for that year. When required, short interval control ("SIC") meetings are created for key resources with stakeholders across the organization to manage resources and forecast impact to work programs.
- **Conformance with standards:** Toronto Hydro designs and constructs new overhead rebuild projects in accordance with applicable standards and specifications that are intended to ensure public and employee safety. However, unique situations can sometimes arise to hinder design or construction in compliance with applicable standards. Identifying and making efforts to accommodate and address these issues during the planning and design stages can mitigate most of these risks. Toronto Hydro has established processes to address potential deviations from standards to ensure that the design and construction processes are not delayed and that any accepted deviations from standards do not impact the utility's ability to remain compliant with applicable requirements (including Ontario Regulation 22/04 - Electrical Distribution Safety).[28]

E6.5.6.2 Overhead Infrastructure Resiliency

Execution risks associated with overhead infrastructure resiliency projects include:

- **Third Party Coordination**: Road moratorium imposed by the City of Toronto (third party utilities) may affect areas where Toronto Hydro intends to relocate overhead assets

[28] Ontario Regulation 22/04 – Electrical Distribution Safety, under the *Electricity Act, 1998, S.O. 1998, c. 15, Schedule A.*

underground. To mitigate this risk, Toronto Hydro will coordinate with the City and identify potential conflicts and work around them or develop solutions for execution.

- **Access Issues**: Under this segment, Toronto Hydro will be targeting some assets specifically because they are located in areas with significant access challenges and associated crew safety issues, such as valleys and ravines. Toronto Hydro cannot use its usual equipment (e.g. bucket trucks) to execute this work and therefore will work to ensure that proper pre-job planning, training, and coordination is completed.
- **Operational Constraints and Project Coordination**: When replacing congested egress cables, the entire load of the egress section being worked on needs to be transferred to other feeders. Load transfers can be restricted in certain months of the year due to high usage of electricity, for example during the summer. Overloading feeders can cause equipment deterioration due to heat generated by losses that can result in deterioration of the insulation material, transformers and others. Toronto Hydro will mitigate this risk by scheduling the work where loading restrictions are low, coordinating with customers to avoid conflicts with their specific needs (e.g. school class times, facility production schedules).

E6.6 Stations Renewal

E6.6.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 175.4	**2025-2029 Cost ($M):** 282.7
Segments: Transformer Stations, Municipal Stations, Control and Monitoring, Battery and Ancillary Systems	
Trigger Driver: Failure Risk	
Outcomes: Operational Effectiveness - Reliability, Public Policy Responsiveness, Operational Effectiveness - Safety, Environment	

The Stations Renewal program (the "Program") manages station-level failure risk through the replacement of end-of-life and obsolete assets, and manages investments to modernize Toronto Hydro's substations. Customers have indicated that rates, reliability, and prudent modernization are their top priorities. Therefore, the proposed Program has been planned to meet two objectives: first, to maintain station reliability; and second, to replace the majority of Toronto Hydro's obsolete electromechanical relays with modern digital relays.

The failure of station assets can result in power outages for thousands of customers lasting several hours or more, and replacing station assets requires significant lead time. For example, TS Switchgear replacements require years to plan and complete. Hence, to meet customer expectations for reliability, Toronto Hydro proposes the proactive renewal of its station assets at a pacing set to maintain their reliability. This pacing is being proposed to balance the priorities of rates with station reliability. Toronto Hydro prioritizes station assets for proactive renewal based on their age, condition, performance, load served, and customers connected.

By the end of 2023, 43 percent of Toronto Hydro's station relays will be technically obsolete electromechanical relays, which do not permit event reporting, fault diagnostics, or power flow observability. Additionally, these obsolete relays have limited functionality to detect and discriminate between more complex faults that can lead to misoperation. The features of modern digital relays are needed to support Toronto Hydro's grid operability and evolution towards a smart grid infrastructure that integrates vehicle-to-grid, peak shaving, and increased distributed energy resource penetration.

The Program is grouped into the four segments summarized below and is a continuation of the station renewal activities described in Toronto Hydro's 2020-2024 Distribution System Plan.[1]

- **Transformer Stations ("TS"):** This segment involves the renewal of Toronto Hydro's TS switchgear, outdoor breakers, and outdoor switches located at TS. Replacing station assets that have deteriorated and are beyond their useful life allows Toronto Hydro to sustain reliability and mitigate crew exposure to safety hazards. TS assets supply commercial, industrial, and key account customers who are highly sensitive to power outages and power quality issues. During the 2025-2029 period, Toronto Hydro plans to replace three TS switchgear, complete four TS from the 2020-2024 period, 12 TS outdoor breakers, and 63 TS outdoor switches. Toronto Hydro also plans to refurbish one station building in preparation for switchgear replacements required over the 2030-2034 period. This segment is estimated to cost $134 million in total over the 2025-2029 period.
- **Municipal Stations ("MS"):** This segment involves the renewal of Toronto Hydro's switchgear and transformers located at MS and their primary supplies. Replacing these deteriorated and obsolete assets will allow Toronto Hydro to maintain reliability, improve worker safety, and sustain the system in the long term. The majority of Toronto Hydro's MS assets serve Toronto's suburban areas which consist largely of residential and general service customers. During the 2025-2029 period, Toronto Hydro plans to replace 12 MS switchgear, 15 power transformers, and one MS primary supply, for a total estimated cost of $70.3 million.
- **Control and Monitoring:** This segment involves the renewal and modernization of protection, control, monitoring, and communication assets at Toronto Hydro's TS and MS. Replacing these deteriorated and obsolete assets will allow Toronto Hydro to sustain reliability, and advance the modernization of Toronto Hydro's substations. During the 2025-2029 rate period, Toronto Hydro plans to renew 33 existing Remote Terminal Units ("RTUs") and replace 251 obsolete relays with modern digital relays, for a total estimated cost of $64.7 million.
- **Battery and Ancillary Systems:** This segment involves the renewal of DC battery and charger systems, station service transformers, and station AC service panels. This segment also installs new systems to mitigate the risk of flooding at targeted stations. During the 2025-2029 rate period, Toronto Hydro plans to replace 55 batteries, eight charger systems, replace

[1] EB-2018-0165, Exhibit 2B, Section E6.6.

three station service transformers, replace five station AC service panels, and install three sump pumps for a total estimated cost of $13.6 million. This work will allow Toronto Hydro to maintain the integrity of its station assets, maintaining reliability outcomes for Toronto Hydro customers.

Toronto Hydro plans to invest $282.7 million in the Stations Renewal Program in 2025-2029, which is a $107.3 million or 61 percent increase over the projected 2020-2024 spending in the Program. This increase is approximately equally split between an increased work volume and forecasted inflation. This level of investment is necessary to address an increasing population of end-of-life and poor condition station assets, address failure risks and trends identified over the 2020-2024 rate period, support Toronto Hydro's grid modernization investments, and prepare Toronto Hydro for continued success in the Program into the following period of 2030-2034.

E6.6.2 Outcomes and Measures

Table 2: Outcomes Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (SAIDI, SAIFI) by reducing the percentage of station assets in deteriorated condition and/or operating beyond their useful life (percentages vary by asset class)
	• Mitigates failure risks to tens of thousands of customers through renewal work
	  ○ 163,000 customers by replacing assets at and beyond useful life at Transformer Stations (e.g. switchgear, outdoor breakers, outdoor switches);
	  ○ 14,200 customers by replacing assets at and beyond useful life at Municipal Stations (e.g. switchgear, power transformers, primary supplies);
	  ○ 596,690 customers by renewing RTUs, Relays; and,
	  ○ 491,370 customers by renewing DC system and AC station service equipment

Public Policy Responsiveness	• Contributes to Toronto Hydro's Grid Modernization plan by replacing obsolete electromechanical relays with modern digital relays: ○ Accommodate increasingly sophisticated customer needs; ○ Help Toronto Hydro operate its system more efficiently to modernize the grid to allow for better observability and controllability; ○ Allow for fault recording; ○ Provide relay diagnostics for easier maintenance; ○ Better fault coordination; and, ○ Help provide increased value to customers • Increasing the population of station digital relays to 90 percent in 2029
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's public and worker safety performance, as measured by the Serious Electrical Incident Index and Total Recordable Injury Frequency by: increasing the population of arc-resistant switchgear, and decreasing the population of oil-filled TS outdoor breakers
Environment	• Contributes to Toronto Hydro's environmental stewardship by reducing the number of station assets containing (or at-risk of containing) degraded oil

E6.6.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Failure Risk
Secondary Driver(s)	Functional Obsolescence, Public Policy

The Stations Renewal Program addresses failure risk and obsolescence issues associated with Toronto Hydro's critical station assets. A large portion of Toronto Hydro's station assets are operating beyond their typical useful lives and are subject to an increased risk of failure due to their age and condition. Station asset failures have large impacts on system reliability due to the large number of customers served by each station. Necessary repairs are often complex and take significant time to complete.

Like distribution line assets, prudent management of station assets is achieved by monitoring asset demographics and condition. However, management strategies that use run-to-fail or just-in-time

asset replacement are generally unacceptable for station assets due to the impacts of failed assets on customers.

In addition to their increasing failure risk, many older assets use technology that has become obsolete due to advancements, emerging industry trends, and evolving best practices related to safety, customer needs, and functionality. Replacing obsolete assets allows Toronto Hydro to meet public policy outcomes, accommodate increasingly sophisticated customer needs (e.g. vehicle-to-grid, peak shaving, and distributed energy resources applications) and operate the utility's system more efficiently.

E6.6.3.1 Transformer Stations ("TS")

Toronto Hydro's TS supply power to all customer classes. Major TS assets include TS switchgear, TS outdoor breakers, and TS outdoor switches. A large portion of these assets are operating beyond their useful life and are at a heightened risk of failure. Toronto Hydro uses a risk-based approach to identify the highest priority TS assets for replacement. The utility's asset management objective is to cost-effectively sustain current levels of reliability and prudently mitigate crew exposure to safety hazards.

1. TS Switchgear

As shown in Table 4 below, about a third of Toronto Hydro's TS switchgear will be operating past its useful life by the end of 2024. Many of these assets are non arc-resistant and have other obsolete design features that increase safety risks for crews and the risk of collateral asset damage in the event of switchgear failure.

Table 4: Transformer Station Switchgear Demographics at end of 2024

Switchgear Construction	# of Assets	% of Assets Past Useful Life	Other Demographic Information	
			% of Non-Arc Resistant Switchgear	% of Switchgear with Obsolete Breakers
Metalclad	45	40%	73%	7%
Brick Structure	3	100%	100%	100%
GIS	5	0%	0%	0%
Total	53	34%	68%	11%

Toronto Hydro uses asset condition, age, and operational feedback to identify and prioritize the renewal of its switchgear assets. Switchgear are complex assets that include several different parts. Each part has its own failure mode and useful life, which are often less than the 50 years attributed to the switchgear as a whole. Toronto Hydro performs reactive repair and maintenance on individual switchgear parts. This reactive approach becomes less prudent as components that cannot easily be replaced age and deteriorate. Examples include bus bars, bus insulators, and miscellaneous control wiring.

Toronto Hydro assesses the condition of switchgear assets using infrared hotspot scanning, and cable termination, connection, and cleanliness qualitative (visual) assessments. Major components such as breakers are also individually assessed. Toronto Hydro previously used these measurements (excluding the breaker condition assessments) to derive a single health index measurement ("HI") for switchgear. However, the HI reflected a limited number of measurements and made it difficult to balance different indicators. As a result, Toronto Hydro now assesses risk using switchgear age, breaker condition, and operational feedback to evaluate these asset components on an asset-by-asset basis. The current age demographics of Toronto Hydro's TS switchgear units are shown in Figure 1 below.

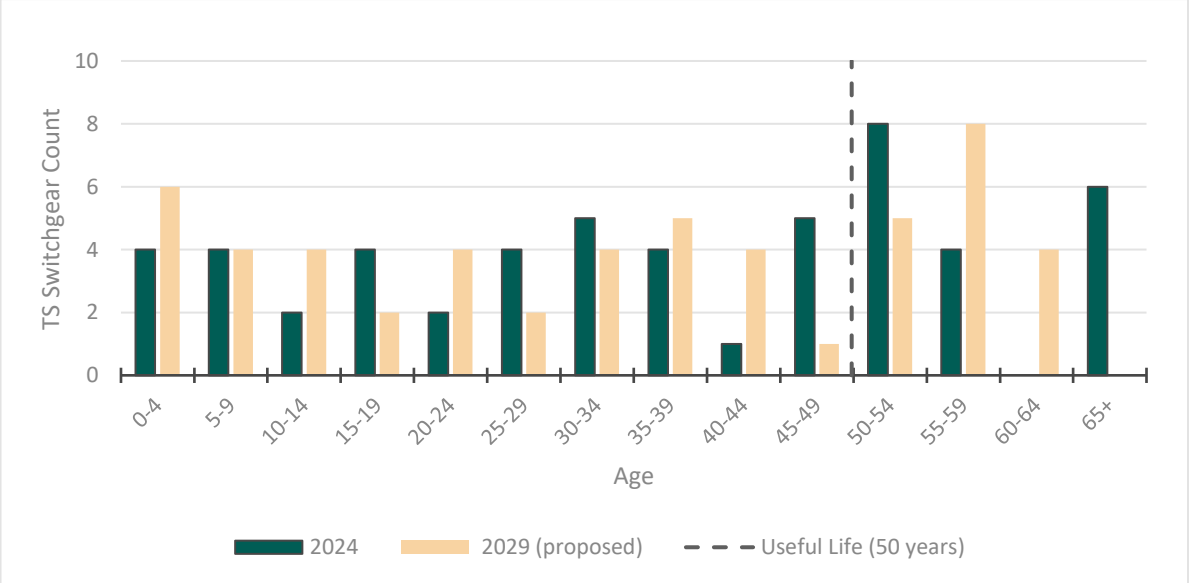


Figure 1: TS Switchgear Age Demographics

As indicated in Figure 1 above, Toronto Hydro anticipates having 18 TS switchgear units operating at or beyond their useful life expectancy by 2024 and 17 units by 2029. Toronto Hydro's condition

assessment for all breakers contained within its TS switchgear population is shown in Figure 2 below. A significant proportion of Toronto Hydro's breakers with moderate deterioration or worse are air-blast breakers. These are the oldest breakers in use. The technology is obsolete and it is difficult to obtain parts for maintenance. These breakers are found in 11 of the switchgear units operating beyond their useful life.

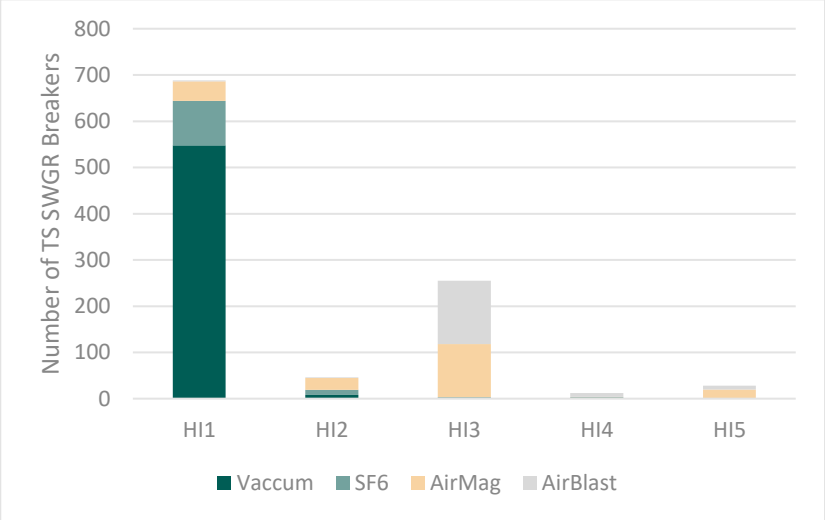


Figure 2: TS Switchgear Breaker Condition by Type as of 2022

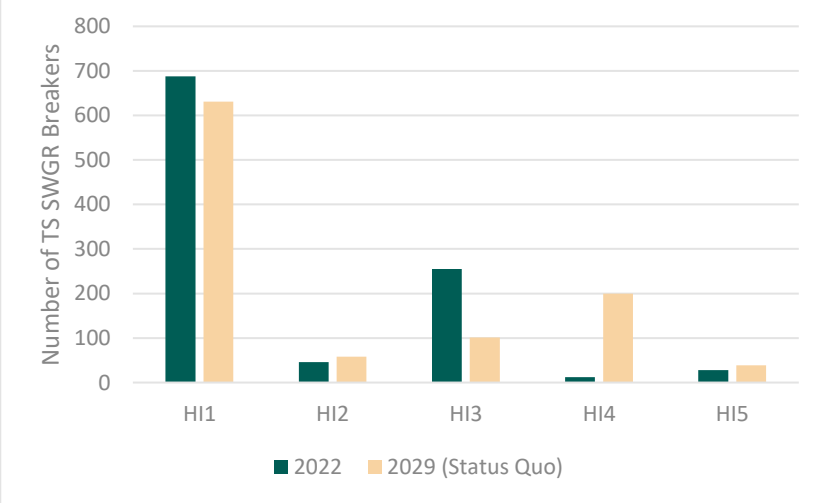


Figure 3: TS Switchgear Breaker Condition Aggregate as of 2022 and in 2029 Without Investment

Switchgear failure has a severe impact on distribution system operations. As one example, a recent failure of a switchgear breaker resulted in a power interruption for 13,152 customers and 10.5 MVA of the bus load. The average affected customer was without power for two hours and it took two and a half hours for the last customers' power to be restored following the failure. A photo of the failed breaker is shown in Figure 4 below. As shown in the photos, visual condition assessment may not always be effective because components are not accessible for the level of inspection required to detect measurable signs of impending failure. This is particularly true for some metalclad switchgears that require a complete switchgear outage to enable a thorough assessment of their condition, which is not possible without significant customer outages. The newer buses address this issue by allowing for efficient load transfers.



Figure 4: Failed Switchgear Air Blast breaker and damaged arcing contacts

Figure 5 below shows the number of bus outages due to failure of TS switchgear components over the last ten years. These include a breaker's failure to open on fault, a failed CT and a failed bus insulator. Investments in asset renewals to maintain TS switchgear components in healthy operational condition are essential for Toronto Hydro to provide its customers with reliable service.

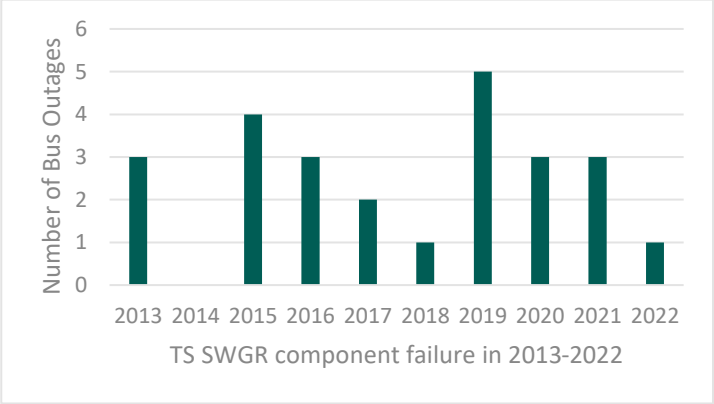


Figure 5: Bus outage caused due to SWGR component failure in 2013-2022

Toronto Hydro's average TS switchgear supplies 37 MVA of load – more than the failure case highlighted above – and its heaviest loaded unit serves 63 MVA of peak load. As shown in Figure 6 below, these assets primarily serve Toronto's downtown and adjacent areas, which include Toronto's financial district, entertainment district, university district, and some of the city's densest residential communities.

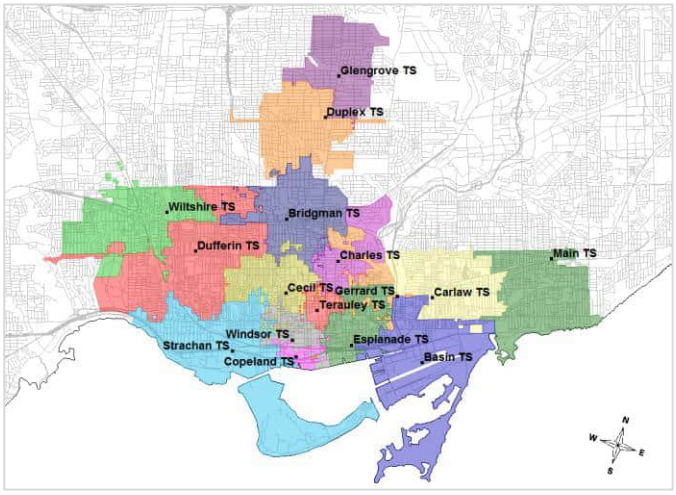


Figure 6: Location of TS containing Toronto Hydro-Owned Switchgear (excluding Cavanagh TS in North Scarborough)

Toronto Hydro proposes to replace the five TS switchgear units identified in Table 5 below during the 2025-2029 period. All of the units proposed for replacement are beyond their 50-year useful life expectancy and feature obsolete circuit breakers contained within non-arc-resistant enclosures. Condition assessments performed during breaker maintenance show that all of the breakers in the switchgear units proposed for replacement suffer from HI4-material deterioration. This is an older air blast type installed in the 1950s that is functionally obsolete. Breakers are used to determine the condition of a switchgear because they are the "moving parts" inside of switchgear and are indicative of a switchgear unit's overall health.

Table 5: TS Switchgear Proposed for Replacement

Station	ID	Enclosure	Breaker Type	2022 Condition Assessment (for Breakers)	Replacement Year
Danforth MS	*A1-2DA*	Brick	Air Blast	Material Deterioration	2029
Bridgman TS	*A7-8H*	Brick	Air blast	Material Deterioration	2029
Windsor TS	*A3-4WR*	Metalclad	Air blast	Material Deterioration	2029

Station	ID	Enclosure	Breaker Type	2022 Condition Assessment (for Breakers)	Replacement Year
Bridgman TS	*A1-2B*	Metalclad	Air blast	Material Deterioration	2029 (building renovation by Hydro One)

As shown in Table 6 below, with these replacements and investments, by the end of 2029 there will be a decrease in non-arc resistant switchgear units from 68 to 53 percent and a decrease in switchgear units with obsolete breakers from and 11 to 2 percent compared to 2024.

Table 6: Transformer Station Switchgear Demographics at End of 2029 with Investment

Switchgear Construction	# of Assets	% of Assets Past Useful Life	Other Demographic Information	
			% of Non-Arc Resistant Switchgear	% of Switchgear with Obsolete Breakers
Metalclad	48	35%	58%	2%
Brick Structure	0	0%	0%	0%
GIS	5	0%	0%	0%
Total	**53**	**32%**	**53%**	**2%**

Figure 7 below shows the volume of customers and quantity of load that will benefit from Toronto Hydro's proposed replacement plan.

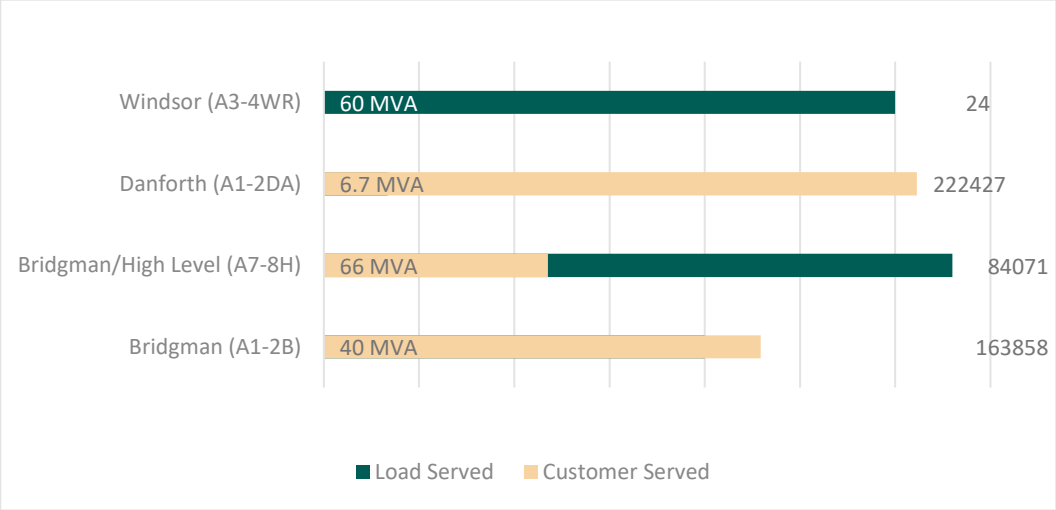


Figure 7: Customer Impact of Switchgear Failure - TS Switchgear Proposed for Replacement

2. TS Outdoor Breakers

As shown in Table 7 below, 13 percent of Toronto Hydro's TS outdoor circuit breakers will be operating past their 45-year useful life by the end of 2024. These breakers (i.e. the KSO oil circuit breakers) are based on obsolete technology and may contain degraded oil, which would increase the safety risk for crews, the risk of collateral damage to other assets, and the risk of environmental damage if a breaker failure occurs. As indicated in Table 7, 100 percent of Toronto Hydro's KSO oil-based circuit breakers will be past their useful life of 45 years by the end of 2024.

Table 7: TS Outdoor Breakers Demographics at the end of 2024

Outdoor Breaker Technology	# of Assets	% of Assets Past Useful Life
KSO Oil Circuit Breaker	12	100%
SF6 Circuit Breaker	24	0%
Vacuum Circuit Breaker	56	0%
Total	92	13%

Figure 8 below compares the condition of the utility's TS outdoor breakers as of 2022 with the condition of the breakers in 2029, in a scenario without investment.

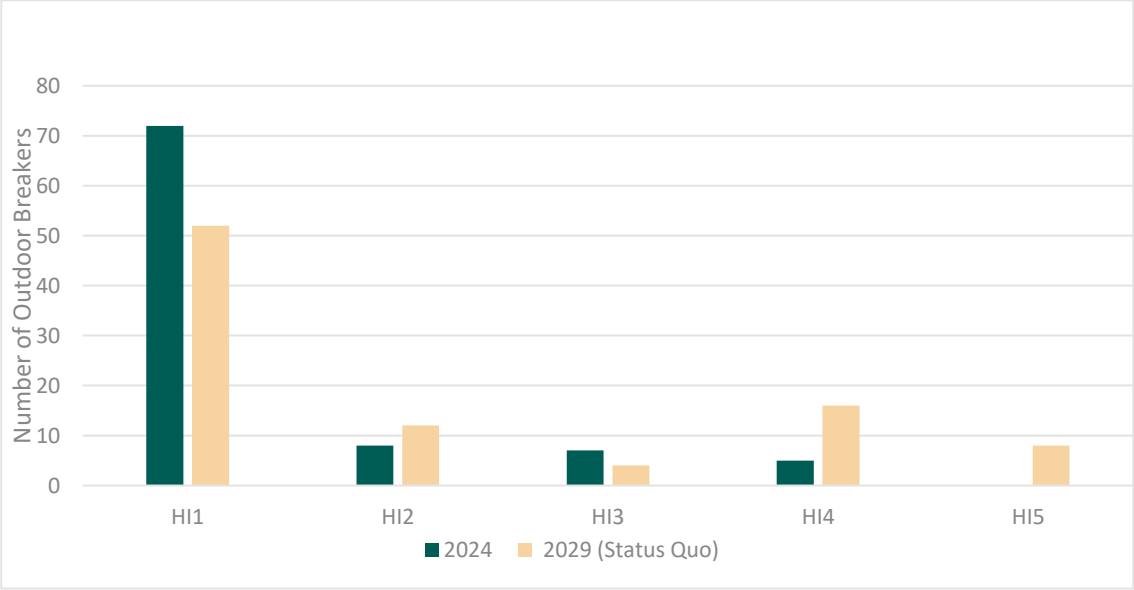


Figure 8: TS Outdoor Breaker Condition as of 2022 and in 2029 without Investment

As of the end of 2022,

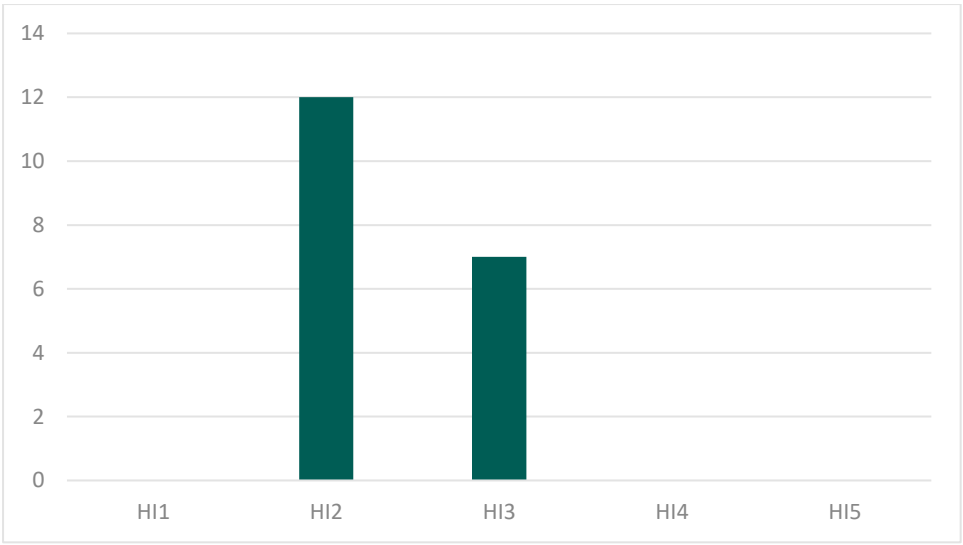


Figure 9 below illustrates the condition of these circuit breakers at the end of 2022 (including the units planned to be replaced in 2023 and 2024).

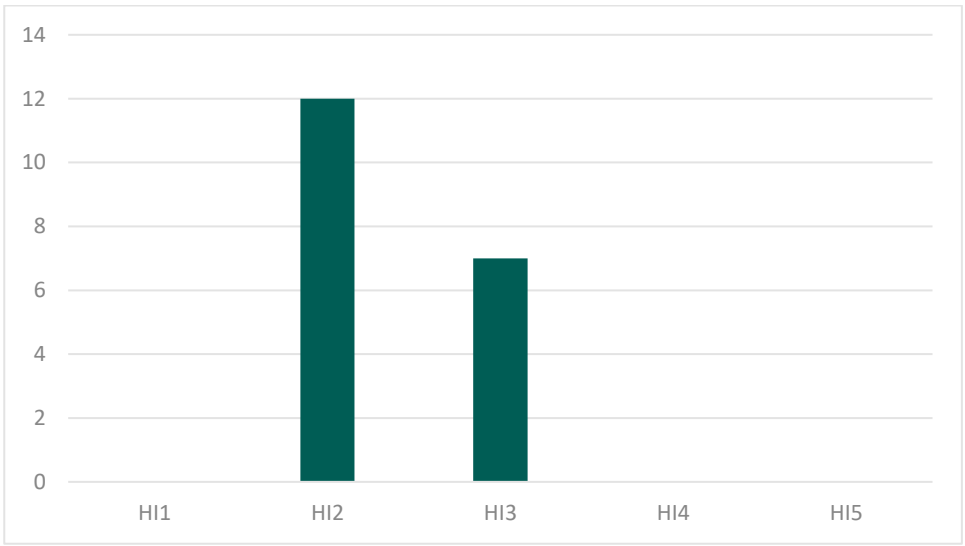


Figure 9: Condition Assessment for KSO Oil Circuit Breakers as of the end of 2022

Toronto Hydro plans to replace all the oil KSO breakers with vacuum breakers by the end of 2029. In order to minimize the outage time for each cell, the relays will be replaced together with the KSO breakers unless cell relays have already been reactively replaced prior.

These investments would enable Toronto Hydro to improve its ability to accommodate new customer connections, including renewable generation or energy storage systems. As such, this work will provide customers with increased reliability and flexibility and will eliminate some of the system's biggest safety and environmental risks.

The failure risk of KSO circuit breakers is high and the impact of failure is significant. When a breaker fails, thousands of customers will experience an outage that typically lasts one to two hours. Circuit breaker failure is most likely to occur when the breaker is triggered to operate. When a circuit breaker fails, the next upstream protection device at the station bus is then triggered to operate. A fault that was otherwise localized on a feeder would then extend to all of the customers supplied by that station bus, potentially disrupting anywhere from 1,000 to 10,000 customers depending on the bus.

Toronto Hydro experienced an outage of this nature when an outdoor breaker at Finch TS failed to open. The bus protection system was forced to operate, interrupting power to nearly 5,000 customers. Most customers were restored within three hours of the initial incident; however, all of those customers were supplied by feeders that would not have suffered an outage had the breaker operated as intended.

Beyond the outage impact to customers, KSO oil circuit breakers run the risk of failing catastrophically. In this situation, the circuit breaker explodes and sets fire to its oil, potentially damaging equipment, injuring personnel in the vicinity and impacting the surrounding environment. In addition to heightened safety risk, catastrophic failures also pose the risk of environmental damage due to oil leakage.

To mitigate the reliability and safety risks noted above, Toronto Hydro plans to replace the 12 TS outdoor breakers identified in Table 8 below during the 2025-2029 period. All of the breakers proposed for replacement are beyond their 45-year useful life expectancy and contain or are at risk of containing degraded oil. Toronto Hydro will prioritize the breakers presenting the highest failure risk for work during the 2025-2029 period.

Table 8: TS Outdoor Breakers Proposed for Replacement

Station	Breaker Type	Feeder	Load Served	Replacement Year
Bathurst TS	*KSO Oil Circuit Breaker*	85-M23	33 MVA	2025
Bathurst TS	*KSO Oil Circuit Breaker*	85-M32	32 MVA	2025

Leslie TS	*KSO Oil Circuit Breaker*	51-M22	16 MVA	2026
Leslie TS	*KSO Oil Circuit Breaker*	51-M29	24 MVA	2026
Leslie TS	*KSO Oil Circuit Breaker*	51-M30	20 MVA	2027
Leslie TS	*KSO Oil Circuit Breaker*	51-M32	17 MVA	2027
Finch TS	*KSO Oil Circuit Breaker*	55-M31	26 MVA	2028
Finch TS	*KSO Oil Circuit Breaker*	55-M32	25 MVA	2028
Fairchild TS	*KSO Oil Circuit Breaker*	80-M21	12 MVA	2028
Fairchild TS	*KSO Oil Circuit Breaker*	80-M22	13 MVA	2028
Fairchild TS	*KSO Oil Circuit Breaker*	80-M23	19 MVA	2029
Fairchild TS	*KSO Oil Circuit Breaker*	80-M24	18 MVA	2029

With the proposed plan and timeline shown in Table 8, below shows the overall state of all TS outdoor circuit breakers within Toronto Hydro's system along with their status in 2029.

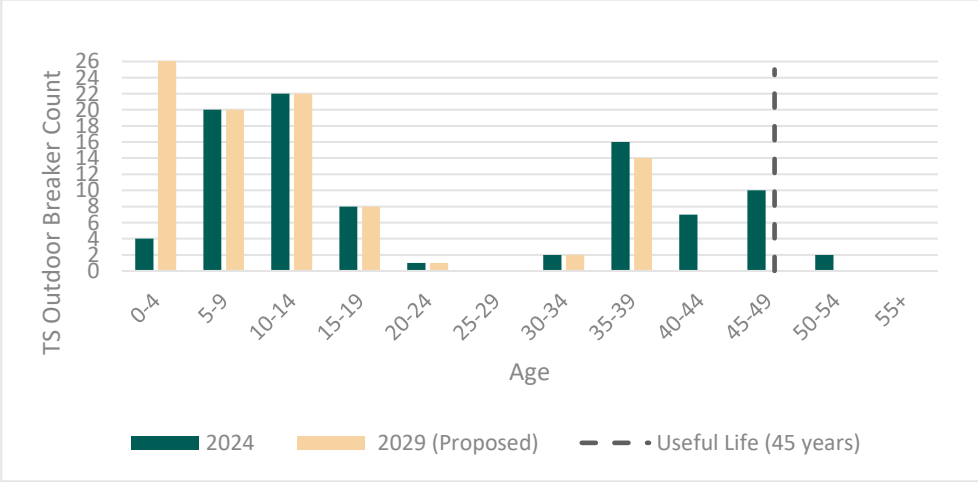


Figure 10: TS Outdoor Breaker Age Demographics at the end of 2024

As per Figure 11, these assets are located at stations serving customers located in the North York area. Once this work is complete, customers and loads connected to these four stations will face reduced risk of power disruptions resulting from breaker failure.

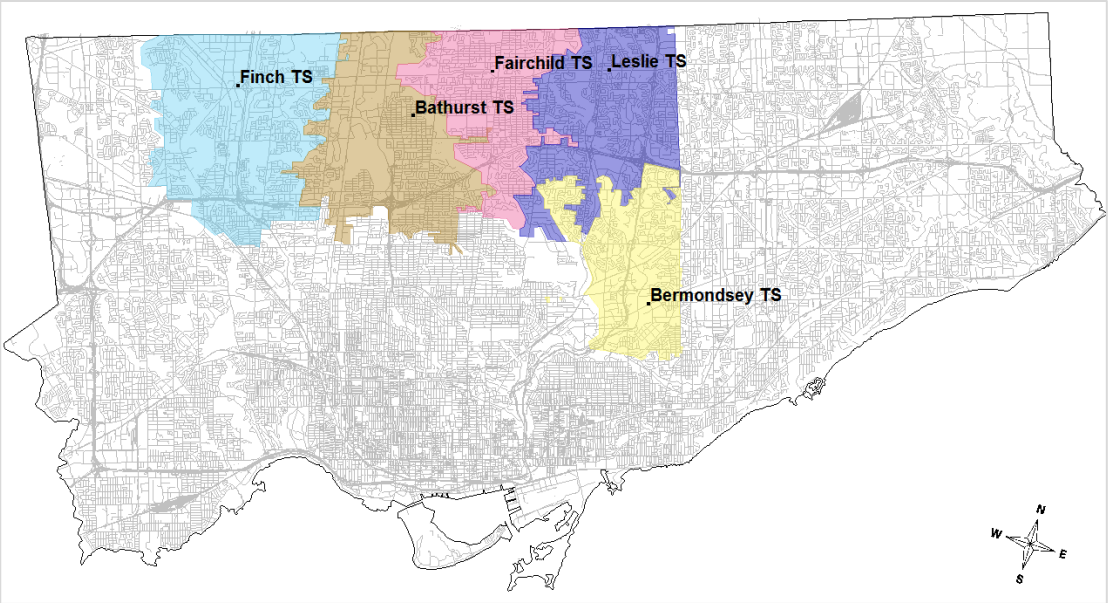


Figure 11: Toronto Hydro-owned TS containing outdoor circuit breakers.

3. TS Outdoor Switches

In addition to owning breakers at the five North York stations identified in Figure 11 above, Toronto Hydro also owns 230 TS outdoor switches located at the same stations. By the end of 2024, 7 percent of these TS outdoor switches will be operating beyond their 50-year useful life. The majority of them have never been replaced since their original switchgear or breaker installations.

Many of these switches have failed in recent years because of their age and deteriorated condition. Personnel have noted difficulty operating these switches, citing that in many cases, excessive force is required to close or open them. This risks damage to the switches and injuries to workers, as difficult to operate switches create safety issues like arc-flash.

Toronto Hydro does not have a Health Index for these switches. Switches are manual devices that either open or close when operated. Therefore, their condition is best captured by relying on visual assessment by Toronto Hydro field personnel and their experiences operating these switches. To increase the reliability of Toronto Hydro's grid system, Toronto Hydro plans to replace 63 TS outdoor switches during the 2025-2029 rate period as outlined in Table 9 below.

Table 9: TS Outdoor Switches Proposed for Replacement

Station	Feeder Tie Switch	Line Disconnect Switch	Total Switches	Replacement Year
Bathurst TS	2	4	6	2025
Bathurst TS	2	4	6	2026
Fairchild TS	3	6	9	2026
Fairchild TS	3	7	10	2027
Finch TS	5	11	16	2028
Leslie TS	5	11	16	2029
Total	**20**	**43**	**63**	

As shown in

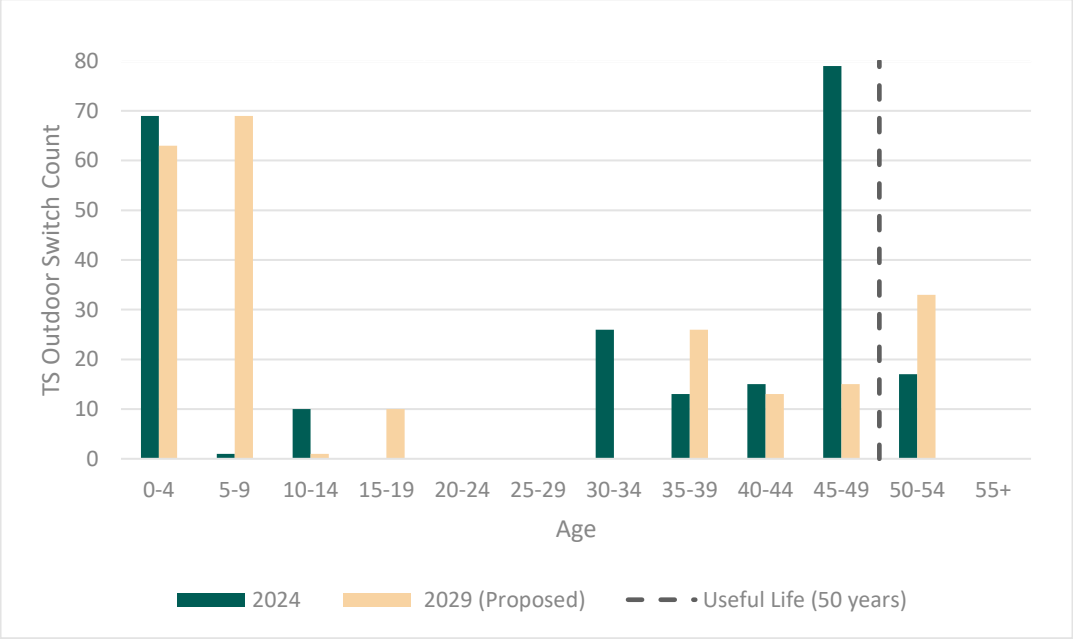


Figure 12 below, 17 of Toronto Hydro's TS outdoor switches will be operating beyond their 50-year useful life by the end of 2024. Without investment, an additional 79 switches will be operating past their useful life in 2029. Without action during the 2025-2029 rate period, 40 percent of Toronto Hydro's TS outdoor switches will be beyond or within five years of their useful life expectancy by 2029. In order to maintain the condition of its TS switches, Toronto Hydro plans to replace 63 TS outdoor switches. This will reduce the proportion of switches within or beyond their useful life from 40 percent to 20 percent by 2029.

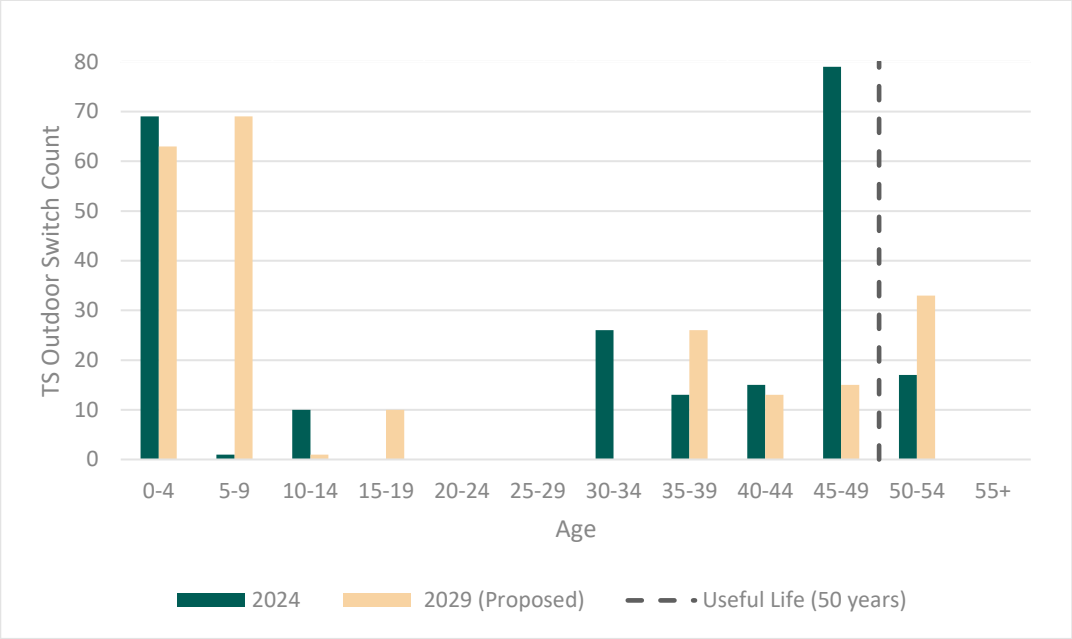


Figure 12: TS Outdoor Switch Age Demographics



Figure 13: Repair of TS Outdoor Switch

E6.6.3.2 Municipal Stations ("MS")

Toronto Hydro's MS supply power to Toronto's suburban areas consist largely of residential and a few small general service customers (<1 MW). Major MS assets include switchgear, power transformers, and MS primary supplies composed of disconnect switches and power cable. A large

portion of these assets are operating well beyond their useful life and are consequently at a heightened risk of failure. The investments proposed under this segment will maintain MS reliability by replacing deteriorated and obsolete assets at MS without upcoming voltage conversion plans.

A given MS supplies hundreds to thousands of customers. All connected customers experience a power outage if any of that MS major assets fail. A power supply must be switched to an adjacent MS in order to restore power to customers. This process typically takes half an hour to six hours. Following this restoration of power, the failed asset is repaired or replaced over a period of weeks or months.

Should an additional failure occur at an adjacent MS, then it is possible that during peak times brown outs (rotating outages) may be imposed on customers until one of the MSs is restored to service. This is because the MS distribution system is not designed to support a MS failure when its backup source is out of service.

For similar reasons, maintenance and renewal work at adjacent MS cannot be overlapped. As the population of MS assets get older without a proper renewal plan, the risk of having an MS failure when its backup source is not available becomes higher. Thus, asset renewal and maintenance plans become more difficult to execute while managing the risk of interrupting service to customers. Where possible, Toronto Hydro coordinates end-of-life asset replacements at a single MS during the same year, rather than having replacements and outages spread over multiple years.

1. MS Switchgear

The useful life of a MS Switchgear is 50 years. All of the MS switchgear targeted for replacement, listed in Table 10, will be between 58-65 years old at their time of replacement. None of them are arc-resistant and they are all equipped with technically obsolete circuit breakers which are no longer supported by manufacturers. One switchgear proposed for replacement utilizes oil circuit breakers, while the rest utilize air magnetic circuit breakers. As seen in Figure 14 below, almost half the population of the MS air magnetic circuit breakers is forecasted to progress to HI4-Material Deterioration by 2029 without investment. Operating these breakers in this condition increases failure risks, which can be mitigated with the proposed replacements.

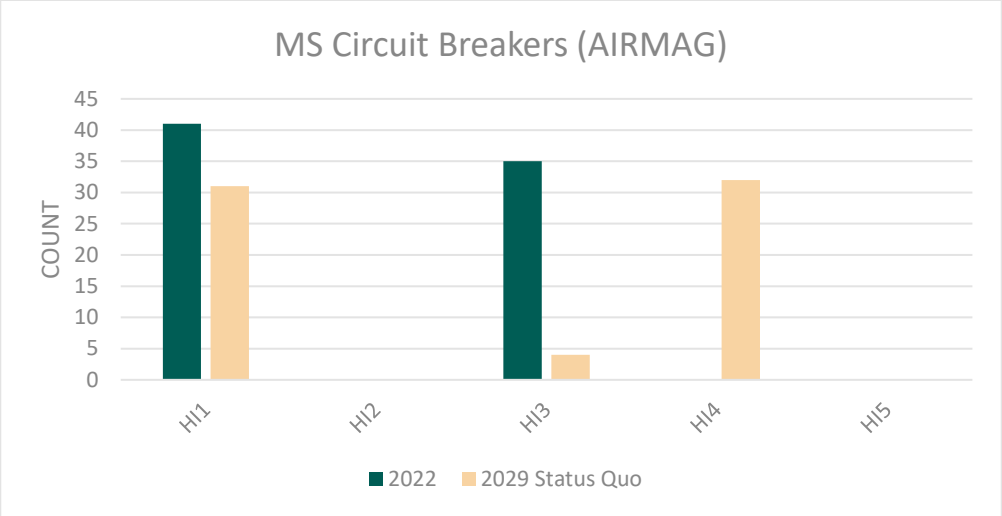


Figure 14: Condition of MS Air Mag Circuit Breakers as of 2022 and 2029 without investment

The switchgears proposed for replacement are functionally obsolete, and replacement parts are no longer available. This makes maintenance of the existing switchgear difficult and expensive, as replacement parts need to be custom made or scavenged from other switchgears. Replacement with new switchgears supported by current manufacturers will allow Toronto Hydro to more efficiently maintain the switchgear as individual components fail in the future.

The switchgears planned for replacement over the 2025-2029 period, shown in Table 10 below, are currently showing signs of deterioration and are anticipated to have circuit breakers with at least in HI4-Material Deterioration by 2029.

Table 10: MS Switchgear Proposed for Replacement

Station	Switchgear	Age at Replacement	Replacement Year
Elmhurst MS	T1SG	63	2025
Midland Lawrence MS	T1SG	61	2025
Hardwick MS	T1SG	65	2026
Windsor MS	T1SG	58	2026
Oberon MS	T1SG	61	2027
Palmwood MS	T1-T2SG	61	2027
Hunting Ridge MS	T1SG	61	2028
Renforth MS	T1SG	63	2028

Station	Switchgear	Age at Replacement	Replacement Year
Walney MS	T1-T2SG	61	2028
Belfield MS	T1-T2SG	65	2029
Braeburn MS	T1SG	61	2029
Centennial Darcy Magee MS	T1SG	58	2029

New switchgears will be arc-resistant and installed with vacuum circuit breakers, a low-maintenance and reliable model of circuit breakers. Each switchgear replacement will also involve the installation of a new SCADA (supervisory control and data acquisition) system at the station since the existing system has far surpassed its useful life and is highly integrated with the switchgear. As a result, MS switchgear renewal will also aid in Toronto Hydro's efforts to renew its fleet of RTUs, as discussed in Section E6.6.3.3 below.

Figure 15 shows the age profile of Toronto Hydro's MS switchgear in 2024 and 2029 under the proposed renewal and conversion plans (see the Area Conversions program, Overhead System Renewal, and Underground System Renewal - Horseshoe, which will remove a switchgear from service).[2]

The failure risk increases as the asset runs past its useful life. At a certain point (i.e. the target maximum age), that failure risk is deemed to be unacceptably high. The proposed renewal plan will result in no units that exceed 65 years (i.e. the new target maximum age) by 2029. Similarly, with the proposed renewal plan, the number of switchgears aged past useful life in 2029 will be similar to that at the end of 2024, and is broadly expected to maintain MS reliability. Figure 15 shows that the proposed plan results in nearly a flat age profile over ages 50-64 years. This will permit stable and executable pacing for the Segment over the next 20 years.

[2] Exhibit 2B, Section E6.1.

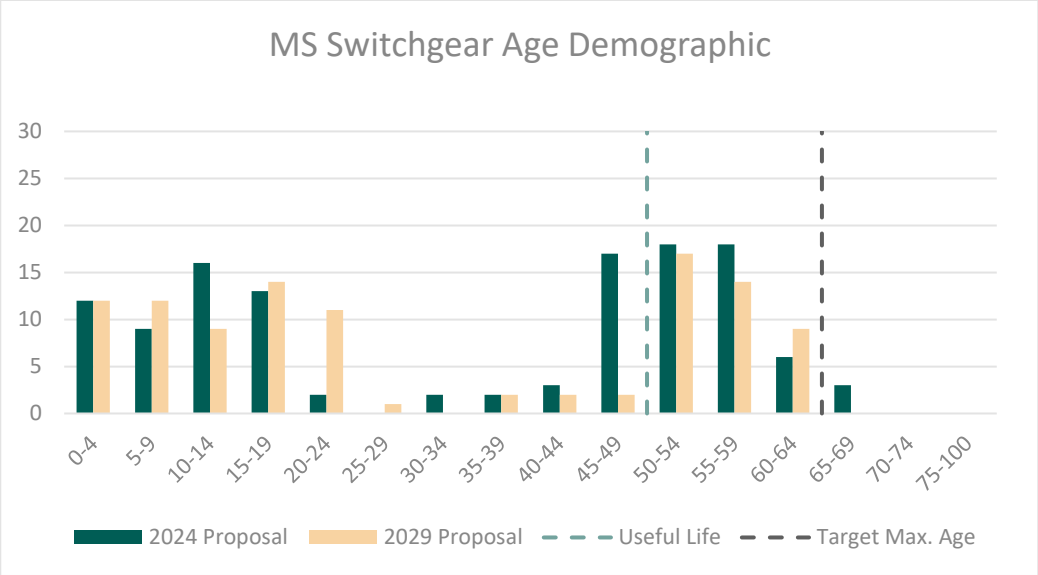


Figure 15: Age Profile of MS Switchgear

2. Power Transformers

The useful life of a power transformer is 45 years. If no investment is made to replace power transformers, there will be an increase in power transformers reaching conditions of material deterioration and end of serviceable life by 2029, as shown in Figure 16 below.

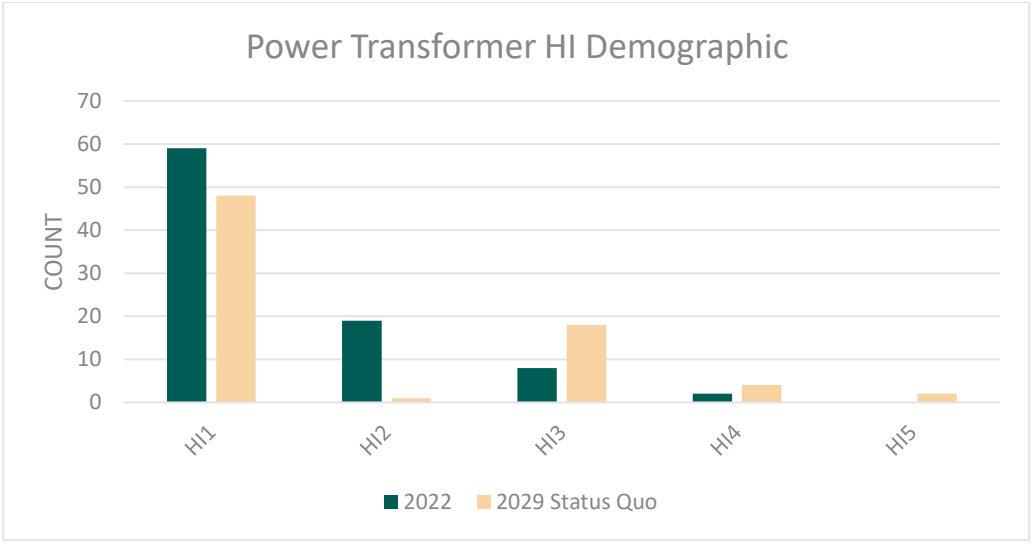


Figure 16: Power Transformer Asset Condition as of 2022 and in 2029 without investment

Over the 2017-2022 period, Toronto Hydro experienced an increased number of power transformer failures, shown in Figure 17. This increase in failures occurred despite decreasing numbers of units past useful life (45 years) as shown in Figure 17 and Figure 18.

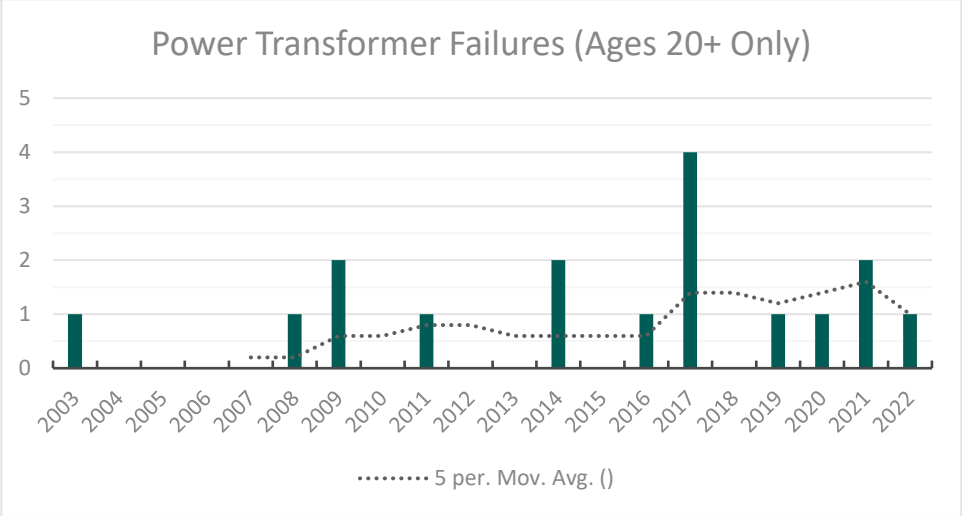


Figure 17: Count of Power Transformer Failures

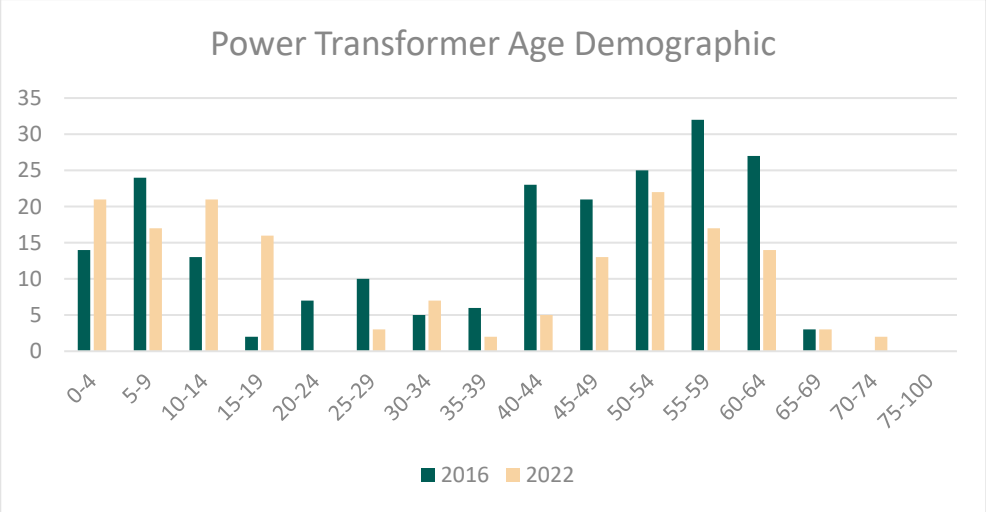


Figure 18 : Power Transformer Population Demographics in 2016 and 2022

To address this emerging trend, Toronto Hydro has taken two actions. First, Toronto Hydro has revised its target maximum age for its power transformers down from 70 to 65 years, in alignment with previous rate applications. The failure risk increases as the asset runs past its useful life. At a certain point (i.e. the target maximum age), that failure risk is deemed to be unacceptably high, as

was observed in the 2020-2024 rate period. If a MS major asset fails, then all connected customers (hundreds to thousands) will experience an outage where restoration would typically occur in half and hour to six hours. The subsequent repair or replacement of the failed asset occurs over a period of weeks or months. By adopting the new target maximum age, the utility intends to avoid reactive replacement. Second, Toronto Hydro is proposing to increase the pace of renewal over 2025-29 compared to 2020-2024, which is discussed in further detail in Section E6.6.4.2.

In addition to customer outages, power transformer failures can have significant safety and environmental impacts on an MS. Upon failure, the tank of the power transformer can rupture, result in oil fire, and even explode. Power transformers hold thousands of litres of oil, which upon failure can result in oil spills and fuel large fires.

All transformers targeted for replacement over 2025-2029, listed in Table 11, will be 54-66 years old at the time of replacement. This level of pacing is required to combat an increased failure rate and ensures the utility is not replacing an increased number of power transformers in the next rate application period. Units will be replaced with units of the same or lesser capacity, where possible, to minimize costs. For example, the failure of power transformers listed in Table 11 that are slightly past their useful life would impact a comparatively large proportion of customers. Planned renewal work is necessary because the reactive replacement of a failed unit takes three to six months to complete even with spare transformers on hand.

Table 11: Power Transformers Proposed for Replacement

Station	ID	Additional Concerns	Replacement Age	Replacement Year
Elmhurst MS	2491	• High power factor • Low insulation resistance	66	2025
Hartsdale MS	2403	• Very high power factor • Low insulation resistance	65	2025
Midland Huntingwood MS	2808	• High power factor & poor power factor sweep • Low insulation resistance	56	2025
Windsor MS	2472	• Questionable power factor • Low insulation resistance	62	2026
Canadine Midland MS	2778	• Low oil dielectric breakdown	60	2026
Palmdale Sheppard MS	2824	• Questionable power factor	53	2026
Oberon MS	2471	• Very high power factor	64	2027

Station	ID	Additional Concerns	Replacement Age	Replacement Year
		• Low insulation resistance		
Palmwood MS	2484	• DGA[3] indications of arcing • Questionable power factor	67	2027
Dunsany MS	2408	• N/A	67	2027
Hunting Ridge MS	2492	• Questionable power factor	64	2028
Sheppard Kennedy MS	2805	• Questionable power factor • Low oil dielectric breakdown • Low paper degree of polymerization	58	2028
Meteor MS	2505	• High power factor	59	2028
Braeburn MS	2442	• High power factor • Low insulation resistance • Poor winding resistances	64	2029
Centennial MS	2412	• N/A	66	2029
Belfield MS	2504	• N/A	60	2029

Figure 19 below shows the age profile of Toronto Hydro's power transformers at the end of 2024 and 2029 under the proposed replacement and conversion plans (see the Area Conversions, Underground System Renewal – Horseshoe, and Overhead System Renewal Programs), which will remove power transformers from service.[4] Toronto Hydro identified 17 power transformers which to be replaced over the 2025-2029 rate period due to their condition, age, and failure impact. Under the proposed replacement plan, noticeable decreases in the number of units past useful life will be maintained by 2029, and the number of units aged beyond the target maximum age of 65 will be nearly equal compared to 2024.

[3] Dissolved gas analysis ("DGA") is a test often used to identify previous and/or persistent thermal and/or electrical faults occurring within a power transformer.
[4] Exhibit 2B, Section E6.1; Exhibit 2B, Section E6.2; Exhibit 2B, Section E6.5

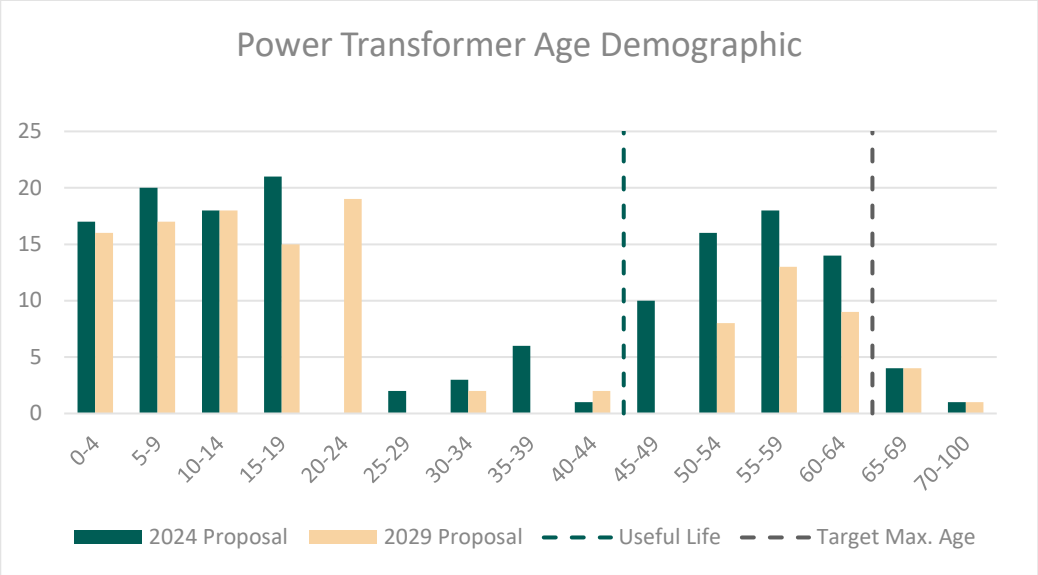


Figure 19: Age Profile of Power Transformers

Although newly installed power transformers contain no PCBs, a release of transformer insulating fluid must still be remediated and potentially reported according to the Environmental Protection Act.[5] To this end, Toronto Hydro will also install an oil containment system as part of its power transformer replacements. Toronto Hydro has been following this practice for all of its power transformer replacements since 2017. The oil containment system will prevent the release of oil into the environment should the power transformer develop an oil leak or tank rupture due to failure. Transformer replacements will also include the replacement of the transformer's primary supply, as Toronto Hydro has been doing for all of its power transformer replacements over 2020-2024.

By replacing the end-of-life power transformers targeted in this segment, Toronto Hydro will mitigate the risk of power transformer failure at its Municipal Stations, thereby maintaining the reliability of its MS.

3. MS Primary Supply

The MS primary supply, or station ingress, consists of all assets in the station between the distribution system and the primary side of the station transformer, including primary cable and a primary disconnect switch (or occasionally circuit breaker). These assets are used to supply the

[5] Environmental Protection Act, R.S.O. 1990, c. E.19. Article 92, 93.

station transformer with power, or to disconnect the transformer from its supply for maintenance or during a fault. It takes three months to reactively replace a failed primary supply.

Prior to 2019, power transformer replacements were typically completed without replacing their MS primary supply. As part of this segment, Toronto Hydro proposes to continue replacing the primary supply at MS where power transformers were previously replaced, but only where the primary cable is direct buried or in direct buried duct since this comprises the majority of the failure risk.

Over the 2025-2029 rate period, Toronto Hydro proposes to replace the primary supply at one MS as listed in Table 12. The proposed station was selected on the basis of failure risk as determined through the age and configuration of the primary supply assets.

Following this project, the remaining primary supplies in the system will be renewed with their power transformer as part of the scope of a power transformer renewal project, as has been done since 2019. This work will mitigate the risk of a primary supply failure.

Table 12: MS Primary Supplies Proposed for Replacement

Station	Age at Replacement	Replacement Year
Markham Pandora MS	63	2027

The useful life for a primary disconnect switch or a primary circuit breaker is 45 years. For non-lead primary cable, present at the proposed stations, the useful life typically ranges from 25-50 years, depending on the type of cable. All MS primary supplies will be past their useful life at the time of proposed replacement.

The existing primary disconnect switches are obsolete end-of-life assets. They can no longer be replaced like-for-like as they are non-standard and no longer manufactured. Primary disconnect switches will be replaced with a standard padmounted switch commonly used in Toronto Hydro's distribution system.

By replacing the end-of-life and obsolete MS primary supplies, Toronto Hydro will mitigate the failure risk these assets pose at its MS, thereby maintaining MS reliability.

E6.6.3.3 Control and Monitoring

Toronto Hydro uses control and monitoring systems at its TS and MS to protect its equipment, provide operators with system oversight, and allow for remote switching operations. Ultimately this

allows Toronto Hydro to reduce outage durations and provide customers with higher reliability. Major Control and Monitoring assets include RTUs and protection relays.

During the 2020-2024 rate period, Toronto Hydro prioritized and is on track to complete the installation of new RTUs at MS that did not have any monitoring systems. Toronto Hydro also prioritized and is on track to complete the Interstation Control Wiring upgrades from copper to fiber (which will result in the removal of that subsegment since it is no longer required). However, there are still copper communications remaining on the system between TS and customers which are planned to be addressed during the 2025-2029 rate period through Relay Renewals.

The 2020-2024 rate period also introduced the Pilot-Wire Protection renewals which has since been expanded to replace other higher risk protection relays such as URD distribution relays and transfer trip relays in the downtown Toronto region.

In addition, Toronto Hydro proposes to modernize its fleet of station relays as part of its Grid Modernization Roadmap.[6] Toronto Hydro will replace its obsolete electromechanical relays with modern digital relays, in order to improve its system observability to the levels needed to achieve an intelligent grid. Toronto Hydro's drivers for its Control and Monitoring assets are summarized in

[6] Exhibit 2B, Section D.5.

Table 13 below.

Table 13: Control and Monitoring

Subsegment	Description	Drivers and Failure Consequences
RTU Renewal	RTU Replacement	The main driver is the failure and risk of aging TS/MS RTUs with secondary driver of functional obsolescence since some RTUs have technology that the suppliers are either no longer in business, replacement parts are no longer available, or minimal support is available to the product from the manufacture. The consequence of an RTU failure is a loss of telemetry data and remote control operation at the station. The loss of remote control operation would increase outage durations for any potential outages that may occur.
Relay Renewal	TS/MS Relay Renewal	The main driver is the modernization of old electromechanical relays to digital relays. The benefit of upgrading the relays to digital is the ability to record events for historical view of issues, as well as better relay diagnostics, enhanced outage fault location, and enhanced protection system security.
	Transfer Trip Relay Renewal	The main driver the risk to replace aging electromechanical Transfer Trip protection systems as well as the copper communication cables used for larger customers. Toronto Hydro would look to replace these assets with digital relays and fiber communication cables respectively. Failure consequence of these systems is an outage to the large customer who rank reliability as their highest priority.
	Pilot-Wire Protection Renewal	The main driver is the risk to replace aging electromechanical pilot-wire protection systems as well as the copper communication cables used for larger downtown customers (including financial institutions, hospitals, telecom companies, sewage plants, etc.). Toronto Hydro would look to replace these assets with digital relays and fiber communication cables respectively. The consequence of these systems failing is an outage to large customer who rank reliability as their highest priority.

Control and Monitoring assets are common to both TS and MS and vary in size and complexity depending on the station and its geographical location. Systems located in downtown Toronto TS are treated with a higher priority than systems located in MS. However, systems in all stations are important because control centre operators rely on them to oversee, control, and protect the system. Modern operation of the electrical grid relies upon having real-time data and control available at the station level at all times.

1. RTU Renewal

As shown in Table 14 below, 29 percent of Toronto Hydro's RTUs are planned to be operating as obsolete RTUs or beyond their useful life of 22 years as of 2024.[7] Many of Toronto Hydro's RTUs are still built from early computer technologies. Computer technology has advanced considerably in the past 25 years making it difficult to find replacement parts that maintain backwards compatibility with what are now obsolete technologies (i.e. MOSCAD, DACSCAN, D20 ME, SEL 3332, SEL 2032).

Table 14 below shows the RTUs in various geographical areas, and the percentage of RTUs that are in-service beyond their useful life (as of the end of 2029 without investment). The number of obsolete RTUs drops to 18 percent due to a combination of planned MS Conversion, MS Switchgear Renewals, and Relay Renewals, all of which either remove the obsolete RTU or replace it.

Table 14: RTU Asset Demographic Plan

Region	Number of Assets	Obsolete / Past Useful Life 2024	Obsolete / Past Useful Life 2029 (Without investment)	% Obsolete / Past Useful Life 2024	% Obsolete / Past Useful Life 2029 (Without Investments)
Etobicoke	64	2	0	3%	0%
North York	22	11	3	50%	14%
Scarborough	37	14	12	38%	32%
Toronto	58	26	17	45%	29%
Total	**181**	**53**	**32**	**29%**	**18%**

Most of Toronto Hydro's D20 ME RTUs are younger than 22 years. However, some units have suffered premature failures over recent years. Moreover, modification to these units requires use of legacy computer operating systems which are no longer supported by the original RTU manufacturer. Similar to MOSCAD and DACSCAN RTUs, like-for-like replacement parts for legacy D20 RTUs are no longer available for purchase. To resolve these issues, Toronto Hydro proposes to replace these units with newer, non-legacy models which are currently supported.

Last, most of Toronto Hydro's SEL 2032s (MS) and SEL 3332 (TS) RTUs, similar to the D20 MEs, have been discontinued by the manufacturer. As a result, support is minimal and finding replacement

[7] An RTU has a useful life of 22 years as identified in the Kinectrics Report K418021 "Useful Life of Assets", August 28, 2009.

units is difficult since Toronto Hydro has to use spare parts if available from previously installed equipment at stations which no longer require their RTU from renewal or from decommissioning.

When an RTU fails, Toronto Hydro's control centre operators lose control and visibility of equipment at the station, leaving the system in a vulnerable state. If an RTU failure occurs at a critical station, field crews need to be dispatched to the station immediately to manually monitor equipment status and operate where required. This is necessary to ensure Toronto Hydro can adequately respond to outages and prevent equipment damage by ensuring the station operates within its limits. Combined with the difficulty of the repair work required, this makes a failure event operationally expensive and puts customers at risk of longer outages.

To mitigate RTU failure risk, Toronto Hydro plans to replace 33 RTUs in total (19 at the TS, 14 at the MS). With the exception of RTUs at stations with planned switchgear renewal or MS conversions, this plan will result in replacing all at risk RTUs.

2. Relay Renewal

Relay Renewal is a continuation and expansion of Toronto Hydro's Pilot-wire Protection Renewal work from the 2020-2024 rate application. Relay renewal over the 2025-2029 rate period will focus on four categories: TS Electromechanical to Digital Renewal; MS Electromechanical to Digital Renewal; Transfer Trip Relay with Copper Communications; and Pilot-Wire Relay with Copper Communications. The renewal of Toronto Hydro's relays is mainly driven by modernization, to allow for Toronto Hydro to monitor the system with higher accuracy, allowing fault recording, relay diagnostics, and better discrimination of and coordination with faults over a wider range of operational conditions. These benefits of digital relays will also help support Toronto Hydro's Grid Modernization Roadmap by improving Toronto Hydro's system observability and controllability.

While the renewal of Toronto Hydro's Relays is mainly driven by modernization for the majority of relays; the Pilot-Wire Protection Systems along with the Transfer Trip Relays are driven by failure risk due to their age, obsolete copper communications, and importance to the individual larger customers served by Toronto Hydro that require these assets for their distribution needs.

Table 15 below shows the categorization and amount of Relay types.

Table 15: Relay Type, Quantity, and Useful Life

Relay Type	Number of Assets	Obsolete / Past Useful Life 2024	Obsolete / Past Useful Life 2029 (Without Investments)	% Obsolete / Past Useful Life 2024	% Obsolete / Past Useful Life 2029 (Without Investment)
TS Relay	1063	419	407	39%	38%
MS Relay	724	371	221	51%	31%
Pilot Wire Relay	71	14	14	20%	20%
Transfer Trip Relay	33	7	7	21%	21%
Total	**1891**	**811**	**649**	**43%**	**34%**

The Transfer Trip Relay and Pilot-Wire Relay Renewals will focus on replacing the Relays along with the aging copper communication wires between the TS Relay to the Customer. This will both modernize the system while also mitigating failure risk of older copper wires. Toronto Hydro's planned switchgear replacements require circuit transfers with this protection system to the new switchgear. An upgrade to newer line protection technology is required since new switchgears cannot be made compatible with the obsolete pilot-wire protection relays.

The relay renewal program overlaps with TS/MS Switchgear Renewal as well as MS Conversions which would remove the need for the asset.

Table 15 above shows a reduction of the total relays obsolete/past useful life in 2024 to 2029 from 43 percent to 34 percent, which is mainly due to MS relays from MS switchgear renewal and MS Conversion plans.

Without a protection relay to isolate a feeder fault, the switchgear's bus differential protection would isolate the entire bus in the event of a fault. Consequently, events that should have been a single element failure, impacting a smaller set of customers, would become an entire TS switchgear outage affecting thousands of customers. In addition, defective electromechanical relays are very difficult to diagnose and most often Toronto Hydro discovers a faulty relay once it causes an issue like not tripping the breaker when it should or nuisance-tripping the breaker. New digital relays can avoid these issues since they have self-diagnostics which are part of the benefits and goals of Toronto Hydro to achieve an intelligent grid.

These improvements to replace electromechanical and copper-based relay protection systems with digital relays and fiber communications have the following benefits:

- Replacing obsolete assets allows Toronto Hydro to meet public policy outcomes, accommodate increasingly sophisticated customer needs (e.g. vehicle-to-grid, peak shaving, and distributed energy resources applications), operate its system more efficiently, and provide increased value to customers.
- Upgrading to digital relays will support the Grid Modernization Roadmap which requires both system observability (fault locating and system loading and condition) and system controllability (ability to easily control the grid and to make system "self-healing" in future).
- Better discrimination and coordination with faults over a wider range of operational conditions;
- New relays have self-diagnostics which simplifies troubleshooting and makes failures easier to predict;
- New relays have fault recording which can help diagnostics and more accurately find outage trends on a give feeder, bus, switchgear, etc.
- Less manual maintenance and testing since the new system has online monitoring and self-diagnostics; and
- As part of each project, copper lines are replaced with fiber. Toronto Hydro will have complete control of the fiber optic communication cables and not be reliant on a privately-owned third-party corporation (many copper cables are owned by Bell); therefore, a faster

response time can be provided by Toronto Hydro crews in the case of communication line failure.

Toronto Hydro plans to replace 100 TS and 130 MS Electromechanical Relays with Digital Relays. The plans from

Table 15 above, along with current planned Switchgear Renewal work and MS Conversions would replace a total of 497 Electromechanical Relays out of 700 (TS, MS, Pilot Wire, Transfer Trip combined). This would equate to having 21 percent of the system still with either electromechancial relays or relays past their typical useful life or obsolete by 2029.

Toronto Hydro also plans on renewing 7 Transfer Trip Relays and 14 Pilot-Wire Relays along with the Copper Communication Wires to be Fiber. This renewal plan would conclude upgrading the Transfer Trip Relays and Pilot-Wire Relays to Digital Relays as well as conclude the Copper Renewal plans.

E6.6.3.4 Battery and Ancillary Systems

As shown in Table 16 below, ten percent of Toronto Hydro's Battery and Ancillary Systems will be operating beyond their useful life in 2024. Depending on the asset, replacement is required due to poor condition, end of useful life, obsolescent technology, or a mixture of these factors. The Battery and Ancillary Systems segment proposes replacing these supporting systems as required to maintain station integrity and system reliability for Toronto Hydro customers.

Table 16: Battery and Ancillary Systems Demographics

Asset Type	Total # of Assets	Useful Life	Assets Beyond Useful Life (2024)	Assets Beyond Useful Life Without Program (2029)	Assets Beyond Useful Life with Program (2029)
Battery	148	10	18	69	14
Charger	148	20	11	20	16
Station Service Transformers	44	45	3	3	0
AC Panels	21	-	5	5	0
Air Compressors[8]	14	15	0	0	0
Total	**361**		**37**	**97**	**30**
Percentage			**10%**	**27%**	**8%**

In addition to the renewal of the assets included in the table above, Toronto Hydro has three TS with flood risk requiring mitigation, as detailed in sub-section 4 below. Furthermore, Toronto Hydro has also identified five stations that require new AC panels to mitigate the failure risk of those panels

[8] No work is planned for in 2025-2029 as no air compressor is beyond useful life. During 2020-2024 one Air Compressor was replaced reactively and the other station was sold to a third party.

with obsolete circuit breakers that have reached the end of their useful life. Sub-section will discuss the AC panel replacements in more detail.

1. Battery and Charger Renewal

A battery and charger system is installed at every TS and MS to provide DC power supply and backup for essential protection, control, and SCADA systems. Due to their critical function, station batteries and chargers must be maintained in reliable condition. These systems must be able to supply power for a minimum of eight hours after the loss of main AC power. As shown in Table 17 below, 11 percent of Toronto Hydro's MS batteries, 19 percent of Toronto Hydro's TS batteries, 9 percent of Toronto Hydro's MS charger systems and 0 percent of TS charger systems will be operating beyond their useful life in 2024.

Table 17: Battery and Charger Systems Demographics

Asset Type	Assets Beyond Useful Life (2024)	Assets Beyond Useful Life Without Program (2029)	Assets Beyond Useful Life with Program (2029)
MS Battery	11%	43%	11%
TS Battery	19%	62%	0%
MS Charger	9%	16%	13%
TS Charger Systems	0	4%	0%

Previously, Battery & Chargers were grouped together into a single category. However, batteries and chargers have different useful lives and replacement schedules and MS and TS unit costs differ by large margins. Toronto Hydro is now providing a breakdown into sub-parts as shown in Figure 17 above.

Battery and charger system renewal is required to mitigate failure risk. All station batteries have a useful life between 10-12 years (depending on the battery type). Batteries deteriorate to the point of failure as they age and a significant number of them are past or close to the end of their useful life. Charger Systems have a typical life of 20 years and once they exceed their useful lives, they are at risk of failing and jeopardizing the station's DC system.

Without replacement, failures are expected to increase resulting in reduced reliability for Toronto Hydro customers as well as significant equipment damage. When a battery or charger fails, its MS or

TS loses the source of DC power supply. This in turn renders all protection, control, Station RTUs, and other communication systems non-functional. Failure of protection and control systems is a major safety and reliability risk as the station would lose its ability to isolate faults, potentially resulting in a station outage. Otherwise, loss of functionality would affect the Control and Monitoring systems with similar failure impacts to those detailed in Section E6.6.3.3.

Therefore, there is a need to maintain the system reliability by ensuring fewer batteries and charger systems continue to operate beyond their useful life. Figure 20 below highlights the decrease in assets past their useful life by replacing the proposed 55 battery units thus minimizing reliability risks.

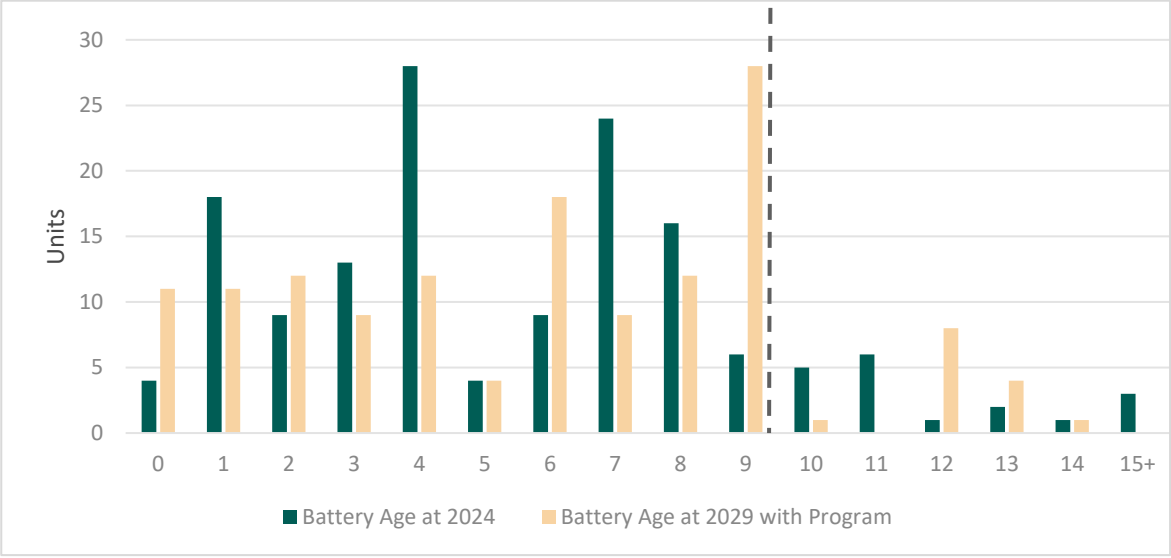


Figure 20: Age Profile of Station Batteries

As listed in Table 18 below, Toronto Hydro plans to replace 55 station batteries over the 2025-2029 rate period, which consist of 16 TS batteries, eight charger systems, and one TS charger. When replacing batteries and chargers, Toronto Hydro will also replace any end-of-life or obsolete DC panels and other smaller series components with similar failure impact.

Table 18: Battery & Charger Proposed Replacement Plan

Year of Replacement	Downtown Replacements	North York Replacements	Scarborough Replacements	Etobicoke Replacements	Total
2025	6	0	5	2	**13**
2026	3	0	4	4	**11**
2027	4	0	3	7	**14**

2028	3	0	5	5	**13**
2029	3	2	4	3	**12**
Total	**19**	**2**	**21**	**21**	**63**

2. Ancillary Renewal

Several ancillary systems require replacement or installation to maintain the integrity of Toronto Hydro's station infrastructure. Toronto Hydro's most pressing risks and needs for these ancillary assets are summarized in Table 19 below.

Table 19: Other Ancillary Systems - Drivers

Asset Group	Asset Class	Drivers and Failure Consequences
Ancillary Systems	*Sump Pumps*	The main driver for this segment is the failure risk of station assets due to flooding. The stations selected for sump pump installation have major equipment installed in the basement (e.g. switchgear, station services etc.) that is at risk in case of water infiltration. Lack of sump pumps can lead to a water build-up which could eventually short-circuit and damage equipment.
	Station Service Transformer (SST)	A station service transformer ("SST") supplies a station with AC power for use in the station's heating, cooling, lighting, ancillary equipment, and DC charging systems. Therefore, an SST failure has a similar impact as a charger failure. Due to this significant failure impact, Toronto Hydro installs two SSTs at its downtown TS. SST replacement projects will only target SSTs supplying these TS. SST renewal is required to mitigate failure risks associated with their age. In addition to the loss of critical systems identified above, a failure of an oil-containing SST has a risk of causing a fire or explosion. Most SSTs are located in close proximity to other critical station assets and pose risk of collateral damage. Therefore, SST replacements will mitigate this safety and environmental risk.
	AC Panels	All the stations loads such as heating, cooling, lighting, ancillary equipment, and DC charging systems are supplied from AC Panels. Unlike SSTs there is no back up for AC panels, therefore, an AC Panel failure has a more severe impact compared to both SST and DC charger failure. The main driver of replacing AC panel is failure risk of obsolete

Asset Group	Asset Class	Drivers and Failure Consequences
		and end-of-life assets. The 5 proposed AC panels are the oldest in the system, which are all more than 50 years old.

AC Panels have the largest failure impact among all battery and ancillary equipment. When an AC panel fails, the SST cannot supply AC power to any of the station loads such as station's heating, cooling, lighting, ancillary equipment, and DC charging systems. Also, no back up AC supply can be brought in. Therefore, the station will have no AC power and only eight hours of DC supply until the AC panel is replaced. During this time, DC supply can be maintained by bringing in a diesel generator and connecting it to the battery charger in order to avoid loss of DC supply for the critical systems. AC panel replacement could take anywhere between a few weeks to few months as the lead times are unknown.

To mitigate the risks identified above, Toronto Hydro plans to replace three sump pumps at the stations identified in the table below.

Table 20: Proposed Sump Pump Replacements

Station	Replacement Year
Glengrove	2025
Wiltshire	2028
Danforth	2029

Toronto Hydro owns 44 SSTs which supply its downtown TS. Three SSTs, equivalent to 7 percent of total SSTs, will be past useful life by 2024, as summarized in Table 21. Other than the three SSTs mentioned, no other SST will reach their useful life during the 2025-2029 rate period. Based on the risk level and relatively low cost of SST replacements, investments will be made to avoid having any of these assets past useful life.

Table 21: Station Service Transformer Demographics

Asset Type	Assets Beyond Useful Life Current State (2024)	Assets Beyond Useful Life Without Program (2029)	Assets with PCB >2ppm
Stations Service Transformers	7%	7%	0

There were originally two SSTs which were assumed to have PCBs (Charles TS, Dufferin TS), both of which have been replaced during 2020-2024 rate period. As shown in Figure 21, all of the targeted SSTs will exceed their typical useful life of 45 years by 2024.[9] Without action during the 2025-2029 rate period, 7 percent of these SSTs will be operating beyond their useful life by 2029.

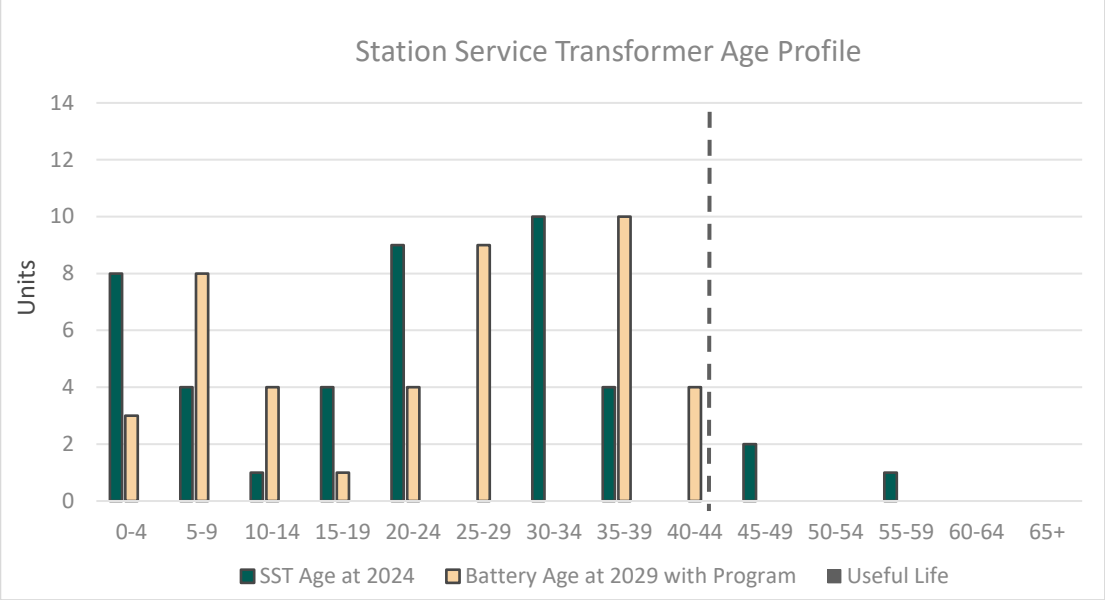


Figure 21 : Age Profile of Station Service Transformers

As listed in Table 22 below, Toronto Hydro plans to replace one SST at each of the three TS during the 2025-2029 rate period. This will significantly mitigate the risk of coincident SST failures at these TS, and in turn will mitigate customer outage risk.

Table 22: Proposed SST Replacements

Station	Asset	Replacement Year
Carlaw	*SST1*	2025
Basin	*SST1*	2026
Charles	*SST2*	2028

Toronto Hydro owns 21 AC Panels in both Downtown and Horseshoe TS. Of these Toronto Hydro plans to replace five AC panels over the 2025-2029 rate period as shown in the table below

[9] An SST has a useful life of 45 years as identified in the Kinectrics Report K418021 "Useful Life of Assets", Aug. 28, 2009.

Table 23 : Proposed AC Panels replacements

Station	Replacement Year
Carlaw	2025
Dufferin	2026
Duplex	2027
Charles	2028
Cecil	2029

E6.6.4 Expenditure Plan

Table 24 provides the Historical (2020-2022), Bridge (2023-2024) and Forecast (2025-2029) expenditures for the Stations Renewal Program. The Program has been organized in 2025-2029 based on the type of system addressed, work required, and driver of the work.

Table 24: Historical & Forecast Program Costs ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Stations TS	12.0	16.7	18.8	18.8	28.8	31.1	31.1	30.0	25.0	16.8
Stations MS	11.5	12.4	2.4	3.9	14.3	10.2	11.3	13.4	17.0	18.4
Stations Control & Monitoring	4.7	3.1	5.1	6.5	8.8	11.9	12.1	13.5	13.1	14.2
Stations Ancillary and Battery	1.9	1.2	1.1	2.2	0.8	3.2	2.2	1.9	3.4	2.9
Total	**30.2**	**33.6**	**27.4**	**31.4**	**52.8**	**56.4**	**56.7**	**58.8**	**58.6**	**52.3**

Spending in the Stations Renewal Program over the 2025-2029 rate period is forecasted to be $282.8 million. This is higher than the $174.7 million forecast in the 2020-2024 Distribution System Plan ("DSP") due to higher than expected project complexity, incremental increases to project scope across multiple projects, and higher than expected inflation costs. However, Toronto Hydro expects to largely complete the projects it had proposed in the 2020-2024 DSP, with the exception of the TS switchgear projects, which have experienced a number of delays.

Complexities involved in the Transformer Stations segment contributing to increased costs include the procurement of unique TS switchgear which meet Toronto Hydro's stringent safety and reliability requirements. As for the Municipal Stations segment, project scope has expanded to include a larger

scope of station civil and building refurbishment to support electrical asset renewals, which has also driven unit costs upwards.

For the 2025-2029 rate period, Toronto Hydro proposes to invest $282.8 million, which is a substantial increase compared to the 2020-2024 rate period. This increase is approximately equally split between an increased work volume, and forecasted inflation. Across all segments, an increased work volume is needed relative to the 2020-2024 rate period to maintain station asset demographics. Toronto Hydro utilizes these demographics to set pacing for the 2025-2029 rate period and then, individual projects are then selected based off an overall assessment of risk (See Tables 29, 32, and 35). As discussed in Section E6.6.3, station assets are critical with large failure impacts and have lengthy replacement times. Maintaining station asset demographics is the best strategy to prevent their high failure impact and, in turn, maintain system reliability.

Another substantial increase in work volume is being introduced under the Control and Monitoring segment, where Toronto Hydro's proposes to replace all of its obsolete station electromechanical relays with modern digital relays by 2034.[10] This pacing is proposed to prepare Toronto Hydro's distribution system for modernization, support increasingly sophisticated customer needs, and provide increased customer value through better control and operability.

Work in the Stations Renewal Program is prioritized at three different levels. First, TS work is prioritized above MS work, since TS supply customers of all classes and serve more customers than MS. Therefore, the TS segment as a whole and the portions of the Control and Monitoring and Battery and Ancillary Systems relevant to TS are given the highest priority. Second, the work inside each segment is prioritized differently depending on the specific failure outcomes and risks associated with each asset class. Finally, with respect to each asset class, work is prioritized using a variety of data and considerations including age, condition, obsolescence, customers served, load served, and maintenance effort.

E6.6.4.1 TS Segment Expenditure Plan

As shown in Table 25, Toronto Hydro expects to spend $95.2 million over the 2020-2024 rate period in its Transformer Stations segment. This is $20.7 million higher than the 2020-2024 Distribution System Plan forecast of $74.5 million. Toronto Hydro forecasts that it will complete an additional

[10] Relays which are part of switchgear which have a switchgear replacement planned within 22 years of 2034 are excluded. Otherwise, the newly replaced relays will be replaced again with the switchgear before the useful life of the relays has been reached. The useful life of a digital relay is 22.5 years.

three outdoor breakers and eight outdoor switches in the 2020-2024 rate period than was previously forecasted. The increase is mainly attributed to procurement challenges resulting in increased unit costs. A variance analysis for each subsegment is provided in the following subsections.

Table 25: TS Historical & Forecast Segment Costs ($ Millions)

Expenditures	Actuals			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
TS Switchgear	8.4	15.8	15.6	14.7	27.3	28.9	27.8	27.2	19.8	12.9
TS Outdoor Breakers	1.7	0.8	2.1	1.6	0.7	1.4	1.5	1.5	3.1	1.6
TS Outdoor Switch	1.8	0.1	1.2	2.4	0.8	0.7	1.9	1.3	2.1	2.2
Total	**12.0**	**16.8**	**18.8**	**18.8**	**28.8**	**31.1**	**31.1**	**30.0**	**25.0**	**16.8**

For the 2025-2029 rate period, Toronto Hydro proposes to spend $134 million in the TS segment, completing seven switchgear, 12 outdoor KSO breakers and 63 outdoor switches. As with the 2020-2024 rate application, the majority of the 2025-2029 spending is planned for TS switchgear renewal. The remainder is for the replacement of TS outdoor breakers and TS outdoor switches.

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete two new TS switchgear projects, complete partial work on four new TS switchgear projects, and has completed one carry-over project from the 2015-2019 rate period. The total cost of this work over 2020-2024 is $81.9 million. The 2020-2024 Filed Plan proposed replacing KSO breaker replacement projects for a total cost of $4.0 million, and therefore expenditures are forecasted to be overspent by $2.95 million while unit volume is forecasted to be three units above target. Due to the deferral of the Finch BY bus upgrade from Hydro One in 2020, the Toronto Hydro breaker replacement was deferred as well. In order to continue improving our grid system, five KSO breakers and 18 associated switches that were in poor condition on the BY bus was replaced instead at Finch TS. As a result, all the proposed work from the previous rate application period was completed with five additional units, but at a higher cost than proposed. Table 26 provides the forecasted spending for each project over the 2020-2024 period.

Table 26: 2020-2024 TS Switchgear – Forecast Costs and Completion Year ($ Millions)

Switchgear Unit	Forecasted 2020-24 Costs	Planned Completion	Carry Over From 2015-2019
Strachan A7-8T	1.9	2021	Yes
Carlaw TS A4-5E	12.3	2023	No
Strachan TS A5-6T	18.8	2023	No
Bridgman TS A1-2H	18.8	2025	No
Duplex TS A1-2DX	7.6	2027	No

Switchgear Unit	Forecasted 2020-24 Costs	Planned Completion	Carry Over From 2015-2019
Windsor TS A5-6WR	8.0	2027	No
Wiltshire TS A5-6WA	14.4	2026	No
Total	**81.9**		

Since TS switchgear projects span multiple years and rate periods, a discussion of project cost better informs the magnitude of the subsegment spend increase. Table 27 below summarizes the project cost variances and major sources.

Table 27: TS Switchgear for the 2020-2024 Period

Switchgear Unit	Total Project Cost		Project Completion		Major Sources of Variances
	Filed Plan	Current Forecast	2020-24 Filed Plan	Current Forecast	
Carlaw TS A4-5E	11.0	12.3	2022	2023	• Switchgear procurement • Load transfer • Metering
Strachan TS A5-6T	14.3	18.8	2023	2023	• Switchgear procurement • Site preparation (Duct banks)
Bridgman TS A1-2H	14.7	18.8	2024	2025	• Switchgear procurement • DC System Upgrade
Duplex TS A1-2DX	10.2	7.6	2023	2027	• Switchgear procurement • Site preparation (RTU relocation)
Windsor TS A5-6WR	18.4	8.0	2024	2027	• Switchgear procurement • Contingency reinforcement
Wiltshire TS A5-6W	-	14.4	-	2026	• New project addition to the 2020-24 period
Strachan TS A7-8T	-	3.5	-	2021	• 2015-2019 Carry-over project

Over 2020-2023, Toronto Hydro has experienced unexpected challenges selecting and procuring TS switchgears that meets the utility's needs in the space-constrained downtown Toronto. First, the procurement challenges affected all projects throughout 2020-2024, increasing the project cost and delaying the proposed schedule from the previous rate application. Additionally, Toronto Hydro's switchgear supplier discontinued its production of and support for TS switchgear that met the utility's space requirements in 2022. To mitigate supply risks, Toronto Hydro has started to reach out

to new manufacturers in efforts to resolve these challenges for the 2025-2029 rate period. The additional time spent on sourcing supplier also caused the schedule delay of switchgear replacement. Preliminary cost estimates show that a 30-50 percent increase for switchgear units is expected.

The two notable projects, Duplex A1-2DX and Windsor A5-6WR, will require additional time for the switchgear procurement, delaying both projects from the previous projected completion date. Toronto Hydro will continue with sourcing suppliers to prevent the future projects from experiencing similar challenges moving forward.

Furthermore, TS switchgear replacement has accrued more costs than prior years due to site conditions. Referencing previous projects, site preparations required additional work to relocate major assets such as more complicated civil work, RTU cabinets and station service transformers in order to facilitate the installation of the new switchgears.

1. TS Switchgear – 2025-2029 Expenditure Plan

Over the 2025-29 period, Toronto Hydro will complete four TS switchgear projects started in the 2020-2024 rate period, complete three new TS switchgear projects, and complete one new building project as advanced site preparations.[11] This presents a minor increase in the number of switchgear replacements under construction over the rate period, relative to the previous rate period. Table 28 below provides the annual spend for each project over the 2025-2029 rate period.

Table 28: 2025-2029 TS Switchgear – Forecast Expenditures ($ Millions)

Switchgear Unit	Cost	Completion Year	Carry Over from 2020-2024
Bridgman TS A1-2H	5.6	2025	Yes
Duplex TS A1-2DX	15.5	2027	Yes
Windsor TS A5-6WR	16.2	2027	Yes
Wiltshire TS A5-6WA	6.4	2026	Yes
Danforth MS A1-2DA	16.1	2029	No
Bridgman TS A7-8H	21.9	2029	No
Windsor TS A3-4WR	21.7	2029	No
Bridgman TS A1-2B – Hydro One Building renovation	13.3	2029	No

[11] These building projects are estimated to have lead times of approximately 5 years, and are needed before select TS switchgear projects planned for 2030-2034 can begin.

Switchgear Unit	Cost	Completion Year	Carry Over from 2020-2024
Total	**117.0**		

Toronto Hydro has further mitigated risks to achieving its 2025-2029 replacement plan by proposing five TS switchgear replacements over the 2025-2029 rate period. One switchgear replacement is building preparation only. This is the renovation of the Hydro One building for Bridgman due to lack of space for new switchgear installation in the existing TS. The four carry over units are Bridgman A1-2H, Duplex A1-2DX, Windsor A5-6WR and Wiltshire A5-6WA. It is forecasted that $43.6 million will be required to complete the work, which includes the expenditures made in 2020-2024. Three units - Danforth A1-2DA, Bridgman A7-8H, and Windsor A3-4WR - will start work within the 2025-2029 rate period, at a forecast spending of $59.8 million, which is required to complete the projects within the 2025-2029 rate period. One unit that will start its initial site preparations over the 2025-2029 rate period, Bridgman A1-2B, is forecasted to cost $13.3 million and will carry over to the 2030-2034 period. By completing this plan, Toronto Hydro will maintain the number of TS switchgear operating beyond their useful life around the current level, which is approximately 32 percent.

This work plan is attainable (and necessary to manage the aging and deteriorating TS switchgear population) in light of the change in circumstances and preparations made during the 2020-2024 rate period. For example, allocating more resources to coordinate with different switchgear suppliers in 2020-2024 will allow switchgear replacements to proceed smoothly during construction. Other projects, largely being carry-overs, have known execution risks and challenges that have been addressed over the 2025-2029 rate period. To plan for TS switchgear replacements for 2025-2029, a feasibility study of six selected switchgears were performed to provide an outline and summary of the project to budget and schedule, and also mitigate the risk of replacement. Currently, four of the six reports have been completed. The remaining feasibility studies will look into each TS on its own regarding specific issues and forecast issues field staff may experience during execution and provide solutions and projected funding to plan for switchgear renewal projects.

Toronto Hydro believes that accepting the increased risk, specifically the risk of continuing to operate these units beyond their useful life, is prudent and necessary in the context of its overall TS Switchgear replacement needs, priorities, and ability. With continued maintenance and monitoring, Toronto Hydro will mitigate failure risk until the units can be replaced.

Toronto Hydro prioritizes the replacement of its TS switchgear in order of the failure risk presented by each switchgear. The failure risk is assessed qualitatively by considering the following factors.

Table 29: TS Switchgear Prioritization

Factor	Prioritization
Age	Older switchgear are given higher priority
Enclosure Construction	Brick constructed switchgear is given higher priority
Condition Assessment	Switchgear receiving worse condition assessments (including breaker condition assessments) are given higher priority
Type of circuit breaker	Priority given in order of: 1) Obsolete non-oil air blast circuit breaker 2) Obsolete asbestos-based air magnetic circuit breaker 3) Current SF_6 circuit breakers 4) Current vacuum circuit breakers
Load	Switchgear supplying larger quantities of load are given higher priority
Protection and Control	Switchgear with obsolete protection and control systems are given higher priority.
Arc Flash Rating	Switchgear with lower arc flash protection ratings are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority

Age and condition assessment are used to gauge the probability of a switchgear failure and when an asset has reached end-of life. Type of circuit breakers, enclosure construction and arc flash rating help determine which of the old standards switchgears that requires renewal. Load and protection and control are used to gauge the impact of the switchgear failure and priority of the replacement.

TS outdoor breakers and switches are located in different stations than TS outdoor breakers and switches, TS switchgear units have longer replacement and lead times and more complex design and construction, and require more capital investment. For these reasons, TS switchgear are prioritized above the other assets in the TS segment, and in the Stations Renewal Program overall.

2. TS Outdoor Breaker – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro expects to spend $6.95 million to replace twelve outdoor KSO breakers at Fairchild TS, Leslie TS, Finch TS, and Bathurst TS. Table 30 below provides an annual breakdown of the forecasted expenditures and the units completed over the 2020-2024.

Table 30: TS Outdoor Breakers - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-2024
Units (Breakers)	2	0	3	5	2	12
Expenditures ($M)	1.7	0.84	2.1	1.6	0.68	7.0

The 2020-2024 Filed Plan proposed replacing KSO breaker replacement projects for a total cost of $4.0 million, and therefore expenditures are forecasted to be overspent by $2.95 million while unit volume is forecasted to be three units above target. Due to the deferral of the Finch BY bus upgrade from Hydro One in 2020, the Toronto Hydro breaker replacement was deferred as well. In order to continue improving our grid system, five KSO breakers and 18 associated switches that were in poor condition on the BY bus was replaced instead at Finch TS. As a result, all the proposed work from the previous rate application period was completed with five additional units, but at a higher cost than proposed.

The 2020-2024 Filed Plan estimated unit cost per breaker replacement at roughly $0.44 million, totalling $4 million for nine units. As a result, the forecasted unit cost over 2020-2024 has increased to $0.6 million above the unit cost for 12 units provided in the 2020-2024 Distribution System Plan of $0.44 million per breaker. The main sources for unit cost increases are: additional work for implementation of Hydro One requirement for demarcation concept, the complex protection scheme for key account customers and material inflation throughout the 2020-2024 rate period.

3. TS Outdoor Breaker – 2025-2029 Expenditure Plan

For the 2025-2029 period, Toronto Hydro proposes to replace 12 KSO breakers, which is the same amount as the previous period. The forecasted cost to complete this work is $9.08 million. Table 31 below provides the annual breakdown of the forecasted expenditures and unit completed over the 2025-2029 rate period.

Table 31: 2025-2029 TS Outdoor Breaker – Forecast Expenditures ($ Millions)

	Actual			Bridge		Total
	2025	2026	2027	2028	2029	2025-2029
Units (Breakers)	2	2	2	4	2	12
Expenditures ($M)	1.4	1.5	1.5	3.1	1.6	9.1

As mentioned in Section E6.6.3.1, the oil-based TS outdoor breakers within Toronto Hydro's system are past useful life and will be replaced with vacuum breakers. All of the 12 KSO breakers proposed for replacement contain oil and are operating beyond their useful life, and need to be replaced as detailed in Sub-Section TS Outdoor Breakers of Drivers and Need. By the end of 2029, Toronto Hydro aims to have no outdoor breakers operating beyond their useful life. The pacing of 12 units ensures that no breakers are past their useful life, allowing for increased reliability to be maintained both in short and long term and aligns to Toronto Hydro's standard of non-oil-base circuit breakers.

The average cost for TS outdoor breaker replacement over the 2025-2029 rate period is roughly $0.74 million per unit. This is slightly higher than initial unit pricing estimated for the 2020-2024 period which was $0.60 million per unit. From the four breaker replacements completed from 2020-2022, the actual cost increased to $0.61 million per unit due to material inflation and increased design and construction costs for new Hydro One demarcation panel requirements. Toronto Hydro has adjusted its 2025-2029 estimates accordingly, forecasting that replacement will cost $0.74 million per unit.

Given its 2020-2024 historical achievements in this segment, Toronto Hydro is well positioned to successfully execute its replacement plan for 2025-2029, which proposes at most four replacements in a single year.

Toronto Hydro prioritizes the replacement of its TS outdoor breakers based on the failure risk presented by each breaker. The failure risk is assessed qualitatively by considering the following factors.

Table 32: TS Outdoor Breakers Prioritization

Factor	Prioritization
Age	Older breakers are given higher priority
Type of circuit breaker	Priority given in order of: 1) Oil circuit Breaker

Factor	Prioritization
	2) SF_6 Breaker 3) Vacuum Breaker
Condition Assessment	Circuit breakers receiving worse condition assessments are given higher priority
Load	Breakers supplying larger quantities of load are given higher priority
Protection and Control	Breakers with obsolete protection and control systems are given higher priority.
Any other issues raised by station crews (such as broken components)	Given higher priority

The type of circuit breaker, protection, and control are used to gauge the impact of the circuit breaker and the priority. All KSO oil breakers are at their end-of-life and will be targets for replacements this rate application period.

4. TS Outdoor Switches– 2020-2024 Variance Analysis

As shown in Table 33 below, Toronto Hydro forecasts replace 69 TS outdoor switches during the 2020-2024 rate period for a cost total of $6.32 million.

Table 33: TS Outdoor disconnect switches - Historical Actual, Bridge and Forecast Unit Volumes

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-24
Units (Switch)	3	6	18	23	19	69
Expenditures ($M)	1.8	0.11	1.2	2.4	0.83	6.3

The 2020-2024 Filed Plan proposed 61 TS switches replacements for a total cost of $1.9 million. With the deferral of Finch TS BY bus renewal, Toronto Hydro plans to allocate the funds to advance the other TS programs as explained in the previous sections. Toronto Hydro forecasts to replace 69 TS outdoor switches during the 2020-2024 rate period at a cost of $6.32 million.

The actual unit cost for the new outdoor switches is much higher than originally estimated in the previous rate application. The average unit cost per switch replacement is roughly $0.09 million, a substantial increase from the estimate of $0.03 million per switch. This Program was a new segment for the 2020-2024 rate application, resulting in higher variance due to lack of experience. The contributing factors for this increase were additional labour costs from the new switches that are

gang-operated on ground and steel mount on existing structure, requiring modifications for installation and material cost inflation. Unit cost was $0.12 million from 15 outdoor switches replaced in 2020-2022. As more switch replacement projects occurs, the average of unit cost will be decreased as Toronto Hydro gains more design and installation experience.

5. TS Outdoor Switches– 2025-2029 Expenditure Plan

For the 2025-2029 rate period, Toronto Hydro is proposing to replace 63 TS outdoor switches, a small increase from the original planned units from the previous period. The forecasted cost to complete this work is $8.32 million. Table 34 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 34: 2025-2029 TS Outdoor Switch – Forecast Expenditures ($ Millions)

	Actual			Bridge		Total
	2025	2026	2027	2028	2029	2025-2029
Units (Switch)	6	15	10	16	16	63
Expenditures ($M)	0.74	1.9	1.3	2.0	2.2	8.3

By replacing 63 units during the 2025-2029 rate period, Toronto Hydro will reduce the number of TS outdoor switches operating beyond their useful life to 14 percent. As detailed in sub-section 3 of section E6.6.3.1 Transformer Stations, if this work is not undertaken during the 2025-2029 rate period, 40 percent of Toronto Hydro's TS outdoor switches will be operating beyond or within five years of their 50-year useful life. Performing the proposed work will allow Toronto Hydro to sustainably manage the demographics of its switches over the longer term and reduce the number of switch failures.

The year-by-year pacing for TS outdoor switch replacement has been developed to target the highest priority switches, while maximizing efficiencies in terms of construction and outage coordination. For the years 2025-2029, Toronto Hydro proposes replacements in sets of three switches per year because each selected set can be replaced in a single outage. This reduces unit costs and reliability risk to customers (which would be higher if each switch was replaced as a separate project).

Toronto Hydro forecasts a cost of $8.32 million over the 2025-2029 rate period to complete the 63 switch replacements. This results in an average unit cost of $0.13 million per switch project, an

increase from the $0.12 million from the previous 2020-2024 rate period. The contributing factors for this increase are material and labour cost inflation.

Toronto Hydro prioritizes the replacement of its TS outdoor switches based on the failure risk presented by each switch, which is assessed qualitatively and outlined in Table 35.

Table 35: TS Outdoor Switches Prioritization

Factor	Prioritization
Age	Older switches are given higher priority
Switch Type	Priority given in order of: 1) Feeder tie switches 2) Bus disconnect switches 3) Line disconnect switches
Number of repairs	Switches with more repairs are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority

Due to the nature of switches, multiple switches will be grouped together for replacement in order to minimize the outage time.

E6.6.4.2 Municipal Stations (MS) Expenditure Plan

As shown in Table 36 below, Toronto Hydro plans to spend $44.6 million over the 2020-2024 rate period in its Municipal Stations segment to complete 12 MS switchgear, 12 power transformers, and four MS primary supplies. This presents an increase of $6.9 million compared to the 2020-2024 forecast of $37.7 million. The total number of power transformers is higher than the 2020-2024 Distribution System Plan.[12] The MS switchgear and MS primary supply are less than the proposed volumes in the DSP due to revised project scopes, an increase in the unit cost of MS primary supplies, an increase in civil and stations work, and distribution work (egress and MS primary supply replacement).

When Toronto Hydro originally estimated the costs in this segment for 2020-2024, the projects prior to 2019 did not include the replacement of the MS primary supply as a part of the transformer replacement and thus, no project or design estimates were completed at the time of writing the 2020-2024 rate application. Therefore, the estimates did not fully account for the aforementioned

[12] *Supra* Note 1

factors, such as the stations and distribution portions of work. A variance analysis for each subsegment is provided in the following subsections.

Table 36: MS Historical & Forecast Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
MS Switchgear[13]	6.4	8.7	0.74	2.7	5.9	5.7	6.2	7.5	11.2	13.2
Power Transformer	3.7	2.6	1.6	0.65	8.1	4.6	5.1	5.3	5.9	5.2
MS Primary Supply	0.39	0.08	0.35	0.55	0.33	-	-	0.56	-	-
Total	11.5	12.5	2.4	3.9	14.3	10.2	11.3	13.3	17.0	18.4

During the 2025-2029 rate period, Toronto Hydro proposes to spend $70.3 million on its MS segment and renew 12 MS switchgear, 15 power transformers, and one MS primary supply. Expenditures are increased due to an increased unit cost (described in variance analysis), a modest increase in volume of work, projects with custom or higher capacity equipment, and forecasted inflation. The majority of the 2025-2029 spending relates to MS switchgear renewal ($43.7 million). The remaining spending is planned almost entirely for power transformers replacement, with only one MS primary supply project proposed for the rate period.

1. MS Switchgear – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete ten new switchgear projects and has completed two carry-over switchgear projects from the 2015-2019 rate period, for a total cost of $25.7 million. Table 37 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 rate period.

[13] Note: the 2020-2024 expenditures do not necessarily align with the volume of units completed since project costs were spread across 2-3 years.

Table 37: MS Switchgear - Historical Actual and Bridge Unit Volumes and Expenditures

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-24
Units (Switchgear)	2	5	1	1	3	12
Total Feeders[14]	6	19	3	3	10	41
Expenditures ($M)	7.0	9.5	0.56	2.7	5.9	25.7

The 2020-2024 Filed Plan proposed 12 new switchgear projects for a total cost of $23.4 million, and therefore expenditures are forecasted to increase by $2.3 million. Although the forecasted unit volume is the same, the replaced units have changed slightly. Toronto Hydro has since updated its MS conversion plans by offloading two of the 12 switchgears and is no longer planning for asset renewals at these stations. As a result, Toronto Hydro achieved a sustained risk profile and completed all the proposed work, but at a slightly higher cost than forecasted.

The two carry-over switchgear projects incurred expenditures of $3.2 million over the 2020-2024 rate period and comprised seven feeders. This results in a forecasted net expenditure of $22.5 million for ten new switchgear projects comprising 34 feeders, and an average unit cost of $0.66 million per feeder. As a result, the forecasted unit cost over 2020-2024 has increased above the unit cost provided in the 2020-2024 Distribution System Plan of $0.6 million per feeder. [15]

Major sources for increases in unit cost are due to the practical implications of new arc-resistant switchgear, underestimation of egress replacement costs, and inflation of switchgear material cost.

1) New MS switchgears are arc-resistant. Thus, it usually requires substantial changes to the station building (including a complete rebuild of entire station floor), and additional relocation work of conduits and ancillary equipment.
2) The unit cost for egress replacement projects used in the 2020-2024 rate application was based on only one project that was completed, which did not end up being representative of average cost.

[14] This is the total number of feeders supplied by the switchgear whose replacements were, or are forecasted to be, completed in the specified year.
[15] *Supra* Note 1.

3) During the past few years, the material cost of switchgear has significantly increased by 47 percent from 2019 to 2022.

These sources have informed forecasted spending for the 2025-2029 rate period.

2. MS Switchgear – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro proposes to replace 12 MS switchgear, which is a modest increase from the previous period. Table 38 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 38: MS Switchgear - Historical Actual and Bridge Unit Volumes and Expenditures

	Forecast					Total
	2025	2026	2027	2028	2029	2025-29
Units (Switchgear)	2	2	2	3	3	12
Total Feeders[16]	6	7	7	10	11	41
Expenditures ($M)	5.7	6.2	7.5	11.2	13.2	43.7

To complete the proposed 12 MS switchgear replacements, comprising 41 feeders, Toronto Hydro forecasts a cost of $43.7 million over the 2025-2029 rate period. This results in an average unit cost of $1.07 million per feeder which is a substantial cost increase from the previous 2020-2024 rate period. This new unit cost is forecasted using the cost increasing trend for the previous years, which considers these factors: updated unit costs from the 2020-2024 rate period, renewal of custom equipment for four projects, and general forecasted inflation.

For most MS, and for historical projects, the MS supplies an overhead distribution system using standard overhead switches. However, over the 2025-2029 rate period, four projects are planned at MS supplying an underground distribution system, which use custom underground egressing switches. Since these are legacy equipment past useful life, located within the station between the switchgear and the distribution system, and are needed to operate the station, these switches require renewal in parallel with the switchgear.

[16] This is the total number of feeders supplied by the switchgear whose replacements were, or are forecasted to be, completed in the specified year.

The additional cost needed to replace the custom underground egressing switches, plus general forecasted inflation, is responsible for the remaining unit cost increase over the 2025-2029 period resulting in an average unit cost of $1.07 million per feeder.

Segment expenditures were forecasted based on project-level estimates for the 12 switchgear replacements proposed, and were informed by actual and forecasted project costs over the 2020-2024 rate period. Project estimates were adjusted based on station configuration as discussed above, rather than simply applying a single unit cost to all projects. Pacing has been chosen to evenly distribute the projects over the period.

Toronto Hydro prioritizes the replacement of its MS switchgear based on the failure risk presented by each switchgear. The failure risk is assessed qualitatively by considering the following factors.

Table 39: MS Switchgear Prioritization

Factor	Prioritization
Age	Older switchgear are given higher priority
Condition Assessment	Switchgear receiving worse condition assessments (including breaker condition assessments) are given higher priority
Type of circuit breaker	Priority given in order of: 1) Obsolete oil circuit breaker 2) Obsolete air magnetic circuit breaker 3) Current SF_6 circuit breakers 4) Current vacuum circuit breakers
Load	Switchgear supplying larger quantities of load are given higher priority
Resiliency of the surrounding distribution system to withstand switchgear failures	MS in areas of low resiliency are given higher priority
Any other issues raised by station crews (such as broken components)	Given higher priority
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need their assets to be replaced

Age, condition assessment, circuit breaker type, and issues raised by station crews are used to gauge the probability of a switchgear failure and when a switchgear has reached end-of-life. Furthermore, switchgear loading and resiliency of the surrounding distribution system (i.e. ability to withstand

switchgear failures) are used to gauge the impact of the switchgear failure and the priority of the replacement.

3. Power Transformer – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro expects to complete 11 new power transformer projects and one carry-over power transformer project from the 2015-2019 period, for a total cost of $ 16.7 million. Table 40 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 period.

Table 40: Power Transformer - Historical Actual and Bridge Unit Volumes and Expenditures[17]

	Actual			Bridge		Total
	2020	**2021**	**2022**	**2023**	**2024**	**2020-24**
Power Transformers	1	4	2	0	5	12
Expenditures ($M)	3.7	2.6	1.6	0.65	8.1	16.7

The 2020-2024 Filed Plan proposed ten new power transformer projects for a total cost of $10.3 million, and therefore expenditures are forecasted to be overspent by $6.7 million while unit volume is forecasted to be one unit above target. One unit was advanced from 2025-2029 plans to mitigate outage coordination risks for the 2025-29 rate period, and to begin accelerating the replacement pacing to address an increased failure rate.

The one carry-over transformer project incurred expenditures of $1.3 million over the 2020-2024 rate period. This results in a forecasted net expenditure of $15.4 million for the 11 new power transformer projects, and an average unit cost of $1.40 million. As a result, the forecasted unit cost over 2020-2024 has significantly increased above the unit cost provided in the 2020-2024 Distribution System Plan of $1.0 million.[18]

Major sources for increases in unit cost are due to underestimated civil and facilities modifications, underestimated distribution costs for MS primary supply replacement, and ground grid refurbishment.

[17] Note: the 2020-2024 expenditures do not necessarily align with the volume of units completed since project costs were spread across 2-3 years.
[18] *Supra* Note 1.

1) In the 2015-2019 rate application, MS primary supply replacement was not included as part of the transformer replacement. Thus, the substantial amount of cost, including the construction the foundation of large primary switch and construction of new concrete encased duct banks, transformer foundation, and facilities modifications to extend equipment clearances to modern standards, was largely underestimated.
2) Similarly, the distribution portion of the MS primary supply replacement was also underestimated.
3) The station ground grid is an asset vital to employee and public safety. While conducting the civil modifications, the ground grid was often found inadequate and / or degraded, and the deficiencies needed to be addressed.

4. Power Transformer – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro proposes to replace 15 power transformers, which is an increase from the previous period. The forecasted cost to complete this work is $26.0 million. Table 41 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 41: Power Transformer - Forecasted Unit Volumes and Expenditures

	Forecast					Total
	2025	2026	2027	2028	2029	2025-29
Power Transformers	3	3	3	3	3	15
Expenditures ($M)	4.6	5.1	5.3	5.9	5.2	26.0

To complete the proposed 15 transformer replacements, Toronto Hydro forecasts a cost of $26.0 million over the 2025-2029 rate period. This results in an average unit cost of $1.73 million, which is a cost increase from the previous 2020-2024 rate period. There are two factors which explain this cost increase: four projects with higher capacity transformers, and general forecasted inflation.

Over the 2020-2024 rate period, only one power transformer renewal project involved the renewal of a unit rated for 10 MVA. However, four such units are proposed for the 2025-2029 rate period. Such units not only have a higher material cost, but they also require a higher rated MS primary supply which also introduces higher material costs. Finally, a unit of this size requires a more sensitive protection scheme to protect it from faults, known as a transformer differential protection scheme.

This protection scheme introduces new equipment and requires a much more intensive engineering design, both of which contribute to a higher cost.

Segment expenditures were forecasted based on project-level estimates for the 15 power transformer replacements proposed, and were informed by actual and forecasted project costs over the 2020-2024 rate period. Lessons learned from variances in the 2020-2024 rate period have been incorporated into project estimates for the 2025-2029 rate period. Project estimates were adjusted based on transformer capacity as discussed above, rather than simply applying a single unit cost to all projects. Pacing has been chosen to evenly distribute the projects over the period.

Toronto Hydro prioritizes the replacement of its power transformers based on the failure risk presented by each transformer. The failure risk is assessed qualitatively by considering the following factors.

Table 42: Power Transformer Prioritization

Factor	Prioritization
Age	Older transformers are given higher priority
Dissolved gas-in-oil analysis	Transformers in worse condition are given higher priority
Condition Assessment	Transformers receiving worse condition assessments are given higher priority
Loading	Transformers loaded higher relative to their capacity are given higher priority
Load	Transformers supplying larger quantities of load are given higher priority
Resiliency of the surrounding distribution system to withstand transformer failures	MS in areas of low resiliency are given higher priority
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need their assets to be replaced

Age, dissolved gas-in-oil analysis, loading, and condition assessment involving electrical tests are used to gauge the probability of a power transformer failure and when an asset has reached end-of-life. Further, transformer loading and resiliency of the surrounding distribution system (i.e. ability to withstand power transformer failures) are used to gauge the impact of the power transformer failure and the priority of the replacement.

5. MS Primary Supply – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete the replacement of four MS primary supplies for a total cost of $1.70 million. Table 43 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 rate period.

Table 43: MS Primary Supply - Historical Actual and Bridge Unit Volumes and Expenditures

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-24
Power Transformers	1	0	1	1	1	4
Expenditures ($M)	0.39	0.08	0.35	0.55	0.33	1.7

The 2020-2024 Filed Plan proposed 11 MS primary supply projects for a total cost of $3.9 million, and therefore expenditures are forecasted to be underspent by $2.2 million while unit volume is forecasted to be seven units below target.

Forecasted unit volume is below target, for three reasons. First, four projects were cancelled because, upon project scoping, the primary cable at these stations was found to be installed in concrete encased duct, which does not meet the criteria set out in Section E6.6.3.2. Second, two projects were cancelled because switchgear replacements were planned for these stations in the 2025-2029 rate period, and to coordinate MS renewal work, the scope of work has been incorporated with their switchgear replacements in 2025-2029. Lastly, one project was deferred to the 2025-2029 rate period to mitigate increased spending in the MS segment as a whole.

Over the 2020-2024 rate period, the average unit cost for the four completed MS primary supply projects is forecasted to be $0.43 million. As a result, the forecasted unit cost over 2020-2024 has increased above the unit cost provided in the 2020-2024 Distribution System Plan of $0.37 million.[19]

Major sources for increases in unit cost are similar to sources for cost increases to power transformer replacements, since the power transformer replacements from 2019 onwards included MS primary supply replacements. In particular, since no projects and no design estimates had been completed at the time of writing the 2020-2024 rate application, both the station and distribution portions of work were underestimated. Based on actual project costs of 2020 and 2022 projects, and estimates

[19] *Supra Note 1*

for 2023 and 2024 projects, the unit cost has been updated to reflect these variances for both station and distribution portions of work.

6. MS Primary Supply – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro proposes to replace one MS primary supply, because this is the last primary supply remaining in the system, which meets the criteria set out Section E6.6.4.2. However, transformer failures which require immediate replacement, without an opportunity to replace the MS primary supply in parallel, may introduce the need for additional MS primary supply replacements.

The cost estimated for the proposed project is $0.56 million. The increased cost relative to the 2020-2024 rate period is due to forecasted inflation.

E6.6.4.3 Control and Monitoring Expenditure Plan

As shown in Table 44 below, Toronto Hydro expects to spend $28.29 million over the 2020-2024 rate period in its Control and Monitoring segment. This presents an overspend of $6.19 million compared to the 2020-2024 Distribution System Plan forecast of $22.1 million.[20] Toronto Hydro forecasts to complete one more TS RTU, 14 more MS RTU, 36 more TS Relays (previously shown as five customer locations, but correlates to two relays per location), and 32km less interstation control wiring as compared to the Filed Plan. A variance analysis for each subsegment is provide in the following subsections.

Table 44: Control and Monitoring Historical & Forecast Segment Costs ($ Millions)

Expenditures	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
RTU Renewal	3.8	1.6	4.1	3.6	6.2	2.8	3.1	3.2	3.3	3.4
Relay Renewal[21]	New Subsegment					9.1	9.1	10.3	9.8	10.7
Pilot-wire Protection Renewal	0.36	1.4	1.1	2.6	2.2	Subsegment Absorbed				
Interstation Control Wiring Renewal	0.58	0.15	-0.13	0.27	0.43	Subsegment Completed				
Total	**4.7**	**3.1**	**5.1**	**6.5**	**8.8**	**11.9**	**12.1**	**13.5**	**13.1**	**14.2**

[20] *Ibid.*

[21] Note: Relay Renewal has absorbed the cost and scope of work of "Pilot-wire Protection Renewal" from the 2020-2024 Rate Custom Incentive Risk Application.

During the 2025-2029 rate period, Toronto Hydro proposes to spend $64.70 million in its Control and Monitoring segment to renew 19 TS RTUs, 14 MS RTUs, 121 TS Relays, and 130 MS Relays. Expenditures are increased due to several factors, including an increase in volume of work for relays due to the modernization driver, more work replacing TS RTUs which have higher unit costs than MS RTUs, and forecasted inflation. The majority of the 2025-2029 spend relates to Relay Renewal ($48.91 million). The remaining spend is planned RTU Renewal with most of the costs being for the TS RTU renewals.

For the 2020-2024 rate period, the majority of proposed spending is for RTU renewal at both TS, MS, and installing RTUs at stations without an existing RTU (which is now completed). The remaining forecasted spending is planned pilot-wire protection upgrades and Interstation Control Wiring Renewal. The subsegment for Interstation Control Wiring Renewal is planned to be absorbed with Relay Renewal after the 2020-2024 rate period since they are accompanied by electromechanical relays and supply Toronto Hydro's larger customers. This will also focus on upgrading electromechanical relays to digital relays along with the communication wire upgrades from copper to fiber. This change will allow for more reliable tracking and reporting on work that is completed.

1. RTU Renewal – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete 12 TS RTU and 48 MS RTU renewals for a total cost of $19.32 million. Table 45 below provides an annual breakdown of the units completed and proposed between 2020 to 2024.

Table 45: RTU Replacement - Historical Actual and Bridge Unit Volumes

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-2024
TS RTUs	2	2	2	1	5	12
MS RTUs	17	6	11	8	6	48
Expenditure ($M)	3.8	1.6	4.1	3.6	6.2	19.3

The 2020-2024 Filed Plan proposed to complete 11 TS RTU and 34 MS RTU renewals for a total cost of $15.4 million. Expenditures are forecasted to be overspent by $3.92 million while TS and MS RTU units are forecasted to be one unit above and 14 units above respective targets. The total breakdown of RTU type is forecasted to be: 31 MOSCAD, eight D20, ten DACSCAN, one NTU, and ten new RTUs. This results in a total of 33 percent more RTUs renewed while spending 25 percent more. The

spending difference can mainly be attributed to doing a larger amount of RTUs at the MS which have a much lower unit cost than at the TS.

a. TS RTU Renewals

The TS System consists of nine different RTUs being SEL 2240, SEL 3530, SEL 3355, D20MX, DACSCAN (obsolete), D20ME (obsolete), ACS NTU (obsolete), ABB COM 500 (obsolete), and SEL 3332 (obsolete).

Toronto Hydro plans to replace a total of 12 TS RTUs during the 2020-2024 rate period for a forecasted total of $7.99 million.

b. MS RTU Renewals

The MS System consists of eight different RTUs being SEL 2240, SEL 3530, D20MX, DACSAN (obsolete), D20ME (obsolete), ACS NTU (obsolete), MOSCAD (obsolete), and SEL 2032 (obsolete).

Toronto Hydro plans to replace or add a total of 48 MS RTUs during the 2020-2024 rate period for a forecasted total of $11.32 million.

2. RTU Renewal – 2025-2029 Expenditure Plan

Over the 2025-2029 period, Toronto Hydro plans to complete 19 TS RTU and 14 MS RTU renewals for a total cost of $15.79 million. Table 46 below provides an annual breakdown of the units proposed between 2025 to 2029.

Table 46: RTU Replacement - Forecast Unit Volumes

	Forecast					Total
	2025	2026	2027	2028	2029	2025-2029
TS RTUs	4	3	4	4	4	19
MS RTUs	2	3	3	3	3	14
Expenditure ($M)	2.8	3.1	3.2	3.3	3.4	15.8

The RTU Renewal subsegment is mainly prioritized according to the failure risks and outage impacts on customers. However, modernization has been incorporated to include upgrading assets that are obsolete. Stations with a larger number of customers, larger loads, and at higher risk of asset failure

will be given higher priority compared to stations with lower number of customers, loads, and lower failure risks. Priority of replacements is assessed qualitatively by evaluating various factors as shown below:

Table 47: Control and Monitoring RTU Renewal Prioritization

Factor	Prioritization
Age	The older the asset, the higher the priority is assigned.
Number of Customers	The larger number of customers connected to the asset, the higher the priority.
Load	The larger amount of load (MVA), the higher the priority.
Failure rate	Assets at stations with higher incident of failures/repairs will have higher priority.
Switchgear Renewal Planned	Stations with switchgear renewals being planned do not need any of their assets to be replaced since the work is assumed to be done along with the switchgear.
Voltage conversion planned	Stations with voltage conversion being planned do not need any of their assets to be replaced.
Modernization	Assets that are driven by modernization while important will have the lowest priority since failure risk is the highest priority of the portfolio.

a. TS RTU Renewals

For the 2025-2029 rate period, Toronto Hydro plans to increase the rate of RTU renewals at the TS level to keep up with the amount of aging and obsolete RTUs for a total of 19 TS RTUs for a forecasted total of $11.12 million.

The associated costs have been estimated by a combination of historical costs of TS RTU renewals on a per switchgear or bus pair level, as well as considering future expected costs for General Alarm Cabinets. The alarm cabinets will need to be replaced along with some RTU renewals to allow the communication of alarms such as batteries, fire suppression, etc. which would not run to newly replaced RTUs.

b. MS RTU Renewals

For the 2025-2029 rate period, Toronto Hydro plans to reduce the rate of RTU renewals at the MS level for a total of 14 MS RTUs for a forecasted total of $4.66 million.

The associated costs have been estimated by historical costs of MS RTU renewals on a per station level. The original cost estimates for RTUs was broken down based off RTU type, however the distinction between station type seems to be the better factor for estimating unit costs. The overall cost increase is mainly due to assumed inflation.

3. Relay Renewal – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to upgrade or renew 46 relays for a total cost of $7.67 million. Table 48 below provides an annual breakdown of the units completed and proposed between 2020 to 2024.

Table 48: Relay Renewal - Historical Actual and Bridge Unit Volumes

	Actual			Bridge		Total
	2020	**2021**	**2022**	**2023**	**2024**	**2020-2024**
TS Relays	2	4	0	19	21	46
MS Relays	NEW SUBSEGMENT					0
Expenditure ($M)	0.36	1.4	1.1	2.6	2.2	7.7

For 2020-2024, Toronto Hydro initially planned to complete ten TS relay renewals (initially number given per customer as five, but assuming two relays per customer its now shown as ten) and 0 MS Relays with a planned spend of $3.5 million. The current plan for 2020-2024 is to complete 46 TS Relays (37 being Pilot Wire/Transfer Trip relays for 18 locations, the rest being URD feeder relay upgrades to digital) and 0 MS RTUs with a planned spend of $7.67 million. This results in a total of 460 percent more relays renewed while spending 119 percent more. This increase in relays with less spend is mainly due to the unit cost of Pilot Wire Renewals seeming to originally include copper renewal costs within the estimate. Also, since this was a newer segment and the costs were more unknown and as such better estimates are being developed as more projects are completed.

4. Relay Renewal – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro plans to upgrade or renew 251 relays for a total cost of $48.91 million. Table 49 below provides an annual breakdown of the units completed and proposed between 2025 to 2029.

Table 49: Relay Renewal - Forecast Unit Volumes

	Forecast					Total
	2025	2026	2027	2028	2029	2025-2029
TS Relays	18	21	22	17	22	100
Pilot Wire Relay	6	2	3	3	0	14
Transfer Trip Relay	2	1	1	2	1	7
MS Relays	19	23	26	27	35	130
Expenditure ($M)	9.1	9.1	10.3	9.8	10.7	48.9

Toronto Hydro plans to increase the work on relays during the 2025-2029 rate period to modernize the system from obsolete electromechanical relays to digital relays, as well as upgrade remaining Pilot Wire and Transfer Trip Relays to Fiber. In total, 121 TS and 130 MS relays are proposed for an estimated total of $48.91 million.

The Relay Renewal subsegment is mainly prioritized according to the modernization to upgrade electromechanical relays to digital relays. Stations with larger number of customers, larger loads, and at higher risk of asset failure will be given higher priority compared to stations with lower number of customers, loads, and lower failure risks. Priority of replacements is assessed qualitatively by evaluating various factors as shown below:

Table 50: Control and Monitoring Relay Renewal Prioritization

Factor	Prioritization
Modernization	Assets that are driven by modernization while important will have the lowest priority since failure risk is the highest priority of the portfolio.
Number of Customers	The larger number of customers connected to the asset, the higher the priority.
Load	The larger amount of load (MVA), the higher the priority.
Failure rate	Assets at stations with higher incident of failures/repairs will have higher priority.
Switchgear Renewal Planned	Stations with switchgear renewals being planned do not need any of their assets to be replaced since the work is assumed to be done along with the switchgear.
Voltage conversion planned	Stations with voltage conversion being planned do not need any of their assets to be replaced.

a. TS Relay Renewals

The TS Relays will focus on modernizing the relays to renew the obsolete Electromechanical Relays with Digital Relays. The TS Relays can be broken down into four categories being:

- TS Electromechanical to Digital Relay Renewal
  - Toronto Hydro is prioritizing modernizing the system from obsolete electromechanical relays to digital relays.
  - Toronto Hydro plans to replace a total of 100 of these Relays for an estimated $25.33 million.
- TS Digital Relay Renewal
  - Toronto Hydro will prioritize renewing existing digital relays that are either past their typical useful life or have obsolete relays that have been having known failures or are no longer available by the manufacture.
  - Toronto Hydro currently does not have any plans for these Relays in the 2025-2029 rate period and plans to begin like-for-like digital relay renewals in the next period of 2030-2034.
- Pilot-Wire Relay Renewal
  - Toronto Hydro is prioritizing renewing existing Pilot-Wire Protection Systems that have either copper communications or electromechanical relays to both avoid failure risk on the copper cables to replace with fiber, and to upgrade the customers with Pilot-Wire Protection Systems to the new standards.
  - These upgrades are also required to facilitate a transfer from an older switchgear to a new switchgear renewal, so proactively replacing these units will also help with TS Switchgear Renewals in the future to take a little less time.
  - Toronto Hydro plans to replace a total of five locations with 14 Relays for an estimated $4.77 million. This will complete the remaining copper cables and electromechanical relays suppling these customers.
- Transfer Trip Relay Renewal
  - Toronto Hydro is prioritizing renewing existing Transfer Trip Protection Systems that have either copper communications or electromechanical relays to both avoid failure risk on the copper cables to replace with fiber, and to upgrade the customers with Transfer Trip Protection Systems to the new standards.

- Toronto Hydro plans to replace a total of 6 locations with 7 Relays for an estimated $4.01 million. This will complete the remaining copper cables and electromechanical relays suppling these customers.

The priority of this work will focus on the Pilot-Wire and Transfer Trip Relays since they supply larger customers who prioritize reliability in their supply. These systems are also the most at risk of faults since they still have older copper communication cables versus fiber. The remaining TS Relay upgrades will focus on obsolete electromechanical relay to digital renewals to modernize the system.

The associated costs have been estimated by a combination of historical average costs of other TS Relay renewals on a per cell basis as well as taking the newer and higher estimates for 2023-2024 work.

b. MS Relay Renewals

For the 2025-2029 rate period, the MS Relays will focus on modernizing the relays to renew the obsolete Electromechanical Relays with Digital Relays. Similarly to the TS Relays, ideally the plans would include replacing existing digital relays that are more at risk to failure than electromechanical. However, as digital relays are newer to the system, Toronto Hydro does not estimate many will need to be replaced and if existing MS digital relays require renewal, it would take priority over electromechanical relays. The MS Relays can be broken down into two categories:

- MS Electromechanical to Digital Relay Renewal
  - Toronto Hydro is prioritizing modernizing the system from obsolete electromechanical relays to digital relays.
  - Toronto Hydro plans to replace a total of 130 of these relays for an estimated $14.80 million.
- MS Digital Relay Renewal
  - Toronto Hydro will prioritize renewing existing digital relays that are either past their typical useful life or have obsolete relays that have been having known failures or are no longer available by the manufacture.
  - Toronto Hydro currently does not have any plans for these relays in the 2025-2029 rate period and plans to begin like-for-like digital relay renewals in the next period of 2030-2034.

The associated costs for MS Relay Renewals have been estimated by a high-level estimation taking MS RTU renewal estimates and TS Relay renewal estimates and trying to determine a fair estimate on a per relay basis. Since this is a newer program, the unit costs are still not very well defined.

5. Interstation Control Wiring Renewal – 2020-2024 Variance Analysis

In the 2020-2024 rate period, Toronto Hydro initially planned to do 45km of Copper Wiring Renewals with a planned spend of $3.1 million. The current plan for 2020-2024 as shown in Table 51 below, is to complete 13km of Copper Wiring Renewals with a planned spend of $1.30 million. This results in a total of 71 percent less distance of copper renewals while spending 58 percent less. As a result of the novelty of this segment and considering Toronto Hydro had not previously performed planned replacement of its interstation control wiring, the costs were originally forecasted to be approximately $70k/km. However, based on projects executed during the 2020-2022 period, Toronto Hydro is revising its unit cost to $100k/km. This subsegment is planned to be completed by 2024 since there should be no more copper communications between stations.

Table 51: 2020-2024 Copper Renewal Plans

	Actual			Bridge		Total
	2020	**2021**	**2022**	**2023**	**2024**	**2020-2024**
Copper Renewal (km)	3	1	2	6	1	13
Expenditures ($M)	0.58	0.14	-0.13	0.27	0.43	1.3

6. Interstation Control Wiring Renewal – 2025-2029 Expenditure Plan

As shown in Table 52 below, Toronto Hydro expects to complete the requirement of Interstation Control Wiring Renewal from copper to fiber in 2020-2024. While copper communications wires still exist on the system, it should only exist from station to customer which will be addressed in the Relay Renewal program under sub-section E6.6.4.3 above.

Table 52: 2025-2029 Copper Renewal Plans

	Forecast					Total
	2025	2026	2027	2028	2029	2025-2029
Copper Renewal (km)	Subsegment Completed					
Expenditure ($M)	Subsegment Completed					

E6.6.4.4 Battery and Ancillary System Expenditure Plan

As shown in Table 53 below, Toronto Hydro forecasts to spend $7.3 million during the 2020-2024 rate period in its Battery and Ancillary System segment which is aligned to the 2020-2024 Battery & Ancillary system plan of $7.1 million. This spend is expected to be of $4.55 million and $2.75 million respectively for batteries/chargers and other ancillary projects. Toronto hydro forecasts to complete 37 fewer Battery and Chargers and three fewer Ancillaries (SST, AC Panel, Sump pump, Air compressor). Variance analysis for each subsegment is provided in the following subsections.

Table 53: Battery and Ancillary Systems Historical & Forecast Segment Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Battery and Charger Renewal	1.0	0.53	0.61	1.9	0.52	0.82	0.71	0.94	0.84	0.80
Other Ancillary Renewal	0.91	0.70	0.49	0.35	0.30	2.4	1.5	0.99	2.6	2.1
Total	**1.9**	**1.2**	**1.1**	**2.2**	**0.8**	**3.2**	**2.2**	**1.9**	**3.4**	**2.9**

During the 2025-2029 rate period, Toronto Hydro proposes to spend $13.6 million in its Battery and Ancillary System segment and complete 63 battery and charger projects, and 11 ancillary projects. The budget of Battery and Charger Renewal has remained relatively similar to the budget approved for the 2020-2024 rate period. However, the cost of the SST and Other Ancillary Renewal have gone up due to two major factors: revised cost of installing Sum Pump and the renewal work required for AC Panels in Downtown TS.

The battery and ancillary systems at Toronto Hydro TS are prioritized above the same assets at MS due to the sheer volume of customers that are served through each TS. A TS asset failure affects significantly more customers than the same asset failing at an MS. Also, recent survey results have shown that the customer needs can be categorized into two main categories which are Rates and

Reliability. The 2025-2029 expenditure plan proposes a plan that looks to minimize the system risk while also maximizing the value of each project.

1. Battery and Charger Renewal – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete 46 MS and ten TS batteries, 39 MS and two TS charger systems for a total cost $4.55 million. Table 54 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 rate period.

Table 54: Battery and Charger Renewal - Historical Actual and Bridge and Unit Volumes

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-24
Battery units	16	8	10	18	4	56
Charger units	15	8	8	9	1	41
Expenditures($M)	1.0	0.53	0.61	1.9	0.52	4.6

The 2020-2024 Filed Plan proposed 60 MS Batteries, 7 TS batteries, 60 MS chargers, and 7 TS Chargers for a total cost of $4.8 million. Therefore, expenditures are forecasted to be underspent by $0.25 million while unit volume is generally forecasted to be below target. Unit variances are respectively: -14, +3, -21, and -5.

Forecasted unit volume is below target, due the following:

- These include a higher unit cost for the replacement of TS batteries relative to the cost of MS batteries. Therefore, as a result of a higher volume of TS battery replacements, Toronto Hydro replaced fewer MS batteries.
- A number of MS batteries and chargers were replaced reactively during the 2020-2022 period.
- As a part of the work done, Toronto Hydro assessed whether it was necessary to replace batteries and chargers together. However, given the fact that the useful life of chargers is much longer than the batteries, Toronto Hydro decided to only replace the batteries if the charger has not reached its useful life in order to be cost-effective.

In addition, the overspend on stations ancillary renewal caused limitation to the DC battery renewal budget. All the factors explained above contributed to the under attainment for both batteries and charger systems.

2. Battery and Charger Renewal – 2025-2029 Expenditure plan

Over the 2025-2029 rate period, Toronto Hydro proposes to replace 55 end-of-life batteries and eight charger systems. The forecasted cost to complete this work is $4.12 million. Table 55 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 55 : Battery and Charger Renewal – Forecast Unit Volumes

	Forecast					Total
	2025	2026	2027	2028	2029	2025-29
MS Batteries	8	6	9	8	8	39
TS Batteries	4	3	3	3	3	16
MS Charger Systems	1	2	1	2	1	7
TS Charger Systems	-	-	1	-	-	1
Expenditures($M)	0.82	0.71	0.94	0.84	0.80	4.1

To complete the proposed 55 batteries and eight charger systems, Toronto Hydro forecasts a cost of $4.12 million over the 2025-2029 rate period. This forecast was developed based on project-level estimates for the proposed replacements, and average unit costs of: of $0.041 million per MS battery, $0.12 million per TS battery, $0.06 million per MS charger, and $0.15 million per TS charger. Unit costs were informed by actual and forecasted project costs over the 2020-2024 rate period.

Toronto Hydro prioritizes the replacement of its battery and charger systems based on the failure risk and impact posed by each system. The failure risk is assessed qualitatively by considering the following factors.

Table 56: Battery and Charger Prioritization

Factor	Prioritization
Age	Older battery and charger systems are given higher priority.
Number of Customers	The larger the number of customers connected to the station, the higher the priority (e.g. battery and charger systems located at Transformer Stations are given higher priority than those located at Municipal Stations).
Other factors determined on a case-by-case basis	Systems which are non-standard or contain obsolescent technology are given higher priority (e.g. some DC distribution

Factor	Prioritization
	panels are obsolete). Spare parts that should be accessible routinely are no longer available (e.g. DC panel breaker).
Voltage conversion planned (see Section E6.6.5.3)	Stations with voltage conversion plans do not need any of their assets replaced.

3. Ancillary Renewal – 2020-2024 Variance Analysis

Over the 2020-2024 rate period, Toronto Hydro forecasts to complete zero air compressors, one sump pump, four SSTs, two carry-over SST, and one carry-over AC panel from the 2015-2019 rate period, for a total cost of $2.75 million. The carry-over projects incurred expenditures of $0.4 million over the 2020-2024 rate period.

Table 57 below provides an annual breakdown of the forecasted expenditures and units completed over the 2020-2024 rate period.

Table 57: Ancillary Renewal - Historical Actual and Bridge Units

	Actual			Bridge		Total
	2020	2021	2022	2023	2024	2020-2024
Air Compressor Replacements	-	-	-	-	-	-
Sump Pump Installations	-	1	-	-	-	1
SST	3	0	1	1	1	6
AC Panels	1	0	0	0	0	1
Expenditures($M)	0.91	0.70	0.49	0.35	0.30	2.8

The 2020-2024 Filed Plan proposed two air compressors, three sump pumps, six SSTs and zero AC panels for a total cost of $2.3 million, and therefore expenditures are forecasted to be aligned while completing fewer units overall. Unit variances are respectively: -2, -2, -2, and +1. Forecasted unit volume is below target, because of multiple factors such as reactive replacements and under estimation of unit costs. However, the major factor of the cost variance is due to the higher unit cost of sump pump installations. Variance analyses for each subsegment are provided in the following subsections.

Air compressors: During the 2020-2024 rate period, the two planned projects were not required as one was replaced reactively and the other was sold to a third party.

Sump Pump Installation: For the 2020-2024 rate period, the plan was to install three sump pumps. Initially, it was determined that no extra civil work is required on site, however after site investigation it was established that there is no existing system in place. As a result, the scope will need to include all the required civil work for the new system installation. This created variance in the project where total budget for sump pumps was $0.2 million and the one project that was completed cost $1.0 million. Toronto Hydro prioritized installing the Cecil TS sump pump since it has many major assets in the basement that would be vulnerable if flooding occurs.

SST: The 2020-2024 Filed Plan proposed six SST renewals for a total cost of $1.9M. One of the SSTs at Dufferin TS was replaced reactively and upon further assessment the SST renewal project at Windsor TS was no longer required. This resulted in two fewer SST replacements.

Overall, Toronto Hydro forecasts to spend $2.0 million on SST replacements. In addition, George & Duke SST renewal was a carryover from the 2015-2019 rate period. This project included replacement of one SSTs and one AC panel. This carryover project incurred expenditure of $0.4 million over the 2020-2024 rate period. This results in a forecasted net expenditure of $1.6M for the four SST renewal projects, and average unit cost of $0.4 million.

As a result, the forecasted unit cost over 2020-2024 has slightly increased from the unit cost provided in the 2020-2024 rate application period. The main factor driving the increase is that Toronto Hydro did not have actual costs or experience executing this work to base its estimates on, as SST renewal was a newer segment in the last rate application period.

4. Ancillary Renewal – 2025-2029 Expenditure Plan

Over the 2025-2029 rate period, Toronto Hydro proposes to install three sump pumps, and replace three SSTs, and five AC panels. The forecasted cost to complete this work is $9.52 million.

Table 58 below provides the annual breakdown of the forecasted expenditures and units completed over the 2025-2029 rate period.

Table 58: Ancillary Renewal - Historical Actual, Bridge and Forecast Units

	Forecast					Total
	2025	2026	2027	2028	2029	2025-29
Sump Pump Installations	1	-	-	1	1	3
SST	1	1	0	1	0	3
AC Panels	1	1	1	1	1	5
Expenditure ($M)	2.4	1.5	0.99	2.6	2.1	9.5

Sump Pump Installations: The utility has increasingly focused on storm hardening its system to ensure reliable power supply for its customers. After completing station risk assessments, Toronto Hydro is proposing $3.01 million for the installation of three sump pumps in 2025-2029.

SST: For the 2025-2029 rate period, Toronto Hydro is proposing $1.55M to replace three SSTs located at three of its 15 downtown TS. The slight increase in cost is driven by addition of the metering to the SST cell allowing for better load tracking and renewal foresight in the future.

Currently, Toronto Hydro does not monitor SST loads, and sizing has been based on theoretical values rather than actual loading data to reference. Furthermore, the cost increase is driven by increased unit costs in recent projects attributed mainly to civil requirements and higher labour requirements than originally estimated.

AC Panels: Based on the experience, the average unit cost of AC panel replacement is $0.99 million. Toronto Hydro is proposing $4.96 million for the installation of five AC panels over 2025-2029. It should be noted that the estimated cost is based only one AC panel replacement in the recent years, therefore Toronto Hydro expects cost variances until a number of these projects are completed.

Historically, AC panel replacements have not been completed. It was assumed that when needed, AC panel replacements would be absorbed into the scope of work of SST or charger renewals. However, an SST replacement at George & Duke MS revealed the complexity and true costs of AC panel replacements.

Toronto Hydro prioritizes the replacement of its ancillary systems based on the failure risk and impact posed by each system. The failure risk is assessed qualitatively by considering the following factors.

Table 59: Ancillary System Prioritization

Factor	Prioritization
Age	Older systems are given higher priority.
Failure Impact on a system-by-system basis	Systems that have more far reaching impacts are given higher priority. For example, AC Panel failure could render entire switchgears breakers inoperable, which could cascade into a larger system problem which has to be solved within the eight hours the DC system could provide, therefore replacing AC Panels will be given a higher priority compared to SSTs. On the other hand, basement flood would have a more immediate impact on the system compared to failure of an air compressor
Number of Customers	The larger the number of customers connected to the station, the higher the priority. For example, ancillary systems located at TS are given higher priority than those located at MS.
Voltage conversion planned? (see Section E6.6.5.3)	Stations with voltage conversion plans do not need any of their assets to be replaced

E6.6.5 Options Analysis

E6.6.5.1 Transformer Stations

The Sustainment Option is Toronto Hydro's proposed plan for the Transformer Stations segment over the 2025-2029 rate period, as presented in this document. This option was selected because it is best aligned with customer priorities: an equal balance on reliability and cost. As a result, the Sustainment Option is expected to maintain TS reliability given population demographics and System Health. In addition, two other options were considered: Improvement and Managed Deterioration. The outcome measures, units, and costs of each option are presented in Table 60 below.

Table 60: Transformer Stations Options – Measures, Units, and Costs

Outcome Measure		2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
APUL [%]	TS Switchgear	42	32	28	34
	Outdoor Breaker	13	8	8	13

Outcome Measure		2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
System Health (ACA) [%]	Outdoor Switch	7	14	14	20
	TS Switchgear	2	15	13	16
	Outdoor Breaker	5	12	12	19
Arc-Resistant TS Switchgear [%]	TS Switchgear	26	36	40	32
CIR Period		**2020-24**	**2025-29**	**2025-29**	**2025-29**
TS Switchgear		5	5	7	4
TS Outdoor Breaker		12	12	12	7
TS Outdoor Switches		69	63	63	49
Cost ($M)		95.2	134.1	168.1	112.2

The Improvement Option would replace an extra two TS switchgear with an additional cost of $34.0 million relative to the Sustainment Option. This option would ensure that population demographics meet or exceed those present over the 2020-2024 rate period. This is expected to result in higher system reliability, and would result in an improvement to all measures provided in Table 60. This option is not recommended because customers have indicated almost equal priority on cost and reliability. The Improvement Option favours reliability over cost, and therefore is not aligned with customer priorities.

The Managed Deterioration Option would replace one TS switchgear, five outdoor switchgear breakers and 14 disconnect switches less, resulting in 21.9 million decrease in spending compared to the Sustainment Option. The Managed Deterioration Option would result in more obsolete and old components remaining in the system, thereby marginally decreasing Toronto Hydro's reliability. In order to maintain Toronto Hydro's standards and align with industry standards, this option is not recommended.

E6.6.5.2 Municipal Stations

The Sustainment Option is Toronto Hydro's proposed plan for the Municipal Stations segment over the 2025-2029 rate period, as presented in this document. This Option was selected because it is best aligned with customer priorities: an equal balance of reliability and cost. As a result, the

Sustainment Option is expected to maintain MS reliability given population demographics and asset failure trends. In addition, two other options were considered: Improvement, and Managed Deterioration. The outcome measures, units, and costs of each Option are presented in Table 61 below.

Table 61: Municipal Stations Options – Measures, Units, and Costs

Outcome Measure	2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
APUL [%]	40	33	31	35
System Health (ACA) [%]	3	21	20	22
Arc-Resistant MS Switchgear [%]	22	37	40	35
Rate Application Period	**2020-24**	**2025-29**	**2025-29**	**2025-29**
MS Switchgear	10	12	15	10
Power Transformers	11	15	17	12
MS Primary Supplies	4	1	1	1
Cost ($M)	44.6	70.3	83.2	57.7

The Managed Deterioration Option would replace two fewer MS switchgear and three fewer power transformers with a cost reduction of $12.6 million relative to the Sustainment Option. The Managed Deterioration Option would result in an increase in the number of the oldest MS switchgear in service, and would maintain population demographics for the power transformers. This is expected to result in lower system reliability, especially given recent failure trends, and would result in a degradation to all measures provided in Table 61. This Option is not recommended because customers have indicated almost equal priority on cost and reliability. The Managed Deterioration Option is expected to reduce reliability, and therefore is not aligned with customer priorities.

The Improvement Option would replace three more MS switchgear and two more power transformers with a cost increase of $12.9 million relative to the Sustainment Option. The Improvement Option would result in equal or improved MS switchgear demographics, and would increase pacing in power transformer replacements to eliminate all units operating past 59 years by the end of 2034. This is expected to result in improved system reliability, and would result in an improvement to all measures provided in Table 61. This Option is not recommended because customers have indicated equal priority on cost and reliability. The Improvement Option is expected

to improve reliability at significantly greater cost, and therefore is not aligned with customer priorities.

E6.6.5.3 Control and Monitoring

The Improvement Option is Toronto Hydro's proposed plan for the Control and Monitoring segment over the 2025-2029 rate period, as presented in this document. This Option was selected because it is best aligned with customer priorities: a balance between reliability and cost in terms of RTU Renewal with the addition of modernizing the grid from older obsolete electromechanical relays to digital relays for Relay Renewal. As a result, the Improvement Option is expected to maintain Control and Monitoring reliability given population demographics and asset failure / corrective work trends while also modernizing the grid to new digital relays. In addition, two other options were considered: Sustainment, and Managed Deterioration. The outcome measures, units, and costs of each Option are presented in Table 62 below.

Table 62: Control and Monitoring Stations Options – Measures, Units, and Costs

Outcome Measure	2024 Bridge	2029 Proposed – Improvement	2029 Alternative 1 – Sustainment	2029 Alternative 2 – Managed Deterioration
RTU APUL/Obsolete [%]	29%	0%	0%	6%
TS Relay APUL/Obsolete [%]	43%	21%	28%	28%
Digital Relays [%]	63%	90%	64%	64%
CIR Period	**2020-2024**	**2025-2029**	**2025-2029**	**2025-2029**
TS RTU	12	19	19	14
MS RTU	48	14	14	8
TS Relay	46	121	98	98
MS Relay	0	130	16	16
Cost ($M)	28.3	64.7	35.7	30.4

The Sustainment Option would focus on replacing both RTUs and digital relays (rather than electromechanical relays) that are obsolete or past their typical useful life, resulting in a cost reduction of $28.96 million. The Sustainment Option would also continue to upgrade pilot wire and transfer trip relay customers with copper communications to fiber and upgrade the relays from electromechanical to digital. This option would replace the same amount of RTUs, pilot wire relays, and transfer trip relays, however, this would still replace 21 electromechanical relays (pilot wire or

transfer trip relays) and focus the remainder on the digital relays which are expected to be obsolete or past their typical useful life. For this option, it mainly focuses on the renewal portion of the portfolio rather than modernizing the system. While this option still seems like an improvement due to the continued improvement to the outage measures (other than Digital Relay percentage), the rate of replacement in terms of total RTUs is less than proposed last rate application and relays are now becoming more integrated into the portfolio so it should lower the amount of relays that are considered obsolete or past their typical useful life to a more reasonable percentage. In addition, these percentages also include the help of current planned Switchgear Renewals and MS Conversions. This option is not recommended because with an ever-growing need for modernization, digital relays can help provide a greater ability for control and monitoring Toronto Hydro distribution.

The Managed Deterioration Option is very similar to the Sustainment option, with the difference being to only replace RTUs that are past their typical useful life versus RTUs that are considered obsolete as well. This would result in a reduction from the proposed option of $34.33 million. This option is not recommended, since modernization and having the ability to control and monitor the system has become a high priority and is crucial for many of Toronto Hydro's operations.

E6.6.5.4 Battery and Ancillary Systems

The Sustainment Option is Toronto Hydro's proposed plan for the Battery and Ancillary segment over the 2025-2029 rate period, as presented in this document. This Option was selected because it is best aligned with customer priorities: an equal balance on reliability and cost. This option would reduce failure risks and provides positive outcome for customers by maintaining reliability. In addition, two other options were considered: Improvement, and Managed Deterioration. The outcome measures, units, and cost of each option are presented in Table 63 below.

Table 63 : Battery and Ancillary Systems – Measures, Units, and Costs

Outcome Measure	2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
Batteries APUL [%]	12%	9%	0%	14%
Charger Systems APUL [%]	7.5%	11%	1%	12%
SST APUL [%]	7%	0%	0%	2%
CIR Period	**2020-24**	**2025-29**	**2025-29**	**2025-29**
MS Batteries	46	39	53	32
TS Batteries	10	16	16	16

Outcome Measure	2024 Bridge	2029 Proposed – Sustainment	2029 Alternative 1 – Improvement	2029 Alternative 2 – Managed Deterioration
MS Charger Systems	39	7	21	5
TS Charger Systems	2	1	1	1
Sump Pump	1	3	3	1
SST	6	3	3	2
AC Panel	1	5	5	3
Expenditure ($M)	7.3	13.6	15.1	8.8

The improvement Option would replace 14 more MS Batteries and 14 more MS Chargers with a cost increase of $1.42 million relative to the Sustainment Option. Overall, this option is expected to improve system reliability and replace almost all batteries and chargers which are past their useful life by 2029. This option is not recommended, because it does not align as well with customer priorities: an equal balance on reliability and cost.

The Managed Deterioration Option would replace seven fewer MS Batteries and two fewer MS Chargers, two fewer sump pumps, one less SST, and two fewer AC Panels at a cost reduction of $4.89 million relative to the Sustainment Option. This Option would permit an increase in APUL for Batteries and Charger Systems and SSTs. Also, for other ancillary systems, two AC panel renewals and two sump pump installations would be deferred to the next rate application period, which is expected to result in lower system reliability. This Option is not recommended because customers have indicated almost equal priority on cost and reliability.

E6.6.6 Execution Risks & Mitigation

Each segment of the Stations Renewal Program faces challenges which can delay or prevent planned renewal work from occurring. Many of these challenges overlap across the four segments of this Program. These challenges are summarized in the Table 64 below.

Table 64: Execution Risk Applicability by Segment

Segment	Execution Risks						
	Resource Constraints	Planned outages	Asset Failures	Procurement Lead Times	Project Assessment	Distribution Coordination	Other Risks
Transformer Stations	✓	✓	✓	✓	✓	✓	✓
Municipal Stations	✓	✓	✓	✓	✓	✓	✗
Control and Monitoring	✓	✓	✗	✓	✓	✗	✓
Battery and Ancillary Systems	✓	✓	✓	✓	✓	✗	✗

E6.6.6.1 Resource Constraints

All four segments of the Stations Renewal Program use the same pool of stations design and construction resources. Therefore, if there are insufficient resources to complete all the projects planned in the Program, then certain projects will need to be deferred to ensure highest priority projects are completed. Prioritization of projects within this Program is discussed in Section E6.6.3.4. Toronto Hydro is mitigating this risk with the help of third-party providers to complete any projects in excess of Toronto Hydro's resource capacity.

E6.6.6.2 Planned Outages

Most of the renewal work cannot be completed unless a planned outage is arranged. Planned outages are needed to de-energize feeders, power transformers, switchgear, or entire stations without causing power outages to customers, so that Toronto Hydro's crews can safely complete replacement or maintenance work. For Toronto Hydro to de-energize station assets without introducing any undue risk of power outages, Toronto Hydro cannot execute multiple planned outages within the same TS or at two neighbouring MS. Additionally, projects occurring at neighbouring MS are planned to take place in different years, and if possible, at least two years apart.

E6.6.6.3 Asset Failures

Failure of station assets are a source of unplanned station outages which can prevent replacement projects from proceeding due to lack of redundancy. This risk can be mitigated by proactively replacing end-of-life station assets in a timely manner as proposed in this Program.

E6.6.6.4 Procurement Lead Times

Procurement lead times for power transformers, MS switchgear, and TS switchgear range from six to 18 months. For this reason, it is difficult and sometimes infeasible to advance or expedite the replacement of a station asset, even if such a change in schedule would result in a more effective execution of the Program. To help mitigate this risk, Toronto Hydro orders this equipment six to 26 months or earlier in advance of expected in-service dates. In addition, with the planned renewal plan for relays, there is an added risk of procurement issues as there has been issues procuring relays recently. Currently, lead times are expected to be around four to five months but with the addition of so many additional planned digital relays, this may add additional complications with procurement.

E6.6.6.5 Distribution Coordination

Distribution coordination is a challenge commonly affecting the TS and MS segments. All TS switchgear replacement projects and all projects under the MS segment require a distribution project to support the replacement of station assets. A switchgear replacement requires distribution feeders to be removed from the old switchgear and connected to the new switchgear, and replacement of the primary cable within a MS is completed through a distribution project. As a result, if there are delays or resource constraints in the distribution projects, then dependent station projects may also be delayed. Similarly, distribution projects also require planned outages as discussed earlier.

To mitigate the risk relating to distribution coordination, Toronto Hydro engineers strive to clearly define the need for coordination between station and distribution projects at the inception of such projects. On this basis, project managers plan interdependent projects as a single entity so that adequate resources can be allocated and adequate outage planning can be initiated.

E6.6.6.6 Project Assessment

All planned work undergoes a risk assessment by Toronto Hydro's control centre prior to execution. This timeframe is accounted for in the pacing outlined in Section E6.6.3.4.

E6.6.6.7 Other Risks

The risks identified below apply only to their specific segments.

1. Hydro One Coordination (TS)

One of the most significant risks for the successful completion of projects under the TS segment will be Toronto Hydro's ability to effectively coordinate with Hydro One. For example, when replacing a TS switchgear, close coordination is required to transfer Hydro One's supplying transformers from the existing switchgear to the new switchgear. For TS outdoor breaker replacements, all protection and control wiring needs to be verified by Hydro One prior to the breakers being placed back in-service.

With this need for coordination, there is always a risk Hydro One might not be able to secure resources to align with Toronto Hydro's work plan. Additionally, similar to the discussion in Section E6.6.6.2, Hydro One also requires that its own equipment undergo planned outages. Given the need for such planned outages, there is a risk that Toronto Hydro's replacement work will be prevented from proceeding due to a lack of redundancy.

Toronto Hydro mitigates this risk by sharing its high-level replacement plans with Hydro One years in advance of planned project start date. As project execution draws closer, Toronto Hydro and Hydro One exchange detailed information and communicate more frequently to ensure that work plans and resourcing aligns for both companies. For more information, see Exhibit 2B, Section B.

2. Physical Constraints (TS)

Space limitations pose a significant risk to the timely completion of TS switchgear renewal projects under the TS segment. In many cases, Toronto Hydro stations do not have space available to install new switchgear. This is a problem because it is usually necessary to install a new switchgear before decommissioning the existing unit, so as to maintain continuous power supply to customers.

The alternative to this approach is to transfer all customers from the existing switchgear to an adjacent switchgear, decommission the existing switchgear, and then install the replacement in the same space. This can only be done if the adjacent switchgear has enough spare capacity to supply these additional customers. Spare capacity on this order is seldom available.

Toronto Hydro mitigates this risk through use of its Station Expansion Program, which is intended to ensure capacity requirements are met on the distribution system. [22] For example, replacement of the Windsor TS A3-4WR switchgear unit will be possible once Windsor A19-20WR been energized,

[22] Exhibit 2B, Schedule E7.4.

following which the electrical load on the Windsor TS A3-4WR switchgear will be transferred to the new A19-20WR switchgear. A19-20 can only be energized with Hydro One T1/T3 after Hydro One replaces their transformers T5/T6 in Q2 2025. Thereafter, A3-4WR can be decommissioned and its space used to install a new switchgear – A21-22WR. This in turn will allow capacity for the next Windsor TS switchgear unit to be replaced.

In the case of TS building not having enough space to install a new switchgear, a new building or renovation for an existing building is required to facilitate the switchgear replacement. However, this solution requires a long-term plan since the construction of the building may take few years to be ready for switchgear installation. Toronto Hydro plans to request Hydro One to refurbish Hydro One owned building for the new switchgear installation at Bridgman TS.

Due to the lack of space at TS in Downtown, it is impossible to expand the building or is very costly to do so. Small footprint switchgear is necessary for limited space in the TS residing in the Downtown area. Pursing the cost-effective switchgear with narrow feeder cell will be only way to implement switchgear replacement in some TS, like Cecil, Charles, Duplex and Windsor.

By ensuring a reasonable level of spare capacity at or adjacent to heavily loaded stations, Toronto Hydro will be able to effectively plan and execute switchgear replacement while accommodating new customer connections.

3. Customer Coordination (Control and Monitoring)

For pilot-wire system replacements under the Control and Monitoring segment, a challenge to successful execution is customer coordination. Such replacements require customer relays and associated equipment to be replaced in parallel with Toronto Hydro's equipment. This introduces a risk since projects cannot be scheduled until a time is found which satisfies both the customer's and Toronto Hydro's needs. Toronto Hydro minimizes this risk by informing customers several months ahead of planned work, allowing sufficient time for customers to respond and schedule a time that is feasible.

E6.7 Reactive and Corrective Capital

E6.7.1 Overview

Table 1: Reactive and Corrective Capital Program Summary

2020-2024 Cost ($M): 297.6	**2025-2029 Cost ($M):** 328.1[1]
Segments: Reactive Capital; Worst Performing Feeders	
Trigger Driver: Failure	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Environment and Customer Focus	

The Reactive and Corrective Capital program (the "Program") addresses the replacement of failed and defective major assets, and provides for near-term corrective actions on Toronto Hydro's least reliable feeders. The work required under this Program is unplanned, unpredictable, and non-discretionary. Toronto Hydro carries out the projects and activities in this Program in response to:

- Major asset failures;
- High risk asset deficiencies discovered through planned inspection or in the course of day-to-day work; and
- Feeders exhibiting especially poor reliability.

The Program is grouped into two segments summarized below, and is a continuation of the reactive and corrective activities described in Toronto Hydro's 2020-2024 Distribution System Plan.[2]

- **Reactive Capital:** This segment covers the non-discretionary replacement of failed or failing major assets across the entire system. There are a significant number of asset failures each year. Between 2018 and 2022, on average, there were over 825 Customer Interruptions ("CI") and over 678 Customer Hours Interrupted ("CHI") associated with each major asset failure across the network. Catastrophic failures of assets can require very large investments by Toronto Hydro which, in the absence of a dedicated reactive capital budget, would deprive other programs of necessary resources to maintain the grid. The objective of this segment is to manage unexpected asset failures and address high-risk deficiencies (or assets

[1] Consistent with the 2020-2024 program, the 2025-2029 program forecast includes allowances for streetlight reactive pole replacement, reactive streetlight replacement and streetlight spot improvement.
[2] EB-2018-0165, Exhibit 2B, Section E6.7

approaching imminent failure) in a timely and cost-effective manner. Toronto Hydro's goal is to mitigate the impact of failures on customer outcomes such as reliability, safety, and the environment for 2025 to 2029 and beyond.

- **Worst Performing Feeders:** The Worst Performing Feeder ("WPF") segment focuses on improving overall service reliability for customers supplied from poorly performing feeders. The objective of this segment is to identify feeders performing poorly over a rolling 12-month period and perform work in an effort to mitigate further interruptions. Toronto Hydro defines a feeder as performing poorly when it meets, or is trending towards meeting, the following criteria:
    - Feeders (with no large customers) at risk of experiencing seven or more sustained interruptions (referred to as Feeders Experiencing Sustained Interruptions of 7 or more, or "FESI-7");
    - Key Account ("KA") feeders at risk of experiencing six or more sustained interruptions (referred to as Feeders Experiencing Sustained Interruptions of 6 or more, or "FESI-6 Large Customer"); or
    - Feeders (KA or non-KA) that are experiencing systemic issues in a localized area that are resulting in, or are at risk of resulting in, multiple sustained or momentary interruptions.

Toronto Hydro has also started tracking a new metric called Customers Experiencing Multiple Sustained or Momentary Interruptions of 10 or more ("CEMSMI-10") to put additional focus on large critical customers with Ion meters who are experiencing poor reliability (including power quality) that negatively impacts their operations. These customers are typically large manufacturing facilities or hospitals, which are sensitive to voltage sags and momentary outages.

Poorly performing feeders that are designated FESI-7 or FESI-6 Large Customer have a disproportionately negative impact on the system's overall reliability performance, as reflected in metrics such as the annual CI and CHI. In an effort to effectively manage these metrics and the impact on customer, outages are analyzed on poorly performing feeders and targeted work is issued.

As the nature of work in this Program is largely unplanned, unpredictable, and can vary significantly from year to year, Toronto Hydro has based its 2025-2029 forecast costs and projected reactive work

volumes for this Program on historical trends and asset condition demographics. The utility forecasts $328.1 million for the Program during the 2025-2029 rate period, which is approximately 10 percent higher than projected for 2020-2024. Timely reactive work improves safety, avoids depriving other capital programs of planned resources, mitigates environmental impacts and public safety risks, and reduces strain on the distribution system.

E6.7.2 Outcomes and Measures

Table 2: Reactive and Corrective Capital Program Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, FESI-6 Large Customer, System Health Index) by: ○ Promptly replacing major assets that have failed or are at a very high risk of near-term failure; ○ Monitoring feeders that are at a high risk of becoming FESI-7 or FESI-6 Large Customer, and taking near-term mitigating actions where feasible.
Operational Effectiveness - Safety	• Contributes to maintaining Toronto Hydro's Total Recorded Injury Frequency (TRIF) measure and safety objectives (including compliance with Ontario Regulation 22/04) by: ○ Replacing failed major assets or assets approaching imminent failure to mitigate the risk of catastrophic asset failure causing injuries to utility employees and/or members of the public.
Environment	• Contributes to reducing environmental impact of Toronto Hydro's distribution system by: ○ Reducing the potential for release of harmful chemicals, smoke, or waste (e.g. oil leaks, SF6 gas) into the environment through timely replacement of failing or failed major assets. ○ Improving Toronto Hydro's Spills of Oil containing PCBs measure and reduce the risk of toxic exposure to the environment by eliminating PILC cable and AILC cable containing asbestos and/or lead.

Customer Focus	• Contributes to Toronto Hydro's customer service obligations and objectives by: ○ Ensuring the accurate billing of all smart metered customers based on actual usage by restoring metering service as soon as possible. ○ Supporting compliance with the Electricity and Gas Inspection Act and the Weights and Measures Act.

E6.7.3 Drivers and Need

Table 3: Reactive and Corrective Capital Program Drivers

Trigger Driver	Failure
Secondary Driver(s)	Reliability, Safety, and Environmental Risk

The Reactive and Corrective Capital program is largely driven by the need to address equipment failure. The Program is focused on ensuring asset and system performance at an acceptable standard by:

- Addressing asset deficiencies and failures through like-for-like replacements;
- Completing short-term and small-scale replacements to reduce safety and environmental risks; and
- Executing short term, targeted, and small-scale mitigation measures to reduce the risk of additional outages on feeders exhibiting poor reliability outcomes.

The needs underlying the Reactive Capital segment must be addressed in short order mainly due to asset failure risk. The Worst Performing Feeders segment mainly aims to improve overall service reliability for customers supplied from poorly performing feeders.

Through the Program, Toronto Hydro will be better able to maintain system performance and reliability, manage or eliminate safety risks to the public and Toronto Hydro employees, and ensure customer satisfaction. The trigger and secondary drivers for this Program are discussed below.

E6.7.3.1 Failure Risk

Asset failure on Toronto Hydro's distribution system presents reliability risks which can lead to outages and directly impact customers, environmental risks such as oil spills, and safety risks such as

arc flashes, and potentially catastrophic fires. These aspects are discussed in more detail in the following sub-sections. Additionally, timely replacement of failed equipment may be required to avoid operating the distribution system under contingency conditions (i.e. with a lack of feeders or assets that can provide backup supply in the event of a subsequent equipment failure).

Various factors can cause failure, including degradation of an asset's condition, foreign interference, and weather (e.g. major storms). For example: a fractured pole caused by a vehicle accident (i.e. foreign interference); or structural deficiencies of an underground vault as a result of gradual degradation. See Figures 1 and 2 below for reference.



Figure 1: Pole struck by vehicle identified through a patrol



Figure 2: Underground vault structural deficiencies

Age and condition can also affect the health of an asset, and contribute to asset failure. With a higher number of end-of-life assets in the system there is a greater likelihood of failure and need for reactive

replacement. Toronto Hydro performs Asset Condition Assessments ("ACA") on many of its major asset classes. The System Health – Asset Condition for a major asset is ranked from HI1 to HI5 where HI5 indicates the worst condition. Table 4 below shows the percentage of combined HI4 and HI5 populations of major assets divided by their total populations. Wood poles represent the highest number of HI4 and HI5 assets out of the total at risk asset population (e.g. 9,628 in the distribution system) which will continue to drive expenditures in this Program.

Table 4: Proportion of Assets in HI4 & HI5 by Major Asset

Major Assets	2022 Total # of Assets Breakdown		
	Total Assets per Asset Class	Current Health Score 2022 Data	
		HI4 & HI5	% HI4 & HI5
Wood Pole	106,386	9,628	9%
Cable Chamber	10,657	592	6%
Vault Transformer	11,497	258	2%
Submersible Transformer	9,161	180	2%
Padmounted Transformer	7,011	257	3%
Network Vault	470	91	19%
Network Protector	1,728	42	2%
Network Transformer	1,718	43	3%
Total	**148,628**	**11,073**	**7%**

In addition to assessing current condition, Toronto Hydro projects future asset condition for the same assets. As an example, Table 5 summarizes Toronto Hydro's ACA results for underground submersible transformers, which indicate:

- 180 submersible transformers exhibit material deterioration (HI4 & HI5) and should be considered for replacement as of end of 2022;
- Without any intervention, the number of transformers exhibiting material deterioration is forecasted to more than double by 2029.

Table 5: Asset Condition for Submersible Transformers[3]

Condition	Submersible Transformers	
	2022	**2029**

[3] For more details on Asset Condition Assessment see Exhibit 2B, Section D1 – Asset Management Process Overview.

HI1 - New or Good Condition	8,120	7,330
HI2 – Minor Deterioration	699	642
HI3 – Moderate Deterioration	162	635
HI4 – Material Deterioration	133	240
HI5 – End of Serviceable Life	47	314
Total	**9,161**	**9,161**

Detailed discussions of the condition and age demographics of various asset classes are provided under Toronto Hydro's System Renewal programs.[4]

1. Reliability

An important driver of the Program is system reliability. Depending on the asset and its location within the distribution system (e.g. Main trunk vs. laterals/sub-laterals), the impact may vary from ten customers experiencing an outage to thousands of customers on the main trunk. Asset failures affect the supply of power to Toronto Hydro's customers (e.g. key account customers, residential and/or industrial) and the additional fault current and switching surges create strain on the system that can lead to cascading failures or reduced expected life of other major assets. Historical system reliability impacts are discussed in detail further below.

Figure 3 below shows the causes of sustained interruptions between 2018 and 2022. The chart shows that 41 percent of all sustained interruptions are caused by defective equipment, which is significantly higher than all other causes. The Program focuses mainly on the mitigation of outages caused by major equipment failures; however, it can also mitigate interruptions by various other causes. For example, when replacing a failing overhead transformer, Toronto Hydro may fit the new transformer with an animal guard that may mitigate the "Animal Contact" cause as well as the "Defective Equipment" cause.

[4] Exhibit 2B, Section E6.

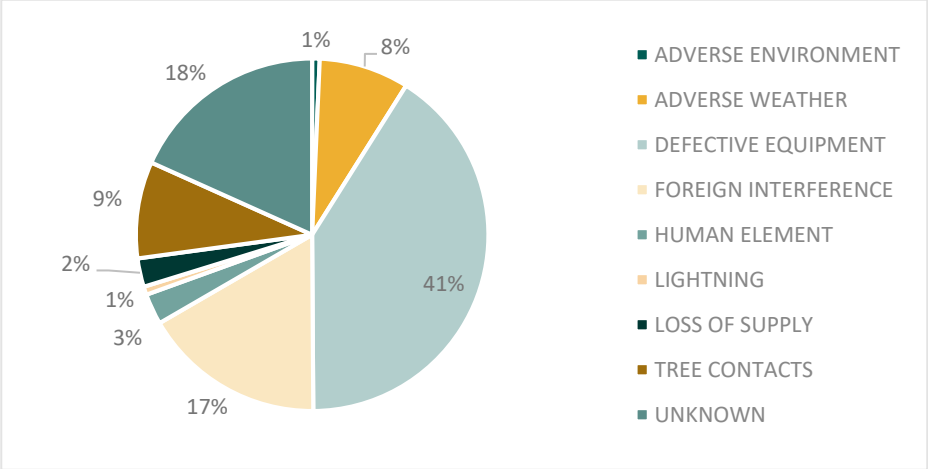


Figure 3: Causes of Sustained Feeder Outages between 2018 and 2022

Table 4 below shows the customer reliability impacts of major asset failures between 2018 and 2022. Each failure of an overhead switch between 2018 and 2022, for example, caused an average of 1,062 customers interruptions and 572 Customer Hours Interrupted. Timely replacement of equipment prior to its failure will mitigate the frequency and duration of interruptions experienced by customers.

Table 4: Average CI and CHI Associated with Failures of Major Assets from 2018 - 2022

Asset	Average Customers Interrupted (CI)	Average Customer Hours Interrupted (CHI)
Overhead Switches	1,062	572
Underground Switchgear	1,204	1,156
Overhead Transformers	115	122
Poles	1,159	673
Underground Cables	881	775
Underground Transformers	596	326

Through Phase 1 of Toronto Hydro's Customer Engagement, "Reliable Service" was identified as a top customer need, and ranked in the top three priorities for all customers, with reliable service being the top priority for key account customers.[5] Most notably, however, there is increasing demand for reliable service from smaller residential customers. A likely contributor to this trend is

[5] See Exhibit 1B, Tab 5, Schedule 1 – Customer Engagement; and Appendix A for Customer Engagement Report.

the transition to work-from-home for many employees at least part of the time, driven by the COVID-19 pandemic. Interruptions to many residential customers is no longer merely an inconvenience, but also impacting businesses through lost labour hours. This Program is intended to address this customer priority, among others, by issuing the necessary mitigation work to reduce the total number of outages and their duration.

2. Safety

Another important driver of the Program is the safety of both the public and Toronto Hydro employees. Failure modes of equipment, depending on their nature, can have immediate and serious safety or environmental consequences. For example, transformers in deteriorated condition may experience transformer fires or oil leaks. Similarly, overhead lines with damaged insulators may lead to tracking and potential pole fires which is a serious safety risk to workers and the public. Furthermore, civil deficiencies such as structural damage in underground assets can jeopardize the public and Toronto Hydro employees. The Reactive Capital segment mitigates safety risks by replacing assets that have failed or are approaching imminent failure. Figure 4 illustrates a pole fire (left) and hazardous civil conditions found in a network vault (right).



Figure 4: Pole fire caused by Tracking (left), Exposed and rusted rebar in Network Vault (right)

3. Environment

Finally, asset failures can also be harmful to the environment. Leaking oil-filled transformers, PILC cable splices, or SF6-insulated switchgear pose a serious environmental risk. Asset failures can also result in the release of harmful contaminants and greenhouse gases into the environment. Timely capital replacements help mitigate such environmental risks. The Reactive Capital segment addresses oil deficiencies by replacing leaking transformers. As an added benefit, during transformer replacement, assets that are at risk of containing PCB are also replaced, thereby reducing the

possibility of oil spill containing PCBs and contributing to complete removal of all PCB transformers by 2025.

E6.7.3.2 Reactive Capital

The Reactive Capital segment is comprised of work relating to overhead, underground, secondary network, stations and metering assets. The purpose of this reactive work is to restore service to customers and maintain system reliability by addressing severe asset deficiencies and failures. Reactive work occurs on an unplanned basis in response to an asset failure or the detection of a high-risk asset deficiency (e.g. a severely cracked or rotten pole). Such issues cannot be addressed under planned capital renewal procedures and timelines, and therefore must be reactively replaced to maintain the safety and reliability of the distribution system. Reactive work is executed within a short timeframe (e.g. within 15 days to within six months, based on assigned priority level) following the detection of an asset requiring replacement. Reactive work covers Toronto Hydro's entire distribution system and affects all asset classes.

Asset deficiencies or substandard conditions across Toronto Hydro's distribution system are identified mainly through the Preventative and Predictive Maintenance programs, but can also be identified either during the normal course of operations or through the Emergency Response program, as shown in Figure 5. Identified deficiencies or substandard conditions are subsequently addressed through a variety of programs:

- Preventative and Predictive Maintenance;
- Corrective Maintenance; and
- Reactive and Corrective Capital programs.[6]

[6] Exhibit 4, Tab 2, Schedules 1-4 for maintenance programs

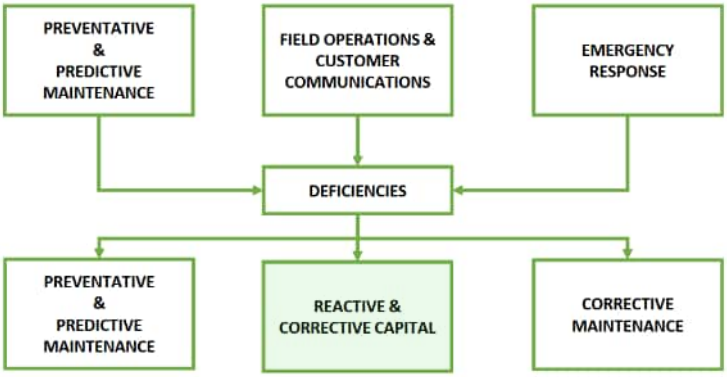


Figure 5: Deficiency Capturing Process[7]

- **Preventative & Predictive Maintenance Activities**: Field crews identify asset failures and deficiencies as part of scheduled maintenance and inspection activities. The inspection cycle depends on the maintenance program as per Reliability Centered Maintenance ("RCM"). The RCM framework is a comprehensive approach to the lifecycle maintenance of distribution system assets. RCM enables Toronto Hydro to leverage a methodological approach to preserve the asset's function by implementing failure management practices that target the potential functional failure.

- **Field Operations & Customer Communications**: Issues or actions identified can also be triggered by sources outside scheduled or planned maintenance activities. These include, but are not limited to:
  - Phone calls from customers to Toronto Hydro;
  - External emails to Toronto Hydro;
  - Observation by field crews during the normal course of operations;
  - Customer inquiries requiring field assessment and follow up; and
  - Line patrol for Worst Performing Feeder Program.

- **Emergency Response:** Reactive capital work can also be required as a result of emergencies or unplanned system events. These include asset failures and deficiencies identified outside of Toronto Hydro's daily (planned) operations but requiring follow-up remediation and reactive replacements in order to permanently restore power or eliminate safety or environmental risks.

[7] The deficiency capturing process is described in detail in Exhibit 2B Section D3.

Deficiencies from the above sources are reviewed to validate the need for reactive intervention, assessed to determine the nature of reactive intervention required (capital versus maintenance) and the level of urgency and priority (e.g. P1-P4) to be assigned to each asset deficiency. Toronto Hydro addresses the deficiencies identified by issuing work requests.[8]

For the Reactive Capital segment, Toronto Hydro uses a prioritization framework that classifies asset deficiencies into four categories:

- P1 requires resolution within 15 days;
- P2 requires resolution within 60 days; and
- P3 requires resolutions within 180 days;
- P4 which indicates that conditions are to be monitored.

Due to the unpredictable nature of asset failures, the number of reactive work requests may vary from year to year. Catastrophic failures of major assets can require large investments by the utility, and as such, Toronto Hydro requires the Reactive Capital segment to manage imminent major asset failures and address high-risk assets approaching imminent failure. This will help with providing reliable, safe, and environmentally responsible service to customers from 2025 to 2029 and beyond.

Figure 6 below shows the volume of reactive capital work requests issued from 2019 to 2022.[9]

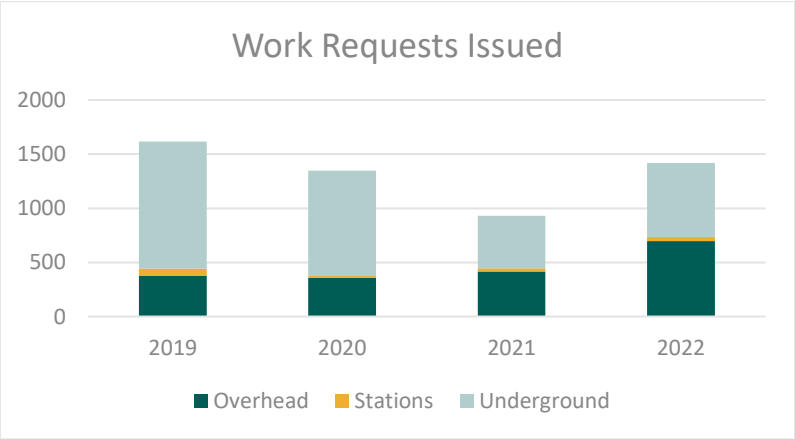


Figure 6: Historical Reactive Capital Work Requests Issued by System Type

[8] Work request are forms issued to assign / schedule corrective work addressed by Toronto Hydro or contractor crews. Deficiencies identified and work requests raised may have a one to one or many to one relationship (i.e. a single work request may contain more than one deficiency).
[9] 2018 data is excluded due to the transition to SAP that occurred during that year.

On average, 1,483 reactive capital work requests were issued each year between 2019-2022, with an overall downward trend, except in 2022, and representing a 9 percent decrease over the 2013-2017 average of 1,624 per year. Generally, the underground system contributes the most to both volume and cost to reactively replace assets, such as Underground Residential Design ("URD") vaults, transformer vaults, and network vaults. Note, that the level of spending depends not just on the volume, but the mix of the different types of work each year. For example, due to the size, operational complexity, and criticality of stations assets, station work can contribute significantly to the overall cost of the Reactive Capital segment, despite the relatively low volume of requests.

1. Metering Assets

The Reactive Capital segment also funds reactive meter replacement. Reactive meter replacement capital work consists of the replacement of defective metering equipment in the field including: smart meters, suite meters, interval meters, and primary meters (Including instrument transformers). The loss of communication with a meter is the primary cause of meter replacements. Primary metering units can also fail due to blown instrument transformer fuses which causes customer consumption to be incorrectly read, resulting in incorrect billing. Failed metering equipment not replaced in a timely manner can result in delayed billing and the need to estimate customer consumption.

Table 7 summarizes the estimated number of meter replacement units and costs for the 2025-2029 rate period. The estimated costs were derived based on a four-year weighted average of historical costs. The average percentage of meters failing remains the same but the population is increasing yearly. The meter replacement costs are embedded into the Reactive Capital segment 2025-2029 forecasts in the Expenditure Plan section.

Table 7: Reactive Meter Replacement Costs (2025 - 2029)

	Projected					
	2025	**2026**	**2027**	**2028**	**2029**	**Total**
Meter Replacements (Units)	5500	5600	5700	5800	5900	28500
Meter Replacement Costs ($ Millions)	3.56	3.66	3.76	3.89	4.02	18.88

E6.7.3.3 Worst Performing Feeders

Toronto Hydro's distribution system contains over 1,500 feeders that supply power to over 790,000 customers in the City of Toronto. While any one of these feeders is subject to random equipment

breakdown, foreign interference and environmental effects that can cause unplanned outages, specific feeders experience a disproportionate number of problems and cause an unacceptably high number of sustained or momentary interruptions to the customers connected to them. Figure 7 below shows that between 15 and 20 percent of the total CI, and approximately 10 percent of CHI in a given year, are attributed to FESI-7 feeders, which make up less than 2 percent of all feeders, as shown in Table 8 below.

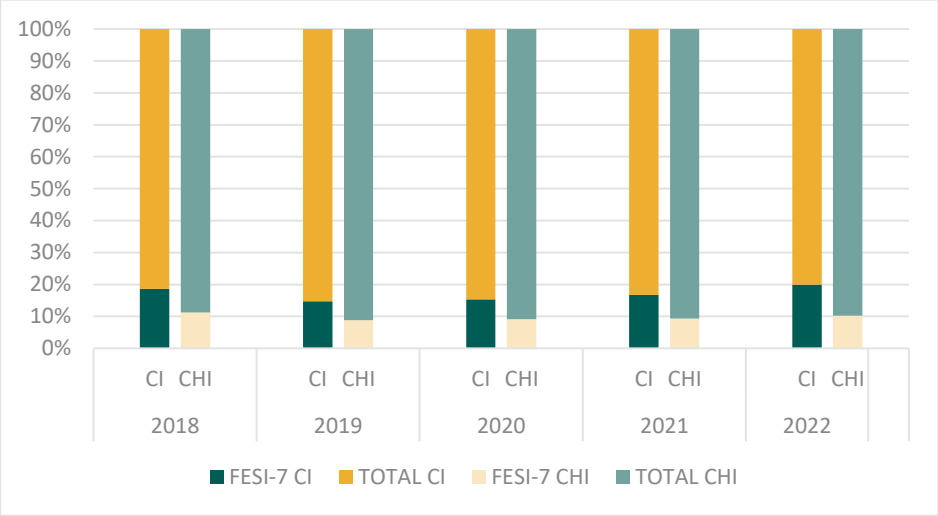


Figure 7: Contribution of FESI-7 feeders to CI and CHI between 2018 and 2022

Table 8: Number of FESI-7 feeders compared to total number of feeders

	2018	2019	2020	2021	2022
# FESI-7 feeders	17	7	9	10	27
Total # feeders	1521				
% FESI-7/total	1.12%	0.46%	0.59%	0.66%	1.78%

Figures 8 and 9 below show the locations of FESI-6 Large Customer feeders in 2020 and 2022 respectively. These feeders typically vary from year to year and are difficult to predict. Since planned renewal programs take a substantial amount of time to plan, design and execute, it is necessary to address emerging issues contributing to interruptions on these feeders in a timely manner.



Figure 8: Locations of 2020 FESI-6 Large Customer Feeders

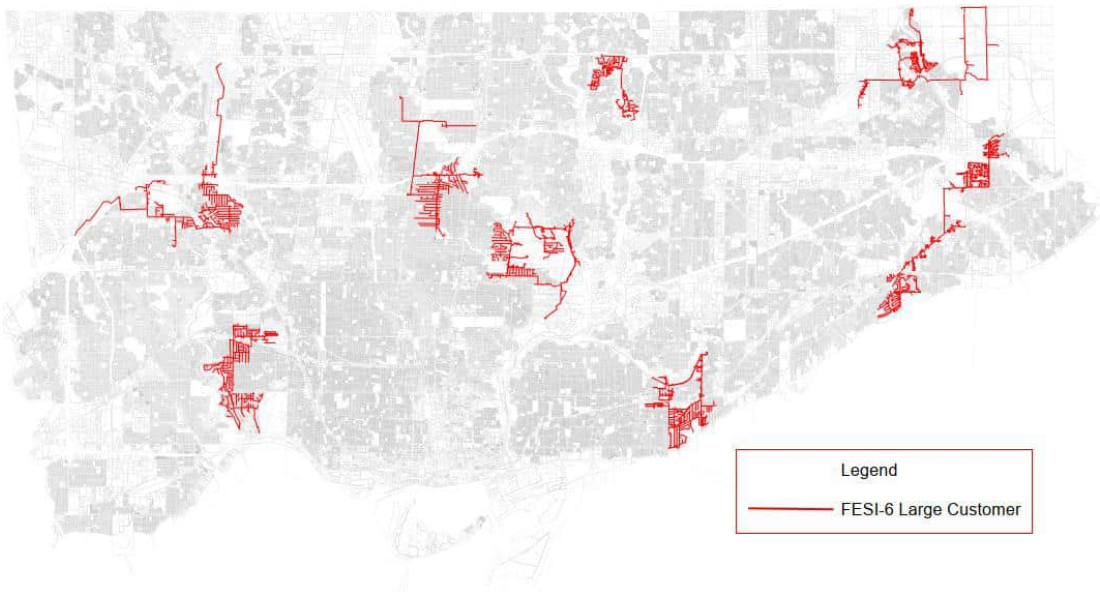


Figure 9: Locations of 2022 FESI-6 Large Customer Feeders

The main objective of Toronto Hydro's WPF segment is to improve overall service reliability for customers supplied from poorly performing feeders, which aligns with results of the Phase 1 Customer Engagement, where reliability is one of the top three priorities across all types of customer types. This improvement is accomplished by employing a feeder-level analytical approach that

selects feeders experiencing a high number of outages or trending towards increased outages, analyzing previous outages to determine the cause, and issuing work intended to address the cause in an effort to mitigate any subsequent outages. The WPF segment is designed to be a short-term mitigation measure and a complement to the planned renewal capital work. Feeders addressed by the WPF segment may still experience unpredictable failure and power outages, albeit at a lesser frequency until permanent, long-term solutions are implemented. Most of this work is targeted for completion within a 12-month period to mitigate the risk of customers being exposed to poor reliability for prolonged periods.

In addition to FESI-7 and FESI-6 Large Customer metrics, Toronto Hydro has begun to track a new metric, Customers Experiencing Multiple Sustained and Momentary Interruptions, or CEMSMI-10. This particular metric closely assesses the experience of each key account customer, as customers may be transferred to alternate supply feeders during contingency scenarios and may not consistently be supplied by their normal supply arrangement throughout the year. Additionally, since many key account customers are also negatively impacted by momentary interruptions (i.e. factory lines, hospital equipment), momentary interruptions are tracked along with sustained interruptions. Where a specific key account customer is trending towards a poor experience over a 12-month period, each feeder that supplies the specific customer will be targeted for analysis in an effort to address any deficiencies that may cause further interruptions.

Through this segment, Toronto Hydro first identifies feeders which are at risk of becoming designated FESI-7 or FESI-6 Large Customer feeders, feeders with KA customers experiencing a high volume of momentary interruptions or power quality issues (i.e. CEMSMI-10), or feeders with specific systemic issues that need to be addressed in the short term. This assessment excludes planned outages, outages occurring on Major Event Days ("MEDs"), outages caused by loss of supply, and interruptions on the secondary side of the distribution transformer. Toronto Hydro then assesses each of the past outages that occurred on the designated feeder, which includes but is not limited to:

- Reviewing comments from the Control Authority and crews attending to the outage;
- Checking for flags raised by SCADA-connected devices; and
- Reviewing voltage and current profiles collected by Ion meters in an effort to localize the outage, so that the cause may be identified and subsequently addressed.

Following a feeder reliability analysis, field crews patrol and inspect the feeders, with a particular emphasis on any locations identified during the analysis, to assess the condition of equipment and identify quick targeted actions that yield immediate reliability improvements. Examples of deficiencies discovered during such feeder patrols are shown in **Error! Reference source not found.**Figure 10 below.



Figure 10: Animal Contact on Metal Switch Bracket (Left)/Rusted Overhead Transformers at Risk of Leaking Oil (Right)

As previously stated and shown in Figure 1, 41 percent of all sustained interruptions are a result of the failure of defective equipment. Through the reliability analysis on poorly performing feeders, assets that are identified as having a risk of imminent failure are targeted for replacement before they would be scheduled for replacement under planned renewal programs. This addresses equipment deficiencies quickly before they cause subsequent outages on already poorly performing feeders.

Between 2020 and 2022, Toronto Hydro issued 107 WPF mitigation scopes to address asset deficiencies across an average of 31 different FESI-7 or FESI-6 Large Customer feeders per year. Figure 11 below shows the breakdown of asset types that were targeted for replacement. Toronto Hydro expects that this trend will continue through the 2025-2029 rate period and that there will be a similar breakdown of asset types requiring replacement through the WPF segment.

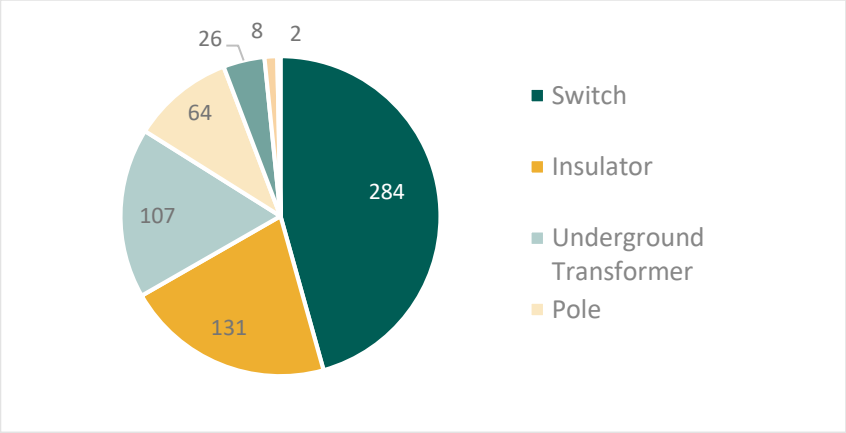


Figure 11: Breakdown of assets replaced under the WPF segment between 2020-2022

The top asset types scheduled for replacement through the WPF segment were overhead switches, insulators, and underground transformers. These assets were targeted for replacement in order to mitigate risk of failures due to the following issues:

Overhead switches with vintage porcelain insulators mounted onto metal brackets are susceptible to electrical tracking, whereby small amounts of current flow from the live switch terminals/end fittings, across the surface of the porcelain shell, to the grounded metal bracket. Electrical tracking is exacerbated by salt spray in the winter months and condensation when warm moisture-laden air comes into contact with a cold porcelain shell. Tracking can cause outages by triggering the operation of upstream protection, as well as degradation of the porcelain shell, leading to its fracture and a full asset failure. Figure 12 below shows a porcelain insulator with a hairline crack and scorch marks. New switches are fitted with larger polymer insulators and are less susceptible to electrical and mechanical failure mechanisms.



Figure 12: Porcelain insulator with small cracks in the shell and scorch marks

- Porcelain insulators mounted onto metal brackets have the same failure mode and mechanism as the above example. New insulators are manufactured using polymer.
- Single-phase submersible transformers manufactured with mild steel tanks and bare, uninsulated low voltage terminals are prone to premature failure where installed in locations susceptible to flooding. Transformers installed in these areas may experience accelerated corrosion of the tank, typically near the base, and potentially heavy corrosion of the aluminum secondary cables and steel tank near the low voltage terminals where the terminals are left bare and water levels inside the vault rise to the height of the terminals. Refer to the photos in Figure 13 below showing two transformers that had been removed from service due to extreme levels of corrosion. New single-phase submersible transformer tanks and lids are manufactured using stainless steel and are fitted with additional components that effectively seal live components from water ingress, mitigating the corrosion.



Figure 13: Mild steel single-phase submersible transformers with heavy corrosion

Figure 14 below shows the historical count of FESI-7 and FESI-6 Large Customer feeders per year. As shown, the annual number of FESI-7 and FESI-6 Large Customer feeders are a small subset of the more than 1,500 total feeders that make-up Toronto Hydro's distribution system and are gradually trending down over time since the inception of the WPF segment. There was, however, a noticeable increase in the number of FESI-7 and FESI-6 Large Customer feeders in 2022 due to the increased sensitivity of the Outage Management System in recording interruptions, which is further explained

in Exhibit 1B, Tab 02, Section 4 "Reliability Performance". It is also important to note, that the WPF segment is not the sole driver for the FESI-7 and FESI-6 Large Customer metrics, and that the success of these metrics is also heavily dependent on planned renewal programs, such as Underground System Renewal – Horseshoe.[10]

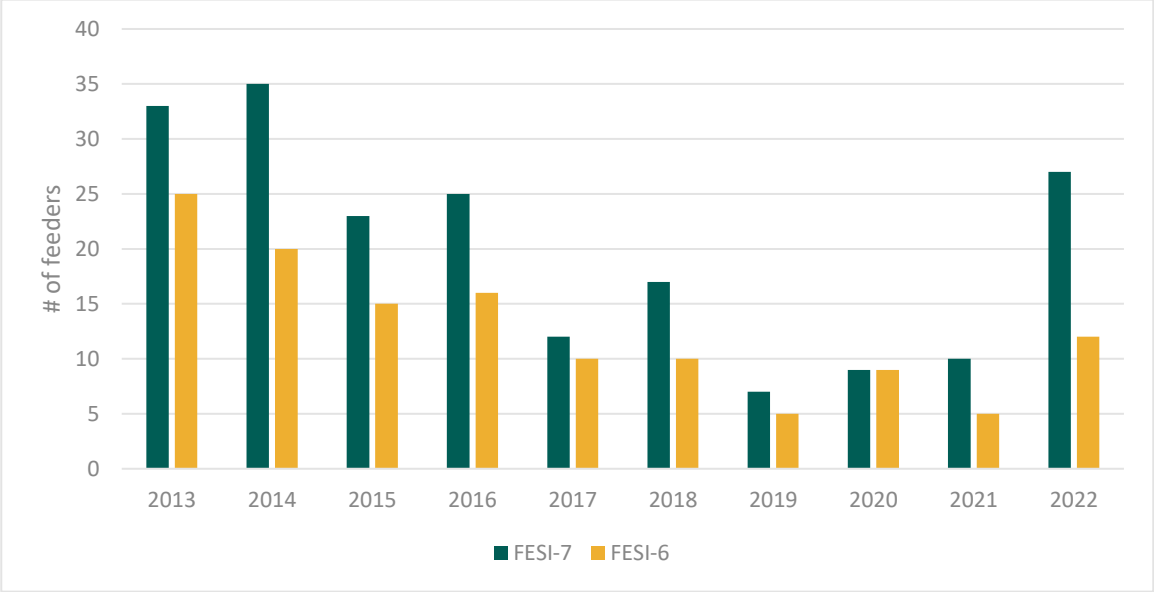


Figure 14: Historical Worst Performing Feeder Interruptions between 2013 and 2022

Although there has been an overall decline in the number of FESI-7 and FESI-6 Large Customer feeders, it is particularly important that the WPF program be maintained to sustain this decrease and continue to mitigate the risk of interruptions caused by equipment failures, as planned renewal programs have been prioritizing the replacement of transformers containing PCBs, which has reduced investment in more reliability-focused work (e.g. replacing high-risk direct-buried cable).

The WPF segment is designed to be a short-term mitigation measure and a complement to the planned renewal capital work. Feeders addressed by the WPF segment still experience unpredictable failure and power outages, albeit at a lesser frequency until permanent, long-term solutions are implemented. Overall, the WPF segment has been successful in reducing the frequency of power

[10] Exhibit 2B, Section E6.2.

interruptions for customers on feeders that are experiencing especially poor reliability performance, as shown in Figure 14 above.

E6.7.4 Expenditure Plan

Table 9 provides the Actual (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for the Reactive and Corrective Capital program.

Table 9: Historical and Forecast Program Costs ($ Millions)

	Actual			Budget		Plan				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Reactive Capital	58.7	50.9	56.0	55.1	53.1	55.4	58.4	58.3	60.6	62.8
Worst Performing Feeder	4.2	3.7	3.8	6.7	5.7	6.1	6.3	6.5	6.7	6.9
Total	**62.9**	**54.5**	**59.7**	**61.7**	**58.7**	**61.6**	**64.8**	**64.8**	**67.3**	**69.7**

E6.7.4.1 Reactive Capital Segment

Toronto Hydro invested $165.6 million in reactive capital work over 2020-2022 and projects to invest a total of $273.7 million by the end of 2024 (including forecasted inflation), which is approximately $17 million more than the $256.8 million budget approved by the OEB in the 2020-2024 rate application. Due to the demand-driven, non-discretionary nature of this segment and the volume and mix of work that needed to be addressed, Toronto Hydro could not reasonably constrain spending for this spending to the OEB approved amount.

Actual work volumes and costs will vary from year to year and Toronto Hydro forecasts future costs based on historical trends. Toronto Hydro developed its forecasts for 2020-2024 in 2018 based on the best available information at the time, which reflected an increasing trend that has since plateaued. That being said, Toronto Hydro has since developed a more detailed projection model for its 2025-2029 forecast, which is discussed below.

The predominant driver for the variance during the 2020-2024 rate period is the demand-driven nature of the actual volumes and type of assets requiring non-discretionary replacement. The unpredictable nature of asset failures can vary in type and number of equipment from year to year due to foreign interference or weather. For example:

- The volume of condemned pole reactive replacements can increase as the overall condition of poles deteriorates, as indicated by the number HI4/HI5 poles. Toronto Hydro replaces condemned poles, identified through inspections, both reactively and through proactive (planned) renewal. The total number of condemned poles approximately doubled from 2020 to 2021 and remained at a similar level in 2022. Toronto Hydro has seen a steady increase in reactive pole replacement, which includes not only condemned poles but any pole replacements required due to emergency or storm events. Given the current and projected condition of Toronto Hydro's wood poles, the utility expects this trend to continue.
- The total volume of overhead and underground transformer replacements declined from 2020 to 2022. In 2020, there were 849 transformer related work requests which decreased by approximately 50 percent in 2022. This reduction is likely due to the Toronto Hydro's recent focus on eliminating transformers at risk of containing PCBs, which are also at higher risk of failure due to their age. Toronto Hydro expects the number of transformer replacements to plateau over the next 3 to 4 years.

Toronto Hydro's 2025-2029 Reactive Capital predictive model uses a layered approach, which is based on the previously established weighted moving average methodology, but also incorporates relevant condition-based information for underground distribution transformers to forecast future capital expenditure. The underground transformer forecast leverages historical reactive replacement data to determine the average probability of reactive replacement for a given health index band. The model considers a 3-year window of anticipated asset deterioration as per ACA projections, which corresponds to the longest underground transformer inspection cycle. Expenditures beyond the 3-year window are calculated using the conventional weighted average methodology. Toronto Hydro's corresponding forecast of work request volumes is shown in Figure 15, along with historical actuals.

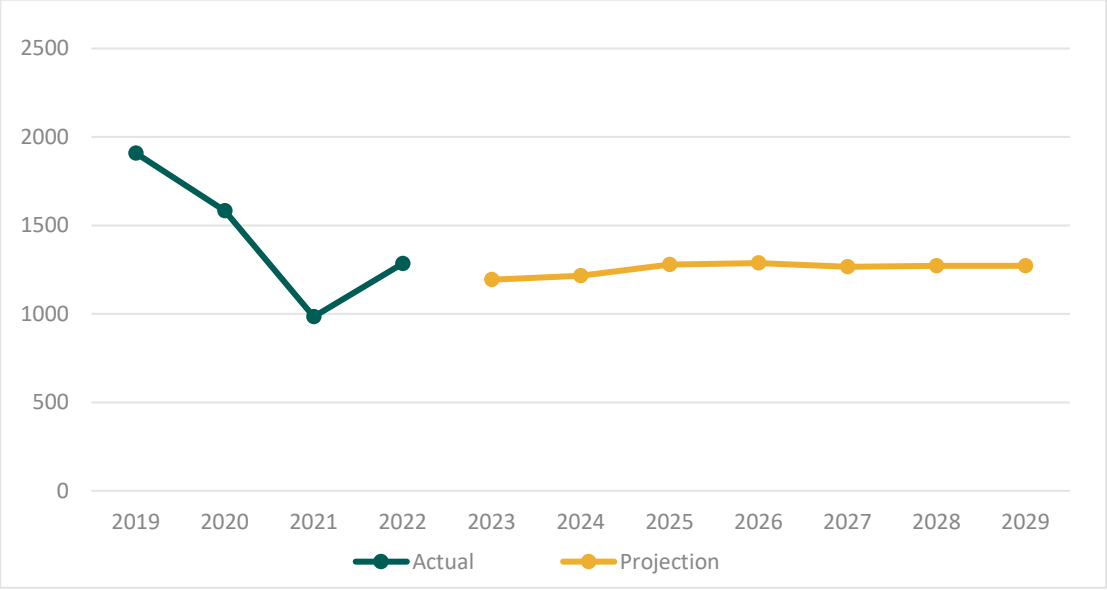


Figure 15: 2019-2029 Reactive Capital Work Requests Actuals and Forecast

As previously noted, the nature of work in this segment is unplanned, unpredictable, non-discretionary, and can vary significantly from year to year. When an asset exhibiting severe deficiencies is found through maintenance inspections, reported by operations teams or customers, or caused by emergency events, the utility immediately assigns personnel to triage and resolve the issue. Based on the expertise and experience of Toronto Hydro engineers and operation teams, deficiencies are evaluated and prioritized for resolution. Crews are then dispatched to address those assets with the highest priority based on severity of the issue and the impact on environmental, safety and reliability.

Since 2015 Toronto Hydro has also undertaken efforts to maximize the productivity, safety, reliability, and environmental benefits of reduced switching work on the downtown "grid" system. Where possible for P3 work types, planned maintenance, customer or capital work can be bundled together to align with feeders that are taken out of service to create a safe work zone for repairs or equipment replacement which can reduce the switching costs. Due to lower urgency and more flexible turnaround times, P3 work can be aligned with upcoming maintenance, capital, or customer work.

Toronto Hydro has also taken steps to improve work processes in this segment, including: better coordination within the utility to ensure material availability; enhanced inspection forms; and

adoption of software tools to improve tracking, management, and reporting of work requests and reduce manual work.

E6.7.4.2 Worst Performing Feeder Segment

Between 2020 to 2022, Toronto Hydro invested $11.7 million in the WPF segment, and projects to invest an additional $12.4 million, for a total of $24.1 million by the end of 2024. The total spend is projected to be slightly less than the $24.9 million forecast in the 2020-2024 DSP, while still generally expecting to meet segment objectives (i.e. meeting or exceeding FESI targets). The WPF segment has proven to be a cost-effective means of managing reliability issues in the short term.

In order to address the evolving needs of customers, for whom reliable service has gained importance, Toronto Hydro needs to invest in this segment at slightly higher rate, for a total of $32.5 million over the 2025-2029 rate period. Some of the main drivers for this are summarized below.

Due to the increased sensitivity of the Outage Management System noted previously, a higher proportion of outage events that occur on the system will be logged, providing Toronto Hydro better visibility into poor performing feeders and actual customer reliability experience. This will enable Toronto Hydro to better mitigate issues and improve service for customers experiencing poor reliability. However, this also requires more investment and will put upward pressure on measures such as FESI-7. Similarly, the new CEMSMI-10 measure provides better visibility into large, sensitive customers experiencing poor reliability (including momentary interruptions), which Toronto Hydro will need to invest in addressing. Finally, due to the recent focus on removing PCBs from the system through programs such as Overhead System Renewal and Underground System Renewal – Horseshoe, Toronto Hydro has been investing less in reliability-focussed proactive renewal of the distribution system, increasing the need for short-term mitigation measures taken through WPF segment.

Toronto Hydro has based its 2025-2029 forecast expenditures for the WPF segment on historical trends and considering the factors noted above. The utility prioritizes WPF scopes based on the reliability performance of each feeder and field patrol findings. The intent of the short-term capital work is to mitigate immediate risk to reliability by replacing or upgrading assets that are at high risk of failure that will result in power outages. Most of this work is targeted for completion within a 12-month period so the outcome of reliability improvement is realized immediately thereafter.

E6.7.5 Options Analysis

E6.7.5.1 Reactive Capital Segment

Toronto Hydro considered three different forecasts for funding the replacement of failed or failing assets for the 2025-2029 rate period:

1) **Lower Bound** – Annual need and costs remain consistently on lower end of historical experience;
2) **Most Likely** – Toronto Hydro's best estimate of needs and costs for this segment based on historical trends and asset condition; or
3) **Upper Bound** – Annual needs and costs reflect higher end of historical experience.

1. Option 1: Lower Bound

As for all three options, this forecast relies on Toronto Hydro's Reactive Capital predictive model to estimate future costs. However, under this option the forecast expenditures in each year are adjusted downward to reflect the assumption that the volume and costs of required work will be consistently on the low end of Toronto Hydro's recent experience with no major storm events or other factors to drive up costs. While it is possible that the required work in one year could drop to this level, it is not very likely and it would be very unrealistic to expect it to stay around that level for a full five-year period.

Implementing this option would very likely result in inadequate funding to meet the demand for reactive capital work based on historical trends. A backlog of work would arise and deprive planned capital or maintenance programs of required resources. Addressing reactive capital work through planned capital rebuilds would also take time to plan, design and execute and would not typically allow for the timely replacement of failed and failing assets. Inadequate funding would also increase environmental risk, and safety risks to the public and Toronto Hydro employees. Ultimately this would lead to more interruptions and longer outages for customers, potentially significant legal consequences (e.g. related to environmental obligations), and risk of worker and public safety incidents.

2. Option 2 (Selected Option): Most Likely

The expenditures for this option are forecast using Toronto Hydro's Reactive Capital predictive model and represent the utility's best estimate of required spending in this segment over the 2025-2029

rate period. The proposed investment levels are necessary to maintain system performance and reliability, ensure customer satisfaction, eliminate safety risks to the public and Toronto Hydro employees, and mitigate environmental risks.

3. Option 3: Upper Bound

This option is the reverse of Option 1, i.e. the forecast expenditures from the predictive model are adjusted upwards to reflect a scenario where the required work is at the higher end of Toronto Hydro's recent experience. Under this option, Toronto Hydro would also ensure no backlogs of work, while also being in a better position to address any storm events without compromising funding needed for its other capital work. While this would be ideal from a risk management perspective, the extra costs are not prudent given the relatively low likelihood of there being that level of need over the full five-year period.

E6.7.5.2 Worst Performing Feeder Segment

Toronto Hydro considered three alternatives for addressing the WPF segment's budget for the 2025-2029 rate period:

1. Managed deterioration - Reduction of work issued under the WPF segment, addressing asset replacement mainly through planned renewals;
2. Sustainment - Continuation of the current WPF segment, addressing asset replacement at similar levels as seen in the 2020-2024 rate period;
3. Improvement - Enhancement of the WPF segment, addressing asset replacement at higher levels than previously seen in the 2020-2024 rate period (preferred option)

1. Option 1: Managed Deterioration

Under this option, Toronto Hydro would reduce the pace of WPF work. Addressing deficiencies on feeders exhibiting poor reliability mainly through planned capital renewal programs is an adequate solution for the long term, however, planned renewal projects take significantly longer to plan, design and execute; and do not typically allow for the timely mitigation of worsening reliability trends on poorly performing feeders. Additionally, the planned capital renewal programs have recently been focused on the replacement of PCB transformers. Without sufficient targeted, short-term interventions on poorly performing feeders, many customers would likely experience worsening reliability. It is expected that the number of FESI-7 and FESI-6 Large Customer feeders, and CEMSMI-10 customers would increase, negatively impacting customers for prolonged periods. This option

does not align with the Phase 1 Customer Engagement report conducted in 2022, which identified a growing preference for reliable service, and therefore this option is not recommended.

2. Option 2: Sustainment

Under the sustainment option, Toronto Hydro would continue issuing mitigation work at the current pace, which has proven effective over recent years. However, given the pressures on reliability metrics discussed previously (e.g. recent focus of planned renewal programs on removing PCBs transformers), Toronto Hydro expects that this level of investment will not be sufficient to prevent the number of FESI-7 and FESI-6 Large Customer feeders, and CEMSMI-10 customers from increasing. More importantly, some customers will face delays in having their poor reliability addressed and customers have made it clear that reliability is a top priority. Therefore, this option is not recommended.

3. Option 3: Improvement

Under the Improvement option, Toronto Hydro will increase the pace of spending by a small amount in this segment to address pressures on reliability and customer priorities. This option will provide immediate reliability improvements to more customers served by poor performing feeders at a reasonable cost, and serves as a "bridge" solution until planned capital rebuilds can be executed. This option is a reasonable balance of the top customer priorities of price and reliability by spending a little bit more to improve service reliability for those experiencing worse than average performance in the short term, until planned renewal projects can take place.

E6.7.6 Execution Risks & Mitigation

Each segment of the Reactive and Corrective Capital program faces challenges which can delay or prevent work from occurring. Many of these challenges overlap across the two segments of this Program. These challenges are summarized in the table below.

Table 10: Execution Risk Applicability by Segment

Segment	Execution Risks			
	Material Constraints	Resource Constraints	Logistics Constraints	Planned Work Restrictions
Reactive Capital	✓	✓	✓	✗
Worst Performing Feeder	✓	✓	✗	✓

E6.7.6.1 Material Constraints

Both segments use major equipment, which includes but is not limited to, transformers, switches, switchgear, and poles. The procurement lead time for a major asset can vary from 21 days to 14 months based on the type. For this reason, it is difficult and sometimes infeasible to advance or expedite the requests. Supplier shortages affecting material availability may cause delays in executing the work in a timely manner. For more details and what Toronto Hydro has been doing to address this issue please see Exhibit 4, Tab 2, Schedule 13 (Supply Chain). To help mitigate this risk, Toronto Hydro orders assets in advance of expected in-service dates and ensures sufficient supply of critical spares.

E6.7.6.2 Resource Constraints

Both segments use design and construction resources. Therefore, if there are insufficient resources to complete all the projects in the Program, certain requests will need to be deferred to ensure highest priority requests are completed. Unpredictable events such as major snow storms or a resurgence of the COVID-19 pandemic could also contribute to lack of construction resources. Furthermore, depending on the location or type of failure, further design, planning, and approval may be required prior to work execution. For example, work may require pole loading, cable pulling or voltage drop calculations by a designer prior to replacing the asset in the field. Toronto Hydro is mitigating this risk with the help of third party (e.g. contractors) to complete any project in excess of Toronto Hydro's resources capacity.

Under the WPF segment, in order to assist with the mitigation of this risk, Toronto Hydro has mapped out the WPF process, where feeder patrols scheduling and timelines for project execution have been clearly established. As a result, mitigation work is normally placed on high priority and scheduled for field execution taking into consideration available resources. Additional emphasis is placed on feeders that have experienced a high number of outages in a 12-month rolling window.

E6.7.6.3 Logistics Constraints

Reactive Capital work can face challenges such as installation of legacy equipment, lack of space in a vault or feeder not being able to be taken out of service. For these reasons, there is a risk of delay as additional teams may need to be involved for further analysis. Toronto Hydro is mitigating this risk by ensuring clear communication with the overhead or underground renewal portfolios.

E6.7.6.4 Planned Work Restrictions

Under the WPF segment, since this is planned work and is not generally considered to be as urgent as reactive replacements of failed equipment, feeder scheduling restrictions and road work moratoriums may also pose risks to the completion of work in a timely manner. To mitigate this risk, monthly stakeholder meetings are scheduled to review status of work, emerging issues, as well as alternatives to ensure work is completed in a satisfactory manner and time frame.

E7.1 System Enhancements

E7.1.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 26.3	**2025-2029 Cost ($M):** 151.2
Segments: Contingency Enhancement, Downtown Contingency, System Observability	
Trigger Driver: Reliability	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Financial Performance	

The System Enhancements program (the "Program") is comprised of three strategic investment initiatives that are designed to modify and augment the distribution system, with the goal of ensuring that, by 2030, the physical grid is equipped with the foundational technologies and capabilities necessary to optimize the efficiency of grid operations and deliver incremental customer value in response to emerging risks and drivers. These drivers include (1) the accelerating electrification of energy demand (e.g. electric vehicles and cold-climate heat pumps); (2) accelerating adoption of distributed energy resources (e.g. rooftop solar and batteries); and (3) increasing risks to reliability and resiliency from the effects of climate change (i.e. adverse weather events).

The System Enhancements program consists of the following three segments:

- **Contingency Enhancement:** This segment enhances Toronto Hydro's ability to optimize the grid and efficiently restore power to customers by: (1) adding remotely operable feeder tie and sectionalizing points on feeders where the number of switching points is currently sub-optimal or where there is an opportunity to facilitate or expand a distribution automation network, (2) upgrading undersized conductors on lateral loops to improve contingency options, and (3) upgrading undersized trunk egress cables. Toronto Hydro plans to invest an estimated $132.9 million in 2025-2029 in Contingency Enhancement, which is a significant increase in segment spending relative to the forecast total for the 2020-2024 period. The increased pace of investment reflects Toronto Hydro's strategic objectives for grid modernization. By 2030, the utility aims to deploy sufficient remote operable switching points to allow for distribution automation across the Horseshoe region, where reliability has typically been more challenging to maintain (compared to the Downtown system) and where significant growth causing system strain is forecasted, particularly in the Horseshoe

west region of the distribution system. This segment also introduces modern switching assets that will provide automated and remote controllability functions to address feeders experiencing numerous momentary and sustained interruptions. Such devices include but are not limited to reclosers on the trunk and laterals of feeders. Reclosers are pole-mounted breakers which will allow Toronto Hydro to better prevent momentary interruptions from cascading into prolonged outages, and to better isolate a feeder during sustained interruptions, thereby limiting the number of customers impacted by an outage. A fault event on the feeder downstream of the recloser will only cut off power to that section instead of the entire feeder by coordinating with the station breaker, which would primarily benefit those customers that are particularly sensitive to momentary interruptions. Furthermore, installing a recloser on the lateral section of a feeder will provide advanced lateral protection, which prevents temporary faults from becoming sustained outages and avoids momentary interruptions on feeders. The devices proposed under this segment support Toronto Hydro's *Grid Modernization Roadmap*.

- **Downtown Contingency:** This segment provides for plans to add provisions in the downtown core for incremental Toronto Hydro-controlled back-up supply to stations – above and beyond existing Hydro One provisions. Toronto Hydro plans to invest an estimated $13.6 million during the 2025-2029 period in the Downtown Contingency segment. Major loss-of-supply incidents – driven by a variety of causes – have become more frequent in recent years, underscoring for the utility and many of its critical downtown customers (e.g., financial institutions; shopping centres; office towers; large multi-residential buildings; hospitals; etc.) the importance of grid resiliency. The planned enhancements will provide N-2 (i.e., two station loss-of-supply issues at the same time) operational capability to address serious loss-of-supply scenarios. These investments will bring the downtown and horseshoe back-up supply practices into greater alignment with one another, improving resiliency in areas of the system with highly critical loads. The impact of significant outage events in the Downtown core will be of increasing concern to customers and stakeholders as the economy becomes more reliant on electricity in the next decade and beyond.

- **System Observability:** This segment introduces new assets that can provide real-time condition data, loading data and fault-finding capabilities. Such devices include, but are not limited to, overhead and underground sensors, online cable monitors, and transformer monitors as well as considerations for emerging technologies. By installing monitoring on

Toronto Hydro's overhead and underground assets, power outage response times would be improved by the devices' ability to provide alerts and fault localization in real time. The installation of online cable monitors provides real-time thermal profiles of cables, determines actual loading to enhance decision making on loading/connections and provides a better understanding of cable risk. These devices are also beneficial for monitoring cables in locations that require long or costly preparations for inspections. Toronto Hydro plans to invest an estimated $4.7 million in 2025-2029 in System Observability. Overall, these assets are intended to provide real-time or near-real-time information and will expand on pilot programs and focus on system reliability improvements for planned and unplanned scenarios.

The investments in this program represent a substantial portion of the Intelligent Grid component of Toronto Hydro's *Grid Modernization Roadmap*. For more details on the Intelligent Grid strategy, please refer to Exhibit 2B, Section D5.

Overall, Toronto Hydro plans to spend an estimated $151.2 million in this Program over the 2025-2029 period.

E7.1.2 Outcomes and Measures

Table 2: Outcomes & Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by:
	  ○ Reducing fault isolation times and the average duration of outages by installing SCADA switches and SCADA-enabled tie and sectionalizing points
	  ○ Reducing the average duration of outages on targeted feeders by installing SCADA-enabled tie and sectionalizing points as well as reclosers;
	  ○ Reducing outages resulting from contingencies by upgrading undersized or de-rated equipment;
	  ○ Using real-time monitoring to detect line disturbance, proactive monitoring of cables, and providing information to identify early signs of failure and to proactively manage the load on the system.
	• Reduces the impact of downtown Major Event Days (MED) by:

	○ Providing back-up supply for low probability, high impact, long duration station loss-of-supply incidents; ○ Reducing the average duration of outages due to loss-of-supply incidents.
Operational Effectiveness - Safety	• Continues to maintain Toronto Hydro's Total Recorded Injury Frequency (TRIF) measure and safety objectives by installing remote switching, thereby reducing crew exposure to safety risks associated with manual switching
Financial Performance	• Contributes to Toronto Hydro's financial objectives by: ○ Leveraging distribution system automation (including real time loading, and remote switching operations) to reduce operational costs associated with patrolling faulted sections of the feeders; ○ Improving power outage response time through real-time power interruption alerts, remote switching operations, and better optimizing resource management (i.e. crews patrolling feeders to identify fault location).

E7.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Reliability
Secondary Driver(s)	Safety, Operational Constraints, System Efficiency

Toronto Hydro has developed a Grid Modernization Roadmap which aims to (1) leverage technology to improve the efficiency of the grid, and (2) develop capabilities that are responsive to emerging risks and drivers. These drivers include the accelerating electrification of energy demand (e.g. electric vehicles and cold-climate heat pumps); accelerating adoption of distributed energy resources (e.g. rooftop solar and batteries); and increasing risks to reliability and resiliency from the effects of climate change (i.e. adverse weather events).[1]

The System Enhancements program (the "Program") is the most important part of the Intelligent Grid component of the utility's Grid Modernization Roadmap for 2025-2029. It is comprised of three strategic investment initiatives which will modify and augment the distribution system, with the goal

[1] Exhibit 2B, Section D5

of ensuring that, by 2030, the physical grid is equipped with the foundational technologies and capabilities necessary to achieve sufficient flexibility, automation and resiliency in grid operations.

Investments in the System Enhancements program are necessary to support the utility's system reliability objectives for 2025-2029. Across the system, Toronto Hydro has identified opportunities to maintain and improve reliability and resiliency by implementing targeted system modifications. These system design interventions can cost-effectively mitigate the consequences of failure in many circumstances (i.e. the number of customers affected and outage duration), as distinguished from investments that reduce the probability of failure, such as replacing or maintaining aging and poor condition assets or trimming trees. The investments in this Program will reduce the consequence of failure by improving power restoration capabilities during both normal interruption events and adverse weather events, which are becoming increasingly frequent, as outlined in the Climate and Weather component of the Overview of Distribution Assets for 2025-2029.[2] Other investments in this program will establish capabilities to monitor distribution asset performance and loading in real-time, allowing for early detection of conditions that could warrant proactive interventions to avoid or reduce the impact of failures and violations of system operating parameters.

The following sections discuss each of the three program segments in greater detail.

E7.1.3.1 Contingency Enhancement

This segment includes the following four types of work, three of which are continuations of activities included in Toronto Hydro's 2020-2024 Distribution System Plan:

1. Installing additional SCADA-enabled tie and sectionalizing points in the Horseshoe area in an effort to reduce outage restoration times, improve system resiliency and support Distribution Automation;
2. Installing additional SCADA-enabled tie and sectionalizing points in the open loop overhead areas of the Downtown distribution system in an effort to reduce outage restoration times and improve system resiliency;
3. Upgrading undersized loop conductors in the Horseshoe area; and
4. Upgrading the capacity of trunk egress cables in the Horseshoe area.

Each of these activities is discussed in the following sections.

[2] Exhibit 2B, Section D2.1.2

1. Installing SCADA-enabled Tie and Sectionalizing Points in the Horseshoe area

When a feeder or section of feeder loses power during a contingency event, customers connected to it should receive power from an alternate feeder via feeder tie points and sectionalizing switches. However, if a feeder is not sufficiently equipped with sectionalizing or tie points that can divide the load into smaller sections, re-routing service may not be possible for all customers. This is especially true during peak loading times. Load growth and the addition of new developments can exacerbate this problem as less capacity is available on the feeders. The Contingency Enhancement segment adds tie or sectionalizing points to those feeders lacking sufficient switches.

A secondary issue is the lack of remote operation at some existing tie-points. Before SCADA-controlled devices were available, manual switches were installed. To restore power with manual switches, crews must travel to perform the switching work on-site. Depending on the location of the fault and accessibility of the switches, this typically takes one to two hours. In contrast, SCADA-controlled switches will relay instant loading information to the control room, enabling controllers to remotely re-route power to adjacent feeders within minutes. Remotely controlled switches are also safer than manual switches because employees are not exposed to live equipment during manual switching operations.

Toronto Hydro plans to deploy reclosers alongside traditional SCADA switches to eliminate interruptions to sections of customers on a feeder, thereby reducing overall outage times and improving system resiliency. Reclosers provide additional protection to overhead electrical distribution systems by acting as circuit breakers with electronic reclosing capability. By installing a recloser on the trunk of a circuit feeder, it effectively and efficiently contains any temporary or forced outages within that specific section, without affecting upstream customers. Toronto Hydro has successfully piloted reclosers within the distribution system and is ready to roll-out at scale in situations where they will provide necessary incremental benefits to static switches.

Toronto Hydro plans to strategically deploy both reclosers and traditional SCADA switches to enable faster power restoration in the Horseshoe area:

1. Installation of SCADA-enabled tie and sectionalizing points to provide appropriate backup supply; and
2. Installation of reclosers to constrain the impact of an outage to a section of a feeder.

The addition of SCADA controlled tie and sectionalizing switches enables Toronto Hydro to segment a feeder into smaller sections, transferring load to alternate feeders and minimizing the duration of power outages. To provide an appropriate back-up supply, Toronto Hydro divides feeders into sections using SCADA-operated switches, where one section serves approximately 700 customers. Each sectionalized portion of the feeder should contain a SCADA tie point that is connected to another feeder. In most instances, to meet this requirement, feeders will require at least three strategically located tie points connected to three unique back up feeders where:

1. The first tie point connects to another feeder from the same substation bus;
2. The second tie point connects to another feeder on a separate bus located at the same substation; and
3. The third tie point connects to another feeder from a different substation.

This configuration ensures a contingency power source is available for the faulted feeder regardless of whether the fault occurs at the feeder, bus, or station level, effectively reducing the duration of an outage. During the 2018-2022 period, the average duration for outages on feeders with less than three SCADA tie-points was approximately 707 minutes per year per feeder, whereas the average duration of those feeders with three or more SCACA tie-points was approximately 496 minutes.

Figure 1 below shows a map of Toronto highlighting the location of all the Horseshoe feeders that have less than three SCADA tie points.

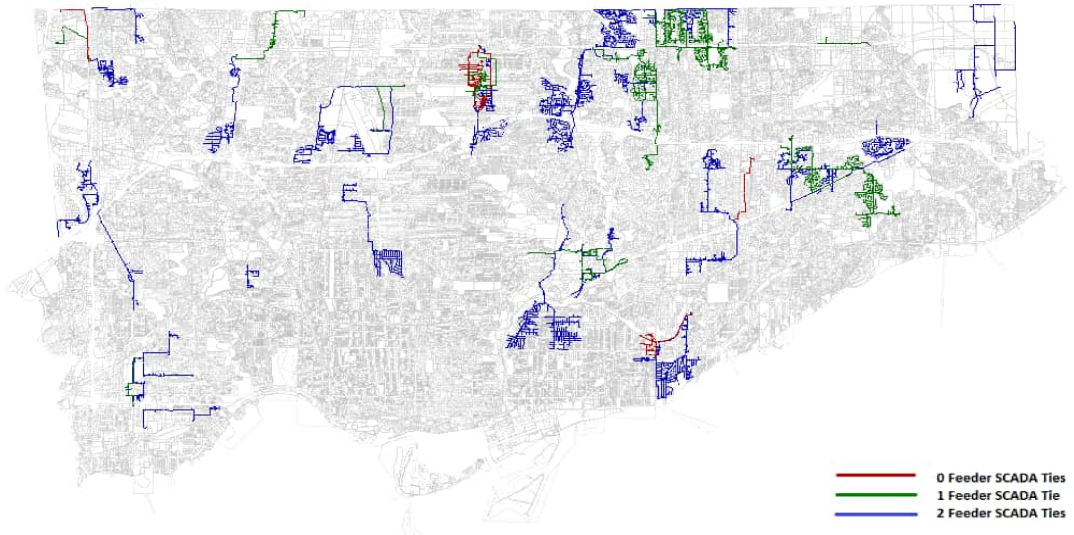


Figure 1: Map of Toronto showing Horseshoe Feeders with less than 3 SCADA Tie Points

Reliability data such as total customer minutes out ("CMO") over the five-year period from 2018-2022 and potential reliability improvement will be the main criteria in determining where the SCADA switch installation work will be carried out. The potential reliability improvement is determined by evaluating the existing SCADA switch condition on a feeder, and what potential improvement could be achieved if the feeder is modified to have a SCADA sectionalizing switch and a SCADA tie switch for every 700 customers connected to the feeder. Figure 2 below illustrates a 25 percent potential reliability improvement when a feeder that has approximately 2,800 customers has been upgraded from its existing condition. The upgrade includes two new SCADA sectionalizing switches to meet Toronto Hydro's Standard Design Practices ("SDP") where approximately 700 customers are to be connected in each section of the feeder. The ability to restore more customers increases following a sustained outage, as more focused isolation of the fault can be achieved.

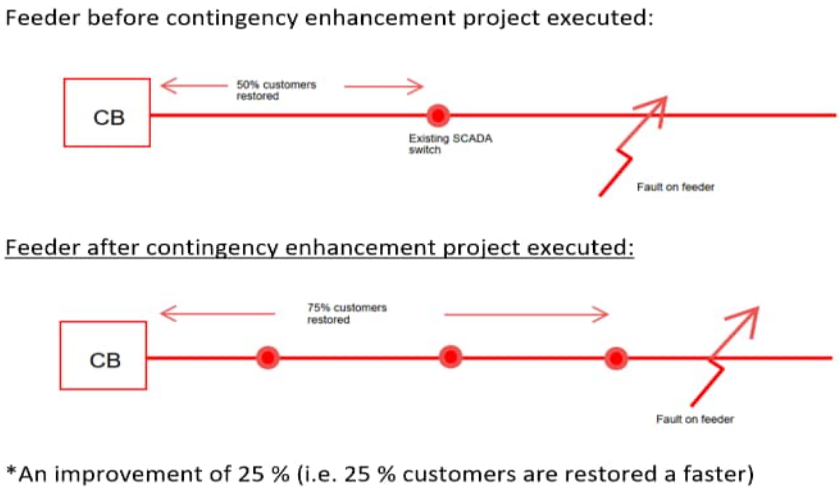


Figure 2: Potential Reliability Improvements Through Contingency Enhancement Investments

During the 2025-2029 period, Toronto Hydro plans to install a total of 205 SCADA switches on 94 feeders in the Horseshoe area. This work is expected to result in an average of approximately 12.6 percent reliability improvement on the 94 feeders where SCADA switch installation work is expected to take place. This will result in an average yearly total CMO reduction from 180,113 during the 2018-2022 period to an improved average yearly total CMO of 162,889. The potential SAIDI improvement as a result of this work is expected to be approximately 0.022 minutes per feeder per year.

Toronto Hydro intends to install reclosers alongside the installation of other SCADA-switches to enhance the grid's response to outages by containing their impact to a specific section of a feeder.

The recloser introduces new functionality where it will also operate automatically in response to a fault in a coordinated manner such that downstream customers on the faulted section of the feeder will be isolated without interrupting the remainder of the feeder. Figure 3 demonstrates that if a sustained or momentary fault were to occur downstream of a recloser, all customers upstream of that recloser will not experience an outage.

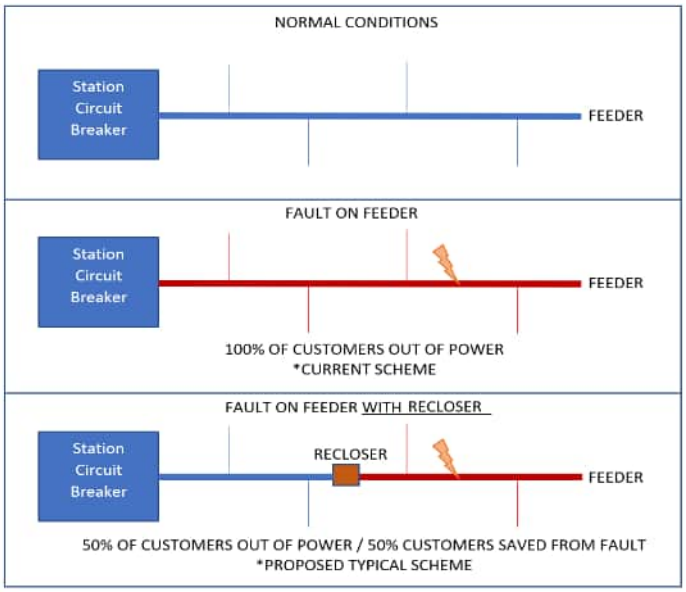


Figure 3: Concept Behaviour of Reclosers in the Distribution System for Sustained and Momentary Faults

The installation of a recloser near the halfway loading point on the circuit feeder trunk will result in significant improvements to MAIFI, SAIFI, SAIDI, and CAIDI. In particular, placing reclosers on the feeder downstream of customers sensitive to power outages can improve power quality as reclosers efficiently respond to downstream faults without impacting upstream customers.

Where coordination is possible, the utility can install multiple reclosers. This will improve reliability by decreasing the number of customers affected by an outage from 50 percent to 33 percent by strategically placing reclosers at the one-third and two-thirds loading points on the feeder trunk.

At a minimum, Toronto Hydro plans to install one recloser per overhead feeder prioritizing those with high historical CMO and CI, high number of customers, and/or on heavily loaded feeders. Based on the results of the recloser pilots, the potential SAIDI improvement is expected to be up to 0.108

minutes per feeder per year. Reclosers also reduce the number of customers experiencing an outage, with a potential SAIFI improvement expected to be up to 0.001 customers per feeder per year.

Additionally, reclosers have intelligent switching capabilities, allowing them to test for faults and voltage sensing on the upstream and downstream portion of the feeder. This enhanced visibility improves outage management and provides incremental information that can be analysed and used for decision-making. These additional features minimize transformer substations faults, extending their useful life; and reduce thermal and mechanical stress on cables, conductors, and connection points will experience less thermal and mechanical stress caused by faults.

Furthermore, the SCADA switch installation work in the Horseshoe will also support Distribution Automation. With the foundational SCADA devices installed, Distribution Automation will be deployed to rapidly isolate a fault and minimize the number of customers affected, without any manual intervention. Distribution Automation requires two main components: SCADA switches, and a Fault Location, Isolation and Service Restoration (FLISR) application. They are as follows:

1. SCADA switches on feeders allow the remote troubleshooting and sectionalizing of feeder faults to achieve more efficient and rapid troubleshooting and restoration, which is the focus of the Distribution Automation work within the Contingency Enhancement segment.

2. FLISR is an application which, together with the Network Management System ("NMS"), can automatically read and process signals from the distribution system to locate a fault. The implementation of Distribution Automation using FLISR would enable Toronto Hydro to rely on autonomous detection and isolation of affected portions

During a feeder level outage, control room operators and crews first work to locate the fault and sectionalize the feeder to isolate the faulted section. This will minimize the impact of the outage to a large portion of the customers before crews are able to identify the root cause of the outage and complete repairs. The use of remote operated SCADA switches reduces the fault isolation time by approximately one hour on average. If a feeder has a recloser and a fault occurs downstream, it can save an upstream customer from experiencing any interruption. The use of FLISR would further improve fault isolation and service restoration by remote operating additional SCADA switches to further sectionalize faulted sections of the feeder and restore healthy portions of the feeder. Figure 4 illustrates the benefits of a feeder with FLISR enabled.

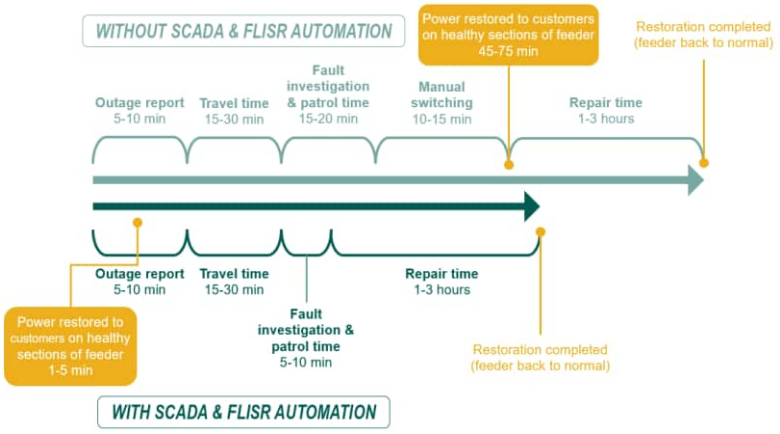


Figure 4: Typical Outage Restoration Times with FLISR VS Without FLISR

In addition, the integration of SCADA switches, reclosers and FLISR has significant benefits and impact on reliability. Figure 5 illustrates the incremental reliability gains for a sustained outage. In the first stage, where only SCADA switches are installed on the feeder, there is no automation and the entire feeder is affected by a fault on the trunk of the feeder. Adding a recloser to the same scenario, automation is introduced and 50 percent of customers will not experience an outage if the fault is downstream of the recloser. In the final scenario, FLISR is implemented in addition to the reclosers and SCADA switches. The three devices will work together to further isolate the fault, activate contingencies and reduce the outage down to 25 percent of the feeder, with the goal of achieving restoration in under one to five minutes.

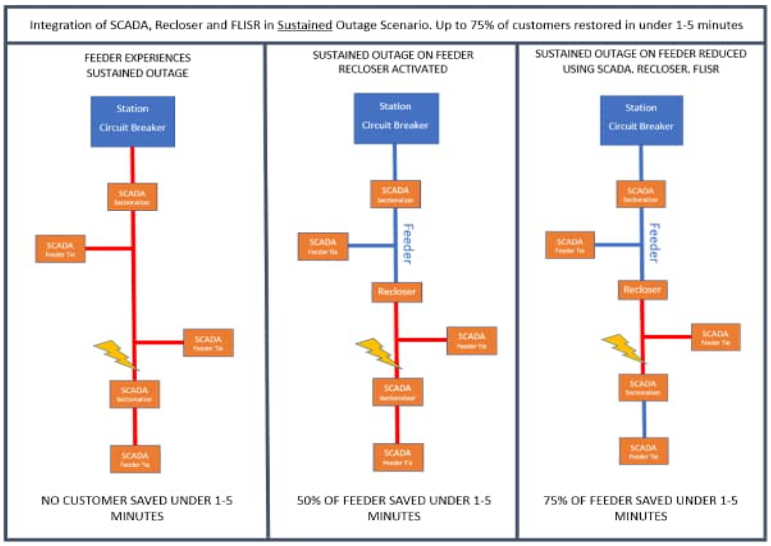


Figure 5: Integration of SCADA, Recloser and FLISR in a Sustained Outage Scenario

Toronto Hydro is focusing the installation of SCADA devices on the trunk feeders on the 27.6 kV distribution network in the Horseshoe area as they have the largest impact on customers. As shown by Figure 6, the 27.6 kV system accounts for the largest share of reliability issues in the system, which also means considerable resources are required to restore outages using manual or remote-operated SCADA switches. Trunk outages interrupt the entire feeder and can impact hundreds to thousands of customers. In contrast, lateral or local outages only impact up to a few hundred customers.

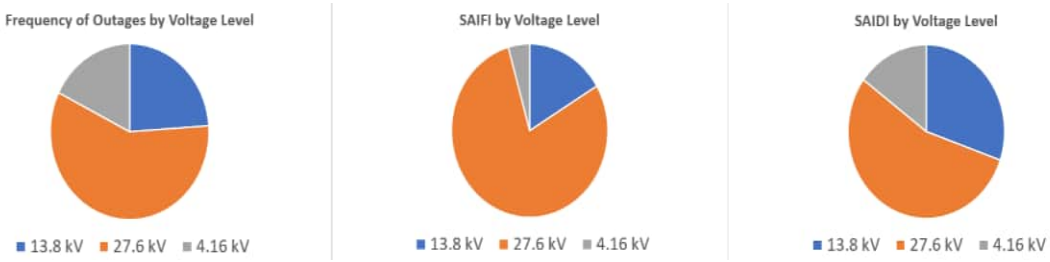


Figure 6: Reliability Impact by Voltage Level – (2018-2022)

Even though trunk outages make up only a third of the outages that occur on 27.6 kV feeders, they can significantly impact SAIFI and SAIDI (as shown in Figure 7 below). The installation of SCADA switches will allow faster sectionalization and restoration of customers in unaffected sections, thereby reducing the impact of trunk outages and improving the reliability of the system.

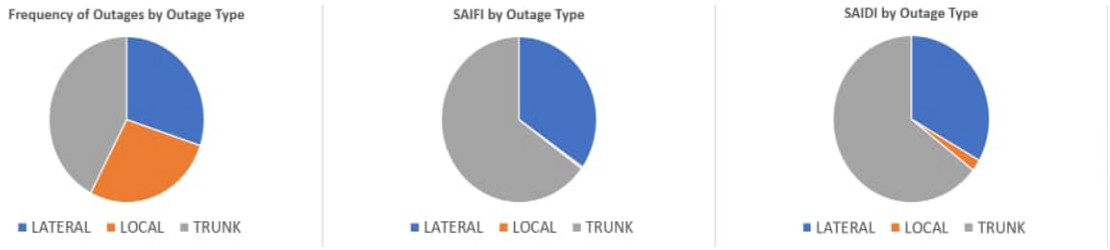


Figure 7: Reliability Impact by Outage Type – (2018-2022)

As of the end of 2022, there are 293 horseshoe feeders of which 230 are considered to be automation ready, defined as having at least two SCADA sectionalizing switches, and at least one SCADA tie point. The switches on these feeders are ready for the implementation of Distribution Automation to realize the full benefits of autonomous restoration. There are 63 Horseshoe feeders that currently do not meet this minimum SCADA switch requirement for Distribution Automation. For these

feeders, additional switch installations are required to provide remote restoration capabilities and to enable Distribution Automation to allow for faster outage restorations to customers. During the 2025-2029 period, Toronto Hydro plans to complete SCADA switch installation work on at least 34 of the remaining 63 feeders which will allow all the feeders in the Horseshoe to be able to reap the benefits of Distribution Automation. Ultimately, this will bring the percentage of feeders which meet the Distribution Automation criteria to over 90 percent in the Horseshoe.

The work planned in the Horseshoe area represents the minimum requirement to ensure feeder readiness in support of Toronto Hydro's automatic FLISR schemes. Additionally, the reliability improvements and operational flexibility gained with the proposed plan supports overall performance outcomes related to SAIDI, SAIFI and worst performing feeders. This proposed plan provides the necessary improvements on the Horseshoe feeder trunks and sets the foundation for future system improvements where future SCADA switch installations will provide more visibility and controllability on more specific areas of the system. For example, future opportunities exist to strategically deploy additional SCADA-operated switches:

- To ensure all remaining feeders have no more than 700 customers per section, per Standard Design Practices ("SDP");
- To reduce the number of customers per section in order to reduce customers impacted when a feeder experiences a fault, especially as 700 customers will represent a significant portion of load on a feeder with each customer;
- On riser poles where the main feeder transitions from overhead to underground and vice versa, to increase fault locating capabilities and add the ability to isolate and test reclose if a suspected fault is on the underground segments through targeting approximately 3444 OH-UG Non-SCADA riser points;
- On riser poles at egress cable risers or at the overhead conductor exiting from the station to have the ability to independently remote operate the first switching device and isolate the entire feeder; and
- On riser poles at expressway/highway crossings where high salt contaminated areas exist and SCADA switches have been able to provide much higher operability and are more resilient when compared to manual switches.

2. Installing SCADA-enabled Tie and Sectionalizing Points in the Downtown area

During the 2015-2019 period and 2020-2024 period, the scope of work for Contingency

Enhancement included installing SCADA-enabled tie and sectionalizing switches for the 27.6 kV Horseshoe distribution system in an effort to reduce outage duration and to support Distribution Automation. The Downtown distribution system is inherently more reliable than the Horseshoe since it is predominantly underground and uses supply configurations like Dual Radial which reserves dedicated standby capacity and the Secondary Grid Network which results in no interruptions to customers under contingency. However, the Downtown distribution system does include overhead feeders that are similar to the Horseshoe which is an open loop distribution system. Toronto Hydro anticipates that the impact of outages in Downtown Toronto will be of increasing concern to customers as they become more reliant on electricity thus increasing the need for greater resiliency to the power supply. As determined through Phase I Customer Engagement results, there is generally support among customers for investments in new technology to improve the system.[3] To address these concerns and improve the resiliency of the power supply in the Downtown core, Toronto Hydro plans to expand the scope of Contingency Enhancement investments to include SCADA switch installations on the open loop overhead feeders in the Downtown distribution system.

During the 2025-2029 period, Toronto Hydro plans to install a total of 93 SCADA switches on 40 overhead feeders in the Downtown area. This work is expected to result in an average of approximately 16.3 percent reliability improvement on the 40 feeders where SCADA switch installation work is expected to take place. This will result in average yearly total CMO reduction from 128,499 during the 2018-2022 period to an improved average yearly total CMO of 104,625. The potential SAIDI improvement as a result of this work is expected to be approximately 0.03 minutes per feeder per year.

3. Upgrading undersized loop conductors in the Horseshoe area

Figure 8 depicts a typical looped distribution lateral supplying a series of transformers off the main trunk portion of a feeder. There is an open point near the middle of the loop so that, under normal operating conditions, approximately half of the load in the loop is supplied from one lateral or the other.

[3] See Customer Engagement – Exhibit 1B, Tab 5, Schedule 1

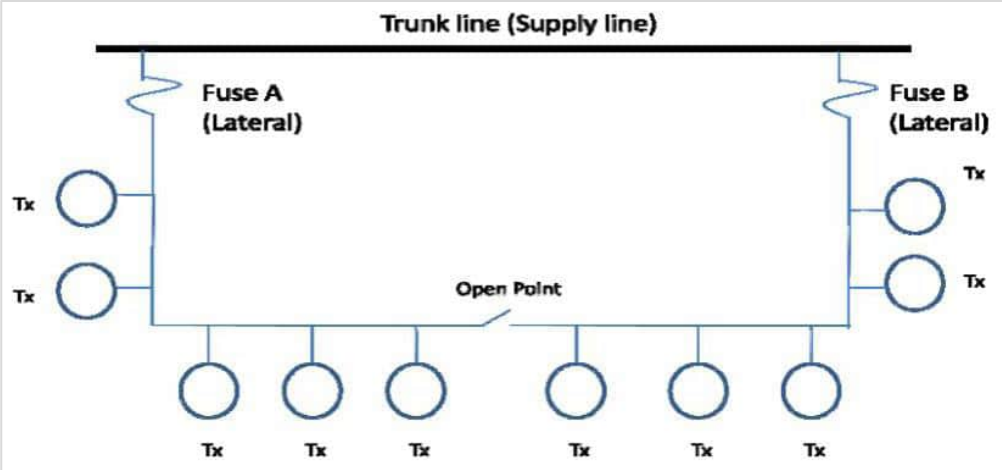


Figure 8: Looped Distribution Design

The conductor on either lateral is designed to be large enough to handle the load of the entire loop if necessary. In a situation where a fault occurs on the first section downstream of Fuse B, the load must be supplied entirely from the other side of the loop, as shown in Figure 9.

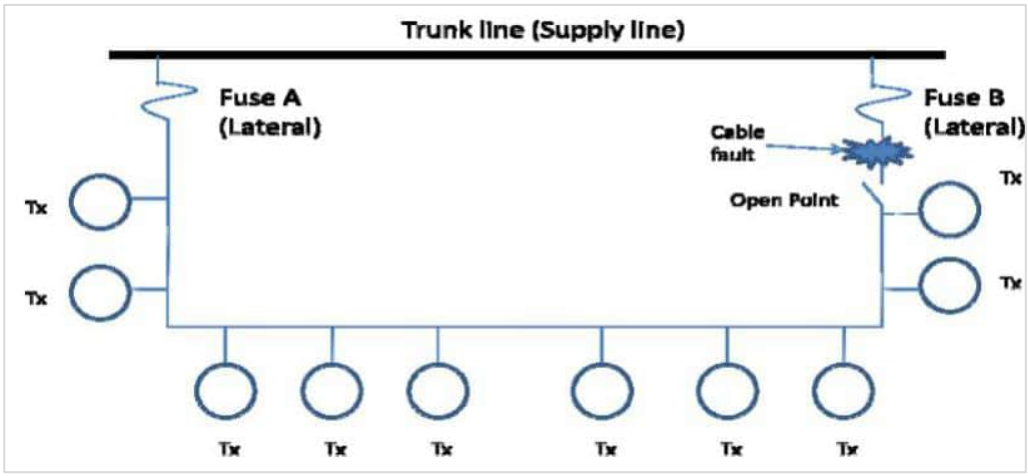


Figure 9: Power restoration in loop after a fault has occurred

Gradual increases in load in certain areas have resulted in existing conductors no longer being able to supply the load of the entire loop. A contingency situation in these locations would cause cascading power outages to the entire loop. Controllers monitor the conductor size and number of transformers transferred to the circuit under contingency; however, the actual load on each transformer may not be known by the controller in real-time.

Toronto Hydro plans to upgrade undersized conductors in lateral loops that are smaller than the utility's standard loop sized conductors during the 2025-2029 period to ensure that they are rated to carry the load of the entire loop under contingency conditions.

3. Upgrading the Capacity of Trunk Egress Cable

Toronto Hydro plans to replace legacy aluminum cable on feeder trunk egress sections with copper cable. The initial section of a feeder, between the station breaker and the first distribution switch (i.e. the section upstream from any load connections), is called the "egress". The egress cable must be adequately sized to supply the load of the feeder, plus any additional load from adjacent feeders under contingency, up to the maximum capacity of the feeder breaker (i.e. 600 A).

Some egress cable installed in the 1960s and 1970s on 27.6 kV feeders is 1000 kcmil aluminum, a cable type that is de-rated (i.e. its current carrying capacity is lowered) when installed in an underground environment, to 500 A in summer and 530 A in winter. In some areas, load growth has exceeded the capacity of this existing configuration. Under contingency, a feeder is required to carry the load of adjacent feeder sections that connect to it. Thus, it is critical that the maximum capacity of the feeder is utilized to restore as many customers as possible. This poses a high-risk situation, as failure of the load-carrying feeder to deliver power to its maximum capacity may result in loss of power to two other feeders, causing outages to a large area for four hours (or more) that it would take to make repairs. Due to the limitation of current carrying capability of these trunk egress cables, customers that would otherwise be served by those feeders under a contingency would experience an outage until the work on their normal feeder has been completed. For these reasons, it is critical that the egress portion of the feeder be fully rated to effectively utilize the rated capacity of the breaker.

Under a contingency condition, controllers may not be able to utilize feeders with a 1000 kcmil aluminum egress trunk cable to pick up load lost on adjacent feeders during a fault or planned maintenance. As a result, affected customers will experience a prolonged power outage until the faulted asset is repaired or replaced on the normal supply feeder. Toronto Hydro may also be required to defer important scheduled maintenance work until the load on feeders is low enough to be re-routed, resulting in the deterioration of asset conditions and further reducing reliability.

As of the end of 2022, there are 11 Horseshoe stations with a total of 88 km of egress cable considered under-rated (i.e. not standard 1000 kcmil copper). Table 4 below shows the amount of under-rated cable for each of these stations. During the 2025-2029 period, Toronto Hydro will

prioritize doing work on feeders that have experienced the most customer minutes out over a five-year period and for feeders where the peak loading of their tied feeder is greater than the capacity of the aluminum egress cable. These targeted upgrades and installations will better equip the distribution system to meet the needs of customers in contingency scenarios and more effectively maximize the customer value derived from existing feeders by minimizing unnecessary failure risk.

Table 4. Stations with Under-Rated Trunk Egress Cable.

Station	Under-Rated Egress Cable (km)	Total Egress Cable (Circuit km)
Bermondsey TS	22	23.3
Runnymede TS	1	14.6
Leslie TS	18	23.9
Agincourt TS	7	8.0
Fairchild TS	13	26.5
Bathurst TS	10	48.2
Rexdale TS	3	9.1
Cavanaugh TS	7	13.1
Fairbanks TS	2	9.7
Finch TS	4	20.1
Scarborough TS	1	7.5
Total	**88**	**203.9**

E7.1.3.2 Downtown Contingency

The Downtown Contingency segment is designed to mitigate the risk of high impact, long duration station supply failures. While the likelihood of a long duration loss-of-supply incident occurring in any given station in any particular year is low, these events do continue to occur. Long duration outages are particularly consequential because critical customer loads such as major financial institutions, hospitals and universities are concentrated in the downtown core.

Between 2003 and 2022, there were 34 major outages directly associated with loss of supply incidents. The typical causes of these outages include foreign interference, transmission equipment failure and station flooding. Most recently, on August 11, 2022, a barge moving a crane in an upright position ran into high-voltage transmission lines in the Port Lands. This incident caused three Hydro One power lines to fail causing loss of supply at three Toronto Hydro stations: Esplanade, George &

Duke, and Terauley, impacting 1,633 customers including local businesses, hospitals, office spaces, and the Eaton Centre. All customers were restored within 6.5 hours of the event. The table below outlines other recent examples of loss of supply incidents. The interstation switchgear ties work proposed in this segment specifically targets the stations impacted by the August 2022 incident.

Table 5: Examples of Major Loss of Supply Events from 2003 to 2022

Event	Description
Loss of Supply (July, 2005)	• 115kV pole and line H5E from Hearn failed • 24,572 Customers interrupted • 4,610,141 Customer minutes out • The last customer restored after 18 hours and 50 minutes
Foreign Interference (January, 2005)	• Station flooding due to broken city water main • 3,556 Customers Interrupted • 2,304,288 Customer minutes out • The last customer restored after 10 hours 48 minutes
CB Failure (July, 2012)	• Circuit Breaker failed causing bus differential trip • 4,565 Customers Interrupted • 1,901,191 Customers minutes out • The last Customer restored after 6 hours and 57 minutes
Loss of Supply (August, 2022)	• Loss of Supply due to crane contact with 115kV lines • 11,183 Customers Interrupted • 2,789,920 Customer minutes out • The last Customer restored after 6 hours 34 minutes

Table 6: Downtown Stations at Risk

Downtown Stations	
Basin	Gerrard
Bridgman	Glengrove
Carlaw	Highlevel
Cecil	Leaside
Charles	Main
Copeland	Strachan
Dufferin	Terauley
Duplex	Wiltshire
Esplanade	Windsor

George and Duke	

The period between 2003 and 2022 saw more incidents than the previous decades. As such, to maximize the benefit of investments in the Program, it is appropriate to target the downtown area through the Downtown Contingency segment. To demonstrate the potential reliability benefits of these Downtown Contingency investments, it is helpful to consider the impacts on customer interruption over the 2003-2022 period had full Downtown Contingency been in place during that period.

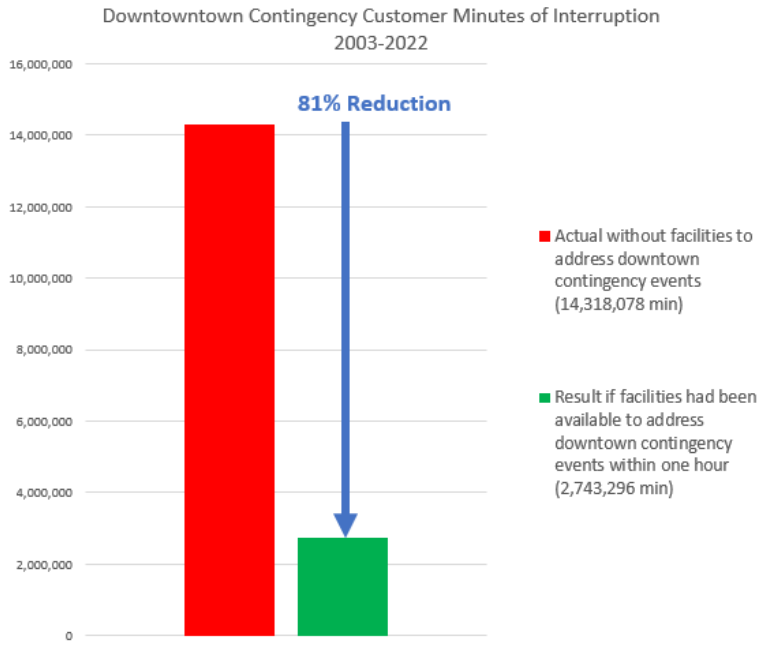


Figure 10: Reliability impact of downtown station load transfer implementation

The operationalization of a Downtown Contingency program with the ability to pick-up customer loads from another station within one hour, could result in an approximately 80 percent reduction in Customer Minutes of Interruption caused by such incidents.

Following the occurrence of downtown contingency incidents, Toronto Hydro analyzes the cause and undertakes projects in an effort to minimize the risk of reoccurrence. Examples of station improvements include: hardening station facilities and equipment to be able to withstand externally and internally-driven failure modes, additional sensors and alarms that can identify developing incidents at the earliest opportunity, and high-volume sump pumps that can address major water

entry incidents such as city water main breaks. As a result, the risks of long duration station supply failures have continued to drop over time. However, although these projects reduce the risks, they often cannot be entirely eliminated. Risks outside of Toronto Hydro's control, such as the recent crane contact with Hydro One lines incident, will therefore cause an increasing proportion of long duration station outage incidents in future years. Concerning the nineteen long duration outage events in 2002-2022 that could be addressed by downtown contingency enhancements, sixteen were due to causes outside of Toronto Hydro's control, or approximately 84 percent.

Contingency enhancement options include a variety of methods to install ties between stations. Including:

- Interstation switchgear ties (i.e., ties between buses in different stations)
- Intrastation switchgear ties (i.e., ties between buses in the same station)
- Interstation feeder ties
- Automated Primary Closed Loop (APCL) ties

Ideally, each station switchgear would have sufficient emergency loading capability to pick-up all, or most, of an interconnected switchgear's load. In addition, each station would also ideally be connected to a different Hydro One source of supply.

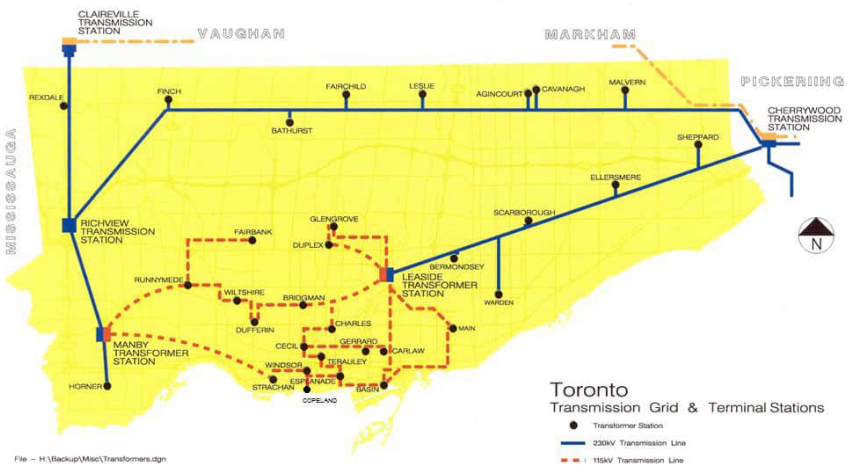


Figure 11: Map of Toronto stations with Hydro One transmission connection

To achieve these benefits, Toronto Hydro has chosen the medium-term plan to provide interstation switchgear ties.

The proposed ties will cover the stations that were impacted by the 2022 crane contact incident, where the best option for an anchor downtown source is Copeland Station. This station has a switchgear designed for load transfer purposes, as well as an extra transformer available for emergencies. Additionally, future plans include replacing the initial 115 kV transmission connection with a 230-kV connection. This means that Copeland Station will ultimately have a Hydro One source of supply well-separated from those supplying all other nearby downtown stations. When combined, these factors make Copeland Station by far the best choice for an anchor source in the downtown area.

E7.1.3.3 System Observability

An important component of Toronto Hydro's *Intelligent Grid* strategy for 2025-2029 is the targeted deployment of technologies that will enhance grid transparency. An overview of these investments is provided in the System Observability category of the utility's Grid Modernization Roadmap (See Exhibit 2B, Section D5). From a materiality perspective, the most significant investment Toronto Hydro is making to enhance grid transparency in the 2025-2029 period is the replacement of end-of-life, legacy smart meters with next generation smart meters ("AMI 2.0").[4] AMI 2.0 has the long-term potential to provide many of the high frequency, multi-parameter insights that will be required to address the operational pressures and requirements expected as electrification and DER proliferation ramps-up. However, many of the potential benefits and use cases for AMI 2.0 are currently untested and will require significant investment in incremental data analytics, digital systems integrations, and business process changes. It is not yet apparent which of these potential AMI-based solutions will prove to be more economical and sustainable as compared to more use-case-specific grid sensor technologies which are currently more proven and available. In light of this uncertainty, and in the interest of providing immediate benefits to customers while diversifying the long-term options available to Toronto Hydro for monitoring the system, the utility is introducing the System Observability segment for 2025-2029.

This segment will involve the strategic deployment of sensors that will provide the utility's planners and grid operators with real- or near-real time insight into asset performance and operating conditions at critical points on the grid. These capabilities will provide Toronto Hydro with two primary benefits: enhanced response capabilities through the use of fault finding sensors and other

[4] For more details about Toronto Hydro's AMI 2.0 investments, please refer to the Metering program in Exhibit 2B, Section E5.4

telemetry; and the ability to make more effective capital investment and maintenance planning decisions.

To achieve these benefits, the System Observability segment will deploy several sensory assets, such as overhead and underground powerline sensors, online cable monitors, and transformer monitors.

1. Overhead and Underground Sensors

Overhead and underground sensors can improve Toronto Hydro's outage response time. As of today, Toronto Hydro depends in large part on customers to notify the utility when there is a localized outage. The most impactful use-case for grid sensors is that they can eliminate extra steps in the process by alerting the control room to an outage in real time so the utility does not have to wait for notification from a customer. With the mature directional sensor capabilities that are now available, Toronto Hydro can cost-effectively introduce and expand visibility to parts of the grid where it has not traditionally been available.

Additionally, overhead and underground sensors enable controllers and dispatch crews to narrow locations of faults, effectively reducing outage response times. They may also aid in helping verify the cause of outages. As a subsequent need, overhead and underground sensors and monitors provide data that enable Toronto Hydro to record information for diagnostic purposes and drive towards proactive asset management to improve SAIFI & SAIDI metrics. Data can also be extracted to find core failure causes and address them proactively. Figure 12 illustrates sensors on overhead lines that could be part of the System Observability investments.

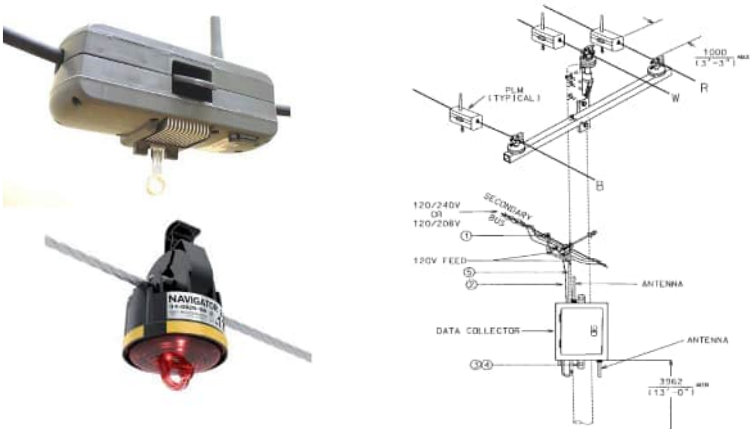


Figure 12: Illustration of Sensors on Overhead Lines

2. Online Cable Monitoring

Online Cable Monitoring utilizes distributed temperature sensing (DTS) technology to obtain a continuous temperature profile of fiber optic cables that are placed alongside underground cables. This information will enable operations and planners to understand feeder loading, increase asset utilization, and identify hot spots. Online Cable Monitoring would allow for proactive measures to be taken on cables such as identifying cables that could be at risk of failure before failure or costly to inspect otherwise. Furthermore, Online Cable Monitors allow for monitoring of load growth and for Toronto Hydro to proactively address and prioritize capacity availability. Lastly, Online Cable Monitors would save OPEX costs and planned outage times when it comes to cable testing and diagnostics. Toronto Hydro plans to deploy Online Cable Monitoring using DTS to complement diagnostic testing as part of Toronto Hydro's cable testing program in order to achieve a better understanding of the overall underground cable system. Currently, limited and targeted cables go through a lengthy and manual testing process of partial discharge which has been cumbersome. Figure 13 illustrates example online cable monitoring devices that could be part of the System Observability investments.



Figure 13: Illustration of Online Cable Monitoring Devices

Online cable monitoring may be deployed in parts of the distribution system that have physical constraints and associated processes to access. One example includes assets within the Western Gap Utility Tunnel bridging Toronto Island to Toronto mainland where cables are located in a tunnel that is pressurised with lake water, making it costly to inspect or maintain.

3. Transformer Monitoring

With the increasing rate of adoption of electric vehicles and increases in residential density in the City of Toronto, there is more pressure due to higher load demand on Toronto Hydro's secondary distribution system. Transformer monitoring allows Toronto Hydro to gain more accurate, real-time loading on the transformer instead of aggregating customer meter loading. The data these devices provide will help improve design requirements when considering new and existing secondary distribution systems. These monitors are also expected to help improve the understanding on the impact of unmetered services on the secondary distribution system to refine connection strategies. The data obtained will also help refine asset management strategies for distribution transformers and optimize their usage and life. An example transformer monitor is shown in Figure 14.



Figure 14: Illustration of a Transformer Monitoring Device

The System Enhancements program segments work together towards the goal of achieving Toronto Hydro's vision of an Intelligent Grid. The continued implementation and enhancement of the Contingency Enhancement segment and the introduction of the System Observability segment specifically contribute to the Intelligent Grid components shown in Figure 15. As key components of the Intelligent Grid, being able to fully implement the System Enhancements program is essential to the overall success of the Intelligent Grid initiative.

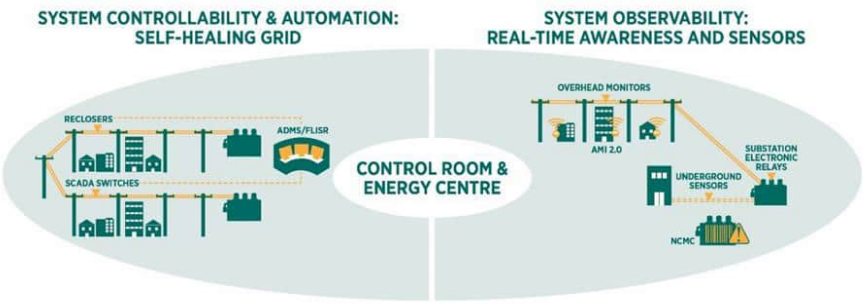


Figure 15: Intelligent Grid Components

E7.1.4 Expenditure Plan

To meet its objectives for an intelligent grid, Toronto Hydro plans to invest $151.2 million over the 2025-2029 period in the System Enhancements program.

Table 6: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Contingency Enhancement	5.0	0.8	4.9	3.7	5.5	17.0	19.6	32.0	29.0	35.3
Downtown Contingency	-	3.7	1.7	-	0.1	1.7	2.9	2.9	3.0	3.1
Customer-Owned Substation Protection	-	0.7	0.1	-	-	-	-	-	-	-
System Observability	-	-	-	-	0.1	0.8	0.9	1.0	1.0	1.0
Total	**5.1**	**5.1**	**6.7**	**3.7**	**5.7**	**19.6**	**23.3**	**35.9**	**33.0**	**39.4**

E7.1.4.1 Contingency Enhancement

1. 2020-2024 Variance Analysis

Toronto Hydro invested $10.7 million in the Contingency Enhancement segment from 2020-2022 period and is projected to allocate an additional $9.2 million in 2023-2024, totalling $19.9 million. This is 25.1 percent lower than the initial proposal outlined in Toronto Hydro's 2020-2024 Distribution System Plan ($24.9 million).

Due to the necessity of installing connections between Copeland TS and Windsor TS in the 2020-2022 period, $5.5 million from the Contingency Enhancement segment was reallocated to Downtown Contingency (see variance analysis below). As a result, planned cable upgrades at Bermondsey TS, Fairbank TS, and Leslie TS were deferred to the 2025-2029 rate period. These entail the replacement of over 4,000 meters of aluminum egress cable with the latest standard copper cable.

Between 2020 and 2022, Toronto Hydro added tie points to 5 feeders, sectionalizing points on 9 feeders, and upgraded one undersized lateral loop. These investments brought 3 feeders up to the minimum Standard Design Practice for operating contingency and prepared three additional feeders for Distribution Automation. Note that a typical Horseshoe feeder serves between 1,400 and 6,000 customers.

For 2023 and 2024, Toronto Hydro plans to install tie points on four distribution feeders and sectionalizing points on three feeders.

2. 2025-2029 Proposed Plan

Toronto Hydro intends to invest approximately $132.9 million in Contingency Enhancement projects during the 2025-2029 period. This increase in expenditure, relative to the 2020-2024 levels, is informed by customer priorities for reliability where they indicated outage durations, particularly during extreme weather events, to be of high importance. Small business and residential customers, in particular, expressed a strong preference for investment in new technology.[5]

Therefore, over the 2025-2029 period in total, Toronto Hydro plans to install approximately 300 SCADA switches (at a pace of 60 per year) on feeders across the Horseshoe and Downtown area with the highest total Customer Minutes Out ("CMO") during the latest 5-year period. As stated in Section E7.1.3.1, this is intended to achieve a total of 18 percent improvement in reliability across 90 Horseshoe feeders and 29 percent on 40 Downtown feeders. This will ensure the remaining 63 Horseshoe feeders meet the distribution automation requirement, thus enabling Toronto Hydro's Grid Modernization objectives.

Specifically, Toronto Hydro plans to install a total of 205 SCADA switches on 94 feeders in the Horseshoe area. This work is expected to result in an average of approximately 12.6 percent

[5] *Supra* note 3

reliability improvement on the 94 feeders where SCADA switch installation work is expected to take place. This will result in average yearly total CMO reduction from 180,113 during the 2018-2022 period to an improved average yearly total CMO of 162,889. The potential SAIDI improvement as a result of this work is expected to be approximately 0.022 minutes per feeder per year.

Furthermore, Toronto Hydro plans to install a total of 94 SCADA switches on 40 overhead feeders in the Downtown area during the 2025-2029 period. This work is expected to result in an average of approximately 16.3 percent reliability improvement on the 40 feeders where SCADA switch installation work is expected to take place. This will result in average yearly total CMO reduction from 128,499 during the 2018-2022 period to an improved average yearly total CMO of 104,625. The potential SAIDI improvement as a result of this work is expected to be approximately 0.03 minutes per feeder per year.

In addition, this investment option plans to install 220 modern reclosers in the distribution system which will yield improved service reliability, a reduction in CMO and CI, and operational efficiency advantages over fault management as stated in Toronto Hydro's Grid Modernization Roadmap (Exhibit 2B, Section D5).

Moreover, this investment initiative will replace approximately 70 km of undersized cable which makes up approximately 80 percent of the total existing undersized egress cables in the Horseshoe area where the peak loading under contingency situation exceeds the capacity of the aluminum egress cable.

Investments made within this segment will be prioritized on the basis of historical reliability performance, loading statistics, cost-benefit analysis, and other relevant data.

E7.1.4.2 Downtown Contingency

In the 2015-2019 rate period, Toronto Hydro's Downtown Contingency program provided station level contingency through load transfer capabilities between stations in the downtown area to mitigate loss of supply risks. Toronto Hydro successfully completed a number of overheard feeder ties, but upon re-evaluating the costs and challenges associated with underground feeder ties, the utility decided not to pursue additional work in this program. However, over the 2020-2022 period, Toronto Hydro spent $5.5 million and installed interstation switchgear ties between Copeland and Windsor stations due to the need to provide contingency mitigation in the downtown core. This work enabled:

- Contingency mitigation at Copeland TS due to the need for transformer repair. These bus ties ensured that should an equipment failure occur, customers supplied by Copeland would not experience an extended power outage.
- Transfer load from Windsor station switchgear to enable switchgear upgrade projects. This work will require the Copeland to Windsor ties to be modified multiple times in the near future. These will provide downtown contingency capability between Copeland and Windsor stations in the long-term.

Recent loss-of-supply incidents have resulted in Toronto Hydro proposing an interstation switchgear tie project from Copeland Station to Esplanade Station over the 2025-2029. The Copeland-Esplanade project work will progress from inspection to design to civil construction and finally electrical construction. Following this window, additional options should become available and are discussed in the next section.

E7.1.4.3 System Observability

The System Observability segment is a new segment with no planned investments in the 2020-2024 DSP. However, Toronto Hydro now plans to spend approximately $0.1 million in 2024 to start installing sensors and monitors before ramping up to $0.9 million per year on average over the 2025-2029 period.

Over the 2020-2022 period, Toronto Hydro assessed a number of overhead and underground sensors and monitors. Over the course of 2023 and 2024, the utility intends to issue a request for proposal to evaluate and select the technology best suited for Toronto Hydro's system.

Once completed, these sensors and monitors will be installed on the overhead and underground system during the 2025-2029 period at a steady pace with ramp up starting in 2024. Priority would be given to areas that are forecasted to increase in load (such as Electric Vehicle growth, electric heating, etc.) and in areas that inspections are costly such as the Western Gap Utility Tunnel bridging Toronto Island to Toronto mainland where cables are located in a tunnel that is pressurised with lake water.

The utility also plans to pilot transformer monitors to validate transformer readings in order to support planning analyses and enhance policy planning decisions. Toronto Hydro intends to pilot transformer monitors across the City of Toronto in various settings to obtain samples of data that

are representative of the many different scenarios. The results of the pilot and additional functionality determined will drive future plans and expenditures.

E7.1.5 Options Analysis

E7.1.5.1 Options for Contingency Enhancement

1. Option 1: Contingency Enhancement at Current pace

Under this option, Toronto Hydro would continue investing at the current pace to spend approximately $20 million over 2025-2029. This would severely limit the scope of work that can be accomplished. Toronto Hydro would have to prioritize only the most critical Contingency Enhancement investments, such as installing 111 SCADA switches for 37 of the feeders in the Horseshoe with the worst reliability and approximately 17.8 km of undersized egress cable upgrades for 7 feeders. The utility would not be able to install SCADA switches on a portion of the Horseshoe feeders that currently fail to meet the minimum Distribution Automation requirement or on overhead Downtown feeders. This option also excludes the implementation of modern reclosers in the distribution system and any upgrades of undersized loop conductors.

Under this option, the utility's ability to reduce the number of customers impacted and outage duration during contingency events would be limited. Moreover, the absence of strategically placed reclosers would leave Toronto Hydro's assets susceptible to damage and strain during system faults. Without the fault testing capabilities provided by recloser features, Toronto Hydro would be constrained in its ability to proactively prevent faults. Considering these factors, the status quo is not recommended.

2. Option 2 (Selected Option): Contingency Enhancement

Executing the proposed Program would strengthen Toronto Hydro's distribution system in contingency conditions, improving reliability for affected customers. The addition of SCADA controlled tie and sectionalizing switches would enable Toronto Hydro to segment a feeder into smaller sections, transferring load to alternate feeders and minimizing the duration of power outages. This investment option entails upgrading approximately 300 SCADA switches for 94 Horseshoe feeders and for 40 Downtown feeders. Furthermore, 44 feeders will be targeted for upgrading undersized egress cables from aluminum to copper, replacing approximately 69 km of

cable. These enhancements align with Toronto Hydro's Grid Modernization plan, ensuring that 90% of Horseshoe feeders meet the Distribution Automation requirement by the end of the period.

Additionally, this investment option will include implementing 220 modern reclosers in the distribution system that will yield improved service reliability, a reduction in Customer Minutes Out (CMO), and operational efficiency advantages over fault management. By targeting high-priority locations and responding to customer concerns, Toronto Hydro will enhance its ability to restore power quickly during outages, especially in the Horseshoe and Downtown areas, including high-impact contingency events. This option offers short-term and long-term benefits, directly benefitting customers and prolonging the life of system assets. Therefore, this option is highly recommended as it strikes a balance between mitigating risks and meeting customer expectations. It aligns with Toronto Hydro's Grid Modernization goals.

E7.1.5.2 Options for Downtown Contingency

1. Option 1: Maintain the status quo

This option maintains the system at status quo. Projects would continue within the Stations portfolio to eliminate downtown reliability risks and to install new equipment which meet the latest standards; reducing vulnerabilities and improving flexibility in emergency situations. Distribution projects that allow customer load transfer between stations during major station outages will be pursued. While these investments would improve reliability risks within the system, they do not mitigate contingency event scenarios. And therefore, this option is not recommended.

These ongoing incremental improvements will continue into the future regardless of other options being undertaken.

2. Option 2 (Selected Option): Station-to-Station switchgear ties (i.e. interstation switchgear ties)

This option involves the installation of station-to-station switchgear ties on eligible stations with the required 3000A feeder positions present. Each station switchgear should have sufficient emergency loading capability to pick-up the majority of an interconnected switchgear's load. Additionally, each station should be connected to a different Hydro One source of supply. This option is the selected option as it would provide the quickest timeline to achieve reliability benefits, while accommodating operational constraints.

As noted in E7.1.3.2, the best option for an anchor downtown source is Copeland Station.

3. Option 3: Station-to-Station feeder ties

This option involves the installation of station-to-station *feeder* ties, and would need to continue into the future in order to maximize benefits. It requires a long time to achieve the stated benefits compared to the previous options. However, the result would provide more benefits.

The feeders should have sufficient emergency loading capability to pick-up the majority of the neighbouring feeder's load and a different Hydro One source of supply. There are approximately 557 feeders in the downtown area suitable for feeder ties, of which 26 have already been tied.

To complete the required feeder ties in a reasonable time frame, this option requires installation of approximately 11 feeder ties annually, for a period of approximately 25 years.

Feeder ties provide limited ability to pick-up loads; therefore, if required, the Control Room would have to select the loads to pick-up out of the options available. The Control Room would be required to prioritize loads such as hospitals, water and sewage treatment, and key financial centers.

Interstation feeder tie projects were undertaken in the 2015-2019 period, but were found to have escalating costs and challenges as noted in 2020 CIR (Section E4.2.3 at, pg. 12-13). Due to the relatively high costs for the benefits achieved, this option is not recommended.

4. Option 4: Switchgear ties within the same station (i.e. intrastation switchgear ties)

This option involves the installation of direct bus ties between switchgears in the same station. These ties can be used to resupply a Toronto Hydro station switchgear that has lost its Hydro One supply, from another Toronto Hydro switchgear within the same station that continues to be supplied by Hydro One.

This work is in the Stations portfolio and will not be undertaken in the downtown contingency segment. In this option, when existing Toronto Hydro station switchgear are replaced, the new switchgear includes provisions for direct bus ties to other switchgear within the same station.

5. Option 5: Automated Primary Closed Loop ties (i.e. APCL ties).

The Automated Primary Closed Loop ("APCL") option provides the most substantial long-term improvements of all the options. It also increases development risks and challenges.

This option involves the installation of station-to-station *feeder* ties. Unlike Option 3, this option involves the addition of components to tie future APCL distribution systems supplied by two different stations. APCL equipment and system design are currently in development, with no plant presently installed in the field. Over the 2023-2025 period, the first prototype APCL vault equipment is expected to be acquired and will be used to develop and test protection and control, as well as operational practices. APCL ties provide fundamentally more cost effective and operational benefits than other options.

This option requires a longer timeline to achieve a specified level of benefits than other options. However, it would achieve more benefits at a lower cost. Ultimately, APCL will not be achievable in the 2025-2029-time frame, but will be considered for future distribution system plans.

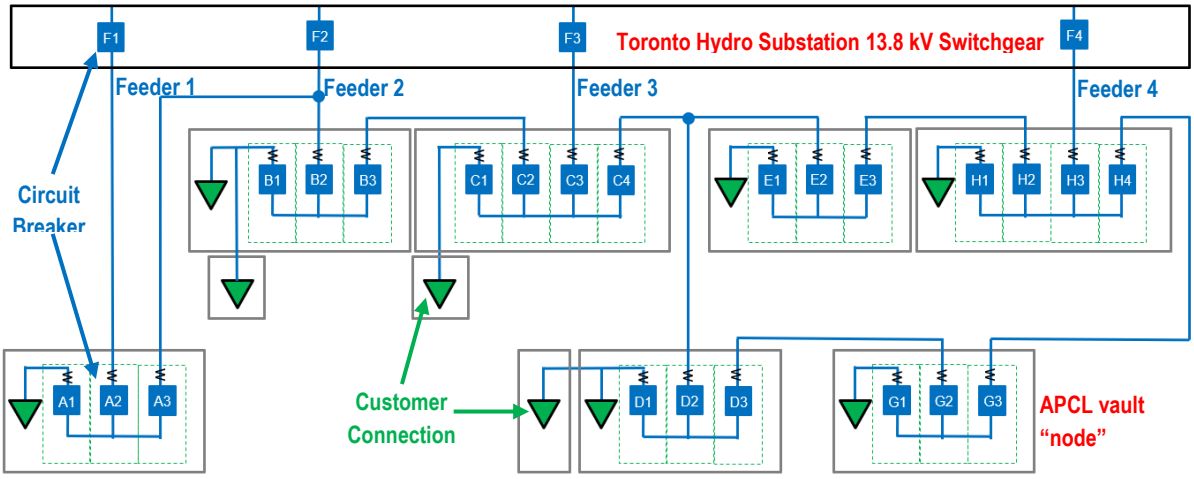


Figure 16: APCL Distribution System

E7.1.5.3 E7.1.5.3 Options for System Observability

1. Option 1: No Installation of System Observability Assets

The present circumstances, being a system without visibility on live data, is costly and timely to customers when it comes to outage restoration. Acknowledging that proven technology is readily available, the existing costs and existing average outage durations are avoidable and capable of being reduced. Without the thermal profiles and partial discharge identifying capabilities through online cable monitors, proactive measures cannot be taken which are costly and preventable. The current system waits for cables to fail and then Toronto Hydro reacts accordingly which is costly and untimely. For these reasons, this option is not recommended.

2. Option 2 (Selected Option): Installation of System Observability Assets

Installing monitoring devices onto Toronto Hydro's existing system will enable visibility on the electrical grid at strategic locations and would be a win-win for customers and Toronto Hydro, and is the recommended option. Observability would provide reduced outage times, extended asset life and improved planning in many cases. Costs can be reduced by less time identifying the fault and less wear-and-tear on equipment that occurs during fault. Without observability assets, manual inspections are undertaken which may not be frequent or sufficient to identify developing issues prior to failure. Online cable monitors and transformer monitors provide a paramount overview of risk failure. This initiative for visibility on faults coupled with communication to Toronto Hydro's controllers and crews is the recommended option.

E7.1.6 Execution Risks & Mitigation

E7.1.6.1 Contingency Enhancement

Unforeseen site conditions, such as the presence of third-party infrastructure (e.g. gas, sewer or water pipes), can necessitate scope changes, and result in cost increases or delays in the completion of the underground cable replacement Contingency Enhancement work. In these situations, Toronto Hydro will reprioritize or reschedule work after taking all factors into consideration.

As well, Toronto Hydro must consider city road moratoriums. Underground cable replacement work which is part of this segment might come in direct conflict with city-imposed road moratoriums. This could delay any civil infrastructure installation required for cable upgrades which will delay the Contingency Enhancement projects. Toronto Hydro will mitigate this risk by ensuring that it maintains open communication with the City of Toronto and coordinates its activities with those of the city.

Distribution Automation projects, by their nature, require robust communication between SCADA switches. Under the proposed centralized approach (FLISR) utilizing the NMS, this risk will be mitigated.

Supply chain challenges is a new risk that Toronto Hydro is currently experiencing where many of the vendors cannot provide material and equipment on time to ensure timely execution and completion of Contingency Enhancement projects. This can be mitigated by working closely with the supply chain team to order as much of the required material in advance, and to reprioritize the order of which

projects get executed each year to minimize disruption to the work program for this segment during 2025-2029 period.

Based on Toronto Hydro's recloser pilot, reclosers require coordination with HONI, System Studies, and Operations to make the reclosers coordinate and operate properly. Without proper coordination between the station circuit breaker and the recloser, there is a risk that both devices will trip resulting in minimal benefits from the recloser. Modern reclosers compatible with Toronto Hydro's system require microprocessor relays at the station to properly set the coordination of the relays. Feeders that meet the criteria for more than one recloser on the feeder, fibre optic communication provisions may be required for coordination and proper operation. Without fibre optic infrastructure connected from the station breaker to the recloser, the feeder may be limited to a maximum of one recloser due to coordination limitations. Hence, the plan may include a two-phase approach of installing reclosers on poles and then adding fibre optic in a subsequent phase or vice versa depending on feeder, station coordination and existing infrastructure.

E7.1.6.2 Downtown Contingency

Unforeseen field conditions, equipment configurations and new standards and materials will impact the station-to-station switchgear ties program. These include, but are not limited to, the following:

- Running new ducts in downtown congested areas: Underground civil structures have been utilized and/or constructed over the last several years. Additional civil plant will likely need to be constructed in congested areas, which may create unanticipated project delays and cost escalation. In addition, recent experience has shown increased civil cost and project delays due to very high-water tables near the waterfront

- The new switchgear requires a swing option. Generally, station-to-station switchgear ties require new switchgears with appropriate configuration. If a new gear is not available at the time of the tie project, project delays will occur. Project plans should ideally be based on suitable existing switchgear. Alternatively, projects should be only planned where there is high confidence that the switchgear will be ready when required

- Furthermore, station-to-station switchgear tie projects are expected to require new cabling, jointing and termination standards. Changes to standards should be addressed as soon as requirements can be firmly established.

- Finally, the response strategy to manage moratoriums and obstacles includes; reschedule civil construction work to avoid moratorium time periods, and redirect duct bank routes to avoid areas under construction moratoriums.

E7.1.6.3 System Observability

Overhead and underground sensors provide real time data which requires consideration for communication infrastructure. Current market products that have been proven and utilised in other Canadian power utilities to date include the use of SIM cards for communications. Considerations for network connectivity and coverage must be tested in advance of installation. In a previous Toronto Hydro study of 32 power line monitors, they all became obsolete after telecommunication networks advanced from the 2G network to the 3G and 4G networks. This significantly reduces the asset's useful life and return on investment. Compatibility with Toronto Hydro's current SCADA and FLISR systems will be considered along with overhead and underground sensors such that they can adapt with changing communication networks or be independent of them entirely. Additionally, some overhead and underground sensors within the current market require their own independent power sources. Top current market products show that the majority require DC power or batteries that may require replacing or charging. Visibility of battery life and signal strength of sensors would be major considerations to mitigate operational risks. Furthermore, risk considerations of extreme weather and extreme high/low Toronto temperatures along with instrument calibration would be realistic risk factors for these measuring assets. To mitigate these risks, data from the manufacturers and other utilities would be considered during the Request for Proposal stage which is planned for in 2023.

Online Cable Monitors will require fibre communication infrastructure to attain live data. Coordination and planning will be required prior to the installation of Online Cable Monitors especially in locations that do not presently have fibre communications that have been identified as an optimum location for an Online Cable Monitor. To mitigate the risk of not having the Online Cable Monitors installed in the most optimum locations, planners and operational controllers will need to ensure that fibre communications is installed prior to the Online Cable Monitors. Part of the strategy is to consider installing Online Cable Monitors where fibre optic already exists and then expand to areas that are fibre optic feasible.

The current market for Transformer Monitors may require a separate software for access to the live data being acquired. Lack of integration with the FLISR system is a risk as it may hamper the

operational benefits if there are separate systems. To mitigate this, product selection must include customised or retrofitted integration to experience the full benefits on operations.

Lastly, integration of new technology into the current Toronto Hydro system will require IT support and vendor support. Accessing real-time data during a power interruption will require fundamental integration into the current software systems to achieve optimum use of the data.

E7.2 Non-Wires Solutions Program

E7.2.1 Overview

Table 1: Program Summary

Total 2020-2024 Cost ($M): $2.2	**2025-2029 Cost ($M): $22.5**
Energy Storage Systems 2020-2024: $1.2	Energy Storage Systems: $ 22.5
Local Demand Response 2020-2024: $1.0	Flexibility Services: OPEX only
Segments: Flexibility Services, Energy Storage Systems	
Trigger Driver: Capacity	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Financial Performance, Public Policy Responsiveness	

Toronto Hydro has been actively exploring how Non-Wires Solutions (NWSs) can support conventional utility planning since 2015, primarily through the Local Demand Response (LDR) program (now included in the Flexibility Services segment), but also through the deployment of grid-supporting Energy Storage Systems (ESS). In previous years, these two programs have been managed separately; going forward, they will be brought together under one Non-Wires Solutions program.

NWSs refer to operating practices, activities or technologies that enable the utility to defer the need for specific distribution or transmission projects, at a lower total resource cost, by reliably reducing system constraints at times of maximum demand in specific grid areas. Typically, these NWSs leverage the use of Distributed Energy Resources (DERs), often in partnership with utility customers, or with other enabling third-parties.

The NWS strategy for the 2025-2029 period is focused on being flexible and adaptable to help system planners respond to load growth while navigating the underlying uncertainty that stems from changing demand patterns and increased reliance on electrification. This strategy builds on Toronto Hydro's experience utilizing DERs to reduce peak demand, helping to defer grid expansions or, in most cases, avoid grid expansions should demand not materialize as expected (e.g., lower than expected demand, fluctuating demand). This approach can help utilities meet system needs while avoiding overbuilding, ultimately reducing the risk of stranded or underutilized assets. Given the scale of investment that will be required to meet high-levels of electrification, NWSs are viewed as additive to conventional utility expansion strategies, enabling Toronto Hydro to expand its planning toolbox to include additional strategies for keeping up with load growth.

The NWS program at Toronto Hydro has two broad streams:

1) **Flexibility Services**

   Flexibility Services at Toronto Hydro refers to programs that address localized distribution issues through targeted procurements with customers or other third-parties. The most well-established flexibility service program at Toronto Hydro is LDR, which has been running since 2015. For the 2025-2029 period, Flexibility Services will be expanded beyond standard 4-hour Demand Response (DR) to include other services that can address a demonstrated grid-need, such as shorter duration DR where appropriate.

2) **Energy Storage Systems**

   Energy Storage Systems at Toronto Hydro are an innovative tool to complement traditional utility technologies in addressing distribution grid challenges. For the 2025-2029 period, Toronto Hydro will focus on developing a scalable, demand-driven, ESS strategy that is responsive to distribution system needs and supports the pathway to renewable integration and electrification

Toronto Hydro's NWS strategy for 2025-2029 reflects the last eight years of experience in both LDR and the energy storage space. The vision for the future is a product of experience and reflection, resulting from facing and overcoming numerous challenges. The program is unique in that in contains both capital expenditures (ESS equipment), as well as operating expenditures (capacity or energy payments for DR capacity). These expenditures are outlined below.

E7.2.1 Flexibility Services

E7.2.1.1 Background and Future Vision

Toronto Hydro's vision for flexibility services is built upon its strong foundation of successfully deploying NWSs. Toronto Hydro, a leader in developing NWSs, intends to continue to evolve the opportunities and benefits afforded by NWSs.

Local Demand Response Overview

The LDR program is Toronto Hydro's flagship NWSs initiative. The LDR program was the first utility-driven NWS program in Ontario and has been deployed successfully since the 2015-2019 rate period. This program is designed to help address short-to-medium term capacity constraints at targeted transformer stations by identifying opportunities where DR, including behind-the-meter and customer-owned DERs, can be leveraged to support the broader distribution system cost-effectively.

The LDR program is a big step forward in evolving conventional utility station planning to include the consideration of NWSs alongside traditional "poles and wires" investments. This approach enables the utility to address capacity constraints using targeted deployment of DR, expanding the planning toolbox beyond conventional wires solutions when evaluating options to address short-to-medium term capacity needs.

Utilities regularly utilize information and data to prioritize infrastructure investment based on where the system needs it the most. Demand Response strategies can provide utilities with increased flexibility when determining which projects should be undertaken, which ones can be deferred to a later date, and which ones can be avoided entirely, ensuring optimal allocation of limited capital funds. This results in a more efficient use of capital, and in some instances, leads to avoiding capital expenditure all-together.

Since launching LDR in the 2015-2019 rate period, Toronto Hydro has demonstrated the ability to procure and deploy contractual DR capacity to support the grid. This experience has helped develop and grow capabilities in utilizing NWSs.

During the 2015-2019 period, Toronto Hydro ran LDR at one station located in the downtown core: Cecil TS. At the time, the utility was forecasting that capacity constraints would materialize on two busses at Cecil TS in 2020. Toronto Hydro used LDR to reduce summer peak demand by about 8 MW, helping to avoid anticipated capital investment. The anticipated capital investment was initially deferred to the 2025-2026 period. However, these upgrades were avoided entirely, as the load profile at Cecil TS evolved over the 2020-2022 period, resulting in a much different outlook which no longer necessitated station expansion. This pilot project is an example of how a utility can leverage customer-owned DERs to gain planning flexibility when dealing with investment needs that carry a high degree of uncertainty.

The Cecil TS LDR Pilot at a glance:

- Successfully contracted 8 MW of DR, working with commercial and institutional customers
- Reduced summer peak demand by 8 MW in 2018 and 2019
- Resource mix included back-up behind-the-meter generation and customer load curtailment activities
- 5-6 events per year, delivered over a 4-hour period (2pm to 6pm)

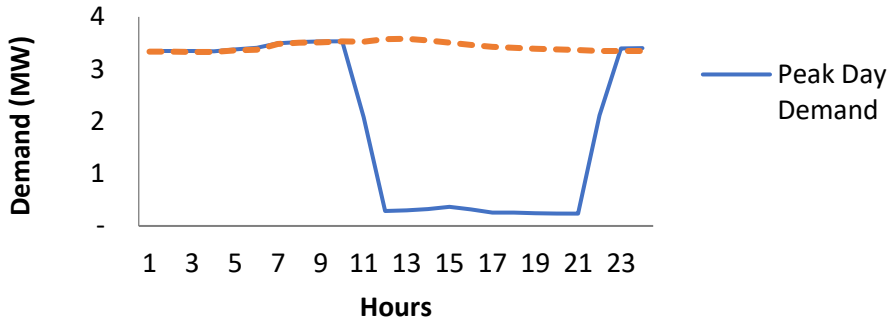


Figure 1. Sample LDR Event with a 3 MW Customer

For the 2020-2024 period, Toronto Hydro expanded the program to target two stations, Manby TS , and Horner TS. The details of this program are outlined in section E.7.2.2.4 below.

Evolution of LDR: Flexibility Services

For the next rate period, Toronto Hydro will build on the success of LDR to build a Flexibility Services program, which will expand to include services other than standard 4-hour DR. As with LDR, Flexibility Services are demand-side services that the utility purchases from customers and third-party vendors (i.e. energy services providers and aggregators) in order to address distribution system needs. These services allow the utility to work with customers and vendors to change where or when electricity is consumed, helping to level out peaks in demand. The goal is to find innovative ways to support electrification while enabling efficient use of capital, avoiding overbuilding the distribution system.

Table 2. Types of Flexibility Services:

Type of Service	Description	Use Case
Demand Response (DR)	Contractual arrangements with customers or aggregators for 4-hour blocks of load curtailment	Peak-shaving, capacity support
Short-Duration DR	Contractual arrangements with customers for 2-hour blocks of load curtailment. Enables participation from a wider variety of loads	Peak-shaving, capacity support

A key feature of the Flexibility Services program is the development of a competitive marketplace for the procurement of resources. To create this successfully, Toronto Hydro will:

- Identify areas in the system where demand-side approaches can help alleviate system constraints;
- Determine characteristics of capacity requirement (i.e. quantity, duration, seasonal need, expected number of activations);
- Conduct an options analysis to determine how these system needs can be addressed conventionally, and utilize this analysis to determine the capacity value and target price for capacity; and
- Communicate this information to prospective participants via an online platform; and
- Hold periodic auctions to procure capacity competitively, allowing Toronto Hydro to match available capacity with system needs.

One result of Toronto Hydro's 2020-2024 LDR program will be the creation of an online DR Capacity Auction tool, which enables the competitive procurement of DR capacity. This tool can be utilized in the 2025-2029 period to target several station areas (see Drivers section for more details). A prototype of the tool is currently under development in partnership with Toronto Metropolitan University's Centre for Urban Energy ("CUE").

E7.2.1.2 Outcomes and Measures

The Flexibility Services program works together with the Stations Expansion and Load Demand programs to ensure Toronto Hydro can supply growing customer demand while maintaining system reliability and improving grid resiliency. By leveraging customer-owned energy resources to offset peak demand, Flexibility Services provides incremental customer value in the form of grid optimization capabilities that were not traditionally available to grid planners and operators, while also providing an incremental source of value to current and prospective DER owners. This aligns with Toronto Hydro's broader modernization strategy, which aims to implement technologies and develop capabilities that will allow the utility to optimize the utilization and performance of its grid, ensuring distribution service and access remains as cost-effective as it can be while keeping up with anticipated demand pressures from electrification and the digitalization of the economy.

Table 3: Outcomes & Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: ○ Engaging with customers and enabling them to participate in the grid ○ Adding flexibility to the grid to enable efficient customer connections ○ Providing revenue opportunities for DERs, thereby encouraging DER uptake and integration
Operational Effectiveness - Reliability	• Contributes to maintaining Toronto Hydro's system reliability objectives by providing additional tools for managing and prioritizing capacity constraints.
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by acting as a bridging strategy to help to avoid (or defer) capital investments where demand is uncertain.
Public Policy Responsiveness	• Contribute to Toronto Hydro's public policy responsiveness objectives by: ○ Responding to the regulator's direction for utilities to consider and leverage NWSs where possible to drive rate-payer value ○ Reducing greenhouse gas (GHG) emissions by enabling the proliferation of energy storage, DERs, and grid-modernization ○ Enabling electrification by investing in additional capacity and operational flexibility

E7.2.1.3 Drivers and Need

Table 4: Segment Drivers – Flexibility Services

Trigger Driver	Capacity
Secondary Driver(s)	Reliability

The Flexibility Services program primarily helps complement conventional station expansion and load demand programs to address capacity constraints on the distribution system. Pressures such as densification, population growth, and electrification create constraints that need to be addressed either by building additional capacity, transferring load, or reducing load on the system via demand-side services.

These conditions are expected to intensify beyond 2024 as supported by the City of Toronto's long-term Precinct Plans[1] for both the downtown and the Horseshoe areas and by Toronto Hydro's 10-Year Station Load forecast (see Section D4 of the DSP). The Station Expansion program speaks extensively to the identified needs in Toronto Hydro's service territory over the 2025-2029 period.[2]

While the Station Expansion program at Toronto Hydro addresses large-scale, longer term load growth challenges through the provision of new or expanded transformer stations, the Load Demand program ensures that sufficient capacity is always available to keep pace with day-to-day load growth, preventing the overloading of system assets.

As described in the Load Demand program, a key tool for meeting capacity needs and ensuring system reliability and efficiency is bus level load transfers (load transfers between station buses to alleviate overloaded buses).[3] The Flexibility Services program directly supports Load Demand by identifying opportunities to defer or avoid these load transfers when and where it is appropriate.

To help identify where to target Flexibility Services, both long-term planning (station expansion) and short-term planning (load demand) needs are considered to identify opportunities for NWS support. Factors that are considered when selecting a target area include high-levels of projected growth, large customer connections (e.g. data centres), high levels of load connections generally, and projections for electrification drivers, e.g. electric vehicle adoption. For the 2025-2029 period, the Flexibility Services program will target six stations in in Toronto Hydro's service territory: three in the Horseshoe (Finch TS, Manby TS, and Leslie TS) and three in the downtown (Cecil TS, Strachan TS, and Copeland TS). /C

It should be noted that a key feature of the Flexibility Services program is that it can easily adapt in terms of scope and location to meet the most pressing system needs. The current focus on the six identified stations is due to the high potential for NWSs to defer capital expenditure. This is based on the identified system needs, as well as an assessment of current and expected future DER capacity. These stations have emerged as ideal target areas because: /C

- High levels of load growth are expected over the next ten years;

[1] City of Toronto, *How Does the City Grow?* https://web.toronto.ca/wp-content/uploads/2017/08/9014-How-Does-the-City-Grow-April-2017.pdf
[2] Exhibit 2B, Section E7.4.
[3] Exhibit 2B, Section E5.3.

- Large-scale developments (including City Downsview Development adjacent to Finch TS) are expected to materialize in the near-term; /C
- Currently has a high-penetration of large Key Account customers, some of which have DER capacity that could be utilized to provide distribution grid services; and,
- It has been identified as an area that will require up to 130 MVA of load-transfers in the next rate-period.

Toronto Hydro plans to execute targeted load transfers on station buses that are expected to become overloaded based on Toronto Hydro's Station Load Forecast and those where opportunities will arise to redistribute load with adjacent station buses.[4] Figure 2 shows all stations that are targeted for bus-level relief in 2025-2029. Some of these stations are excluded (i.e. Dufferin TS, Terauley TS, Esplanade TS, Horner TS and Windsor TS) as the transfers are either carry over projects from 2020-2024, or projects where overloading is not the primary driver. /C

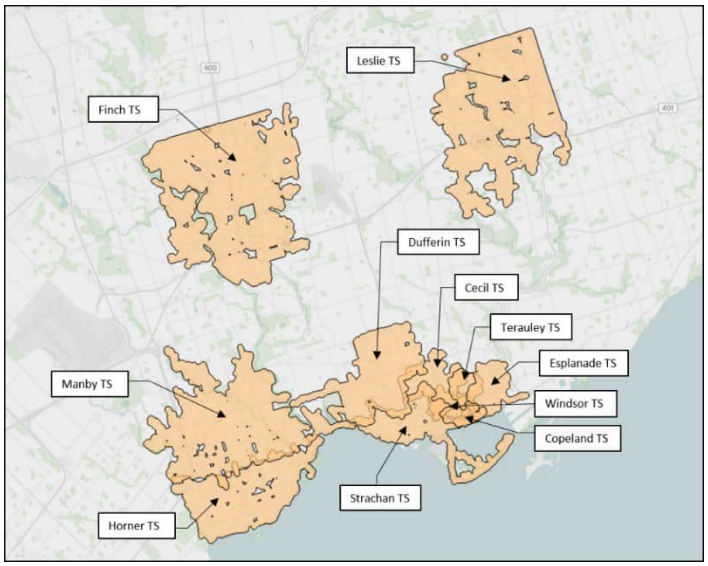


Figure 2: Stations Targeted for Bus-Level Relief during the 2025-2029 Rate Period

[4] Exhibit 2B, Section E7.4.

The current shortage of feeder positions or bus capacity makes it difficult to connect new customers to an optimal supply point within the station service area. In this case, feeders are extended outside the boundary of the station service area, which may require the construction of additional civil infrastructure. Furthermore, load transfers between feeders could also be required to accommodate new customer connection from the nearest available feeder.

Table 5. Load Transfers Anticipated at Target Stations in 2025-2029 Period

Station	Bus	Estimated Load to Transfer (MVA)	Area
Cecil	A1-2CE	10 - 20	Downtown
Copeland	A1-2CX	10 - 20	Downtown
Finch	J-Q	35 - 50	Horseshoe
Leslie	B&Y	15 - 30	Horseshoe
Manby	Q-Z	20 - 35	Horseshoe
Strachan	A9-10T	10 - 20	Downtown

/C

Flexibility Services targeting these stations can provide temporary relief, giving planners flexibility to determine whether load transfers will become necessary. As part of the Load Demand program, station bus load forecasts are re-evaluated annually and informed by up-to-date system conditions, new connections, and updated weather corrected load forecasts. Based on the outcome of this evaluation, the need for specific load transfers can either be escalated in priority or deferred. This provides Toronto Hydro with the opportunity to explicitly consider and use NWSs to help avoid a portion of these load transfers when possible[5]. This consideration will inform where to focus NWS procurement efforts on an annual basis utilizing the appropriate, competitive process. This has been an auction process in the 2020-2024 period; however, as part of the ongoing evolution of this program, Toronto Hydro will continue to consult with stakeholders to refine and update the procurement mechanism, ensuring maximum participation from customers and aggregators.

Given the range of expected load transfers in Table 5, Toronto Hydro will aim to procure up to 30 MW of demand response capacity in the areas served by the six target stations. This could help avoid about 25% percent of the total load required to be transferred in these areas. This translates to

/C

[5] As noted in the Load Demand narrative (Exhibit 2B, Section E5.3.), Manby TS and Horner TS, which were originally planned for relief in the 2020-2024 period, have been deferred to the 2025 period, in part due to the Local Demand Response program.

avoided capital expenditure in the range of $10 million, at a projected cost of about $5.7 million in operating expenditure. Further details about costs are provided in the Expenditure plan.

E7.2.1.4 Expenditure Plan

Table 6 and Table 7 below summarize the LDR Program plan for 2020-2024.

Table 6: 2020-2024 CIR – LDR ($ Millions)

	2020	2021	2022	2023	2024	Total
CAPEX	1.0	-	-	-	-	1.0
OPEX	-	0.8	0.8	0.8	0.8	3.2

Table 7: Actual and Bridge Costs- LDR ($ Millions)

	Actual			Bridge	
	2020	2021	2022	2023	2024
CAPEX	1.0	-	-	-	-
OPEX	0.2	0.2	0.2	0.7	0.7

For the 2020-2024 period, Toronto Hydro has moved the majority of the capital allocated to the LDR battery system into the ESS program to plan and track all ESS projects under one program. The remainder of the total 2020-2024 Local DR program cost (e.g. incentives, labour) is not capitalized (i.e. OPEX). The majority of the costs are related to DR capacity payments ($1.4 million), and the remainder of the costs ($0.6 million) are related to program administration, legal costs, and consulting costs. Details about costs are provided in the program description below.

1. 2020-2024 Local Demand Response Program

For the 2022-2024 period, Toronto Hydro has continued to advanced capabilities in the NWS space, building on the work done in the 2015-2019 period at Cecil TS. For this period, the LDR program targeted two transformer stations (TS): Manby TS and Horner TS. These stations were selected based on specific needs; Manby TS has been reaching capacity on two busses for several years and overloading at Horner TS has been forecasted in the near-to-mid term. These capacity issues were

identified in Toronto Hydro's 2015-19 Custom IR Application[6] and Hydro One's 2016 Regional Infrastructure Plan for the Metro Toronto Region.[7]

Several load transfers north to the Richview TS have been completed. Further transfers are difficult due to the distance between the stations and a lack of remaining overhead corridors running north-south. Load transfers to neighbouring stations to the east cannot be easily achieved due to capacity constraints at Runnymede TS, the Humber River posing a geographical barrier, and different system voltages (13.8 kV vs 27.6 kV). Load transfers to the west and south are not possible because the Manby TS and Horner TS are on the boundary of Toronto Hydro's service territory. Due to limited space at Manby TS for expansion, work has been underway to expand capacity at Horner TS. This new capacity will be utilized to relieve Manby TS in 2025. In the meantime, while the expansion work is undertaken, LDR has been leveraged to provide increased flexibility in the Manby TS and Horner TS area. As a result, some additional load transfers from Manby and Horner TS have been avoided over this rate-period and it is expected that this will continue to be the case until 2025, when load will be permanently removed from Manby TS to Horner TS.[8]

As noted, the majority of the LDR program costs are related to capacity payments for demand response ($1.4 million), and the remainder of the costs ($0.6 million) are related to program administration.

The capacity payments made to DR providers are benchmarked against the cost of additional load transfers that would have otherwise been required at Manby TS and Horner TS. It was estimated that the capital cost of executing 10 MW of load transfers from Manby TS or Horner TS to adjacent stations would be in the range of $4 million. Utilizing LDR to avoid these load transfers between 2023-2025 has effectively helped manage demand in this area until the expansion of Horner TS is complete and a permanent transfer can be made from Manby TS in 2025. As such, it was important to ensure that the total cost of LDR (capacity payments + admin) was well below the cost of the wires solution on a net present value basis. The maximum capacity payment for LDR was benchmarked utilizing a discounted cash flow model comparing the cost of load transfers to the cost of LDR, and the capacity payment was further driven down as a result of competitive procurements. The LDR

[6] Toronto Hydro Custom IR Application for 2015-2019 (OEB File No. EB-2014-0116). https://www.rds.oeb.ca/CMWebDrawer/Record?q=CaseNumber=EB-2014-0116&sortBy=recRegisteredOn-&pageSize=400
[7] https://www.hydroone.com/about/corporate-information/regional-plans/metro-toronto
[8] Exhibit 2B, Section E5.3

program was initially projected to cost $4 million but will cost closer to $2 million over the current rate-period.

Evolution of LDR: Grid Innovation Fund Pilot Project

In late 2021, Toronto Hydro identified an opportunity to build on the LDR program planned for Manby TS and Horner TS to examine how Toronto Hydro and other distributors can work with the Independent Electricity System Operator (IESO) to better coordinate the use of DERs as NWSs in order to maximize value and lower resource acquisition costs. The IESO's regional planning documents indicated that capacity constraints were expected in the Richview-Manby transmission corridor starting in 2021. Transmission system upgrades will be necessary to address these capacity constraints. Due to project lead-time, the upgrades are not expected to come into service until 2025. The IESO is pursuing short-term measures, such as incremental Conservation and Demand-side Management (CDM) and DR, where feasible and cost-effective, to assist in reducing customer reliability risk until the transmission system upgrade can come into service.

Given the clear alignment of needs between Toronto Hydro and the IESO, Toronto Hydro partnered with Power Advisory LLC and Toronto Metropolitan University's CUE, to create a project that explores how to effectively and efficiently procure and deploy DR capacity to address overlapping distribution and transmission system level needs. This project is called the Benefit Stacking Transmission and Distribution Pilot ("Benefit Stacking Pilot") and is supported by the IESO's Grid Innovation Fund, and the Ontario Energy Board's (OEB's) Innovation Sandbox.

Currently, customers with load control capabilities or behind-the-meter DERs seeking to provide DR services interact with Toronto Hydro's distribution system (e.g., LDR) and the IESO-operated transmission/bulk system (e.g. as Market Participant) separately. There is limited opportunity for coordination between the two systems to maximize the benefit and value of the DERs.

The Benefit Stacking Pilot Project explores how customer-owned DERs can provide services to both the distribution grid and transmission/bulk system using an efficient single pathway that works with existing market mechanisms. By making it easier for DER owners to participate in multiple programs thereby maximizing the value proposition for DERs to provide non-wires services, it is anticipated that participation levels would increase which would then, over time, drive down resource procurement costs. A key deliverable of the Benefit Stacking Pilot Project will be an analysis of the resulting rate-payer value of the dual DER participation.

Toronto Hydro will simulate offering LDR capacity into the IESO market, unlocking additional revenue streams and system benefits, often referred to as "benefit stacking". Toronto Hydro will also simulate the utilization of the LDR resources in the IESO's real-time markets, testing how Transmission-Distribution system coordination can be undertaken to avoid conflicting dispatch instructions between the two levels. The costs of the simulation are being funded through the IESO's Grid Innovation Fun (GIF). The pilot explores current barriers to LDC-IESO coordination, seeks to improve overall visibility for both LDCs and the IESO with respect to DR resource activities and identify pathways for better coordination, leading to more efficient dispatch at both levels.

2. 2025-2029 Forecast Expenditures

Given the range of expected load transfers in Table 5, Toronto Hydro will aim to procure up to 30 MW of demand response capacity in the areas served by the six targeted stations. This could help avoid about 25% of the total load required to be transferred in these areas. This translates to an avoided (or deferred) capital expenditure in the range of $10 million (at minimum), at a projected cost of about $5.7 million in operating expenditure. /C

Because Flexibility Services are market-based, the goal will be to again run competitive procurements that enable Toronto Hydro to drive down the cost of contracting for DR. The anticipated spend of $5.7 million dollars is based on the current market value of demand response in the LDR program, which is $700/MW-day for the summer 2023 period. However, each time a procurement is planned, Toronto Hydro will go to market to determine if the NWS is cost-effective as compared to the wires solution. To determine the cost-effectiveness, the cost of the specific load transfers would be compared to the procurement of DR over a specified period of time. This analysis determines the reference price for the DR, and the competitive procurement seeks to further lower this price through competition.

Table 8. Segment Unit Scenarios over 2025-2029 period

Segment	Cost per unit	Target Capacity	Projected cost	Capital Avoidance & Deferral
Flexibility services	$0.7M/MW	Up to 30 MW	$5.7M	$10M

Table 9: 2025-2029 CIR – Flexibility Services ($ Millions)

	2025	2026	2027	2028	2029	Total
Flexibility Services (OPEX)	0.2	0.9	1.1	1.6	1.9	5.7

It is anticipated that Toronto Hydro will spend the first year of the 2025-2029 rate period prioritizing targeted stations, setting capacity targets, and developing procurement processes and documentation. Between 2026-2029, Toronto Hydro will set the following procurement targets:

- 2026: 10 MW
- 2027: 15 MW
- 2028: 25 MW
- 2029: 30 MW

Program operating costs are based on an assumed capacity payment of $700/MW-day plus $200,000 per year for labour and operations. It is highly likely that the $700/MW-day figure will be driven down through competitive procurements over time, which means the total program cost for Flexibility Services should be understood as a maximum cost that could be significantly lower. The 2020-2024 total program cost, for example, will come in at almost half of what was anticipated due to procurement efficiencies.

E7.2.1.5 Options Analysis

Option 1: Conventional Wires Options

As noted, the wires option for addressing short to medium term constraints in the areas served by the six targeted stations would include bus level load transfers. The range of expected load transfers are indicated in Table 5 above. Proceeding with Option 1 would mean failing to consider the role of NWSs when scoping and prioritizing those bus-level load transfers, losing the opportunity to defer or avoid anywhere between 23 percent to 54 percent of the total load required to be transferred in this area. Financially, this translates to a potential deferral or avoidance of up to $10 million in capital in the Load Demand program. /C

Additionally, proceeding without a Flexibility Services program would present a lost opportunity to build a more intelligent and interactive grid that can leverage local sources of generation and capacity resources to optimize grid performance. Doing nothing in the NWS space also presents a missed opportunity to work with customers and third-parties such as aggregators to find innovative

solutions to distribution system problems. Customer engagement results indicate that it is important to customers to find ways to engage with the utility to better manage electricity usage, as well as to find efficiencies and cost reductions. The Flexibility Services program is directly responsive to this priority. Ultimately, the goal is to find the lowest-cost solution by exploring all possible options, including demand-side measures.

As demand becomes increasingly unpredictable due to increased uptake of DERs, Flexibility Services can help the utility navigate this uncertainty by providing a greater number of cost-effective options. This strategy checks an important regulatory requirement to evaluate alternatives to building traditional poles and wires infrastructure. It also enables a new lens on productivity – one that is focused on managing total system cost by optimizing how capital is allocated to address system needs more efficiently. In the Conservation and Demand-Side Management Guidelines, the OEB directs all utilities to explore NWSs alongside conventional wires solutions to provide cost-effective system options. Not proceeding with the Flexibility Services program would impact Toronto Hydro's ability to explicitly consider LDR options when addressing system issues.

Option 2: Continue with a small-scale LDR program that targets 1-2 stations

This option entails continuing with the LDR program as it is currently run in the 2020-2024 period, which means focusing on a modest capacity procurement of 10 MW and selecting 1-2 stations within the six identified station group to target. This option would help defer a small number of load transfers in this area, and would come in at a lowered cost of about $3.6 million (about $2 million less than the proposed plan in Option 3). There are several drawbacks to this approach. While it does cost less, it also provides a reduced opportunity for load transfer deferral (about $4 million versus the $10 million in the proposed option). Furthermore, in the current LDR program, the feedback from aggregators has been that smaller target areas make it very challenging and costly to acquire enough capacity to make participation in LDR economical from their perspective. Targeting 1-2 stations can mean a relatively small pool of possible participants, leading to more difficult procurement processes. From a program administration perspective, it does not cost significantly more to procurement 30 MW versus 10 MW, making a larger-scale program more cost-effective overall. Looking at the number of large loads and DERs connected in the areas served by the six selected stations, targeting a greater number of stations results in a larger opportunity to contract for flexibility services.

/C

/C

Option 3 (Selected Option): Create a Flexibility Services Program that the Six Selected Stations /C

Option 3, which is the recommended option, is to build a Flexibility Services program that works in tandem with the Load Demand program to address short-to-medium term load constraints across three stations in the Horseshoe area and three stations in the Downtown area of Toronto Hydro's service territory. This program will enable the explicit consideration of NWSs when evaluating and prioritizing bus level load transfers to address load growth and capacity issues in this area. /C

Because Flexibility Services are market-based, they also provide a crucial opportunity for utilities to leverage relationships with customers and third-parties to solve grid problems. Utilities have a great deal of system knowledge, data, engineering and operational experience; private sector organizations have developed excellent tools to help customers manage load behind the meter. Through working together, new and innovative ideas and solutions are generated that can help the sector better prepare for challenges ahead.

E7.2.1.6 Execution Risks and Mitigation

Procurement of Flexibility Services requires careful consideration of several factors. Over the last 8 years of running LDR, Toronto Hydro has navigated many challenges and come away with important lessons learned for how to manage risks.

Risk: Low participation levels in procurements

Going to market to procure flexibility services may not always yield successful results. This can be related to lack of resources, misaligned incentives, customer/participant confusion, or poor timing. To help mitigate these risks the following measures can be taken:

- Targeting station areas with a large penetration of large customers and existing DERs;
- Ensuring customers and aggregators are educated about programs through early participant engagement via program materials, webinars and one-on-one conversations;
- Creating programs that are straight-forward, with simple participation pathways and performance charges that create the right incentives without being too punitive; and,
- Ensuring aggregators have sufficient time to recruit customers.

Risk: Price discovery

One of the biggest challenges in the procurement of NWSs is price discovery. It is a given that the reference price for an NWS must be benchmarked against the cost of the wires alternative. However, the benchmark price may not always reflect the market price (i.e. the price the market participant is willing to take for their services). This process of price discovery presents many opportunities for learning and adapting in order to find the right balance of incentives. This includes not only the capacity or energy payment, but also any performance charges that may apply to ensure the services are reliably delivered. Some of the risks involved could include:

- Overpaying for services
- Setting prices too low resulting in low uptake
- Creating performance charges that are too lenient, resulting in poor performance
- Creating performance charges that are too stringent, resulting in poor uptake

To help manage these risks, it is important to learn from other jurisdictions, work with stakeholders in advance to understand their costs, and remain nimble and adaptable by doing shorter term procurements while working to understand the market. The experience gained in the 2020-2024 period has been instrumental in learning what works and what does not work in terms of price discovery. These learnings will be taken into the next rate period.

E7.2.2 Energy Storage Systems (ESS)

E7.2.2.1 Background

Energy Storage Systems give utilities the flexibility to store energy and use it at a later time. As demand for system flexibility increases and battery technology costs decrease, ESS are expected to play a growing role in generation, transmission and distribution system planning. Utilities can utilize ESS in a variety of ways to support the grid. Toronto Hydro has been active in the energy storage space since 2017, with several existing projects, including behind-the-meter ("BTM") and front-of-the-meter ("FTM") installations outlined in Table 10 below.

Table 10. Existing Toronto Hydro ESS Projects

Project	Description/Use Case	Nameplate Capacity	Learnings
Bulwer BESS	FTM BESS supporting Cecil TS via peak-shaving	2MW/ 2MWh	○ BESS deployment and optimization utilizing Toronto Hydro's Energy Centre (DERMS) platform ○ Trouble-shooting operational challenges (e.g. faults) ○ Experience with creating baselines and measuring peak-shaving success on feeder
500 Commissioners	BTM BESS located at Toronto Hydro's facility, used for peak-shaving and GHG reductions	500kW/ 500kWh	○ Optimizing use of BESS to lower facility electricity costs and target GHG reductions via peak-shaving ○ Experience with maintaining BESS
TTC eBus	Customer-specific project providing charging support and peak-shaving	1MW/ 4MWh x 3	○ Understanding of connection requirements from other stakeholders, such as HONI and IESO, for large size BESS deployments ○ Optimizing BESS operation for EV charging use case ○ Understanding of design and commissioning requirements of features such as black start and dynamic transfer which are needed for islanding scenarios
Metrolinx Eglinton Crosstown LRT	Customer-specific project used for emergency back-up and load displacement	10MW/ 30 MWh	

Toronto Hydro has learned a great deal with respect to procuring, designing, constructing, commissioning, and utilizing BESS over the last six years. The Bulwer project, which is the only FTM BESS that is entirely owned and operated by Toronto Hydro, has been instrumental for developing knowledge around utilizing BESS to provide distribution-level grid support. This project was built in the 2015-2019 rate period and energized in January 2020. Over the 2020-2023 period, this project has been tested, commissioned, and transitioned to operations for deployment. This project helped Toronto Hydro develop:

- New processes for monitoring and controlling BESS assets on a daily basis,
- IT frameworks for integrating BESS software platforms safely and seamlessly with existing Toronto Hydro IT infrastructure,

- Methodologies for determining charging schedules, managing BESS state of charge, and measuring peak-shaving at the feeder level, and
- Maintenance of BESS assets.

Toronto Hydro also has experience with BTM BESS projects, including one at the 500 Commissioners street facility, and two that are located on customer sites (Metrolinx ECLRT and TTC eBus). These projects have also enabled building significant capabilities building, integrating and deployment of BESS. Based on current system needs, Toronto Hydro does not expect to own and install any BTM or customer-specific BESS projects in the next rate-period.[9]

2025-2029 ESS Vision

Toronto Hydro will build on its experience with BESS to move from individual pilot projects towards a standardized approach for design and deployment. The planned deployments will target areas with grid constraints to enable Renewable Energy Generation (REG) connections.

The BESS program has matured significantly as a result of the last six years of experience. Due to the new and innovative nature of this program area, the work achieved up until this point has been primarily pilot driven. Toronto Hydro has tried various approaches for procuring and siting BESS. One of the main challenges has been finding locations to install projects in areas where the grid has specific needs that could be addressed by BESS. Given the urban and dense nature of Toronto Hydro's service territory, land comes at a premium, and the use of this land must be assessed carefully to ensure asset siting decisions are prudent and cost-effective. Another challenge has been to integrate different types of BESS projects, each with unique software platforms and maintenance needs.

The strategy for the next rate period will explore a standardized approach for siting, designing and procuring BESS, utilizing small scale installations that enable siting on the right-of-way, similar to other distribution system equipment (e.g. pad-mounted transformers). This, in addition to standard BESS deployments, will help Toronto Hydro build a more scalable and streamlined BESS program in the future.

Based on current, identified distribution system needs that will be examined below, as well as Toronto Hydro's commitment to support the electrification and anticipated growth of renewable

[9] See for example: OEB Staff Bulletin, August 6, 2020 re Ownership and operation of behind-the-meter energy storage assets for remediating reliability of service. https://www.oeb.ca/sites/default/files/OEB-Staff-Bulletin-ownership-of-BTM-storage-20200806.pdf

generation in the city, the BESS portfolio will focus primarily on the renewable enablement use case in the 2025-2029 rate period. Several studies have shown that significant penetration of renewable generation can lead to destabilizing grid parameters.[10] In the renewable enablement use case, ESS can act as a load to prevent output curtailment from the renewable assets while ensuring a stable grid through controlling the minimum load to generation ratio (MLGR).

Based on internal studies, Renewable Enabling ESS can be installed anywhere along a feeder in order to help mitigate concerns regarding generation to minimum load ratio. Therefore, to avoid additional costs, the proposed ESS units could potentially be connected to existing Toronto Hydro assets (i.e. pad mounted transformers) that can accommodate the nameplate capacity, footprint and layout. If such assets and locations cannot be established, then new assets (i.e. transformer) will be installed to accommodate the proposed ESS.

Toronto Hydro is also actively working to optimize the deployment of BESS projects by leveraging its corporate-academic partnership with the Toronto Metropolitan University CUE. With this partnership, Toronto Hydro and CUE are developing an Optimal Planning Program which optimizes sizing and the return on investment of an ESS for both BTM and FTM applications. This tool will be an essential method in which Toronto Hydro evaluates and deploys BESS projects in the future for applications such as load displacement, deferred system expansion and premium reliability service. Quantifying net benefits for each of these scenarios will allow Toronto Hydro to design storage systems that can maximize the value proposition to the customer and the utility.

Another part of the BESS strategy is to improve asset integration so that newly deployed systems can co-exist with Toronto Hydro's IT framework. This will involve continuing to integrate all existing storage platforms within the Distribution Grid Operations Energy Centre DERMS platform.

E7.2.2.2 Outcomes and Measures

Table 11: Outcomes & Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer service objectives by enabling customer investments in renewable energy and reducing energy costs.

[10] Seguin, R., Woyak, J., Costyk, D., Hambrick, J., & Mather, B. (2016). (tech.). High-Penetration PV Integration Handbook for Distribution Engineers (pp. 4–26). Oak Ridge, Tennessee: Office of Scientific and Technical Information.

Operational Effectiveness - Reliability	• Contributes to service reliability by utilizing BESS technology to improve load-balancing on feeders that have been identified to have issues with respect to MLGR.
Financial Performance	• Contributes to Toronto Hydro's financial objectives and performance by cost-effectively enabling renewable generation where applicable.
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy objectives by enabling the proliferation of energy storage, renewable DERs, and grid-modernization.

E7.2.2.3 Drivers and Need

Table 12: Segment Driver

Trigger Drivers	Capacity
Secondary Driver	Reliability, Public Policy

Renewable Enabling BESS

Policy, economic conditions and the preferences of customers and consumers, have facilitated a growing interest in DERs within Toronto Hydro's service territory. This trend is expected to continue into the foreseeable future supported by a number of drivers that are stemming from global, national and local levels such as the Federal Government's green energy tax credit and the recent Regulatory policy changes. In 2022, the Ontario Energy Board enacted changes that enabled third-party ownership of Net Metered generation facilities. Toronto Hydro anticipates that third-party installations will play a key role in driving renewable energy generation ("REG") growth during the next rate period as it did in other provinces and the US where this arrangement is already well established. In addition, the anticipated decreasing costs of photovoltaic panels is expected to have a positive impact on customer interest in REG. These drivers will increase interest in distributed renewable generation projects within Toronto Hydro's service territory by 2029, as shown below on Figure 3. Please refer to the Generation Connections narrative for more details on the drivers behind the anticipated REG growth in the next rate period.

An increase in renewable generation projects will lead to a fundamental change in the power flow conditions at the distribution system and how they need to be managed. This has challenged the conventional radial nature of the grid to accommodate bi-directional power flow. Large scale

deployment of REG is known to cause issues in distribution system planning and operations such as unintentional islanding and overvoltage on feeders. As a result, Toronto Hydro must proactively relieve certain grid constraints on feeders in order to accommodate future REG growth.

As part of its DER connection process, Toronto Hydro offers a pre-application report for its customers, providing information about the proposed point of interconnection so the customer can determine if a DER system installation is worth pursuing. The pre-application process also allows Toronto Hydro to discover potential distribution system issues that must be addressed to accommodate the proposed DER. In such instances, Toronto Hydro would work with the customer to find the best solution to move the DER installation forward, such as modifying the proposed system to satisfy the pre-application screening. Although Toronto Hydro has been able to manage DER customer expectations to date through this pre-application process, certain parts of the distribution system are approaching their technical limits and the problem could worsen over the next few years. Renewable Enabling ESS investments can help Toronto Hydro alleviate these issues to accommodate future REG growth, while maintaining adherence to the Transmission Interconnection Requirements.

As can be seen in the Figure 3 below, there has been a consistent increase in the number of renewable generation connections to the distribution grid. The data observed assumes a negligible uptake of wind or other inverter-based DER technologies and therefore uses the solar PV forecast as the primary REG type driving increased penetration. These assumptions are based on historical consumer behaviour in REG adoption in the City of Toronto and are consistent with forecasting models used in the Generation Connections segment.

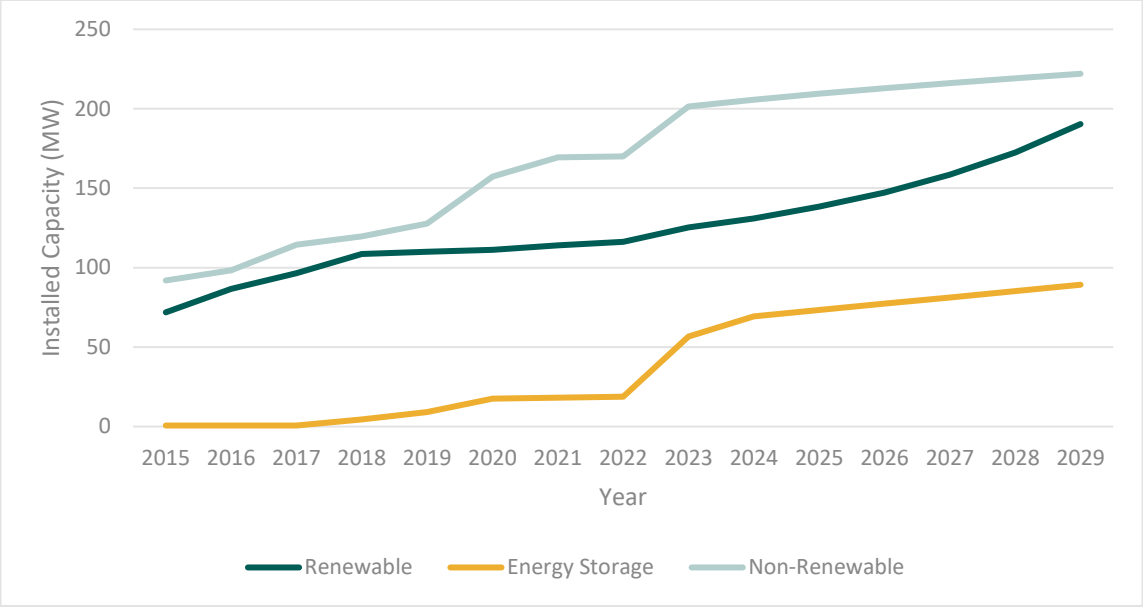


Figure 3: Historical and Forecasted Renewable Generation (MW)

Table 13: Forecast Generation Capacity (in MW)

Generation Type	2023	2024	2025	2026	2027	2028	2029
Renewable	126.4	133.4	143.4	155.1	168.5	183.6	200.4
Energy Storage	56.6	60.0	73.4	77.4	81.4	85.4	89.5
Non- Renewable	198.2	212.1	215.6	218.7	221.6	224.3	226.8
Total	**381.2**	**405.5**	**432.4**	**451.2**	**471.5**	**493.3**	**516.7**

High penetration of renewable energy generation sources can lead to grid instability if not managed appropriately. Two modes of grid instability can be seen: unintentional islanding and system overvoltage. While these issues can not be resolved easily using conventional utility approaches, ESS solutions present an ideal alternative given their ability to dynamically charge and discharge to balance feeder loading. The following sections will outline the two modes of grid instability and expand on how ESS can help alleviate the issues.

Unintentional Islanding

In the past few years, there have been numerous studies, standards and guidelines with respect to DER integration, such as IEEE Standard P1547.2/D6.5, August 2023 (Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces)[11] and National Renewable Energy Laboratory's High Penetration PV Integration Handbook for Distribution Engineers (NREL Handbook). These documents prescribe limitations on DER aggregate capacity to be less than one-third of the minimum load of the Local Electric Power System. [12] As the ratio of generation capacity to minimum load increases, the amount of time required by inverters to respond to anti-islanding scenarios increases and this can adversely impact the effective inverter response to anti-islanding scenarios. This scenario can be mitigated with the addition of transfer trip protection, which is only a requirement for DER connections over 1MW; however, this is a costly measure. Furthermore, for feeders that have a high penetration of small to medium DER connections, it would not be economically feasible for each customer to install transfer trip as the cost is too high relative to the cost of the connection. Since most of the REG connections that get connected to Toronto Hydro's grid are small to medium size connections, renewable enabling ESS becomes an attractive option as it can serve to mitigate this risk for any customer along the feeder as opposed to being an individual customer solution.

Toronto Hydro conducted an analysis for all feeders in its system to establish minimum load to generation ratios[13] in accordance with the applicable guidance found in IEEE-P1547.2/D6.5, August 2023. The methodology consisted of aggregating the DER generation capacity at the feeder level. For this particular study only the DERs that were connected and in-service were used, and DERs that were proposed were only factored into the forecasted values. The next step involved using load profiles to determine the minimum load on each feeder in the past three years and computing the MLGR. This process was repeated for all feeders that had aggregate DER capacity above 500 kW. The list was further refined by calculating the REG penetration ratio on each feeder which helps identify feeders that would best be served by a renewable enabling ESS solution.

The DER forecast shown in Figure 3 above is a system level forecast that is consistent with the GPMC and Customer Connections narratives. This system level forecast was applied to the feeder level

[11] "IEEE Draft Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," in IEEE P1547.2/D6.5, August 2023 , vol., no., pp.1-322, (11 Aug. 2023).
[12] Ibid.
[13] Determined as available utility fault current divided by DG fault contribution in affected area.

forecast in Table 14 below to determine the DER forecast for each of the shortlisted feeders as well as the forecasted impact on MLGR.

The study found that 23 feeders currently exceed the 3:1 minimum load to generation screening ratio outlined by the NREL Handbook and is shown in Table 14 below. Assuming there are no short circuit capacity constraints at the transformer station and given the forecasted growth in REG only by 2029, an additional 24 feeders would exceed the generation to minimum load ratio.

Table 14: MLGR feeder analysis

Station	Feeder Name	Nameplate Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Minimum Load (MW)	Current MLGR	MLGR Forecast 2029	REG Connections enabled (MW)
Agincourt TS	63-M6	3.530	100.0%	5.77	7.10	2.011	1.230	2.24
Finch TS	55-M31	1.750	100.0%	2.95	3.52	2.011	1.193	1.20
Fairbank TS	35-M8	1.997	83.0%	2.80	5.50	2.753	1.750	1.15
Rexdale TS	R29-M1	1.115	100.0%	1.94	2.54	2.275	1.305	0.83
Horner TS	R30-M3	0.760	100.0%	1.38	1.91	2.519	1.387	0.62
Scarborough TS	E5-M24	3.712	16.5%	1.15	4.12	1.109	0.969	0.53
Horner TS	R30-M10	4.573	12.5%	1.08	5.12	1.120	1.007	0.51
Bathurst TS	85-M6	6.761	7.5%	0.98	5.56	0.822	0.768	0.47
Bathurst TS	85-M30	5.250	9.5%	0.97	2.83	0.539	0.495	0.47
Finch TS	55-M32	1.508	33.2%	0.97	4.09	2.712	2.069	0.47
Leslie TS	51-M25	1.677	25.5%	0.85	4.88	2.911	2.322	0.43
Finch TS	55-M29	1.914	21.7%	0.83	4.22	2.205	1.809	0.42
Fairchild TS	80-M10	1.300	23.1%	0.65	2.69	2.069	1.629	0.35
Leslie TS	51-M23	2.100	14.3%	0.65	4.58	2.181	1.868	0.35
Bathurst TS	85-M7	6.105	1.7%	0.34	2.62	0.429	0.413	0.24
Bathurst TS	85-M1	6.013	0.2%	0.20	6.86	1.141	1.107	0.18
Finch TS	55-M2	5.300	0.0%	0.18	2.96	0.558	0.541	0.18
Bathurst TS	85-M32	4.750	0.0%	0.18	6.08	1.280	1.234	0.18
Windsor TS	A-61-WR	1.500	0.0%	0.18	2.75	1.835	1.642	0.18
Esplanade TS	A-39-X	7.000	0.0%	0.18	14.50	2.072	2.021	0.18
George Duke TS	A-45-GD	1.050	0.0%	0.18	2.18	2.074	1.776	0.18
Fairchild TS	80-M23	0.900	0.0%	0.18	2.12	2.356	1.970	0.18
Cecil TS	A-41-CE	1.275	0.0%	0.18	3.37	2.646	2.326	0.18

Renewable Enabling ESS can be deployed on such feeders in order to increase the minimum load to generation ratio to the recommended threshold. The technology has the capability to do so by functioning like a load when the minimum load is low. Conversely, when the minimum load is appropriately above the threshold, the ESS can act like a generator by supplying energy. This can provide FTM load displacement as well as other target area specific benefits.

In short, the screening ratios show that by 2029 all 47 feeders will have a high penetration of PV generation and require grid investments or other solutions to ensure the safety of the grid and allow further REG connections. ESS is recognized as an effective distribution system solution to increase the PV connection capacity. [14]

The direct benefit of installing renewable enabling ESS can be quantified by the amount of REG capacity that is enabled through these investments which is shown on the far-right column in Table 14 above. This also forms the basis for prioritizing which feeders should be resolved as they provide the largest benefits as a renewable enabling investment. Otherwise, a lack of these renewable enabling ESS investments would result in a forecasted amount of 30MW of REG by 2029 to be potentially rejected for connection.

Toronto Hydro also envisions renewable enabling ESS investments that are driven by large customers installing large renewable DERs. Such a large and sharp increase of renewable DER penetration could disturb the grid stability and the generation to load ratio. Renewable enabling ESS solutions would be installed on the relevant feeders to support the grid, smooth the ratio and allow for the increase of renewable generation on the grid.

System Overvoltage

ESS deployments can also mitigate the grid risk of experiencing overvoltage on some of Toronto Hydro's feeders. Load demand and PV generation have different impacts on a feeder's voltage profile. As load demand increases, operating voltage dips, while as PV generations increases, the voltage spikes. Based on internal studies, there is an increased overvoltage risk for equipment on feeders with low load demand and a high PV penetration. Results have shown that utilizing a BESS to balance the load on such feeders could mitigate that risk and consequently enable further renewable connections on the grid.

[14] For example, see:
(i) J. Seuss, M. J. Reno, et al, "Improving distribution network PV hosting capacity via smart inverter reactive power support", Proc. IEEE PES General Meeting, July 2015, pp. 1–5.
(ii) Z. Waclawek, et al, "Sizing of photovoltaic power and storage system for optimized hosting capacity", Proc. IEEE International Conference on Environment and Electrical Engineering, June 2016, pp. 1–5.
(iii) B. P. Bhattarai, et al, "Overvoltage mitigation using coordinated control of demand response and grid-tied photovoltaics", Proc. IEEE SusTech, Jul 2015.
(iv) F. Capitanescu, et al, "Assessing the potential of network reconfiguration to improve distributed generation hosting capacity in active distribution systems", IEEE Transactions on Power Systems, Jan 2015, vol. 30, no. 1, pp. 346–356.
(v) Y. Takenobu, et al, "Maximizing hosting capacity of distributed generation by network reconfiguration in distribution system", Proc. Power Systems Computation Conference (PSCC), June 2016, pp. 1–7.

E7.2.2.4 Expenditure Plan

1. 2020-2024 CIR Energy Storage Systems ("ESS") Program

Table 15: 2020-2024 CIR – ESS Program ($ Millions)

	2020	2021	2022	2023	2024	Total
GPESS	-	2.7	2.8	-	-	5.5
REBESS	1.0	1.0	1.0	1.0	1.0	5.0

Table 16: Actual and Bridge Costs – ESS Investments ($ Millions)

	Actual			Bridge	
	2020	2021	2022	2023	2024
BESS[15]	-	0.5	0.1	0.3	0.3

Toronto Hydro planned to install aggregate capacity of 8MW/4MWh of Grid Performance ESS over the 2020-2024 period, at a total cost $5.5 million. The plan was for the project to be implemented in 2021 and 2022. Toronto Hydro also proposed in the last rate application to install three Renewable Enabling ESS units with an aggregate capacity of 2.35MW/9.5MWh, at a total cost of $5 million.

Toronto Hydro faced numerous challenges in completing the proposed projects and was unable to proceed as planned. After exploring additional opportunities to deploy ESS, Toronto Hydro is proceeding with one renewable enabling ESS unit in the current rate period. This process has provided valuable information and experience that has informed the development of Toronto Hydro's ESS plan going forward. Toronto Hydro is revising its approach for this program in the 2025-2029 period, focusing on creating a more scalable, demand-driven ESS program that utilizes small-scale ESS technologies.

Toronto Hydro faced three significant challenges in deploying ESS in the 2020-2024 rate period:

i) Siting projects;
ii) Supply chain constraints; and
iii) Integration of one-off procurements into Toronto Hydro's IT and other systems.

[15] BESS amounts reflect combined investments for GPESS and REBESS.

Building on the lessons learned from navigating these challenges, Toronto Hydro has identified an opportunity to deploy an ESS unit to target a feeder that exceeds the MLGR threshold.

Challenges Deploying ESS

Siting ESS Projects

Finding a site has been the one of the biggest roadblocks for installing ESS in Toronto. It is often difficult to line-up a site in an area where ESS can provide cost-effective grid services. This challenge is uniquely difficult for Toronto Hydro as its service area is dense and urban. So far, Toronto Hydro has installed one front-of-the-meter ESS (Bulwer) at a decommissioned Municipal Station site.

Supply Chain Constraints

During the current rate period, COVID-19 led to significant supply chain issues resulting in major delays throughout the entire ESS sector. Certain types of equipment, such as Static Transfer Switches (STSs) had lead times of up to 2 years. Many of the after effects of these supply chain issues continue to impact project execution, specifically with respect to shortages in lithium production for Lithium Ion ESSs. Supply chain risks have diminished since the height of COVD-19 and are not expected to be material over the next rate period.

Integration of One-off Procurements

Another challenge relates to the integration of ESS into existing frameworks and systems. This is exacerbated by one-off procurements with several different vendors. For example, it has been a challenge to integrate various types of custom BESS systems that utilize different software platforms for system charging and management from an IT perspective. Toronto Hydro's IT systems have strict requirements with respect to data access, hardware and security. It is also necessary to create maintenance plans for the ongoing management of these assets, which can be made complicated when there are various types of custom system installed. To that end, Toronto Hydro is currently working on standardizing the process of ESS design and procurement through the development of technical requirements that will be used in future RFPs.

Grid Performance ESS (GPESS) Project

As part of the 2020-2024 period, Toronto Hydro explored the possibility of installing a 5 MW ESS to mitigate voltage sags on feeder 51-M30, which is fed by Leslie TS. This project was intended to pilot

the use of an ESS to resolve voltage sag issues for large commercial customers located on the targeted feeder. This feeder was selected based on analysis evaluating the following criteria:

- Number of customers impacted:
  - More than one key account customer connected on the feeder
- Land for ESS installation:
  - Feeder must be in proximity to existing decommissioned Municipal Stations (MS) that can be utilized for ESS site
- High number of sags:
  - ION meter data for key account customers on select feeders exhibited high number of sags recorded for the 2018 to mid 2021 period
  - The number of interactions regarding voltage sag concerns between the customer and the Key Account team at Toronto Hydro were also considered a factor

Table 17: Targeted Feeder for GPESS Deployment

Candidate Feeder	Decommissioned MS Nearby?	# of Key Customers	2021 Recorded Sag Event	Recommended GPESS Size
51-M30	Yes (Lesmill MS)	2	Key Customer #1 - 32 Key Customer #2 - 29	5.2MW/1.3MWh

In 2020, Toronto Hydro hired Quasar to perform a study about the technical feasibility of an energy storage system that eliminates short duration voltage fluctuations on a feeder. The final report provided a high-level cost estimate for the feasible options, identified completed projects in which the solutions have been implemented and developed a list of vendors that offer the required equipment to implement suggested solutions.

In 2021, Toronto Hydro worked with GE to determine the feasibility of integrating a power conditioning system within the distribution system. The aim of the study was to identify the main possible topologies, determine load case scenarios, simulate the performance of the best selected topology and develop a preliminary sizing of required components.

In 2022, Toronto Hydro developed and ran a Request-for-Proposals ("RFP") process to procure an ESS capable of providing voltage support on the identified feeder, as well as peak-shaving support, and the ability to island for the purpose of outage mitigation. This RFP was put out to market twice:

once in July 2022 and once in September 2022. Both processes resulted in no appropriate bids from vendors.

To understand the lack of response from vendors, Toronto Hydro conducted feedback sessions and learned that many BESS developers were focusing on larger-scale deployments (greater than 10 MW) that enabled ownership retention and power purchase agreements with the IESO (via medium and long-term contracts). Other vendors noted that the technical requirements of Toronto Hydro's RFP were complex and necessitated more in-depth preliminary engineering analysis to accurately define the requirements. With these lessons learned, Toronto Hydro is working with external consultants to undertake engineering studies assessing the technical feasibility of a BESS that addresses feeder-level voltage sags, while also determining the compatibility of this use case with others (e.g. peak-shaving, load-balancing, black-start). The goal is to be better equipped to scope BESS projects that enable benefit stacking, maximizing the cost-effectiveness of these projects.

Renewable Enablement ESS Project

Despite the previously-described difficulty in finding a viable site for REBESS, Toronto Hydro aims to target one small deployment within this rate period. The deployment being targeted this rate period will be on one of the 23 feeders which are above the MLGR threshold as highlighted in Table 14 above. The feeder selected for the deployment will hinge on the various constraints such as location, sizing and budget. The prudent approach would be to target a singular small deployment in an area that is relatively easy to deploy, gather learning lessons and carry those lessons into the planned deployments for the next rate period.

In addition to this, Toronto Hydro is working with internal stakeholders and vendors to explore innovative methods of deployment such as smaller scale BESS units along the right of way in order to alleviate the need to find large land areas as well as available decommissioned Municipal Stations that can be repurposed to site BESS.

2025- 2029 Forecast Expenditures

Table 18: 2025-2029 CIR – BESS ($ Millions)

	2025	2026	2027	2028	2029	Total
BESS	3.6	3.6	7.5	3.8	4	22.5

Table 19: 2025-2029 CIR – BESS (Systems)

	2025	2026	2027	2028	2029	Total
BESS	1	2	2	2	2	9

Toronto Hydro plans to deploy nine projects in the BESS program with an aggregate capacity of 10.2 MW to mitigate the forecasted impact of PV penetration and enable further renewable growth on the grid. The 10.2 MW of BESS capacity is what is needed to bring up the MLGR ratio on the 9 high-priority feeders outlined in Table 14, to the required MLGR threshold. The planned deployments are estimated to cost $22.5 million with an assumption of $446/kWh This works out to $1.78M/MW for a four hours system and results in an expenditure cost of $18.19 million. A 10 percent buffer was added for potential cost overruns resulting in a $20 million total expenditure cost. The derived $/MW is based on industry benchmark[16] as well as Toronto Hydro's renewable enabling ESS technology evaluation. Toronto Hydro plans to distribute the planned numbers of projects evenly over the next rate period to optimize utilization of current staff and take advantage of one project's lessons learned onto the next one.

Renewable enabling BESS investments are distribution investments that support the growth of distributed renewable generation on the system, that in turn offset generation and transmission investments to the benefit of all Ontario rate payers, and that also create environmental benefits. As with other renewable enabling improvements, renewable enabling BESS are funded six percent in Toronto Hydro's rate base and 94 percent through the provincial renewable enabling improvement revenue stream. Over the 2025-2029 period, $22.5 million is proposed for this segment, $1.6 million (six percent) allocated to Toronto Hydro's rate base as the assets are in-service. These investments are expected to enable the aggregate connection of 10.2 MW of REG by 2029, which wold otherwise not be possible due to the technical limitations of the grid.

[16] Viswanathan, Vilayanur, et al. "Energy Storage Cost and Performance Database." *Pacific Northwest National Laboratory*, 1 Aug. 2022, www.pnnl.gov/lithium-ion-battery-lfp-and-nmc.

Table 20: Priority REBESS Deployments

Station	Feeder Name	Existing DER Capacity (MW)	REG Penetration (%)	DER Forecast 2029 (MW)	Minimum Load (MW)	Current MLGR	MLGR Forecast (2029)	REG connections enabled by 2029 (MW)	Req. BESS Size (MW)
Agincourt TS	63-M6	3.53	100.0%	5.77	7.10	2.011	1.230	2.24	3.49
Finch TS	55-M31	1.75	100.0%	2.95	3.52	2.011	1.193	1.20	1.73
Fairbank TS	35-M8	2.00	83.0%	2.80	5.50	2.753	1.750	1.15	0.49
Rexdale TS	R29-M1	1.12	100.0%	1.94	2.54	2.275	1.305	0.83	0.81
Horner TS	R30-M3	0.76	100.0%	1.38	1.91	2.519	1.387	0.62	0.37
Finch TS	55-M32	1.51	33.2%	0.97	4.09	2.712	2.069	0.47	0.43
Leslie TS	51-M25	1.68	25.5%	0.85	4.88	2.911	2.322	0.43	0.15
Finch TS	55-M29	1.91	21.7%	0.84	4.22	2.205	1.809	0.42	1.52
Fairchild TS	80-M10	1.30	23.1%	0.65	2.69	2.069	1.629	0.35	1.21
Total				**16.57**				**6.12**	**10.2**

E7.2.2.5 Options Analysis

1. Option 1: Do Nothing

Twenty-three feeders in Toronto Hydro's territory currently exceed the acceptable generation to minimum load ratios and an additional 24 feeders are forecasted to exceed acceptable ratios by 2029. If no action is taken, it is possible that forecast demand for DG, including REG, would not be safely accommodated in those areas. This could potentially put forecasted REG connections with an aggregate capacity of 29.78MW at risk of getting rejected by 2029. This would be an undesirable outcome for customers, the City of Toronto, and Toronto Hydro and would hinder Toronto Hydro's ability to meet its obligation to connect renewable generation (i.e. pursuant to Section 6.2.4 of the Distribution System Code). This will also restrain the efforts being made to accelerate the uptake of renewables and meet net zero targets in Toronto. Customers who are willing to invest in modernizing the grid will likely become frustrated, and the associated grid and upstream benefits will not be realized. Finally, this will be in non-compliance with the results of Toronto Hydro's customer engagement process, which stressed on the importance of allocating expenditures to modernize the grid and support renewable growth.

2. Option 2: Traditional "poles and wires" solutions

While Toronto Hydro has the Generation Protection Monitoring & Control (GPMC) program to address system-wide issues to enable DER, issues involving generation to minimum load ratio, feeder phase imbalances and bus voltage imbalances will still persist and could potentially inhibit the connection of new renewable DER projects. GPMC will give Toronto Hydro the required control to disconnect DERs in case of an unintended islanding situation. However, the issues explained in section E7.2.2.4 cannot be addressed with the GPMC initiatives.

Feeder re-configurations and reverse load transfers could be performed to increase load on forecasted feeders where generation to minimum load ratios are high. However, this method may decrease reliability and may not always be feasible due to the existing network configuration. Furthermore, these are static solutions not well-suited to managing the dynamic nature of balancing load to generation, meaning these options would not resolve the issue the way a BESS would.

Another traditional option to mitigate the risk of unintentional islanding is with the addition of transfer trip protection; however, this is only a requirement for DER connections over 1MW and is a costly measure. Since most of the REG connections that get connected to Toronto Hydro's grid are small to medium size connections, it would not be feasible for customers to install transfer trip as the cost is too high relative to the cost of the connection.

3. Option 3: Production Curtailment and Decreasing Operational Margin

With better resource monitoring, and forecasting and real-time estimation of the grid capacity, applicable operational margins can be reduced. This in turns allows the existing infrastructure to be used more efficiently and to a greater extent (i.e. with a higher capacity factor). For more detailed information regarding this option, please refer to the Generation Protection, Monitoring, and Control Program.[17]

Curtailment occurs when plants are required to reduce their generation output in order to maintain the operational limits of the grid. This may entail a small gradual decrease of the production (referred to as soft curtailment) or a complete stop to production through measures such as inter-tripping (referred to as hard curtailment). Soft curtailment requires a communication infrastructure and methods to assess the real-time performance of the grid and the appropriate production decrease.

[17] Exhibit 2B, Section E5.5.

In a deregulated market without vertically integrated utilities, it requires willingness from grid users to participate and a legal framework enabling such participation. Moreover, economic arrangements are required to allocate the loss of income stemming from curtailed production.

It is also important to note that for renewable enablement, curtailment is not an option as REG is either connected or not. While curtailment is not viewed as a viable option at the moment, Toronto Hydro is assessing the feasibility of having flexible DER connections on its system, which could work to mitigate load-to-generation imbalances for further DERs. More information about this program is outlined in the Grid Modernization Roadmap narrative.

4. Option 4 (Selected Option): Proposed Solution

The proposed Renewable Enabling BESS program will provide Toronto Hydro with strategic capabilities to address specific issues relating to REG enablement in targeted areas of its distribution system. It will allow Toronto Hydro to mitigate the problems described in Section 7.2.2.4 and fulfill its regulatory obligations to connect REG projects pursuant to the DSC. The proposed solution also best positions Toronto Hydro to support the goals of the Climate Action Plan with respect to enabling renewable generation and deploying energy storage. It is expected that these investments will enable the aggregate connection of 10.2 MW of REG by 2029 which would otherwise be constrained. The overall cost of this option is an estimated $20 million over the 2025 to 2029 period.

E7.2.3 Execution Risks and Mitigation

Project execution risks may impact project design, project siting, approvals, construction, project schedule and commissioning. Compared to traditional technologies, there are fewer technical resources in the sector with knowledge on ESS that are available to design, install and commission the systems, which can lead to a delay in program implementation and increased costs. Toronto Hydro will manage this risk by researching and applying relevant experiences from other jurisdictions and investing in training and staff development for engineering and skilled trades.

ESS projects are complex due to bi-directional power flow and interface protections between project locations and their associated feeder or station supply point. Commissioning risk can be mitigated by using a standard requirements matrix and site acceptance testing protocol. Further, in-depth training in advance of actual field work is planned for crew members and operations staff who will take part in ESS installation and commissioning.

Toronto Hydro will manage risks regarding integrating BESS with our current IT network through consciously working with the IT team to understand their technical requirements and considerations. This will help establish a standardized IT framework for the BESS program that we can incorporate in our upcoming project RFPs.

As outlined in earlier sections of this document, Toronto Hydro anticipates project siting to be one of the critical risks for this program in the next rate period. In order to manage this risk in the short term, Toronto Hydro is working with its Stations and Facilities teams to explore any available opportunity to repurpose existing Toronto Hydro facilities such as decommissioned Municipal Stations. At the same time, the end goal is to establish a more standardized and reliable approach for project siting. Toronto Hydro's vision is to create a strategy that leans on modular and small-scale BESS to enable BESS deployments on city boulevards, similar to other traditional Toronto Hydro assets.

Project schedule risk can be effectively managed by dedicated project teams that provide short-interval control and regular coordination between the utility and customers. Toronto Hydro will dedicate its efforts to ensure labour availability and manage project prioritization with other capital project and planned maintenance work will be managed to implement this program on-schedule.

Construction cost variance is mitigated through a competitive procurement system for ESS projects and standard contract provisions which provide fixed price responsibility and liquidated damages for non-performance. Based on the 2022 Grid Energy Storage Technology Cost and Performance Assessment by Pacific Northwest National Laboratory,[18] battery ESS technology will mature and prices will fall, providing some protection against year-over-year inflation and a degree of budget contingency. Battery costs represent approximately half the cost of ESS, while inverters, switchgear, transformation, controls, conditioning, civil work and enclosures make up the balance. Further, the report determined that current installed costs for Lithium Ion (LFP) BESS is $446/kWh and this is expected to decrease to $340/kWh by 2030. As such, over the 2025-2029 period, the cost/benefit value proposition of ESS will likely continue to improve, thereby facilitating increased use of this solution to address customer needs.

[18] Viswanathan, Vilayanur, et al. "2022 Grid Energy Storage Cost and Performance Assessment." *Pacific Northwest National Laboratory*, Aug. 2022.

E7.3 Network Condition Monitoring and Control

E7.3.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 56.8	**2025-2029 Cost ($M**): 6.0
Segments: Network Condition Monitoring and Control	
Trigger Driver: Reliability	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Environment, Operational Effectiveness - Safety, Financial Performance	

The Network Condition Monitoring and Control ("NCMC") program (the "Program") is introducing real-time, Supervisory Control and Data Acquisition ("SCADA")-enabled monitoring and control capabilities to Toronto Hydro's low voltage secondary network distribution system. The network system supplies 10-15 percent of the peak load in downtown Toronto, including customers like banks and hospitals who are highly sensitive to service interruptions. SCADA-enabled monitoring and control will benefit these customers, and the public who relies on these customers, by introducing remote monitoring and switching capabilities that are already utilized in many other parts of the system. It will also introduce real-time monitoring capabilities with respect to the following types of operating parameters:

- Air temperature and water level in the vault;
- Oil level, top-oil temperature and tank pressure of the network transformer;
- Current, voltage, open/closed status and presence of water level in the network protector, which is essential to the automatic transfer capabilities that allow the maximum reliability benefits of the network design to materialize; and
- Other sensors such as fire and analog water sensors for early detection of fire events and flooding.

These capabilities will enable improvement in key outcomes for downtown customers, the public, and the environment, including: remote identification of active failure risks (e.g. floods) and prevention of subsequent outages; the ability to sustain service for substantially more customers during multiple contingency events; early identification of potential safety risks (e.g. vault fires); early identification of oil leaks; and improved loading data accuracy, which will help Toronto Hydro provide

greater and more efficient access to the network system for connecting customers. Finally, these capabilities will enable a reduction in yearly inspection activities, leading to maintenance cost savings once most of the network vaults are commissioned.

Toronto Hydro's progress in this program in 2020-2023 is a recent example of its grid modernization track record. For more information on how the NCMC program supports the Intelligent Grid component of the utility's Grid Modernization Roadmap, please refer to Exhibit 2B, Section D5.

The low voltage network distribution system has historically been Toronto Hydro's most reliable system. Over the last several years Toronto Hydro began deploying new, higher voltage network units to better accommodate new customer requirements in the downtown area and help reverse a gradual decline in the number of customers connected to the network. At the same time, the condition of the existing network is worsening as vaults experience floods and transformers corrode and leak oil, as evidenced by the many deficiencies observed in recent years. Catastrophic and highly disruptive failures affecting customers have also occurred in recent years. Given these constraints and pressures, Toronto Hydro is prioritizing the program as a means of improving reliability, system resiliency, and efficiency of operations on the network.

Toronto Hydro is investing $56.8 million in the 2020-2024 rate period and $6 million in the 2025-2029 rate period to install monitoring equipment and fibre optic cable in approximately 920 network vaults. Once this initial deployment is complete, Toronto Hydro plans to invest $1.8 million between 2026 and 2029 on a pilot project to further enhance real-time monitoring capabilities by installing additional sensors in the network vault. This will support the outcomes summarized above and described in more detail below.

E7.3.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives (e.g. OEB's ESQR targets, which require new services to be connected on time 90 percent of the time) by enabling more efficient connections through use of live loading data for power flow modeling.

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives by:
	  ○ Reducing flooding-related equipment damage;
	  ○ Enabling the early detection of conditions that can cause vault fires to improve response time and mitigate damage;
	  ○ Providing real-time loading data and remote switching capabilities to allow controllers to drop approximately one-third fewer customers from the network during multiple contingency events.
	• Contributes to network grid resilience by:
	  ○ Identifying flooding so that measures can be taken to prevent equipment damage.

Environment	• Contributes to Toronto Hydro's environmental objectives by reducing oil leaks through monitoring of transformer oil levels.
Operational Effectiveness - Safety	• Contributes to maintaining Toronto Hydro's Total Recorded Injury Frequency measure and safety objectives by enabling early warning of potential risks associated with vault loading, flooding and fire. • Remote monitoring will reduce time crews spend in the confined space of a vault to determine loading and protector status.
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by reducing the need for crews to perform inspections needed to obtain summer load readings.

E7.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Reliability
Secondary Driver(s)	Safety, Failure Risk, System Efficiency, Resiliency

As summarized in Toronto Hydro's Grid Modernization Roadmap, the NCMC program is an important part of Toronto Hydro's Grid Modernization Roadmap and a recent example of its modernization track record. The NCMC program is successfully introducing the capabilities and benefits of an Intelligent Grid to Toronto Hydro's network system, including enhanced observability (i.e. real-time or near real-time data on grid performance and conditions) and incremental controllability. Together, these capabilities are providing a foundation for the realization of substantial reliability, resiliency and efficiency benefits.[1]

The Program aims to improve the reliability of Toronto Hydro's low voltage secondary network system by introducing real-time SCADA-enabled monitoring and control. The installed equipment and fibre optic communication cables provide live condition, loading data and remote-control capabilities in approximately 920 vaults that will enable Toronto Hydro to respond proactively and more effectively to emerging hazards and multiple-contingency events, leading to fewer and shorter interruptions for sensitive downtown customers. The planned number of vaults represents approximately 90 percent of the network vaults in the system. Toronto Hydro is not planning to target the remaining 10 percent due to the following factors:

- The equipment in the vault is manual and not automation ready, such as using manual secondary switches instead of network protectors; and
- The location of the vault requires high civil costs due to its remote location and lack of spare ducts required for fibre.

As the Program matures, Toronto Hydro is piloting other options to connect vaults without the need for fibre, such as using a long-term evolution ("LTE") communication device. Toronto Hydro is piloting this solution in a few vaults using customized Vault Communication Boxes ("VCBs"). If successful, this

[1] Exhibit 2B, Section D5

could allow Toronto Hydro to bring NCMC functionality and capabilities to vaults that would otherwise be cost-prohibitive.

Figure 1 depicts the components required to enable monitoring and control of a network vault and unit. Vault sensors – which include a water level sensor and a vault temperature sensor – are connected directly to the VCB. Transformer mounted sensors include oil temperature, oil level and tank pressure. Protector monitoring and control are all enabled through a special communication-ready network protector relay mounted inside the network protector.[2] Based on the age and make of the network units, some need to be retrofitted as they do not have the required sensors built-in (oil temperature, oil level and tank pressure). These retrofit packages will allow for NCMC capabilities to be available at the vault.

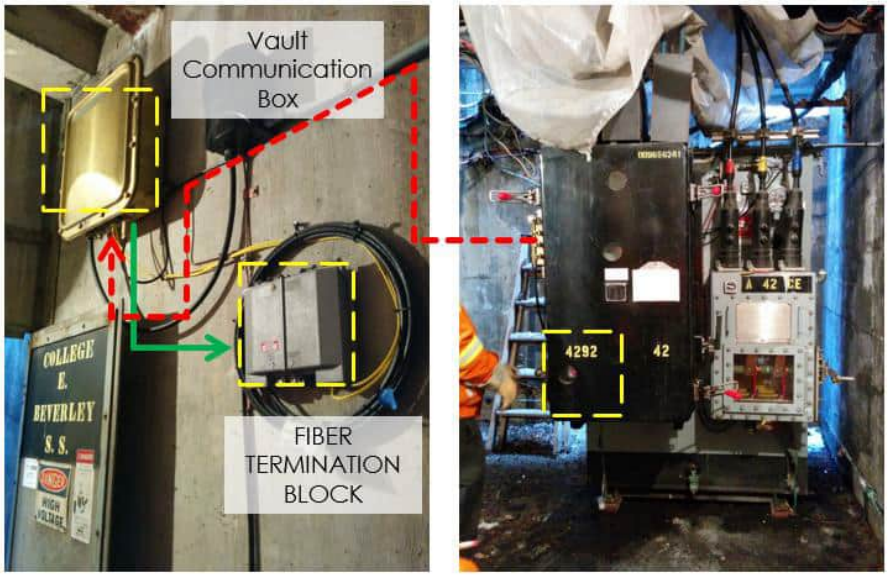


Figure 1: Vault Layout with Network Condition Monitoring and Control Equipment Installed

Once the VCB is installed, connected and commissioned inside the vault, Toronto Hydro can monitor and control the automated vaults through a SCADA screen from the control room, an example of which is shown in Figure 2 below.

[3] The network protector automatically connects and disconnects individual transformers from the secondary grid to compensate for primary feeder switching and equipment failures.

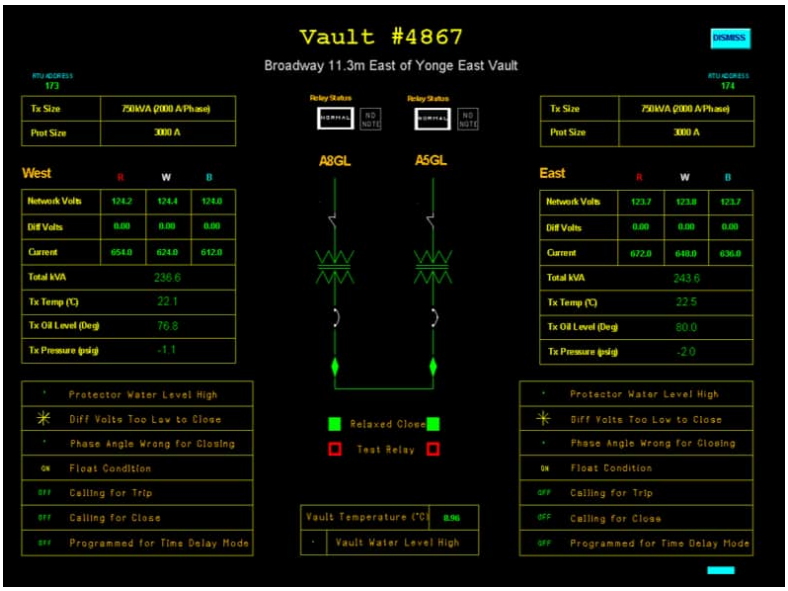


Figure 2: SCADA Screen for a Vault with Network Condition Monitoring and Control

E7.3.3.1 Benefits of Network Condition Monitoring

The Program will provide real-time condition data of the vault and network units. This will give the Control Room access to important information on developing hazardous conditions such as flooding, fire, and oil leaks, allowing proactive measures to be taken to prevent equipment failure and mitigate safety and environmental risks. Such data includes vault temperature and water level, network transformer operating temperature, oil level and tank pressure, and the presence of water inside network protectors. When real-time condition data is not available through NCMC, it is acquired through estimates or field inspections, which are both less accurate and more resource intensive.

The use of water level sensors can mitigate the risk of equipment damage and reduce customer service interruptions due to vault flooding. Once installed, water level sensors trigger alarms in the Control Room as rising water reaches the sensor. Toronto Hydro can then dispatch a crew to address the flooding prior to water levels reaching a point where equipment is damaged or at risk of failure. In the past two years, water alarms were raised at 56 network vaults which helped prevent flooding in the vault from occurring.

Monitoring of the network vault temperature will also enable Toronto Hydro to detect fires earlier, improving response time and mitigating any damage to equipment and safety risks that may result. If a fire occurs, the Control Room will be informed and can remotely operate vault equipment to

prevent catastrophic failures. This would help lessen the impact to the customers directly connected to a given vault, as well as minimize potential widespread network outages that impact all customers connected to the network grid. In the past two years, temperature alarms from 14 unique vaults were triggered, allowing for pre-emptive response to potentially catastrophic failures.

Oil leaks are another concern which can be addressed through network monitoring. If a serious transformer oil leak is not promptly identified, the transformer is likely to fail once the oil level drops below the windings or upper cooling tubes. This could result in a catastrophic transformer fire causing widespread and prolonged customer interruptions and safety risks. In addition, early oil leak identification can minimize environmental damage. Leaking oil within a vault may enter the vault drainage system and discharge into the environment. Oil level monitoring data will also support the accurate reporting of oil quantities to the Ministry of the Environment and Climate Change and the City of Toronto should a spill occur.

This Program has already contributed to reducing the number of oil leaks and, more specifically, high-volume leaks as seen in Figure 3. In 2021 and 2022, SCADA event logs indicate there were 34 incident alarms of low oil level at 16 vaults which enabled early detection of oil leaks, limiting the volume of those leaks.

The majority of the oil leaks from 2020 onwards were within the 0-10 litre volume range. This timeframe aligns with the start of network vault commissioning with NCMC. A specific example of NCMC mitigating oil leaks occurred in June 2022, when a NCMC commissioned unit was leaking approximately 500 ml of oil per day. Once the alarm occurred, the controller trigged a crew to verify and open the primary switch to isolate the defective unit. The unit was subsequently reactively replaced. As Toronto Hydro continues to commission more vaults, the Control Room will be able to respond much earlier to any potential oil spill across the network system to minimize the number of spills as well as their volume.

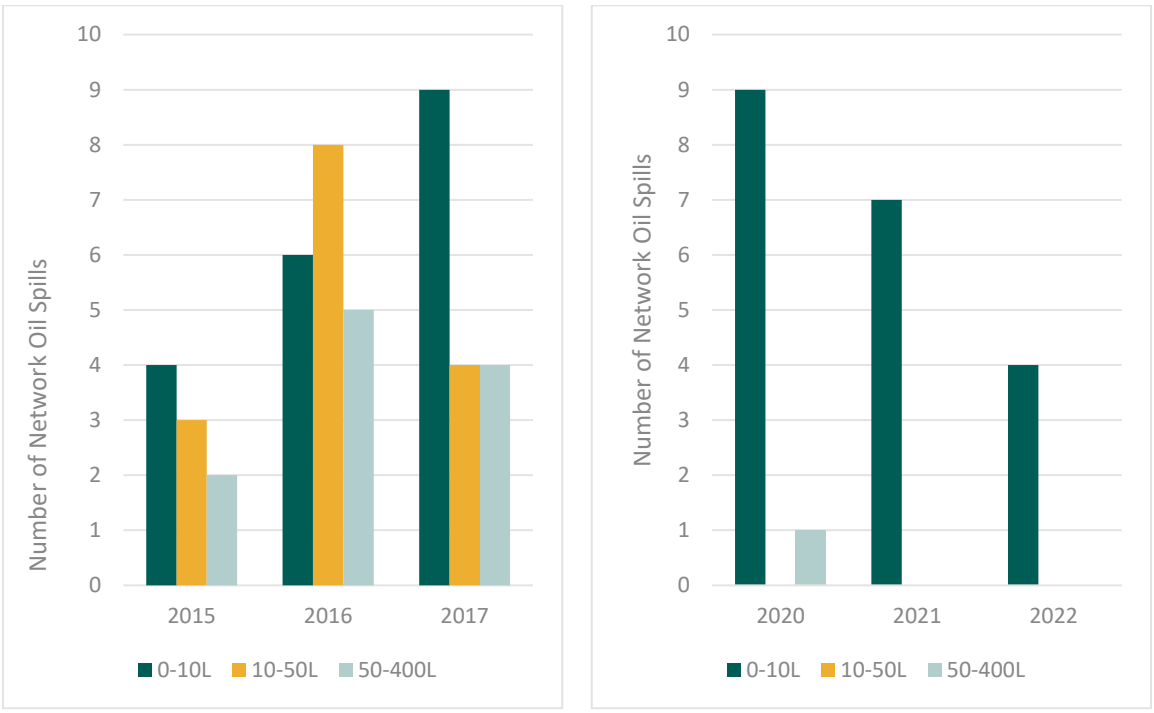


Figure 3: Network Transformer Oil Spills before NCMC (left) and after (right) NCMC

This Program will reduce the need for field staff to patrol networks, identify and investigate deficiencies such as protectors, flooded vaults (after heavy rainfall) and faulted network transformers. This results in estimated cost savings of $200 per hour per incident.[3] In the last five months of 2022, Toronto Hydro saved approximately $78,600 in operating costs by remotely checking protectors in commissioned vaults rather than sending trucks and crews. Toronto Hydro expects these benefits to scale as it continues to commission vaults.

Toronto Hydro has realized benefits from the condition monitoring achieved in the network vaults commissioned to date. As of the end of 2022, 379 vaults have been commissioned, which amounts to approximately one-third of all network vaults. As the Program continues to mature and more vaults are commissioned, Toronto Hydro is planning to continue to calibrate alarms and improve business processes in order to maximize the benefits of the Program.

[3] This is the cost of sending a crew to investigate an incident in a network vault.

E7.3.3.2 Benefits of Network Unit Control and Loading Data

Monitoring and control equipment also provides remote control capabilities and loading data required for emergency operations as well as normal analysis and planning. Real-time loading data allow controllers to more effectively respond to multiple-contingency events and emergency situations, resulting in fewer and shorter customer interruptions. Remote monitoring and control can also reduce the need for crews to visit vaults during switching events. For example, as of June 2023, Toronto Hydro has saved approximately $119,850 through the reduced need to deploy crews to vaults during switching events. This benefits customers by both expediting service restoration during network emergencies, as well as reducing costs associated with normal network system operations. Features that will provide these benefits include:

- Monitoring of operating voltages and currents;
- Monitoring of the open/closed status of network protectors;
- Ability to remotely open or close protectors;
- Automatic reporting of conditions preventing equipment from automatically operating as desired (e.g. voltage too low to reclose); and
- Ability to temporarily alter equipment settings to facilitate automatic operation (e.g. “relaxed close”) that would otherwise not occur.

The loads for the low voltage secondary networks targeted for this program in 2020-2025 are shown in Table 4 below. Through this program, Toronto Hydro expects to avoid dropping one third of the total network load (which would otherwise have to be dropped in multiple contingency events). These networks are designed to handle first contingency (N-1) outages at both the feeder and network unit levels without causing customer interruptions. However, second contingency (N-2) or higher events require network analysis to determine whether customer loads can be sustained or must be dropped in order to avoid excessive equipment loading levels. In the absence of live loading data, conservative load estimates are made for this analysis. Toronto Hydro derives these estimates using loading data from summer inspections, which may not be accurate due to variances in season, ambient temperature, time of day, and day of the week. In contrast, accurate real-time loading information will allow the Control Room to operate network equipment according to the actual limits during multiple contingency events.

Table 4: Potential Customer Load Saved from Network Monitoring and Control4

Network	Total Load on Feeders (MVA)	Network Load (MVA)	Commissioning Year	Expected Load Saved During Multiple Contingency Events (MVA)
Cecil-North Phase 1	32	6.5	2019	4.3
Cecil-South Phase 1		6.5	2020	
Windsor-West Phase 1	55	12.5	2020	8.3
Windsor-West Phase 2		12.5	2021	
Terauley-North Phase 1	44	13.5	2021	9
Terauley-North Phase 2		13.5	2021	
George and Duke Phase 1	49	11.6	2021	9.7
George and Duke Phase 2		17.4	2021	
Charles-West Phase 1	45	11	2022	7.3
Charles-West Phase 2		11	2022	
Bridgman Total	29.2	14.6	2023	4.9
High-level Total	112	56	2023	18.7
Glengrove Total	28	14	2024	4.7
Duplex Total	69.6	34.8	2024	11.6
Gerrard Total	12	6	2024	2.0
Dufferin Phase 1	21.2	4	2024	5.3

[4] Full benefits will be realized when the full network has been commissioned (automation).

Dufferin Phase 2		12	2024	
Wiltshire Total	1	1	2025	0.3
Leaside Total	3	2	2025	0.7
Main Total	9	7	2025	2.3
Carlaw Total	9	7	2025	2.3
Strachan Total	9	7	2025	2.3

In the last two years, real-time loading data from commissioned network units was used by controllers during multiple contingency events to determine accurate loading conditions and improve operating decisions:

- In January 2022, a fire in a cable chamber was caused by the network's secondary cables. Loading analysis was required to determine if a widespread outage on the Windsor network would be required. Controllers used real-time loading data as the input and determined that it was possible to support a multiple contingency event to isolate the affected area without resulting in a large outage on the network.
- In February 2022, a fault occurred on the Cecil network which supplies highly sensitive customers such as banks and hospitals. Using the NCMC real-time data allowed the crews to identify the fault and re-energize the network in an hour. In addition, NCMC capabilities allowed Toronto Hydro to confirm that the network was able to operate on second contingency and avoid taking the network down completely.
- In February 2023, a feeder on the George and Duke network experienced a cable fault and a neighbouring feeder tripped shortly after, causing the need for an N-2 assessment. The use of real-time loading data determined that the multiple contingency event could be supported on the network.

Real-time loading also helps support planned work in addition to failures. Historically, when real-time loading data was not available, Toronto Hydro could not schedule an outage on multiple feeders and vaults simultaneously for planned work, as the specific impact to the network would not be known or definitive. For example, in April 2022, the Cecil network was assessed and confirmed through loading data that multiple feeders and vaults could be taken out of service to support planned work. This allowed the planned work to be scheduled on time.

Table 4 also shows the potential customer load that may be saved for each network during a multiple contingency event. These are estimated based on the avoidance of dropping one third of the network load once the whole network has NCMC capabilities.

Continued deployment of the Program will provide highly accurate peak readings of Toronto Hydro's network assets than can be achieved through summer vault inspections. From a planning perspective, engineers will be able to model the various parts of the system with greater accuracy and plan based on more accurate power flow models. Network customer requests can be challenging to handle, and accurate power flow models are essential for efficiently connecting customers. More efficient connections will result in lower-cost and faster customer connections, contributing to Toronto Hydro's compliance with OEB-prescribed objective to connect new services on time 90 percent of the time.

Toronto Hydro inspects and maintains its network vaults and equipment through the Preventative and Predictive Underground Line Maintenance program.[5] As a result of the implementation of NCMC, Toronto Hydro expects to reduce the number of planned vault inspections required for each network vault per year, reducing maintenance costs in that program by approximately $300 per vault starting in 2027. At the end of the NCMC program (e.g. once all vaults are commissioned), this will result in approximately $275,000 in maintenance costs avoided each year.

E7.3.3.3 Enhanced Monitoring Capabilities Post 2025

Toronto Hydro expects to complete the original objectives of the program by the end of 2025, at which point the utility plans to initiate a pilot project to further enhance real-time monitoring capabilities by exploring different types of additional sensors that can be installed in network vaults:

- **Fire sensor**: This will allow earlier detection of fire events and allow timely intervention to limit equipment damage as compared to the vault temperature sensor.
- **Analog Water Level Sensor**: The analog sensors will provide additional data (i.e. measure of actual water level versus just the presence/absence of water) to remotely assess flooding severity as compared to the binary water level sensors thus reducing dispatches to assess vault condition. It would provide a means for the Control Room to prioritize reactive crew allocation.

[5] Please see Exhibit 4, Tab 2, Schedule 2 for more details.

- **Video Camera**: These can help detect unauthorized intrusion, and provide remote verification of alarm or unsafe conditions. This would allow the crews to better understand the situation of the vault prior to entering.
- **Vault Hatch Open Sensor**: Identify unauthorized intrusion and mitigate risk to the public (access to energized vault or a tripping/fall hazard).
- **Secondary Cable Monitoring with Cable Sensors and a Remote Node Collector**: Enhance the ability to extend operation of secondary networks under second contingency by identifying when secondary cables reach critical overload. Also, it will allow monitoring of the loading and condition of secondary cables emanating from network protectors and provide timely detection of the operations of cable limiters which could result in complete or partial outage to customers.

Overall, these enhancements will assist Toronto Hydro in further reducing safety and reliability risks, and in strengthening the resilience of the grid. This will also help save important utility assets before they fail or reach end of life earlier than they should. Lastly, by early detection of potential catastrophic situations, the utility will be able to prevent major incidents from occurring.

E7.3.4 Expenditure Plan

The program aims to improve issues related to reliability, safety, failure risk, and system efficiency primarily by investing in monitoring and control equipment installations inside network vaults, as well as a fibre optic communications backbone installed under city streets. Table 5 below depicts the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) spending for this program.

Table 5: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Network Condition Monitoring and Control	8.1	12.5	13.0	11.0	12.2	4.2	0.2	0.4	0.6	0.6

The prioritization, scheduling and completion of projects in this program are based on the proposed fibre optic installation plan shown in Figure 4. Installation of the necessary fibre backbone is a prerequisite for testing and commissioning of monitoring and control equipment installed in

individual vaults. Therefore, equipment installation in vaults is planned for the year following the completion of fibre installation. In addition, network units installed after 2010, including those to be replaced through the Network System Renewal program, will be equipped with the necessary relays and sensors required for monitoring and control. Network units that are retrofitted are also allocated within the budget under VCB installation.[6]

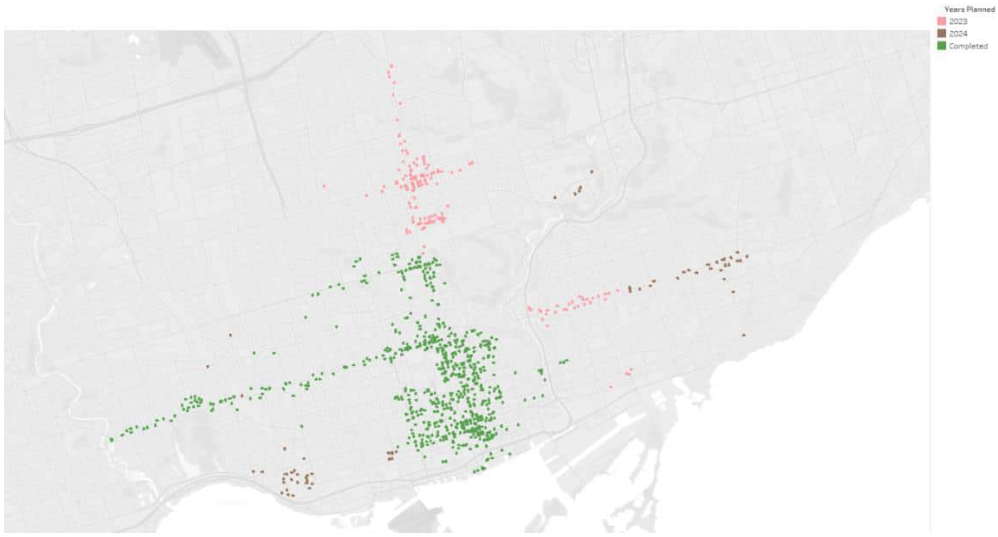


Figure 4: Fibre Optic Cable Deployment by Year

E7.3.4.1 2020-2024 Expenditures

Over the course of the Program so far, Toronto Hydro has commissioned 379 vaults, including 367 over 2020 to 2022. Toronto Hydro spent $33.6 million over 2020 to 2022 and plans to spend approximately $23.2 million and commission an additional 320 vaults over 2023 to 2024. Toronto Hydro no longer expects to complete the program by the end of 2024, as was originally proposed. As shown in Table 4, Toronto Hydro expects to complete commissioning of all except six of the networks proposed in the 2020-2024 DSP, four of which are the smallest networks by load.

The delays have been driven primarily by three factors. Firstly, fibre projects have been completed more slowly than expected due to execution challenges, such as resource constraints in 2020-2021, and additional time required to coordinate with external utilities to complete necessary civil work. Secondly, the work related to commissioning of the vaults started later than planned and the pacing

[6] Exhibit 2B, Section E6.4.

was also slower due to the learning curve from introducing new equipment, training requirements, and change management challenges. Thirdly, supply chain delays for VCBs caused work plans to slip and carry over into subsequent years. In 2022, the VCB supplier informed the utility of expected delays in acquiring the raw materials (brass sheets) required for manufacturing. To mitigate delays in program implementation, Toronto Hydro's engineers developed a new standard that allowed the VCB to be constructed from stainless steel. This innovation allowed Toronto Hydro to complete 129 of its planned 161 units before year-end as well as have a backup option to avoid any potential material delays. Remaining units have been scheduled and completed in Q1 2023.

It should be noted that while Toronto Hydro has been modernizing its system for many years, the NCMC program represents Toronto Hydro's first full-scale implementation of a new set of distributed grid technologies since the roll-out of the first generation of smart meters. While some challenges and delays have been encountered in this implementation, Toronto Hydro believes that the lessons learned, skills developed, and organizational capacity gained through this experience will support a successful and efficient implementation of the Grid Modernization Roadmap in the 2025-2029 rate period.

E7.3.4.2 2025-2029 Expenditure

Toronto Hydro plans to spend approximately $4.2 million in 2025 and commission the remaining 222 network vaults required to complete the original NCMC program plan. Any future renewal of the equipment installed through this Program and associated recommissioning work will be completed through the Network System Renewal program.

Over 2026 to 2029, Toronto Hydro plans to invest approximately $1.8 million to assess the viability of commissioning the remaining vaults not completed by 2025 as well as launch a pilot project that will install additional sensors, such as fire and analog water sensors, cameras, vault hatch open sensors and secondary cable monitoring, to further enhance monitoring capabilities in 35 network vaults (approximately 4 percent of network vaults). The network vaults targeted will be prioritized based on factors including, but not limited to history of flooding, higher voltage units, top entry vaults, and network grids where there is larger amount of secondary cabling. The investments in additional sensors will further improve real-time awareness in the network system, leading to improved decision making and pre-emptive response to different types of failures. These incremental investments will lead to substantial benefits as the investments already made in fibre and VCBs can be leveraged.

E7.3.5 Options Analysis

E7.3.5.1 Option 1: Sustainment

Under this option, Toronto Hydro will complete the original NCMC program plan in 2025, installing and commissioning monitoring and control equipment installations inside a total of 920 network vaults and providing associated reliability, safety, and system efficiency benefits. Once this is complete, Toronto Hydro would not do any additional work to further enhance real-time monitoring capabilities by installing additional sensors.

This option would forego additional modernization on the network system and limit the value of the upfront investments made on the infrastructure to enable NCMC. Benefits from future developments and technology in network system modernization would be missed, including substantial reliability, resiliency and efficiency benefits, as described in more detail in Sections E7.3.3 and E7.3.4.2.

E7.3.5.2 Option 2: Improvement

Under this option, the same as under Option 1, Toronto Hydro will complete the original NCMC program plan in 2025. Once that is complete, Toronto Hydro plans to initiate a pilot project to further enhance real-time monitoring capabilities by installing additional sensors, such as fire and analog water sensor, vault camera, vault hatch open, and secondary cable monitoring in 35 network vaults over 2026 to 2029. This additional monitoring will further improve awareness of the condition and operation of the vault and network assets, leading to further enhanced decision making, reduction of failures, and improved safety for internal crews and the public. The additional sensors will leverage equipment and infrastructure already in place such as fibre and VCBs, thereby maximizing overall benefits of the upfront investments in the program.

Under this option, Toronto Hydro will complete the original NCMC program plan in 2025. Once complete, Toronto Hydro plans to initiate a pilot project to further enhance real-time monitoring capabilities by installing additional sensors, such as fire and analog water sensor, vault camera, vault hatch open, and secondary cable monitoring in 35 network vaults over 2026 to 2029. This additional monitoring will further improve awareness of the condition and operation of the vault and network assets, leading to further enhanced decision making, reduction of failures, and improved safety for internal crews and the public. The additional sensors will leverage equipment and infrastructure

already in place such as fibre and VCBs, thereby maximizing overall benefits of the upfront investments in the program.

E7.3.6 Execution Risks & Mitigation

E7.3.6.1 Fibre Installation

Fibre optic cable is the first asset that must be installed as part of the Program. Installation of fibre under city streets poses a number of risks that may cause program delays and increase costs, including:

- Lack of existing duct capacity for the fibre optic cable;
- Road construction moratoriums and road work restrictions;
- Construction blocking access to cable chambers and vaults; and
- Leaking cables posing hazards that prevent workers from entering cable chambers and vaults.

If a problem is only identified once construction begins, it results in reactive work, increased cost, and program delays. Toronto Hydro mitigates these risks by performing detailed field inspections during the design phase of the program and then designing solutions that avoid problem locations altogether. Alternatively, Toronto Hydro can plan ahead for necessary construction work to avoid impacting the program's critical path timeline. Toronto Hydro has piloted the use of wireless technology in NCMC applications by utilizing a long-term evolution ("LTE") communication device to connect to SCADA systems. If successful, this technology will provide an alternate way to add NCMC capabilities to network vaults by enabling remote connection where fibre optic communication cannot be deployed due to the risks mentioned above.

E7.3.6.2 Vault Equipment Installation

Certain risks can delay the installation of equipment inside network vaults and increase costs, including:

- Flooded vaults;
- Lack of suitable available space to install equipment;
- Existing primary feeder installation interfering with the installation of transformer sensors; and

- Legacy protectors not compatible with newer communicating relays required for NCMC.

Toronto Hydro mitigates all of these risks by performing a detailed field inspection during the design phase. Toronto Hydro can complete corrective work on flooded vaults prior to starting construction work for this program. To address a lack of suitable available space to install equipment, such issues will be proactively identified, and the relevant project will be designed to include the necessary equipment relocation work and scheduled to avoid impacting the program's critical path timeline. Where existing primary feeder installations interfere with installation of a particular transformer sensor and incompatible legacy network protectors, Toronto Hydro will complete a network unit renewal and then install NCMC capabilities.

E7.3.6.3 Material Delays

Supply chain issues can cause delays in receiving material for all NCMC components and therefore delay execution of projects, as was the case with VCBs in the 2020-2024 rate period, as discussed in section E7.3.4.1. Toronto Hydro mitigates this risk by ensuring all relevant stakeholders are engaged to proactively identify issues and develop solutions, such as developing new standards that increase options available. This is also mitigated through Toronto Hydro's procurement strategy. For more details on this procurement strategy and what Toronto Hydro has been doing to address this issue, please see Exhibit 4, Tab 2, Schedule 15 (Supply Chain).

E7.3.6.4 Security and Privacy Issues

Once the initial plan of the program is completed, Toronto Hydro plans to introduce enhanced monitoring capabilities, which may include vault cameras and vault hatch open sensors. These two sensors pose security and privacy issues that need to be resolved prior to planning installations. However, Toronto Hydro is making investments in IT Cybersecurity to ensure that current systems, applications, and endpoints can continue to operate reliably and with minimal risk exposure to cyber threats in response to an evolving threat landscape, please refer to Exhibit 2B Section E8.4 for more details.

In addition, secondary cable monitoring sensors will pose data overload issues and cables identified for sensor installation need to be carefully selected to provide useful benefits for system emergency operations as well as planning enhancements. These concerns will be discussed with the appropriate stakeholders before rolling out these sensors, and will be considered alongside other modernization initiatives in the context of Toronto Hydro's broader analytics strategy.

E7.4 Stations Expansion

E7.4.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 139.9	**2025-2029 Cost ($M):** 121.9
Segments: Downsview TS, Hydro One Contributions[1]	
Trigger Driver: Capacity Constraints	
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Public Policy Responsiveness, Environment	

/C

Toronto Hydro's Stations Expansion program (the "Program") addresses medium to long-term system capacity needs. The Program is driven by capacity constraints at the station or regional level, which can no longer be effectively managed by the Load Demand program alone. Increased and continued densification, population growth, and electrification are driving the need to relieve the station loading and create additional capacity. If not addressed proactively, this will impact Toronto Hydro's ability to connect customers to its distribution system, and expose Toronto Hydro's stations to risk during peak loading periods. The primary focus of the work planned in the 2025-2029 rate period is on the horseshoe northwest and horseshoe east regions of the distribution system, where constraints currently exist or are forecasted to materialize with growth.

The Stations Expansion program consists of the two segments summarized below, and is a continuation of the expansion activities described in Toronto Hydro's 2020-2024 Distribution System Plan.[1]

- **Downsview TS**: This segment aims to expand station capacity by constructing a new transformer station ("TS") in the Downsview area of Toronto, with a capacity of 174 MW. Additional capacity is needed to support forecasted growth and development in the City's Downsview area, while relieving the highly-loaded Bathurst and Finch TSs. A demand study of the Downsview area has forecasted a load demand of 195 MW by 2035.[2] The construction of a new TS is a large project requiring a long lead time. In order to be ready to meet the forecasted demand, Toronto Hydro must start planning and preparing for this project in the

[1] EB-2018-0165, Exhibit 2B, Section E7.4
[2] Downsview Area Secondary Plan – Electricity Demand Justification Report by DMP Energy (Aug 08 2022)

2025-2029 rate period for an anticipated energization date of late 2033. This planning and preparation stage will include preparatory capital investments such as: property acquisition, property site preparation construction of a new station building, high voltage circuit breakers and bus work, and partial construction or payments towards station assets.[3] Toronto Hydro forecasts to spend $70.2 million in this stage. Once planning and preparation is complete, Toronto Hydro will move into the construction and energization stage, which will include the installation of the remaining electrical assets, the installation of station ancillary assets, and the commissioning and energization of all electrical assets. Toronto Hydro forecasts to spend $70.0 million during the commissioning and energization stage post-2029.

- **Hydro One Contributions:** this segment covers Toronto Hydro's forecasted capital contributions to Hydro One for work related to:
  - Downsview SS: A new Hydro One switching station to provide Toronto Hydro's new Downsview TS access to Hydro One's transmission network;
  - Sheppard TS New Switchgear: A new switchgear to provide access to existing idle capacity at the existing Sheppard TS and enable new Distributed Energy Resources (DER) connections [E3.3 Capacity and Constraints to Connect DER]; /C
  - Manby TS T13/T14 DESN Upgrade: An upgrade to the transformers at this DESN during their natural end-of-life (EOL) renewal and an expansion of the switchyard to accommodate new feeders, to facilitate future load growth at this highly loaded station; and
  - Cost-effective capacity upgrades of EOL Hydro One-owned power transformers, as anticipated based on the IRRP process and latest Planning work in 2022.[4]

Toronto Hydro plans to invest an estimated $51.7 million in this segment in the 2025-2029 rate period compared to a forecasted $60.4 million in 2020-2024. /C

The investments summarized above for Hydro One transformer replacement are informed by the recent Regional Infrastructure Plan ("RIP") and 2020 Integrated Regional Resource Plan ("IRRP") activities conducted in coordination with Hydro One. The most recent planning document from this process is the 2022 Needs Assessment Report for the Toronto Region ("Needs Assessment"). A

[3] Site preparation will include items such as, but not limited to, the clearing of land, construction of a ground grid, installation of crushed stone, and a station fence.
[4] Hydro One Needs Assessment Report, Toronto Region, Dec 2022

reconciliation of the Needs Assessment with Toronto Hydro's Stations Expansion program is found in Section E7.4.7 Regional Planning Needs of this narrative.

The Stations Expansion program also responds to the need to maintain system reliability and increase grid resiliency to support Ontario public policy drivers. To this end, the Program focuses on Toronto Hydro's broad strategy of grid modernization within the context of an aging, dense urban infrastructure, aiming to support customers and load growth and both mitigating and adapting to climate change through grid resiliency and innovation.

In total, Toronto Hydro plans to invest $121.9 million in the Stations Expansion Program in 2025-2029, compared to a forecasted $139.9 million in 2020-2024. Toronto Hydro expects to add 321 MW of new capacity to its system from projects completed by 2029, and start projects that will contribute to an additional 174 MW of capacity when completed in 2030-2034.[5] /C /C

E7.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: ○ Reducing the number of stations unable to connect new large customers in the downtown and Horseshoe areas by investing in 321 MW in additional supply capacity by 2029; ○ Alleviating feeder position limitations that prevent customer connections; and ○ Enabling new DER connections by providing increased short-circuit capacity with new DESNs.
Operational Effectiveness - Reliability	• Contributes to maintaining Toronto Hydro's system capacity and reliability objectives by: ○ Providing redundancy and operational flexibility by upgrading capacity at supply points to keep the number of highly loaded stations (with loads > 90 percent capacity) at a minimum for the downtown and Horseshoe areas;

[5] The Downsview TS will contribute 174 MW of new capacity and is forecasted to come in-service during the 2030-2034 rate period. /C

Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy objectives by: ○ Supporting the provincial long-term energy planning and IRRP by meeting local needs; and ○ Enabling electrification by investing in additional capacity and operational flexibility.
Environment	• Contributes to Toronto Hydro's environmental objectives by investing in capacity to support operational flexibility, enable electrification.

E7.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	Capacity Constraints
Secondary Driver(s)	Reliability, DER Connections

The Stations Expansion program is driven by constraints at the station or regional level, which can no longer be effectively managed by the Load Demand program alone. Over the next decade, Toronto Hydro's distribution system is expected to face many new challenges and demands due to population growth, densification, and electrification. These factors will ultimately result in increased capacity constraints at its stations, creating the need to relieve constraints by building additional capacity.

Because these challenges, particularly the acceleration of electrification, are subject to many factors outside of Toronto Hydro's control, such as government policies and consumer preferences, the timing for when capacity constraints will materialize is uncertain. Toronto Hydro has managed this uncertainty by considering multiple inputs to develop a plan that will satisfy its capacity needs, in a least-regrets investment approach. These inputs are as follows.

- **Load Forecasts:** Toronto Hydro's 10-Year Peak Demand Forecast (see Section D4 of the Distribution System Plan), and Hydro One's Needs Assessment Report 10-Year Load Forecast /C
- **City of Toronto Development Plans:**[6] Downsview Area Secondary Plan, East Harbour Development, Golden Mile Secondary Plan, and Scarborough Centre Secondary Plan

[6] City of Toronto, Secondary Plan Key Map (November 2015) https://www.toronto.ca/wp-content/uploads/2017/11/980a-cp-official-plan-Map-35_SecondaryPlans_AODA.pdf

- **Future Energy Scenarios ("FES"):**[7] Six scenario-based outlooks to assess impacts to station loading due to: the electrification of heating and transportation, building stock growth, and DER integration.

From this analysis, Toronto Hydro identified that the City of Toronto Development Plans will be a primary driver of forecasted load growth in both the Downtown and the Horseshoe areas. In particular, Toronto Hydro expects that this growth will add constraints to Fairbank TS and Finch TS within 10 years, and at Bathurst TS within 15 years. Due to the long lead time needed to implement a lasting solution for these stations, Toronto Hydro must begin making necessary investments in the 2025-2029 rate period. /C

A second key driver of forecasted load growth identified is electrification, which is forecasted to impact Toronto Hydro's system more broadly than the Secondary Plans which target specific areas. This is driving a need for capacity to be made available throughout Toronto Hydro's system, to ensure that Toronto Hydro's system does not become a barrier to new customers looking to access its system, regardless of where those customers may materialize.

The lack of capacity at Toronto Hydro's stations results in two negative consequences. First, it negatively impacts customer connections by preventing new customers from connecting to the grid or burdening connecting customers with higher connection costs. Second, it reduces the reliability of the station, and may result in load shedding.[8]

When a customer submits a connection request to a station which is highly loaded, Toronto Hydro can either connect the customer to the highly loaded station by first completing a load transfer, or to another station with capacity further away resulting in a higher connection cost. When multiple neighbouring stations are highly loaded, these options become even more limited, and connection costs become even higher.

When station load exceeds capacity, equipment losses result in customer outages during periods of peak loading. As a result, Toronto Hydro or Hydro One is not able to complete maintenance or replacement work during peak periods, which typically results in the deferral of work needed to

[7] Exhibit 2B Section D4 Capacity Planning & Electrification
[8] Load Shedding is the process during which Toronto Hydro temporarily shuts down power supply to a limited number of customers, in order to reduce its station load beneath its station capacity. Power supply is restored to customers when doing so would no longer result in an overload. When needed, load shedding is generally rotated across customers for a few hours each, so that no customers experience long duration outages while others experience no outages at all.

maintain station reliability. To otherwise complete the work during peak periods would result in a shortened life of the existing station assets, which cannot be readily replaced. A lack of station capacity results in reduced reliability at the station, which affects tens of thousands of customers and typically 100-300 MW of customer load per station. Because of the significant consequences in the event of an outage, Toronto Hydro would be required shed load[8] to maintain station load within its capacity.

Hydro One's 2022 Needs Assessment, as part of Regional Planning identifies station capacity needs at: Bathurst and Finch TSs, Basin TS, Fairbank TS, Glengrove TS, Sheppard TS, Strachan TS, and Warden TS. The Report also recommends incremental capacity upgrades at Basin TS, Duplex TS, Manby TS, and Strachan TS during renewal work. Toronto Hydro's analysis has reached similar conclusions; and as a result, the work planned under the Stations Expansion Program is aligned with the NA needs and those in the 2020 Regional Infrastructure Plan ("RIP") report.[9] Table 4 and Table 5 below highlight the needs and how they are addressed through the Stations Expansion program.

The IESO's Integrated Regional Resource Plan ("IRRP")[9] for the Toronto Region is currently underway, and as a result, IRRP needs and recommendations have not been produced at this time. However, Toronto Hydro is presenting the same needs to the Toronto IRRP Working Group as those presented in the Stations Expansion Program.

Table 4: Station Capacity Needs from Needs Assessment and RIP

Station Capacity Need	Needs Assessment Report Timing	Needs Assessment Report Section	RIP Report Section	Stations Expansion Narrative
Bathurst TS / Finch TS	*Beyond 2031*	*7.3.6*	*N/A*	See E7.4.3.2.1
Basin TS	*2030-2035*	*7.3.4*	*7.9.4*	See E7.4.3.2.2
Fairbank TS	*2030-2035*	*7.3.1*	*7.9.1*	Included in 2020-2024 Stations Expansion plan, and in E7.4.3.2.1.
Glengrove TS	*Beyond 2031*	*7.3.5*	*N/A*	Addressed with new capacity at Duplex TS in E7.4.3.2.6
Sheppard TS	*2030-2035*	*7.3.2*	*7.9.2*	See E7.4.3.2.4

[9] Exhibit 2B, Section B, Appendix A, B, C, D, and E

Station Capacity Need	Needs Assessment Report Timing	Needs Assessment Report Section	RIP Report Section	Stations Expansion Narrative
Strachan TS	*2030-2035*	*7.3.3*	*7.9.3*	Addressed through transformer upgrade in E7.4.3.2.6
Warden TS	*Beyond 2031*	*7.3.7*	*N/A*	See E7.4.3.2.3

Table 5: NA Asset Renewal Needs where Upgrade is Recommended in NA and RIP

Asset Renewal Need	Renewal Timing[10]	Needs Assessment Section	RIP Report Section	Stations Expansion Narrative
Basin TS T3/T5 Transformers	*2027*	*7.1.4*	*N/A*	See E7.4.3.2.6
Charles TS T3/T4 Transformers	*2026*	*7.1.2*	*N/A*	
Duplex TS T1/T2 Transformers	*2026*	*7.1.3*	*N/A*	
Duplex TS T3/T4 Transformers	*2031*			
Manby TS T13/T14 Transformers	*2030*	*7.1.9*	*7.6*	
Strachan TS T14 Transformer	*2025*	*7.1.1*	*N/A*	
Strachan TS T13/T15 Transformers	*2031*			
Windsor TS (John TS) T2/T3 and T5/T6 Transformers	*2026*	*N/A*	*7.8*	Included in 2020-2024 Stations Expansion plan.

The station expansion program continuously improves and expands Toronto Hydro's grid in order to align itself with the City's growth and electrification endeavors. The work in the station expansion program will make Toronto Hydro's system more resilient to sudden load demands, and will ensure sufficient capacity exists to ensure station reliability.

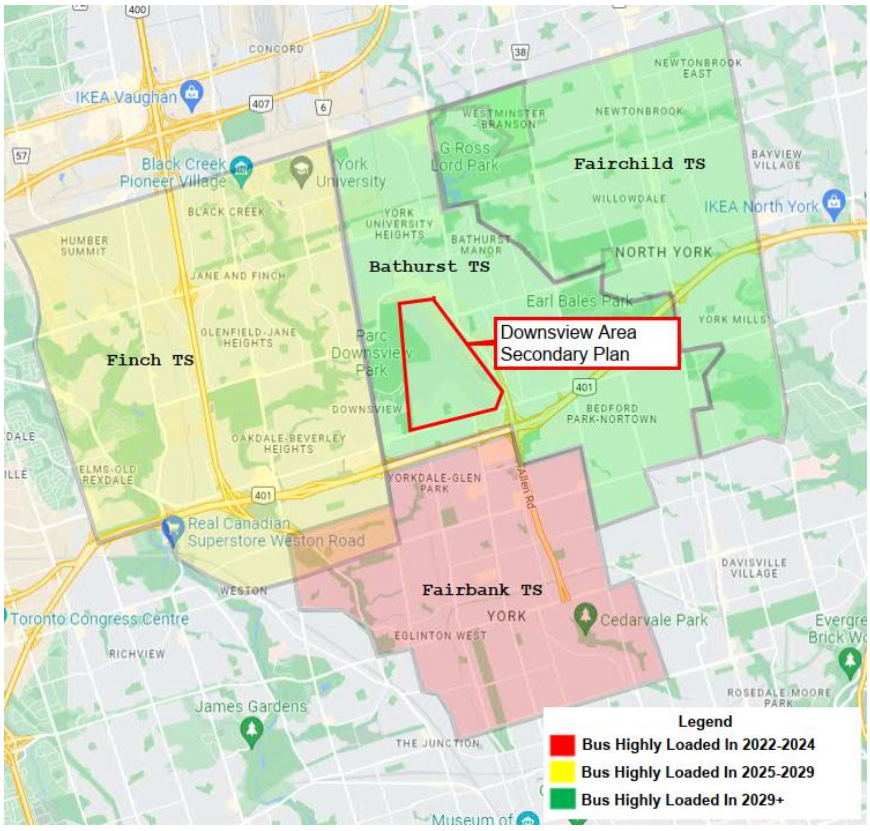
[10] If present in both the NA and RIP, the NA timing is used, as the NA is the more recent document.

The system needs are addressed through two segments: Downsview TS and Hydro One Contributions, as further discussed below.

E7.4.3.1 Downsview TS

The area affected by the Downsview TS segment consists of: Bathurst TS, Fairbank TS, Fairchild TS, and Finch TS. This area will be called the "Downsview Area" throughout the rest of this document. The Downsview Area is show in Figure 1.

In recent years, the Downsview Area has been attracting a large quantity of new load, and that trend is forecasted to persist into the future. On average, the area is forecasted to grow by 1.2 percent per annum over the next 10 years. /C



/C

Figure 1: Service Territories of Stations in the Downsview Area

1. Toronto Hydro's Peak Demand Forecast

Table 6 shows the existing load forecast for the stations in the Downsview Area based on firm connection requests, as provided in Toronto Hydro's Peak Demand Forecast.

Table 6 : Non-Coincident Downsview Area 10-Yr Load Forecast[11]

Station	Summer LTR (MW)	2021 (Actuals)	2022 (Actuals)	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bathurst TS	361	67%	70%	60%	64%	64%	67%	69%	70%	70%	70%	69%
Fairbank TS	182	104%	91%	77%	71%	80%	81%	80%	81%	84%	86%	88%
Fairchild TS	346	61%	64%	60%	61%	63%	64%	65%	66%	68%	70%	71%
Finch TS	366	69%	72%	78%	81%	84%	86%	87%	89%	91%	93%	95%
Area Non-Coincident %	1255	71%	72%	68%	69%	72%	74%	75%	76%	78%	79%	80%

Finch TS is forecasted to be highly loaded (past 90%) by 2029, and Fairbank TS is forecasted to reach the 90% threshold just after 2031. Fairbank TS has historically been highly loaded, and is being relieved by the recent expansion work at Runnymede TS; nonetheless, the station remains highly loaded and requires subsequent relief. Fairchild TS has significant capacity in the Downsview Area, but cannot provide direct relief to the highly loaded Fairbank and Finch TSs, due to geography.

Despite remaining capacity at Bathurst and Fairchild TSs, and the practical challenges of utilizing Fairchild TS for relief, the entire Downsview Area is forecasted to reach 90% loading by 2037. This signals a lack of capacity at the regional level, which is needed to support new connections, growth, and electrification. Since existing station equipment is already sized to maximum ratings, Toronto Hydro determined that a new station will be needed to relieve regional constraints. Given the long lead time required to construct a new station, and considering the possibility of electrification demand (e.g. transportation and buildings) materialzing faster than expected, Toronto Hydro must therefore make necessary investments in the 2025-2029 rate period to ensure that new capacity is ready to serve the Area in the next decade.

/C

[11] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.

In addition to the impacts from the Peak Demand Forecast, Toronto Hydro is considering the longer-term impacts to the Downsview Area resulting from the Downsview Secondary Development Plan, and its Future Energy Scenarios outlooks. These are described in the subsections below.

~~1.~~2. Downsview Area Secondary Plan ("DASP")

The Downsview Lands are approximately 210 hectares (520 acres) situated in the City of Toronto, bounded by Sheppard Avenue to the north, Allen Road to the East, Wilson Avenue to the south, and Downsview Park and the Park Commons to the west, as shown in Figure 2. The lands reside within the Bathurst TS service territory, as shown in Figure 1.

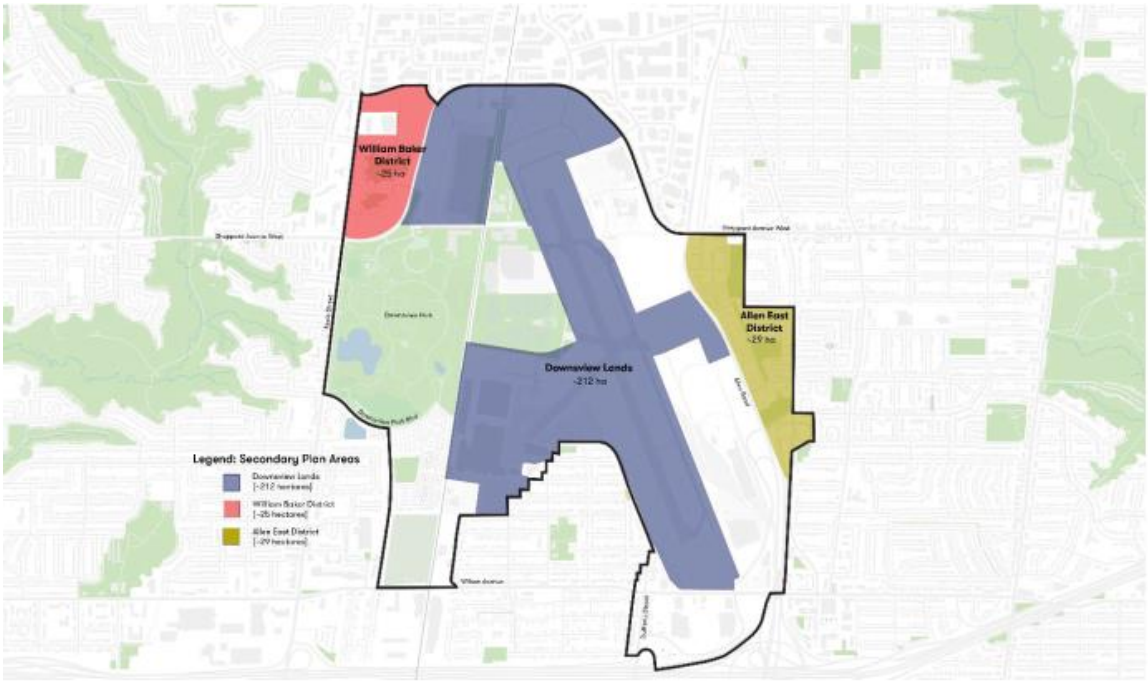


Figure 2: Proposed Downsview Secondary Plan Lands

The City of Toronto plans to redevelop the Lands into a dense new community as described in their Downsview Area Secondary Plan ("DASP"), published in 2017.[12] The DASP divides the Downsview Lands into districts and describes the expansion of each district with a mix of commercial, office, industrial and institutional buildings. The DASP preceded the city's net zero 2040 plans but is to align

[12] City of Toronto, Downsview Area Secondary Plan, "online", https://www.toronto.ca/wp-content/uploads/2017/11/902d-cp-official-plan-SP-7-Downsview.pdf

with the adoption of current day power demands of 6W per square foot and EV chargers for the projected EVs by 2045.

An independent party, DPM Energy, completed a preliminary study which estimates the electrical demand that will materialize from the DASP. This study suggests that load will begin to materialize in 2022 and could materialize up to: 103 MW by 2029, 180 MW by 2034, and 509 MW by 2051. This is equivalent to 8%, 14%, and 41% of the existing Downsview Area's Summer LTR of 1255 MW, as provided in

Table 6. As a result, supplying the Downsview Lands with existing regional capacity will not be feasible without capacity investments.

The Peak Demand Forecast only extends to 2031, and already considers load growth from the DASP. However, the DASP is expected to result in load growth up to 2051, with the majority of load materializing after 2031. Therefore, in order to ensure that cost-effective decisions are made now for the long term, Toronto Hydro has developed a 25 Year Forecast for the Downsview Area which considers the impact of the DASP from 2029 onwards. The 25 Year Forecast is based on the following assumptions:

1. **The annual load growth of the DASP for 2032-2051 is adjusted to 70 percent.**
    - Toronto Hydro's standard bus load forecasting methodology adjusts new customer load to 70% of the requested load in order to forecast bus load impacts. This reduction is based on historical results of customer load materialization.
2. **The 30 percent reduction to the DASP load for 2032-2051 is offset by:**
    - Load growth due to electrification of heating and transportation in the Downsview Area, in alignment with municipal and federal decarbonization goals.
    - General load growth in the Downsview Area, beyond the Downsview Lands.

Based on these assumptions, Toronto Hydro has adopted the 25 Year Forecast as the load forecast for the entire Downsview Area for post-2031. The results appear in Table 7.

Table 7: 25 Year Forecast for Downsview Area

Station	Summer LTR (MW)	2031	2034	2039	2044	2049	Year 100% Capacity is Reached
Bathurst TS	361	77%	81%	90%	99%	109%	2045
Fairbank TS	182	96%	101%	109%	118%	128%	2034
Fairchild TS	346	71%	71%	71%	71%	71%	N/A
Finch TS	366	99%	101%	105%	110%	115%	2032
Area Non-Coincident %	1255	85%	87%	92%	97%	103%	2046

/C

This forecast shows that by 2037, the Downsview Area as a whole will reach 90% loading, signaling a lack of capacity at the regional level. The forecast continues to show substantial load growth continuing past then, with no capacity remaining by 2046. Prior to that, 90% loading is forecasted at both Fairbank TS and Finch TS by 2031, and overloading by 2034. In summary, the 25 Year Forecast forecasts regional capacity constraints in the medium term, which worsen further into the long term.

/C

~~2.~~3. Load Projections – FES

To consider the impacts that the electrification of heating and transportation, building stock growth, and DER integration may have on Toronto Hydro's station loading, Toronto Hydro completed the FES[7]. The FES produced six 30-year system and station bus load projections based on different scenarios.

The FES incorporates current growth trends, econometric factors, and electrification goals into its modeling, but does not incorporate any DASP load. The results from the FES outlooks are provided in Table 8.

Table 8 – FES Projections for the Downsview Area

Station	Summer LTR (MW)	2031	2034	2039	2044	2049	Year 100% Capacity is Reached[13]
Bathurst TS	361	84-94%	89-101%	95-114%	99-118%	98-122%	2034-N/A
Fairbank TS	182	120-132%	124-142%	130-167%	132-174%	131-180%	2021

[13] According to the FES only. As a result, this year may be earlier than what is provided in the Needs Assessment.

Station	Summer LTR (MW)	2031	2034	2039	2044	2049	Year 100% Capacity is Reached[13]
Fairchild TS	346	68-74%	69-78%	70-84%	70-85%	69-86%	N/A
Finch TS	366	113-122%	118-133%	124-150%	127-153%	126-156%	2024
Area Non-Coincident %	1255	93-102%	97-109%	102-122%	104-126%	103-129%	2030-2037

Across all FES projections, all but one station will become heavily loaded by 2035. Additionally, the Downsview Area is to become highly loaded between 2025-28, and overloaded between 2030-37. Consistent with Toronto Hydro's 25 Year Forecast, the FES projections indicate a regional need for additional capacity that increases with time, and foresees the possibility that constraints will arise even earlier. /C

~~3.~~4. Proposed Solution – New Downsview TS

In order to address both medium- and long-term regional needs for additional capacity in the Downsview Area, Toronto Hydro proposes to build a new transformer station, named Downsview TS. The objective of the new Downsview TS is both to provide load relief to the existing TSs in the Downsview Area, and to directly supply the new loads resulting from the DASP and electrification.

Downsview TS is proposed to be located within the Downsview Lands, within the Bathurst TS service territory. This location has been chosen so that it may directly supply local DASP loads, and because it is also a central location between Bathurst TS, Fairbank TS, and Finch TS. As a result, the station will be well-placed to offload the three highest loaded stations in the Downsview Area. Downsview TS will provide 174 MW of new capacity to supply the Downsview Area, increasing the Area's capacity by an additional 14%.

There will be both a Toronto Hydro and Hydro One component of work to construct the new Downsview TS. The Hydro One portion is discussed in E7.4.3.2 and involves the construction of a new Downsview Switching Station ("Downsview SS"), which will serve as the connection point to Hydro One's transmission network.

The construction of a new TS is a large project requiring a particularly long lead time, and for this reason, a portion of the work needed to build the new TS was advanced into the 2025-2029 rate period. In order to energize Downsview TS at the end of 2033, Toronto Hydro forecasts that work

must begin in 2025. Toronto Hydro has planned for the Downsview TS project to proceed in two stages. The Planning and Preparation stage and the Construction and Energization stage.

The Planning and Preparation stage will proceed over the 2025-2029 rate period, and will include preparatory capital investments such as: property acquisition, property site preparation, construction of a new station building, high voltage circuit breakers and bus work, and partial construction or payments towards station assets.[14] The cost to complete this stage is forecasted to be $70.2 million.

The Construction and Energization stage will proceed starting in 2030 and will include the installation of the remaining electrical assets, the installation of station ancillary assets, and the commissioning and energization of all electrical assets. The remaining electrical assets include: a new 230 kV underground cables from Downsview SS, two new transformers, and one new switchgear. Toronto Hydro forecasts to spend $70.0 million during this stage, excluding the Hydro One contributions related to Downsview SS (see E7.4.3.2 – 1.).

Because the forecasted in-service date is beyond the range of the Peak Demand Forecast, the effect of Downsview TS is provided using the 25 Year Forecast and the FES load projections, and shown in Figure 3. With the addition of new capacity at Downsview TS, the Downsview Area loading is expected to be manageable out to 2049. FES Projections show that there is risk of Area overloading as early as 2036, and the magnitude of the potential overloading increases with time. To mitigate the risk of overloading in the long term, Downsview SS is proposed to be constructed with the provision to install a second DESN in the future, if and when it is needed. /C

[14] Site preparation will include items such as, but not limited to, the clearing of land, construction of a ground grid, installation of crushed stone, and a station fence.

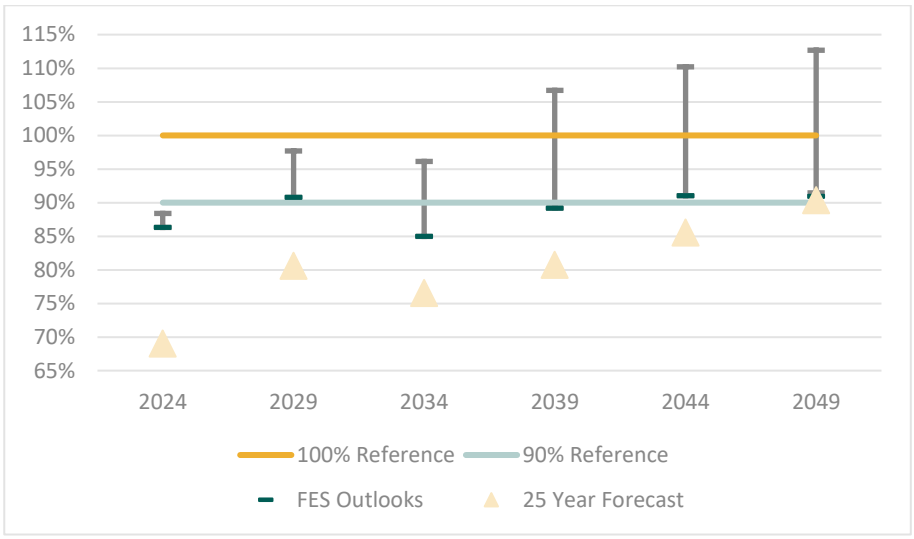


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Figure 3: Downsview Area Loading Outlooks After Downsview TS is In-Service

Toronto Hydro believes that the proposed solution strikes the right balance between the risk of capacity constraints and cost in least-regrets investment approach. Toronto Hydro will continue to monitor the actual and forecasted load of the Downsview Area to assess the risk of capacity constraints shortly after Downsview TS is completed. If this risk persists, Toronto Hydro may consider introducing another DESN into the Downsview Area at a later time; however, it would not be in the best interest of the ratepayer to invest immediately in two new DESNs. For this reason, the proposed solution includes only one new DESN, which is expected to provide adequate capacity until 2049. /C

E7.4.3.2 Hydro One Contributions

The most recent Needs Assessment reaffirms needs that were identified in the IRRP and highlights additional emerging needs. These needs are summarized in Table 26, Table 27, and in Section E7.4.7.

In response, Toronto Hydro plans to make capital contributions to Hydro One to carry out upgrades at Hydro One stations during the 2025-2029 rate period, as detailed in the following subsections.

1. New Downsview SS

Toronto Hydro plans to make a capital contribution to Hydro One over the 2025-2029 rate period to support their construction of a new Hydro One-owned Downsview SS. As discussed in section E7.4.3.1 above, the Downsview TS will provide additional capacity of 174 MW to alleviate forecasted constraints in the Downsview Area. Hydro One will support the project by constructing a new

switching station, Downsview SS, to supply Downsview TS from the Hydro One 230 kV transmission line corridor. Toronto Hydro will construct and own the TS itself.

2. Sheppard TS Bus Expansion

The area affected by the Sheppard TS bus expansion consists of: Malvern TS, and Sheppard TS. This area will be called the "Sheppard Area" throughout the rest of this document. The Sheppard Area is shown in Figure 4.

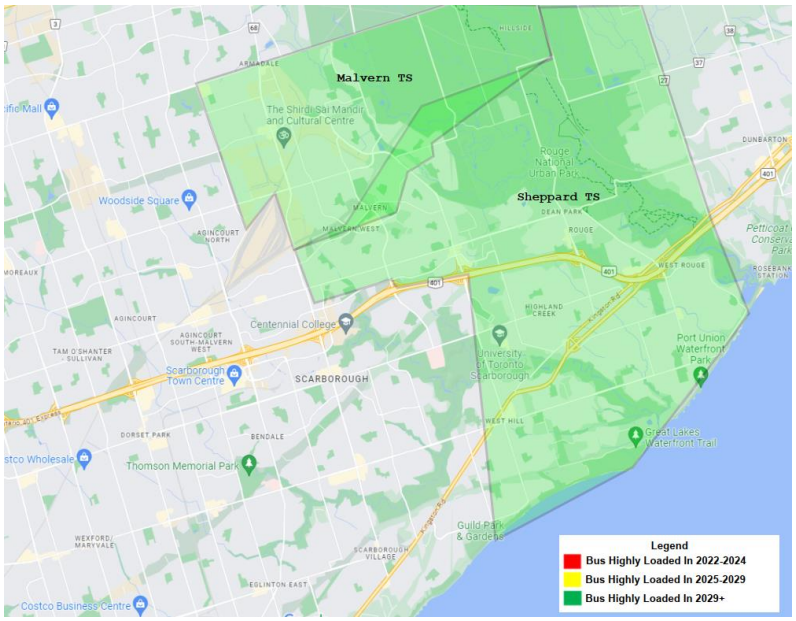

Figure 4 : Service Territories of Stations in the Sheppard Area

Table 9 shows the existing load forecast for the stations in the Sheppard Area based on firm connection requests, as provided in Toronto Hydro's Peak Demand Forecast.

Table 9: Non-Coincident Sheppard Area 10-Yr Load Forecast[15]

Station	Summer LTR (MW)	2021 (Actuals)	2022 (Actuals)	2023	2024	2025	2026	2027	2028	2029	2030	2031
Malvern TS	176	60%	64%	60%	61%	62%	63%	63%	64%	66%	67%	68%
Sheppard TS	204	77%	70%	66%	66%	67%	64%	65%	67%	70%	72%	75%

[15] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.

Station	Summer LTR (MW)	2021 (Actuals)	2022 (Actuals)	2023	2024	2025	2026	2027	2028	2029	2030	2031
Area Non-Coincident %	380	69%	67%	63%	64%	65%	63%	64%	66%	68%	70%	72%

Sheppard TS is forecasted to be 75% loaded by 2031, and since the Peak Demand Forecast has been produced, Toronto Hydro has received a new customer request for an additional 20 MW in the Sheppard TS service area. Malvern TS is forecasted to be loaded to a similar level, bringing the forecasted Area loading to 72% by 2031.

In addition, Sheppard TS is experiencing a lack of short circuit capacity, which is forecasted to persist into the future. As discussed in the Generation Protection, Monitoring, and Control Program ("GPMC Program"), short circuit capacity is a requirement to connect new DERs to Toronto Hydro's system. The GPMC Program also states that the available short circuit capacity of the Sheppard TS EZ bus in 2023 is -57.3 MVA, indicating a present need for relief and an inability to connect new DERs to the bus. Therefore, in order to ensure that its system does not act as a barrier to new DER connections, Toronto Hydro must relieve short circuit capacity constraints at Sheppard TS.

/C

The existing configuration of Sheppard TS also presents a unique opportunity to expand the station for a significantly reduced cost and in a shorter timeframe than comparable expansion projects.[16] This is because the station is already equipped with idle transformer windings, and as a result, the scope of work would not include transmission or transformation components. The expansion of Sheppard TS would only involve the installation of a new switchgear.

Toronto Hydro investigated alternatives to increase short circuit capacity at Sheppard TS, including the use of bus-tie reactors, a solution actively under consideration for other transformer stations in the current CIR period. However, due to technical limitations, such an investment is not suitable for this station. In 2016, Sheppard TS underwent an upgrade which replaced the outdoor air insulated switchgear with indoor Gas Insulated Switchgear ("GIS"). The newer enclosed and hermetically sealed design does not permit access to the switchgear bus that would allow the installation of a bus tie reactor.

[16] Comparable projects include the Runnymede TS expansion project from the 2015-2019 CIR, the Horner TS expansion project from the 2020-24 CIR, and the newly proposed Scarborough TS expansion project for the 2025-29 CIR.

Given the significantly reduced cost of expansion presented at Sheppard TS, the expansion of Sheppard TS would present a reliable and cost-effective solution to relieve the station's short circuit capacity constraints and enable new DER connections. The expansion would provide an estimated 126 MVA of short circuit capacity, with the additional benefit of 95 MW of new thermal capacity.[17]

3. Manby TS DESN Reconfigurations

The area affected by the Manby TS DESN Replacements Preparations ("DESN RPs") consists of: Horner TS, Manby TS, and Richview TS. This area will be called the "Manby Area" throughout the rest of this document. The Manby Area is shown in Figure 5.

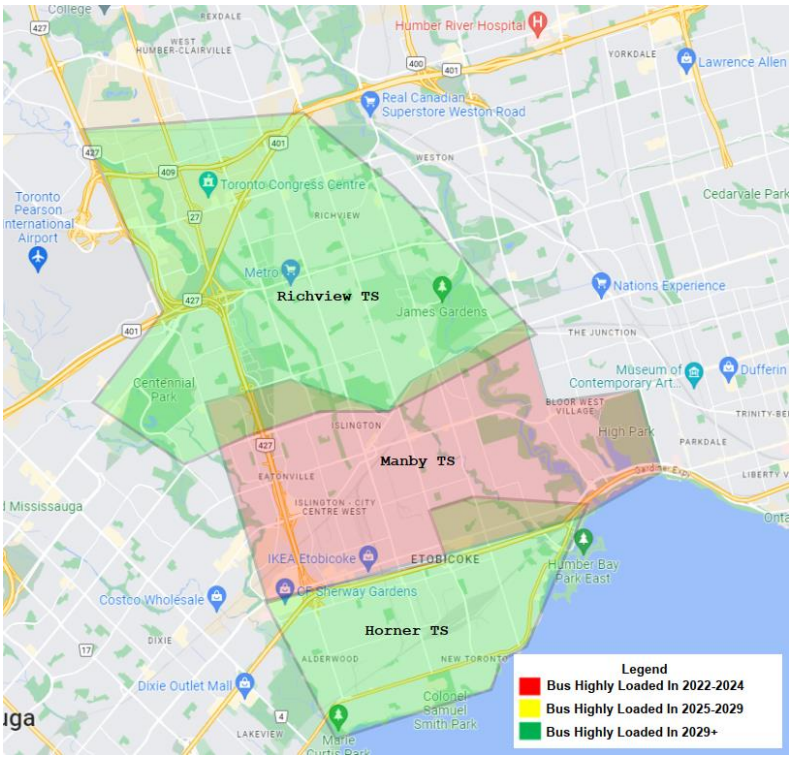

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Figure 5 : Service Territories of Stations in the Manby Area Table 10 shows the existing load forecast for the stations in the Manby Area based on firm connection requests, as provided in Toronto Hydro's Peak Demand Forecast.

[17] Toronto Hydro is seeking for treatment of costs associated with the Sheppard TS bus expansion as eligible investments for provincial rate recovery under section 79.1 of the Ontario Energy Board Act, 1998. Please refer to Exhibit 2A, Tab 5, Schedule 1 for a summary of eligible investments and Schedules 5 and 6 for the breakdown of provincial rate protection amounts associated with the bus expansion.

Table 10: Non-Coincident Manby Area 10-Yr Load Forecast18

STATION	Summer LTR (MW)	2021 (Actuals)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Horner TS	366	40%	44%	47%	53%	58%	70%	72%	74%	75%	77%	78%
Manby TS	226	110%	97%	85%	86%	88%	77%	79%	81%	85%	88%	91%
Richview TS	460	63%	64%	60%	65%	64%	66%	61%	62%	64%	65%	65%
Area Non-Coincident %	1052	65%	64%	61%	65%	67%	70%	69%	70%	72%	74%	75%

/C

Due to the recent Horner TS expansion completed during the 2020-2024 rate period, the Manby Area is forecasted to have excess capacity to 2031. However, due to forecasted high loading at Manby TS specifically, and given the T13 and T14 transformers require renewal, the Hydro One 2022 Needs Assessment ("NA") Report recommends the upgrade of the Manby TS T13 and T14 transformers to the current standard size of 125 MVA. These upgrades are mentioned in the following Section "Hydro One Transformer Upgrades".

Because of the existing configuration at Manby TS, if the transformer replacements proceed without any reconfiguration of its associated DESN, then the DESN will actually decrease in capacity by 15 MW. Although the new T13 and T14 transformers will be rated at higher capacity, their additional capacity will be locked in idle windings, similar to the current configuration at Sheppard TS. However, the upgrade of the T13 and T14 transformers can provide additional renewal and long-term capacity benefits, if its DESN is reconfigured from the existing Jones configuration to a Bermondsey configuration in coordination with the transformer upgrades.[19][20]

The T3/T4 switchyard at Manby TS will require renewal in the near future. The existing T3/T4 DESN is under-rated which has made managing its load difficult. Rather than replace the T3/T4 switchyard like-for-like and the T13 and T14 transformers life-for-like, Toronto Hydro proposes to upgrade the T13 and T14 transformers (as recommended in the Needs Assessment) and also replace both the existing T13/T14 Jones switchyard and the T3/T4 Jones switchyard with one new Bermondsey

[18] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.
[19] A DESN in Jones configuration is composed of two single-winding transformers and two buses, with one transformer supplying each bus, and a normally-closed bus tie connecting the two buses to one another.
[20] A DESN in Bermondsey configuration is composed of two dual-winding transformers and two buses. One winding from each transformer supplies each bus, and a normally-open bus tie is installed between the buses.

switchyard. The new Bermondsey switchyard will be supplied by the upgraded T13 and T14. In summary, two existing Jones switchyards will be replaced with one new Bermondsey switchyard.

The near-term benefits of this proposal are as follows.

- No loss of capacity for the T13/T14 switchyard;
- Increase in station capacity by +16 MW once both switchyards are replaced;
- Higher reliability replacement plan for the T3/T4 switchyard, rather than replacing the switchyard "in-place" while still supplying customers;
- Fully-rated new Bermondsey switchyard can properly manage the combined load of the existing T3/T4 and T13/T14 DESNs;

In addition, this proposal presents two subsequent long-term options to increase station capacity at Manby TS when needed:

1. When the T3/T4 switchyard is replaced onto the new Bermondsey switchyard, the existing T3/T4 will be left idle in a similar configuration as what currently exists at Sheppard TS. As a result, Toronto Hydro can initiate for a new 60 MW switchyard to be installed using the idle windings, and thereby increase station capacity by 60 MW; or,
2. At the time when the third and last DESN at Manby TS requires renewal, if Toronto Hydro has not pursued the above option, then Toronto Hydro may be able to replace the last DESN and the idle T3/T4 with another new Bermondsey-configured DESN. This would increase the station capacity by approximately 123 MW.

Therefore because of both the near-term and long-term benefits to the renewal and upgrade of Manby TS, Toronto Hydro proposes to replace the existing T3/T4 and T13/T14 switchyards with a new Bermondsey switchyard, in coordination with the T13 and T14 transformer upgrades. This proposal is being referred to as "DESN Reconfigurations".

4. Hydro One Transformer Upgrades

To alleviate capacity constraints, Toronto Hydro proposes to invest in incremental upgrades to Hydro One transformers during the 2025-2029 rate period, as Hydro One completes the renewal of these end-of-life assets. The renewal plans are initiated by Hydro One and included in the Needs Assessment. Because of the coordination with renewal work, these investments present the greatest

value-for-money in terms of $/MW, and are pursued even when the incremental capacity may not be immediately accessible.[21]

Based on the most recent Needs Assessment, City of Toronto Development Plans, and electrification risks to station capacity adequacy, Toronto Hydro has identified benefits in upgrading transformers at the stations listed in Table 11 below. These upgrades will immediately provide an estimated 226 MW of new capacity to Toronto Hydro's system, and up to another 272 MW of new capacity with further investments. For similar reasons, the Needs Assessment also recommends the upgrade of these units, with the exception of Carlaw TS.[22]

Hydro One will not plan to replace transformers until the units have reached end-of-life, typically after 45 years.[23] It is cost effective for Toronto Hydro to coordinate upgrades with Hydro One's renewal project schedule. Upgrades are only possible by removing and replacing the existing transformer. The cost to remove and replace the existing unit with a higher capacity unit outside of a Hydro One renewal project is approximately $10 million per unit, less asset depreciation. Alternatively, the incremental cost to upgrade a transformer in coordination with its renewal is approximately $0.8 million. Based on the needs identified from the NA and RIP as shown in Table 4 and Table 5, Toronto Hydro foresees the need for additional capacity at each of the stations in Table 11. Given the long life of these assets and the cost efficiencies achieved by coordinating with Hydro One's renewal schedule, Toronto Hydro has determined that it is prudent to invest in the incremental transformer upgrades listed in Table 11 to ensure that transformation capacity does not become a bottleneck to station capacity over the long term.

[21] Additional investment(s) may be needed following the transformer upgrade to realize the new capacity. For example, the station switchgear may need to be replaced.
[22] The Carlaw TS T1/T2 transformer renewals are not included the Hydro One NA Report, but their timing for renewal approaches the end of the 2025-2029 CIR rate period. Toronto Hydro proposes to prioritize their replacement and upgrade to support capacity needs identified at the adjacent Basin TS, as noted in the NA and RIP and referenced in Table 5. The East Harbour Master Plan and Port Lands development plans will intensify capacity needs at Basin TS.
[23] Kinectrics "Useful Life of Assets" Report, filed in the EB-2010-0142 application (Exhibit Q1, Tab 2)

Table 11: List of Toronto Hydro Owned Busses Connect to Hydro One Transformer Replacement

Project	Transformer Ratings (MVA)		Immediate New Capacity[24] (MW)	Potential New Capacity[25] (MW)
	Existing	New		
Basin TS – T3/T5 Upgrade	75	100	36	-
Carlaw TS – T1/T2 Upgrade[22]	75	100	54	-
Duplex TS – T1/T2 Upgrade	75	100	-	43
Duplex TS – T3/T4 Upgrade	75	100	-	16
Leslie TS – T1 Upgrade	125	125	-	91
Manby TS – T13/T14 Upgrade	93	125	16	60-122
Scarborough TS – T23 Upgrade	125	125[26]	38	-
Strachan TS – T14 Upgrade	75	100	53	-
Strachan TS – T13/T15 Upgrade	75	100	29	-
Total			**226**	**210-272**

E7.4.4 Expenditure Plan

Spending in the Stations Expansion program over the 2020-2024 rate period was forecasted to be $139.9 million. Toronto Hydro proposes to spend $121.9 million over the 2025-2029 rate period to add 321 MW of new capacity to its system, and contribute to an additional 174 MW of capacity realized in 2030-2034.[27] Forecasted growth, largely driven by City of Toronto Development plans, is driving the need for substantial new capacity to be added to Toronto Hydro's system, resulting in the need for increased expenditures. /C

Table 12: Historical & Forecast Program Costs by Segments ($ Millions)

[24] New capacity which will be realized following the Hydro One transformer(s) upgrade(s)
[25] Additional investment(s) will be needed following the Hydro One transformer upgrade to realize the new capacity. For example, the station switchgear may need to be replaced, a new switchyard may need to be installed, or an additional transformer may need to be upgraded.
Toronto Hydro replaces end-of-life transformer station switchgear in the Station Renewal program (See Exhibit 2B, Section E6.6 Stations Renewal – Section E6.6.3.1 sub-section 1 TS Switchgear). /C
[26] Although the Scarborough T23's rating will not change, during the replacement components associated with the unit which limit station capacity will be upgraded, resulting in new capacity.
[27] The Downsview TS project will contribute 174 MW of new capacity and is forecasted to come in-service during the 2030-2034 rate period. /C

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Copeland TS Expansion	7.5	35.1	26.5	6.3	4.0	-	-	-	-	-
Hydro One Contributions	10.7	15.2	21.0	11.5	2.1	7.8	4.0	12.6	14.8	12.5
Downsview TS	-	-	-	-	-	3.2	3.9	9.6	25.9	27.7
Total	**18.2**	**50.3**	**47.5**	**17.8**	**6.1**	**11.0**	**7.8**	**22.2**	**40.7**	**40.2**

Over the 2020-2024 rate period, Toronto Hydro forecasts to spend $139.9 million in its Stations Expansion Program, which is a small overspend of $8.2 million or 6 percent relative to the $131.7 million forecasted in the 2020-2024 Distribution System Plan.[28]

This variance is mostly attributable to variances in the Hydro One Contributions segment, with a variance of $7.1 million. The major sources of variances in this segment result from: a Copeland TS Phase 1 True-Up payment, switchyard expansions at Bermondsey TS and Richview TS, Hydro One support for a new supply cable between Carlaw TS and Gerrard TS. Each of these sources is included in the Reactive Hydro One Contribution subsegment, which by its nature is challenging to forecast.

The proposed projects in the Stations Expansion program will address capacity constraints in areas identified by the Hydro One's 2022 Needs Assessment ("NA") Report, and will coordinate with the sustainment plans outlined in the Report. Given the complexity and size of these individual projects, these projects entail extensive coordination with Hydro One and other stakeholders (such as contractors, vendors, public etc.), long lead times for ordering equipment, and logistical challenges in heavy electrical equipment delivery. Due to these challenges, the Stations Expansion program is susceptible to fluctuations in spending from year-to-year.

E7.4.4.1 2020-2024 Variance Analysis – Copeland TS Expansion

Copeland TS Phase 2 expansion work commenced in 2017 and is expected to be completed in 2024. Table 13 below provides the cost summary with Actual and Bridge amounts for Phase 2. Over the 2020-2024 rate period, Toronto Hydro forecasts to spend $79.5 million on Copeland TS Phase 2, which is which is aligned with the $78.4 million forecasted in the 2020-2024 DSP.

[28] Less the Local Demand Response segment, which has moved to the Non-Wires Alternatives Program, Section E7.2

Table 13: 2020-2024 Budget (Actual/Bridge/Forecast) Copeland TS – Phase 2 ($ Millions)

	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Copeland TS – Phase 2	7.5	35.1	26.5	6.3	4.0	0	0	0	0	0

An engineering, procurement, and construction (EPC) contractor was selected through a competitive bid process in 2020 and the vast majority of the project costs are incurred in the 2020-2024 rate period. Phase 2 of Copeland TS is expected to complete in early 2024, therefore no expansion cost is forecasted for the period of 2025-2029. Table 14 below summarizes the annual spending on Copeland Phase 2.

Table 14: Copeland Phase 2 Annual Budget Comparison ($ Millions)

Year	Initial Budget (EB-2018-0165)	Current
2017	0.5	0.3
2018	1.8	0.2
2019	7.8	3.5
2020	8.9	7.5
2021	29.7	35.1
2022	38.8	26.5
2023	1.0	6.3
2024	0	4.0
Total	**88.5**	**83.4**

Overall, the total project cost is expected to be $5.1 million below the initial total project cost and the contingency portion of the budget is not utilized. Cost savings arise primarily from more efficient execution and labour expenses, better procurement agreements for major equipment, and experience with execution and incorporation of lessons learned from Copeland Phase 1.

The EPC contractor selection took slightly longer and EPC contractor started work in 2020, whereas it was initially planned in 2019. Thus, the entire schedule and spending profile is shifted later by approximately a year. Costs were lower in 2019 due to planned design work by the EPC contractor starting in 2020 rather than 2019.

In mid-2020, the EPC contractor mobilized to site and pre-construction works and evaluation of existing site conditions was completed. By end of 2020, design progressed to 50 percent and procurement operations commenced. Project management and ancillary costs ramped up in 2020 and continued throughout to the end of the project.

In 2021, project spending was $5.4 million higher than initial plan due to completion of the majority of procurement of major electrical assets slightly ahead of plan. In particular, three Medium Voltage ("MV") Gas-Insulated Switchgears ("GIS"), three MV Air-Insulated Switchgears ("AIS"), High Voltage ("HV") cable, MV cable, and Protection and Control ("P&C") control equipment were delivered to site in 2021. Manufacturing was underway for the three Gas-Insulated Transformers ("GIT") and approximately 47 percent of their costs were incurred by end of 2021. Furthermore, all design was completed (except for 2 percent remaining on mechanical and structural design and a few electrical studies.)

Assembly, installation, testing, and commissioning of the three GIS and three AIS was completed in 2022. In addition, the three GITs were delivered to site from Japan in late 2022. Installation of HV and MV cable, P&C equipment and GITs progressed. Spending in 2022 was $12.3 million lower than initial plan due some procurement work completed earlier in 2021, and electrical equipment construction work continuing into 2023.

Spending in 2023 is $5.3 million higher than initial plan due to construction work continuing into 2023 whereas they were planned to be completed in 2022 in initial version. In particular, assembly, installation, testing, and commissioning of the three GITs and P&C equipment continued into 2023. Energization of major electrical equipment, including all three GITs, will be carried out in 2023.

Full system integration testing will commence near the end of 2023 and continue into 2024. Project closeout, site restoration and final site landscaping works is expected to be completed in early 2024.

2020-2024 Variance Analysis – Hydro One Contributions

Table 15 below provides the 2020-2024 variances for each project requiring Hydro One Contributions, as compared to the 2020-2024 DSP. Toronto Hydro forecasts an overspending of $7.1 million relative to the $53.3 million forecasted in the 2020-2024 DSP.

Table 15: Hydro One Contributions 2020-2024 Variances ($ Millions)

Subsegments	2020-2024 Planned	2020-2024 Actual/Forecast Cost	Variance
Horner Expansion	34.4	29.2	-5.2
Hydro One Transformer Upgrades	3.1	6.3	+3.2
Finch TS B-Y Bus Replacement	4.1	0	-4.1
Reactive Hydro One Contribution and True-Up Costs	11.7	24.9	+13.2
Total	**53.3**	**60.4**	**+7.1**

1. Horner TS Expansion

In the 2020-2024 rate application, Toronto Hydro forecasted a $34.4 million capital contribution to Hydro One for the Horner TS expansion based on a Class C estimate provided by Hydro One at the time. The actual costs incurred over 2020-2024 was $29.2 M, but a true-up payment may be required in the 2025-2029 rate period.

2. Hydro One Transformer Upgrades:

Over the 2020-2024 rate period, Toronto Hydro forecasts to contribute $6.3 million to Hydro One to upgrade existing Hydro One-owned power transformers. This will result in an overspend of $3.2 million compared to the forecast of $3.1 million in the 2020-2024 rate application. The projects are driven by Hydro One sustainment plans and new customer connections. Major sources of variance are as follows.

- **Carry-over transformer upgrades from the 2015-2019 rate period:** additional $2.7 million for lagging payments or to complete work initially forecasted to be complete by 2019, at Cecil TS, Dufferin TS, and Main TS.
- **Additional transformer upgrades:** additional $1.8 million capital contribution to Hydro One to upgrade transformers at Bridgman TS and Strachan TS, which was not included in the 2020-2024 DSP due to the timing of Hydro One's sustainment plans.
- **Variances to costs of proposed projects:** less $1.5 million capital contribution to Hydro One for planned transformer upgrades at Charles TS, Duplex TS, and Windsor TS. Hydro One is forecasted to charge an additional $1 million for the Charles TS transformers, the Duplex TS transformers have been deferred to the 2025-29 rate period, and Hydro One did not charge to upgrade the transformers at Windsor TS due to downsizing other equipment.

3. Finch TS B-Y Replacement

In the 2020-2024 rate application, Toronto Hydro proposed to replace Finch BY bus in coordination with Hydro One for a contribution of $4.1 million; however, Hydro One deferred the BY replacement to beyond 2025. To address a progressing failure risk, Toronto Hydro decided to replace the end-of-life circuit breakers and disconnect switches on the BY bus instead of waiting for the entire BY bus to be replaced.[29] Therefore, by pursing this alternative through the Stations Renewal Program, this Hydro One Contribution was never made and resulted in a variance of -$4.1 million.

4. Reactive Hydro One Contribution and True-Up Costs:

In the 2020-2024 rate application, Toronto Hydro allocated $11.7 million for reactive Hydro One contributions to support expansion projects or true-up costs unforeseen at the time of the application. Toronto Hydro forecasts to contribute $24.9 million over the 2020-2024 rate period for these reasons, resulting in an overspend of $13.2 million.

Pursuant to applicable cost recovery agreements (including criteria regarding cost reconciliation review), Toronto Hydro incurred $9.9 million to reconcile past Hydro One capital contributions to Copeland TS Phase 1. Such reconciliations are typically based on actual asset or station loading and project in-service anniversaries, making the costs difficult to forecast in advance. In particular for this project, $5.7 million was incurred due to reduced station loading, and $4.2 million was incurred due to additional spend by Hydro One relative to their CCRA estimate.[30]

Toronto Hydro forecasts to contribute $10.9 million to Hydro One for the following expansion projects which could not be estimated at the time of the previous application.

- **Switchyard expansions at Bermondsey TS and Richview TS:** These projects will expand the switchyards at the respective stations by six and four circuit breakers, permitting new feeders to access stranded station capacity. A forecasted $8.5 million capital contribution is required.
- **New supply cable between Carlaw TS and Gerrard TS:** This project will increase the capacity of Carlaw TS by 20 MVA and resulted in a Hydro One contribution of $2.4 million.

[29] Please refer to the Stations Renewal Program Section E6.6.4.1 "TS Segment Expenditure Plan", subsection "TS Outdoor Breaker – 2020-2024 Variance Analysis".
[30] Connection Cost Recovery Agreement

Finally, Toronto Hydro has allocated a remaining $1.9 million in 2024 for additional unforeseen Hydro One Reactive contributions, in the form of cost variances from current forecasts.

E7.4.4.2 2025-2029 Expenditures - Downsview TS

Toronto Hydro forecasts to spend $70.2 million on Downsview TS during the Planning and Preparation stage over the 2025-2029 rate period, and expects to spend another $70 million over the Construction and Energization stage over the 2030-2034 rate period. Downsview TS is expected to complete in late 2033. An annual breakdown of the expenditures is shown below in Table 16.

Table 16: 2025-2029 Budget Downsview TS ($ Millions)

	Forecast – Planning and Preparation					Forecast – Construction & Energization				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Downsview TS	3.2	3.9	9.6	25.9	27.7	30.7	24.0	7.6	7.7	--

1. Downsview TS – Planning and Preparation

The Downsview TS project will be a large and complex project for Toronto Hydro, with only the Copeland TS project being comparable.

The Planning and Preparation stage will involve the portion of work completed in the 2025-2029 rate period, which will involve the: procurement and preparation of a new site, installation of 230 kV station assets, new building construction, and partial work on remaining station assets. The expenditures for this scope are forecasted to total $70.2 million over the period with $14.6 million included in the rate base when civil assets are completed. The remaining forecasted spend is related to electrical assets which will be energized when the station is completed in 2033, and will not be included in the rate base until such time.

There are four major activities to be completed in the 2025-2029 rate period: contractor Request for Proposal ("RFP"), design and engineering, major asset procurement, and construction or installation of some major assets.

A summary of the Downsview TS – Planning and Preparation stage schedule and annual cost is provided below in Table 17: Summary Schedule and Annual Cost of Downsview TS – .

Table 17: Summary Schedule and Annual Cost of Downsview TS – Planning and Preparation

Year	Budget ($ Millions)	Work Schedule
2025	3.2	• Partial Property Acquisition and Site Preparation
2026	3.9	• Completion of Property Acquisition and Site Preparation • Design of 230 kV bus work and disconnect switches
2027	9.6	• Procurement of 230 kV bus work and disconnect switches • Design of 230 kV circuit breakers and procurement • Design of 230 kV underground circuits and supporting civil structures • Design of switchgear building • Procurement of construction equipment and materials for new building
2028	25.9	• Installation of 230 kV bus work and disconnect switches • Partial installation of 230 kV circuit breakers and foundations • Partial construction of civil structures for 230 kV underground circuits • Partial construction of switchgear building • Partial design of power transformers, foundations, fire walls, fire suppression, and oil containment systems
2029	27.7	• Completed installation of 230 kV circuit breakers and foundations • Continued construction of civil structures for 230 kV underground circuits, and partial procurement of 230 kV circuits and protection systems • Completed construction of switchgear building • Completed design for power transformers and supporting assets • Partial procurement of first power transformer • Procurement of materials for power transformer foundations and oil containment systems • Design and partial procurement of 27.6 kV switchgear • Design and partial procurement of station AC, DC, and ancillary services

2. Downsview TS – Construction and Energization

The Construction and Energization stage will involve work completed starting in 2030 until commissioning of the new station in 2033. Work in this stage will involve the: completion of 230 kV underground circuits, installation of power transformers, installation of switchgear, installation of station services, and overall commissioning. The expenditures for this scope are estimated to total $70 million over the period.

A summary of the Downsview TS – Construction and Energization stage schedule and annual cost is provided below in Table 18.

Table 18: Summary Schedule and Annual Cost of Downsview TS Construction and Energization Stage

Year	Budget ($ Millions)	Work Schedule
2030	30.7	• Completed construction of civil structures for 230 kV underground circuits • Completed procurement of 230 kV circuits and protection systems • Partial installation of 230 kV circuits and protection systems • Installation of foundations and oil containment systems of power transformers • Partial procurement of first and second power transformers • Delivery of 27.6 kV switchgear • Completed procurement and partial installation of station AC, DC, and ancillary services
2031	24.0	• Completed installation of 230 kV circuits and protection systems • Delivery and installation of first power transformer • Partial procurement of second power transformer • Installation of fire wall between first and second transformer • Partial installation of 27.6 kV switchgear • Completed installation of station AC, DC, and ancillary services

Year	Budget ($ Millions)	Work Schedule
2032	7.6	• Delivery and installation of second power transformer • Completed installation of 27.6 kV switchgear
2033	7.7	• Installation of fire suppression systems for power transformers • Final commissioning of power transformers, 27.6 kV switchgear, and integrated protection systems with Hydro One

E7.4.4.3 2025-2029 Expenditures - Hydro One Contributions

Toronto Hydro forecasts to spend $51.7 million on Hydro One capital contributions over the 2025-2029 rate period. The expenditures include contributions to Hydro One for stations expansions and for transformer upgrades. These projects are planned based on the Needs Assessment (see below at Section 7.4.7 Regional Planning Needs). Additionally, contributions towards the Hydro One-owned Downsview SS are included. /C

Table 19: 2020-2029 Budget (Actual/Bridge/Forecast): Hydro One Contribution ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Horner TS Expansion	8.5	5.0	15.7	--	--	--	--	--	--	--
Finch TS B-Y Bus Replacement	--	--	--	--	--	--	--	--	--	--
Downsview SS	--	--	--	--	--	--	0.6	1.7	2.9	0.6
Sheppard TS Bus Expansion	--	--	--	--	--	--	0.5	4.5	5.0	5.0
Manby TS DESN Reconfigurations	--	--	--	--	--	--	0.5	3.5	4.0	4.0
Hydro One Transformer Upgrades	1.1	--	2.5	2.5	0.2	4.3	0.4	1.6	1.6	1.6
Reactive Hydro One Contributions & True-Up Costs	1.1	10.1	2.5	9.0	1.9	3.5	2.0	1.3	1.3	1.3
Total	**10.7**	**15.1**	**21.0**	**11.5**	**2.1**	**7.8**	**4.0**	**12.6**	**14.8**	**12.5**

/C

/C

1. Hydro One Switching Station for Downsview TS

Based on high level estimates from Hydro One, Toronto Hydro forecasts to contribute $5.8 million over the 2025-2029 rate period to Hydro One as an initial contribution towards Hydro One's Downsview Switching Station ("Downsview SS"). Downsview SS is expected to be largely constructed during the 2030-2034 period. As a result, Toronto Hydro is only forecasting expenses over the 2025-2029 rate period to be associated with the procurement of land for and the site preparation of the new SS.

Table 20: Downsview TS Expansion Hydro One Payment Breakdown

Project	Expenditures ($ Millions)	Payment Year
Downsview SS	0.0	2025
	0.6	2026
	1.7	2027
	2.9	2028
	0.6	2029

/C

2. Sheppard TS Bus Expansion

In order to install a new bus at Sheppard TS, Toronto Hydro forecasts to contribute $15.0 million to Hydro One over the 2025-2029 rate period. The forecasted annual expenditures are provided in Table 21 below.

Because this project is still in its early stages, Hydro One has not been able to provide Toronto Hydro with a cost estimate at the time of this filing. However, Toronto Hydro has estimated expenditures based on the scope of work, which is similar to its TS switchgear installations from its Stations Renewal Program and from its Copeland Phase 1 and Phase 2 expansion projects.

The scope of work includes the installation of a new gas-insulated switchgear (GIS) comprised of six feeder circuit breakers, three padmounted feeder-tie disconnect switches, P&C devices, and a new building to house the GIS and P&C devices.

Table 21: Sheppard TS Bus Expansion Hydro One Payment Breakdown

Project	Expenditures ($ Millions)	Payment Year
Sheppard TS Bus Expansion	0	2025
	0.5	2026

Project	Expenditures ($ Millions)	Payment Year
	4.5	2027
	5.0	2028
	5.0	2029

3. Manby TS DESN Reconfigurations

In order to replace two Jones switchyards with one Bermondsey switchyard at Manby TS, for both capacity and renewal benefits, Toronto Hydro forecasts to contribute $12.0 million to Hydro One over the 2025-2029 rate period. The forecasted annual expenditures are provided in Table 22 below.

This project is still in its planning phase with Hydro One, due to the need to coordinate with and adapt Hydro One's existing T13/T14 transformer upgrade plans, which they have proposed for 2030. Because the T13/T14 upgrade is planned to take place seven years into the future from the time of this filing, Hydro One has not been able to develop a scope of work at this time. Similarly, Hydro One also has not been able to provide Toronto Hydro with a cost estimate at the time of this filing.

As a result, Toronto Hydro has estimated the scope of work involved, and has used this to estimate the needed Hydro One contributions. Consequently, there is more uncertainty in this expenditure forecast compared to the other projects proposed in this Program.

However, Toronto Hydro will need to provide its capital contribution to Hydro One during the 2025-2029 rate period, and that the capital contribution for this project will be too substantial to be managed by the Reactive Hydro One Contributions subsegment. Therefore, Toronto Hydro has elected to budget for this project separately, and has produced the best expenditure forecast it can with the information available at this time.

Table 22: Manby TS DESN Reconfigurations Hydro One Payment Breakdown

Project	Expenditures ($ Millions)	Payment Year
Manby TS DESN Reconfigurations	0	2025
	0.5	2026
	3.5	2027
	4.0	2028
	4.0	2029

4. Hydro One Transformer Upgrades

Toronto Hydro forecasts to contribute $9.5 million to Hydro One over the 2025-2029 rate period, in order to upgrade certain end-of-life transformers during their natural renewal projects. Table 23 below outlines the contributions to Hydro One by project, and the year the contribution is expected to be made.

The cost for each project was forecasted based on the actual costs of transformer upgrade projects completed or in-progress over the 2020-2024 rate period. The timing of each project has been provided in the NA assessment, which has been used to forecast when each capital contribution will be required, based on historical timing trends.

Table 23: Hydro One Transformer Upgrades Payment Breakdown

Hydro One Transformer Upgrades	Expenditures ($ Millions)	Payment Year
Basin TS – T3/T5	1.6	2025
Carlaw TS – T1/T2	1.6	2029
Duplex TS – T1/T2	1.6	2025
Duplex TS – T3/T4	1.6	2028
Leslie TS – T1	0.3	2025
Scarborough TS – T23	0.4	2026
Strachan TS – T14	0.8	2025
Strachan TS – T13/T15	1.6	2027

5. Reactive Hydro One Contributions

As noted in Section E7.4.4.1, **2020-2024 Variance Analysis – Hydro One Contributions**, Toronto Hydro forecasts to contribute $24.9 million over the 2020-2024 rate period towards Reactive Hydro One Contributions. This subsegment was first introduced during the 2020-2024 CIR based on previous experience of funding shortfalls as new, unbudgeted, Hydro One projects were initiated, or as unexpected Hydro One true-up costs were billed to Toronto Hydro. Examples of such Hydro One projects include transformer or cables upgrades, or the installation of new circuit breakers, which result in an incremental increase in capacity.

As predicted, there were indeed significant unexpected projects and true-up costs which developed during the 2020-2024 rate period, and the Reactive Hydro One Contributions subsegment is

forecasted to mitigate (approximately half of) the unexpected spending in the Hydro One Contributions segment, as intended. Therefore, Toronto Hydro proposes this subsegment continue into the 2025-2029 rate period, as a continued mitigation measure since it again anticipates a need in the 2025-2029 rate period.

To this end, Toronto Hydro has allocated $9.4 million over the 2025-2029 rate period towards Reactive Hydro One Contributions. The annual expenditures are provided in Table 24 below.

Table 24 : Reactive Hydro One Contributions Annual Allocations

Subsegment	Expenditures ($ Millions)	Payment Year
Reactive Hydro One Contributions	3.5	2025
	2.0	2026
	1.3	2027
	1.3	2028
	1.3	2029

E7.4.5 Options Analysis

Toronto Hydro has identified and evaluated various options to address system needs, as outlined in the below sections.

E7.4.5.1 Options Comparison for the Downsview Area

To address the forecasted need for additional capacity in the Downsview area, Toronto Hydro considered several options including: Status Quo, Load Transfers, Non-Wires Solutions, Station Upgrades, New DESN(s), and a new Downsview TS. The key results of the Options studied are summarized in Table 29. Options were considered in order of increasing level of intervention, until an acceptable option was identified. Option 6 – building the new Downsview TS is the only option capable of meeting system needs with reasonable risks and quantity of load transfers. See Exhibit 2B, Section E7.4, Appendix A – Downsview Business Case for further details of the assessment of these options.

The options were assessed as follows:

- **Option 1 – Status Quo** was rejected. Status quo is never recommended when capacity constraints are identified, but this option illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress.

- **Option 2 – Load Transfers** was also rejected as it is only viable up until 2034. /C

- **Option 3 – NWSs** was rejected because it would not provide a long-term solution and had a very high execution risk. NWSs are designed to address short-to-medium term capacity constraints. The quantity of load that needs to be addressed is at a magnitude well in excess of levels achieved and planned to date (e.g. 10 MWs achieved and 30 MW planed compared to a need for 93 MW by 2044 and 162 MW by 2049).[31] /C

- **Option 4 – Station Upgrades** was considered, but all station equipment in the Downsview Area is already sized to maximum ratings and cannot be further upgraded. Therefore, this option is technically infeasible and was rejected.

- **Option 5 – New DESN(s)** was considered for each of the four existing stations within the Downsview Area; but only Finch TS could accommodate a new DESN. Although possible, a new DESN at Finch TS would be especially difficult to utilize effectively in the Downsview Area, due to: existing congestion, geographic barriers, and distance from the DASP area. These challenges translate into high execution risks, an expectation of stranded capacity at Finch TS (inaccessible to the rest of the Downsview Area), and an expectation for higher than typical load transfer costs. Finally, because Finch TS is remote from the DASP area and is not central to the broader Downsview Area, this Option is forecasted to require a high quantity of load transfers, specifically 129 MW by 2044 and 192 MW by 2049, to redistribute the new capacity across the Downsview Area. As a result of the many significant risks, challenges, and inefficiencies presented by Option 5, this Option was ultimately rejected. /C

- **Option 6 – Construction of Downsview TS** is the selected option. Because of the proposed placement of the new TS, it is suited to offload existing stations and directly supply the new DASP loads, which is the major driver of load growth in the broader Downsview Area. This results in a minimal execution risk in terms of addressing system needs once the new TS is in service. The construction of a new TS is a large and complex undertaking. Therefore, overall

[31] See E7.2.1.4

execution risk was evaluated as Medium. Because of the designed placement of the new TS, the required load transfers of this Option are less than in the previous Option 5 at: 55 MW by 2044 and 142 MW by 2049. Option 6 also includes a provision to address the risk of subsequent overloading in the long term by permitting a second DESN to be installed at the newly constructed TS, whereas no provision exists in Option 5. If if the second DESN is constructed by 2044, then the required load transfers of this option can be limited to 55 MW, rather than 142 MW by 2049.

/C

Table 25: Summary of Options Outcomes for the Downsview Area

Option (Increasing in Level of Intervention)	Decision	Reason for Decision	Decision Criteria				
			Acceptable Long Term Solution	Cumulative Load Transfers or NWSs Required [by 2044/2049] (MW)	Operational + Customer Connection Risks	Execution Risk	Risk of Subsequent Overloading
1 – Status Quo	Reject	This Option is only viable as a short-term solution.	No	N/A – viable only for a short term	High	Medium	Forecasted Overload
2 – Load Transfers	Reject	This Option can only manage loading until 2034.	No	N/A – viable only for medium term	Low	Minimal	Forecasted Overload
3 – NWSs	Reject	NWSs are not designed to be long term solutions. Very high execution risk due to unprecedented quantity of NWSs needed.	No	93/162	High	Very High	Mitigated
4 – Station Upgrades	Reject	Technically infeasible: Station equipment is already sized to maximum ratings.	No	N/A	N/A	N/A	N/A
5 – New DESN(s)	Reject	High execution risks, likelihood of stranded capacity, and excessive quantity of load transfers drive the need for an alternative solution.	Yes	129/192	Minimal	High	Unmitigated
6 – New TS	**Accept**	Meets system needs with reasonable risks.	Yes	55/142	Minimal	Medium	Mitigated

/C

E7.4.5.2 Options for the Sheppard Area

In addition to the proposed option to address needs in the Sheppard TS Area, that is to install a new bus at Sheppard TS, two alternative options were considered: first, bus-tie reactors; and second, DER transfers. As mentioned in Section E7.4.3.2, 2. Sheppard TS Bus Expansion, the switchgear installed at Sheppard TS does not permit access to the switchgear bus that would allow the installation of a bus tie reactor. Therefore, due to technical limitations, this alternative option was rejected.

It is impractical, inefficient, and inconvenient for the affected customers to address short circuit capacity constraints through DER transfers to adjacent stations. For this option to be effective, Toronto Hydro would need to identify large DER customers, located near the border of a station's service territory, to be reconnected to a nearby station that has both sufficient thermal and short-circuit capacity. However, because of the geographical sparsity of large DER customers, it is rare to find enough such customers located near the border rather than in the interior. When such customers are located in the interior, there are notable drawback in pursuing the DER transfers option.

Let us consider the present case where Sheppard TS has a short circuit capacity constraint, and Malvern TS is technically available to reconnect large DER customers. In order to transfer a large DER customer located in the interior of the Sheppard TS territory, a feeder must run: from Malvern TS, through the boundary between Malvern and Sheppard TSs, and then into the interior of the Sheppard TS territory. Effectively, a Malvern TS feeder must extend further than any of the other Malvern TS feeders, and intrude into the Sheppard TS territory to reach the large DER customer. /C

Building such long feeder lengths results in high costs, reduced reliability of supply to the customer, and large voltage drops during feeder contingencies (planned or forced). Additionally, the intrusion of a feeder from another station results in unnecessary pole or cable chamber congestion, and the disruption of clear station service boundaries. For these reasons, the DER transfers option is impractical; however, the proposed option of installing a new bus addresses the short circuit capacity constraints and avoids these challenges.

The proposed option also introduces two large benefits not present with the alternative of DER transfers. First, the new bus at Sheppard will introduce an estimated 126 MVA of new short circuit capacity to the station, which not only will relieve the constraint, but will also provide new short circuit capacity to enable new DER growth at Sheppard TS. Second, the new bus will also introduce

95 MW of thermal capacity to the Sheppard Area to provide operational flexibility and support future demand driven by electrification. /C

In summary, the Sheppard TS bus expansion is the preferred option.

E7.4.5.3 Options for the Manby TS Area

The proposed Manby TS DESN reconfigurations project is being triggered by Hydro One's planned renewal and upgrade of its T13/T14 transformers as stated in the Needs Assessment, and by the upcoming need to renew the T3/T4 switchyard. As a result, there are only two options to consider are to either take advantage of the renewal opportunity to improve the station (as proposed), or to dismiss this opportunity.

For similar financial reasons as discussed with the Hydro One Transformer Upgrades subsegment in E7.4.3 Drivers and Need, if Toronto Hydro does not take the opportunity to improve the station during the upcoming renewal work, it will likely have to wait another 45 years before it has another opportunity to complete the proposed improvements or undertake upgrades at a significantly higher cost.

As discussed in the Manby TS DESN Reconfigurations subsection of E7.4.3 Drivers and Need, the proposed option has multiple short term and long-term benefits, related to capacity, reliability, and the execution of the renewal of Manby TS. Ultimately, this option will permit up to 139 MW of new capacity to be added in the long term. These benefits will be lost if the proposed DESN reconfigurations do not proceed.

Upon consideration of the FES, Toronto Hydro believes it is prudent to enable options to increase the capacity of Manby TS in the long term. Four of the six FES project that the Area will require additional capacity between 2035-2039. With the Horner TS expansion complete in the 2020-2024 rate period, there are presently no expansion options available in the Area other than the installation of a new TS, which was considered as the alternative to the Horner TS expansion.

To align with an investment philosophy of a least-regrets approach, Toronto Hydro should not dismiss the limited-time opportunity to enable Manby TS to be expanded in the future, when needed. In order to do this, Toronto Hydro must invest in the proposed Manby TS DESN reconfigurations project in coordination with Hydro One's T13/T14 transformer renewal project.

For this reason, and because of the other benefits discussed in E7.4.3 Drivers and Need, the proposed option was selected over the alternatives.

E7.4.6 Execution Risks & Mitigation

E7.4.6.1 Downsview TS

The Downsview TS segment is a large undertaking and involves multiple execution risks, which include:

- Given the complex nature of these projects, a host of inherent planning challenges and risks can impact overall project cost and execution, such as the length of time required to acquire permits;
- New Downsview TS site location and land purchase;
- Road moratoriums established by the City of Toronto;
- 230 kV U/G cable design and construction and Hydro One 230kV switching station design and construction – potential timeline issues;
- Engage Hydro One 230kV Switching Station Design and Construction;
- Logistical challenges in delivering electrical equipment into the city; and
- Coordination with distribution planners as well as with third parties.

Toronto Hydro will communicate key lessons learned from past projects to Downsview TS bidders during the RFP procurement process to mitigate project execution risks. In particular, Toronto Hydro will provide risk information associated with facility conditions and restrictions, logistical and transportation issues, unique specifications of major electrical equipment, and permitting issues. Coordination with Hydro One for switching station construction, the city new TS land and association on the new 230kV route will be the risks on the new TS's construction timeline.

Financial risks will be mitigated by pursuing a fixed-price, turn-key, EPC contract. A competitive bid process will result in a selection of one general contractor responsible for all the major tasks. This is expected to be completed in 2026.

Quality control risks will be mitigated via the use of reputable third-party firms with extensive electrical station construction experience to carry out verification and payment review/billing certification. A consulting engineering firm will be utilized to investigate and resolve emerging site issues and ensure that construction is carried out according to specifications.

E7.4.6.2 Hydro One Contribution

The following risks are associated with the execution of Hydro One contribution project:

- Schedule depends on Hydro One's ability to execute the work;
- Overall project cost is highly dependent on Hydro One estimates; and
- Additional tasks (such as installation of bus and feeder ties or other safeguard measures to protect Toronto Hydro assets during Hydro One asset replacement) may be identified during detailed equipment outage planning. If an identified task is performed by Toronto Hydro, it will increase the project's cost for Toronto Hydro.

To mitigate these risks, Toronto Hydro engages in active coordination with Hydro One through bi-monthly meetings and as-required on-site meetings with relevant stakeholders to remain aligned with Hydro One's latest sustainment plans.

E7.4.7 Regional Planning Needs

The following Table 26, Table 27, an dTable 28 (from the IRRP Needs Assessment Report), highlight the emerging needs that have been identified in the Toronto Region since the previous regional planning cycle, and reaffirms the near, medium, and long-term needs already identified in the previous RIP.[32] The tables below also highlight how the Stations Expansion program is expected to address these needs.

Table 26: New Needs Identified in the Needs Assessment

New Needs	Needs Assessment Section	Stations Expansion Program
End-of-Life (EOL) Assets	*7.1*	See E7.4.3.2, Section 2. – Hydro One Transformer Upgrades.
East Harbor / Port Lands Area and Basin TS – Transformation Capacity	*7.1.4*	Needs Assessment identified this need by long term planning, short term by replacing T3/5 with 100 MVA.

[32] See Exhibit 2B, Section B, Appendix A, B, C, D, and E for Regional Planning Reports.

1 **Table 27: Needs Identified in Previous RIP**

Needs Identified in Previous RIP	Needs Assessment Section	RIP Report Section	Stations Expansion Program
South-West Toronto – Station Capacity	7.2.1	7.2	Addressed with Horner expansion in 2020-2024 Stations Expansion plan.
Downtown District – Station Capacity	7.2.2	7.3	Addressed with Copeland TS - Phase 2 expansion in 2020-2024 Stations Expansion plan.
230 kV Richview x Manby Corridor – Line Capacity	7.2.3	7.4	Transmission network constraint. Not applicable to Toronto Hydro.
Supply Security – Breaker Failure at Manby West & East TS	7.2.4	7.6	Transmission network constraint. Not applicable to Toronto Hydro.
230/115 kV Leaside Autotransformer – Transformation Capacity	7.2.5	7.10	Transmission network constraint. Not applicable to Toronto Hydro.
Voltage Instability of 115 kV Leaside Subsystem	7.2.5	Identified in Central Toronto Area IRRP report – Appendix E	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Leaside x Wiltshire Corridor – Line Capacity	7.2.6	7.10	Transmission network constraint. Not applicable to Toronto Hydro.
230/115 kV Manby Autotransformers – Transformation Capacity	4.2.7	7.10	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Manby West x Riverside Junction – Line Capacity	7.2.8	7.10	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV Don Fleet JCT x Esplanade TS – Line Capacity	7.2.9	Identified in Central Toronto Area IRRP report – Appendix E	Transmission network constraint. Not applicable to Toronto Hydro.

1 **Table 28: End-of-Life Assets – Metro Toronto Region**

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Program
Fairbank TS: T1/T3, T2/T4 Transformers	*2022-2023*	EOL transformers and other HV equipment are identified at these stations for replacement with similar type equipment of the same ratings (discussed further in Section 7.1.1.1 of Needs Assessment).	Current 50/83 MVA transformer is largest 115-27.6 kV standard size.
Fairchild TS: T1/T2 Transformers	*2023-2024*		Current 75/125 MVA transformer is largest 230-27.6 kV standard size.
Leslie TS: T1 Transformer	*2023-2024*		Current 75/125 MVA transformer is largest 230-27.6 kV standard size.
Runnymede TS: T3/T4 Transformers	*2021-2022*		Proposed 50/83 MVA transformer is largest 115-27.6 kV standard size.
Sheppard TS: T3/T4 Transformers	*2019-2020*		Toronto Hydro determined increase in capacity to larger 75/125 MVA transformer was not required.
Bridgman TS: T11/T12/T13 Transformers	*2022-2023*	EOL Transformers and other HV equipment are identified at these stations for replacement with higher rated equipment, and are discussed further in Section 7.1.1.2 of Needs Assessment	Included in 2015-2019 Stations Expansion plan.
Charles TS T3/T4 Transformers	*2024-2025*		Included in 2020-2024 Stations Expansion plan.
Duplex TS: T1/T2 Transformers	*2023-2024*		Included in 2020-2024 Stations Expansion plan.
Strachan TS: T12 Transformer	*2020-2021*		Included in 2015-2019 Stations Expansion plan.
Bermondsey TS: T3/T4 Transformers	*2022-2023*	EOL Transformers and other HV equipment are identified at these stations where scope for replacement is to be further assessed, and are discussed further in Section 7.1.1.3 of Needs Assessment.	Identified as consideration for downsizing, therefore Not Applicable to Toronto Hydro. See section 7.1.1.3 of Needs Assessment for details.
John TS: T1, T2, T3, T4, T6 Transformers and 115 kV breakers	*2024-2025*		Included in 2020-2024 Stations Expansion plan.

EOL Asset	Replacement/ Refurbishment Timing	Details	Stations Expansion Program
Main TS: T3/T4 Transformers and 115 kV line disconnect switches	*2021-2022*		Included in 2015-2019 Stations Expansion plan.
Manby TS: T7, T9, T12 Autotransformers, T13 Step-Down Transformer and rebuild 230 kV yard	*2024-2025*		Transmission network constraint. Not applicable to Toronto Hydro.
115 kV C5E/C7E Underground Cable: Esplanade TS to Terauley TS	*2024-2025*	EOL Line section is identified for replacement with similar type equipment, and is discussed further in Section 7.1.1.4 of Needs Assessment.	Transmission network constraint. Not applicable to Toronto Hydro.
115 kV H1L/H3L/H6LC/H8LC: Bloor Street JCT to Leaside JCT	*2020-2021*		Transmission network constraint. Not applicable to Toronto Hydro.
115 kV L9C/L12C: Leaside TS to Balfour JCT	*2020-2021*		Transmission network constraint. Not applicable to Toronto Hydro.

E7.4.8 Flexibility Considerations

Depending on policy changes by all three levels of government, changes in customer preferences, and decarbonization efforts, there are a large range of outcomes from the energy transition which could impact Toronto Hydro's distribution system. For example, using the Future Energy Scenarios model, the impact of the high electrification/low efficiency scenario (NZ40 – Low) projects an unprecedented increase in system load which would translate into a significant level of additional investment for the Stations Expansion Program in order to meet such need. Table 29shows the estimated costs under this scenario.[33]

[33] See Exhibit 2B, Section D4, Appendix A – Future Energy Scenarios Overview and Appendix B – Future Energy Scenarios Report.

Table 29: Estimated Stations Expansion Investment Needed under Future Energy Scenarios NZ40-Low Efficiency Scenario

CIR Period	Estimated Investment Need ($M)[34]
2025-2029	95
2030-2034	191
2035-2039	527

/C

Scarborough TS Expansion

The Scarborough TS Expansion (included in Toronto Hydro's original evidence filed on November 17, 2023) entails installing a new Dual Element Spot Network ("DESN") to provide relief to the Horseshoe East area and support future load growth in this area. Growth in this particular area is driven in large part by the Golden Mile Secondary Development Plan ("GMSDP"). Adopted by the City of Toronto in 2020, the GMSDP which proposes a mixture of residential, commercial, and office building development in the area knowns as the Golden Mile – a 113 hectares (280 acres) piece of land, generally bounded by Victoria Park Avenue to the west, Ashtonbee Road/Hydro Corridor to the north, Birchmount Road to the East and an irregular boundary to the south, as shown in Figure 6 below.

/C

[34] This is the additional investment needed incremental to the 2025-2029 investment proposed in this Program, and incremental to the 2030-2034 expenditures forecasted for the Downsview TS and Scarborough TS expansion projects. No expenditures have been forecasted in this Program for 2035-2029. No inflation assumptions have been included.

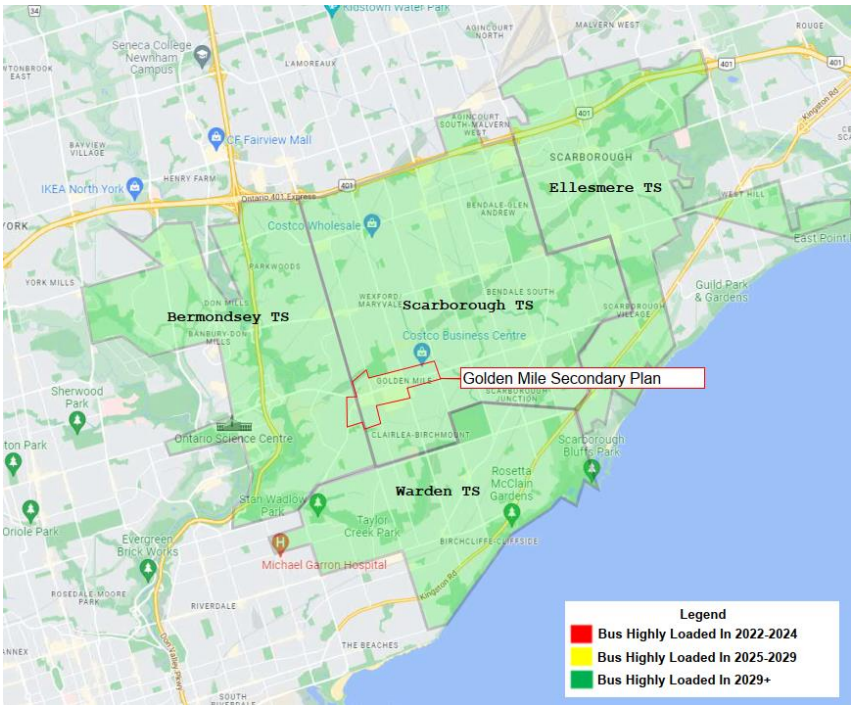

Figure 6: Service Territories of Stations in the Scarborough Area

Based on the updated System Peak Demand forecast filed on January 30, 2023, Toronto Hydro determined that the Scarborough TS expansion can reasonably be deferred from the 2025-2029 rate period and has amended its capital expenditure plan to exclude this investment. However, under different electrification assumptions (e.g higher uptake of electrified heat and transportation technologies), the Scarborough area could see faster and higher demand for electricity than currently expected. In an accelerated electrification scenario, as envisioned by the FES, Scarborough TS may require an expansion in the 2025-2029 period to ensure that grid is equipped to serve the evolving needs of customers in this area in the next decade and beyond.

If a higher need for electricity demand arises in the Scarborough area (or other parts of the City) due to faster uptake of electrified technologies or other growth drivers, Toronto Hydro needs to be able to invest to expand the capacity of its distribution system. The proposed regulatory flexibility mechanism (known as the Demand Related Variance Account outlined in Exhibit 1B, Tab 2, Schedule 1) would enable the utility to make additional prudent investments needed (such as Scarborough TS) in the 2025-2029 rate period.

/C

Downsview TS Business Case

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1 EXECUTIVE SUMMARY

Project Name	Costs	
Downsview TS	$	192.2 M

This project will address forecasted capacity constraints in the Northwest portion of the City due to confirmed large customer requests, the Downsview Area Secondary Plan, and electrification.

The proposed solution is to install a new TS, Downsview TS, in the Downsview Area, roughly between Bathurst TS and Finch TS. This location will permit the new TS to supply the new developments arising from the Downsview Area Secondary Plan, as well as offload the heavily loaded Bathurst, Fairbank, and Finch TSs.

The scope of work involves procuring new land for the new station, and constructing new 230 kV underground cables and duct banks from a Hydro One station, a new building, two new transformers, and one new switchgear. Downsview TS will provide 174 MW of new capacity to supply the Area.

The project is expected to start in Q1 2025 with an in-service date set to Q4 2033. Given the long lead time required to construct a new station, the project will be completed over two stages – Planning and Preparation during 2025-2029 and Construction and Energization over 2030-2034.

The project cost is estimated to be $76.0 million over the 2025-2029 rate period and $116.2 million over the 2030-2034 rate period, including Hydro One contributions and inflation assumptions. Only $14.6 million of the project's estimated cost are planned to be capitalized in the 2025-2029 rate period. These costs are related to the completion of site acquisition and preparation, and the completion of civil construction. The remaining project costs will be capitalized at the completion of the project once the station has been energized.

2 BACKGROUND

2.1 Existing Regional Growth

The area under consideration in this Business Case consists of Bathurst TS, Fairbank TS, Fairchild TS, and Finch TS. This area is shown in Figure 1. This area will be called the “Downsview Area” throughout the rest of this document.

In recent years, the Downsview Area has been attracting a large quantity of new load, a trend that is forecasted to persist into the future. On average, the Downsview Area is forecasted to grow by 1.2% per annum.

Table 1 shows the existing load forecast for the stations in the Downsview Area based on firm connection requests. A station is considered to be highly loaded once loading reaches 90% or higher.

Finch TS is forecasted to be highly loaded (past 90%) by 2029, and Fairbank TS is forecasted to reach the 90% threshold just after 2031. Fairbank TS has historically been highly loaded, and is being relieved by the recent expansion work at Runnymede TS; nonetheless, the station remains highly loaded and requires subsequent relief. /C

In addition to the impacts from the Peak Demand Forecast, Toronto Hydro is considering the longer-term impacts to the Downsview Area resulting from the Downsview Secondary Development Plan, and its Future Energy Scenarios outlooks. These are described in the subsections below. /C

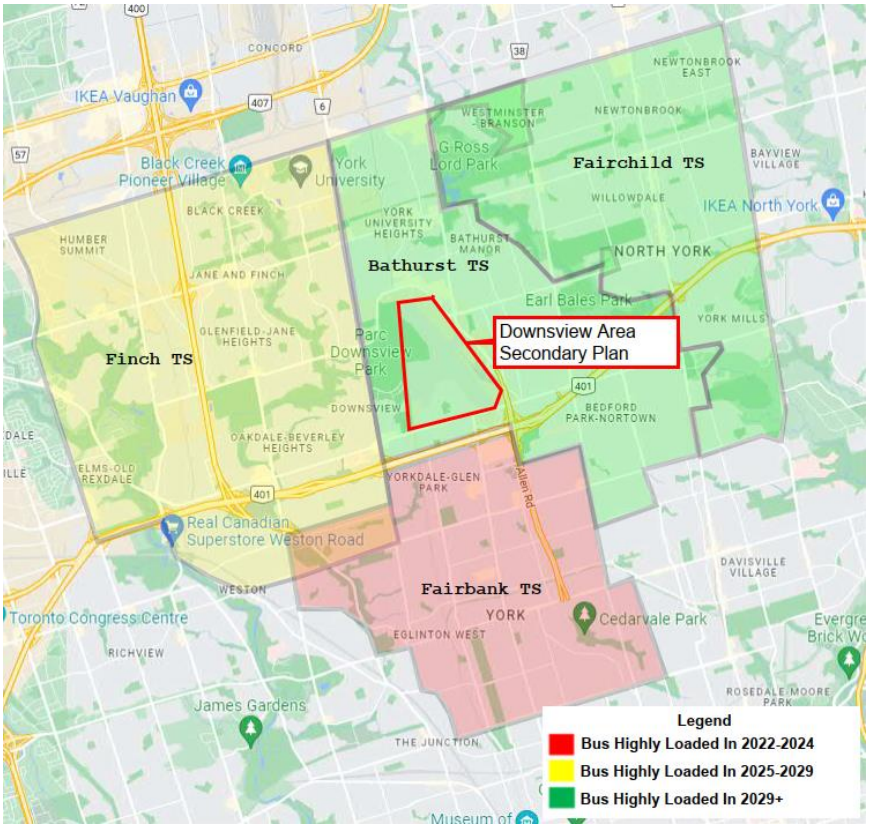

Figure 1 – Map of the Downsview Area and its Stations

Table 1 – Non-Coincident Downsview Area 10-Yr Load Forecast[1]

Station	Summer LTR (MW)	2021 (Actuals)	2022 (Actuals)	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bathurst TS	361	67%	70%	60%	64%	64%	67%	69%	70%	70%	70%	69%
Fairbank TS	182	104%	91%	77%	71%	80%	81%	80%	81%	84%	86%	88%
Fairchild TS	346	61%	64%	60%	61%	63%	64%	65%	66%	68%	70%	71%
Finch TS	366	69%	72%	78%	81%	84%	86%	87%	89%	91%	93%	95%
Area Non-Coincident %	1255	71%	72%	68%	69%	72%	74%	75%	76%	78%	79%	80%

/C

2.2 Downsview Area Secondary Plan

In 2017, the City of Toronto approved of the Downsview Area Secondary Plan ("DASP"). The area is generally bounded by Sheppard Avenue to the north, Allen Road to the East, Wilson Avenue to the south, and Downsview Park and the Park Commons to the west, as shown in Figure 2.

The DASP plans to expand each district with a mix of commercial, office, industrial and institutional buildings. Mid-rise buildings (10-14 storeys) will be built around the existing TTC Downsview station and lower mid-rise buildings (6-10 storeys). The Allen East District will be primarily be a residential area of 3,500 dwelling units.

DPM Energy, an independent party, has completed a preliminary study which estimates the electrical demand that will materialize from the DASP. This study suggests that load will begin to materialize in 2022 and could materialize up to: 103 MW by 2029, 180 MW by 2034, and 509 MW by 2051. This is equivalent to 8%, 14%, and 41% of the existing Downsview Area's Summer LTR of 1255 MW, as provided in Table 1. As a result, supplying the Downsview Lands with existing regional capacity will not be feasible without capacity investments.

[1] Loading from Toronto Hydro's Peak Demand Forecast. Summer LTR from Hydro One Needs Assessment Report, Toronto Region, Dec 2022.

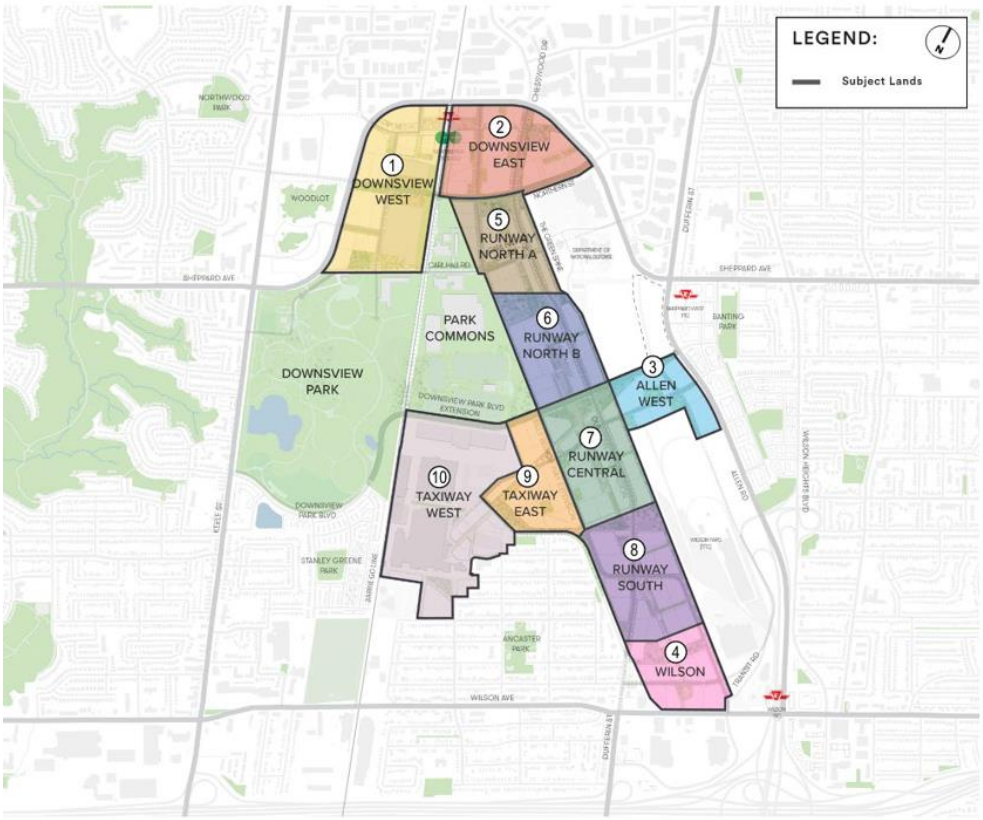

Figure 2 – Downsview Area Secondary Plan Map

2.3 Anticipated Future Loads

Toronto Hydro must ensure that its distribution system is capable of accommodating the anticipated load and generation growth in the City of Toronto. For the City of Toronto to achieve its TransformTO Net Zero Strategy targets, Toronto Hydro is anticipating the overall area load will grow by 40-70% over the next 20 years, largely due to the electrification of heating and transportation. As this transition occurs, Toronto Hydro must ensure that its distribution system is not a barrier to new customers looking to access its system, nor to existing customers looking to decarbonize.

Additionally, two existing large customers in the Downsview Area have approached Toronto Hydro to inquire about expanding their load by an additional 85 MW by 2030. These inquires have not been explicitly included in any forecasts. Although not yet firm requests, such inquiries corroborate the potential for the rapid load growth needed to achieve the TransformTO Net Zero Strategy targets, and the demand for capacity in the area.

Given the current highly-loaded state of the Downsview Area, the addition of the approved DASP, and the likelihood of rapid electrification underway, Toronto Hydro faces a large risk of either overloading its stations or of becoming a barrier to customers. Station loading can be managed in the short term, but medium and long-term solutions are needed to prepare for upcoming developments.

Options with several-year lead times (such as station expansion) must be considered far ahead of need to ensure that cost-effective solutions are pursued in a least-regret manner. Load relief plans for the Downsview Area should also consider the potential for future load growth, to ensure that investments are chosen to be cost-effective in the long term.

3 DOWNSVIEW AREA LOAD FORECAST – LOAD SENSITIVITY ANALYSIS

3.1 Peak Demand Forecast with Downsview Load

The Peak Demand Forecast only extends to 2031; however, as an additional approach to the sensitivity analysis, we will assume that the total Downsview Area load growth past 2031 is provided exclusively by the DASP. The NA forecast already includes consideration for the DASP up until 2031.

A preliminary study from DPM Energy estimates the electrical demand that will materialize from the Downsview Area Secondary plan. The annual load growth from this forecast over 2032-2051 was first adjusted to 70%[2], and then added to the 2031 station loads from the Peak Demand Forecast. The results are provided in Table 222, and referred to as the "25 Year Forecast" hereafter.

Table 2 - Estimated Station Loads under the 25 Year Forecast

Station	Summer LTR (MW)	2031	2034	2039	2044	2049	Year 100% Capacity is Reached
Bathurst TS	361	77%	81%	90%	99%	109%	2045
Fairbank TS	182	96%	101%	109%	118%	128%	2034
Fairchild TS	346	71%	71%	71%	71%	71%	N/A
Finch TS	366	99%	101%	105%	110%	115%	2032
Area Non-Coincident %	1255	85%	87%	92%	97%	103%	2046

/C

This forecast shows that by 2037, the Downsview Area as a whole will reach 90% loading, signaling a lack of capacity at the regional level. The forecast continues to show substantial load growth continuing past then, with no capacity remaining by 2046. Prior to that, 90% loading is forecasted at both Fairbank TS and Finch TS by 2031, and overloading by 2034. In summary, the 25 Year Forecast forecasts regional capacity constraints in the medium term, which worsen further into the long term.

3.2 Future Energy Scenarios

Depending on policy changes by all three levels of government, changes in customer preferences, and decarbonization efforts, there is a large range of outcomes which may impact Toronto Hydro's distribution system. To prepare for this range, Toronto Hydro commissioned the development of a long-term modelling tool known as Future Energy Scenarios or FES. The Future Energy Scenarios model projects what the demand would be under various policy, technology and consumer behaviour assumptions that are linked to the varying aspirations, goals, targets and constraints of decarbonizing the economy by 2040 or 2050.

[2] THESL's standard bus load forecasting methodology adjusts new customer load to 70% of the requested load in order to forecast bus load impacts.

Across the six modelled Future Energy Scenarios, Toronto Hydro expects that all but one station will become heavily loaded by 2035, and that the area as a whole will become overloaded between 2030 and 2037. Table 3 provides the station and area loading under the Future Energy Scenarios, and Figure 3 illustrates the area non-coincident loading under the Future Energy Scenarios. The Future Energy Scenarios do not specifically consider the DASP.

Table 3 – Non-Coincident Downsview Area Loading under Future Energy Scenarios

STATION	Summer LTR (MW)	2021	2024	2029	2034	2039	Year 100% Capacity is Reached[3]
Bathurst TS	361	67%	78-80%	82-89%	89-**101%**	95-**114%**	2034-N/A
Fairbank TS	182	**108%**	**114-117%**	**117-127%**	**124-142%**	**130-167%**	2021
Fairchild TS	346	62%	65-66%	67-72%	69-78%	70-84%	N/A
Finch TS	366	69%	**102-103%**	**109-116%**	**118-133%**	**124-150%**	2024
Area Non-Coincident %	**1255**	**72%**	**86-88%**	**91-98%**	**97-109%**	**102-122%**	2030-2037

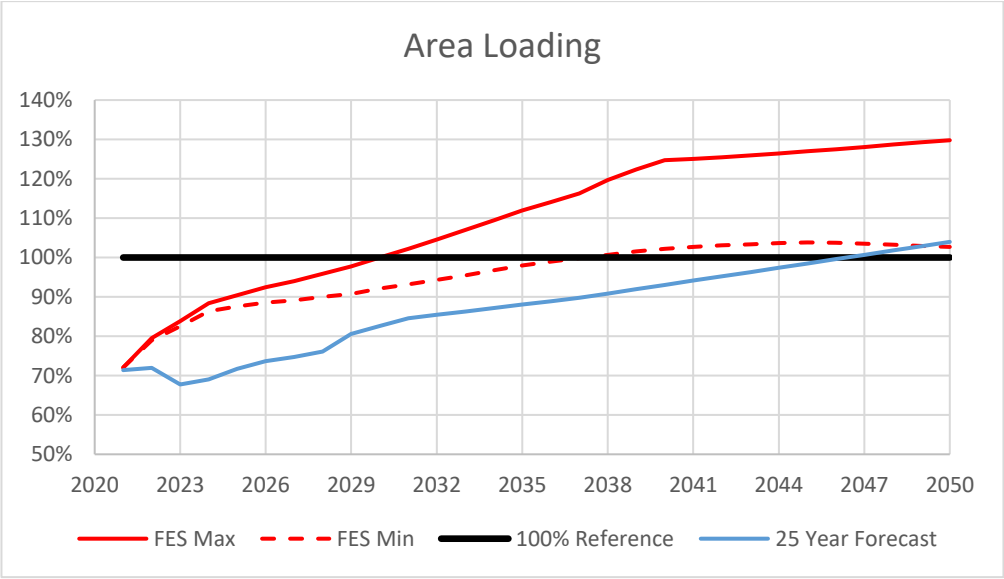

Figure 3 - Non-Coincident Downsview Area 20-Yr Loading from the Future Energy Scenarios Projections

3.3 Sensitivity Conclusions

Two approaches were considered to respectively assess loading impacts to the Downsview Area based on electrification, and the DASP. The first approach using the DASP shows regional constraints in the medium term, and the second FES approach shows regional constraints in the short term. This is marked

/C

[3] According to the Future Energy Scenarios output only. As a result, this year may be earlier than what is provided in the Peak Demand Forecast.

by overall Downsview Area loading reaching 90% or higher. Both approaches foresee regional loading increasing further past the 90% point to 100% or higher in the long term. /C

4 OPTIONS CONSIDERED

To address the needs of the Downsview Area, several options were considered, as outlined in the following subsections.

4.1 Option 1: Status Quo

In practice, the Status Quo option is never recommended when capacity constraints are identified. But this option establishes the minimal level of intervention which is feasible, and illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress.

This option proposes to complete the minimal work needed, and only when immediately needed, in order to maintain station loading throughout the Downsview Area at or below 100%. Specifically, this Option assumes that load transfers will be completed just as each station reaches 100% loading, and only to the extent to keep the station at 100% loading. As a result, load transfer projects will need to be initiated and completed on an annual basis, and as a prerequisite for each new customer connection.

According to the Peak Demand Forecast in Table 111 in Section 2.1, the Downsview Area will not reach 100% loading over 2024-31, and therefore this option is possible. However, this option also presents large operational and reliability risks.

The 25 Year Forecast forecasts Finch TS and Fairbank TS to become highly loaded (90%) by 2029 and 2030 respectively. Once highly loaded, customer connections become challenging to accommodate in a timely manner, particularly large customer connections (28+ MVA). Further, connection costs charged to individual customers tend to increase, since pre-requisite load transfers are commonly needed to accommodate the new customers. By 2034, both stations are forecasted to become overloaded (100%), and offloading to Bathurst TS would be needed just to maintain the stations. /C

In this manner, the cumulative load transfers needed according to the 25 Year Forecast are shown in Figure 4. Over 2033-39 load transfers increase by approximately 5 MW annually, and then increase by approximately 20 MW annually until 2046. In total, 178 MW in load transfers would be needed over 2033-2046. After 2046, the Downsview Area is forecasted to be overloaded, and this option is no longer feasible.

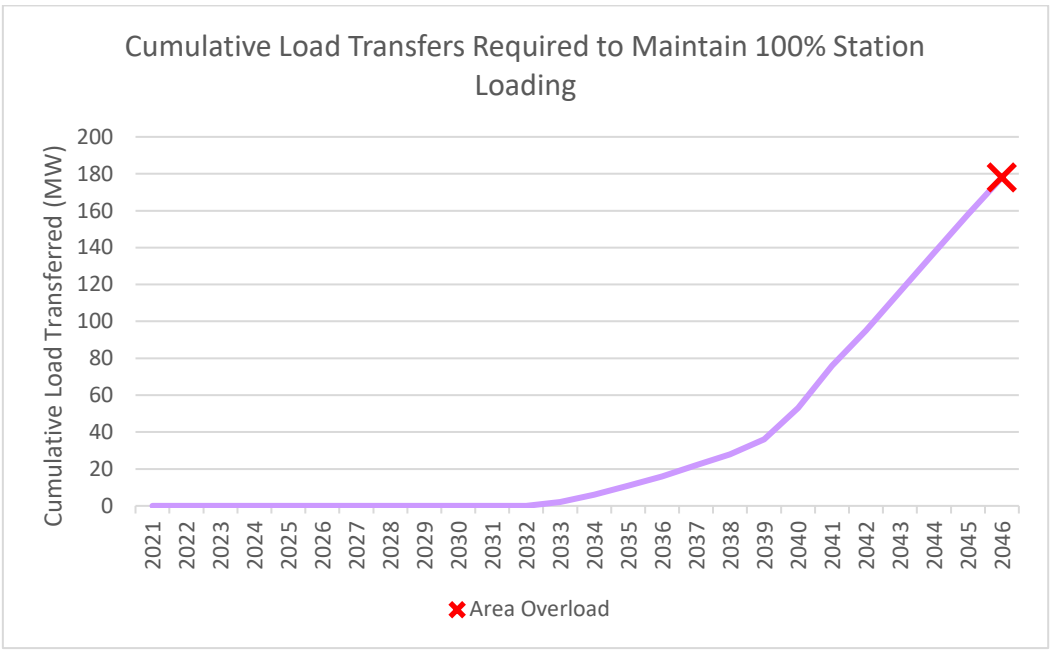

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Figure 4 – Cumulative Load Transfers Required Over Time

The FES projections predict a much more rapid load growth, and by contrast load transfers would be needed over the 2024-2037 period. The FES projections predict that the Downsview Area will become overloaded by 2030-2037.

Aside from the cost impacts needed to complete the load transfers, there is also substantial operational risk involved in running stations at 100% load. The lack of capacity at Toronto Hydro's stations results in two negative impacts. First, it prevents new customers from connecting to the grid and burdens customers with higher connection costs. Second, it reduces the reliability of the station and may result in load shedding. These impacts would result in a detriment to Toronto Hydro's "Customer Focused" performance outcomes.

When a customer submits a connection request to a highly loaded station, Toronto Hydro must either offload the station by first completing a load transfer, or connect the customer to a station with capacity located further away. Both options results in higher costs and timelines for customers to connect. When multiple neighbouring stations are highly loaded, these options become even more limited, and connection costs and timelines increase further. Since these load transfers must be completed on-demand as needed and in highly loaded areas, this option carries substantial execution risk which is expected to further increase connection timelines. /C

If a single station asset is lost at a station whose load exceeds capacity, then Toronto Hydro would need to shed load[4] to avoid damaging the remaining assets. Consequently, a lack of station capacity results in reduced reliability at the station, which affects tens of thousands of customers and typically 100-300 MW of customer load per station. Because of the significant impacts to customer connections and reliability, this option is only considered as a short-term, interim solution.

In conclusion, this option is not a feasible solution. It requires a high level of risk to be maintained and managed for an unacceptably long period. /C

[4] Load Shedding is the process during which Toronto Hydro temporarily shuts down power supply to a limited number of customers, in order to reduce its station load below its station capacity. Power supply is restored to customers when doing so would no longer result in an overload. When needed, load shedding is generally rotated across customers for a few hours each, so that no customers experience long duration outages while others experience no outages at all.

4.2 Option 2: Load Transfers

The Load Transfer option presents what is needed to maintain station loading in a state which does not adversely affect daily operations nor incumber new customer connections, using existing station capacity.

This option proposes to complete load transfers on a planned basis, once at the start of each 5-year rate application period, to maintain station loading throughout the Downsview Area at or below 90% over the period. This is done while regional capacity remains, in order to free station capacity ahead of load growth and new customer connections. As a result, capacity constraints will not be felt during each period.

Given the 25 Year Forecast provided in Table 112 of Section 3, the Downsview Area will reach 90% loading by 2037. Table 4 below shows that 14 MW in load transfers will be needed over the 2025-29 period, 76 MW will be needed over 2030-34, and following that the Area loading will surpass 90%. In total, 90 MW in load transfers would be required over 2025-2034 under this option.

Additionally, each FES Outlook estimates that the Downsview Area will exceed 90% loading by 2029. Therefore, this Option is only considered feasible up to 2034, with risk that this option may become infeasible by 2029.

Table 4 – Annual Load Transfers Required to Maintain Station Loading ≤ 90%

Annual Load Transferred (MW)		
2025-29	**2030-34**	**2035-39**
14	76	Above 90%

In conclusion, this option is not a feasible solution, since it can only be implemented up to 2034. To address needs in time for the 2035-2039 period, other options must be initiated in the 2025-2029 period.

4.3 Option 3: Non-Wires Solutions

This Option considers the possibility of addressing high loading and overloading within the Downsview Area using Non-Wires Solutions ("NWSs"), specifically the Flexibility Services segment. For further explanation on NWSs, please refer to the 2025-2029 Rate Application, E7.2 Non-Wires Solutions Program.

NWSs include the means to reduce the peak load of a targeted area, without increasing station capacity, and is designed to help address short-to-medium term capacity constraints. The Flexibility Services segment of the NWSs program includes local demand response ("LDR").

LDR is able to reduce peak load through contracts with customers or aggregators to reduce their load during times of peak demand. As a result, the quantity of peak load which can be addressed is limited by the capability of customers to reduce their demand on Toronto Hydro's distribution system. According to the 25 Year Forecast, 162 MW of LDR capacity would be needed by 2049 in order to maintain the Downsview Area loading at 90%. Such a large quantity of LDR capacity is unprecedented and is far beyond customer capability in the foreseeable future. For this reason, this option is not considered feasible as a long-term solution.

A key difference between LDR and other solutions, is that since it is a contracted service provided by customers or aggregators, LDR requires an annual cost. Therefore, as a long-term solution, it is possible for the cumulative LDR costs to exceed expansion costs. Similarly, because it is a contracted service, Toronto Hydro does not directly own any assets and faces operational and longevity risks due to dependency on third parties. For these reasons, LDR is best considered a short-to-medium term solution.

In conclusion, this option is expected to be able to address system needs in the short-to-medium term, but poses large long-term feasibility, operational, and financial risks.

4.4 Option 4: Station Upgrades

This option considers the possibility of expanding the capacity of existing DESNs in the Downsview Area by increasing the capacity of the limiting component(s) of the DESN. Such components may be: power transformers, secondary cables, circuit breakers, or buses. Generally, this allows for an incremental increase in station capacity.

All stations in the Downsview Area are already sized to their maximum ratings. Therefore, this option is not feasible.

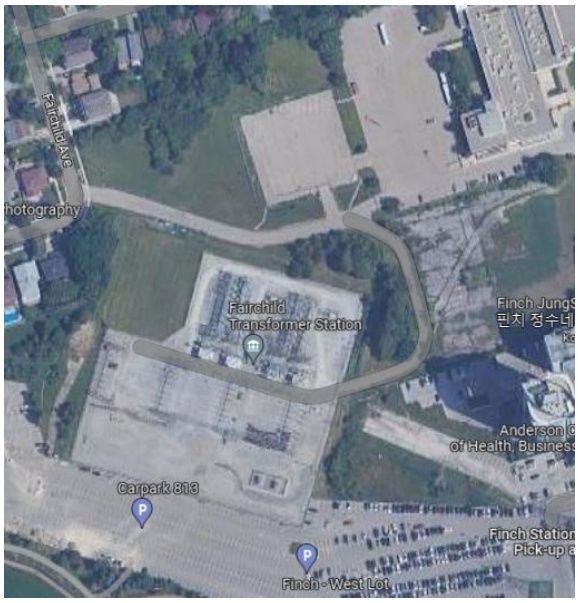
4.5 Option 5: New DESN(s)

This option considers adding one or more new DESNs at the existing stations in the Downsview Area, referred to as “station expansion”. A typical DESN provides 174 MW of new capacity and supplies 12 new feeders. This option provides the benefit of new capacity, but avoids the site procurement and transmission connection costs required of a new station.

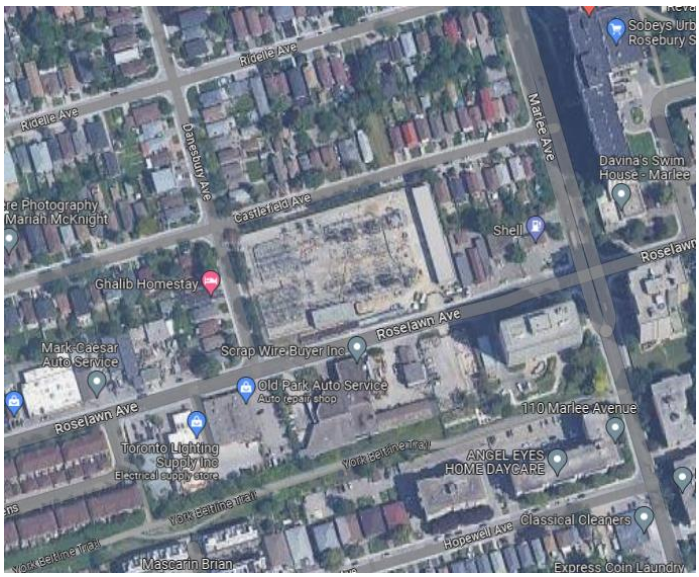
Of the four existing stations in the Downsview Area, only two have space surrounding the station which may potentially be considered for station expansion: Fairchild TS, and Finch TS. Bathurst TS and Fairbank TS are located in urban neighborhoods, surrounded by residential and small commercial buildings where expansion would not be feasible. Aerial views of the existing stations are provided in Figure 5 below.



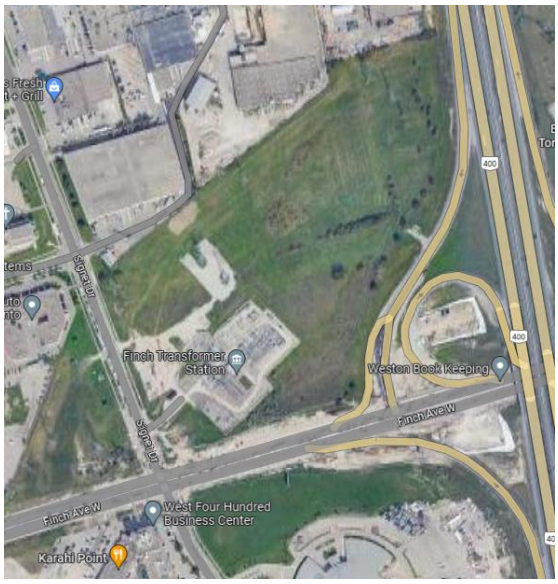
Bathurst TS



Fairchild TS



Fairbank TS



Finch TS

Figure 5 – Aerial Overview of Existing Stations in the Downsview Area

Although some space may be available at Fairchild TS, expansion of this station is not well suited to meet the needs of the Downsview Area. First, the existing spare land would likely be insufficient to install a new DESN, and likely new land would need to be procured towards its north, east, or south, which presents feasibility challenges. Those challenges aside, the location of Fairchild TS is also far from Fairbank TS and Finch TS which need load relief, as can be seen in Figure 1 in Section 2. As a result, load relief would have to be achieved by cascading load transfers through Bathurst TS. Similarly, Fairchild TS is also located away from the DASP area, making it challenging to connect the new loads to new capacity which would be installed at Fairchild TS. Finally, Fairchild TS already supplies two DESN and egresses 24 feeders. Egressing another 12 feeders effectively from the same location would present a significant design challenge.

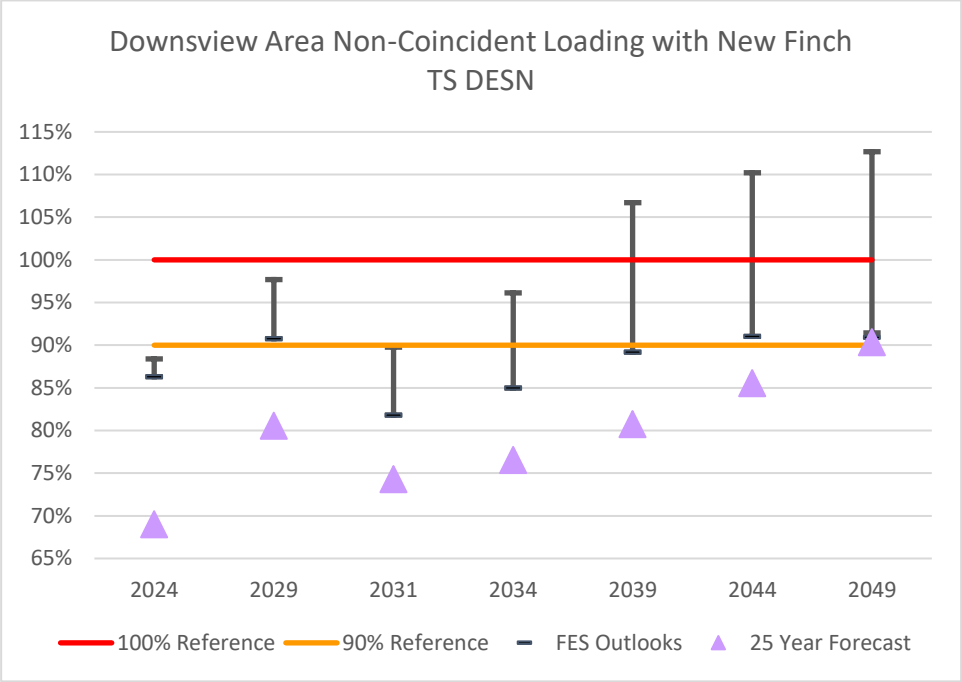
Finch TS has better land availability, and could likely accommodate another DESN, although it faces significant implementation challenges to be discussed later. Additionally, referring back to Figure 1 in Section 2, Finch TS could provide meaningful load relief to Bathurst TS, but not to Fairbank TS. Therefore, cascading load transfers[5] from Fairbank TS through Bathurst TS to Finch TS, would be needed to ultimately relieve Fairbank TS. This will ultimately magnify load transfer needs, discussed later and illustrated in Figure 888, reducing the efficacy of this option.

As a result of the above considerations, the expansion of Finch TS is the only technically feasible expansion option to consider, although it faces significant challenges in utilizing its new capacity. Therefore, the remainder of this option considers the impacts of an expansion only at Finch TS, and the risks involved.

Given a new DESN at Finch TS, Downsview Area loading is shown at 5-year intervals in Figure 666. Given the 25 Year Forecast, the addition of the new DESN will provide sufficient capacity until 2049. /C

[5] Cascading load transfer: When one station (“A”) cannot directly offload to a neighbouring station (“B”) with capacity, the station (“A”) must instead first offload to an intermediate station (“C”). Following this, the intermediate station (“C”) must transfer the same quantity of load to station (“B”) which has the available capacity. Ultimately, station (“A”) is offloaded by some amount, station (“B”) increases in load by the same amount, and station (“C”) experiences no change in load. This is process is called a cascading load transfer.

However, FES projections show that there is risk of Downsview Area overloading as early as 2036, and the magnitude of the potential overloading increases with time.



/C

Figure 6 – Downsview Area Loading with a New DESN at Finch TS

The scope of work involved is assumed to be completed entirely by Hydro One, with Hydro One owning all new assets. This is the standard for new Hydro One DESNs, which involve gas-insulated switchgear. Based on a similar expansion completed at Horner TS in 2022, the total cost in Hydro One Contributions is estimated to be $119 million with a project timeline of 6 years. The in-service date would therefore be Q1 2031. The annual estimated Hydro One Contributions are provided in Figure 7.

Because the 25 Year Forecast forecasts stations loading past 90% before the new DESN at Finch TS will be ready, this option assumes that the load transfers presented over 2025-29 in option 2 will be completed to manage station loading in the meantime. Once the DESN is ready in 2031, load transfers will again be needed to offload the existing stations onto the new DESN. Finally, although the new DESN will introduce capacity into the Downsview Area, it will not be situated to supply all new DASP load. As a result, load transfers will be needed again from 2035 onward in order to relieve Bathurst TS and/or Fairbank TS as they supply new DASP load. In total, 192 MW in load transfers are expected by 2049. The expected load transfers in 5-year increments are shown in Figure 888.

/C

/C

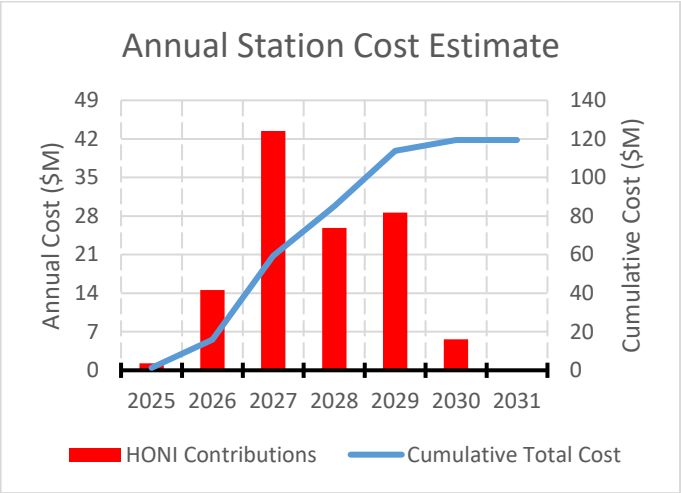


Figure 7 – Estimated Annual Hydro One Contributions for a new DESN at Finch TS

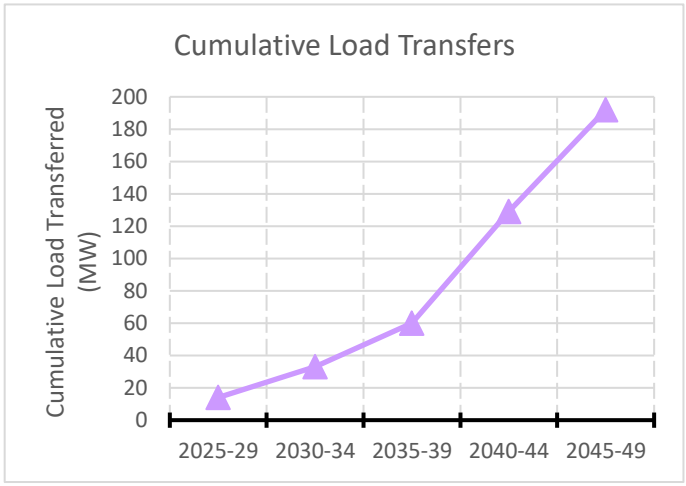


Figure 8 – Cumulative Load Transfers Required for a new DESN at Finch TS

/C

As an exercise intended to quantify the magnitude of load transfers needed, the above load transfer analysis does not consider the significant implementation challenges which are discussed below. Nonetheless, the analysis and Figure 888 show that an unprecedented load of 192 MW will need to be transferred over 25 years in order to make effective use of the new capacity installed in this option. Such a large level of needed load transfer to effectively utilize new capacity signals that the new capacity has been added in the wrong location within the Downsview Area.

/C

In addition to the large magnitude of load transfers needed, a solution at Finch TS would encounter several significant implementation challenges which jeopardize the success of this option in the long term. First, Finch TS already supplies two DESNs and would face similar egressing challenges as Fairchild TS. Second, the DASP area is at the limit of the reach of Finch TS. Given the magnitude of the load expected from the DASP and the distance, reliability and voltage drop concerns would prevent Finch TS from supplying the entire DASP load. Finally, the geographical barriers of Highway 400 and the linear parks that already divide the Finch TS and Bathurst TS service territories would limit the number of feeders that could be extended from Finch TS eastward, effectively bottlenecking new capacity. These geographical barriers are shown in Figure 9 and Figure 10.

/C

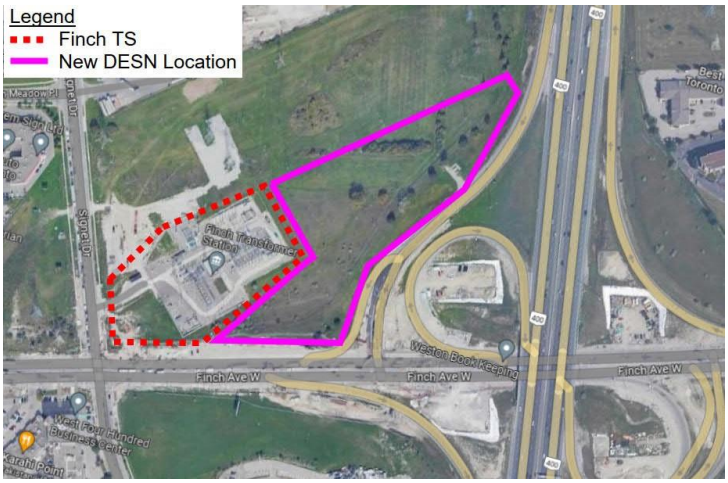


Figure 9 – Potential Location for New DESN at Finch TS

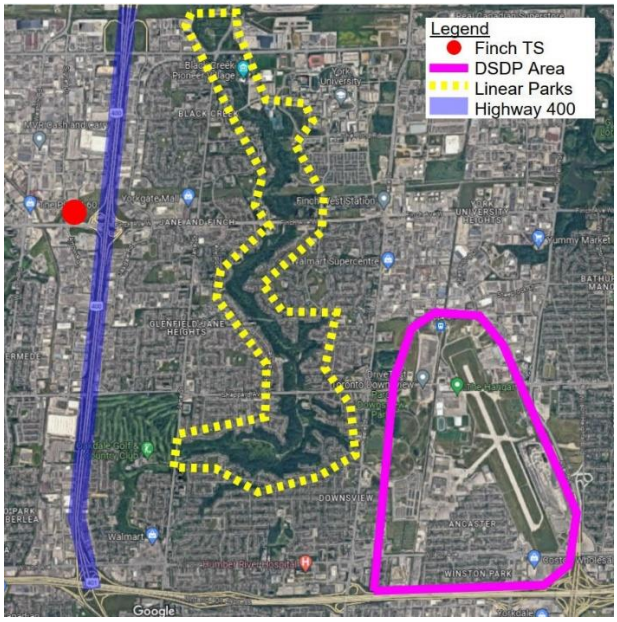


Figure 10 – Finch TS in Relation to the DSDP Area and Geographical Barriers

As a result of these implementation challenges and geographic barriers, there is a large risk that in the long term a significant portion of the new capacity installed at Finch TS will become stranded, while the adjacent Bathurst TS and Fairbank TS become overloaded. This risk is another signal that the new capacity has been incorrectly placed within the Downsview Area.

In addition to execution risk, this option carries a risk to cost which is expected to be even more likely to materialize. In order to overcome at least some of the challenges mentioned, and because of the high quantity of load transfers required, there is a high likelihood that the cost to complete the required load transfers will be significantly higher than average costs. Regarding the magnitude of load as being a driver of cost, this is because when large quantities of load are transferred, accompanying civil work such as new poles, duct banks, and/or cable chambers must be also be constructed.

In conclusion, the expansion of Finch TS is the only existing station in the Downsview Area which can accommodate an expansion. The expansion of Finch TS would introduce 174 MW of new capacity to the Downsview Area, and is expected to bring Downsview Area loading down to 90% until 2049. To achieve this outcome, an estimated $119 million in Hydro One Contributions is needed over 2025-2031, and an unprecedented 192 MW in load transfers is needed over 2025-2049. Because of congestion and geographical barriers, there is a high risk in achieving the total magnitude of load transfers required, which is expected to result in higher than average load transfer costs and stranding of the new capacity provided. The mentioned large risks and the need for an excess quantity of load transfers has motivated consideration of option 6, which seeks to add new capacity directly where it is needed. /C

4.6 Option 6: New Station (“TS”)

This Option considers building a new transformer station within the Downsview Area, in order to bring new capacity to the area. Because the station will be newly constructed, it can be situated to facilitate the offloading of adjacent stations and/or the connection of new loads.

In particular, this Option proposes to build a new transformer station, named “Downsview TS”, within or on the border of the DASP area. Not only will this facilitate supply of the DASP loads directly, but the DASP area is also located in proximity to all stations in the Downsview Area requiring load relief: Bathurst TS, Fairbank TS, and Finch TS. Therefore, a new station in the DASP area will also be well placed for

providing load relief. Similar to option 5, this option considers the installation of one new DESN providing 174 MW of new capacity and suppling 12 new feeders.

Given Downsview TS, the Downsview Area loading is shown at 5-year intervals in Figure 111111. Given the 25 Year Forecast, the addition of the new Downsview TS will provide sufficient capacity until 2049. However, FES projections show that there is risk of Area overloading as early as 2036, and the magnitude of the potential overloading increases with time. To mitigate the risk of overloading in the long term, Downsview SS (introduced below) is proposed to be constructed with the provision to install a second DESN in the future, if and when it is needed.

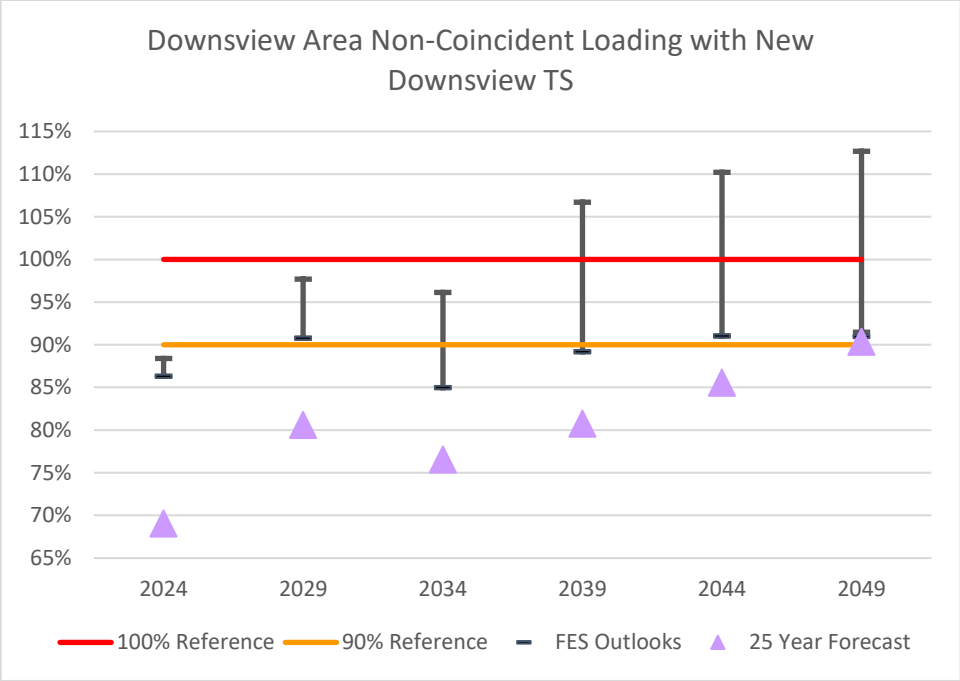


Figure 11 – Downsview Area Loading Following the Energization of Downsview TS

/C

The scope of work of this option involves both a Hydro One and Toronto Hydro portion. The Hydro One portion includes the construction of a new switching station ("Downsview SS") in the vicinity of the Hydro One right-of-way along Finch Ave W, which will serve as the supply and demarcation point for Toronto Hydro's new Downsview TS. The Toronto Hydro portion of work will include the procurement of land for Downsview TS and the construction of: 230 kV underground cables and duct banks from Downsview SS to Downsview TS, a new station building, two primary circuit breakers and transformers, and one switchgear. Because of the large scope of work, Downsview TS's in-service date is estimated to be Q4 2033, assuming it begins in Q1 2025.

Based on estimates of the costs for each major asset installed, and an estimated schedule of the project, an annual cost estimate was developed and is shown in Figure 11. The total cost over 2025-2033 is estimated to be $170 million, excluding inflation assumptions, comprising of $118 million in Toronto Hydro costs and $52 million in Hydro One Contributions.

Because the 25 Year Forecast forecasts stations loading past 90% before Downsview TS will be ready, this option assumes that the load will be completed over 2025-2033 to manage station loading in the meantime. Once Downsview TS is ready in 2034, load transfers will be completed to offload the existing stations. Because Downsview TS will be located in the vicinity of the DASP area, it will be able to directly supply the new loads without additional load transfers. As a result, no significant load transfers are

/C

anticipated until the Downsview Area loading is forecasted to reach 90% again in 2045. The expected load transfers in 5-year increments are shown in Figure 12.

In total, 55 MW in load transfers are expected by 2044, and 142 MW are expected by 2049. Load transfers increase in 2045 to prevent overloading at Downsview TS. An alternative to these subsequent load transfers is to install a second DESN at Downsview TS, whose provision will be included as part of this option.

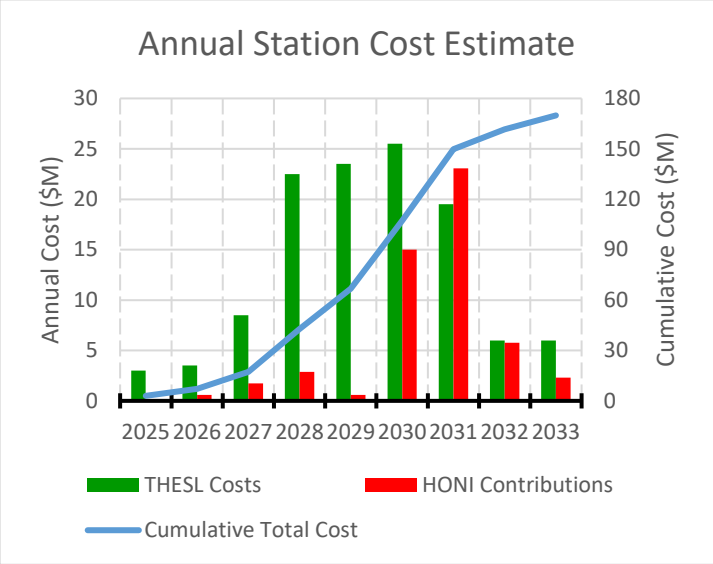


Figure 12 – Estimated Annual Expenditures for Downsview TS[6]

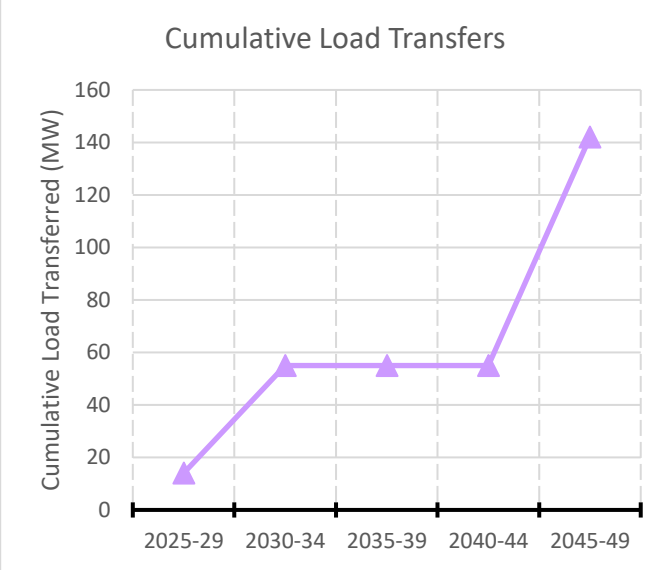


Figure 13 – Cumulative Load Transfers Required for Downsview TS

/C

In conclusion, this option presents a feasible solution by constructing a new Downsview TS and introducing 174 MW of new capacity to the Downsview Area. This investment is expected to bring the Downsview Area loading down to 90% until 2049. To achieve this option, an estimated $170 M[6] of expansion work is needed over 2025-2033, and an estimated 142 MW in load transfers is needed over 2024-2049. This option will also include the provision to install a second DESN in the future; which if pursued in 2044, would reduce the load transfer investment from 142 MW to 55 MW.

/C

[6] Excluding inflation assumptions

5 OPTION ANALYSIS AND RECOMMENDATION

The key results of the options studied are summarized in Table 554. Options were considered in order of increasing level of intervention, until an acceptable option was identified. This ultimately led to the identification of the proposed option, Option 6 – New TS, as the only option capable of meeting system needs with reasonable risks.

Table 5 – Summary of Options

Option (Increasing in Level of Intervention)	Decision	Reason for Decision	Decision Criteria				
			Acceptable Long Term Solution	Cumulative Load Transfers or NWSs Required [by 2044/2049] (MW)	Operational + Customer Connection Risks	Execution Risk	Risk of Subsequent Overloading
1 – Status Quo	Reject	This Option is only viable as a short-term solution.	No	N/A – viable only for a short term	High	Medium	Forecasted Overload
2 – Load Transfers	Reject	This Option can only manage loading until 2034.	No	N/A – viable only for medium term	Low	Minimal	Forecasted Overload
3 – NWSs	Reject	NWSs are not designed to be long term solutions. Very high execution risk due to unprecedented quantity of NWSs needed.	No	93/162	High	Very High	Mitigated
4 – Station Upgrades	Reject	Technically infeasible: Station equipment is already sized to maximum ratings.	No	N/A	N/A	N/A	N/A
5 – New DESN(s)	Reject	High execution risks, likelihood of stranded capacity, and excessive quantity of load transfers drive the need for an alternative solution.	Yes	129/192	Minimal	High	Unmitigated
6 – New TS	**Accept**	Meets system needs with reasonable risks.	Yes	55/142	Minimal	Medium	Mitigated

Option 1 – Status Quo, as mentioned in Section 4.1, is never recommended when capacity constraints are identified, but illustrates what Toronto Hydro may do as a short-term solution while longer-term solutions are in progress. Since this option is only viable in the short term, it was rejected. Similarly, the analysis for Option 2 – Load Transfers showed that the Option is only viable up until 2034, and as a result it was also rejected. /C

Option 3 – NWSs would be required indefinitely and would require an unprecedented quantity of load to be addressed, 162 MW by 2049. As mentioned in Non-Wires Solutions Program Narrative E7.2.1.1, NWSs are "designed to help address short-to-medium term capacity constraints", and are not designed to be long term solutions. Moreover, Toronto Hydro's NWSs over 2015-2019 have targeted a maximum of 10 MW, and the Program over 2025-2029 proposes a maximum target of 30 MW (see E7.2.1.4). As a result, a target of 162 MW by 2049 is highly unprecedented which translates into a very high execution risk. Therefore, because it is not designed to be a long-term solution and its very high execution risk, this option was rejected. /C /C

Option 4 – Station Upgrades was considered, but all station equipment in the Downsview Area is already sized to maximum ratings and cannot be further upgraded. Therefore, this option is technically unfeasible and was rejected.

Option 5 – New DESN(s) was considered for each of the 4 existing stations within the Downsview Area; but as mentioned in Section 4.5, only Finch TS could accommodate a new DESN. Although possible, a new DESN at Finch TS would be especially difficult to utilize effectively in the Downsview Area, due to: existing congestion, geographic barriers, and distance from the DASP area. These challenges translate into high execution risks, an expectation of stranded capacity at Finch TS (inaccessible to the rest of the Downsview Area), and an expectation for higher than typical load transfer costs. Finally, because Finch TS is remote from the DASP area and is not central to the broader Downsview Area, this option is forecasted to require a remarkably high quantity of load transfers: 129 MW by 2044 and 192 MW by 2049. These load transfers would be needed to redistribute the new capacity across the Downsview Area. As a result of the many significant risks, challenges, and inefficiencies presented by this option, this option was ultimately rejected. /C

Motivated by the challenges encountered in its analysis of option 5, Toronto Hydro next considered installing new capacity both within the DASP area where new capacity is needed most, and in a central location within the broader Downsview Area to facilitate relief of the existing stations. This resulted in Option 6 – New TS which specifically considers installing a new TS within the DASP area, and whose details are reviewed next.

Because of the proposed placement of the new TS, it is suited to offload existing stations and directly supply the new DASP loads, which is the major driver of load growth in the broader Downsview Area. This results in a minimal execution risk in terms of addressing system needs once the new TS is in service. However, the construction of a new TS is a long and complicated project; and therefore, overall execution risk was evaluated as Medium. Because of the designed placement of the new TS, the required load transfers of this option are less than in the previous option 5 at: 55 MW by 2044 and 142 MW by 2049. /C

Option 6 also includes a provision to address the risk of subsequent overloading in the long term (illustrated in Figure 111111), by permitting a second DESN to be installed at the newly constructed TS, whereas no such provision exists in option 5. Moreover, if the second DESN is constructed by 2044, then the required load transfers of this option can be limited to 55 MW, rather than 142 MW by 2049. This is because the load transfers in 2045-2049 are needed solely to relieve Downsview TS. /C

In light of the multiple benefits of Option 6 – New TS shown over Option 5 – New DESN(s), and given the multiple significant drawbacks of Option 5, Toronto Hydro selected Option 6 – New TS as the only reasonable solution to address capacity needs within the Downsview Area. Toronto Hydro proposes to implement option 6 with its Downsview TS Project included in its 2025-2029 rate application, E7.4 Stations Expansion Program.

6 CONCLUSION

Toronto Hydro has identified a need for additional capacity within the Downsview Area due to forecasted high station loading in the medium term, and forecasted Area overloading in the long term from the Downsview Area Secondary Plan ("DASP").

To address this need, Toronto Hydro has considered multiple options including: Status Quo, Load Transfers, NWSs, Station Upgrades, New DESN(s), and New TS.

When considering short-to-long term needs, project costs, risks, and secondary benefits, Toronto Hydro concluded that its Option 6 – New TS is the only reasonable option which addresses system needs.

The recommended option will construct a new TS, Downsview TS, which will provide 174 MW of new capacity to the Downsview Area, with forecasted energization in Q4 2033. The proposed location of Downsview TS is in proximity to the lands of the DASP, and also central to the Downsview Area. This will permit it both to directly supply new DASP loads, and relieve the highly loaded Bathurst TS, Fairbank TS, and Finch TS.

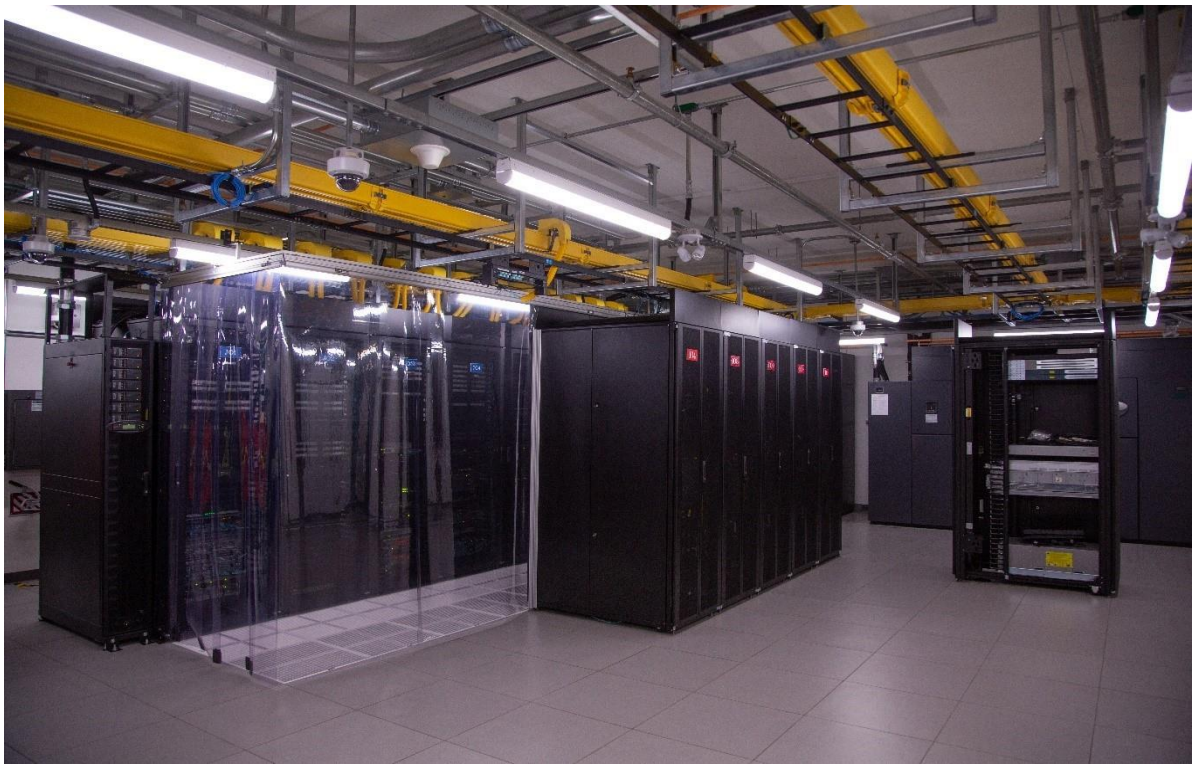
The cost to construct the new TS is estimated to be $76.0 million over the 2025-2029 period and $116.2 million over the 2030-2034 period, including Hydro One contributions and inflation assumptions. Only $14.6 million of the project's estimated cost is planned to be capitalized in the 2025-2029 period. These costs are related to the completion of site acquisition and preparation, and the completion of civil construction. The remaining project costs will be capitalized at the completion of the project once the station has been energized.

Because of the long construction timeline, load transfers and/or NWSs will be needed in parallel with construction of the new TS. An estimated 14 MW in load transfers or NWS capacity will be needed by 2029, and a subsequent 41 MW will be needed between 2030-2034. /C

Downsview TS will be constructed with a provision to install an additional 174 MW of capacity if and when needed in the future. This will address the risk of subsequent high loading or overloading, and can eliminate the need for subsequent load transfers after 2034. /C

The proposed investments will address upcoming high loading in the Downsview Area, support the City of Toronto's Downsview Area Secondary Plan, and prepare the Downsview Area to support electrification over the next 25 years. /C

E8.1 Enterprise Data Centre ("EDC") Relocation



E8.1.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): N/A	**2025-2029 Cost ($M):** $72.0
Segments: Facilities	
Trigger Driver: Operational Resilience	
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Environment, Customer Focus, Financial Performance	

Toronto Hydro's 24/7 operations are supported by its Enterprise Data Centre ("EDC"), which houses the utility's essential networking, telephony and telecommunications systems, data storage and backup systems, and server infrastructure across two distinct locations ("centres") that collectively support the following organization-wide ("enterprise") processes ("data"):

- Control centre operations, including real-time control of Toronto Hydro's distribution system through supervisory control and data acquisition ("SCADA"), and remote monitoring and operation of substations and in-field devices;
- Grid management and response, including outage management, isolation and restoration activities, and radio communications with field personnel;
- Delivery of planned investments, including capital and maintenance activities;
- Asset management activities, including system planning, analytics and decision-making, and regulatory reporting functions;
- Financial activities, including capital budgeting and financial reporting;
- Engineering activities, including design, cost estimation, and job scheduling;
- Customer services, including customer care and billing, call centre operations, meter reading, meter data management and customer communications; and,
- Information technology ("IT") services, including IT systems and software, technical support services, office phone systems, and online services.

Figure 1 illustrates the foundational role that the EDC plays within Toronto Hydro, and how a failure of this physical infrastructure could result in an organization-wide outage impacting all enterprise processes.

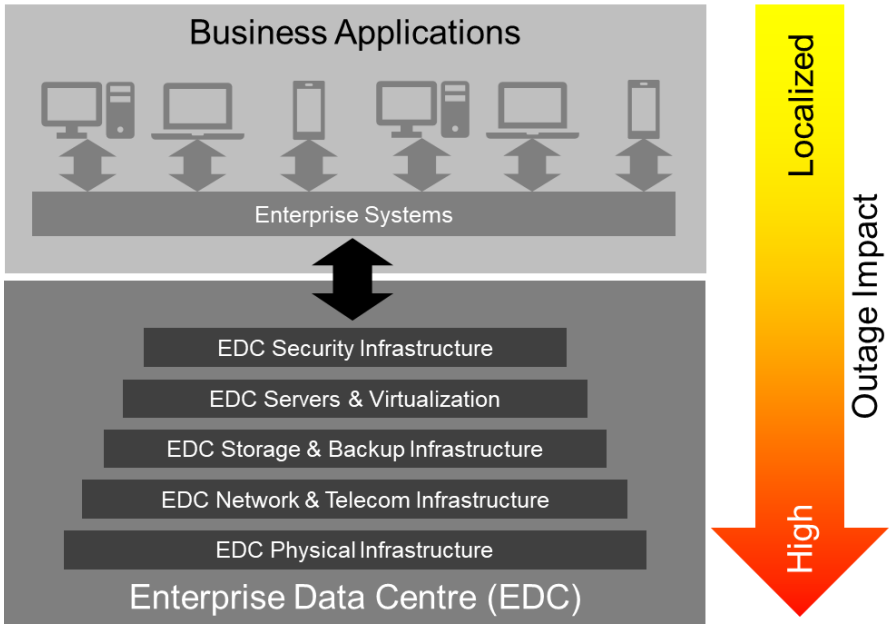


Figure 1: EDC and Supported Business Applications

An organization-wide outage would immediately disrupt operational systems and processes within Toronto Hydro's Control Centre Operations program, because power system controllers would be unable to access any real-time or near-real-time data within the Advanced Distribution Management System ("ADMS"), Outage Management System ("OMS") or Supervisory Control & Data Acquisition ("SCADA") systems.[1] Planned and unplanned activities within the utility's distribution system would suffer immediate disruption due to the loss of communication between the control centre and field crews, meaning that isolation, sectionalisation, and restoration activities would no longer be performed safely or effectively, resulting in extended outages to customers and significant delays in planned construction activities.

To better safeguard Toronto Hydro and its customers against the severe and significant impacts that an organization-wide outage could introduce, the EDC has been implemented across two physically separated locations for the purposes of providing redundancy and enhanced resiliency, should one or both EDC locations experience a normal or catastrophic failure event. Having multiple physically separated data centres is a common practice in the industry to enhance overall reliability, with recent surveys indicating that over 85 percent of organizations have three or more physically separated data centres in operation.[2] [redacted]

Toronto Hydro's EDC is facing emerging operational resilience, reliability, safety and security, and decarbonization issues specific to EDC 1 that require immediate intervention to mitigate the risks of a potential organization-wide outage. [redacted] 60 percent of the existing building infrastructure and facilities assets at EDC 1 are beyond their useful lives. Furthermore, Toronto Hydro has limited options to invest in necessary upgrades to building envelope systems at EDC 1 that can help mitigate current EDC capacity constraints. These growing facilities-related challenges are contributing to increased reliability risks for the EDC, including water damage, flooding, and physical safety and security risks that, if realized, would require the EDC to

[1] Exhibit 4, Tab 2, Schedule 7.
[2] See e.g. E. Thorne, "Corporate Data Center Geography, Explained", TeleGeography Blog, 2021, https://blog.telegeography.com/corporate-data-center-geography-explained

shut down. Finally, although Toronto Hydro estimates that it can fully meet its decarbonization goals with respect to the [redacted][3] Current energy efficiency goals as established by the Building Owners & Managers Association ("BOMA") and Energy Star are simply unfeasible to achieve within the EDC 1.

As Toronto Hydro continues to build, maintain, and operate its distribution system in accordance with the evolving needs and nature of load customers, distributed energy resource ("DER") owners and operators, and other stakeholders, it will aim to modernize its infrastructure and practices by introducing new enterprise systems and business processes throughout the 2025-2029 rate period. In other words, the EDCs will need to continue to grow to consistently meet the utility's, and by extension, its customers' needs. Although Toronto Hydro has prudently managed and maintained reliability and operational resilience within both EDC locations through its robust asset management strategy and asset renewal and repair activities,[4] the utility expects that EDC 1 will reach its capacity within the next five years and will no longer be able to accommodate new data and support new systems. Once this capacity threshold is reached, EDC 1 will no longer provide 1:1 redundancy to EDC 2. Under such a scenario, there will be a partial loss of business applications across the organization.

EDC 1 suffers from additional risks due to its limited and restricted footprint within the [redacted] which could increase the overall probability of an EDC failure event. For example, EDC 1 will continue to require at least two to three shutdowns per year to allow for the execution of necessary and essential facilities operations and maintenance activities aiming to safeguard the integrity of the location. Should EDC 2 fail during a shutdown of EDC 1, or should both EDC locations be impacted by a single event, an organization-wide outage will occur.

The EDC Relocation program (the "Program") proposes to relocate EDC 1 to [redacted] to enhance the overall redundancy and resiliency of the EDC and minimize the risks of an organization-wide outage. Through this relocation, Toronto Hydro will also be able to mitigate risks associated with operational resiliency, reliability, safety and security, and decarbonization. Subsection E8.1.2.1 on page 6 provides further details on the proposed investments within this

[3] Outlined in greater detail in Exhibit 2B, Sections D6 (Net Zero 2040 Strategy) and E8.2 (Facilities Management and Security).
[4] Respectively discussed under Exhibit 2B, Sections D5 (Facilities Asset Management Strategy) and E8.2 (Facilities Management and Security), and Exhibit 4, Tab 2, Schedule 14 (Facilities Management OM&A program).

program, while subsection E8.1.2.2 on page 15 provides further details on the key drivers and risks to be mitigated through the execution of this program.

E8.1.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's reliability and resiliency objectives by: ○ Reducing the risk of an organization-wide outage due to EDC failure; ○ Maintaining critical business applications, including control centre functions, grid management and response, planning and engineering, customer care and billing, and project execution; ○ Mitigating current reliability challenges due to the constraints and external factors at EDC 1; and ○ Enhancing the geographic diversity of the EDC to create redundancy and mitigate the risk of failure by reliance on a single EDC facility.
Operational Effectiveness - Safety	Contributes to Toronto Hydro's safety objectives by: • Mitigating health and safety hazards from building infrastructure deterioration at EDC 1 (raised floor, windows, life safety infrastructure and fire suppression); and • Providing safe access to the relocated EDC for deliveries and during the loading/unloading of components.
Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: ○ Allowing for customer service and call centre operations to continue uninterrupted in the event that one of the EDCs fail and minimizing the risks of potential call centre outages; and ○ Mitigating the risks of an organization-wide outage that can result in the extension of outages to customers.
Environment	• Contributes to Toronto Hydro's environmental objectives by: ○ Assisting with the achievement of goals outlined in Toronto Hydro's Net Zero 2040 Strategy by reducing scope 1 greenhouse gas emissions; and ○ Leveraging energy efficient HVAC and lightning systems.

Financial Performance	• Contributes to Toronto Hydro's financial performance objectives as measured by the total cost and efficiency measures by: ○ Reducing capital costs by sharing existing infrastructure at the proposed EDC including cabling pathways, physical security, access control, and power redundancy solutions; and ○ Leveraging an existing fiber-optic connection between EDC 2 and the proposed EDC to reduce project costs.

E8.1.2.1 Program Description

This program proposes the relocation of EDC 1 to the [redacted]. Toronto Hydro will require $72 million over the 2025-2029 rate period to execute and complete this program.

The utility proposes the [redacted] as the optimal relocation site for the following reasons:

- [redacted] and
- Existing Fibre-Optic Connections and Footprint: The proposed EDC contains a fibre-optic connection with EDC 2, which would enable the transfer of data and communications from the [redacted], thereby reducing overall project costs when compared to other potential locations. The proposed EDC also provides a 12,000 square feet footprint, which is necessary for housing all EDC assets.

Further details regarding the various relocation options and how the utility determined the optimal relocation site are provided in subsection E8.1.4 on page 23.

The proposed EDC will be a [redacted] to the existing warehouse area within the [redacted] and the EDC will be located [redacted]. A total of 11,500 square feet of space will be dedicated to house the following key components:

[5] From the completion of the Control Operations Reinforcement program in Exhibit 2B, Section E8.1 of Toronto Hydro's 2020-2024 Custom Incentive Rate Application (EB-2018-0165). See also Exhibit 2B, Section E4 of this application.

- Physical Infrastructure: Provides the necessary vertical and horizontal space requirements to load, test and integrate, and store core assets within the proposed EDC. This includes the data hall, staging area, access trap, and loading dock;
- Electrical Infrastructure: Powers the EDC and provides redundancy should a localized failure at the proposed EDC occur. This includes the electrical supply points, uninterruptible power supply ("UPS"), and generators;
- Environmental Infrastructure: Maintains optimal environmental conditions within the EDC, while also providing essential protection against threats such as fires. This includes the HVAC and fire suppression systems;
- Telecom Infrastructure: Connects the EDC to Toronto Hydro's Control Centres, work sites, offices, substations and distribution system components;
- Network Infrastructure: Facilitates communications between servers, storage, and applications;
- Storage and Backup Infrastructure: Provides centralized storage of all production, test, and development data for online access and long-term archival;
- Computing Resources: Includes the servers, which provide the necessary processing, memory, virtualization, and connectivity to support business applications and associated middleware/database components; and
- Security Infrastructure: Enables physical and cyber security controls to sufficiently protect assets contained within the EDC.

The Program aims to retire the existing assets and infrastructure at EDC 1, while supporting Toronto Hydro's continued efforts to modernize its operational systems. The execution of the Program will ensure that Toronto Hydro's EDC continues to withstand evolving hazards and threats, thereby allowing the utility to continue operations and provide customer services, effectively safeguard, manage, and operate its distribution system, minimize potential safety hazards to the public and employees, and minimize business interruption impacts on its customers as efficiently and effectively as possible. The following subsections provide further details on the various components as specified above.

Figure 2 illustrates key components within the proposed EDC and its relation to the broader [redacted], all components of the proposed EDC will be secured with [redacted]



1. Physical Infrastructure

To further enhance the resiliency and reliability of the EDC 2 and EDC 1 locations, Toronto Hydro has aligned these locations to the requirements established by the Uptime Institute within its Tier Classification System.[6] EDC 1, [redacted], aligns to Tier I requirements within this classification system and cannot be further enhanced to align to Tier II or Tier III requirements, due to the lack of available space, electrical supply, environmental conditions, and installed redundancy within EDC 1.

With the increased space availability at the location for the proposed EDC, it will be possible for Toronto Hydro to align the proposed EDC with Tier III requirements, meaning that the EDC will be more reliable than the existing EDC 1 and EDC 2 locations by several orders of magnitude, with completely redundant components. Despite the enhanced Tier III functionalities, the utility will build the proposed EDC at a cost that remains proportional to the up-front costs for EDC 2.

[6] Uptime Institute, Tier Classification System https://uptimeinstitute.com/tiers. A higher tier indicates more sophisticated standards and controls and thus, greater expected reliability.

Key physical infrastructure components within the proposed EDC will include the following:

- Data Hall: A 3,800 square feet area that holds the server racks, servers, storage and cooling units. This data hall is significantly larger than the current one in EDC 1 and will provide the necessary physical capacity to ensure that more equipment can be added as Toronto Hydro's operations continue to grow;
- Loading Dock: A dedicated loading dock designed to provide no height restrictions, with 7 feet x 6 feet doors, providing the necessary clearances to move critical asset infrastructure in and out of the EDC. This will help reduce time, costs, and overall complexity of bringing equipment into the EDC, especially when compared to EDC 1, which does not possess a loading dock;
- Corridor: A 2,030 square feet corridor designed to allow assets to be safely and securely moved from the loading dock to the staging room. This corridor will help reduce time, costs and overall complexity of transporting and integrating equipment into the EDC, especially when compared to EDC 1 where equipment is currently brought in through the main freight elevator and then brought in through the general office area before integration into the data hall directly;
- Staging Room: An 830 square feet staging room designed to allow assets to be assembled and tested before being integrated into the EDC. This staging room will greatly reduce the risk of asset failure by allowing assets to be properly evaluated prior to their integration. By comparison, EDC 1 does not contain a staging room or lab area, and therefore assets cannot be tested at all prior to integration;
- Electrical Rooms: Contains all dedicated electrical supply infrastructure supporting the proposed EDC. The isolation of the electrical rooms and UPS allows for facilities operations and maintenance activities to be performed without any shutdowns being required to the EDC, unlike EDC 1;
- Mechanical Rooms: Provides critical cooling capacity to the EDC through two computer room air conditioning ("CRAC") gallery rooms;
- Communications Rooms: Contains all necessary telecommunications equipment, designed to support Toronto Hydro's telephone and radio systems;
- Access Trap: Designed to provide enhanced security features within the proposed EDC. This access trap will permit only one door to be unlocked and opened only after the other door has been locked and closed;

- Locking Cabinets: Designed to house EDC assets and associated infrastructure;
- Cable Systems and Network Designs: Designed as per the TIA-942 industry standard; [7] and
- [redacted]

The increased size of the proposed EDC data hall allows for expanded corridors between EDC assets and provides enhanced physical capacity to install additional equipment in the future. For illustrative purposes, the physical capacity of EDC 2 is shown in Figure 3. By comparison, EDC 1's data hall is already at physical capacity and adding additional infrastructure would require significant reconfiguration of the existing EDC assets.

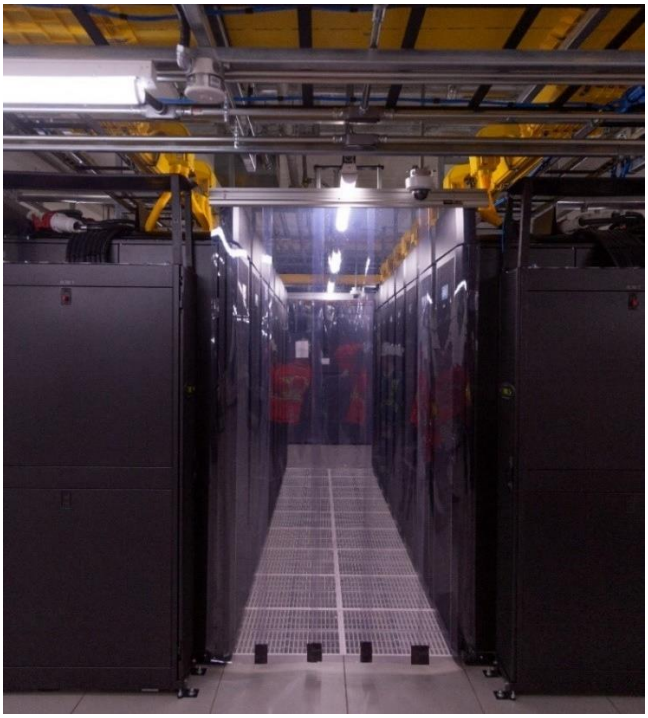


Figure 3: Available Physical Capacity at EDC 2

[7] "ANSI/TIA-942A 2012 Telecommunications Infrastructure Standard for Data Centers", Telecommunications Industry Association, 2012.

2. Electrical Infrastructure

The proposed EDC will have its own dedicated electrical supply points, along with dedicated electrical rooms, UPS and generators. A dedicated 1.25 megavolt-amperes substation will provide power distribution into the EDC. Two dedicated 1.0-megawatt generators will provide enhanced redundancy should an electrical supply failure or upstream outage occur. The dedicated supply points will allow the proposed EDC to remain unaffected by any facilities operations or maintenance activities taking place within [redacted]

Two 550 kilovolt-ampere modular UPS systems will serve the proposed EDC, with each system providing enhanced redundancy, while also being within the secure access perimeter. The size of these UPS systems will be to enable continued growth and allow the proposed EDC to maintain 1:1 redundancy with EDC 2.

3. Mechanical / HVAC Infrastructure

The proposed EDC will contain an advanced HVAC system designed to provide optimal cooling to the overall EDC environment and contained assets. A 24-inch raised floor system will be installed to provide efficient cold air flow panels with flow management capabilities for 20 network cabinets and 64 server equipment cabinets. This HVAC system will leverage free cooling technology to deliver reliable cooling at reduced energy costs when compared to the existing EDC 1. Only the cooling system will be installed within the raised floor system to maximize underfloor space, while the electrical supply will feed EDC equipment from overhead. For illustrative purposes, the underfloor capacity at EDC 2 is shown in Figure 4.

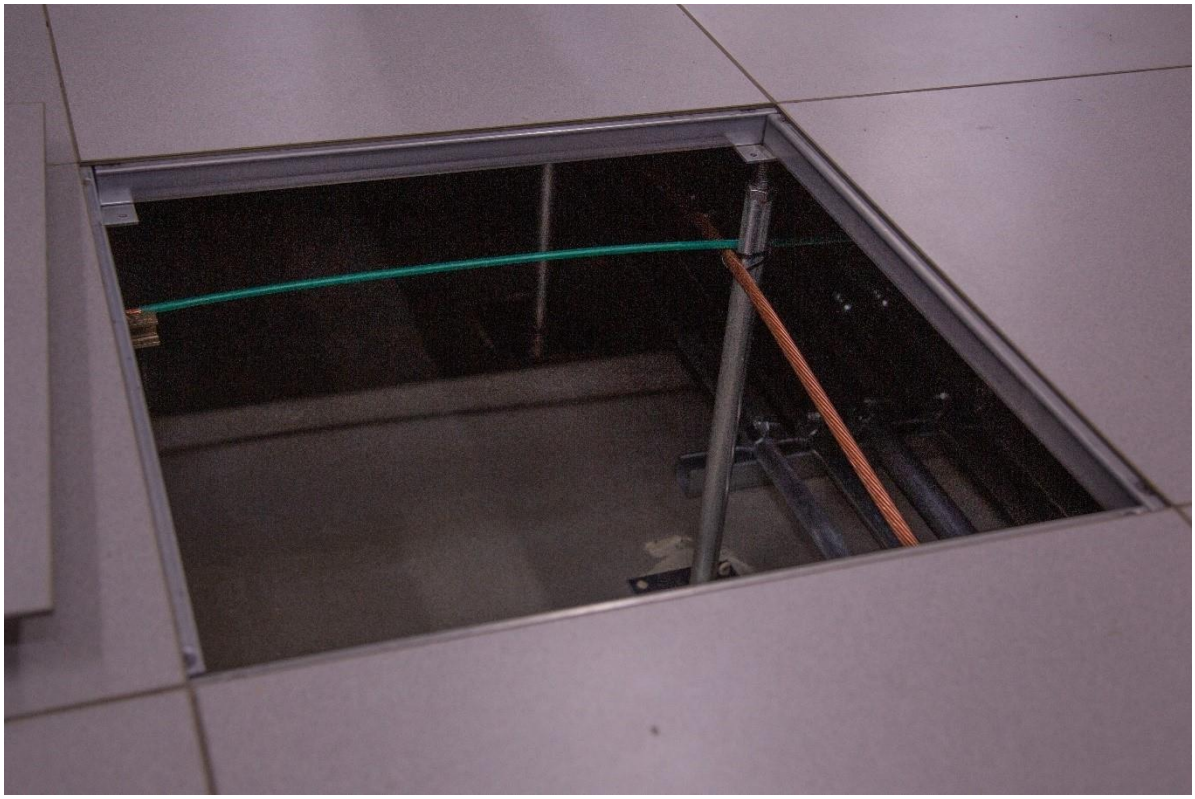


Figure 4: Available Underfloor Capacity at EDC 2

Two CRAC units will be installed within their own dedicated gallery rooms. These units will be stand-alone from the HVAC system and designed to provide redundancy within the proposed EDC. By comparison, the CRAC units within the current EDC 1 are installed directly within the data hall and do not provide redundancy, meaning that if the system fails, there is no backup cooling units available, which may cause the temperature of EDC hardware to increase beyond safe operation limits and result in equipment failure.

An advanced pre-action fire suppression system with sprinkler piping and heads, along with a clean agent gas fire suppression system will be installed within its own dedicated area to provide multi-zone protection within the proposed EDC, including the data hall, CRAC galleries and, electrical rooms.

4. Telecom Infrastructure

The proposed EDC already possesses a fibre-optic connection EDC 2, enabling continuous communications between these two facilities and thereby supporting the 1:1 redundancy across the

EDC. This fibre-optic connection is under 20 miles in length, and therefore aligned with industry standards of ten to 50 miles to provide replication data integrity and operational efficiency. By leveraging this existing connection, Toronto Hydro can reduce overall program costs.

5. Network Infrastructure

Network infrastructure within the proposed EDC will be designed to enhance overall disaster recovery ("DR") and reliability by improving end-to-end fault-tolerance architecture, modular redundancy, operational performance, reliability, and availability of enterprise physical Infrastructure. The network infrastructure will be configured to enhance overall scalability capabilities by featuring an optimized architecture designed from the ground up with flexibility and scalability to support the utility's evolving needs.

6. Storage and Backup Infrastructure

All storage and backup infrastructure within the proposed EDC will be on-premises, thereby allowing for data to be retrieved quickly, while allowing compliance with applicable data sovereignty and legislative and regulatory requirements.

7. Computing Resources

All computing resources will be modernized such that they are dynamic and capable of enabling physical connectivity in a scalable manner. Resources will be monitored via real-time monitoring technologies to measure overall performance and respond to emerging risks.

8. Security Infrastructure

The security infrastructure of the proposed EDC will consist of an enhanced security perimeter containing all EDC infrastructure, including the dedicated electrical room, UPS, generators, data hall, staging area, access trap and loading dock, thereby reducing potential safety and security risks.

To enhance overall physical security and control access within the proposed EDC, a multi-step entry system with limited entry points will be configured. EDC access will be based upon dual authentication through card readers and keypads. Access into the data hall, CRAC galleries, staging room, and electrical room will be based upon the card reader system. Access control will be further enhanced via perimeter lighting, thermal cameras, a vehicle security station, and license plate

recognition systems to enable employee and vehicle access, as well as incursion protection and video surveillance systems.

E8.1.2.2 Program Drivers

Table 3: Program Drivers

Trigger Drivers	Operational Resilience
Secondary Driver(s)	Reliability, Safety, Customer Service, Decarbonization, Financial

1. Operational Resilience

Operational resilience is the primary driver of Toronto Hydro's need to maintain dual EDCs in good condition. A failure of the EDC would result in the immediate interruption of services across the organization that rely on business applications, underlying data, and communication systems. This organization-wide outage, which would include catastrophic disruptions to the previously discussed business processes and operations, would impact overall operational resilience across the organization as further discussed below.

[redacted] As Toronto Hydro's business and operations continue to evolve, the EDC will require more physical and electrical capacity to store and manage more data and to support more enterprise systems and business processes.

In the event of an organization-wide outage due to an EDC failure, the following impacts would immediately arise:

- Reliability impacts: Mission-critical applications that allow the utility to monitor and manage the distribution system, including ADMS and OMS systems would no longer function, eliminating any visibility of the grid. Outages that are already in progress or occur following

an EDC failure would be extended indefinitely, until such time that the EDC can go back online;

- Safety impacts: Without visibility of the grid or functioning radio systems, power system controllers can no longer effectively monitor the system, manage planned and reactive outages, or communicate with field crews, giving way to potential safety risks to both crews and the public; and
- Customer service impacts: Toronto Hydro's meter data management ("MDM") systems, customer information system ("CIS") and telephone systems would be unable to function, impeding the meter-to-cash process and the ability of customer care personnel to manage customer service requests.

As noted in Toronto Hydro's Facilities Asset Management Strategy (the "Strategy", filed at Exhibit 2B, Section D6), [redacted] In addition, fully achieving the utility's decarbonization goals with respect to 14 Carlton appears unattainable. Most critically, the operation and maintenance of work centre and EDC assets often involve conflicts between the effects of activities in one sphere upon the other. For example, any high-impact renovation and construction projects aimed at improving the work centre assets would require the EDC space to be vacated during the renovations to avoid physical impacts upon EDC infrastructure and vice versa.

[redacted] Over the past five years, these risks and challenges have continued to increase in volume.

Table 4: [redacted] Condition Assessment Results

Item	Condition	Status
Roof	**Very Poor**	[redacted]
Stone Cladding	**Poor**	Performance depends on external conditions.
Windows	**Poor**	[redacted]
Heating & Cooling	**Fair**	Unreliable five-pipe system cannot be replaced without first vacating EDC 1.
Storm Water Piping	**Poor**	Aging stormwater piping must be replaced.
Domestic Water	**Poor**	Aged piping must be repaired.
Sanitary	**Poor**	Aged sanitary system must be repaired.
Electrical Distribution	**Very Poor**	[redacted]
Electrical Service	**Poor**	[redacted]
Abatement	**Very Poor**	[redacted]

Examples of asset condition issues within EDC 1 that cannot be resolved due to the risk of materially affecting the integrity of the EDC include the following:

- Building exterior, including masonry and façade issues [redacted] and deteriorating building envelope and water tightness;
- Deterioration of windows due to age and poor condition, leading to the risk of water infiltration; and
- An aging, unreliable, and corroding five-pipe heating and cooling system that cannot be replaced with a modern duct-based system due to lack of headroom clearance.

In some cases, even smaller initiatives can have larger and broader impacts on EDC 1. For example, shutdowns of EDC 1 were necessary when Toronto Hydro [redacted]

[redacted]. This logistical complication increased the costs of installing the new stations.

As the location continues to age and the backlog of high-impact renovations and maintenance activities close to the EDC increase in volume, EDC 1 will impose significant challenges and restrictions in mitigating these asset risks, leading to higher overall costs due to the complexity, effort, and time needed to coordinate the execution of facilities operations and maintenance activities without materially impacting EDC operations. By deferring these high-impact renovations, the utility's operational resiliency will continue to deteriorate over the 2025-2029 rate period.

Currently, EDC 1 aligns to Tier I data centre requirements at best, which include the following:

- A single UPS for power sags, outages, and spikes;
- A dedicated location for IT systems;
- Dedicated cooling equipment that runs 24 hours a day, 365 days a week; and
- An engine generator that will allow the facility to operate through power outages.

According to the Uptime Institute, meeting Tier I requirements only constitutes a basic level of resiliency controls. For example, while a Tier I data centre is expected to provide protection against failures due to human error, it would not provide necessary protection against unplanned failures or outages.[8]

The previously discussed challenges, combined with the current footprint and asset configuration of the [redacted], render it impossible to upgrade EDC 1 to better align to Tier II or Tier III requirements. Even if Toronto Hydro were to attempt upgrades, it would have to take EDC 1 offline for a significant period of time. This would require all EDC operations to be solely supported by EDC 2 for the duration of the upgrades, which would eliminate the redundancy between the two EDC facilities and unacceptably increase the risk of an organization-wide outage.

2. Reliability

As previously illustrated in Figure 1, the EDC plays a foundational role in supporting all of Toronto Hydro's business applications and processes that are in operation 24/7, including control centre

[8] Uptime Institute, Tier Classification System https://uptimeinstitute.com/tiers. A higher tier indicates more sophisticated standards and controls and thus, greater expected reliability.

functions, grid management and response, planning and engineering, customer care and billing, and the execution of planned capital work across the distribution system.

A complete EDC failure would result in all of Toronto Hydro's business applications becoming unresponsive and non-functional. In the event of a distribution system outage, this would have cascading and substantial financial and economic impacts on customers within the City of Toronto—the largest city and economic centre of Canada, as well as fourth largest city in North America. During an organization-wide systems failure, customers would have no way of reporting distribution system outages or communicating with the utility due to the disruption to contact centre and communications channels. Due to power losses, commercial customers would face immediate revenue impacts as well as major disruptions to their business operations and harmful side effects, such as the potential spoilage of inventory goods and materials. Industrial customers without available backup systems would see immediate disruptions to their business (e.g. manufacturing) processes and even after power is restored, it would take time for these customers to return to full operations. Critical customers such as hospitals, water pumping stations, emergency management services, or transit operators such as the Toronto Transit Commission ("TTC") would also see immediate disruptions during an organization-wide outage event.

Another reliability factor informing the Program is that EDC 1 is expected to reach its electrical capacity within the next five years due to the limitations of the current UPS system. [redacted]

Finally, EDC resiliency is threatened by increasing vandalism, cyber and physical terrorist threats, and extreme weather event trends. A recently commissioned study conducted by the U.S. Department of Energy has shown an increasing trend since 2015 with respect to vandalism and extreme weather events that are impacting utility-owned infrastructure, as illustrated in Figure 5.[9] As extreme weather and vandalism events continue to grow, both in terms of magnitude as well as frequency, [redacted]

[9] U.S. Department of Energy, Electric disturbance events (DOE-417), Archives https://www.oe.netl.doe.gov/oe417.aspx; Toronto Region Conservation Authority, Taking Action on Climate Change in Toronto Region https://trca.ca/climate-change-impacts-gta/

Relocating EDC functions to the proposed EDC will enhance geographic diversity and help mitigate the risk of a single point-of-failure due to an extreme weather, vandalism, or terrorist event.

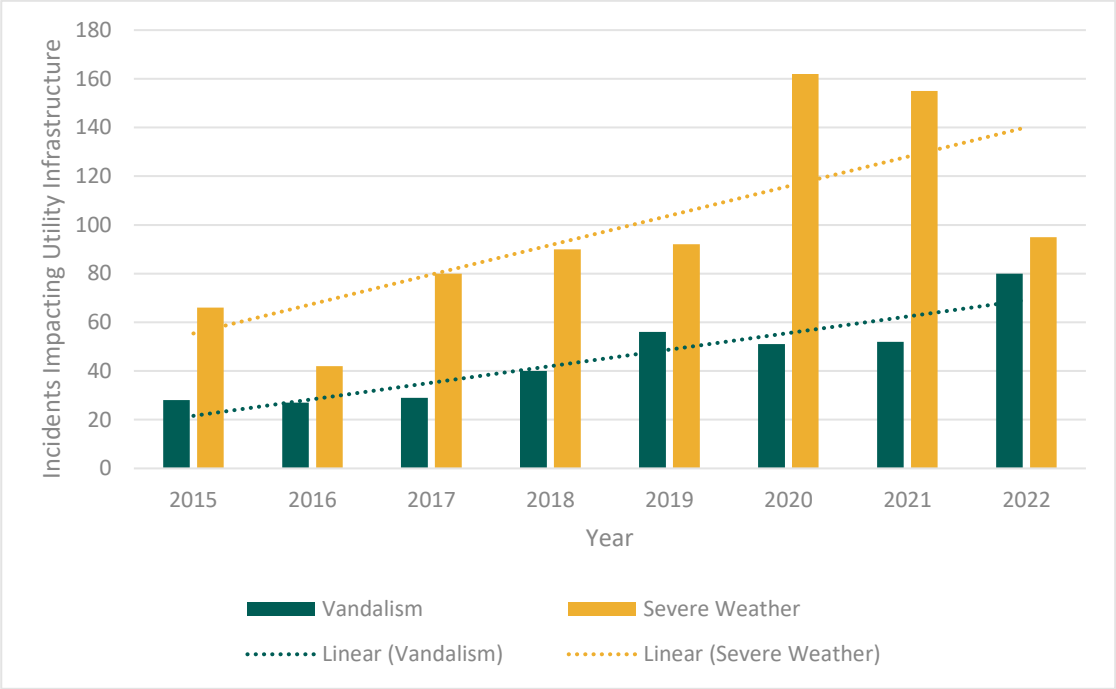
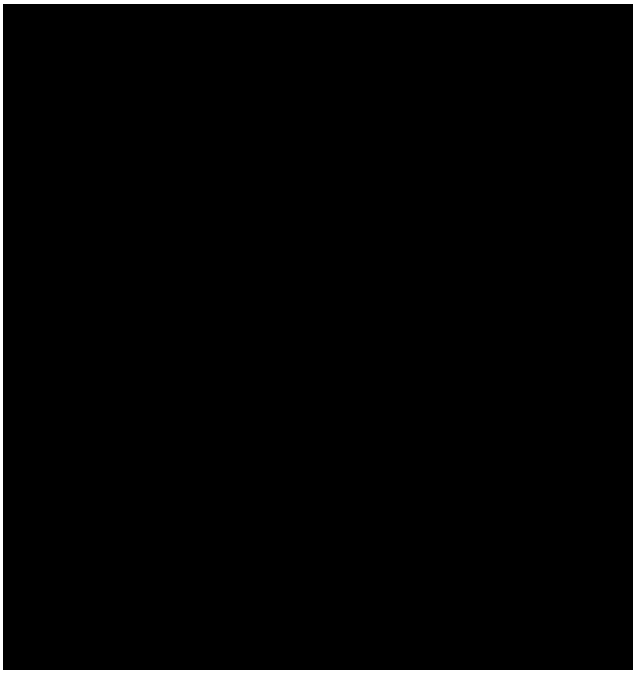


Figure 5: Severe Weather & Vandalism Incidents Impacting Utility Infrastructure

3. Safety & Security

Figure 6 illustrates the supporting systems for EDC 1 that currently reside outside of the secure access perimeter and within common areas of the [redacted] that are exposed to additional safety and security risks. There is also no dedicated or secure location for the storage of EDC assets and spare parts. Only one of Toronto Hydro's UPS units is located within the secure access perimeter of EDC [redacted] Furthermore, EDC 1 does not provide adequate physical capacity for components such as a loading dock, staging area, or access trap. For these reasons, EDC 1 remains exposed to considerable safety and security-related risks. By contrast, as illustrated by Figure 2, all [redacted] EDC components and functions would be fully secure within the secure access perimeter with two-factor authentication, such that only authorized persons can gain access.



[redacted]

4. Decarbonization

As outlined in the Net Zero 2040 Strategy, in Exhibit 2B, Section D7, Toronto Hydro plans to implement several initiatives throughout the 2025-2029 rate period and beyond to reduce the utility's scope 1 greenhouse gas emissions and achieve net zero by 2040. Although Toronto Hydro estimates that it can fully achieve its decarbonization goals for the [redacted], requiring the EDC space to be fully vacated and thus giving rise to the previously discussed risks. Current energy efficiency goals as established by the BOMA and Energy Star are not achievable within the [redacted]

5. Financial

Toronto Hydro's options analysis in section E8.1.4 on page 23 describes the criteria and requirements that the utility assessed to identify the optimal site for the proposed future location for the EDC in

light of the high costs of asset management due to the continued risks, challenges, and constraints that are caused by the EDC 1.

E8.1.3 Expenditure Plan

The Program proposes to relocate the existing EDC infrastructure located at Toronto Hydro's EDC 1 to a new location within the proposed EDC to maintain the utility's operational capabilities and mitigate identified resiliency, reliability, safety and security, and decarbonization risks.

The proposed EDC meets all necessary pre-requisites for Toronto Hydro to align to Tier III data centre capabilities as defined by the Uptime Institute.[6] This includes establishing concurrently maintainable capabilities using redundant components and redundant power distribution paths. [redacted] also possesses a vital fiber-optic connection to the 500 Commissioners location which enables the 1:1 redundancy between these two locations as well as communications between Toronto Hydro's Control Centres. Program costs can be significantly reduced by leveraging this existing connection.

Finally, the proposed EDC is located more than 18 km (33 minutes) away from EDC 2. This provides greater geographical diversity between the two locations, reducing the possibility for a single event (e.g. deliberate attacks, extreme weather) to simultaneously impact both locations at the same time.

Toronto Hydro requires $72 million over the 2025-2029 rate period to execute and complete the Program. This expenditure plan consists of four work categories, namely:

- Non-direct construction costs: Pre-construction planning and equipment expenditures;
- Alterations and demolitions: Costs associated with performing targeted demolitions and alterations within the proposed EDC to support the integration of the EDC;
- Building: Costs associated with facility upgrades needed to meet required standards; and
- Site works: Preparation of the area where the EDC will be constructed.

E8.1.3.1 Planned Project Timeline

The planned project timeline will take place within the 2025-2029 rate period. Planned work and non-direct construction costs will begin in 2025. The construction work will be phased out to minimize any overtime or premium costs and minimize disruptions to business operations. The estimated in-service date for the project is 2029.

E8.1.4 Options Analysis / Business Case Evaluation ("BCE")

Toronto Hydro has considered the following options to manage the current risks associated with the EDC, including:

- Status quo: Maintaining the EDC 1 and EDC 2 locations in their current state;
- Relocating all EDC functionality to EDC 2;
- Relocating EDC 1 to a non-Toronto Hydro-owned property; and
- Relocating EDC 1 to a Toronto Hydro-Owned Property.

E8.1.4.1 Option 1: Status Quo

The status quo option would entail continuing with the existing EDC 1 as it is configured today, with redundancy being maintained between EDC 1 and EDC 2.

Under this scenario, current risks relating to operational resiliency, reliability, safety and security, and decarbonization would remain in place. Toronto Hydro will be unable to further expand EDC 1, due to current vertical and horizontal footprint limitations and the [redacted] Consequently, EDC 1 will be unable to support a more advanced cooling system to support the introduction of higher density asset infrastructure. Without increases to the density of asset infrastructure, due the utility's reliance on the EDC to process increasing volumes of data and business processes, the UPS of EDC 1 will reach the limits of available capacity over the next five years. This would significantly reduce the efficiency of the UPS in providing sufficient backup power during an outage event and eliminate the 1:1 redundancy between the two EDC locations. In other words, in the event of a failure at EDC 2, EDC 1 could only support a finite number of business applications, meaning that the utility would suffer at least a partial systems outage and incur major business continuity risks.

As major systems within EDC 1 reach end-of-life, the asset management costs to replace or upgrade individual components will increase due to the limited footprint and [redacted] and the unique hazards it presents (such as the presence of asbestos), any cabling or electrical work may lead to delays, cost overruns, and overall higher replacement/upgrade costs.

Due to physical and electrical constraints, EDC 1 can never attain Tier II or Tier III data centre controls and therefore can never provide full redundancy should any of the EDC assets require maintenance

or outright replacement. [redacted]

Finally, due to the geographical proximity of EDC 1 and 2, both locations and the EDC infrastructure contained within them could be impacted by a single extreme weather event, natural disaster, threat, or attack. In such a scenario, all functions supported by the EDC would be immediately and adversely impacted and result in operational disruptions and safety risks to Toronto Hydro personnel and potentially to the public. These risks would impede Toronto Hydro's ability to: (a) locate failed assets and affected parts of the distribution system; (b) perform the necessary system isolations to enable crews to safely perform repairs; (c) mobilize crews to affected locations within the system; and (d) remotely control distributed energy resources.

To sufficiently mitigate and manage risks within tolerance levels at EDC 1 while maintaining operations of the current EDC configuration, Toronto Hydro would need to spend approximately $110.4 million, making the status quo option the costliest for the utility.

E8.1.4.2 Option 2: Relocate All EDC Functionality to EDC 2

An alternative option would be to eliminate EDC 1 in favor of having a single EDC operating out of EDC 2. Under this option, Toronto Hydro would entirely shift EDC functionality to the EDC 2 location, which would eliminate the redundancy that currently exists by virtue of the utility's operation of two physically separate EDC locations.

This scenario would also increase Toronto Hydro's risk exposure, as a single disruptive event at the EDC 2 could potentially impact the entire EDC and result in an organization-wide systems outage. Although EDC 2 provides the necessary features and footprint to support continued growth of the EDC and enable the attainment of Tier II data centre controls, the lack of geographical redundancy would nonetheless significantly expose the utility to the risk of weather-related events, natural disasters, and deliberate threats.

As this scenario would leave the single EDC excessively vulnerable to a variety of risks and the costs to mitigate these potential risks would be too high, the utility does not consider this to be a feasible option.

E8.1.4.3 Option 3: Relocating EDC 1 to a Non-Toronto Hydro-Owned Property

In developing the Program, Toronto Hydro also assessed whether alternative real estate and construction configurations may result in greater cost savings. For example, one alternative would be the relocation of EDC 1 to a location outside the city of Toronto, where real estate costs are significantly lower. The utility further evaluated whether it would be feasible and cost-effective to replace the on-premises EDC 1 with an entirely cloud-based solution.

1. Relocating EDC 1 to a Location Outside of Toronto

Toronto Hydro assessed potential cost-saving opportunities from relocating EDC 1 to a location that is outside of Toronto, where real estate and development costs would be lower than in the city of Toronto.

The major challenge posed by this approach would be maintaining the 1:1 redundancy between the relocated EDC and EDC 2, which is currently achieved [redacted] at a location outside of Toronto Hydro's service area would be extremely costly, due to the larger distances required to secure this connection. These additional costs would likely offset any savings achieved in real estate and/or development costs. To install this [redacted], Toronto Hydro would also be required to coordinate with the utility that is managing the adjacent service area. This level of coordination and approval may result in greater project delays and cost overruns.

As the EDC directly supports all of Toronto Hydro's Control Centre functions, and as there are shared resources and infrastructure with respect to cabling pathways, physical security & access control solutions, as well as power redundancy solutions that can be extended to the proposed EDC location, there are enhanced benefits in moving the EDC [redacted]

Distance also becomes a key parameter in disaster response. For example, employees would have to travel large distances to potentially inaccessible locations to provide emergency and disaster responses. This is not safe or ultimately reliable for employees. When considering these constraints as well as the additional costs, this option is not considered to be feasible or viable for Toronto Hydro.

2. Development of a Cloud-Based Control Operations Systems Centre

Toronto Hydro's EDC 1 is [redacted]

As discussed in Toronto Hydro's Information Technology Asset Management and Investment Planning Strategy in Exhibit 2B, Section D8, the availability of cloud-based solutions, where a third-party provider can manage the servers and perform the maintenance and security updates supporting a business function or software platform, is steadily increasing. Cloud-based solutions are also available in the form of "private clouds", where all cloud computing resources remain exclusive to a single client. However, the cost structure of cloud-based data centre hosting would be significantly different than implementing an [redacted], as vendors typically charge for cloud solutions on an ongoing, monthly basis. In other words, the implementation of a cloud solution would introduce new operational, maintenance, and administrative ("OM&A") costs for Toronto Hydro that over time would exceed the up-front capital expenditures that are proposed under this program and reduce the cost effectiveness of this option.

Furthermore, the implementation of a cloud-based solution—even a "private" one—would introduce several reliability or operational risks that would not exist under an on-premises solution. Toronto Hydro would have to rely upon its vendor(s) to manage the reliability of the cloud-based environment or restore functionality after planned downtimes or unplanned outages, in contrast to an [redacted] This would increase reliability and business continuity risks with respect to the critical functions performed by the EDC. Many of the business applications supported by the EDC, particularly those that are critical for Control Centre Operations,[10] would be better served by an [redacted] that would better meet the latency and communications parameters required for the underlying functions.

In addition, several traditional hard-wired components that are directly supporting the EDC and its connectivity with the field asset infrastructure, including fibre-optic connections, would not be

[10] Exhibit 4, Tab 2, Schedule 7.

compatible with cloud-based services. Given the collective risks presented by the above factors, Toronto Hydro determined that a cloud-based solution would not be feasible option.

E8.1.4.4 Option 4: Shifting EDC 1 to a Toronto Hydro-Owned Property

The fourth and final option involves relocating EDC 1 to an existing property already owned and operated by Toronto Hydro and within Toronto Hydro's service area. Relocating EDC 1 to an alternative Toronto Hydro location would introduce cost savings by utilizing existing footprints and building systems in place. The subsequent sub-sections will individually examine potentially viable locations to assess the feasibility of relocating the EDC functions.

3. Relocating EDC 1 to [redacted]

Toronto Hydro's operations [redacted] Unlike the proposed EDC, the [redacted] does not possess the necessary square footage to house all EDC assets. In addition, there is no current fiber-optic connection with EDC 2, to maintain the 1:1 redundancy between the EDC locations. While a fiber-optic connection can be installed between these two locations, it would considerably raise the overall costs for the program. As the EDC directly supports all of Toronto Hydro's Control Centre functions, and as there are [redacted], there are enhanced benefits in keeping both EDC locations close to the existing Control Centre facilities. [redacted] For these reasons, the [redacted] is not considered to be a prudent, cost-effective option.

4. Relocating EDC 1 to the Proposed EDC (Selected Option)

Toronto Hydro's operations [redacted] As is the case with the [redacted], the proposed EDC has the necessary footprint and characteristics to support the development of a Tier III data center solution, as defined by the Uptime Institute. As there are cost-savings opportunities by leveraging shared resources and infrastructure, including cabling pathways, physical security & access control solutions as well as power redundancy solutions that can be extended to the proposed EDC location, there are enhanced benefits in moving the EDC to a [redacted]

Cost savings are further achieved as the proposed EDC [redacted], which is needed to maintain 1:1 redundancy between the two EDC locations. This current-state connection is further illustrated in Figure 7. The [redacted] possesses a total of 11,500 square feet of space to accommodate a fully functioning EDC with all required assets. Ultimately, when taking into consideration costs, footprint and building characteristics, [redacted] remains the sole option that meets all requirements and cost considerations.



[redacted]

E8.1.4.5 Evaluation of Options

Toronto Hydro selected a set of evaluation criteria to compare each available option, and identify the most optimal, cost-effective, and prudent option for this program. Evaluation criteria included the following:

- Environment (humidity, moisture/condensation, extreme floods, ice storms, etc.);
- Space for EDC footprint;
- Space for EDC generators;
- Prerequisites to meet Tier III requirements as defined by Uptime Institute;
- Geographic diversity (the longer the distance between the two EDC locations, the better);
- [redacted]
- Proximity to Existing Control Centre; and
- Total Cost Impact to Ratepayers.

Each of the above criteria were taken into consideration when selecting the best overall option for Toronto Hydro.

Figure 8 illustrates the results of the options analysis, comparison, and final recommendations, based upon what has already been discussed for each of the options above.

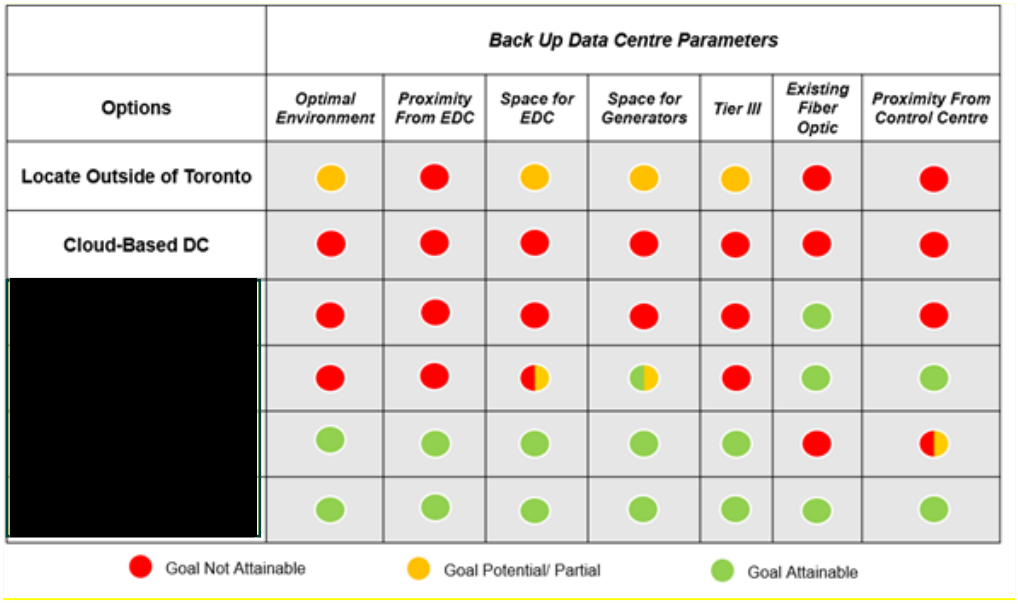


Figure 8: Results of Option Analysis

When assessing current-state risks, availability of space and technological capabilities, costs, as well as overall ability to meet the current and future objectives for the EDC, this comparison indicates that the relocation of EDC 1 to the proposed EDC satisfies all the criteria. Ultimately, relocating the EDC to the proposed location is the most effective and prudent solution to satisfy all requirements for this program.

E8.1.5 Execution Risks & Mitigation

The largest risk to the successful execution of the Program involves timing and costs. Material costs are generally subject to greater price fluctuations over time and therefore cost overruns may transpire. However, through the expertise of experienced project management leadership and industry experts, a proactive approach will be taken to manage these costs.

In addition, there are also construction related risks associated with the Program, including:

- Unexpected construction conditions;
- Occupational health and safety;
- Disruption to Toronto Hydro employees at [redacted];
- Design change approvals;
- Budget shortfalls;
- City approval delays;
- Procurement / Tender delays; and
- Design changes.

These issues can be mitigated with proper communication, leveraging the expertise of the consultants and proper project planning. Overall, leading project management tools and practices will be utilized, and the expertise of highly qualified project management leadership and industry experts will be leveraged to take a proactive approach to managing unknown conditions.

Toronto Hydro's Facilities Asset Management Strategy (filed at Exhibit 2B, Section D6) has established a strong foundation to ensure that these potential planning and execution risks will be mitigated accordingly.

E8.2 Facilities Management and Security

E8.2.1. Summary

Table 1. Program Overview

2020-2024 Cost ($M): 84.8	**2025-2029 Cost ($M):** 145.5
Segments: Facilities Management and Security	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Operational Effectiveness - Safety, Operational Effectiveness - Reliability, Financial Performance, Environment	

Through the Facilities Management and Security Program (the "Program"), Toronto Hydro invests in building improvements that are critical to the operation of the utility's electricity distribution system, demand-driven projects that support the utility's decarbonization objectives, and the ability to modernize its business processes in accordance with the evolving needs and nature of its customers. The facilities owned by Toronto Hydro and covered by the Program include four work centres that have unique footprints and functions, along with 185 stations that serve a critical role in operating the utility's distribution system.

The Program's primary objective is to maintain the infrastructure that supports critical operations of Toronto Hydro's distribution system and replace assets that are end of life and in poor or critical condition. These assets pose an increased risk of failure, which results in an increased risk of business interruption and the deterioration of key outcomes such as safety, reliability, customer service, and productivity. The Program also supports the management and maintenance of Toronto Hydro's buildings in accordance with the growth and evolving needs of the distribution system.

The Program is comprised of the following three areas:

1) **Stations**: Includes investments and improvements to build and maintain the facilities that house Toronto Hydro's distribution stations and manage risks that may arise from any facilities assets deteriorating to the point of poor condition or end of life. As the integrity and operating conditions of stations buildings may significantly affect safety and the reliability of distribution equipment housed within, these assets are critical to grid safety and performance.

2) **Work Centres:** Includes repairs to the facilities that provide a work space for Toronto Hydro personnel and also serve as storage and parking spaces for the utility's equipment, materials, and vehicle fleet. The utility's four work centres are located in the city of Toronto at 14 Carlton Street, 500 Commissioners Street, 71 Rexdale Boulevard and 715 Milner Avenue. The primary function of investments in this area is to minimize safety risks to utility personnel, visitors, and the general public and ensure productivity by replacing poor condition and end of life assets that may otherwise cause hazards or business interruptions. This area also includes investments that support the utility's strategic objectives and outcomes, such as the modernization of business processes in accordance with the evolution of customer expectations and distribution services, and investments to decarbonize in line with Toronto Hydro's Net Zero 2040 Strategy in Exhibit 2B, Section D7.
3) **Security Improvements:** Includes investments in security enhancements at Toronto Hydro's facilities that are necessary to protect the safety and security of employees, assets, and the public. These investments include up-to-date security equipment and technologies. Toronto Hydro also plans to upgrade its preventative security measures to reduce the risk of trespassing, theft, injuries, and cybersecurity attacks.

The Program is a continuation of the activities described in Toronto Hydro's 2020-2024 Rate Application,[1] embodying the utility's Facilities Asset Management Strategy (the "AM Strategy") in Exhibit 2B, Section D5, as well as applicable industry standards, such as ISO 55001. The utility relies on the AM Strategy to manage assets in a cost-effective manner and in order to ensure that facilities remain safe and functional. As discussed in the AM Strategy, the asset condition assessment process determines both a) the risks that may be present in respect of facilities assets and b) plans to mitigate these risks. This assessment and risk management process is a significant part of the planned scope of work for the 2025-2029 rate period. Without sufficient funding to make these investments, Toronto Hydro's facilities would be exposed to the risk of structural failures and significant hazards and/or damage, e.g. due to flooding or leaking. If these risks were to materialize, they would cause severe disruption to the utility's business activities and potentially prolonged outages.

The Program coordinates evaluation and repair work in order to efficiently plan and execute projects. The utility internally coordinates a) its evaluation of a given asset with surrounding asset conditions and its future planned work, and b) capital work on the distribution system, outlined in in the Stations

[1] EB-2018-0165, Toronto Hydro-Electric System Limited Application, Exhibit 2B, Section E8.2.

Renewal (Exhibit 2B, Section E6.6), to align planned facilities projects with distribution projects. For example, if a building requires basement and foundation work, the Program evaluates if other scopes of work can be included at the same time, such as introducing a leak detection system, a sump pump system, or other plumbing refurbishment when the concrete is being removed and trenching can readily take place. Grouping projects together minimizes disruption to stations operations, reduces the potential impacts of the work on customers, and helps the utility manage costs more effectively.

Figure 1 below outlines some examples of stations and work centres. Table 1 outlines some high-level statistics of Toronto Hydro-owned properties.

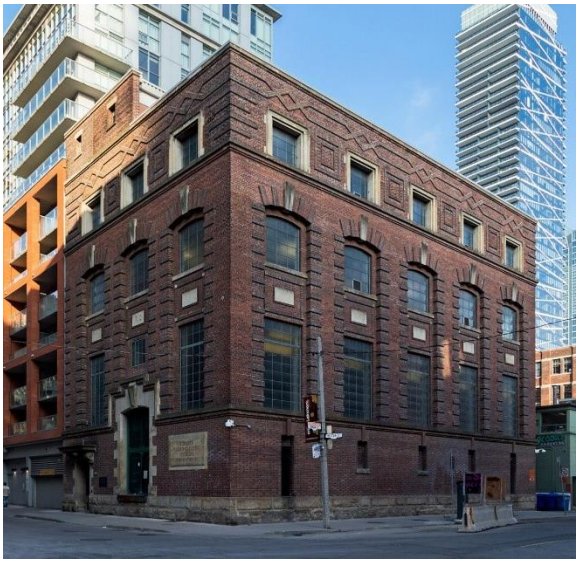




Figure 1: Examples of Toronto Hydro infrastructure; a downtown substation and work centre.

Table 1: Toronto Hydro Stations Properties Statistics

Category	Quantity
Average Station Property Area	6,200 sq. ft.
Stations Properties above 50,000 sq. ft.	12
Heritage Stations Properties	8
Stations Properties over 40 Years Old	165

E8.2.2. Program Outcomes

Table 2: Outcomes and Measures Summary

Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety objectives by: ○ Ensuring compliance with applicable legislative and regulatory requirements, such as the Occupational Health and Safety Act[2], Ontario Regulation 851: Industrial Establishments[3], the Ontario Building Code[4] and the Fire Code[5]; ○ Providing the utility's employees safe and functioning work centres by repairing deficiencies that may cause hazards; ○ Addressing stations related deficiencies such as the absence of secondary exits, non-compliant stairs, and inaccessible doors along pathways; and ○ Improving internal lighting conditions and repairing external damaged lighting in work areas. ○ Installing enhanced safety systems to deter theft, vandalism and violence towards employees, and reduce the risk of unauthorized access into work centres and stations.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's network reliability objectives and ensures compliance with applicable legislative and regulatory requirements such as the Ontario Energy Board's Cyber Security Framework[6] by: ○ Implementing, maintaining and managing modern commercial security systems and technology in partnership with security subject matter experts; ○ Applying security management policies and procedures across all Toronto Hydro sites; ○ Investing in building-related improvements at stations and work centres that are critical to the operation of Toronto Hydro's distribution system; ○ Mitigating the risk of damage to critical distribution equipment housed within the stations; and ○ Prioritizing preventative maintenance of assets that are end of life or in poor condition to mitigate against costly reactive repairs.

[2] Occupational Health and Safety Act, R.S.O. 1990, Ch O.1.
[3] Occupational Health and Safety Act, R.R.O. 1990, Reg. 851: Industrial Establishments.
[4] Building Code Act, 1992, S.O. 1992, c. 23, O. Reg 332/12.
[5] Fire Protection and Prevention Act, 1997, S.O. 1997, c. 4, O. reg 213/07.
[6] Ontario Cyber Security Framework, 2017.

Financial Performance	• Contributes to Toronto Hydro's financial objectives as measured by the total cost and efficiency measures by: ○ Using the AM Strategy (filed at Exhibit 2B, Section D6) to optimize assets' capital and operational costs in line with the condition assessment
Environment	• Contributes to Toronto Hydro's environmental objectives and enables the goals outlined in utility's Net Zero 2040 Strategy (filed in Exhibit 2B, Section D7) by reducing greenhouse gas ("GHG") emissions through: ○ Electrification of building operation systems such as replacing natural gas heaters with air-source heat pumps

E8.2.3. Program Drivers and Need

Table 3. Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Safety and Failure Risk

The Program prioritizes investments that address assets at end of life and in poor condition, in line with the AM Strategy and Toronto Hydro's objectives to operate and maintain a safe and reliable distribution system. The utility evaluates the condition of building assets pursuant to the AM Strategy.[7]

Figure 2 below illustrates the relationship between the probability and impact of failure for the various building systems according to the Uniformat II framework, as discussed in the AM Strategy. The probability and impact measures are an output of periodic building condition assessments. Understanding the relative risk associated with each of the building systems allows Toronto Hydro to efficiently allocate capital funding to the areas that provide the best value and address the greatest risk.

[7] Exhibit 2B, Section D6, Pg. 3-4.

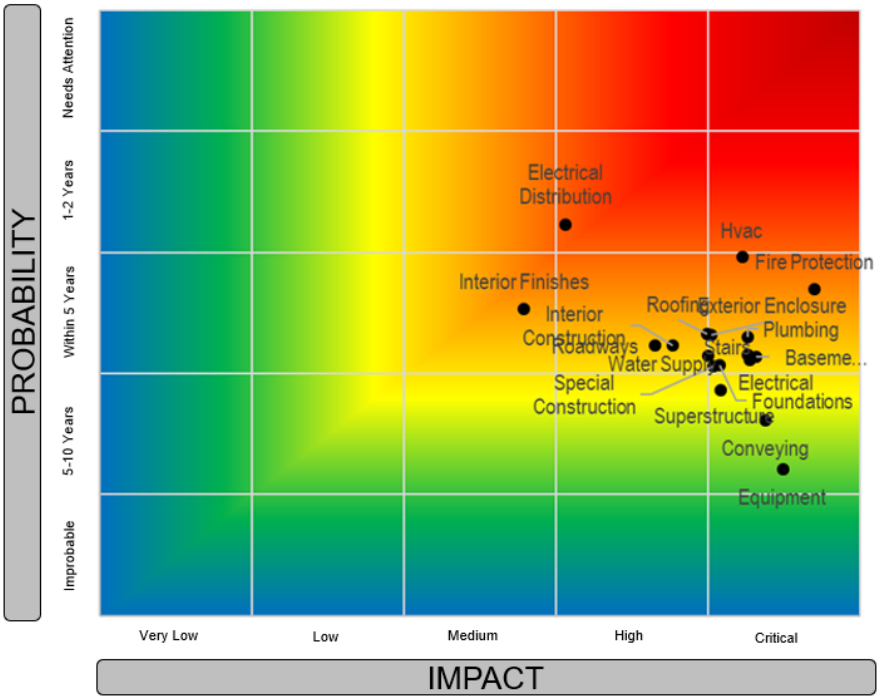


Figure 2: Likelihood-impact matrix for UNIFORMAT II building elements as of 2023

E8.2.3.1 Categories of Facilities Work

Table 4. Types of Program Projects Planned for the 2025-2029 Rate Period

Project Category	Rationale	Risk of Failure
Structural & Envelope (e.g. repairs to the building envelope and façade, windows, foundation and structural elements, beams, joists, columns, etc.)	Addresses safety issues and prevents structural damage of critical supporting functions and deteriorated building performance.	If a structural element were to fail and damage distribution equipment, significant and prolonged outages could occur.
Architectural & Interiors (e.g. roofs, doors, building finishes, office work areas, etc.)	Addresses safety issues and building water-tightness, and promotes optimal building performance.	If a building asset or system failure were to expose interiors to the elements (e.g. water infiltration), distribution equipment could be

		permanently damaged, costly business interruptions could ensue and hazards may exist to workers and the public.
Fire & Life Safety (e.g. stations fire alarm system upgrades, signage and emergency lighting, etc.)	Replaces obsolete fire alarm systems and addresses safety and compliance issues.	Deficient or lacking fire and life safety systems and assets may endanger employees due to hazards from fire and harmful gases, and also put equipment at risk of damage or destruction, thereby increasing the risk of outage.
Mechanical, Electrical & Plumbing (e.g. HVAC system replacements, supplementing cooling systems, upgrading and replacement of lighting, sump pump replacements, plumbing fixtures, hot water tanks, etc.)	Addresses assets in poor condition, equipment overloading and capacity issues, safety concerns, and achieves compliance with mandated requirements.	Failures of these types of assets and systems may cause damage to equipment (e.g. in the event of flood in basements) or cause operational disruptions and a loss of productivity (e.g. in the event of loss of power).
Civil & Sitework (e.g. exterior access ways and walkways, including pavement, driveways, and parking spaces, etc.)	Addresses safety and security-related concerns.	Deficiencies in assets could cause safety risks (e.g. trip and fall hazards) for employees and the public. Furthermore, deficient or lacking features (e.g. doors that do not properly lock) could result in security risks such as theft, vandalism, or unauthorized access.

1. Structural & Envelope

Structural features are those supporting a building. Envelope features are those that separate a building's interior from its exterior. The integrity and operating condition of a building's structural and envelope features are critical to keeping Toronto Hydro's distribution system reliably operational

and ensuring the safety of employees and the public. Structural and building envelope components cannot run-to-fail because one beam or column failure can result in a full building failure, leading to potentially catastrophic safety and reliability risks and significant operational disruptions.

The sections below outline some planned structural and envelope repairs and refurbishments for assets in a deteriorating state. These sections provide the categories of planned work on station assets and the rationale for each type of investment.

a. Structural

Toronto Hydro plans to address issues related to the foundation and supporting structural elements (e.g. beams, joists, and columns) within work centres and stations, including two downtown station structural refurbishments.

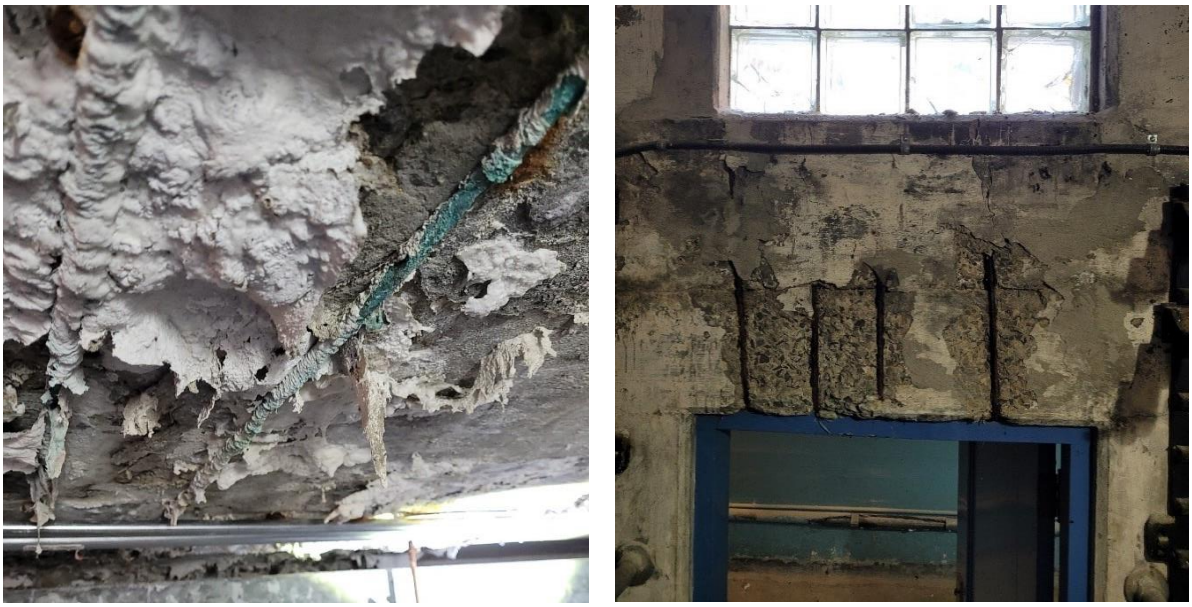


Figure 3: Examples of structural deterioration at stations, from left to right: Wiltshire Station exposed and corroded rebar with significant water infiltration, Wiltshire Station exposed rebar in concrete wall.



Figure 4: Examples of structural deterioration at stations, from left to right: Windsor Station cracked concrete floor slab, Windsor Station corroded rebar columns.

Figure 5 provides examples of aging structural assets where deterioration can occur more rapidly and in a greater number of locations when water infiltration is present.



Figure 5: Examples of structural deterioration at work centres, from left to right: 500 Commissioners Building C – spalling concrete wall with preventative netting; 500 Commissioners Building C – exposed deteriorated waterproofing; 500 Commissioners Building C – rusted steel staircase.

b. Envelope

Toronto Hydro plans to address issues related to end of life building envelope elements such as exterior cladding, windows, and roofing systems to protect critical equipment from weather. The

utility's envelope investments in stations' window upgrades and increased façade insulation will advance the utility's objective to reduce its facilities' GHG emissions by increasing energy efficiency



Figure 6: Examples of envelope deterioration at stations, from left to right: Glengrove Station concrete block wall cracking, Duncan Station brick wall cracking, Junction Station brick wall cracking.



Figure 7: Examples of envelope deterioration at work centres, from left to right: 500 Commissioners Building A – cracking of precast panels; 14 Carlton – deteriorated windows, sealant, and frame.

2. Architectural & Interiors

The architectural system and interiors of a building comprise a building's core systems, including the roof, doors, floor plans and wall partitions, and interior finishes and furnishings.

a. Architectural

Toronto Hydro must proactively and preventatively invest in architectural repairs to maintain the integrity of its stations portfolio. When structural damage is unearthed once damaged waterproofing is removed from a station, the utility typically pairs architectural repairs to waterproofing systems with structural repairs of the underlying building assembly and structure. Other architectural items that require repair or maintenance to ensure worker safety are fire rated enclosures, egress systems, and exits.



Figure 8: Examples of architectural deterioration at stations, from left to right: George and Duke Station deteriorated concrete stairs, Centre Drive Station water infiltration from roof.



Figure 9: Example of Terauley Station, replacing non-code-compliant stairs and railings with functional ones, and improved dock access.

b. Finishes

Within the utility's stations portfolio, Toronto Hydro plans to address issues related to buildings' interior finishes that directly impact user safety. As examples, certain lighting standards are required to keep buildings at an acceptable level of brightness. Furthermore, deteriorated flooring and stair treads can cause tripping hazards. Maintaining, repairing, and replacing these finishes provides a safe and accessible workplace for the employees who interact with the utility's stations.

Within the utility's work centres, Toronto Hydro plans to address issues related to the building interior finishes (e.g. coatings, carpets, workstations and office furniture) where existing materials are end of life or in poor condition and where assets no longer meet the needs of the utility's workforce. As examples, improving the working condition of some finishes will promote employee safety, such as lighting standards to keep buildings at an acceptable level of visibility, and mending deteriorated carpet and flooring will help reduce the risk of tripping hazards. Furthermore, maintaining finishes at a reasonable standard prevents the need for significant renovations to address cumulative deterioration.

3. Fire & Life Safety

Fire and life safety systems, including fire suppression, alarms, and preventative equipment, protect workers in the event of fire or environmental hazards and are essential to building, staff, and public safety.

Stations without functioning life safety or fire alarm systems are a high priority investment. The Program will continue work that the utility commenced in the 2020-2024 rate period work to replace outdated fire alarm panels. As of 2023, Toronto Hydro upgraded five (5) panels to a current and compliant fire panel system during the current rate period.

It is safer and less expensive to proactively repair and replace fire and life safety systems. If a fire alarm device is in a state of disrepair, the utility must hire fire watch personnel for patrol until the fire alarm system is back online. The cost of hiring a 24/7 fire watch for a device is prohibitive if the fire watch must be in place for days or weeks until a part is shipped for the alarm repair or replacement. This type of reactive response incurs significantly higher costs than a proactive repair and replacement program.

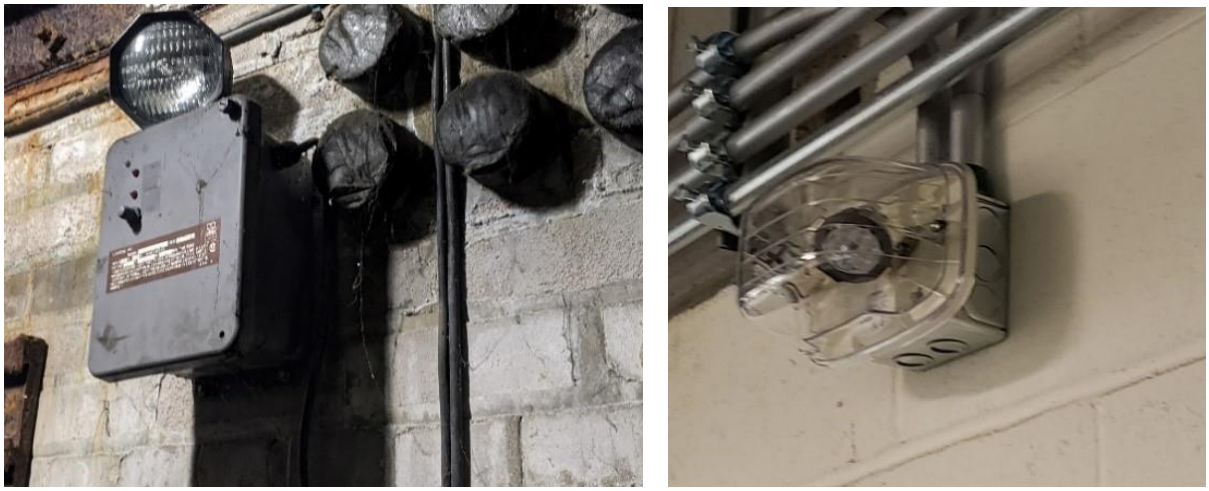


Figure 10: Example of Terauley Station, replacing non-compliant emergency lighting (left) with functional and compliant lights (right).

Within work centres, the 500 Commissioners work centre has aging dry sprinkler systems and faulty water systems that require maintenance and repair. A side benefit of modernizing and improving the condition of these systems would be to reduce nuisance alarms that disrupt work at work centres.

[redacted] Reducing the incidence of false alarms triggered by faulty systems would alleviate this risk. Furthermore, by implementing modern systems like two-stage alarms, fire alarms and evacuations can target localized building zones and minimize the disruption to critical control operations.

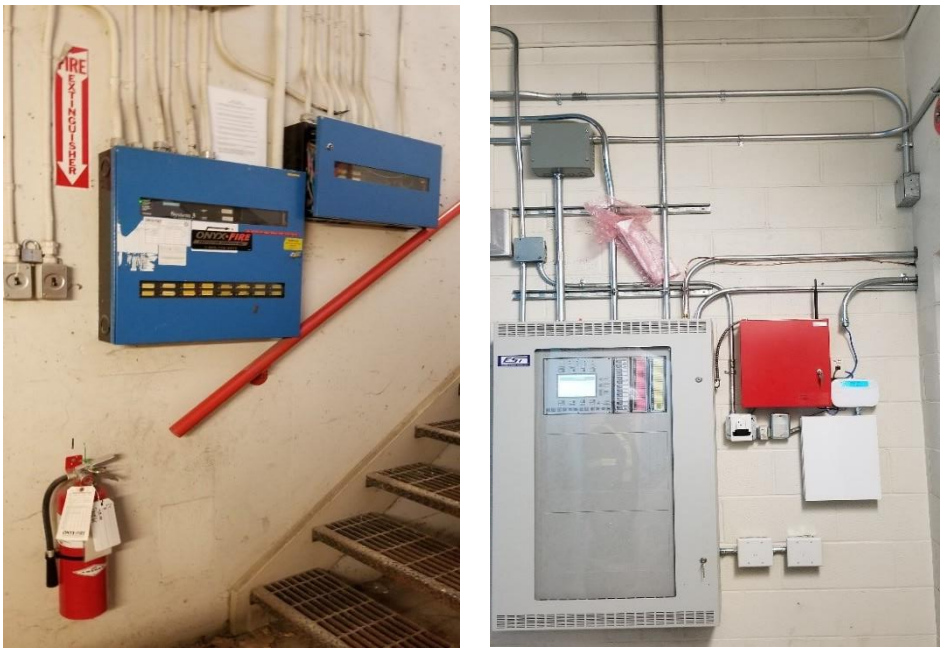


Figure 11: Example of Esplanade Station outdated fire alarm panel (left) with a new, functional panel (right).

4. Mechanical, Electrical & Plumbing

Mechanical and electrical assets include plumbing, heating, ventilation and air conditioning ("HVAC") systems, site lighting, electrical panels, electrical wiring, building automation systems, and power distribution systems in Toronto Hydro's buildings.

These systems are critical to reliable operation of the utility's work centres and stations buildings. Toronto Hydro plans to replace end of life infrastructure and equipment, including cooling systems

for critical equipment in stations, to improve reliability on high temperature days and prevent disruptions or outages due to overheating equipment. The utility also plans to make investments in plumbing and emergency sump systems and other infrastructure to reduce the risk of asset failures and damage to equipment, which may disrupt grid operations.

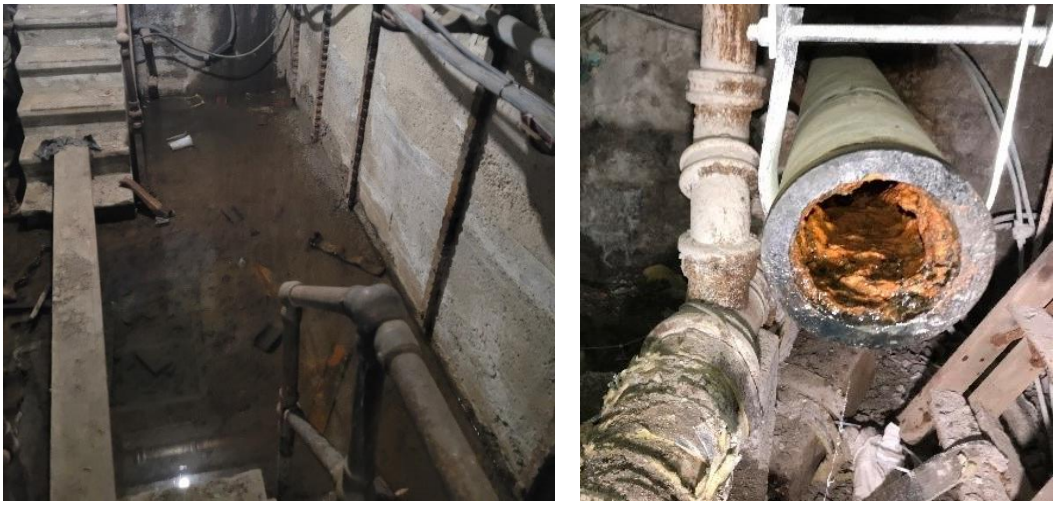


Figure 12: Examples of mechanical and plumbing deterioration at Stations: Terauley Station with a flooded basement and Terauley Station water service line clogged and full of debris.



Figure 13: Examples of HVAC additions at Stations: Strachan Station without additional air conditioning (left) and after with two new condensing units installed for keeping air temperature and equipment cool (right).



Figure 14: Examples of HVAC additions at Stations: Cavanagh Station without additional air conditioning (left) and after with ducts and venting installed for keeping air temperature and equipment cool (right).

5. Civil & Sitework

Property civil work and sitework includes work related to exterior access ways and walkways, pavement, driveways, parking spaces, and exterior lighting. A variety of investment and maintenance needs are present in this area. Certain exterior surfaces at work centres and stations are in poor condition and need repair to prevent tripping hazards, pot holes, delamination, and water ponding. Exterior lighting at certain stations is currently inadequate for response crews' ability to work safely. Additional paving is required to accept multiple trucks on site at several stations as a need for operational efficiency.



Figure 15: Examples of driveway deficiencies at Stations: Hunting Ridge Station driveway in disrepair, Longfield Station with no available parking for response crews.

E8.2.3.2 Stations

Toronto Hydro's investments over the 2025-2029 rate period will focus on stations. Approximately 50 percent of the planned work will address stations assets and infrastructure. Figure 14 below highlights some examples of stations with poor quality structural assets. Deterioration at this level indicates that the structural system has operationally lost its serviceability for the actual service load that the structure is subjected to and presents a high risk to occupant and equipment safety. To mitigate the risk of partial or complete building collapse that may ensue from these conditions and prevent significant damage to distribution equipment or catastrophic safety risks to employees and the public, the utility must address these deficiencies in a timely and effective manner.



Figure 16: Examples of existing stations in critical condition, from left to right: George and Duke Station, beam with exposed rebar, Defoe Station cracked beam, Junction Station deteriorated foundation wall.

Toronto Hydro's portfolio includes large-footprint stations, stations on heritage sites, and stations integrated into residential neighborhoods. To address stations-related issues, the utility must tailor specialized design and investment plans to each station's features and condition. These investment plans consider asset age, site condition, priority, probability of failure, and impact to yield a system criticality rating.

E8.2.3.3 Work Centres

1. Overview

In addition to investments to maintain, repair, and replace assets as discussed above under subsection E8.2.3.1, Toronto Hydro plans to invest in work centres in accordance with its strategic outcomes and objectives. Work centres house Toronto Hydro employees and provide a physical space to operate the business. Employees have functional workplaces that enable them to provide quality service to customers. As the nature and needs of customers evolve and the utility invests in growing its distribution system and modernizing its business processes in response, it also must have adequately furnished work centres for employees to execute work and provide customer service. Approximately 35 percent of the planned work in the Program is related to work centres.

The volume of asset management work required at work centres over the 2025-2029 rate period is lower compared to the Stations segment, with three of the four work centres being relatively new (having been built or retrofitted within the last few decades) and in good operating condition.

Key work centre-specific initiatives include:

- **Work Centre Decarbonization:** targeted projects that will decrease GHG emissions from Toronto Hydro's work centres; and
- **Work Centre Modernization:** select improvements to office workspaces that support the future of collaborative and flexible work, and efficiently use office areas.

2. Work Centre Decarbonization

The Program includes investments to decarbonize work centres in alignment with the utility's Net Zero 2040 Strategy.[8] Toronto Hydro's Customer Engagement showed that a majority of the utility's

[8] Exhibit 2B, Section D6.

customers indicate general support for investments that reduce Toronto Hydro's environmental impact.[9]

Toronto Hydro will phase the timeline for decarbonization investments, starting in the 2020-2024 rate period and continuing through the 2025-2029 rate period and beyond, until Net Zero targets are achieved by 2040. The utility will execute these investments in a balanced manner to achieve decarbonization objectives while maintaining costs at a reasonable level and minimizing the risk of stranded assets and business interruptions.

Toronto Hydro's decarbonization investments in the 2025-2029 rate period will focus on assets that are at end of life to avoid stranding assets. The utility will engage in fuel switching by replacing selected fossil fuel-powered assets identified with electric assets to prudently deliver a high level of decarbonization proportionate to project costs. The utility will concurrently make investments in building efficiency, building automation systems ("BAS"), and other building envelope measures to improve the energy efficiency of its work centres, which will reduce overall energy use and require fewer electrified assets for heating and cooling work centres.

The three main investment streams targeting GHG emissions at work centres will consist of:

1. **Fuel Switching (Eliminate Scope 1 Emissions)**: replacing natural gas- or other fossil fuel-powered equipment with electric assets.[10]
    a. GHG emissions from natural gas heating accounted for majority of all of the utility's GHG building emissions in 2022.[11]
    b. Toronto Hydro will target aging and/or poor condition natural gas equipment minimize stranded assets.
2. **Improve Building Efficiency (Reduce Scope 2 Emissions)**: improving energy performance to reduce buildings' electrical loads.
    a. In conjunction with eliminating GHG emissions from fossil fuel-powered equipment, Toronto Hydro will reduce the electrical load of its buildings through efficiency

[9] Exhibit 1B, Tab 5, Schedule 1
[10] Scope 1 emissions are direct GHG emissions that occur from sources controlled or owned by an organization. Scope 2 emissions are emissions that an organization causes indirectly and that come from where the energy it purchases and uses is generated. Scope 3 emissions are emissions that are produced by an organization's value chain, and not as the result of an organization's assets or activities. This program does not address measures to reduce the organization's Scope 3 emissions.
[11] For more details on Toronto Hydro's performance results, please refer to Exhibit 1B, Tab 3, Section 2.

measures, which would further reduce GHG emissions associated with line losses from the utility's consumption of electricity delivered through transmission and distribution grids.

b. Building Automation Systems ("BAS"): BAS provide a centralized control system for a building's facilities systems, including electrical and mechanical (heating, ventilating, air conditioning) systems, which provides both visibility and control of the building's operations and performance, ensuring harmonious and efficient operations according to occupant requirements. Part of the investments will add legacy and new equipment to the BAS network.

c. Envelope Improvements: identifying areas with air leakage and implementing appropriate repairs reduces unnecessary heating and cooling, and lowers the demand on building operation. Intensive envelope improvements include façade retrofits and roof repairs. Although these retrofits and repairs are standard maintenance for aging buildings, Toronto Hydro's investments will enable increased insulation above minimum code requirements to retain heating and cooling more effectively, lowering energy consumption.

3. **Additional Improvements (Reduce Scope 1 & 2 Emissions):** other improvements to building operation efficiency.

   a. Adding two cooling setpoints to air conditioning units that allow high operation on hot days and low operation on more frequent mild days.

   b. Providing additional CO_2 sensors to act as occupancy monitoring, to automatically adjust ventilation for a space according to real-time occupancy.

   c. Air curtains at warehouse overhead doors to reduce outdoor air infiltration at warehouse and garage spaces when the overhead doors are open.

3. Work Centre Asset Management

As discussed in the AM Strategy,[12] Toronto Hydro applies a tailored investment approach to its head office located at 14 Carlton, in accordance with the age and deteriorated condition of the building. The utility must reactively repair and maintain assets to reduce the risk of infrastructure failure, while navigating rising costs and operational challenges due to the building's age, limitations from the original design, heritage status, location, and operational significance. One example that highlights

[12] Exhibit 2B, Section D6, subsection D6.3.

the challenge of maintaining the 14 Carlton work centre is ongoing façade repairs. The last major building masonry repair project was executed in 2016. Toronto Hydro plans to undertake the next repair project in the 2025-2029 rate period, as the risk of leaving the façade in disrepair could result in material falling from the building, causing hazards to employee or public safety. Since masonry repairs tend to be disruptive of building operations, involving significant vibrations, dust, loud noise, and scaffolding structures, the utility will plan these repairs in a manner that will minimize the risk to critical operations.

4. Work Centre Modernization

Toronto Hydro will selectively invest in its office workspaces to support an engaging environment that promotes productive and collaborative hybrid work, and to efficiently optimize office footprints. Investments in physical office spaces such as workstations, meeting rooms, leader offices, and shared spaces will enable employees to more efficiently engage in collaborative and inter-departmental group work. As Toronto Hydro's workforce grows and evolves,[13] the utility will also leverage these investments to improve the efficiency of office spaces by consolidating workstations with a large footprint and providing space for new employees without requiring expansions. Since the relevant assets typically consist of furniture and technology with relatively short lifecycles that are typically capitalized within ten years, the utility can plan investments in a flexible manner.

Investments to modernize work centres will support the growth of the utility's workforce and promote employee satisfaction, retention, and adaptation to flexible work practices, enabling personnel to efficiently and effectively perform business operations and serve customers.

c. Workstations

Toronto Hydro will install new workstations to replace bulky, space-inefficient, and aging or deteriorating workstations and increase employee density. These investments will reduce the cost of expanding the utility's workforce by providing a smaller physical footprint per employee.

d. Meeting and Training Rooms

Toronto Hydro will install audio and visual upgrades, including speakers, microphones, monitors, and TVs, in meeting and training rooms to support online web conferencing. The utility will also invest in

[13] See Exhibit 4, Tab 4, Schedule 4 for more information on Toronto Hydro's workforce over the 2025-2029 rate period.

modern furniture and design features to replace damaged and outdated furniture. These investments will support employee productivity and efficiency within the hybrid work environment.

e. Common Spaces

Toronto Hydro will make investments to update common spaces in its work centres to support hybrid office work by facilitating face-to-face communications. The purpose of these investments is to transform simplistic waiting areas and empty spaces in the utility's work centres into places for employees to work, gather around, charge devices, break up their day with a change of scenery, meet visitors or guests, share content, or take a phone call. Providing access to spaces for collaborative and in-person interactions to take place will contribute to employee satisfaction, and thereby productivity and retention.

E8.2.3.4 Security Improvements

Toronto Hydro will make investments to improve the utility's physical security infrastructure and support operations. Approximately 15 percent of the planned work under the Program is associated with security improvements. As the utility's properties are located in a broad range of neighbourhoods across the city of Toronto, stations and work centres are at risk of general theft, vandalism, and trespassing. Other threats include attempts by customers or members of the public to harass staff or threats to distribution operations and the distribution system by malicious organized actors, such as terrorism or cyber security breaches. Security measures that protect properties from physical threats also contribute to the safety of employees and critical equipment and assets, and to the overall reliability of the distribution system. The integrity of the utility's physical security systems is essential to ensure the distribution system's safe and reliable operation. Toronto Hydro will plan and make investments in a manner that is strategic, proactive, and responsive to identified risks as well as in alignment with the Ontario Energy Board's Cyber Security Framework.[14]

Electricity distributors are targets for security breaches because they play a critical role in providing an essential service and host a broad database of customer information, Similar to other public service providers and infrastructure operators such as hospitals, public transit operators, traffic management systems, emergency services, and financial hubs. The utility's planned security

[14] Ontario Cyber Security Framework (December 6, 2017), available at: < https://www.oeb.ca/sites/default/files/Ontario-Cyber-Security-Framework-20171206.pdf>.

improvements will address existing gaps in the physical safety systems and implement proactive measures to lower the risk of safety breaches.

Toronto Hydro will focus on improving security measures in two categories: physical access measures and technology and network measures. Within the physical access category, the utility will implement physical changes to site security to improve control over access to properties. Within the technology and network measures category, the utility will improve video monitoring to provide improved response abilities by its Physical Security Operating Centre ("PSOC") to address breaches of security.

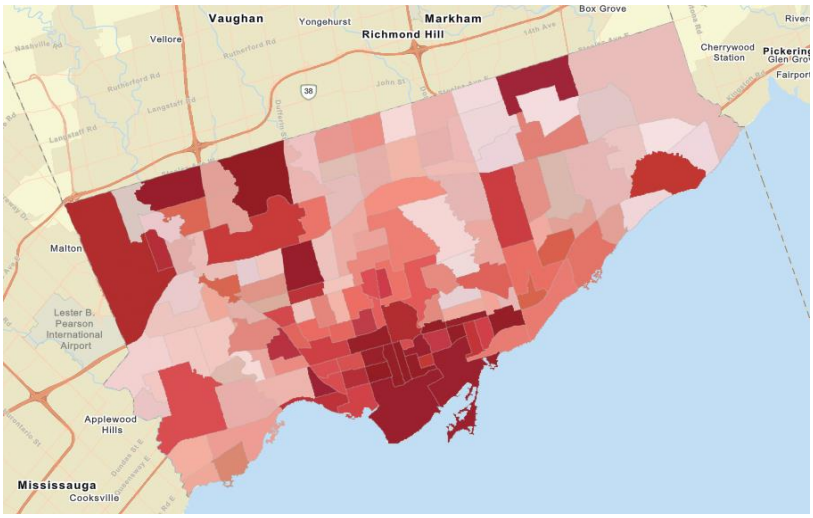


Figure 17: Major crime indicators; Toronto Police Service 2014-2021 statistics for breaking and entering and robbery.[15]

5. Network Security Improvements

The information technology and operating technology ("IT/OT") assets that enable Toronto Hydro to effectively and efficiently manage its distribution system, such as Supervisor Control and Data Acquisition ("SCADA"), also attracts heightened physical and cyber security risks. The utility must protect its IT/OT infrastructure and increase resilience against these diverse risks to ensure that critical grid distribution equipment and customer service functions remain reliably operational.

[15] Toronto Police Service Public Safety Data Portal https://data.torontopolice.on.ca/pages/major-crime-indicators

Within network security improvements, Toronto Hydro plans to replace analog security cameras with Internet Protocol ("IP") cameras [redacted]

The utility implemented IP-based cameras in three stations over the 2020-2024 rate period, including the [redacted] As of December 2022, [redacted] had analog cameras. Toronto Hydro will continue to expand the IP-based camera network to stations over the 2025-2029 period and will prioritize locations based on risk and strategic considerations.

These investments in IP-based cameras will also improve the PSOC's functionality and improve the effectiveness of its video management system ("VMS") [redacted] Upgrades to hardware, such as monitor and video displays will further improve PSOC and support these security initiatives.

6. Physical Security Improvements

Toronto Hydro will invest in physical security measures to prevent unauthorized access to stations while also keeping them accessible for authorized personnel. Examples include providing increased outdoor lighting, repairing fencing, having adequate fence heights, and installing additional barriers such as barbed wire where required. Other improvements relate to door and gate openings. The utility will make investments to ensure that card readers work reliably when staff need to access a location [redacted]



Figure 18: Examples of University Station entrance door in poor condition (left) and after being retrofitted via the station door program (right).

E8.2.4. Expenditure Plan

Toronto Hydro plans to spend approximately $145.5 million over the 2025-2029 rate period to respond to the previously discussed needs and to make the proposed investments. The historical and forecast costs for the Program are set out in Table 5 below. The utility will determine the full scope of work to be performed under the work centres and stations categories based on risk-based prioritization in line with the AM Strategy and workload balancing over the 2025-2029 rate period.

Approximately 50 percent of Program expenditures will be dedicated to stations work. As discussed in detail above, 87 percent of Toronto Hydro's stations are over 40 years old and require significant upgrades to architectural, fire and life safety, mechanical and electrical, and civil and plumbing infrastructure and to ensure building and fire codes compliance. These investments will also enable the utility's security measures to better align with the principles of the Ontario Energy Board Cyber Security Framework.

35 percent of Program expenditures will account for work centre-related projects to address aging and deteriorating assets and office space modernization initiatives that will increase the productivity

of Toronto Hydro's workforce. This work will also facilitate investments in decarbonization at the utility's work centres to reduce facilities-related GHG emissions in accordance with the Net Zero 2040 Strategy

The remaining 15 percent of the Program expenditures will focus on implementing security improvements at stations and work centres.[16]

In accordance with the AM Strategy, the Program will prioritize the proactive replacement of critical assets that are end of life and in poor condition for the 2025-2029 rate period. This approach will reduce the risk of emergency work, which can impact the safe and reliable distribution of electricity, and optimize the value the utility receives from assets in service.

Table 5. Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Stations	1.7	4	11.8	11.3	10.3	15.1	15.1	14.5	14.5	13.3
Work Centres	5.5	6.2	6.9	8.0	5.5	10.2	10.4	10.5	10.6	10.6
Security Improvements	3.4	5.4	2.7	1.5	1.0	4.3	4.3	4.1	4.2	3.8
Total	**10.6**	**15.6**	**21.4**	**20.8**	**16.8**	**29.6**	**29.8**	**29.1**	**29.3**	**27.7**

Toronto Hydro will prioritize planned work according to the impact of a given asset's failure on the utility. As described in the AM Strategy, the Program first prioritizes assets whose failure poses a safety risk to Toronto Hydro personnel or the general public. The program next prioritizes assets whose failure impacts business continuity and the protection of the distribution system. Finally, the program prioritizes assets whose failure would impact productivity gains and the achievement of other business objectives third.

E8.2.4.1 Stations

Toronto Hydro assesses stations building assets and assigns a condition rating of critical, poor, fair, good or excellent on a regular basis in line with the AM Strategy. Assets that received a poor condition rating will be addressed within the 2025-2029 plan period. Assets in fair condition will be closely monitored and maintained under a preventative maintenance program. Assets will be also

[16] *Supra* note 8

be evaluated to ensure that a net reduction in GHG emissions to support net zero targets will be prioritized upon repair or replacement.

Finally, repairs for assets in good condition are not planned for the 2025-2029 period. Toronto Hydro will only replace assets that are end of life and are in poor condition. Work on these identified assets will proceed in line with the prioritization identified in the AM Strategy and described above.

Refer to Table 6 below for the planned capital expenditure work for Stations.

Table 6. Stations Capital Projects Work

Project Category	Major Assets to be Replaced	Percentage of Estimated Segment Costs
Structural & Envelope	Foundation, beams, joists, columns	20 percent
Architectural & Interiors	Roofs, doors, window	15 percent
Fire & Life Safety	Fire alarm systems, emergency lighting, signage	25 percent
Mechanical, Electrical & Plumbing	Interior systems, power distribution, lighting, HVAC, sump pumps, plumbing fixtures, hot water tanks, drainage pipes, tanks, fittings, sanitation	30 percent
Civil & Sitework	Pavement, driveways, parking areas, walkaways	10 percent

E8.2.4.2 Work Centres

As mentioned in section E8.2.4.1 Stations, the AM Strategy and priority ratings are also used to classify work centre assets. Toronto Hydro will only replace assets that are end of life and in poor condition. This means deferring the replacement of assets that are end of life but are in fair or good condition or are “run-to-fail”.

Refer to Table 7 below for the planned capital expenditure work for Work Centres.

Table 7. Work Centre Capital Project Planned Work

Project Category	Major Assets to be Replaced	Percentage of Estimated Segment Costs
Structural & Envelope	Foundation, beams, joists, columns	20 percent
Architectural & Interiors	Roofs, doors, window	20 percent
Fire & Life Safety	Fire alarm systems, emergency lighting, signage	20 percent
Mechanical, Electrical & Plumbing	Interior systems, power distribution, lighting, HVAC, sump pumps, plumbing fixtures, hot water tanks, drainage pipes, tanks, fittings, sanitation	20 percent
Civil & Sitework	Pavement, driveways, parking areas, walkaways	15 percent
Office Workspace Transformation/ Modernization	Collaborative furniture, open spaces, hybrid work areas, audio visual enhancements	5 percent

E8.2.4.3 Security Improvements

The planned projects for the 2025-2029 rate period under the Security Improvements segment will support and expand integrated security features (e.g. video systems, keys, intercoms, access control measures, and duress stations). These security investments will both replace existing aging and deteriorated and also expand new assets to address any identified security gaps or risks [redacted]

Security improvements can be broken down into two areas: network security improvements and physical security improvements. Table 8 below shows a breakdown of the capital expenditures in each of these areas.

Table 8. Security Capital Projects Work

Project Category	Major Investments and Assets to be Replaced	Percentage of Estimated Segment Costs
Network Security Improvements	Access controls, video management system, IP-based cameras, Security Operations Centre, Security Access Control Software ("CCURE"), IP camera conversion and, modernization.	50 percent
Physical Security Improvements	Exterior lighting, fencing, card readers, automatic gates, exterior doors, exterior windows, and modernization.	50 percent

E8.2.5. Options Analysis / Business Case Evaluation ("BCE")

E8.2.5.1 Option 1: Run-to-Fail Approach

Under the run-to-fail approach, Toronto Hydro would delay necessary investments in work centres and stations and would perform replacements and repairs only on a reactive basis, when an asset fails. Since the majority of assets that are end of life and in poor condition are critical to the utility's operation, this approach would pose a significant risk to the business continuity of Toronto Hydro's operations. This approach would also run counter to the Ontario Energy Board's Cyber Security Framework, which stresses the importance of physical security to support utilities' cyber security objectives. This option would incur costs to reactively repair and replace assets, and significantly increase costs associated with reactive work, rentals, and labour to accommodate long lead times for specialty equipment.

Some of the effects of instituting a run-to-fail strategy would include:

- **Stations:** Maintenance and repairs to fire alarm panels, large HVAC units, and heritage station assets must be planned in advance to account for engineered design, analysis, material purchases with long lead times and/or custom-built materials (e.g. in support of heritage preservation). Applying a run-to-fail strategy to these types of assets would lead to business disruptions when the assets fail. Asset failure could also directly affect grid reliability if failing assets were to damage distribution equipment or expose them to damage and faster deterioration. The cost associated with unexpected failures and reactive repairs

often outweighs the cost of proactive repairs due to the fact that reactive repairs generally require additional scope and rapid response involving labour overtime. This approach would also increase the risk of safety hazards by deferring work to bring the utility's stations into compliance with the Ontario Building Code by addressing existing water infiltration, building integrity and exterior lighting issues.

- **Security:** Deferring investments in security improvements will increase the likelihood of unauthorized access to physical facilities or the IT/OT network and consequently increase the risk of cyber security threats. Deferring these investments will also increase the risk of criminal activity at stations and work centres, jeopardizing the safety of Toronto Hydro's employees and causing property damage.
- **Work Centres**: Deferring efforts to decarbonize facilities assets at the utility's work centres would cause the utility's emissions to remain at current levels, compromising the utility's Net Zero by 2040 objective and leaving more decarbonization work for future rate periods.

E8.2.5.2 Option 2 (Selected Option): Maintenance and Replacement of End of Life and Poor Condition Assets and Investment in Security Improvements at Certain Toronto Hydro Facilities

Under this approach, Toronto Hydro would focus on asset lifecycles and condition assessments to selectively determine assets that require maintenance and replacement. Ongoing preventive maintenance reduces the risk of unexpected asset failures that could disrupt the utility's operations. Furthermore, this option allows the utility to optimize its capital expenditures by replacing assets in poor condition and retaining assets that are at end of life but in good condition.

Some of the effects of implementing this option would include:

- **Stations:** Assets that are end of life, but are either in good or fair condition or are run-to-fail by nature will remain in service, allowing the utility to focus expenditures and efforts on stations assets that require more immediate attention. By addressing hazards and asset deficiencies (e.g. those relating to lighting, HVAC, flooring, and stairs), Toronto Hydro can achieve and maintain compliance with legislative and regulatory requirements and minimize the safety hazards posed by current issues. This approach also allows the utility to use a competitive bids process to obtain more favourable acquisition costs for goods and services while maintaining the quality of work and process integrity.

- **Security:** By taking a proactive approach to improving security systems, Toronto Hydro can minimize physical threats to its assets by enabling a real-time response to threats. The security improvements planned under this option would also increase the efficiency of onboarding and offboarding procedures for employees and contractors. For example, automating the granting, modification, and revocation of card access privileges as employees are hired or when their role changes (e.g. through promotions or terminations) would enable the utility to complete these steps more quickly and less manual intervention.
- **Work Centres:** Decarbonization, electrification, and energy efficiency investments under this option would enable Toronto Hydro to meet its emissions reduction outcomes over the 2025-2029 rate period and enable healthy progress to the utility's target to reach Net Zero by 2040, while pacing investments to contain costs for optimum benefits and avoid stranded assets.[17]

E8.2.5.3 Option 3: Preventative Maintenance and Replacements of All End of Life Assets and Investing in Security Improvements at All Toronto Hydro Facilities

Under this option, Toronto Hydro would replace all assets that are end of life, irrespective of specific asset condition, and would implement security improvements (such as upgrading video management system hardware and software) at a greater number of stations. This approach would also include preventative maintenance on all assets, without regard for asset condition, function, or criticality. This approach would require significantly higher capital expenditures, and would increase the risk of stranding assets.

In addition to the points listed under Option 2, the benefits of this option would include:

- **Stations**: Toronto Hydro would replace all assets at end of life, which would improve their reliability and provide operational savings by reducing the financial burden of reactive maintenance. These benefits would be offset by a significant increase in proactive capital investments under this option.
- **Security:** Security enhancements would be completed at a greater number of Toronto Hydro locations, increasing the utility's physical security as well as protection against unauthorized entry, vandalism, and trespass.

[17] Exhibit 1B, Tab 2, Schedule 1

- **Work Centres:** This option would enable advanced lighting systems across all sites, HVAC retrofits, and renovations for refined BAS and building operation and offer greater employee work optimization. Under this option, Toronto Hydro would also significantly accelerate decarbonization, electrification, and energy efficiency investments, which would reduce GHG emissions faster and set the stage for the utility to reach Net Zero earlier than 2040.

E8.2.5.4 Evaluation of Options

Toronto Hydro has selected Option 2 as the Program's preferred approach for the 2025-2029 rate period since it ensures the optimal outcomes in terms of employee and public safety, grid reliability, cyber security, and GHG emissions while optimizing overall asset lifecycle costs and prudently pacing capital investments. In addition, the proactive approach to asset management in accordance with the AM Strategy under Option 2 would yield several productivity and efficiency benefits. This option provides the best safety, reliability, security and GHG emissions outcomes for ratepayers while controlling costs more effectively than Option 3.

Option 1 offers lower planned maintenance costs but potentially higher reactive maintenance costs. The implementation of this option would compromise the utility's grid reliability and would create the risk of business disruption. It would further compromise public and employee safety, and would lead to a less efficient allocation of capital expenditures, as the utility incurs cost and time benefits from the proactive procurement and replacement of facilities assets.

Option 3 offers additional asset reliability and would decrease the utility's operational costs but does not optimize the utility's asset management process and would represent a significant cost escalation for ratepayers.

E8.2.6. Execution Risks & Mitigation

The Program is vulnerable to several risks that could affect the planning and timing of proposed investments, including:

- Delays in obtaining the necessary approvals and permits may delay the start or completion of projects. To mitigate against this risk, Toronto Hydro will utilize subject matter experts to work with the necessary stakeholders in order to obtain approvals and permits in a timely manner. In addition, the utility will initiate the relevant processes as early as possible to ensure permits are issued for the project's scheduled execution timing and mitigate delays.

- The rising costs of material and labour are an ongoing issue in the post-COVID market. Supply chain disruptions have become an ongoing issue across many industries as well, and have continued to pose a risk throughout 2023.
- Legacy environmental conditions (e.g. asbestos or PCBs) might require further testing and analysis, which may affect project budget and execution schedule. To mitigate against this risk, Toronto Hydro will seek subject matter expertise for a thorough review of actual field conditions in high-risk locations prior to developing a project plan and incorporate these findings during the procurement process to limit the cost escalation of abatement work.

E8.3 Fleet and Equipment Services

E8.3.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 36.7	**2025-2029 Cost ($M): 43.7**
Segments: Fleet and Equipment Services	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Operational Efficiency - Reliability, Environment, Operational Efficiency - Safety, Financial Performance	

The Fleet and Equipment Services program (the "Program") governs the procurement, maintenance, and disposal of vehicles and equipment that are required to support Toronto Hydro's functional and operational needs. The Program's primary objectives are to optimize the utility's vehicle and equipment asset lifecycle costs, and to ensure that fleet assets perform reliably and maintain employee and public safety. Capital investments within the Program are grouped into two categories: (1) vehicles: which includes, (a) heavy duty vehicles, used primarily to perform distribution work and transport operators and equipment; and (b) light duty vehicles, which are fully equipped for employees to inform, manage, and monitor distribution work; and (2) equipment for employees and vehicles (e.g. forklifts, trailers, telematics systems, boom lifts, protective gear, etc.). The Program and its constituent segments are a continuation of the activities described in the Fleet and Equipment Services program in Toronto Hydro's 2020-2024 Rate Application.[1]

Toronto Hydro's capital investments in its vehicle fleet yield the following benefits:

- Optimization of vehicle operating costs;
- Minimization of fleet downtime due to repairs and a corresponding increase in fleet reliability;
- Increase in vehicle efficiency, i.e. lower fuel consumption and idling reduction;
- Improvements in shop efficiency through replacing older and poor condition vehicles that are more labour-intensive for maintenance purposes with new vehicles;
- Reduction in environmental impacts such as reductions in greenhouse gases emissions the amount of maintenance fluids used; and

[1] EB-2018-0165, Toronto Hydro-Electric System Limited Application, Exhibit 2B, Schedule 8.3.

- Increased employee, field crew, and public safety, as newer vehicles are equipped with new safety technology (such as back-up cameras, lane departure warning, emergency braking warning, driver safety alerts, etc.).

E8.3.1.1 Toronto Hydro's Fleet Asset Management Strategy

Toronto Hydro optimizes the level and pace of capital investments to minimize the utility's maintenance and repair costs while maintaining safety and reliability. Toronto Hydro applies its fleet asset management strategy (the "Strategy") to achieve these outcomes. The Strategy takes a two-step approach as follows.

At the first step, it uses a Life Cycle Analysis ("LCA") approach to identify groups of assets whose characteristics (e.g. vehicle type, age, mileage, anticipated corrosion) enable the utility to estimate potential increases in their operating costs. As vehicles age, ownership costs such as purchase costs decrease and operating costs such as fuel, maintenance costs, and downtime increase. The utility uses its LCA to anticipate vehicle needs and fleet turnover for short term (0-2 years) and long term (2-7 years) expenditure planning purposes.

In the second step, the Strategy then assesses the actual condition of assets under consideration using an asset condition assessment to decide whether to replace or dispose of a given vehicle. This is an 85-point vehicle condition inspection metric to annually evaluate all asset components and determine whether parts and systems are working effectively. Because a replacement cycle varies depending on the vehicle make, model year, equipment design, and operating environment, some vehicles that are in poor condition may require replacement before the LCA criteria is met and some vehicles that meet LCA criteria may be in good condition and not warrant replacement. Replacement cycles are additionally impacted by organizational objectives, such as the decarbonization and electrification of fleet assets, whereby the utility may replace decommissioned internal combustion engine vehicles with electric or hybrid vehicles.

The Strategy enables Toronto Hydro to replace vehicles at the lowest total lifecycle cost, which occurs at the point in time immediately before operating costs exceed ownership costs. It also promotes utility performance through the maintenance of a reliable fleet for completing distribution work in a timely and safe manner, and enables the utility to prudently plan and pace its fleet investments. Finally, the Strategy enables Toronto Hydro to meet its organizational objectives, such as the decarbonization of the utility's fleet assets.

To assist with modelling its LCA, Toronto Hydro has successfully operated in line with recommendations from a third-party consultant on the optimal replacement of fleet vehicles. The utility will continue to apply its current methodology over the 2025-2029 rate period. Over the 2020-2024 period, Toronto Hydro's application of the LCA has benefited the utility by enabling it to forecast future fleet needs with a high degree of accuracy, and plan and pace its investments appropriately to maintain fleet safety and reliability.



Figure 1: Toronto Hydro Fleet

E8.3.1.2 Decarbonizing Toronto Hydro's Fleet

Over the 2025-2029 plan period, Toronto Hydro will plan its vehicle and equipment investments in alignment with its objective to achieve net zero scope 1 greenhouse gas ("GHG") emissions by 2040, as outlined in the Net Zero 2040 Strategy document in Exhibit 2B, Section D7. Decarbonizing Toronto Hydro's fleet portfolio is critical to achieving this goal.

Aiming to reduce Toronto Hydro's GHG emissions, the utility will reconfigure its fleet composition to gradually increase its complement of electric and hybrid operation vehicles. Within a given vehicle class, electric vehicles ("EVs") and hybrid vehicles currently command higher capital costs than internal combustion engine ("ICE") vehicles, typically resulting in a 20-120 percent higher purchasing cost. In response to the OEB's direction in the last rebasing application to engage in a more detailed cost benefit analysis between EVs, hybrid, and combustion engine vehicles[2] and to assist in investing

[2] OEB Decision and Order, EB-2018-0165 (December 19, 2019), at p. 104.

prudently across these different vehicle types, Toronto Hydro analyzed various phasing and cost options for electrifying its fleet and the results of this analysis informs Toronto Hydro's procurement strategy for EVs and hybrid vehicles. In procuring electrified or hybrid vehicles, Toronto Hydro considers factors including safety, incremental annual capital cost and operating cost impacts, availability, similarity between electric and hybrid models to existing vehicles, ease of maintenance and operation, familiarity with the technology, scope 1 GHG reductions, and all associated change management considerations.

A paced approach for replacing ICE vehicles with EV and hybrid models results in a much more balanced capital expenditure profile than adopting more aggressive fleet decarbonization strategies. This paced approach helps Toronto Hydro meet its decarbonization goals, while minimizing the risk of stranded assets through the prudent management of OM&A costs (e.g. against possible increases from vehicles in poor condition and overdue for replacement), and capital expenditures (e.g. in respect of vehicles that are still in good condition despite being close to their projected end-of-life). Alternative approaches, such as aggressively replacing ICE vehicles in short order to accelerate decarbonization to a greater degree, would likely hamper the utility and its ratepayers from achieving optimum value from existing vehicles that are still in good condition, as such an approach would likely require such assets to be replaced sooner, meaning their total cost of ownership could not be optimized.

Conversely, an overly conservative approach attempting to extend the life of aging or poor-condition ICE vehicles and significantly defer capital investments in electric and hybrid vehicles would result in an increase in operational costs. A paced and balanced replacement strategy would help Toronto Hydro replace existing vehicles closer to their optimal lifetime total cost of ownership, while meeting its decarbonization goals. This approach would balance the utility's year-over-year capital expenditures and would not require significantly more capital investments compared to a like-for-like replacement strategy that that does not aim to meet decarbonization goals.

Toronto Hydro will prioritize EV options if they are able to meet the requirements necessary for users to carry out distribution work and other day-to-day operations. If EV options are not available in the market or the operational feasibility of deploying EVs for a particular function remains under analysis, the utility will consider hybrid options. If hybrid options are not available in the market, the utility will pursue ICE options. In view of the size and dense urban nature of its service territory, Toronto Hydro estimates that all vehicle types (ICE, EV, and hybrid) would perform at the same level of reliability.

The utility is currently exploring fully electric heavy-duty vehicles in small numbers and on a pilot basis as the market availability of these types of vehicles remains relatively low and further field experience is required to analyze the reliability and performance of these units under normal and emergency operating conditions. While the pilots continue, Toronto Hydro has adopted hybrid configurations of heavy-duty vehicles by having some vehicle components run off additional batteries. For example, some heavy-duty vehicles use electric power take-off ("PTO") aerial boom units and auxiliary batteries instead of gasoline- or diesel-burning generators for operating tools.

E8.3.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Ensuring crews have the necessary vehicles and equipment to perform distribution work when required; and ○ Ensuring that the fleet is in good operating condition and assets are replaced before critical equipment failures arise, which may necessitate lengthy and costly offsite repairs.
Environment	• Contributes to Toronto Hydro's environmental objectives by reducing GHG emissions associated with fleet fuel consumption through: ○ Opting for hybrid and electric vehicles and biofuels while maintaining fleet reliability ○ Implementing anti-idling technology, GPS reporting used to drive changes in driver behaviour, and the use of biofuels.3 ○ A targeted 8-10 percent reduction in tonnes CO2 emission by the end of 2029.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by implementing vehicle packages and accessories that help ensure employees are working safely with minimal exposure to hazards.
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives as measured by the total cost and efficiency measures by: ○ Managing fleet and equipment assets to the lowest overall lifecycle cost; and

[3] The use of technology to drive these results is limited by funding and classes of vehicles where the return on investment is justifiable.

	○ Mitigating fuel expense by aiming to reduce fuel consumption through a combination of utilizing hybrid and electric vehicles; idling-reduction technologies; and replacing vehicles at the point of lowest lifecycle cost.

E8.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Safety, Reliability, Business Operations Efficiency

E8.3.3.1 System Maintenance and Capital Investment Support

The trigger driver for the Program is Toronto Hydro's need for safe and reliable vehicles that support the utility's capital work and system maintenance during the 2025-2029 rate period and beyond. The utility requires access to vehicles and equipment that meet current and future functional requirements to transport employees and materials to and from job sites, perform distribution work onsite, and provide shelter and working areas for workers on site. Vehicle uses on job sites include lifting and positioning material, storing material, preparing material for installation, acting as a planning station, and serving as shelter. Fleet vehicles must be available to support these work functions in a safe, reliable, and operationally efficient manner.

Toronto Hydro's fleet consists of several vehicle types that are designed to meet the utility's evolving portfolio of requirements and support other investment programs and the utility's distribution work. Heavy duty vehicles are required to transport equipment for distribution work. Light duty vehicles are required to facilitate the engineering and management functions of distribution work. Associated equipment assets for these vehicles are used to perform lifting and towing, and include operator safety implements, such as network protection relays, rubber gloves, and gas monitors.

During the 2020-2024 rate period, the average age of assets in the utility's fleet has been trending slightly upwards. This is primarily due to the decommissioning and replacement of some vehicles after their optimal replacement age, delayed due to recent global supply chain issues affecting the availability of new vehicles for replacement and the need to retain a sufficient complement of vehicles enabling conformance with organizational health and safety requirements (e.g. worker social distancing) during the COVID-19 pandemic. The projected average age of the fleet for the 2020-

2024 rate period is 4.9 years. The projected average age of the fleet for the 2025-2029 rate period is 5.4 years.

E8.3.3.2 Safety

Toronto Hydro's investments mitigate the risk of deficiencies and safety hazards to the public and Toronto Hydro employees from structural, component, and electrical failures. Mitigating the following safety risks requires sufficient funding to keep the utility's fleet in good operating condition.

1. Corrosion

Managing corrosion and replacing corroded vehicles is important to maintain fleet reliability and safety. The utility's vehicles are continuously used throughout the year and spend the majority of the time outdoors in direct exposure to the weather and external elements. Humid weather and road salt can lead to corrosion that damages and weakens a unit's frame over time. As shown in Figure 2 and Figure 3 below, corrosion can also make vehicle body parts weak and brittle. Brittle panels are subject to breaking, leaving sharp edges or presenting a potential fall hazard if the rusting occurs on a step, handle, or vehicle floor.

Corrosion of a vehicle's frame can lead to the frame breaking during a lift operation, cable pull, or material loading. Frame weakness can also decrease a vehicle's ability to withstand crashes and jeopardize the safety of the operators and the general public. Corroded vehicle components can also impact safety and are difficult and costly to repair. For example, a corroded transmission line that ruptures could result in a seized transmission. If this occurs while in motion, the operator is at risk of losing control of the vehicle.



Figure 2: Corrosion on Cube Van Steps



Figure 3: Axle Corrosion on Bucket Truck

2. Hydraulics

Similar to the impact of corrosion, unaddressed hydraulic problems mediate in favour of vehicle replacement, as repairs are costly, take the vehicle out of service, and indicate that the vehicle's overall condition has deteriorated. Components such as the hydraulic hoses running through an

aerial boom cannot be directly inspected at service intervals. As the hoses age, they become less flexible and more brittle. Hose failure results in hydraulic fluid leaks to the environment and could also render aerial buckets on bucket trucks inoperable or cause a failure while an employee is operating the bucket. Rescuing a trapped employee from a failed aerial bucket presents a potential safety risk to the employee in the bucket, other field employees who are assisting with the operation, and the public.

3. Electrical

The maintenance of appropriate fleet age and condition is important to protect electrical circuitry from causing safety and reliability issues. The longer a vehicle is in service, the more likely electrical failure becomes. Electrical failures could lead to the malfunctioning of auxiliary safety lighting systems and onboard equipment required for field staff to perform their distribution functions.

E8.3.3.3 Reliability

Toronto Hydro's fleet investments ensure the reliability of the utility's distribution operations and the execution of its capital and maintenance programs. As vehicles age, they become increasingly unreliable and require more maintenance. In addition, even with regular maintenance, vehicles are more likely to fail while in use or will need to be held out of service for repairs following an inspection. Furthermore, parts availability for aging vehicle models decreases over time, especially as certain makes and models of vehicles become obsolete. As a result, there is an increased probability that an older vehicle will remain out of service for longer periods of time while Toronto Hydro procures the requisite parts. Unreliable or unavailable vehicles adversely impact the utility's ability to provide acceptable levels of reliable service to customers and result in lost productivity and business disruption.

E8.3.3.4 Business Operations Efficiency

Toronto Hydro tracks its fleet utilization by measuring "days used", meaning that the utility measures whether a given vehicle is used on a given business day, compared against the total number of work days in a year. This measurement produces both individual scores for the vehicle and aggregate scores for the fleet. The utility uses these scores to inform its investment planning and to optimize the use of its existing assets, by prudently maintaining a sufficient number of vehicles for use by business units as required, without retaining more vehicles than necessary. Optimal fleet utilization also allows for the regular maintenance of vehicles without interrupting distribution operations.

Toronto Hydro changed its fleet utilization methodology from "standard utilization percentage" to the current "days used" metric in the 2020-2024 rate period after monitoring both methods for efficiency and accuracy. The utility chose this updated measure of fleet utilization because it more accurately reflects vehicles' availability and reliability on a day-to-day basis compared to the previous utilization metric which omitted usage during overtime hours and did not account for usage during shift changes. It also allows the utility to track and measure the usage of particular vehicles against other vehicles of the same class within the fleet, to track on an ongoing basis if vehicles can be re-allocated to different departments and areas of distribution work to increase productivity. The below figure demonstrates Toronto Hydro's historical fleet utilization over 2018-2023 and estimated utilization over 2024-2029. The utility tracks utilization in two separate tiers of "Core Fleet" (distribution operations vehicles) and "All Fleet" (Core Fleet + pool vehicles, specialized support vehicles, etc.).

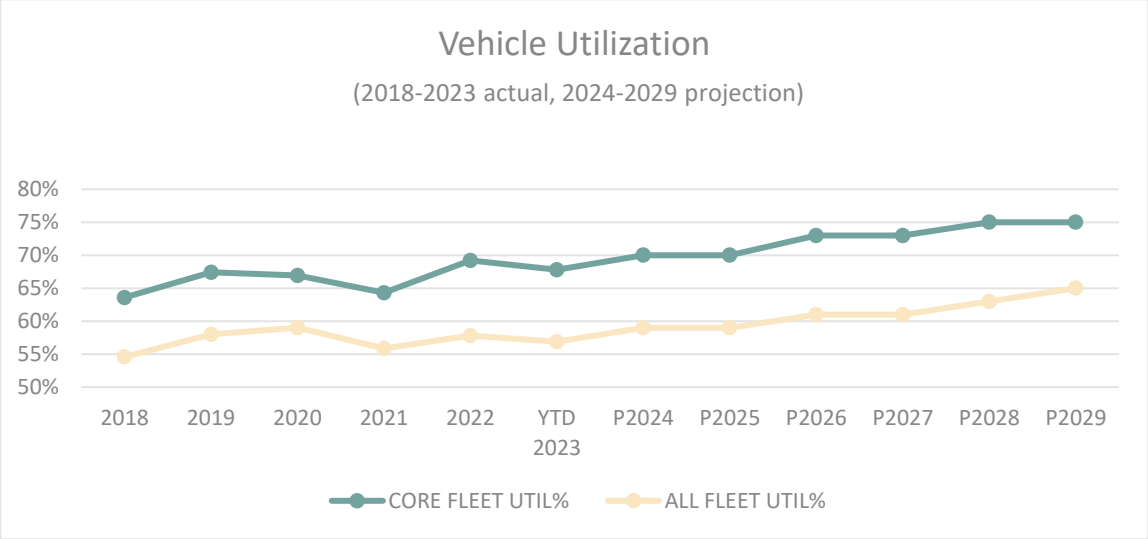


Figure 4: "Days Used" Vehicle Utilization Metric

Early in the 2020-2024 rate period, Toronto Hydro experienced countervailing factors exerting both upward and downward pressure on the vehicle utilization metric. The utility's ongoing decommissioning of underutilized vehicles within its fleet going into 2020 helped improve utilization rates. However, the onset of the COVID-19 pandemic and the health and safety measures that Toronto Hydro adopted (such as social distancing measures that limited each vehicle to a single occupant) required the utility to retain fleet vehicles that otherwise would have been taken out of

service. This increased fleet utilization rates during the early stages of the pandemic, and decreased rates as social distancing measures were phased out prior to retiring the excess fleet vehicles. Toronto Hydro expects its utilization rate to continue to improve as effects of the pandemic subside and the utility rationalizes its vehicle count following the discontinuation of related measures.

The "All Fleet" utilization score includes highly specialized vehicles such as elevated bucket trucks for unique applications, emergency vehicles, Fleet and Facilities support vehicles, and pool vehicles that are crucial to the utility's operations because they provide support to specialized operations and are equipment that cannot be procured on a short-term rental basis. Toronto Hydro uses these vehicles during emergency situations such as power outages and mutual aid excursions, and to provide alternatives during extensive vehicle repairs or for other short-term requirements. These scenarios require a complement of pre-equipped vehicles to be readily available for emergency or rapid response.

The "Core Fleet" represents approximately 75 percent of Toronto Hydro's total fleet; the majority of these vehicles are assigned directly to Distribution Operations teams to help support day-to-day business operations. The core fleet includes a wide spectrum of light and heavy-duty vehicles.

E8.3.4 Expenditure Plan

Table 4: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Heavy Duty Vehicles	5.1	1.1	8.8	5.1	4.8	7.0	5.3	7.7	5.8	3.2
Light Duty Vehicles	1.3	1.1	5.5	1.2	1.1	2.0	4.4	0.9	1.9	4.4
Equipment	0.1	0.1	1.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Total	**6.5**	**2.3**	**15.5**	**6.4**	**6.0**	**9.2**	**9.9**	**8.8**	**7.9**	**7.8**

Toronto Hydro's capital expenditure and asset replacement planning for the Program begins several years in advance in order to account for lead times and to effectively procure vehicles. The utility uses the Strategy to identify candidate vehicles for future replacements, plan the pace of procurement, and identify the optimal point at which to replace a given asset based on ongoing assessment of its condition. If Toronto Hydro does not receive the requested funding and is unable

to make the planned investments over the 2025-2029 rate period, its fleet will incur increasingly high operational costs, will be less reliable, and will pose a greater risk to safety, to ongoing distribution operations, and to the execution of capital programs.

As shown below in Table 5 below, Toronto Hydro shuffles asset replacements across the five-year rate period as necessary to balance spending year over year and prudently manage costs. Replacing assets in batches and optimizing spending in a given year makes it easier for the Program to balance work throughout the lifecycle of the vehicle. Table 6 shows the parameters and factors by vehicle class that inform Toronto Hydro's prioritization of its long-term capital planning for fleet and equipment assets.

Table 5: Replacement Costs[4] for Fleet by Segment for the 2025 to 2029 Period ($ Millions)

Description	2025		2026		2027		2028		2029		Total Cost
	No.	Cost	No.	Cost	No.	Cost	No.	Cost	No.	Cost	
Heavy Duty	13	7.0	13	5.3	23	7.7	11	5.8	12	3.2	**29.0**
Light Duty	18	2.0	26	4.4	10	0.9	12	1.9	40	4.4	**13.6**
Equipment	2	0.2	1	0.2	1	0.2	1	0.2	10	0.2	**1.1**
Total	**26**	**18.6**	**39**	**8.4**	**35**	**8.8**	**22**	**9.1**	**52**	**2.4**	**43.7**

Table 6: Factors Influencing Capital Planning by Asset Class

	Functional Criticality	Procurement Time	Average Cost/Unit ($M)	Degree of Customization
Heavy Duty Vehicles	High	24-36 months	$0.32	High
Light Duty Vehicles	Medium	10-18 months	$0.06	Medium
Equipment	Low	6-12 months	$0.07	Low

Heavy duty vehicles take the highest priority in planning because they are the costliest and take the longest to procure, with timelines typically around 24-36 months. The procurement process begins by determining the specifications of vehicles and continues to with the delivery of the units. In planning its heavy-duty fleet, Toronto Hydro engages multiple vendors to determine the feasibility of particular vehicle configurations and ensure all vehicle components can work as intended.

[4] These costs are inclusive of all up-fitting necessary for the job, such as storage bins, partitions, racking, lighting, additional power supply, and any other aftermarket additions required in a particular light duty vehicle.

The procurement of light duty vehicles follows the same procurement steps, but the timelines are typically shorter. Light duty vehicles usually feature more standardized specifications as they are typically used for transporting people or equipment, and are not used to perform distribution work. Thus, it takes the utility less time to determine the specifications of the light duty vehicle and prepare it for operations once acquired, since such vehicles typically require fewer components to be built or installed.

E8.3.4.1 Equipment

Toronto Hydro's equipment investments over the 2025-2029 rate period are targeted to ensure safety for fleet operators and to implement decarbonization measures where options for switching to EVs or hybrid vehicles are limited. These investments include anti-idling technology, GPS units, laptop mounts installed in vehicles, trailers, and lift equipment, described in greater detail below. The utility replaces equipment on a reactive or "run to fail" basis because equipment generally has a long lifespan, procurement times are quick, replacements are available on the market, equipment failure poses a low safety risk, and variability in use makes it difficult to predict when a given piece of equipment will require replacement.

Table 7 below shows the forecasted costs of replacing equipment on a reactive basis. Toronto Hydro assesses equipment every six months through a preventative maintenance review and determines respective replacements based on units' condition and performance.

Table 7: Equipment Replacement Costs For 2025 to 2029 Period ($ Millions)

	2025	2026	2027	2028	2029	Total
Equipment	0.22	0.22	0.22	0.22	0.2	1.1
Total	**0.22**	**0.22**	**0.22**	**0.22**	**0.22**	**1.1**

The utility's investments in telematics and anti-idling systems help the utility monitor and continuously improve vehicle idling, utilization, driver safety, and diagnostic maintenance. Some heavy-duty diesel vehicles are equipped with GRIP anti-idling technology to reduce idling, which increases the vehicle's lifespan and decreases GHG emissions. The utility's purchase contracts require vehicle vendors to comply with these specifications. The anti-idling system manages, monitors, and provides real-time data on battery voltage, coolant, temperature, idling, anti-theft mode, and engine starts and stops. It also provides reporting on driver behaviour that helps reduce speeding and harsh braking, which increases fuel efficiency. The use of telematics GPS hardware and

software provides several benefits, including real-time tracking of vehicle locations and maintenance indicators,[5] aiding customer complaints investigations and claims by enabling access to historical tracking of the entire fleet and history of vehicle location, providing speeding notifications based on local speed limit and set data, and the management and creation of zones based on work centre locations to optimize vehicles' arrivals and departures.

Other onboard equipment includes laptop mount kits for ruggedized laptops used in the field, equipped with pedestal, docking station, and wiring needed to power devices. These mounts are installed in most light and heavy-duty vehicles to facilitate the ergonomically safe use of laptops for onsite crew inspections, site visits, and other situations without requiring field crews to drive back to a work centre and file paperwork. Ergonomic features (such as dock tilt, spring loaded, telescopic, and adjustable base) and periodic risk assessments help enhance user safety and performance over time.

Figure 5, below, shows views of a steel lap mount installed in a cube van which includes a pedestal bolted to the base of the cab along with a docking station, battery protector, and antenna.



Figure 5: Laptop Mount Installed in Cube Van

E8.3.5 Options Analysis / Business Case Evaluation ("BCE")

Toronto Hydro considered three options for investments in the Program over the 2025-2029 rate period. The first, managed fleet deterioration, entails a fleet replacement strategy that would increase the average vehicle age by approximately 5-7 percent across the fleet. The second, sustained fleet replacement, entails replacing vehicle assets at the optimal age as outlined in the

[5] For example, engine light on, fuel tank, battery voltage, tire air, GPS not reporting/working, unplugged devices, idling, zoning, trip history, and PTO used for commercial vehicle operation registration ("CVOR") units.

Strategy, i.e. when the lifecycle costs of a given vehicle are the lowest. The utility is proposing to follow this option, as it enables the utility to maintain vehicle availability and reliability, make process towards decarbonization goals, meet customer expectations and facilitate the execution of the utility's investment plan. The third approach would entail improving the lifecycle of vehicles by one year in order to improve vehicle reliability and availability, and would pace the majority of the utility's investments to decarbonize its fleet into the upcoming rate period.

E8.3.5.1 Option 1: Managed Fleet Deterioration

This option delays heavy duty vehicle replacement to one year later than recommended by the LCA, subject to assets' actual condition assessments. However, Toronto Hydro would not delay the procurement of light duty units in order to continue making progress on vehicle electrification in accordance with the utility's Net Zero 2040 Strategy.

Overall, this option would translate to an approximately 5-7 percent increase in the average vehicle age across the fleet. Under this option, the Program's objective would be to ensure that the vehicle replacements continue at an acceptable pace without materially compromising the reliability and safety outcomes. The investment plan under this option, would contemplate replacing all light duty vehicles and ten heavy duty vehicles with electric or hybrid vehicles.

As this option is based on a reduced capital expenditure profile, it would likely restrict Toronto Hydro's flexibility to scale fleet investments up or down in accordance with the utility's needs. This approach also risks increasing labour costs and vehicle downtime due to aging vehicles requiring more frequent maintenance and more support compared to the other options. To the extent that these challenges cause fleet capacity issues, there may be also delays of or interruptions to capital work, system maintenance, and outage restoration, adversely affecting a number of safety, reliability, and customer service outcomes.

More specifically, this option would have the following consequences:

- Unit field failures will likely increase as vehicles age and adversely affect field crew productivity. In some cases, unit field failures may render Toronto Hydro unable to conduct system maintenance and capital work as planned. This will lead to higher operational labour and support costs (such as permits, penalties for late work completion, additional fuel on account of more frequent trips to and from a work location, etc.).

- The severity of asset failures is likely to increase and these failures could potentially become more catastrophic, leading to safety risks, injuries, damage to property or equipment, and environmental spills.
- Toronto Hydro's operating costs for repairs are likely to increase as parts fail and are replaced. As a vehicle ages, parts will likely become less available, resulting in increasing costs with respect to their purchase.
- The utility may have to increase its vehicle count to maintain similar vehicle availability levels in order to deliver equivalent service levels to customers. This is because as vehicles age, time out of service will likely also increase due to increasing repair challenges that result from an aging fleet (such as deteriorating components and the consequent need for more significant repairs). To ensure that vehicles are available for use, Toronto Hydro would likely require the use of 'spare' vehicles should the main service vehicles become unavailable on account of maintenance or repairs. In addition, the utility may have to rent new equipment for vehicles at a significant cost.
- The replacement of vehicles that have reached a total state of failure may require long lead times (e.g. up to 30 months for the purchase and delivery of specialized vehicles). During this period, Toronto Hydro's ability to perform capital work and system maintenance may be impaired or delayed if alternate vehicles cannot be sourced internally or through renting or leasing externally.

E8.3.5.2 Option 2: Sustained Fleet Replacement (Recommended Option)

This spend option replaces vehicle assets at the optimal replacement age. As discussed in the Strategy, Toronto Hydro determines a vehicle's optimal replacement age by using the LCA as a baseline indicator, with adjustments based on the assessment of individual assets' condition. Under this option, the Program's objective would be to ensure that vehicle replacements occur at the point in time where the lifecycle cost of ownership is lowest. The electrification strategy under this option would involve replacing all light duty units and 15 heavy duty units with electric or hybrid vehicles.

The proposed vehicle replacement pace under this option would allow the sustainment of the fleet at the optimal age profile and result in a lower average age of vehicles compared to the managed fleet deterioration option. This approach would optimally balance capital expenditures against the need to ensure the reliability and availability of fleet and equipment assets. In addition, this option would optimally support the utility's progress towards its decarbonization goals.

This option would have the following consequences:

- Toronto Hydro will replace vehicles according to asset management criteria that will optimize the average total cost of vehicle ownership over time;
- Overall vehicle reliability will improve, resulting in less downtime, fewer vehicle failures, and improved field crew productivity;
- Fleet vehicle and equipment performance will improve;
- Overall safety of fleet vehicles will improve thanks to enhanced safety features found in newer vehicles; and
- Fuel efficiency will improve, leading to reduced GHG emissions and fuel costs.

E8.3.5.3 Option 3: Improved Fleet Availability & GHG Emissions Reduction

This spend option aims to replace fleet vehicles sooner by reducing the baseline lifecycle assumptions by one year. This would result in an approximately seven percent decrease in the average age of Toronto Hydro's fleet compared to the sustainment option. The objective of the Program under this option would be to improve vehicle reliability and availability. By replacing vehicles earlier, the utility would avoid the more significant and costlier repairs typically seen in the final year of a vehicle's lifecycle and increase vehicle availability. For example, for certain vehicle types, the vehicle's lifecycle could be aligned with the battery warranty to avoid significant battery repair costs, which often exceeds the value of the vehicle itself when nearing end of life. The improved condition of fleet vehicles would also result in overall lower operational expenses due to less maintenance needs and the lower likelihood of having to rent vehicles to substitute for out-of-service fleet vehicles. The resulting higher reliability levels compared to other options would allow Program resources to better focus on continuous improvement since vehicle conditions will remain at more consistent levels across the fleet. This option also aims to accelerate the electrification of the fleet by replacing all light duty vehicles and 20 heavy duty vehicles with electric or hybrid vehicles in accordance with Toronto Hydro's Net Zero 2040 Strategy.

This option would have the following consequences:

- Pre-emptive mitigation of age-related safety risks and associated repair costs;
- Improved reliability levels reducing reliance on external repair services for more significant repairs;
- Better availability of vehicles to perform capital work, system maintenance, and outage restoration during extreme weather and other emergency events; and

- Potential logistical challenges with putting greater numbers of new vehicles in service and disposing of decommissioned vehicles.

E8.3.5.4 Evaluation of Options

Toronto Hydro proposes to proceed with Option 2, the Sustained Fleet Availability approach, as it is the most cost-effective option to manage Toronto Hydro's vehicle fleet while providing the opportunity to meet Toronto Hydro's Net Zero goals. These aims help ensure asset reliability, customer service, and contribute to employee and public safety.

Replacing the vehicle fleet on a Managed Deterioration basis (Option 1) will not only adversely affect field crew productivity and hamper planned system maintenance and capital work, but also result in upward pressure on vehicle maintenance and repair costs. In comparison to Option 2, the Sustained Fleet Replacement scenario, this option allows for further investment in electric and hybrid vehicles while also further improving fleet age profiles to enhance reliability and cost-effectiveness.

The Improved Fleet approach (option 3) accelerates capital investments; but also reduces asset maintenance and repair costs. Option 3 speeds up the electrification of the fleet but does not allow for the prudent and measured evaluation of EV technology to ensure its suitability in our operating environment. Both options 2 and 3 allow us to achieve 2040 Net Zero goals.

The summary of this options analysis is as follows:

Table 8: Options Analysis Summary

Outcome Measures at End of 2029	Deterioration	Sustainment	Improvement
Option Cost ($M)	34.35	43.69	47.45
Average Fleet Age (years)	6.7	5.4	5.0
GHG Emissions (tonnes CO2)	1222	1177	1034

E8.3.6 Execution Risks & Mitigation

There are three primary execution risks inherent in the Program: (i) escalating vehicle costs; (ii) increasing procurement lead times; (iii) supply and availability of fully electric heavy-duty vehicles. Vehicle costs have been escalating since the onset on the COVID-19 pandemic due to supply chain issues in getting parts and vehicles delivered; the weakening of the Canadian dollar versus the American dollar which impacts most heavy duty vehicle chassis' costs; semiconductor shortages

impacting the availability of both light and heavy duty vehicles; automotive industry production and manufacturing cuts due to the pandemic and changes in the workforce; and the unpredictability and longer lead times for acquiring fully electric vehicles.

As a mitigation strategy, Toronto Hydro issues multi-year tenders with limitations on cost increases per year where possible and provides vendors the option to update pricing and delivery schedules for EV and hybrid options on tender submissions as they become available. In addition, where possible, the utility chooses Canadian suppliers to maximize repair efficiency where they are the lower cost bidder. The Program has also extended planning lead times for procurement to accurately reflect the most current delivery expectations provided by vendors given supply chain, production, and electrification constraints. For more information on the more general mitigation measures the utility has adopted with respect to procurement risks, please refer to the Supply Chain Services program in Exhibit 4, Tab 2, Schedule 15.

E8.4 Information Technology and Operational Technology Systems

E8.4.1 Overview

Table 1: Program Summary

2020-2024 Cost ($M): 256.6	**2025-2029 Cost ($M):** 301.3
Segments: IT Hardware, IT Software, and Communication Infrastructure	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Operational Effectiveness - Reliability, Customer Focus, Public Policy Responsiveness, Operational Effectiveness - Safety, and Financial Performance	

The Information Technology and Operational Technology Systems (IT/OT) program (the Program) invests in hardware, software, and communication assets that provide critical support to Toronto Hydro's customer and business-facing services.[1] Toronto Hydro relies on IT/OT systems to execute capital and operational programs, including customer-facing and operationally-critical functions. The investments proposed in this Program were developed in accordance with Toronto Hydro's Information Technology Asset Management Strategy and Investment Planning procedures (Strategy) and are intended to mitigate risks to reliability, cybersecurity, and the utility's business operations.[2]

The Program's objective is to provide reliable technology solutions and services to support Toronto Hydro's business functions, including effective and reliable service to customers, safe and efficient management and operation of the distribution system, compliance with legal and regulatory requirements, and sustainment of the utility's long-term financial viability.

The Program consists of the following three segments:

- **IT Hardware**: includes the core back end infrastructure assets (e.g. servers, local area networks and data storage/centres), security appliances and endpoint assets (e.g. desktop computers, laptops, printers, smart phones, and tablets) that support Toronto Hydro's day-to-day operations and core systems;

[1] Note: Operational Technology refers to hardware and software that detect or cause a change through the direct monitoring and/or control of physical devices, processes, and events in the enterprise. See: Gartner Inc., IT Glossary, Operational Technology Definition.
[2] Exhibit 2B, Section D8.

- **IT Software**: includes software applications that provide process improvements and operational capabilities to a range of customer-facing and business functions; and,
- **Communication Infrastructure**: includes assets that enable the monitoring and control of distribution communication infrastructure, including fibre-optic assets and wireless Supervisory Control and Data Acquisition (SCADA) infrastructure.

E8.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: ○ Implementing and maintaining a range of customer service and communication tools and systems; ○ Improving the customer experience of interacting with the utility through digital platforms; and ○ Supporting accurate and timely communication with customers during prolonged power outages.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Maintaining the availability of modern, reliable and secure enterprise-wide IT/OT systems that support efficient distribution system management; ○ Supporting outage restoration efforts by ensuring that system operators have the necessary IT/OT tools to promptly identify incidents, develop effective resolution plans and communicate with operational teams; ○ Enhancing IT/OT systems to enable remote equipment monitoring and operations capabilities; and ○ Supporting the creation and maintenance of cyber security controls to mitigate against potential vulnerabilities and threats that may jeopardize the safe and proper functioning of IT/OT assets.

Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by: ○ Providing the technological infrastructure framework required to improve the distribution system's ability and capacity to evolve and meet emerging needs (e.g. the integration of distributed energy resources, new load types such as electric vehicles, and increasing reliance on energy flow data); and ○ Providing the technological infrastructure required by the utility to continuously improve its processes and adapt to evolving legal and regulatory requirements, business conditions, and customer expectations.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency (TRIF) by: ○ Enabling the constant monitoring of substation and field assets to prevent asset overloads and failures, which might result in injuries to anyone in the close proximity of the equipment; and ○ Maintaining the effectiveness and availability of IT/OT Systems that support the utility's safety performance (such as SCADA, Automated Vehicle Locator, Radio, and Network Management System).
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by ensuring that the Tier 1 IT systems are available and reliable in support of efficient and accurate customer and market invoicing and settlements and financial reporting and recordkeeping.3

E8.4.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Cyber Security Risks, Regulatory Compliance, Functional Obsolescence, Modernization, and Electrification

[3] Exhibit 2B, D8. Tier 1 applications enable Toronto Hydro's critical business operations and support company-wide business processes. They are functionally integrated with other applications, and are supported by complex, highly redundant underlying infrastructure such as databases, middleware, storage, and network.

The Program supports Toronto Hydro's core operations and business processes, and enables the safe and efficient execution of the utility's capital and operational programs. The utility relies on its IT/OT systems to manage and operate the electricity distribution system, satisfy its obligations to customers, comply with existing and emerging legal and regulatory requirements, and provide the technological infrastructure to continuously improve and adapt its business processes to evolving industry trends such as the pace of electrification increases and the resulting changes in customers' needs and preferences.

E8.4.3.1 IT Hardware

Toronto Hydro's IT hardware must be renewed on a regular basis to ensure the ongoing reliability of systems that support customer-facing services and core distribution operations by maintaining a low risk of failure. The utility's IT hardware also ensures a strong cybersecurity posture to mitigate against potential vulnerabilities and threats that may jeopardize the safe and proper functioning of IT/OT assets.

IT Hardware segment consist of two subsegments:

- IT Hardware Infrastructure;
- IT Cybersecurity Practice.

1. IT Hardware Infrastructure

Toronto Hydro employs many software applications to automate processes and efficiently execute a variety of daily tasks such as preparing customers' bills and dispatching crews to respond to outages. Renewing the underlying IT Hardware on a routine basis is essential to ensure that the software applications remain available. IT Hardware Infrastructure refers to the environment supporting Toronto Hydro's entire Information Technology ecosystem. It aims to provide adequate sizing, availability, scalability, performance and security of the environment to fit business application needs, while ensuring obsolescence prevention and vendor supportability. IT infrastructure assets are classified as either Endpoint Assets or Core Infrastructure Assets.

Endpoint Assets are the assets that the end-user interfaces with to execute, process, complete and review business tasks and operations. These include computing assets (e.g. desktops, laptops, and tablets) that support the execution of business processes, data transactions and analysis, as well as printing assets (e.g. printers, plotters, and photocopiers) that translate electronic documents like

engineering drawings and contracts onto paper. Both are relied upon extensively by Toronto Hydro's users to execute daily work across the utility.

Core Infrastructure Assets are responsible for the computation, storage, and communication necessary to support IT systems. Servers manage access to centralized resources and services in the network and security appliances secure the network from unwanted traffic. Storage assets enable the secure retention of digital data such as customer information, and include disk and flash arrays, which store records for access by servers. Communication assets facilitate the exchange of data within and between the core backend assets and the endpoint assets, so that users can access information from a central IT system. Network and telephony assets enable computers, services, and storage devices to exchange data and manage communication services. Figure 1 depicts the typical structure and dependency of IT infrastructure assets.

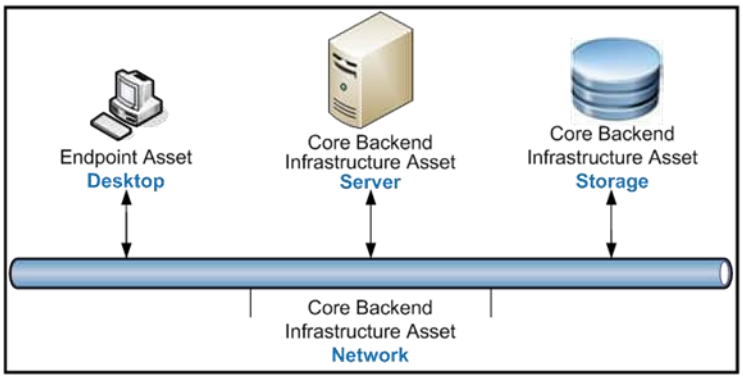


Figure 1: Typical Endpoint Asset to Core Infrastructure Relationships

IT infrastructure environment forms the foundational technology layer upon which all other IT functions and business processes are deployed, including IT Cyber Security, IT Operations, IT Software and company-wide resourcing and workforce management functions. Operational efficiency improvement opportunities are continuously explored and evaluated. These include provisioning more powerful hardware to allow for denser resource deployment and streamlining of systems architecture to fully realize technological potential.

The lifespans of IT infrastructure assets range from four to seven years, which are considered to be within industry norms. At the end of its lifecycle, hardware assets' risk of failure increases significantly, potentially impacting core business processes. To determine the refresh cycle for existing hardware, Toronto Hydro maintains an inventory of infrastructure assets that includes

technical details and lifecycle information such as date of implementation and end of vendor support. This approach ensures that IT hardware assets are up-to-date and available to support the effective and efficient execution of the utility's operations.

Adhering to this approach, approximately 90 percent of Toronto Hydro's core backend infrastructure, and 100 percent of its endpoint assets will need to be replaced during the 2025-2029 rate period. This includes data and voice network routers, switches and appliances, storage network switches, storage arrays, data backup appliances, file storage appliances, UNIX, Linux and Windows servers, monitoring appliances, uninterruptable power supplies and others. IT hardware infrastructure assets support a number of customer service functions. In 2023, approximately 320,000 customers use the online electronic billing function and have accounts that provide key self-serve functions, such as management of account details, customer moves, payment options, and landlord information as of 2022. IT hardware assets also support a number of customer interfacing applications and processes delivered via telephony through the Toronto Hydro Call Centre. If hardware assets supporting these functions were to fail, customers would be unable to access these systems, and could experience significant delays in completing routine transactions. This would impact overall customer satisfaction and may result in increased volume of calls and complaints to Toronto Hydro's Call Centre. Higher call volumes will also limit Toronto Hydro's ability to meet Ontario Energy Board (OEB) prescribed service quality metrics such as First Contact Resolution.

IT hardware supports systems are also used to manage field crews and respond to outages, and thus are critical to the utility's ability to conduct day-to-day operations and ensure reliability. By providing access to real-time data for crew availability, geographical location of outages and crews, these systems enable Toronto Hydro to deploy crews in a timely and effective manner and restore power to customers faster. In the event of core infrastructure failure, the functionality of these applications would be impaired, leading to longer outage response times and poor customer satisfaction. Longer outage response times will negatively impact Toronto Hydro's ability to meet OEB prescribed reliability performance standards such as System Average Interruption Duration Index (SAIDI).

IT hardware also underpins the utility's environmental, health, and safety processes across its work centres and job sites. Such processes range from completion of site conditions and safety forms, review of Material Safety Data Sheets, safety and environmental audits, and incident and claims investigations. In the event of IT hardware failure, employees may not have access to the information required to make informed decisions about environmental and health and safety issues. This may be

compromising workers' safety or contributing to non-compliance with applicable OEB requirements and Utility Work Protection Code.

IT hardware investments are planned and implemented based on existing and future utility needs and operational requirements. This allows Toronto Hydro to execute its plans and programs securely and efficiently in pursuit of its short-term and long-term objectives. IT hardware standards are regularly reviewed, assessed, and implemented based on the utility's existing and ongoing requirements from operational, regulatory and customer service perspectives. In order to continuously adapt its standards and processes to meet these needs, Toronto Hydro requires ongoing investments in its IT hardware assets.

2. IT Cybersecurity Practice

Cybersecurity practice is responsible for the ongoing protection of the organization from all external and internal information security threats. Growing industry reliance on IT as a key business enabler also carries the increased risk of cybersecurity exposure. Global cybersecurity threat landscape is constantly evolving, with attacks ranging from social engineering to destructive ransomware attacks to nation-state backed advanced persistent threats. Cybersecurity has been identified as one of the growing corporate risks. As such Toronto Hydro is continuously investing in cybersecurity controls to monitor cybersecurity threats and develop a robust response to cybersecurity breaches which serves to minimize the potential damage to enterprise assets, data and brand reputation. The primary role of the cybersecurity practice is maintaining a strong cybersecurity posture to mitigate against potential vulnerabilities and threats that may jeopardize the safe and proper functioning of IT/OT assets. Cybersecurity practice includes a combination of Run, Grow and Transform (RGT) investments, as per Gartner's RGT model.

The Run program is primarily centered around the maintenance and organic growth of existing Cyber Security capabilities. From the Threat, Risk and Compliance (TRC) perspective, this includes the orchestration of recurring enterprise IT asset security patching as well as lifecycle upgrades of perimeter and endpoint security controls, such as firewalls, Intrusion Prevention Systems (IPS) and malware protection software. Identity & Access Management (IAM) aspect of the Run program is aimed at ensuring that the organization maintains secure, role-based access to resources, properly logged for auditing and forensic analysis purposes.

The Grow program expands baseline cybersecurity capabilities, through the adoption of advanced threat protection technologies and user education processes aimed at curbing the exposure to social engineering attacks. Grow initiatives are focused on the expansion and strengthening of existing protection capabilities, through the investment into advanced technologies, such as behavioral Endpoint Detection and Response (EDR) solutions to prevent zero-day attacks, perimeter and endpoint Data Loss Prevention (DLP) solutions to stop information exfiltration, and intelligent email phishing prevention solutions.

The Transform program explores pioneering technologies and cyber-defense mechanisms to attain higher protection levels for digital assets, safeguard customer and employee privacy and install stakeholder confidence. Falling under this program are initiatives such as proactive threat hunting, persistent attack surface management,[4] honeypots,[5] network detection & response, attack pattern recognition and micro-segmentation.[6] These initiatives are aimed at limiting corporate exposure to and damage from advanced threats, such as zero-day ransomware attacks.[7]

Investments in cybersecurity solutions are required to ensure that current systems, applications and endpoints can continue to operate reliably and with minimal risk exposure to cyber threats in response to evolving threat landscape, and regulatory compliance obligations.[8] This ensures that the existing security controls are continuously enhanced and matured to meet the cyber resiliency requirements. Cybersecurity requirements need to detect uncertainties in the environment such as pandemic driven infrastructure changes, heightened monitoring requirements, Advanced Persistent Threats (APT) related to the geopolitical situation, and exposure to critical zero-day security vulnerabilities. In order to build security requirements that can respond to these uncertainties, Toronto Hydro plans to make continuous investments into its robust cyber security infrastructure using layered Defence-in-Depth model to ensure the protection of both IT and OT assets. These investments will help the utility to develop a strong cybersecurity posture which will be essential in

[4] The continuous discovery, analysis, remediation and monitoring of cybersecurity vulnerabilities and potential attacks to the system.
[5] A decoy system that is designed to look like attractive targets, and deployed to allow IT teams to monitor the system's security responses and to redirect the attacker away from their intended target.
[6] A method of security that involves dividing a network into segments and applying security controls to each segment based on the segment's requirements.
[7] A type of ransomware which exploits unknown and unprotected vulnerabilities.
[8] *Electricity Act*, 1998, SO 1998, Ch 15, Sched A,
Ontario Regulation 633/21, Section 3. Section 3 of the Regulation allows customers to submit authorizations to allow third party access to their energy data.

providing an effective response to expected increases and sophistication in emerging cybersecurity threats, due to industry shift towards electrification.

Outdated or reactive security controls and technologies pose several risks to Toronto Hydro's systems, applications, and endpoints including risks to business continuity, distribution system reliability, and financial health. Toronto Hydro is governed by a variety of legislative and regulatory requirements relating to privacy and data security, including the OEB's Cyber Security Framework. The planned expenditure for IT Hardware ensures that Toronto Hydro is able to protect its IT environment, meet security compliance requirements, provide assurance to our industry partners, customers and stakeholders, and evolve its security controls and technologies and associated processes to adapt to the emerging security threats, in response to industry shift towards electrification.

E8.4.3.2 IT Software

Investment in IT software is required in order to ensure that current applications continue to operate reliably, with minimal risk exposure to cyber threats, while also making targeted and prudent IT investments to enhance functionality. Functional improvements are also required in response to core business needs or risks in addition to meeting evolving regulatory or compliance obligations. IT software is an integral part of a modern utility. Toronto Hydro relies upon, and must maintain, various IT software systems to efficiently manage core operations and business processes and to execute planned programs relating to distribution grid operations, engineering design, construction, customer billing and corporate services (e.g. finance, human resource management, legal and regulatory).

Without these systems, a utility of Toronto Hydro's size and complexity would encounter significant challenges in operating its electricity distribution system, delivering capital programs and satisfying changes in customers' needs and expectations and other stakeholders that the organization interacts with. Ensuring reliability and availability of software plays a crucial role in supporting modernization of its business processes in response to the industry shift towards electrification, including electric vehicles (EVs), and distributed energy resources (DERs). If software is not reliable or available, it can hinder the utility's ability to enable these technologies. Moreover, if the software used to manage the grid is unreliable, it can lead to an increase in the number of outages and other disruptions, resulting in lower customer satisfaction. For example, automating customer-facing processes

through enhanced channel offerings and the use of targeted digital tools can improve the overall customer experience. However, if the software used for process automation is unreliable, it can cause errors and disruptions in accessing these services, resulting in poor customer satisfaction.

Software applications deliver tangible value to customers directly through customer-facing IT services, and indirectly through the improved performance or avoided risks of business-facing platforms and solutions. To maintain a reliable and productive suite of IT Software, Toronto Hydro makes three types of investments: Software Upgrades, Software Enhancements, and Regulatory Compliance.

1. Software Upgrades

Toronto Hydro plans to upgrade all of its software applications over the 2025 to 2029 period. These upgrades will ensure that Toronto Hydro's software systems receive support from vendors, keep pace with technology changes in the industry, remain integrated with other relevant software systems, and are protected against future cyber security threats.

When IT systems have surpassed the period of extended vendor support, the vendor and the marketplace do not guarantee availability of qualified resources and expertise needed to resolve any potential issues. As a result, the failure of these systems may result in prolonged downtime, which can significantly affect the utility's operations and its ability to execute planned work programs and deliver services to its customers.

In addition, IT systems without vendor support do not receive security patches and upgrades or fixes, rendering the applications more vulnerable to cyber-attacks. These attacks attempt to tamper with normal IT system operations, gain unauthorized access to customers' and employees' confidential information, or cause a machine or network resource to malfunction or be unavailable to authorized users.

For example, the ransomware cyber attack in May 2021 on Colonial pipeline (a major fuel pipeline operator in the United States that carries gasoline, diesel, and jet fuel from refineries), resulted in the shutdown of the pipeline for several days, causing a shortage of fuel in several states and leading

to panic buying and price spikes at gas stations. Colonial pipeline paid $4.4 million in ransom to the hackers to regain control of its systems[9].

In October 2021, the Toronto Transit Commission (TTC) cyberattack resulted in the disruption of multiple computer systems, including email and payroll, causing significant inconvenience for both customers and employees. The attack impacted the ability of the transit agency to communicate with its customers, as the company's website and social media channels were temporarily taken offline.[10]

In December 2022, the cyberattack on The Hospital for Sick Children had a significant impact on its operations. The attack resulted in the disruption of several services, including appointment scheduling and telemedicine. The hospital was forced to reschedule some appointments and revert to manual processes to continue providing essential medical care. The attack also affected the hospital's ability to access patient data and medical records, which posed a significant risk to patient safety and care.[11]

These events highlight the real risk and consequences of cyber intrusions and the ongoing need for Toronto Hydro to regularly upgrade its software in order to protect its systems from external attacks. A leak of Toronto Hydro's sensitive operational information could lead to and assist in malicious attempts to jeopardize day-to-day operations and, in extreme cases, the successful exploitation of a system vulnerability could cause mass outages across the grid.

The ongoing use of applications past end of useful life leads to retention and maintenance of standalone underlying components that lack vendor support lifecycles. This exposes the IT systems to security and reliability risks that could result in severe outcomes. Functional obsolescence is an additional consideration driving the need to invest in software upgrades. Finding skilled resources to ensure ongoing support optimization for legacy systems is and will become more challenging.

[9] Colonial Pipeline, Media Statement Update: Colonia Pipeline System Disruption, "online", https://www.colpipe.com/news/press-releases/media-statement-colonial-pipeline-system-disruption
[10] Toronto Transit Commission, TTC provides update on cyber security incident, "online", https://www.ttc.ca/news/2021/November/TTC-provides-update-on-cyber-security-incident
[11] Sick Kids, SickKids Lifts Code Grey with 80 per cent of priority systems restored, "online", https://www.sickkids.ca/en/news/archive/2023/sickkids-lifts-code-grey-with-80-per-cent-of-priority-systems-restored

Toronto Hydro must address these risks by upgrading its applications to maintain compatibility with underlying infrastructure. Toronto Hydro categorises its Software applications as Tier 1, Tier 2, and Cloud solutions.[12]

Tier 1 applications support a variety of critical processes across the utility. These applications are functionally integrated with other applications, and are supported by a host of databases, middleware, storage and network devices. Tier 1 systems include: Geospatial Information System, Supervisory Control and Data Acquisition System, Distribution Network Management System, External Website Platform, Corporate E-Mail System, Operational Data Store, Meter Management System, Customer Information System, and Enterprise Resource Planning System. The lifecycle of Tier 1 systems is generally 5 years, after which a major upgrade is required.

The Enterprise Resource Planning (ERP) upgrade and Advanced Distribution Management System (ADMS) program are two major software upgrades planned for the 2025-2029 rate period. An ERP system is critical for Toronto Hydro, as it integrates various financial, procurement, human resource, and asset management business processes into a single system. The ADMS program will ensure continued vendor support for its key components such as the Distribution Management System (DMS), the Outage Management System (OMS) and the Supervisory Control and Data Acquisition (SCADA) system that serve as the foundation of the utility's core system monitoring and operation processes. These upgrades are described in greater detail in the Expenditure Plan section of this document below (Section 8.4.4).

Engineers, designers, and field crews depend on IT systems such as the Geospatial Information System (GIS) and the Distribution Network Analytical Tool to access important asset information across the distribution system, and to develop asset replacement plans, determine project detailed estimates and review the asset conditions prior to physical intervention.

Toronto Hydro's construction project teams and outage response teams rely on IT solutions to execute work plans and respond to outages in a timely and efficient manner. The inventory management system facilitates this function by managing asset inventory levels across multiple warehouse locations, and enabling the delivery of materials at job sites and key locations across the

[12] Tier 2 applications enable divisional and departmental processes. These applications have less complex integration with other enterprise applications than Tier 1, and are typically supported by infrastructure with a lower complexity and lower target for overall availability.

system. A failure of this system could lead to errors in materials information, jeopardize the safety of employees using these materials, delay material delivery to project sites, hamper the utility's ability to respond to outages and execute planned work in a timely and efficient manner.

In addition, Toronto Hydro is proposing to upgrade its suite of Tier 2 IT software applications, which support targeted processes and have fewer integration points with other enterprise applications. Compared to Tier 1 applications, Tier 2 applications generally have lower maintenance costs and support a smaller user base. As such, both the operational risks and corresponding investments associated with Tier 2 software upgrades are lower than Tier 1 applications. Examples of such applications are the data analytics software, power quality application, and the fuel data system. Lifecycles developed in accordance with Toronto Hydro's Strategy are five years or less for these applications. Accordingly, all Tier 2 systems will require one or more upgrades during the 2025-2029 period.

2. Software Enhancements

Over the 2025-2029 period, Toronto Hydro plans to undertake software enhancement projects in alignment with its Strategy. Whereas software upgrades are typically triggered by vendor system support lifecycles, software enhancements are driven by risks or opportunities to improve a particular customer-facing or business process.

Toronto Hydro expects customers' and IT/OT users' demands to continue to change. In order to keep up with the pace of changes in these demands, external facing system enhancements, such as initiatives related to the web portal and customer billing will be required. Data analytics expansions could enable the development of descriptive and predictive data models to assist in areas such as long-term strategy and planning, generation and capacity planning, asset maintenance planning, outage prediction, system planning, and power quality and reliability planning.

Software Enhancements can be implemented using a variety of different IT approaches. Independent systems can be integrated to mitigate the risk of data errors and completeness. Incremental reporting capability can be built to fill gaps in management processes and decision-making. Adding new functionality or new software can expand capability to meet emerging customer needs and preferences.

3. **Regulatory Compliance**

Each year, Toronto Hydro must make changes to its business processes in order to comply with emerging regulatory requirements and in response to emerging public policy priorities. Toronto Hydro needs to comply with regulatory requirements from a number of agencies, such as Measurement Canada, the OEB, the IESO, the Ontario Securities Commission, and the Ministry of Labour. Failure to meet regulatory compliance obligations exposes Toronto Hydro to financial risk, in the form of penalties, and reputational harm.

Between 2020-2022, Toronto Hydro implemented a number of software changes to respond to evolving regulatory compliance matters, including the OEB customer service rule amendment, Utility Worker Protection Code (UWPC) changes, and COVID-19 Energy Assistance Program (CEAP).

Toronto Hydro anticipates this policy-driven investment to continue in the 2025-2029 period.

E8.4.3.3 Communication Infrastructure

Toronto Hydro has three discrete communication infrastructure needs in the 2025 to 2029 period. Communications infrastructure is relied upon by core utility operations to maintain and operate the distribution system in a safe and reliable manner. The proposed investments address functional obsolescence in Toronto Hydro's current communications infrastructure footprint, address safety and reliability risks, and support the monitoring and control of future smart grid technologies.

Reliability and availability of communication infrastructure play a crucial role in supporting the modernization of business processes to meet changes in customers' needs and preferences in response to the shift towards electrification. If the communication infrastructure used to manage the grid is unreliable, it can lead to longer power outages and operational disruptions, resulting in lower customer satisfaction. In addition, unreliable communication infrastructure will lead to increased worker safety risk and non-compliance with UWPC.

Toronto Hydro plans to undertake the following three communication infrastructure projects in the 2025-2029 period:

1. **Cellular SCADA Telecom Infrastructure Upgrade**

   In the current 2020-2024 period, the communications technology focus had shifted from proprietary SCADA radio technologies to more widely available, resilient and future proof

cellular SCADA technologies. As such, cellular SCADA Telecom Infrastructure foundation has been deployed to facilitate the shift towards pole top cellular SCADA endpoints. The current version of the deployed backend cellular SCADA infrastructure will reach the end of its useful life in 2026 and will need to be upgraded to maintain security, functionality and supportability of the environment.

2. Cellular SCADA Endpoint Deployment

The current rate filing period saw the commencement of the migration of pole top SCADA endpoints from proprietary radio systems to standardized cellular technologies. In the 2025-2029 period the migration of the legacy radio system will continue, marking the end of reliance on proprietary and niche vendor radio SCADA technologies, improving the overall reliability of the environment and streamlining maintenance and support.

3. P25 Voice Radio SUA Upgrade Cycle

Motorola P25 Voice Radio system, originally deployed in 2016, provides dedicated, bi-directional voice communication channel between control room staff and field crews, enabling coordination of work efforts and ensuring worker safety. In order to keep the system operational, a series of hardware upgrades and refreshes covered by the System Upgrade Agreement (SUA) must be periodically performed to prevent system obsolescence. The upgrade of the current cycle is scheduled for 2025 and will extend the system's useful life until 2028. Another upgrade in 2029 will be required to keep the system operational until 2031.

E8.4.4 Expenditure Plan

Table 4: Historical & Forecast Program Costs ($ Millions)

Segments	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
IT Hardware	11.6	15.1	14.9	15.9	15.0	17.5	19.8	22.6	18.1	20.3
IT Software	22.2	26.6	42.4	42.3	38.7	38.6	40.6	41.0	33.3	34.8
Communication	3.6	2.4	0.7	1.8	1.7	3.7	2.5	0.9	6.8	1.0

Segments	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Infrastructure										
Total	**37.4**	**44.7**	**58.0**	**60.6**	**56.0**	**59.7**	**62.9**	**64.5**	**58.2**	**56.0**

Over the 2025-2029 period, Toronto Hydro forecasts spending $301.3 million across the three IT/OT Program segments. This represents an increase of $46.5 million (or approximately 18.2 percent) compared to the 2020-2024 planned spend under the IT Hardware, IT Software and Communication Infrastructure segments.

IT/OT systems perform vital functions that are central to the safe and reliable operation of the distribution system and to the effective interaction between the utility and its customers. The proposed spending is required to (i) refresh IT hardware systems at the end of their useful life (ii) upgrade Toronto Hydro's IT software applications to ensure system is current, and make targeted investments to provide software enhancements that address business risks, process improvement opportunities or compliance matters; (iii) address specific OT system needs to mitigate risks such as functional obsolescence; and (iv) maintain a strong cybersecurity posture to mitigate against potential vulnerabilities and threats that may jeopardize the safe and proper functioning of IT/OT assets.

As detailed in Exhibit 2B, Section D8, Toronto Hydro has a robust decision-making process to govern its IT/OT program. In accordance with this Strategy, the utility ranks and prioritizes initiatives in this program by weighing and balancing the following considerations and their impact on the utility's operations and customers:

- Compliance with applicable regulatory requirements;
- Alignment with the organization's strategic objectives including Grid Modernization, Energy Storage, Process Automation, Customer Experience, and Customer Engagement;
- Required availability of the IT/OT systems to support core business operations and planned work programs. As described above, enterprise software applications are categorized into two tiers based on their criticality. Upgrades to Tier 1 applications take priority over Tier 2;
- Ensuring data in the IT/OT systems are secure and protected from cyber-attacks;
- Sustaining and improving current levels of customer service; and

- Other considerations such as application complexity, resource balancing, and inter-dependencies with other programs.

A number of controls and practices are in place to ensure that IT investments deliver value to customers either directly, through improved customer service, or indirectly from performance or cost improvements. IT/OT expenditures are subject to Toronto Hydro's procurement policy, which can be found in Exhibit 4, Tab 3, Schedule 1, Appendix A. For IT software investments, this applies to both the application itself and the system integration support services that are required to implement the solution efficiently and cost-effectively. Toronto Hydro leverages existing vendors of record lists at the municipal or provincial level to secure potential volume discounts to obtain IT products at lower price points.

An independent benchmarking study performed by Gartner Consulting (Gartner) concluded that Toronto Hydro's IT expenditures as of 2022 benchmark competitively against industry peers.[13] Gartner also concluded that the distribution of Toronto Hydro's IT investments by cost category, investment category, and functional area are all comparable to the peer group, with the exception of higher allocations to Applications spending (51.2 percent of IT spend for Toronto Hydro versus 41.9 percent for peers, largely due to the CIS Upgrade) and IT Management and Administration (14.8 percent of IT spend for Toronto Hydro versus 10.8 percent for peers, largely due to increased investment in Cyber Security services).[14]

Gartner further assessed Toronto Hydro's spending in a Run-Grow-Transform paradigm, defined as:

- **Run**: "essential (and generally non-differentiated) business processes."
- **Grow**: "improvements in operations and performance, within current business models."
- **Transform**: "new services and new operating models."

In both 2017 and 2022, Toronto Hydro IT investments were primarily directed at maintaining current business capabilities ("run") with the remainder directed at expanding existing business capabilities or driving new ones ("grow" and "transform" respectively).[15] The resulting split among the three categories is comparable to the peer group average. The increase in Toronto Hydro's 2022 IT

[13] Gartner Consulting (2023), *IT Budget Assessment Final Report* found in Exhibit 2B, Section D8, Appendix A
[14] *Ibid* at page 5.
[15] *Ibid*.

spending compared to 2017 is similar to industry peers. Toronto Hydro interprets this result as confirmation that its IT expenditures are appropriately balanced.

E8.4.4.1 IT Hardware

1. IT Infrastructure

The table below outlines the approximate volume of hardware assets for the 2020-2024 period and the 2025-2029 period. Projected cost increases are a function of higher cost-per-unit, due to hardware prices increases and higher Capacity/Unit Count which can be attributed to several factors including optimizing system performance, supporting the implementation of new IT transformation initiatives and increases in workforce. This will result in more processing power, larger storage capacity and higher network performance. Core Infrastructure units are presented in terms of Windows, Linux and UNIX virtual servers with individual unit costs reflecting the burdened cost of the entire underlying Core Infrastructure, including power, telecom, network, storage, backup, server and virtualization infrastructure layers.

Table 5: Hardware Volumes

Asset Category	IT Hardware	2020-2024 Actuals/Bridge		2025-2029 Plan	
		Capacity /Units	Total Cost ($M)	Capacity /Units	Total Cost ($M)
Core Backend Infrastructure Assets (Capacity)	*Unix Virtual Servers*	560	47.9	650	64.3
	Linux x86 Virtual Servers	349		400	
	Windows Virtual Servers	2656		3100	
Endpoint Assets (Units)	*Personal Computing Devices*	2308	11.9	2500	13.6
	Printers & Plotters	180		130	

IT hardware cost estimates are derived by forecasting the number of hardware assets that are past their useful life and that are needed for incremental needs over the 2025-2029 period. Table 5 illustrates that the Hardware program covers the replacement of existing units of infrastructure and the expansion of numbers of units to support enhancement and transformation initiatives, with the exception of printers and plotters which decreased by 28 percent.

The Strategy details the utility's approach to replacing IT hardware assets. The timing and pacing of investment in each asset sub-type is driven by the asset lifecycle. This is defined by the applicable standard, which is based on factors such as the criticality of the infrastructure, industry best practice, and vendor specifications. These standards are designed to extract the maximum value from hardware assets and minimize the negative impact of potential asset failures.

Toronto Hydro also considers forecast capacity requirements to ensure it has the necessary IT hardware to support general business growth and associated increased data storage and data processing requirements. The forecasts are based on the analysis of the following factors:

- Historical trends of current assets capacity versus utilization by existing IT systems;
- Asset resource requirements to support system enhancements and new initiatives; and
- New operational requirements that necessitate increased hardware resources.

Based on this approach, Toronto Hydro will require $77.9 million to replace and expand the number of IT hardware assets. Of Toronto Hydro's current assets, approximately 90 percent of existing core backend infrastructure (e.g. network, storage, and server assets) are forecast to require replacement in order to address obsolescence, security and reliability risks associated with aging assets and provide the incremental capacity needed to support Toronto Hydro's IT footprint. The utility anticipates that all endpoint assets will need to be replaced between 2025 and 2029, at a pace that will address an approximately equal number of assets each year.

The investments proposed above will provide for secure and reliable IT infrastructure, supporting all operational activities, business processes, IT/OT systems and applications of Toronto Hydro. They will enable alignment with IT Assets Lifecycle & Capacity specifications outlined in the Toronto Hydro IT architecture standards by replacing all hardware assets before the end of useful life, ensuring adequate capacity and continued vendor support. Adhering to effective asset management practices will also ensure that adequate cybersecurity posture is maintained through timely system upgrades and new technology deployments.

2. IT Cybersecurity Practice

The table below outlines the approximate volume of cyber-security controls for the 2020 – 2024 period and the 2025 – 2029 period. Projected cost increase is primarily a function of growing IT footprint and higher unit costs arising from the need for more complex cybersecurity technologies

to maintain adequate cybersecurity posture in response to expected increases in emerging threats, as well as vendor price increases across the board.

Table 6: Cybersecurity Systems and Controls

IT Cybersecurity Practice	2020-2024 Actuals/Bridge		2025-2029 Plan	
	Capacity /Units	Total Cost ($M)	Capacity /Units	Total Cost ($M)
OEB CSF Controls & Compliance	545	12.7	600	20.2
Asset Security: Systems/Applications	1,600		1,800	
Asset Security: Endpoints	30,265		33,000	

Cybersecurity systems and controls are grouped into three distinct categories, namely the OEB Cyber Security Framework (CSF) Controls & Compliance, Asset Security Systems and Applications and Asset Security for Endpoints. These categories are inclusive of the entirety of Cybersecurity technology landscape, such as Firewalls, Intrusion Detection System (IDS), Intrusion Prevention System (IPS), Endpoint Detection and Response (EDR), Data Loss Prevention (DLP), Virtual Private Network (VPN), vulnerability management, anti-malware, anti-phishing, logging, alerting and other related systems. Costs associated with these technologies have been allocated on a per-unit basis to the ecosystem of IT systems, applications, endpoints and associated data being protected.

The investments proposed above will enable Toronto Hydro to not only maintain its cybersecurity posture at the current levels, but also develop future state readiness to adapt to the constantly changing cybersecurity threat landscape. This will be achieved through investment in advanced cybersecurity technologies, such as honeypots, attack surface management and micro-segmentation, aimed at proactively detecting and containing inherently unknown threats, such as zero-day attacks, in addition to defending against known threats.[16]

E8.4.4.2 IT Software

The table below outlines the spend for the 2020-2024 and 2025-2029 rate periods:

[16] *Supra* notes 5-8.

Table 7: IT Software Costs ($ Millions)

IT Systems	2020 - 2024 Actual & Bridge	2025 - 2029 Plan
Total Cost	172.1	188.3

1. Software Upgrades

Over the 2025-2029 period, Toronto Hydro plans to spend $188.3 million on IT software upgrades, enhancements and regulatory compliance initiatives.

As discussed in the driver's section, Toronto Hydro plans to upgrade its Tier 1 software applications. Table 8 below outlines the historical and forecast spending for the Tier 1 software applications.

Table 8: Tier 1 IT Systems Upgrades Costs ($ Millions)

IT Systems	2020 – 2024 Actual & Bridge	2025 - 2029 Plan
ERP	24.4	28
CIS	38	N/A
ADMS	N/A	34.2
Tier 1 Systems excluding ERP, CIS	41.6	46
Tier 1 Systems Total	104	108.2

a. Upgrade to SAP Enterprise Resource Planning (ERP) System

An ERP system is critical for Toronto Hydro, as it integrates various financial, procurement, human resource, and asset management business processes into a single system. [17] For instance, the ERP system can support managing inventory of equipment and supplies, scheduling maintenance and repairs, managing vendors and inbound logistics, and managing workforce. By providing a centralized and unified view of the company's operations, an ERP system helps improve decision-making capabilities, identify areas for cost savings, and optimize operations for maximum efficiency. Additionally, the ERP system enables compliance with regulatory requirements by providing tools for tracking and reporting on the company's activities.

[17] Exhibit 2B, Section E8.4, Appendix B.

Based on the Strategy, Toronto Hydro is proposing to upgrade its ERP system to the next version (i.e. S4 HANA) in the 2025-2029 period. The initiative will deliver a modern ERP system that is fully vendor supported and that effectively and efficiently executes business processes. The ERP system would strengthen Toronto Hydro's cybersecurity posture, modernize Toronto Hydro's business processes in response to changes in customers' needs and expectations due to shift towards electrification.

b. Advanced Distribution Management System (ADMS)

Toronto Hydro is looking to upgrade its current Advanced Distribution Management Systems (ADMS) which is a software platform consisting of a suite of several software applications to assist Control Centre operators in monitoring and controlling the distribution system.[18] Currently, Toronto Hydro operates separate instances of SCADA and Network Management System (NMS). Core operational systems are supported by a number of purpose-specific auxiliary applications, such as Automated Call-Out and voice radio communications with field crews.

Since the integration between these systems is unidirectional from SCADA to NMS, manual processes are required to keep the systems synchronized. This results in disparate user interfaces, data duplication and risk from human error.

By upgrading the existing ADMS, Toronto Hydro can achieve operational and safety excellence, enable advanced predictive and automation capabilities, implement a self-healing grid for automated outage restoration, provide automated and smart dispatching, offer holistic situational awareness, optimize distribution grid performance and customer experience, and gain full DERMS capabilities. ADMS can help Toronto Hydro manage the response to outages, meet growing customer and regulator expectations, and address the complexity introduced by the expected increase in penetration of distributed energy resources (DERs) in the electric distribution system. ADMS software analyzes data from field devices, alerts operators to adverse electrical conditions and inefficiencies, and offers advice to address these issues or performs recommended control actions automatically. These new advanced capabilities will equip Toronto Hydro with the tools required to respond effectively to future challenges associated with electrification by providing its customers with a timely and efficient outage response.

[18] Exhibit 2B, Section E8.4, Appendix A.

c. Other Tier 1 Systems

During the 2025-2029 period, Toronto Hydro plans to upgrade its other Tier 1 applications (listed in Section 8.4.3.2) in line with lifecycles developed and pursuant to its Strategy. Cost variances for these upgrades, as shown in Table 8, are primarily due to inflation.

d. Tier 2 Systems

Table 9: Planned Tier 2 Application Upgrades

	2020-2024 Actuals/Bridge		2025-2029 Plan	
	Number of Applications	Cost ($M)	Number of Applications	Cost ($M)
Tier 2 Systems	72	12.4	80	14

The forecasts in the table above were derived by analyzing the lifecycles of all Tier 2 applications. Applications must be upgraded before reaching the end of their useful lives to mitigate the risk of failure and disruption to the business processes they support. Increasingly, vendors are reducing the lifecycles of Tier 2 applications (i.e. less than 4 to 5 years), meaning an increasing number of applications will require more than one upgrade over the 2025-2029 period. The primary drivers of the variance between 2020-2024 and 2025-2029 rate periods include the increased cost of upgrading on shorter intervals, additional Tier 2 Systems and general price inflation.

2. Software Enhancements

Software enhancements mitigate core business risks that would not be technically feasible or cost-effective to address through a non-IT solution or manual business processes. The table below presents the number of forecasted software enhancements initiatives and their associated costs in the 2020-2024 period and 2025-2029 period.

Table 10: Software Enhancements Volumes and Cost

	2020-2024 Actuals/Bridge		2025-2029 Plan	
	Number of Enhancements	Cost ($M)	Number of Enhancements	Cost ($M)
Software Enhancements	42	45.1	55	54.6

As discussed in the Drivers section, software enhancements can take a number of different forms: adding new functionality to an existing application (aside from ERP and ADMS, which are discussed above), integrating two systems to leverage otherwise independent data sets, expanding of reporting capabilities to make better use of existing data, or adding a new application.

The increase in cost for Software Enhancements between 2020-2024 and 2025-2029 is a result of multiple factors. Toronto Hydro expects that customer and operationally-driven enhancements will be necessary to address business continuity and operational risks, respond to changing consumer preferences and shift towards electrification. Inflation also contributes to the increase in Toronto Hydro's proposed planned expenditures.

A reduction in funding for software enhancements may lead to Toronto Hydro's inability to keep pace with technology changes in the industry, and less capability to respond to emerging customers' needs and business-driven risks. The $54.6 million in software enhancements planned for the 2025-2029 plan period accounts for approximately 29 percent of Toronto Hydro's IT software segment. Toronto Hydro's total IT expenditures, of which Software Enhancements is one component, are generally consistent with its peer group in terms of the Run-Grow-Transform paradigm articulated in the Gartner IT benchmarking study (See Exhibit 2B, Section E8.4, Appendix C).

3. Regulatory Compliance

The table below presents the anticipated number of regulatory compliance initiatives Toronto Hydro will be required to complete in the 2025-2029 period and the associated budget.

Table 11: Regulatory Compliance Volumes and Cost

	2020-2024 Actuals/Bridge		2025-2029 Planned	
	Number of Initiatives	Cost ($M)	Anticipated Number of Initiatives	Cost ($M)
Regulatory Compliance	5	10.6	6	11.5

Toronto Hydro anticipates it will require incremental funding for new compliance-related initiatives in the 2025-2029 rate period, attributable to forecasting a similar volume of public policy initiatives driving new compliance requirements as occurred during the 2020-2024 period.

E8.4.4.3 Communication Infrastructure

Communications infrastructure is relied upon by the utility's core operations to maintain and operate the distribution system in a safe and reliable manner. The proposed investments address functional obsolescence in Toronto Hydro's current communications infrastructure footprint, address safety and reliability risks, and support the monitoring and control of future smart grid technologies.

The table below outlines the actual and forecasted volume of communication infrastructure assets for the 2020-2024 and the 2025-2029 rate periods. It is important to note as the program scope for the 2025-29 period is different than 2020-2024, the new projects are shown as separate rows at the bottom of the table below.

Table 12: Communication Infrastructure Volumes and Cost

Asset Category	Communication Hardware	2020 – 2024 Actuals / Bridge		2025 – 2029 Plan	
		Capacity / Units	Total Cost ($M)	Capacity / Units	Total Cost ($M)
Communication Infrastructure	*SONET Migration and Decommissioning*	31	3.1	0	0
	Fibre-Optic Cable	15	1.8	0	0
	SCADA High-Site Capacity Upgrade	12	0.9	0	0
	Wireless SCADA Endpoint Radio Migration	1,103	3.0	0	0
	Radio Installation	0	0	0	0
	Underground Radio Sites	0	0	0	0
	Cellular Telecom Infrastructure (initial deployment)	2	1.4	0	0
	Cellular SCADA Telecom Infrastructure Upgrade	0	0	2	1.5
	Cellular SCADA Endpoint Deployment	0	0	1,250	4.2
	P25 Voice Radio SUA Upgrade Cycle	0	0	1	9.1
	Total		**10.2**		**14.8**

As detailed in Section E8.4.3.3, over the 2025-2029 period Toronto Hydro plans to undertake work in three discrete projects in this segment:

1. Cellular SCADA Telecom Infrastructure Upgrade

Toronto Hydro expects to spend approximately $1.5 million in 2026 for this upgrade and system capacity expansion at its two data centers, facilitating future growth as the number of Cellular SCADA endpoints extends to other use cases beyond pole top RTUs, such as underground vaults and pad-mount transformers.

2. Cellular SCADA Endpoint Deployment

Toronto Hydro expects that the migration of pole top SCADA endpoints from proprietary radio systems to Cellular SCADA will be conducted in the 2025-2029 rate filing period. Toronto Hydro expects that approximately 1250 endpoints will be migrated to Cellular SCADA in the 2025-2029 period at a total cost of $4.2 million. This work will be paced uniformly from year to year over the 2025-2029 period, considering the available resource capacity to perform the migrations.

3. P25 Voice Radio SUA Upgrade Cycle

Toronto Hydro expects to perform an upgrade of the Motorola P25 Voice Radio System in 2025 at a cost of approximately $2.6 million. This is the last system upgrade, in the cycle of upgrades, under the current System Upgrade Agreement (SUA), extending the system's useful life until 2028. Toronto Hydro expects to sign a new SUA in 2028 that will keep the system operational for future years, extending its useful life and avoiding premature costly replacements. Based on provided vendor estimates the new SUA is expected to require $6.5 million of Capital expenditures between 2028-2029.

E8.4.5 Options Analysis/Business Case Evaluation (BCE)

E8.4.5.1 Options Analysis/BCE for IT Hardware Segment

1. IT Infrastructure

a. Option 1: Managed Deterioration

Choosing this option will result in a reduction of investment in the IT Hardware Infrastructure program and in IT capacity upgrades. As a consequence, IT equipment will be operated beyond its useful life and the hardware will no longer be supported by vendors. This situation can cause a significant increase in operational costs due to higher-priced extended support and insufficient IT

capacity to meet key business processes. This option poses several major risks, including frequent IT service outages, reduced and eroded availability of mission-critical IT systems, and insufficient capacity to support growing data volumes and processing requirements. Additionally, using obsolete equipment may result in increased exposure to cybersecurity attacks, data loss, service unavailability, and impact to brand reputation. There is a high likelihood that this will result in software compatibility issues and jeopardize any changes, improvements and upgrades to IT Software. Unsupported hardware failures may result in data losses and the inability to recover lost data, posing an unacceptable risk to the utility's ability to provide core services to ratepayers and comply with legislative and regulatory obligations.

Furthermore, adopting this option for the rate filing period will create much greater capital and operational spend requirements in the next filing period. Toronto Hydro will need to catch up on the insufficient spend and perform major version and architectural upgrades as opposed to gradual incremental ones. This option is not advisable as it can negatively impact Toronto Hydro's ability to adequately support existing business needs, service customers and result in increased operational costs.

b. Option 2: Sustainment (Preferred Option)

Under this option Toronto Hydro will manage the IT Infrastructure program as per approved hardware standards. Opting for the sustainment option will enable Toronto Hydro to ensure consistent and reliable IT infrastructure with minimal service disruptions. By selecting this option, IT infrastructure can remain upgraded, ensuring that all assets are sized to adequate capacity with appropriate vendor support. This means that IT teams can focus on maintaining and enhancing existing systems, rather than constantly troubleshooting outdated equipment and software.

Furthermore, choosing the sustainment option enables the organization to maintain an adequate security posture by ensuring that system upgrades and new technology deployments are implemented in a timely fashion. This approach minimizes the risk of security breaches and protects confidentiality of customers' and employees' personal data from potential threats.

By aligning Toronto Hydro IT hardware programs with standards, it secures a nominal spend request for the next filing period. The sustainment option optimizes IT spend, avoids significant spikes in capital/operational spend and reduces overall costs. The sustainment option provides a stable and secure IT environment that allows the organization to focus on its core business activities and

customer services, without increasing risks to the reliability and availability of the underlying IT infrastructure.

c. Option 3: Improvement

Under this option Toronto Hydro could provision extra capacity and enable early lifecycle replacement. Opting for the Improvement option may seem like a preferable choice to enhance IT infrastructure, but it will result in suboptimal utilization of available IT hardware resources and increased support costs. This approach does not yield any tangible benefits over the optimal selection of technologies covered in the Sustainment option. There is a high likelihood that with overprovisioned infrastructure a large number of resources are idle resulting in inefficient investment.

This approach will lead to increased operational cost burden through a larger technology footprint. Furthermore, exercising this option may lead to increased operational cost burden in the next filling period due to a larger IT hardware asset footprint.

d. Options Evaluation

The Sustainment option is the preferred option because it achieves an optimal balance that allows Toronto Hydro to maintain its IT infrastructure at an adequate level while optimizing the utility's overall IT spend. In comparison to the Managed Deterioration option, the Sustainment option provides a stable and secure IT environment that minimizes the risk of security breaches and ensures that IT teams can focus on enhancing existing systems. In comparison to the Managed Deterioration and Improvement options, this option will allow Toronto Hydro to avoid significant spikes in capital and operational spending.

In comparison to the Improvement option, the Sustainment option decrease likelihood of large number of resources being idle. By aligning with approved hardware standards, Toronto Hydro can ensure that all hardware assets are sized to adequate capacity with appropriate vendor support. This approach minimizes the sunk costs from unutilized or underutilized hardware resources. The Sustainment option secures the same security posture as the improvement option and protects confidentiality of customers' and employees' data from potential threats.

Overall, the Sustainment option provides a balance between minimizing business continuity and operational risk, optimizing IT spend, and maintaining adequate IT infrastructure.

2. IT Cybersecurity Practice

Cybersecurity practice investment options are presented in the form of Managed Deterioration, Sustainment and Improvement, with Improvement being the preferred option. Each option covers the entirety of the IT domain in terms of the number of OEB Cyber Security Framework (CSF) controls, systems and applications and endpoints that are in scope, but differ in the amount of investment into the latter two categories.

a. Option 1: Managed Deterioration

Managed deterioration option includes limited investment into the overall Cybersecurity posture, and primarily focuses on maintaining the existing controls, which may lead to the inability to maintain compliance with OEB CSF in the future. In addition, this option will effectively prevent any innovation in the Cybersecurity space resulting in gradually deteriorating security posture unable to cope with evolving cybersecurity threats.

This option carries the largest amount of risks to the environment, as suboptimal cybersecurity controls arising from inadequate investment will inevitably leave the organization vulnerable to cybersecurity threats, potentially compromising critical OT systems and sensitive customer and employee information. This will negatively impact Toronto Hydro's ability to avoid business disruptions and ensure security and confidentiality of sensitive information. Opting for Managed Deterioration will also translate into operational spend increases due to the need to secure extended support for obsolete systems and increase future investment requirements. Due to the increased risk of cybersecurity exposure, this option is the least preferred way forward.

b. Option 2: Sustainment

Sustainment option encompasses continued investment into the Cybersecurity practice with the goal of ensuring all existing controls are managed and expanded to keep up with the evolving threats, with the intent of maintaining Cybersecurity posture at the same level as the previous filing. Investment at the sustainment level will ensure that all existing controls will continue to be adequately maintained and new functionality would be organically integrated into the threat protection ecosystem.

Sustainment option aims to maintain the level of risk consistent with the previous filing, ensuring that all systems, applications and endpoints remain adequately protected against the constantly

changing threat landscape. However, this option will not reduce the risk to the organization from its current baseline, as transformative initiatives exploring cutting edge protection mechanisms would not be implemented. Due to the inherent uncertainty of the future threat landscape, maintaining cybersecurity posture at historical levels may not be sufficient to ensure adequate protection going forward. As such, Sustainment, while preferable to Managed Deterioration, remains a suboptimal option compared to the Improvement alternative.

c. Option 3: Improvement

Improvement option encompasses the increased investment into the Cybersecurity practice to enable the expansion of existing Cybersecurity threat management and response capabilities, resulting in a stronger security posture. In addition to ensuring that all existing cybersecurity controls are maintained at adequate levels, Improvement option will add new cybersecurity technologies to ensure that Toronto Hydro is capable of adapting to the continuously evolving threat landscape while reducing its risk exposure.

Improvement option aims to reduce the cybersecurity risk by implementing additional controls across IT/OT systems, applications and endpoints to ensure better ability to prevent, detect and contain threats compared to the current state. This will have the net effect of improving cybersecurity posture, resulting in better protection of Toronto Hydro's IT/OT assets and confidentiality of customers' and employees' personal information while further reducing the chance of cybersecurity-related incidents and business disruptions. Therefore, Improvement option is positioned as the preferred investment option.

d. Options Evaluation

Improvement is positioned as the most optimal spend for the IT Cybersecurity practice area. Increased investment into this area will enable Toronto Hydro to handle the evolving threats of tomorrow in addition to maintaining its current cybersecurity posture and preventing technological obsolescence, ultimately reducing overall risk for the organization.

Managed Deterioration and Sustainment options are considered inferior, due to the inherent compliance, privacy and cyber security corporate risks associated with the inability to strengthen cybersecurity posture in response to the everchanging cybersecurity threat landscape. Managed deterioration in particular carries the implication of weakening cybersecurity posture and increased operational expenditures to maintain end-of-support ecosystem. Opting for either of these options

would increase Toronto Hydro's liability risk at the corporate level due to elevated cybersecurity risk levels.

Failing to grow and expand the security controls protecting Toronto Hydro systems, applications and endpoints carries a high risk of negatively impacting Toronto Hydro business continuity, customer information protection, reputation and revenue generation. Toronto Hydro is governed by OEB recommended privacy and security controls, government regulations and data protection requirements. The incremental planned expenditure presented in the Improvement option aims to reduce the occurrence of future cybersecurity related incidents or business disruptions in addition to protecting its IT/OT assets, safeguarding employees' and customers' personal information, meet security compliance obligations, provide assurance to our industry partners, customers and stakeholders, and facilitate the shift towards electrification.

E8.4.5.2 Options Analysis/BCE for IT Software

1. Option 1: Managed Deterioration

The Managed Deterioration option involves reducing investment in IT software capital expenditure, specifically in the categories of Tier 1 upgrades, Tier 2 upgrades and software enhancements, with the exception of the ERP Upgrade and ADMS upgrade. This option implies that Toronto Hydro would not upgrade all its Tier 1 and Tier 2 applications according to the Strategy, increasing the risks to system reliability and availability. Toronto Hydro would need to maintain and customize these applications using manual work-arounds, which could become increasingly complex, inefficient, and costly over time. The lack of vendor support for security-related patches poses significant cyber security risks, as outdated systems would be more vulnerable to cyber-attacks and compromises. This could result in data loss, IT service interruptions, and negative impact on brand reputation.

IT software systems are essential to many critical business procedures and processes, such as the Toronto Hydro's public policy processes, safety procedures, and financial reporting. A reduction in capital spend would negatively impact all of these processes, and limit Toronto Hydro's ability to support key divisional and corporate metrics such as reliability, safety, customer service and financial indicators. Potential risks include frequent IT service outages and reduced availability of critical IT systems.

Limiting software enhancements would negatively affect business units' ability to meet their goals and objectives, potentially affecting grid operations and ability to restore power. Toronto Hydro

would be unable to invest in advanced digital platforms to improve customer experience or enhance technologies to provide timely and accurate communication with customers during outages.

Moreover, there would be a significant increase in operational costs to support legacy and out-of-support systems, which would impede the organization's ability to implement systems that support future changes in business process requirements and growth.

2. Option 2: Sustainment

The Sustainment option focuses on minimizing risks to the reliability and cybersecurity of Toronto Hydro's IT software applications. In this option, all IT systems will be actively managed and timely upgraded. This would ensure Toronto Hydro has vendor support and it would eliminate risks to business continuity from system downtime and minimize cyber security risks. It would address compatibility risks that could arise from integrating systems that are not current.

This option will allow Toronto Hydro to meet its commitments with regulatory compliance and achieve the upgrades of the ERP System and ADMS System.

However, Toronto Hydro would curtail the spend in Software Enhancements to meet the spend objectives. This will limit Toronto Hydro's ability to modernize its IT business processes and address customers' changing needs and preferences in response to industry shift towards electrification. Limited funding in software enhancements would also leave Toronto Hydro unable to keep pace with technology changes in the industry.

3. Option 3: Improvement

The Improvement option balances spend across upgrades, regulatory compliance and enhancement initiatives. Similar to Sustainment option, all IT systems will be actively managed and timely upgraded. Toronto Hydro will meet its commitments with regulatory compliance and achieve the upgrades of the ERP System and ADMS System.

Additionally, this option will provide an optimal level of investment in software enhancements, which would allow Toronto Hydro to stay on par with its peer group.

This option will support the modernization of IT business processes in alignment with Toronto Hydro's growth and modernization strategic objectives and meet customers' changing needs and preferences in response to electrification.

4. Options Evaluation

The Improvement option is the preferred option. The Improvement option is optimal because it focuses on minimizing risks to the reliability and cybersecurity of Toronto Hydro's IT software applications while enabling the company to sustain its IT/OT systems and modernize its IT business processes.

Similar to Sustainment option, the Improvement option proposes all software upgrades to ensure that Toronto Hydro's software systems receive vendor support, remain integrated with other relevant software systems, are protected against cybersecurity threats.

In contrast, the Managed Deterioration option involves reducing investment in IT software capital expenditure, specifically in software upgrades and enhancements, which would leave some Toronto Hydro's IT systems without vendor support and vulnerable to cyber-attacks and compromise security. This option would negatively impact critical business procedures and processes, increase operational costs to support legacy systems, and hinder Toronto's Hydro's ability to deliver on performance outcomes such as System Reliability and Resilience.[19]

The Sustainment option proposes to sustain the status quo level of investment. However, the Sustainment option limits Toronto Hydro's ability to invest in IT enhancements, innovation and the modernization of IT business processes. In contrast, the Improvement option would allow Toronto Hydro to stay on par with its peer group and effectively respond to changing customers' needs due to shift towards electrification and future business transformation.

E8.4.5.3 Options/BCE for Communication Infrastructure

1. Option 1: Managed Deterioration

The Managed Deterioration option for communication infrastructure involves reducing investment in Communication Hardware Assets where a fewer number of wireless SCADA endpoints are

[19]Exhibit 1B, Tab 2, Schedule 1.

migrated from private radio to cellular communications. In turn, it increases operational risks and extends the time needed to complete the program. Critical SCADA communications equipment is run past the end of its useful life, resulting in obsolete hardware that is no longer supported by vendors. This can lead to higher operational and business continuity risks due to system obsolescence resulting in frequent outages, significantly increased operational costs, inability to replace faulty equipment in a timely fashion due to supply chain issues, and a lack of availability of qualified personnel to perform skilled work. Adopting this option will likely result in greater capital investment and operational spend for the period beyond 2029 to catch up on delinquent installations and upgrades, and maintain obsolete equipment past its useful life. In addition, a higher level of capital investment will be required to complete upgrades beyond 2029 due to anticipated increases in costs (e.g. inflation). This option also does not align with the organization's strategic objectives of growth and modernization as communication hardware assets will not be able to respond to changes in customers' needs and preferences associated with future industry challenges such as electrification. Limited investments in communication hardware assets will render them without vendor support, resulting in inability to perform the necessary upgrades or access patches to respond to future industry challenges.

2. Option 2: Sustainment

The Sustainment option ensures that communication infrastructure is replaced as per the Information Technology Asset Management Strategy and Investment Planning procedure, and all communications equipment remains supported by vendors. This option ensures an available and reliable communication infrastructure with little to no service disruption, resulting in minimal operational risk. In addition, the adoption of efficient and secure communications with cellular SCADA endpoints significantly reduces cybersecurity risk by ensuring an adequate security posture through timely upgrades and new technology deployments. It avoids significant increases in capital investment and operational spend, which is beneficial in the long run. The sustainment option ensures that an adequate security posture is maintained, and the risk of obsolescence is mitigated.

This option optimally aligns with the organization's strategic objectives of growth and modernization by ensuring the availability of reliable and secure communication infrastructure to sustain day-to-day operations and ability to adapt to changes in customers' needs and preferences in response to future industry challenges such as electrification.

3. Option 3: Improvement

The Improvement option for communication infrastructure involves accelerating the deployment of wireless SCADA endpoints. The utility would need to onboard additional resources on a one-time basis to fulfill this requirement. This option can help Toronto Hydro take advantage of the benefits of faster adoption of cellular communications technology for wireless SCADA endpoints. This option will require the availability of necessary specialized resources, including personnel and equipment, to meet the increased workload. As a result, there is a significant operational risk associated with securing these resources as they are not easily and readily available to Toronto Hydro and will require greater capital investment. Despite the risks, this option offers several benefits, including faster adoption of cellular technology, which can improve the efficiency and reliability of Toronto Hydro's communication services. By accelerating the deployment of wireless SCADA endpoints, Toronto Hydro can take a proactive approach to improving its communication infrastructure and enhancing the overall customer experience.

4. Options Evaluation

The Sustainment option is recommended. In comparison to the Managed Deterioration option, the Sustainment option offers a more proactive and long-term approach to ensure the reliability, availability and security of Toronto Hydro’s communication infrastructure. The Sustainment option also ensures communication infrastructure assets are upgraded as per Information Technology Asset Management Strategy and Investment Planning procedure and remain supported by vendors. This option ensures alignment with modernization by enabling system growth and preventing the risk of obsolescence, service disruption, and cyber-security threats. The Managed Deterioration option involves limited investments and extending the time needed to complete the upgrade, which can result in increased operational risks and frequent outages.

The Improvement option for communication infrastructure offers benefits such as faster adoption of cellular technology and improved efficiency and reliability of communication services. However, it poses high operational risks due to significant uncertainty in ensuring the availability of personnel and equipment resources to complete the extra work and greater capital investment.

The Sustainment option offers an optimal balance between investment required and operational risk management, ensuring that Toronto Hydro's communication infrastructure remains secure, reliable, and adequately supports future business requirements. Therefore, the Sustainment option is the preferred option.

E8.4.6 Execution Risks & Mitigation

This section discusses various potential risks to the execution of the IT/OT program, and Toronto Hydro's corresponding mitigation measures:

- **Cybersecurity Threats:** Even with a strong cybersecurity posture, it is possible for cyber threats to impact a company's ability to execute the IT/OT program on time and within budget. To mitigate these risks and minimize the associated impacts, Toronto Hydro developed incident response and business continuity plans to address potential disruptions caused by cyber threats. Mitigation strategies include employing backup systems, implementing redundant infrastructure, and sourcing alternative suppliers or vendors.
- **Regulatory Requirements:** Implementation of new regulatory requirements may require more resources and time than budgeted. If new regulatory requirements emerge at a higher than expected rate, resources will be re-allocated accordingly to ensure that Toronto Hydro complies with application requirements. Projects will be rescheduled as necessary in accordance with the project prioritization considerations outlined in section E8.4.4.2 above.
- **Software Release Dates:** Changes to application version release dates will impact the project schedule and potentially impact downstream projects in the program. If one or more software upgrades require another software upgrade to be completed first, any delay in the release of the first software upgrade will delay the upgrade of the dependent software system(s). To address this risk Toronto Hydro monitors release dates, ensures that all impacted projects are properly sequenced and maintains a holistic view of IT environment/architecture to identify interdependencies.
- **Technology Change:** New technology may be introduced after previous assets were refreshed during the asset's lifecycle. This risk may impact project cost, as new technology may need to be procured to meet business requirements. Toronto Hydro closely monitors the latest trends to determine how technology fits into existing Toronto Hydro IT standards and business requirements. In addition, Toronto Hydro assesses and evaluates future IT

investments to ensure preparedness to respond to future challenges such as electrification and align with the organization strategic objectives.

- **Solution Fit to Utility Requirements**: A design approach that considers functionality in isolation is particularly risky. The solutions proposed for incorporation into the upgraded and expanded IT systems must be able to deliver the functionality Toronto Hydro requires to meet its operational, regulatory, and customer obligations. Toronto Hydro will fully consider all areas of its operations before any configuration or coding has taken place. All processes and system requirements will be defined and documented by Toronto Hydro prior to tools, components and modules selection, and integration. End-to-end operational process scenarios will be used in the testing phase of the system.
- **IT/OT Systems Integration:** Different systems may not properly integrate with each other when a system or group of systems are upgraded or replaced. If the current level of integration is not maintained, business processes could be impeded and process inefficiencies could be introduced from manual data updates. Toronto Hydro considers and analyzes new component configurations in defining project scopes, and conducts thorough due diligence during technical feasibility studies.
- **Internal Resource Availability:** There may be insufficient resources to complete the planned program tasks and activities, which could delay interdependent and downstream work activities and lead to escalations in project costs due to the need to procure temporary skilled resources at a premium. In response, Toronto Hydro will: (i) adopt a long-term resource plan based on required skills to support project tasks and activities that the utility plans to undertake over the 2025-2029 period; (ii) train and cross train resources to ensure employee engagement, employee retention and workforce sustainability; and (iii) ensure appropriate responsibility overlaps between labour resources to minimize impact from attrition.
- **Vendor Management:** Vendors may not meet program delivery obligations or may change the product cost structure. More specifically, a vendor may be unable to provide the product according to project schedule or in compliance with Toronto Hydro's specifications, thereby leading to delays or cost overruns to address the issue. In this regard, Toronto Hydro will ensure mechanisms are available to oversee and enforce contract terms and conditions. Toronto Hydro will adopt the following mitigation measures within its contracts:

- Complete comprehensive due diligence of scope and requirements prior to undertaking projects and incorporate findings in the tender documentation.
- Solicit vendor responses to competitive bids from qualified parties.
- Enter into long term contracts, where appropriate, with vendors and suppliers to ensure costs are fixed over a long period of time.
- Clearly state expected timelines and have resolution clauses to address delays.
- Identify an escalation path to quickly resolve conflicts and discrepancies.
- Enforce short interval control on vendor performance and deliverables through project status updates.

- **Adherence to Budget & Timelines:** If a project tracks above budget or falls behind schedule, this could take resources away from other important IT projects and delay their implementation. To address this risk, Toronto Hydro uses modern project management methods, tools, and vendor agreements to ensure on-time and on-budget project execution. Moreover, Toronto Hydro's experienced project managers will control the implementation timing of projects in accordance with each project plan and closely monitor emerging risks. Contract tools and incentives will also be incorporated to aid the management of timelines.
- **Project Delivery**: A new IT/OT System version could cause established core business processes to change and, without proper integration, could disrupt, and cause inefficiencies in these processes. Toronto Hydro undertakes extensive regression testing and user testing prior to rolling out the final upgrade to the business units. In addition, risks are mitigated through appropriate user engagement and communication, change management, training and project governance including contingencies to minimize the impact to the business users in the final implementation.

Preliminary Scoping Business Case:

Advanced Distribution Management System (ADMS) Upgrade

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1. EXECUTIVE SUMMARY

Project Name	Costs (2025-2029)
Advanced Distribution Management System (ADMS) Upgrade	$34.2 million

Toronto Hydro relies on its current ADMS to meet service quality requirements and maintain the reliability of the distribution grid. The ADMS is a software platform consisting of a suite of several software applications to assist Control Centre operators in monitoring and controlling the distribution system. Key components of ADMS include:[1]

1. the Distribution Management System (DMS);
2. the Outage Management System (OMS); and,
3. the Supervisory Control and Data Acquisition (SCADA) system.

These three systems are the foundation of the utility's core system monitoring and operation processes. DMS and OMS enable operators to manage critical functions such as the identification and response to outages, and the safe planning and execution of field work using planned or emergency switching, combined with other elements of the Utility Work Protection Code (e.g. Work Permits, Supporting Guarantees, Hold Offs etc.). These systems are essential to supporting the evolving needs of Toronto Hydro's distribution grid and its users as a greater number of households, businesses, and government organizations electrify their energy usage, and as the penetration of distributed energy resources (DERs) increases. ADMS software, in particular SCADA, analyzes information acquired from field devices, alerts system operators to adverse electrical conditions, possible inefficiencies, and reliability issues, and either assists operators in addressing these issues or performs recommended control actions automatically.

Given the criticality of these systems to Toronto Hydro's day-to-day operations and overall system reliability and security, technical upgrades to the ADMS to ensure continued vendor support are necessary to ensure business continuity and adequate protection from existing and emerging cyber security threats. In addition, many ADMS components currently operate in silos and have limited ability to communicate effectively with each other, often contributing to process delays and inefficiencies that may result in longer outages. Upgrades to ADMS will enable effective co-ordination and communication among its various components by allowing Toronto Hydro to hand pick components in order to achieve a synchronized and harmonious platform. These upgrades will also align with the utility's grid modernization objectives by supporting future automation functionalities (e.g. in support of the self-healing grid) and improving business process efficiencies through leveraging technical and functional enhancements.

[1] A detailed list of components is available in the Appendix

Upgrades to ADMS will also enable Toronto Hydro to continue to meet or exceed the Ontario Energy Board's (OEB) reliability performance standards, particularly the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). ADMS contributes to grid reliability by providing Control Centre operators the capabilities to monitor and control the distribution network in real-time and enabling a comprehensive view of the network status of all connected devices including transformers, breakers and switches. It also contributes to the achievement of service quality requirements by enabling the automatic location and isolation of faults through the Fault Location, Isolation, and Service Restoration (FLISR) function, which reduces outage response times. ADMS is also equipped with advanced diagnostics to analyze the health of the distribution system and to identify outage root causes faster.

To ensure an effective ADMS solution for Toronto Hydro, the following options were assessed:

1. **Managed Deterioration** - Maintain status quo with current ADMS software platform.
2. **Sustainment** - Maintain status quo and execute only reactive and mandatory changes to keep the ADMS systems current without undertaking an upgrade.
3. **Modernization and Growth -** Implement a modern ADMS platform by leveraging the advantages of each system in a "Multiple Vendor Approach" strategy (i.e. "best fit" vendor offerings to meet Toronto Hydro's business needs).
4. **Replacement and Harmonization** - Implement a single platform, migrating all OMS, DMS, SCADA, and Distributed Energy Resource Management System (DERMS) functionality to the one integrated vendor.

The utility evaluated each option against the following categories:

- **Strategic Risks –** Each option was evaluated for alignment with strategic criteria which included alignment with Toronto Hydro's strategic objectives such as intelligent grid, grid modernization and process automation.
- **Tactical Risks**: Each option was also evaluated against tactical considerations including operational risk, security risk, implementation risk, timeline risk and budget risk.

Based on this evaluation, Modernization and Growth is the preferred option. This option positions the utility well to ensure grid reliability, alignment with Toronto Hydro's strategic objectives, the modernization of the utility's operations, and the improvement of customer experience. In addition, this option will assist Toronto Hydro in achieving its strategic objectives.

The Modernization and Growth approach will leverage multiple vendors to identify components that best fit Toronto Hydro's needs, and ensure compatibility and effective communication between different components in order to develop a synchronized platform. This approach also enables the utility to implement planned enhancements more effectively and flexibly based on functional phases that target specific areas such as FLISR, SCADA, DERMS, etc.

The intended benefits of the ADMS Upgrade are to:

- Ensure critical operational technology platforms are fully supported by respective vendors and are resilient against cyber security threats;
- Achieve operational and safety excellence;
- Enable advanced predictive and automation capabilities to reduce the frequency and duration of outages, resulting in improved system reliability and customer experience;
- Improve grid resiliency through automated and efficient restoration of outages with minimal interruption to customers;
- Deliver streamlined and effective responses to outages with crews addressing outages more quickly in the field through automated and smart dispatching;
- Leverage new technologies to enhance the utility's ability to assess and prioritize responses to outages due to major events such as storms through a holistic view of the grid;
- Ensure optimal distribution system performance and improve customer experience;
- Enable better monitoring and control of distributed energy resources in the field; and,
- Ensure optimal utilization of IT assets by enabling effective lifecycle management of secure and supported systems, minimizing operational and cyber security risks.

2. PROBLEM/OPPORTUNITY STATEMENT

2.1 Background

The upgrade of Toronto Hydro's Advanced Distribution Management System (ADMS) platform is necessary to enable the utility to maintain and modernize critical distribution system monitoring and management processes into the 2025-2029 rate period and beyond.

Current functions and components of ADMS allow Toronto Hydro to execute a variety of processes relating to the monitoring, operation, maintenance, and general oversight of the distribution system, such as:

- identifying outages;
- scheduling responses by field crews or remotely operating components of the grid to restore outages;
- monitoring and controlling DERs connected to the grid;
- performing various tasks in support of capital or maintenance work (such as switching); and,
- coordinating the management of the utility's distribution system in alignment with the operation of the bulk transmission grid by Hydro One and the Independent Electricity System Operator (IESO).

All of these functions are essential in enabling the utility's compliance with legislative and regulatory obligations relating to customer, public, and worker safety, grid reliability, and customer service.

Toronto Hydro plans to renew the systems comprising these functions and components of ADMS during the 2025-2029 period in order to 1) ensure that vendor support remains current and available and 2) enhance ADMS with various upgrades that will improve the effectiveness and efficiency of the underlying processes. The utility expects that its planned enhancements to ADMS will be crucial for operational effectiveness as society moves towards decarbonization, increasing the pace of electrification, and as the nature and needs of customers and stakeholders interacting with Toronto Hydro's distribution system continue to evolve.

The proposed upgrade would also present opportunities for the utility to streamline the operation and integration of ADMS functions and components and manage the relevant information and operational technology (IT/OT) assets in a more cost-effective manner, in accordance with

Toronto Hydro's IT Asset Management and Investment Planning Strategy (the Strategy).[2] In addition, ADMS upgrades will provide a comprehensive path for managing assets as per the Strategy by enabling effective tracking, utilization and co-ordination among various components. Given the rapid advancement in technology, without the ADMS upgrades, current systems will begin losing access to new and existing features, security will become a greater risk and vendor support will become more difficult to maintain. In addition, ADMS is a dynamic integrated platform that depends on all components working together in a synchronized fashion. Currently, not all ADMS components can be fully integrated to communicate effectively with each other, often contributing to process delays and inefficiencies that may result in an increase in outage response times. Integration will become increasingly important as the components age and component capabilities change, resulting in gradual degradation in ADMS' ability to perform critical activities. Upgrades to ADMS will enable effective co-ordination and communication among its various components by handpicking components from multiple vendors in order to achieve a synchronized platform, enabling the utility to provide a timely and effective response to outages.

2.1.1 Application Components

Toronto Hydro's ADMS platform includes the following current operational functions (listed with possible enhancements to each function through the ADMS Upgrade project):

- Distribution Supervisory Control and Data Acquisition (SCADA) system – Enhance integration with other ADMS components and introduce more automation.
- Outage Management System (OMS) – Increase monitoring capabilities across the grid, improve productivity by automating simple dispatch transactions, and optimize the utilization of Control Centre and field resources.
- Distribution Management System (DMS) – Provide more detailed and up-to-date visibility into grid conditions.
- Distributed Energy Resource Management System (DERMS) - Enable more precise monitoring and control of distributed energy resources connected to the distribution grid.
- Overall Enhancements - Interfaces to other internal and external systems such as Toronto Hydro's Geospatial Information System (GIS) and corporate data historian, Hydro One's energy management system (EMS), and others.

2.2 Problem Statement

As previously noted, the ADMS platform is critically important to the execution of Toronto Hydro's day-to-day operations and compliance with applicable legislative and regulatory obligations

[2] EB 2023-0195, Exhibit 2B, Section D7

relating to customer, public, and worker safety, grid reliability, and customer service. The following subsections provide more details on the risks that may arise in the event that the utility does not upgrade the ADMS platform in the 2025-2029 period.

2.2.1 System Risks: Infrastructure Lifecycle

Although the current ADMS infrastructure is fully supported and optimized for existing systems, the current application and database servers are forecasted to reach end of life by 2027. Operating these assets beyond end of life would require Toronto Hydro to establish backup infrastructure that is not optimized to accommodate ADMS components and to procure specialized technical resources for maintenance purposes. These mitigation measures could cause further risks affecting the reliability of ADMS and the continuity of distribution operations. For example, if issues with the ADMS infrastructure were to materialize, the utility will have limited ability to ensure the solution will work on an outdated infrastructure. This, in turn, may present a greater risk to restoring full functionality following infrastructure failures in a timely and effective manner, jeopardizing Toronto Hydro's ability to effectively monitor and manage the distribution system.

2.2.2 System Risks: Cyber Security Protection

The systems that currently comprise the ADMS platform receive regular service packs and patches from their respective vendors, including occasional ad hoc security patches to address any critical vulnerabilities. This approach ensures that the systems remain up-to-date with the most current features and are protected against cyber security risks. However, as ADMS systems age and lose vendor support, Toronto Hydro will no longer have access to these timely updates and patches, resulting in greater exposure to cyber security threats and putting at risk the continuity and integrity of the critical functions supported by ADMS systems.

2.2.3 Business Continuity Risks

Based on Toronto Hydro's past experiences, various vendors will discontinue future investments in product updates, functional enhancements, and technical improvements in respect of the systems that currently comprise the ADMS platform, as early as 2024. If the utility is consequently unable to keep up with product standards and improved functionality, these developments may result in significant risks to the continuity, efficiency, or timeliness of critical business operations in support of outage restoration and capital and maintenance work. In addition, continuing the use of obsolete products would hinder the utility's ability to modernize its business processes in accordance with the evolving nature and needs of customers and stakeholders interacting with the distribution system, for example due to electrification. Deferring system upgrades may require Toronto Hydro to deploy alternative solutions in the meantime, which may be less effective in maintaining business processes. Furthermore, as the gaps in capabilities of different ADMS components continues to grow, the utility's ability to have these components operate in a

coordinated and effectively integrated manner will become increasingly difficult, posing significant risks to process continuity, system reliability, and the effectiveness of reactive solutions. Collectively, these risks may cause adverse impacts beyond Toronto Hydro and its service territory, for example by hampering the utility's obligations to support outage restoration and participate in bulk system event management tasks in accordance with the IESO's Ontario Power System Restoration Plan.

2.2.4 Lost Efficiencies and Opportunities of Process Automation and Innovation

As the number of connections to the distribution system increase due to electrification and the nature of connections become more diverse through increased uptake of DERs, Toronto Hydro will need to invest in its tools and processes to efficiently perform both traditional system management and outage restoration tasks and emerging functions such as DER monitoring and control. Achieving continuous improvement and productivity gains in these areas will require the utility to increasingly focus on process automation and innovation. The proposal to upgrade ADMS components and other integrated systems incorporates a number of enhancements that will enable such automation and innovation, as described in greater detail in sections 3 and 5 of this document.

Without the ADMS upgrade, Toronto Hydro would lose the ability to benefit from improved product functionalities that would enable automation and associated productivity and efficiency gains. This would greatly hamper the utility's ability to achieve favourable outcomes for ratepayers, including its strategic objectives (e.g. intelligent grid, grid modernization and process automation), and to implement key technologies and initiatives that underpin the utility's modernization plan for the 2025-2029 rate period, such as FLISR.

Currently many ADMS components have limited integration with each other, hindering effective communication between systems. As these components age, the integration gaps between them will likely grow. In the future, this may impede effective decision-making and operations by Toronto Hydro and consequently affect the utility's overall efficiency. The proposal to upgrade ADMS components provides an opportunity for the utility to enable effective coordination and communication between the platform's systems by handpicking the most optimally integrated solutions.

2.2.5 Summary

In summary, Toronto Hydro expects the ADMS upgrade to add value and address risks relating to the following areas:

- ✓ **Monitoring the distribution system:** ADMS provides the utility with a real-time network model. Without it, Control Centre operators would lack an efficient and reliable way to understand the state of the distribution system. Furthermore, as DER penetration increases,

the utility may need greater visibility into system parameters (e.g. DER outputs, power flows, localized voltage and current, etc.) to better monitor and manage the safety and reliability of the grid.

- ✓ **Responding to all emergencies in accordance with legislative and regulatory requirements:** Improvements to OMS and other components would enhance the utility's ability to efficiently identify and prioritize grid emergencies.
- ✓ **Outage restorations:** The implementation of enhanced automation and system aided switching through components such as FLISR would be critical to achieving continuous improvement in the utility's ability to prioritize and schedule actions to restore power and remedy outages.
- ✓ **Dispatch and grid response functions:** Solutions such as automated dispatching and route optimization would enhance the utility's decision-making and organization processes for assigning Control Centre and field resources to both emergency response and planned activities.
- ✓ **Safety:** Enhanced functions under ADMS would facilitate compliance with safety requirements (e.g. under the Utility Work Protection Code) and enable effective auditing of relevant records.
- ✓ **Grid Analytics and System Planning:** Upgrades to the ADMS would supply the utility with more sophisticated tools to proactively monitor the grid performance, analyze opportunities for improvement, and effectively plan for actions and investments to improve grid resilience and capacity. Furthermore, such solutions would be more responsive to challenges posed by increasing volumes and types of DERs such as battery storage, electric vehicles, and distributed generation.

3 BUSINESS REQUIREMENTS SUMMARY

This section provides a high-level summary of the requirements for the ADMS upgrade to meet business needs and align with strategic objectives. A detailed list of functional requirements can be found in Section 5, the Appendix to the Business Case document.

As this business case is described at a program level, this may lead to multiple phases and releases that will encompass it. As such, considerations such as execution strategy will help determine the prioritization of the below requirements.

ADMS Requirement Categories	High Level Requirements
Intelligent Grid	• Automated FLISR/Self-Healing Grid - Automatically operating devices in the field to restore power to customers and minimize outage duration. • Improve outage resolution by leveraging fault location analytics (FLA) capabilities which use real time data and predictive algorithms that makes outage restoration more efficient • Gather real-time grid data via SCADA to help identify grid weaknesses and assist with evaluating level of outage risk • Improve the quality and reliability of field data available to Control Centre operators and meet reliability performance targets • Support remote terminal unit (RTU) testing • Support multiple communication protocols, standards and data acquisition techniques • Support multiple control actions • Exchange data with other systems in real time
Process Automation	• Enable automation where possible within dispatching to improve execution of planned and un-planned activities • Introduce training simulator for staff to improve the management of storm events
Customer Experience	• Improve outage management processes to achieve: o Greater situational awareness regarding outages o More accurate and timelier provision of estimated times of restoration and outage map updates o More effective damage assessment leading to faster outage resolution

ADMS Requirement Categories	High Level Requirements
	○ Improved grid response processes to restore power to as many customers as possible, as quickly as possible
IT Asset Management	• **System Currency** - Keep up to date with system upgrades and retain effective system support • **Cyber Security** - Ensure security risks are identified and mitigated or minimized by aligning with industry and technological best practices • **Performance** - Ensure appropriate level of performance that allows the efficient use of system tools by all system users, particularly during storm situations • **Improved release management** - Take advantage of system solutions that support high availability, resulting in fewer planned IT system outages.

*Detailed list of requirements is available in Appendix

3.1 Assumptions & Dependencies

The following assumptions underpin the scope of the ADMS Upgrade project. Any change in the assumptions will require a reassessment of the project scope, timelines, and costs.

- The existing integration between various ADMS components will remain intact until a new specific ADMS system component goes live.
- Other non-ADMS systems (e.g. GIS, the Customer Information System, etc.), impacted by the project will remain unchanged until a new specific ADMS component goes live.
- No new and major technological developments that impact ADMS and its underlying infrastructure will emerge for the duration of the project.
- No new and major functional or technical requirements will emerge for the duration of the project.
- There will be no change in the organizational direction to the overall project approach as described in this Business Case document.

4. OPTIONS ANALYSIS AND RECOMMENDATION

Toronto Hydro engaged various internal and external stakeholders to evaluate a number of options to address the problems and opportunities outlined in Section 2 of the Business Case.

The utility considered available solutions and processes to identify challenges and opportunities, and to establish baseline requirements and objectives.

The utility also invited industry leading ADMS vendors to showcase their solutions, which allowed the evaluation of new technologies against existing and future business needs, the refinement of product evaluation criteria, and the identification of additional requirements and considerations.

This exercise helped Toronto Hydro in identifying the four options discussed below. The utility assessed these options against the evaluation criteria presented in Subsection 4.2, ensuring alignment with applicable strategic objectives and IT/OT standards. The following subsections provide details of the options considered and the rationale supporting the selected option.

4.1 Options Analysis

Option 1 – Managed Deterioration

In this option, Toronto Hydro will continue to work with existing ADMS systems with no enhancements, upgrades, new integrations, or patches. The utility will continue to run systems past their end-of-life and address defects on a best efforts basis only, with the limited capabilities available.

As this option focuses solely on maintaining status quo with respect to existing systems, it represents the least expensive option in terms of upfront capital investments and initial operational costs. However, this option poses a high degree of risk due to degrading system performance and system currency as well as increasing cyber security concerns. This option would eventually result in a gradual degradation of operational capabilities due to decreasing levels of vendor support for current systems. From a cyber security standpoint, this option would lead to increased vulnerability to cyber attacks due to the lack of vendor-supplied security patches, increasing the likelihood of more frequent and severe disruptions in day-to-day operations. Ultimately, this is not a sustainable option, as it would lead to significant deterioration of operational resiliency.

The increasing operational and security risks that would accumulate over time under this option far outweigh the low implementation costs, and budget and timeline risks. Over time, the utility's inability to address system vulnerabilities may lead to increases in cyber security breaches and a subsequent decrease in business process efficiencies. Limited and degrading vendor support and maintenance can also lead to longer and more frequent system breakdowns of ADMS systems, hampering distribution system management and operations and resulting in lower customer

satisfaction and inability to meet legislative, regulatory, and performance requirements relating to safety and reliability. In addition, resourcing legacy applications is challenging. Currently, ADMS technical resources are focusing on updating their skill sets for new ADMS component versions, which shrinks the pool of resources that will be available in the future to support legacy applications. Externally, ADMS vendors will shift their support pool to the latest versions and support for legacy versions will become increasingly limited or unavailable after 2028.

Finally, this option does not allow Toronto Hydro to support its grid modernization objectives by enabling process automation and advanced features that will become available through newer versions of ADMS components, as the utility would continue running its current systems past the point of obsolescence. This outcome would present a lost opportunity in terms of achieving greater process efficiencies and productivity gains, and leave Toronto Hydro's distribution system ill-prepared to meet the challenges presented by evolving consumer preferences and industry conditions, such as electrification or increasing DER uptake.

Option 2 – Sustainment

In this option, Toronto Hydro will maintain status quo with respect to existing systems, and be able to sustain day-to-day operations, in a limited capacity, by relying only on the minimum infrastructure, application upgrades, and security and system patches, for as long as they are available.

This option has the advantage of low up-front capital expenditures and would only require minimal investments in change management actions required to sustain the utility's day-to-day operations. However, over time this may result in increasing operational costs associated with obtaining vendor support and having to manage greater exposure to cyber security threats. While this option would maintain short term system currency and operational resiliency, Toronto Hydro would find it increasingly difficult and costly to sustain old technologies with fewer upgrades and patches from declining vendor support to maintain adequate levels of security and system reliability. The inefficiencies from the lack of integration between legacy systems would continue and attempting to integrate them further as they age would be costlier and carry a higher chance of system failure.

This option also does not allow Toronto Hydro to support its grid modernization objectives by enabling process automation and advanced features that will become available through newer versions of ADMS components, as the utility would only maintain currently available functionalities. Without access to new features and functions, current systems may be unable to adapt to customers' evolving needs and preferences in to the context of emerging industry trends such as electrification or increasing DER uptake. In addition, this outcome would present a lost opportunity in terms of achieving greater process efficiencies and productivity gains.

Option Three – Modernization and Growth (Recommended Option)

In this option, Toronto Hydro will implement a modern ADMS platform by upgrading its component systems and leveraging the advantages of each system through procurements with multiple vendors, which would allow the utility to acquire the most optimal technologies for OMS, DMS, SCADA, and DERMS. This option will involve upgrades to the latest version of each specific system, while continuing to enable more advanced capabilities such as FLISR and artificial intelligence with an agile implementation approach.

Furthermore, this option will allow the utility to achieve targeted benefits using a phased approach. By relying on multiple vendors and workstreams, Toronto Hydro can realize benefits as each project phase is completed. This option will also take advantage of new technologies and vendor solutions that will address the risks outlined in subsection 2.2 and meet the business requirements outlined in section 3.

This option will require moderate capital expenditures for implementation and relatively higher operational costs to maintain multiple systems and vendors, as well as user training and knowledge base management across several different platforms. However, the incremental operational costs would be partially offset thanks to lower needs of operational change management, through the proposed strategy of upgrading current systems on an ongoing basis. In the long term, this option would also allow Toronto Hydro to holistically balance and optimize project costs (capital and operational) and business units' operational costs by pacing and tailoring the selection and implementation of particular upgrade solutions in accordance with the urgency of business needs, rather than having to invest in all system upgrades all at once under a one-vendor approach.

This option would maintain vendor support through the proposed system upgrades and consequently result in lower cyber security and operational risks, as access to vendor-supplied enhancements, upgrades, and, patches would serve to strengthen the organization's cyber security posture and reduce the likelihood of operational disruptions.

This option would also allow Toronto Hydro to support its grid modernization objectives by enabling process automation and advanced features that will become available through newer versions of ADMS components. The multiple vendor approach would enable the utility to procure solutions in a more flexible and customized manner in accordance with the business needs underlying each upgrade. These solutions, in turn, would yield process efficiencies and productivity gains (e.g. through the implementation of FLISR and the self-healing grid), and put Toronto Hydro in a much better position to respond to emerging industry trends such as electrification or increasing DER uptake. Finally, this option would provide opportunities to improve integration and communication among ADMS' various systems by handpicking

components from multiple vendors to achieve a synchronized platform, laying the groundwork for future enhancements.

Option Four - Replacement and Harmonization

In this option, Toronto Hydro will migrate all OMS, DMS, SCADA, and DERMS functionalities under one integrated vendor. This option would pose significantly higher change management risks as all business processes currently dependent on ADMS systems would require modifications and some of the previously integrated enhancements would require re-implementation under the selected vendor's solutions. This option would offer several benefits from the adoption of a single integrated system such as uniform user experience, lower integration and ongoing sustainment costs. However, these benefits would be offset by the higher up-front capital investment required to redo and redesign unique customizations and configurations. In addition, this option will require significant retesting and extensive change management including user retraining, changes to operational procedures and related documentation, employee communications, all contributing to longer implementation timelines. Realizing the benefits of the system upgrades would take approximately 2-3 years longer than under Option 3 due to the migration to a single platform. Implementation would also be subject to higher timeline and budget risks due to reliance on a single vendor. Finally, to the extent that this option were to require the early replacement of any ADMS component before end of life, it would result in suboptimal utilization and value from previous investments, to the detriment of ratepayers.

4.2 Evaluation Criteria

Toronto Hydro evaluated each option based on the following strategic criteria:

1. **Alignment with Strategic Objectives:**
    a. Intelligent grid & grid modernization
    b. Process automation
    c. Customer choice
    d. Customer experience
    e. IT asset management
2. **Grid Reliability**: Measure of ADMS systems' ability to support operational processes feeding into grid reliability, distribution during peak times for electricity use, the reduction of outage durations, and the automation of outage response.
3. **Cyber Security**: Overall assessment of cyber security configuration and capabilities.
4. **Environment and Safety**: Concurrence with legislative and regulatory obligations and utility and industry standards relating to health and safety.

5. **Change Management**: Amount of effort required to prepare and enable the organization and users to adapt to the new systems/processes
6. **Cost**: Overall implementation and sustainment costs
7. **Timeline**: Overall timeline to project completion and the achievement of projected benefits
8. **Overall Risk:** Denotes the holistic assessment of previously described strategic risk categories

The utility assessed each of the above strategic risks under the four options as follows.

Table 1: Evaluation of Strategic Risks

Options/Criteria	Alignment with Strategic Objectives	Grid Reliability	Cyber Security	Environment and Safety	Change Management	Cost	Timeline	Overall Risk
1. Managed Deterioration								
2. Sustainment								
3. Modernization and Growth								
4. Replacement and Harmonization								

Legend	Exceed Criteria	Meets Criteria	Partially Meets Criteria	Does Not Meet Criteria

Toronto Hydro also evaluated each option based on the following tactical criteria:

1. **Operational Risk:** Risk of disruption to the day-to-day business activities of the utility
2. **Security Risk:** Cyber security and other types of security risks
3. **Implementation Risk:** Risk of challenges to system/project implementation due to difficulty and/or complexity
4. **Timeline Risk:** Risk that project tasks and deliverables will take longer than forecasted
5. **Budget Risk:** Risk that costs for the project will be higher than forecasted due to unexpected expenses, delays, or increases in scope

Table 2: Evaluation of Tactical Risks

Options/Criteria	Operational Risk	Security Risk	Implementation Risk	Timeline Risk	Budget Risk	Overall Risk
1. Managed Deterioration						
2. Sustainment						
3. Modernization and Growth						
4. Replacement and Harmonization						

Legend	Exceed Criteria	Meets Criteria	Partially Meets Criteria	Does Not Meet Criteria

4.3 Evaluation Summary and Recommendation

As outlined in subsections 4.1 and 4.2, Toronto Hydro is recommending the Modernization and Growth option (option 3). This option will enable Toronto Hydro to continue attaining the benefits offered by the ADMS platform by keeping its systems current and its vendor support intact, while also unlocking future benefits in support of grid modernization and process automation in the most flexible and cost-effective manner.

The Modernization and Growth option positions the utility well to meet a range of grid reliability and health and safety outcomes by maintaining the key ADMS systems supporting relevant business operations and enabling their continuous improvement. Although the Replacement and Harmonization option will also contribute to reliability and health and safety outcomes, the previously discussed implementation challenges associated with that option may put those outcomes at risk. While the Sustainment option also serves to maintain the status quo with respect to reliability and safety criteria, it is unlikely to provide optimal support for reliability and health and safety outcomes (e.g. employee and public health and safety, compliance with relevant legislative and regulatory requirements) in the long term as this option will restrict ADMS system upgrades to the bare minimum. The Managed Deterioration option represents the most significant risk to reliability and health and safety outcomes, as the deterioration of ADMS systems and the lack of vendor support would greatly increase the likelihood of disruptions to the related business processes depending on ADMS.

Due to the increasing number and sophistication of threats, cyber security continues to be a growing concern for many utilities. The Managed Deterioration option ranks the lowest in this regard as the deterioration of ADMS systems and the lack of vendor support under this option would greatly increase cyber security risks. Although maintaining the status quo under the Sustainment option allows the system to maintain the existing level of protection from cyber security threats in the short run, restricting system upgrades to the bare minimum overtime will

hinder the utility's ability to ensure adequate protection of the ADMS platform against threats in the evolving cyber security landscape. Both the Modernization and Growth option and Replacement and Harmonization options would position the utility well against current and emerging cyber security threats through the system upgrades contemplated under those options.

The Modernization and Growth option supports the adoption of emerging technologies and new functions which align with Toronto Hydro's grid modernization and process automation initiatives (e.g. through the implementation of FLISR and the self-healing grid). Although the Replacement and Harmonization option also aligns with these strategic objectives, it is a suboptimal solution because of the lack of flexibility resulting from the single vendor approach contemplated under that option. In order to leverage the technology solutions that best-fit the utility's business needs and enhance the overall customer experience, Toronto Hydro adopted a multiple vendor approach under the Modernization and Growth option. This option also contemplates the achievement of better integration and communication among ADMS' various systems, it is well-poised for enabling future enhancements, despite the greater diversity of systems and components compared to the Replacement and Harmonization option. In contrast, the restricted approach to system upgrades under the Managed Deterioration and Sustainment options will hamper the utility's adoption of new technologies and functions in alignment with strategic objectives, jeopardizing the evolution of underlying business processes.

With respect to change management, timelines, and budget, the Managed Deterioration option fares best, as it would minimize capital expenditures, change management activities, and execution risks. The Sustainment option also presents a lower risk profile with respect to these criteria. For example, in the short term the need for change management would be minimal from maintaining existing systems. However, in the long-term Toronto Hydro would find it increasingly difficult to maintain current systems as they reach end of life and vendor support diminishes. Ultimately, both the Managed Deterioration and Sustainment options involve other types of unacceptable risks and shortcomings that offset the relatively lower change management, timeline, and budget risks. The Replacement and Harmonization option is the least favorable in terms of change management, timelines, and budget, as implementing a single vendor solution to meet all functional needs would likely require higher up-front capital costs and more extensive change management, resulting in longer implementation timelines (See Section 4.1 for more details). The Modernization and Growth option represents the optimal balance with respect to these criteria as it would holistically mitigate financial and operational risks by leveraging individual vendor capabilities through competitive procurement and implementing smaller, targeted initiatives over multiple phases instead of larger and more complex initiatives during a shorter period of time. Under this approach, Toronto Hydro would also retain the flexibility to implement better integration and communication among ADMS' various systems. In this sense, the Modernization and Growth is also the option that best aligns with Toronto Hydro's IT Asset Management and Investment Planning Strategy.

In implementing the Modernization and Growth option, the first step would be the discovery and documentation of the current state and detailed business and technical requirements. Then, Toronto Hydro would assess each requirement and design a suitable solution. This process would likely involve multiple steps as different system upgrade projects are awarded to different vendors. The utility expects the majority of the work and costs to occur in the various implementation phases.

Under this option, the ADMS Upgrade would constitute multiple projects with different delivery dates. This would enable Toronto Hydro to realize the benefits of each element as it is implemented as some of the planned system upgrades and enhancements would benefit from synergies with current initiatives in the 2020-2024 rate period. In addition, multiple projects will be run simultaneously by multiple teams working in parallel as opposed to a single team working on each phase of a project one at a time. This approach is expected to lead to greater cost savings and improve time management.

The multi-phase implementation of upgrades by multiple different vendors under the Modernization and Growth option will require significant testing to successfully integrate different solutions. This effort will contribute towards mitigating the timeline and budget risks associated with this option.

The Modernization and Growth option will require the utility to manage change management at the program level with each phase/project involving tailored training, staff communications, and other change management activities. Since many of these changes will reflect upgrades associated with existing system components, the costs of such change management activities will be modest.

In summary, the Modernization and Growth option is the most favourable option for both mitigating the strategic and tactical (project) risks outlined in previous sections of the Business Case document and supporting Toronto Hydro's achievement of favourable outcomes for ratepayers in the short and long term.

Table 3: Breakdown of Estimated Program Costs

Program Phase	Description	Cost
Initiation and Discovery	• Prepare for execution and kick-off initiative(s) • Document and assess current state processes • Establish and gain approval on detailed requirements	$4.1 million*
Blueprinting	• Assess and confirm functional options and decide on solutions • Establish and gain approval on future state processes • Establish methods for confirming and monitoring benefits	$4.5 million*
Build & Implementation	• Develop/configure/formulate solutions • Conduct testing • Train stakeholders	$21.3 million*
Launch	• Establish means for operational support • Launch solution and deliver on post go-live launch strategy • Prepare for initiative closure and sustainment	$4.3 million*
Total		$ 34.2 million*

*All costs account for inflation

5 APPENDIX

This section provides a detailed description of the requirements by area:

ADMS Features and Components	Requirements

User Interface	• The users shall interact with the ADMS components via workstations installed at the Control Centre and various other locations.
	• The user interface (UI) shall allow authorized personnel to:
	  • view measured and calculated real-time and near real-time, outage information (including vehicle and crew locations);
	  • view Distributed Energy Resource (DER) information;
	  • view historical outage and load data;
	  • initiate control actions (with suitable security limits and controls); and,
	  • interact with the ADMS applications.
	• UI includes Areas of Responsibility (AORs) that shall provide the means to route alarms, restrict supervisory control, restrict data entry, and enable data viewing to those personnel having the associated responsibility and authority.
	• As a minimum, the ADMS displays shall include:
	  1. Tabular displays
	  2. Trend lines
	  3. Displays containing bar charts, pie charts, and other mechanisms to view equipment status and trends
	  4. Single-line schematic diagrams showing the configuration, status, and loading of the distribution feeders, substations, and other power system facilities
	  5. Map-style displays showing properly scaled and geographically correct depictions of distribution lines overlaid on street maps. It shall also be possible to view dynamic data
	  6. Satellite style displays (e.g. Google Earth) containing similar information as map-style displays
	  7. Application function displays (alarm displays, video trend displays, and displays used to interface with the ADMS application functions)

ADMS Features and Components	Requirements
	8. System management and diagnostic displays (security administration, system configuration, on-line/offline diagnostics, etc.) • Users shall be able to add operator notes containing free-form text associated with a specific device or ongoing outage. • On demand, the user shall create a simplified schematic display using the geographic information from GIS. • The User Interface security settings shall comply with Toronto Hydro security policies, standards and procedures. • This feature shall include Alarm Processing functions to alert system users to abnormal conditions on the power system. The Alarm Processing function shall also alert system users to ADMS and communication equipment failures and other abnormal ADMS conditions requiring attention.
DMS	• DMS includes a single Distribution System Operations Model (DSOM) that supports all distribution applications, including advanced distribution applications, outage management, and DERMS. • DMS includes load profiles for estimating the load for a given time/date for each different type of customer (residential, commercial, industrial, etc.). • DMS shall be a single centric process that supports model updates for all applications. • DMS shall enable a user to add, modify, or remove temporary elements to the Distribution Network Model through the operator user interface. • DSOM shall include Information for schematic displays of the electrical facilities, showing individual elements and interconnections, along with the operating state and other related information. It shall display current and nominal state. • The DSOM function shall include an Impedance Calculation application that shall calculate the impedance of overhead and underground line segments needed for the execution of other applications such as Unbalanced Load Flow and Fault Location.

ADMS Features and Components	Requirements
	• This component shall support a full-featured study mode environment that shall enable the user to execute any ADMS application (including DMS, OMS, and DERMS applications) to determine the impact of proposed operating actions and changes to the power system configuration in an "off-line" mode. • Network Topology Processor: shall use the DSOM connectivity model to determine the dynamic network connectivity and the energized, de-energized, looped, paralleled or grounded status of power system components, and DSOM shall visually represent these states. • DMS shall include suitable mechanisms for determining the real and reactive power on each distribution service transformer at any given time. • The component shall include facilities for determining the output of each distributed generating unit that is connected to the distribution system. • The Distribution Unbalanced Power Flow (UBLF) shall use the DSOM to calculate the electrical conditions (current, voltage, real and reactive power) for the entire distribution system. • This component shall include a Distribution State Estimation (DSE) application for calculating the distribution network state • This component shall include a short circuit analysis (SCA) application function that shall be able to compute short circuit currents for faults of all types. • The FLA function shall determine the approximate location of faults on distribution feeders. • FLISR shall be a model-driven solution that uses the as-operated distribution system model and topology processor, along with the status of circuit breakers, line reclosers and other feeder switches, fault detectors and faulted circuit indicators to determine an appropriate switching strategy to isolate the faulted feeder segment and restore service to as many healthy (un-faulted) sections as possible.

ADMS Features and Components	Requirements
	• Optimal Feeder Reconfiguration (OFR) function shall define optimal network configuration required for achieving one or more user-specified business objectives. • DMS shall include Volt-Amps-Reactive (VAR) Optimization functionality • DMS shall include load and generation forecasting (LGF) functions that are able to predict real and reactive load and generator output in the near future. • The Distribution Contingency Analysis (DCA) function shall identify and evaluate the impact of contingencies on the distribution network and recommend control actions capable of limiting their impact. • The ADMS Switch Order Management (SOM) function shall support the creation, execution, display, modification, maintenance, printing, and emailing (manual and automated) of switching orders containing a list of steps needed to support various work activities, and indicating executing field resources. • Customer Network Status Tracking System (CNSTS) Displays - The ADMS shall be able to generate tabular displays of customer/network connections to a user specified feeder, including associated (alternate) feeders in a dual radial/network feeder configuration. Toronto Hydro system operators will use the CNSTS display to perform feeder isolation. • The user shall be able to apply a tag to a single point, group of points, or all points in an RTU or in a substation (except for “limit override” and “normal state override” tags), to non-telemetered points, and to calculation points. When a tag has been applied to a point, a tag symbol separate from the quality code symbol shall be presented next to the tagged point on any display or report where the point is presented. • DMS shall include a Confined Space Hold Off function to prevent a feeder from being re-energized if there are any crews working in Confined Spaces on that feeder. • DMS shall record all of the information that is needed to precisely calculate the key reliability metrics that are tracked by Toronto

ADMS Features and Components	Requirements
	Hydro, to display these metrics in dashboard, and support data extraction into Business Intelligence (BI) for data analytics.
OMS	• The OMS function shall assist system operators in identifying customer outages, determining the approximate location of the outage, dispatching first responders, coordinating restoration activities, and confirming that power has been successfully restored to all affected customers. The OMS shall also assist in gathering data needed to compute outage statistics. • The OMS shall include a complete set of tabular, schematic, and geographical displays to allow authorized OMS users to view all outage related information and interact with the OMS applications. • The OMS display system shall include a set of application functions for locating user specified items that enables the user to rapidly navigate to specified locations such as a specific asset (e.g. a transformer, line switch, or fused cut out), a specific street address, or other location. • The OMS shall be able to acquire real-time inputs from field devices via Toronto Hydro's existing SCADA communications network, Inter-Control Centre Communication Protocol (ICCP) link to the Hydro One EMS, and other sources of near-real-time data used by Toronto Hydro. The OMS shall use this near-real-time information for detecting and predicting outages. • The OMS shall include a report writing package that is able to generate ad hoc and predetermined reports containing outage information and statistics for a user-defined time frame, specific equipment, customer, circuit, cause or system wide, for user defined time frames, specified areas, substations and feeders. • The OMS shall include several mechanisms for determining that an outage has occurred. As a minimum, these mechanisms shall include: 1. Telephone "lights out" calls from customers and other sources 2. Last gasp messages for Toronto Hydro's Advanced Metering Infrastructure (AMI) system 3. Operation of SCADA monitored/controlled circuit breakers, reclosers and other remote controlled and automated switchgear

ADMS Features and Components	Requirements
	4. Entries in Toronto Hydro's outage map website 5. Direct manual entries by the dispatcher 6. Toronto Hydro external website/app allowing customers to report outages 7. Customer outage calls reported from Interactive Voice Response System (IVR) • When outage information is received from more than one premises, the OMS shall group the calls, messages, and data that appear to be part of a single power system disturbance by applying user-specified rules. OMS should allow user to configure these grouping rules based on type of event (Real Outage versus Planned Switching) and time between events. • Once the trouble calls and AMI messages have been grouped, the OMS should use the "as operated" connectivity/topology model of the distribution feeder to trace upstream from the grouped outage call/message locations to the next fault interrupting device (fuse, recloser, circuit breaker) that is upstream from the customers who are experiencing an outage. • The OMS shall include a Damage Assessment function that Toronto Hydro will primarily use during major events (especially those requiring special incident response/storm centres) for managing a group of resources that are responsible for damage assessment. • The OMS shall have a function to automatically produce an Estimated Time of Restoration (ETOR) for each identified outage event. This function shall automatically calculate an ETOR for every outage that is predicted by the OMS. • The OMS should support receiving ETORs from mobile crews and dispatchers as well as automatic creation. • The OMS shall have a Crew Management module that enables the Trouble Dispatcher to manage crews, allocate/re-allocate resources, track contact information and their history of all previous calls and whether they were reached, whether they came in, or declined when called. This module should support different types of crews (e.g. System Response, Power Lineman, Metering, Forestry, Supervisors, etc.) • The OMS shall have a module for managing call backs to customers who have been restored following a power outage or interruption. This should

ADMS Features and Components	Requirements
	be done through callback, text or email update depending on customer preference. • During widespread outages that impact multiple locations, the OMS shall be able to sort and filter the outages to ensure that the most urgent incidents are addressed first. Prioritization of restoration activities shall be performed automatically by the OMS. • The OMS shall be able to manage "planned" outages that are scheduled in advance by Toronto Hydro to perform routine maintenance, repair work, new construction, and other activities. • The OMS shall track and record "momentary" interruptions that last less than a minute, which are often caused by the operation of circuit breakers, line reclosers, and distribution automation (DA) facilities • OMS shall support the future addition of a full-function Interactive Voice Response System (IVR). • The OMS shall be able to support Mobile Workforce Management (MWM) in order to reduce operation cost, enable more effective distribution system and asset management, and improve customer service by improving the management and dispatch of field personnel • The system shall provide mechanisms for managing incidents that do not result in outages but require controller attention and possible follow-up action, damage assessments including, foreign object on powerline, leaning pole, broken guy wire, etc.
SCADA	• SCADA shall be able to acquire real-time information from various sources, including: 1. Substation automation systems, RTUs, and Data Concentrators 2. Feeder devices that are equipped with SCADA communication facilities (remote controlled switches, line sensors, etc.) 3. Energy Centre (DERMS) via secure ICCP (two way) link 4. Hydro One Energy Management System via ICCP (two way) link 5. Oracle Network Management System (NMS) via ICCP (one way) link 6. Schneider ION PQ meters via cloud communications • The SCADA Administrator shall be able to put an RTU or individual points in the RTU in a test mode that will provide the capability to monitor,

ADMS Features and Components	Requirements
	transmit, and receive messages on a communication channel, RTU, and individual point basis. • All data acquired from the power system, all real time calculated values, and all manually entered data for non-telemetered points, as well as parameters to be output to field devices, and parameters that control the operation of real-time application programs shall be stored in a comprehensive system real-time database (RTDB). • The RTDB shall be the central interface between all elements of SCADA including the data acquisition software and the user interface software for real time information. • To facilitate flexible assignment of operational responsibilities to operators, the capability to associate the field devices with Areas of Responsibility (AOR) shall be provided. • The SCADA system will support multiple communication protocols and standards, and data acquisition techniques. • Data retrieved from RTUs shall be immediately checked for certain basic error conditions including incorrect response, data buffer overwrite error, and invalid message security codes. All detected errors shall be recorded for maintenance purposes. • Data acquired from RTUs as well as data received from other data sources (e.g. ICCP data) shall be processed and placed in the RTDB as soon as it is received. • Status data shall be processed for every scan period when such data is received to determine if changes have taken place. • The Operations Monitoring function of SCADA shall track the number of operations made by every breaker, capacitor switch, recloser, and load break switch that is monitored by the ADMS. • SCADA shall include analog and status “pseudo” points whose value or state is manually inserted or calculated by performing arithmetical and/or logical operations on the values or states of other system input variables and other pseudo points. • SCADA shall include "pulse accumulator" points representing the number of times an associated piece of power equipment has changed state. • Any data received from other systems through ICCP links and secure ICCP links shall be processed using the same data processing methods

ADMS Features and Components	Requirements
	as telemetered points. Data items shall be checked for reasonability as soon as it is received. • SCADA shall control power system apparatus located at distribution substations and field locations (out on distribution feeders). This component shall support the following types of control actions: 1. Digital outputs: on/off control commands that activate control output contacts 2. Analog outputs: control commands that activate a voltage or current signal whose magnitude varies with the desired level of control 3. Setpoint control: change the settings in an intelligent controller associated with the device being controlled • Tags: It shall be possible to assign any of the following supervisory control inhibit properties to each tag type: 1. All controls allowed 2. Control inhibited in one direction, such as “Close” function 3. Control inhibited in the other direction, such as “Trip” function 4. All controls inhibited • Control Command Validations: The request shall be rejected by the system if: 1. The device is not subject to supervisory control of the type being attempted. 2. The requested control operation is inhibited by a tag placed on the device. 3. An Uninitialized, Failed, Deactivated, or Manually Entered data quality indicator is shown for the device. 4. The user’s AOR does not permit this action. 5. The Operating Mode of the workstation attempting control does not permit supervisory control. 6. A control request for the same device from another workstation is still pending (i.e. the request is not yet executed or the commanded control is not yet completed).

ADMS Features and Components	Requirements
	7. A control request for a device is in a direction that is not allowed (i.e. single sided control where the device is defined to only be controlled in one direction). • The system shall include the capability to define pre-operational checks • SCADA shall be able to exchange real-time data with other systems. The communication for these data exchanges shall be International Electrical Commission (IEC) 60870-6 TASE.2, and shall be in compliance with the ICCP security requirements in IEC 62351-3 and IEC 62351-4 for those external systems that also support secure ICCP.

DERMS	• DERMS shall be able to monitor and control customer-owned and Toronto Hydro-owned DERs that are connected to the electric distribution portion of the electric grid. DERs managed by DERMS shall include distributed generators (cogeneration, combined heating and power, microturbines, etc.), intermittent renewable generators (solar photovoltaic (PV), wind, etc.), energy storage, controllable loads (demand response), and electric vehicles (EVs).
	• DERMS shall include secure and convenient mechanisms for viewing real time, historical, and forecasted information, alarms and events, reports and logs, and other information about the DERs and for interacting with the DERMS application functions.
	• DERMS shall support a variety of techniques for controlling DERs including, but not limited to:
	  • Direct control of active and reactive power at the DER point of common coupling
	  • Set a voltage reference value, power angle, and schedule for operational VAR limits/settings
	  • Modify maximum volt-amp limits/ settings
	  • Switch DERs from autonomous control to remote control
	  • Establish a fixed schedule for operating the DER
	• All DER control actions shall be accomplished through SCADA using RTUs installed at each DER location
	• DERMS shall enable system operators to initiate changes in the DER output level.

ADMS Features and Components	Requirements
	• It shall be possible to analyze DER operations and impacts of distribution system operation in "study mode" which allows the user to switch DERs on and off, change the output level, and perform other possible changes without impacting the real time (Live) operation of the electric distribution system. • [redacted] • Modeling: DERMS shall maintain awareness of DER ratings and limitations and shall be able to enforce operating requirements from technical studies which are written into the contract. As a minimum, DERMS shall be able to enforce limits on operating power factor, voltage, frequency, ramp rates, charging and discharging limits (storage only), and power quality requirements. If ratings are violated, DERMS shall generate an alarm to alert the operator of this condition.

ADMS Features and Components	Requirements
	• DERMS shall include facilities for storing (archiving) and later retrieving historical DER operational data. • Forecasting: DERMS should be able to supply DER Generation forecasts for various time intervals, including short term (next hour), middle term (next few days), and long term (next week or longer). • DERMS shall be able to monitor and control customer-owned and Toronto Hydro owned microgrids comprised of a set of interconnected DERs in a well-defined portion of the electric distribution system. DERMS shall be able to initiate "planned" transitions of the microgrid from grid-connected to islanded mode of operation. • DERMS shall provide mechanisms for registering customer-owned and Toronto Hydro owned DERs so that these DERs can be monitored and in some cases controlled by DERMS. DERMS shall also facilitate incentive payments for verified services provided at Toronto Hydro's request during system events (e.g. emergency load shedding). • DERMS system should support transactive energy concepts as well as the economic and control techniques used to manage the flow or exchange of energy within an existing electric power system in regards to economic and market based standard values of energy.
Training Simulator	• The Dispatcher Training Simulator (DTS) shall include playback mode and interactive (simulator) mode. Playback mode shall enable the user to examine previously-recorded data in view-only mode. Interactive mode shall enable the user to view information computed by the simulator in response to a simulated event (e.g. a fault), enter simulated control commands, and view the simulated power system response to these commands. • When operating in playback mode or interactive simulator mode, it shall be possible to simulate all types of data items that are available in the ADMS, including time series SCADA inputs and calculated data items, customer outage calls, AMI last gasp messages, available crews and crew locations, and DER operation (distributed generators, energy storage, and controllable loads (Demand response)). • The DTS shall enable the user to view dynamically updating information on any ADMS display that contains the information in question, such as

ADMS Features and Components	Requirements
	tabular displays, graphical displays, trend lines, satellite (Google Earth) displays, and any other available ADMS display format. • The DTS shall allow Toronto Hydro to simulate the operation of all SCADA, OMS, DMS, and DERMS application functions and displays in interactive simulator mode. • The DTS shall support multiple simultaneous trainers and trainees. • The DTS interactive simulator mode shall use a power system model to determine how the actual power system would react to random trainer-initiated events. • The System's trainer module shall contain trainee evaluation tools to facilitate assessment of the trainee's performance. These tools shall monitor the ability of the trainee to respond to events such as overload violations and outages. At the end of each session, the system shall provide trainers with customizable reports on trainee performance.

Preliminary Scoping Business Case:

SAP ERP Upgrade

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1 Executive Summary

Project Name	Capital Expenditure
SAP ERP Upgrade	$ 28 million

Toronto Hydro uses SAP's Enterprise Resource Planning (ERP) system. The ERP system supports a number of cross-functional critical organizational processes such as customer connections, event management, and meter to cash. The SAP system is highly integrated with a number of core information technology (IT) systems that support key organizational processes such as health and safety, and asset management. The ERP is a critical Tier 1 application as operations across a number of different business units significantly depend on the ERP system's workflows, data, and reports.

The current version of the SAP ERP system will reach end of life by 2027. A system that is within the vendor support lifecycle receives the latest security patches and service packs. This helps protect the system from existing and emerging cyber security threats and keeps the system compatible with the underlying infrastructure, ensuring reliable performance and robust system availability. Thus, maintaining vendor support ensures the timely resolution of system incidents and minimizes the risk of system downtime, which allows business operations to proceed uninterrupted and maintains productivity.

In order to maintain these benefits and avoid reliability and cyber security risks, Toronto Hydro plans to upgrade its ERP system within the 2025-2029 rate period to a newer version that will retain current vendor support. A well-supported ERP system also aligns with the utility's strategic objectives as continuing vendor support enables the enhancement and adaptation of the system and the modernization of business processes in accordance with customers' evolving needs and broader industry trends such as electrification.

Given the criticality of the ERP system to Toronto Hydro's day-to-day operations, the maintenance of system reliability, and business continuity, the SAP ERP upgrade is necessary to support current and future business processes in an efficient and effective manner. To ensure an effective solution, the utility assessed four options as follows:

1. Managed Deterioration: Maintain status quo with the current SAP Enterprise Central Component (ECC) version;
2. System Sustainment: Execute required reactive work to keep the SAP ECC current without undertaking an upgrade;
3. S/4 HANA Private Cloud (On-Prem): Upgrade to S/4 HANA, the next supported SAP ERP version and implement on-premises (i.e. on-prem) on private cloud; or
4. S/4 HANA Public Cloud: Adopt SAP's ERP solution on public cloud.

Toronto Hydro evaluated each option against three broad categories:

A) **Project Approach** – This category considered criteria such as expected project complexity, project costs, project timeline, and change impacts to the organization.

B) **Innovation** – This category evaluated each option in terms of contribution to productivity and efficiency, as well as alignment with Toronto Hydro's strategic objectives and outcomes.

C) **Maintenance** – This category evaluated the options from an operational perspective with respect to expected ongoing vendor sustainment costs, cyber security risks, and overall system reliability.

Toronto Hydro concluded through its options analysis that S/4 HANA Private Cloud (On-Prem) is the preferred option because of the stability it provides from a system reliability and maintenance perspective, and the potential flexibility it provides to help the utility improve efficiency and modernize its business processes in accordance with it's strategic objectives and outcomes. Under this option, Toronto Hydro will receive full vendor support until 2040. Although this option entails some project-related risks in the short term, the utility expects to mitigate these risks through appropriate planning and strong project governance.

Overall, the SAP ERP Upgrade project will:

- Reduce business continuity risks that may arise from system and infrastructure failures relating to the ERP system;
- Contribute to maintaining a robust cyber security posture;
- Build a foundation to support future process automation opportunities and associated productivity gains; and,
- Provide Toronto Hydro with greater flexibility to innovate and modernize its business processes in alignment with its strategic objectives and outcomes.

2 Problem / Opportunity Statement

2.1 Background

Toronto Hydro implemented the SAP ERP system on October 1, 2018. The SAP ERP system is a core Tier 1 IT system as it supports over 150 business processes in Toronto Hydro and impacts a large number of the utility's business units.

2.1.1 Application Components

Toronto Hydro's SAP ERP system is currently comprised of both cloud and on-premises modules.

The cloud modules include:

- SAP SuccessFactors: A solution that supports human resources (HR) processes such as recruiting, onboarding and offboarding, training, and performance management.
- SAP Ariba: A strategic sourcing suite that serves a variety of procurement functions such as sourcing (e.g. RFx)[1], contracting, and vendor spend analysis.
- SAP Concur: An expense management system to manage travel and business expenses.

The cloud modules are integrated with the on-premises modules and follow a subscription licensing model. SAP maintains and updates these systems as part of system lifecycle management. The SAP ERP system upgrade does not include upgrades to cloud modules.

The on-premises module, called Enterprise Central Component (ECC), includes the following components:

- Enterprise Asset Management (EAM): used for managing the financial lifecycle of the utility's assets.
- Record to Report (R2R): used to collect, process, and present financial data.
- Source to Procurement (S2P): enables integrated procurement processes such as purchase requisitions or purchase orders in SAP.
- Human Capital Management (HCM): integrates HR processes relating to payroll, time sheeting, and attendance, with financial systems.
- Warehouse Management System (WMS): enables warehouse management processes and integrates with procurement and financial processes.

[1] RFx is defined as request for any type of proposal including Request for Information (RFI), Request for Quotation (RFQ), Request for Proposal (RFP) and Request for Information (RFI) proposal.

These components follow the conventional perpetual licensing, support and maintenance model. The SAP ERP system upgrade will focus primarily on upgrading the on-premises module (i.e. ECC).

2.1.2 Application Integration

In addition to integrating with the previously discussed cloud modules, the on-premises SAP modules also integrate with many Tier 1 and Tier 2 IT systems. These business systems and their supported functions include:

Systems	Supported Business Functions
Asset Investment Planning	Distribution asset management processes
Emergency Callout System	Automated callout system used in disaster and emergency conditions
Customer Information System	Linking customer billing and accounts receivable processes to financial systems
Employee Health Benefits	Employee benefits management
Enterprise Data Warehouse	Reporting and analytics across various enterprise systems
Electronic Tailboard System	Tool for on-site safety risk assessments by field crews
Financial Institution of Record	Payroll processing, accounts payable and accounts receivable processes
Financial Reporting System	External reporting processes for financial disclosures
Vehicle GPS System	Fleet vehicles management
Labour Relations System	Business processes for employee and labour relations
Network Management System	Real-time network modelling used in distribution system operations
ERP Data Warehouse	ERP Reporting for SAP
Vendor Invoice Management System	Accounts payable processes

2.1.3 Infrastructure Components

The on-premises SAP modules are supported by a technology stack hosted in Toronto Hydro's Enterprise Data Centre. This infrastructure is comprised of the following:

- Server Infrastructure: The server infrastructure consists of both physical server hardware and virtual servers. This infrastructure relies on IBM infrastructure.

- Database Infrastructure: The database infrastructure supports the structured and unstructured data in the ERP System. The infrastructure is supported by an Oracle database farm.
- Middleware Infrastructure: The middleware infrastructure enables the integration between systems, and supports the movement of data. The two primary middleware components are the Websphere Application Integration Platform (AIP) and SAP Data Services.

2.2 Problem Statement

As previously discussed, the secure and reliable operation of the SAP ERP system is critical to Toronto Hydro's operations. Although the SAP ERP system is currently fully supported, SAP plans to terminate vendor support by 2027. Therefore, Toronto Hydro needs to maintain and upgrade the SAP ERP system and the underlying infrastructure to retain vendor support and continue receiving periodic service packs, patches, cyber security fixes, and technical support for product releases, incidents, or service requests. Current and active vendor support would ensure appropriate housekeeping and enable incremental maintenance and enhancements of the system. The following section discusses the risks that the utility may incur in the event that vendor support is lost and the condition of the SAP ERP system deteriorates without further upgrades.

2.2.1 System Risks: Infrastructure Lifecycle

While the current SAP ERP infrastructure is fully supported, the end of life for the current application servers and database servers is forecasted to be in the 2026–2027 timeframe. Beyond the SAP ERP system's end of life, Toronto Hydro would need to plan for contingencies that include sourcing hardware components from third party vendors. In extreme cases (e.g. system interruptions), the resolution of infrastructure issues might require applying solutions on a trial and error basis, greatly reducing the reliability of the solution and possibly prolonging system restoration times. In any case, without infrastructure upgrades significant risks of delayed recovery from system failure would arise and adversely impact business operations.

2.2.2 System Risks: Cyber Security

The SAP ERP system receives periodic service packs and patches from SAP. Occasionally, SAP also releases ad hoc security patches to address known critical security vulnerabilities. However, without vendor support, Toronto Hydro would lose access to these service packs and patches, which would increase the ERP system's exposure to cyber security threats and increase the risk to the utility.

2.2.3 Business Continuity Risks

Without upgrades and vendor support, when the SAP ERP system is past its end of life, Toronto Hydro may not be able to resolve system defects and incidents in a timely manner. As a result, business processes and functions would be adversely impacted resulting in a decrease in productivity and a reduction to the overall reliability of the system.

To address these challenges, the utility might have to implement manual workarounds, which may introduce significant operational inefficiencies resulting in lower service levels (i.e. longer processing times). In addition, the technical availability of vendor products or support (e.g. the compatibility of certain patches and security updates) in the future may be contingent upon Toronto Hydro upgrading its ERP system. In other words, if the utility were to defer system upgrades to the point where the existing systems and infrastructure are no longer compatible with new patches or products, it would need to find alternative mechanisms to execute its business processes until it upgrades its ERP system to the latest version. This exposes a number of critical business processes to operational inefficiencies, risk of failure, and could hinder day-to-day operations.

2.2.4 Process Automation and Innovation

In order to effectively respond to the evolution of customers' needs and expectations arising from emerging industry trends such as electrification and decarbonization, Toronto Hydro will need to invest in modernizing its business processes through process automation, innovation, and the adoption of industry best practices. An upgraded SAP ERP system will allow Toronto Hydro to adopt new business processes and streamline existing business processes with greater flexibility and speed.

At this point in the product lifecycle, SAP no longer provides any new functional enhancements to the ECC product functionality. If Toronto Hydro were to forego upgrades to a newer solution, it would be hampered from efficiently achieving the above goals, as it would no longer receive functional enhancements, improvements, and efficiency gains from the vendor. As a result, the utility may be severely constrained in customizing the current SAP ERP system, limiting Toronto Hydro's ability to flexibly adapt its business processes to the evolution of customers' needs and expectations as well as other industry trends.

3 Business Requirements Summary

The SAP ERP Upgrade is a transformational project that impacts various business processes across Toronto Hydro. This section provides a high-level summary of the functional (i.e. related to maintaining current system functionality) and technical (i.e. related to conformance with the utility's IT standards) requirements for the upgrade. A more detailed list of can be found in the Appendix to this Business Case.

3.1 Functional Requirements

Categories	Functional Requirement
Asset Plan Build Maintain Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Track, manage, and report the asset lifecycle - Include details for each phase of the asset lifecycle (e.g. cost elements, approvals, work assignments, projects, and maintenance associated with an asset) with consideration for data and workflows - Require data consistency across multiple divisions and understanding of detailed business processes to enable future cross-functional innovation opportunities
Customer Connections Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Serve customers' specific grid connection needs - Include the end to end workflow, data, and financial aspects across all connection process stages from design to construction and ultimately energization - Ensure effective communication with customers and facilitate financial transactions to better serve customers, and create opportunities for process improvement and efficiencies - Evaluate project estimates at a granular level, calculate accruals and net present value (NPV), and retain an audit trail of estimates with parameter changes, timestamps, and user name
Event Management Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Govern the interactions between field work and Control Centre processes from planning to execution including the procedural aspects as well as the underlying components - Ensures business process consistency as noted with the current SAP ERP system, including the different elements supporting field work, such as planning, costing, and engaging operationally with customers. - Support an efficient and effective event management process to serve customers

Human Capital Management Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Administer timekeeping and payroll processes - Ensure time entries and approvals are appropriately recorded and payroll is appropriately disbursed. - Maintain timekeeping processes and provide opportunities for continuous improvement. - Calculate different payroll components and produce the necessary payroll related artifacts and compliance reporting - House a number of workflows and complex rules to support time submissions that comply with collective agreements and legislative requirements - Prescribe the details for workflows, data, business and legislative rules, and reporting to support and govern these processes
Meter to Cash Pillar: Innovation Topic(s): Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Administer accounts receivable and payment receipts from customers - Administer rules for monthly interest, late payment charges, deposits, and record the correct transactions to Toronto Hydro's General Ledger (GL) - Elicit details of different workflows, data elements, approvals, and user roles to fulfill the Meter to Cash process - Support industry best practices associated with relevant document lifecycles and their management in the Meter to Cash process, including items such as job quotations, billing, etc. - Consistently execute the process in an efficient and effective manner by calculating the monthly interest due to customers for deposits and process bills for or refunds to customers for capital contributions and expansion deposits
Record to Report Pillar: Innovation Topic(s): User Experience Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Support key financial backend activities - Apply rules to support asset level transactions from the balance sheet perspective - Ensure asset costs are appropriately captured across the asset lifecycle - Enable accurate and detailed financial reporting through detailed workflows - Specify the necessary elements to capture financial transactions, apply stringent controls, consolidate the transactions across the organization, and accurately report them in accordance with applicable accounting, regulatory and financial guidelines

	- Accept summary values for billing and cash from the Customer Information System and define the schedule to close the inventory sub-ledger - Enhance end user experience - Ensure compliance with accounting, financial, and regulatory guidelines
Source to Pay Pillar: Innovation Topic(s): User Experience Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Provide the framework for procurement activities like sourcing, contracts, inventory management and vendor management - Build on procurement policies and procedures and include the entire contract lifecycle - Configure spend approval workflows to efficiently manage the procurement process - Functional requirements will specify the details for these components to ensure the process in the system is comprehensive and runs effectively - Allow the system to meet procurement and payment guidelines, govern the procurement process and track vendor performance - Optimize the procurement process by increasing process efficiencies
Other Requirements Pillar: Innovation Topic(s): User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	- Allow all attributes associated with the following data be appropriately ported over and verified: accounts payable, accounts receivable, journal entry, cost center accounting data, asset and equipment master data, functional location data, Work Breakdown Structure (WBS) and Internal Order (IO) data, material and vendor master data, purchase order, contract and project data - Allow users to book a vehicle and capture necessary user information. Present the user with vehicle attributes and apply business rules at the time of the booking - Continue to integrate with other core Toronto Hydro systems to ensure ongoing uninterrupted service

3.2 Technical Requirements

Categories	Technical Requirements
Infrastructure Components Pillar: Innovation Topic(s): Alignment with TH IT Standards User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases IT Reliability	- System infrastructure must adhere to Toronto Hydro's IT standards, including alignment with industry norms for optimal system performance and operations - Ensure the time between system loss and system recovery is minimized, and system downtime is reduced, ensuring business continuity
Cyber Security Pillar: Innovation Topic(s): Enablement Alignment with TH IT Standards User Experience Pillar: Maintenance Topic(s): Vendor Support Cyber Security Risks IT Reliability Control of Product Feature	- Adhere to Toronto Hydro's IT standards, including alignment with best practices related to user access to the system, data encryption within SAP, and appropriate security practices integrated with other systems - Allows users to view data corresponding to their respective roles and to execute their core functions

3.3 Assumptions & Dependencies

Toronto Hydro makes the following assumptions relating to the overall scope of this project:

- The SAP ECC lifecycle will not change.
- Toronto Hydro will not implement any new SAP modules within the current SAP ECC.
- The cloud modules SAP Ariba, SAP SuccessFactors, and SAP Concur will persist until the SAP ERP Upgrade concludes.
- Existing integrations to the SAP ECC will remain intact until the SAP ERP Upgrade concludes.
- No new and major technological developments that impact SAP ECC and its underlying infrastructure will emerge.
- SAP's S/4 HANA product, services and licensing will not deviate from the current state.
- There will be no new and major changes to functional and/or technical requirements.

- There will be no change in organizational direction relating to the overall project approach described in this Business Case document.

Any change in the assumptions listed above, will require a reassessment of the project scope, timelines, and costs.

4 Options Analysis and Recommendation

Toronto Hydro evaluated a number of options to address the risks and challenges discussed above in Section Two and engaged various internal and external stakeholders to determine the optimal solution.

As a starting point, Toronto Hydro reviewed the current state functional and technical requirements that the SAP ERP system fulfills and the system's footprint against the utility's Information Technology Investment Strategy.[2]

Toronto Hydro also considered available options in terms of their alignment with the utility's strategic objectives and outcomes for the 2025-2029 rate period, and specifically whether individual options would provide sufficient flexibility in modernizing business processes by enabling enhancements to the SAP ERP system.

This exercise helped Toronto Hydro identify and assess the four options that are discussed in greater detail below.

4.1 Options Analysis

Option 1 - Managed Deterioration

Under this option, Toronto Hydro would not upgrade the SAP ERP system's current infrastructure and applications. Due to the several drawbacks discussed below, the utility has not selected this option.

Maintaining current assets in operational condition under this option would require Toronto Hydro to purchase extended support for the infrastructure and the application at a premium. Although extended support by the vendor would provide the technical resources to troubleshoot incidents, incident resolutions would not be guaranteed. Purchasing extended support would increase the utility's operational costs and vendors typically provide this type of support only on a best efforts basis. Therefore, if an incident or failure were to compromise the integrity of the ERP system, Toronto Hydro and its vendor likely could not effectively remediate the issue, which may significantly and adversely impact distribution operations and financial reporting. These impacts potentially could be so severe as to affect the utility's financial viability, e.g. by rendering it unable to pay its employees and vendors. As such, this option would pose high operational and financial risks.

This option would also significantly increase cyber security risks. As an application ages, the code and communication standards used by it become outdated, making the application more vulnerable to cyber security threats. Toronto Hydro would be severely constrained in its ability to

[2] Exhibit 2B, Seciton D8 – Information Technology (IT) Investment Strategy

mitigate this risk, and any efforts to mitigate this risk may compromise other functions. For example, the utility may be unable to modify the SAP ERP system to the extent that any customizations would adversely impact system performance and efficiency. Alternatively, if customizations by the utility are not supported by SAP, Toronto Hydro would run the risk of voiding its support contract with SAP, leaving the aging system even more vulnerable to cyber security threats without comprehensive vendor support.

Furthermore, finding the technical resources to support legacy applications is challenging. As the resources that are qualified to support SAP are currently focusing on updating their skillsets for S/4 HANA, the industry pool of resources available to Toronto Hydro to implement this option would significantly shrink in the near future and as a result, the utility may not be able to address this gap.

Finally, this option would not allow Toronto Hydro to enhance its business processes through automation and innovation, and by extension, respond effectively to changes in customers' needs and expectations due to future industry trends such as electrification and decarbonization. Continuing to work with the legacy version of the SAP ERP system would prevent the utility from accessing new enhancements and technological developments, and thus severely curtail its ability and flexibility in modernizing its services or underlying business processes. Therefore, this option does not align with Toronto Hydro's strategic objectives and outcomes.

Option 2 - System Sustainment

Under this option, Toronto Hydro would implement only the minimally necessary upgrades to the SAP ERP system's underlying infrastructure components in the 2025 – 2029 rate period. The application would not receive any upgrades or any new features or functionality beyond 2027 (i.e. the end of vendor support). Although the risk profile of this option would be somewhat more moderate compared to Option 1, it would also represent significant lost opportunities for Toronto Hydro, as the utility would not be able to leverage new enhancements and technological developments from more comprehensive system upgrades to modernize its services and underlying business processes in response to changes in customers' needs and expectations due to future industry trends such as electrification and decarbonization.

Similar to Option 1, maintaining current assets in operational condition under this option would require the utility to purchase extended support at a premium. Although extended support by the vendor would provide the technical resources to troubleshoot incidents, incident resolutions would not be guaranteed. Purchasing extended support would increase the utility's operational costs and furthermore, vendors typically provide this type of support only on a best efforts basis. Therefore, if an incident or failure were to compromise the integrity of the ERP system, Toronto Hydro and/or its vendor likely could not effectively remediate the issue, which may significantly and adversely impact distribution operations and financial reporting. These impacts potential

could be so severe as to affect the utility's financial viability, e.g. by rendering it unable to pay its employees and vendors. As such, this option would pose high operational and financial risks.

This option would mitigate cyber security risks to a limited extent. Under the extended support, the applications and underlying infrastructure would continue receiving vendor security patches; however, there would be no guarantee that these security patches could fully mitigate all types of cyber security threats encountered today and in the future.

It is highly likely that Toronto Hydro will need to upgrade the SAP ERP system's underlying infrastructure in the 2025 – 2029 time period. However, it is possible that the renewed infrastructure might not be fully compatible with the current SAP ECC version, which would require the utility to rely on manual workarounds to ensure the continuity of business processes, consequently decreasing the efficiency of such processes. In any case, Toronto Hydro likely would have to invest in upgrading to the latest version of the SAP product and migrating the HANA database at some point, as the benefits of the new infrastructure would not be fully realized until Toronto Hydro migrates to the new SAP system. Because this option would not fully address the previously discussed issues and drive further investments in the future, it ranks poorly in terms of cost effectiveness.

Although this option would allow Toronto Hydro to modernize its business processes through automation and innovation to a limited extent, the value received from related investments likely would not be optimized, as the utility would have to make further upgrades in the near term, before the end of life of the newly implemented assets. In addition, this option may require Toronto Hydro to procure and operate a number of outdated peripheral systems to continue to innovate.

Option 3 - S/4 HANA Private Cloud (On-Prem) – Recommended Option:

Under this option, Toronto Hydro would implement the S/4 HANA (On-Prem) solution, which is the latest available version of the SAP ERP system. It would embed the latest software, code, security, and communication standards, which would also align with the utility's IT standards. This option will mitigate cybersecurity risks for both, the applications and underlying infrastructure by ensuring a robust cybersecurity posture through continued access to vendor security patches.

To implement this option, Toronto Hydro would purchase private cloud licenses to install the application on its infrastructure in its on-premises Enterprise Data Centre. The application would be configured to enable existing business processes in the system. This may require incremental changes to some existing business processes which would result in some change management risk. This option would allow the utility to flexibly control the maintenance windows for the SAP application and infrastructure based on organizational needs. Furthermore, Toronto Hydro would be able to evaluate new product releases based on new functionalities, validate them against existing and future business needs, and determine the appropriate time to implement the new functionality.

By upgrading to the latest version of the SAP solution, Toronto Hydro would have access to a large resource pool of technical and functional resources whose skillsets would evolve to include HANA in the next few years. This would ensure that the utility is able to operate and maintain its ERP system in a much more cost-effective way and without having to depend on technical resources to support and sustain a legacy system.

SAP will fully support the S/4 HANA application until 2040. The SAP ERP Upgrade will mitigate business continuity risks by ensuring high system availability and full vendor support to resolve any issues in a timely and effective manner. Toronto Hydro would also have the option to implement periodic enhancement packs based on the desired benefits. This flexibility would support the utility's modernization of business processes through automation, innovation, and integration with other applications and systems. Thus, Toronto Hydro could adapt its services and underlying business processes much more easily and at an optimal cost in response to changes in customers' needs and expectations due to future industry trends such as electrification and decarbonization.

Option 4 –S/4 HANA Public Cloud

Under this option, Toronto Hydro would implement SAP's S/4 HANA public cloud solution, which is a software-as-a service (SaaS) application. Although this solution would also have the latest features and releases, the utility anticipates that the available configurations would not align with its business practices. As such, Toronto Hydro would need to adapt its existing business processes to work in tandem with the functionality of the S/4 HANA public cloud application, which may result in inefficiencies and generate additional change management costs. For example, the utility might need to update its job quotation templates to adhere to the standard formatting used in the S/4 HANA public cloud.

This option would pose significant change management risks, as the vendor might release new features and functionalities to users with limited or no ability to modify them to meet business requirements. Thus, redesigning business processes to conform to the evolution of the ERP system would require considerable efforts and time to implement, plan, and manage changes, and retrain employees accordingly.

Under this option, Toronto Hydro would have very limited direct control of the application and some application components would not be configurable or customizable. For example, the utility uses SAP for timekeeping and the current solution caters to different employee types and their associated rules and workflows. By contrast, the public cloud option might not be able to fulfill all functional and business requirements. Consequently, Toronto Hydro may need to resort to a number of manual procedures to fully meet such requirements. Effectively, the utility would be dependent on its vendor(s), namely the cloud infrastructure provider and the application host, who would determine at their sole discretion release schedules and service elements. In order to meet the vendor timelines and release schedules, Toronto Hydro might need to reallocate resources

from other areas to ensure that testing is completed on time. This lack of control over downtime hours and maintenance windows could present a major risk to the utility's ability to restore outages and respond to major events in a timely and effective manner. Therefore, this option would introduce significant operational and business continuity risks.

SAP will fully support the S/4 HANA application until 2040. Toronto Hydro would have the option to implement periodically released enhancement packs based on the desired benefits. Access to such enhancements would support the utility's modernization of business processes through automation and innovation to a limited extent. However, these benefits would be likely offset by the need to deploy extensive resources to ensure integration with other applications and systems and redesign business processes to conform to the vendor-led evolution of the ERP system.

4.2 Evaluation Criteria

Toronto Hydro evaluated each option based on the following criteria:

A) The **Project Approach** category includes the different factors in executing a project such as:

- Project complexity (e.g. challenges in project design and technical details, end user impact and associated risk);
- Project costs (e.g. planning, design, implementation costs);
- Project timelines (project task start and end dates); and,
- Change Management (implementation of a single new technology, or an overall digital transformation overhaul, adapting to market changes, launching new products)

B) The **Innovation** category considers how the ERP technology fosters business process improvements, increases the velocity of business processes, enables future organizational transformation, and provides more meaningful information to the end user for sound business decisions. It ensures the project's alignment of:

- SAP technology landscape against Toronto Hydro's IT standards; and,
- Toronto Hydro's strategic objectives and outcomes, overall industry trends, and future improvement opportunities, in accordance with the IT Investment Strategy.

C) The **Maintenance** category evaluates day to day operations from the perspective of ongoing system operability, including the ability to respond to system issues and incidents, and the sustainability of business operations. The relevant factors under this category are:

- Cyber Security – which includes protection from cyber threats against the integrity and operation of the distribution system and the confidentiality of customers' and employees' personal information;

- Flexibility in System Maintenance Windows - to ensure business continuity under all operating scenarios, including critical storm events and high volume outage events; and,
- Toronto Hydro's control of the end-use product to ensure minimal disruption from system changes.

High Level Options Comparison

A high-level comparison of the options is provided in the table below.

Table 1: Options Comparison

Options	Project Approach				Innovation			Maintenance			
	Project Complexity	Project Costs	Project Timeline	TH Change Management	Enablement	Alignment with TH IT Standards	User Experience	Vendor Support	Cyber Security Risks	IT Reliability	Control of Product Feature TH Releases
1. Managed Deterioration											
2. System Sustainment											
3. S/4 HANA Private Cloud (On-Premise)											
4. S/4 HANA Public Cloud											

Legend	Exceed Criteria	Meets Criteria	Partially Meets Criteria	Does Not Meet Criteria

4.3 Evaluation Summary and Recommendation

Comparing all of the options presented in the preceding sections, Toronto Hydro recommends Option 3, the S/4HANA Private Cloud (On-Prem) solution for the 2025–2029 rate period as it poses the least amount of overall risk and provides the greatest benefits across all three categories of project approach, innovation, and maintenance. Specifically, the benefits of the S/4 Hana Private Cloud (On-Prem) solution include a customized system that provides enhanced capabilities to process data and execute business functions, and ongoing vendor support.

Although there are increased project risks associated with implementing a new system, these risks can be mitigated though a robust project governance structure.

With respect to the project approach criteria, the Managed Deterioration and System Sustainment options rank the highest. Both options maintain the status quo to differing degrees and involve a limited level of investment in new products or initiatives, and thus have little to no impact on the end-user experience. As a result, both options result in a relatively low risk with respect to the overall project scope, timelines, and costs. However, in the long-term, both options would require Toronto Hydro to upgrade its SAP ERP system beyond 2030, therefore introducing inherent maintenance risks that are further elaborated on below. The S/4 HANA Public Cloud option ranks the lowest with respect to project approach criteria. This option provides little to no customization alternatives to the utility, and requires the project to expend resources to conform Toronto Hydro's current processes and functional requirements to the vendor-supplied solution. As such, there is a high risk that the project outcome could result in process inefficiencies in business operations, increase the costs of executing business processes, and limit the development of a more effective system. With respect to project approach criteria, the S/4 HANA Private Cloud (On-Prem) option ranks higher than the S/4 Public Cloud option. This option has higher costs than the Managed Deterioration and System Sustainment options as a full system upgrade is required, and this includes re-establishing existing business processes on the new ERP system. However, this option leads to lower overall risk through greater control over configuration and customizations, and limited impacts to existing business processes thereby reducing the organizational and change management risk. While there are some increased project complexity risks due to implementation of these new functionalities, these risks can be mitigated through a robust project governance structure.

With respect to the innovation criteria, the S/4 HANA Private Cloud (On-Prem) option would rank the highest as it would enable the utility to establish a modern platform with enhanced capabilities to process data and efficiently execute business processes. This option would take full advantage of product enhancements and new technologies, and would enable further modernization and business transformation. By contrast, the Managed Deterioration and System Sustainment options rank the lowest as both options would retain the current SAP ERP version. As a result, they would provide fewer opportunities for Toronto Hydro to improve business processes, enable future business transformation, and enhance the end-user experience. Both options would involve retaining outdated back-end infrastructure that would be unable to support new data processing capabilities and would result in the deterioration of the end-user experience. While the S/4 HANA Public Cloud option would rank higher than the Managed Deterioration and System Sustainment options with respect to innovation, this option would only allow for modernization within the confines of the vendor-supplied solution. Therefore, it would pose a risk of misalignment between Toronto Hydro's strategic objectives and the vendor's product roadmap. This would impact the

effectiveness and pace of the utility's ability to implement system changes and modernize its business processes in response to future industry challenges.

Lastly, under the Maintenance criteria, S/4 HANA Private Cloud (On-Prem) option ranks the highest, as it ensures ongoing vendor support, greater control over feature releases and the timing of those feature releases. The Managed Deterioration and System Sustainment options would rank the lowest. Both options would retain the current infrastructure, which would likely limit vendor support to a best effort basis and would not benefit from security updates to mitigate cyber threats to the SAP ERP system. S/4 HANA Public Cloud ranks higher than the Managed Deterioration and System Sustainment options with respect to Maintenance criteria. Under this option, the utility's dependence on its vendor(s) would give rise to several risks related to business continuity (e.g. in securing support from vendor resources in a timely fashion during emergencies) and risks with respect to the timing and flexibility of product releases if the utility were to require a rescheduling to account for unforeseen circumstances.

4.4 Estimated Project Timelines and Costs

Estimated Project Delivery Duration: 24 months

Estimated Capital Expenditure Breakdown:

Group	Description	Costs ($M)
Internal labor (IT and business resources, stream leads, etc.)	Toronto Hydro full-time employees assigned to the project from initiation, blueprinting, build and launch to closure	$ 4.7
Contractors	Third party specialist resources onboarded with specific S/4 HANA project skillsets to augment the Toronto Hydro team	$ 3.8
Licences	IT software costs for using the new S/4 HANA Private Cloud (On-Premises) ERP system	$ 4.5
Hardware	IT infrastructure to support the new and upgraded S/4 HANA ERP system IT infrastructure to execute the backend system processes as per specifications	$ 3.0
Vendors (S/4 Upgrade System Integrator, other specialized vendors)	Vendor identified to implement the project from initiation, blueprinting, build and launch to closure	$ 12.0
Total		**$ 28.0**

Estimated Project Operational Expenditure:

Group	Description	Costs ($M)
Data Migration	Migrate data from the current SAP ECC system Complete necessary data migration checks Ensure continuity in business processes	$ 0.5
Training and Change Management	Train employees in the new S/4 HANA system Engage and educate employees of system changes and business process changes	$ 0.5
Post Go-Live Support	Hand-off technical and functional aspects of the project to the appropriate Toronto Hydro resources Ensure business processes are functioning as expected and address any user queries	$ 0.6
Total		**$ 1.6**

5 Appendix

The SAP ERP Upgrade is a transformational project and impacts a large number of Toronto Hydro's business units. The requirements presented in this Business Case consider the following:

- Functional Requirements: Maintain current system functionality to support business processes
- Technical Requirements: Consider new technology trends consistent with Toronto Hydro standards

5.1 Functional Requirements

Categories	Functional Requirement
Asset Plan Build Maintain Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system should allow creation of Work Orders (WOs) and populate an estimate of Maintenance Work • The system must capture: o schedule constraints such as vacation, training and feeder planned outages o crew capabilities, o vehicle / equipment usage and build an overarching plan with some rules to accommodate corrective deficiency notifications • The system must assist building a schedule with a framework for users to cater to their specific needs, and track progress against the plan based on schedule and financials • The system should assign work orders to inspection work and allow users to assign inspectors to work orders • The system should record the overall goal of the scope item with linkages between the scope package and the regulatory filing, and ensure appropriate approvals are secured within a workflow • The system must allow user to create a maintenance plan for any asset level through work orders and apply some business rules for those assets due for replacement as part of the capital program • The system should process change requests and capture detailed material, labour, and assets required with a view of the impact to the master schedule and secure approvals via workflows • The system should assist program planning activities in a consistent project structure across different time horizons and consider resources, materials and costs calendarized over the life of the program with reporting capabilities

	• The system must identify failed assets from planned and reactive work orders with outage / event information and provide a higher-level asset class view to view system issues • The system should allow accruals to a Work Order when an invoice is requested and allow invoice submission based on service entry sheets linked to Work Orders • The system must allow the assignment of Work Breakdown Structure (WBS) to the project development team and assignment of the team costs to the WBS • The system, across applicable business units, must allow sign-off and attainment on receipt of the Green Construction Folder with linkages to the design hours and updated assets • The system must allow the user to close out a design project after the pre-requisites are met and must allow the project to be put on a construction schedule • The system must allow for long terms planning using conditions by asset class and receiving key data measures from other systems to build the scope definition, complete data analysis and to study impact analysis • The system must capture units of work in hours, units of assets, notes and view materials for project planning and reporting purposes • The system must define work packages, relate them to investments, assets, similar and adjoining projects, and use workflows for approvals • The system must track the work package from design to execution with risks defined from a Master List and allow to report on progress • The system will allow users to build the project structure with templates containing breakdown structures and pre-populated data and allow the flexibility to tweak the project structure as needed • The system must allow user to build estimates using applicable methods (e.g. asset assemblies, unit price methods), maintain versions, view design costs and actuals and secure approvals through workflows • The system must record and report construction work completed against a plan line in terms of asset assemblies and schedules • The system must allow users to build packages estimates based on applicable frameworks (e.g. asset assemblies, unit price methods), and summarize the resource and asset needs using Future State data and guided by Historical Trends • The system must allow the user to assign a risk score at the scope, project level and support scenario planning with appropriate versioning • The system must allow the user to issue materials against a work order while applying appropriate checks for quantities and secure approvals in case of exceptions

	The system must capture details when an asset is energized with planned versus actual details of Order to Operate (OTO) and Planned Outage information • The system must retain a record of the assets and their conditions, by location, by asset and by hazard to predict the financial risk and the reactive capital expenditure spend • The system must correlate current feeder loading information, future state studies and estimates from external tools to determine future load • The system must be able to use datasets in the Maintenance Investment Model to identify assets for renewal and perform what-if analysis • The system must allow work assignment to specific Designated Responsible Person (DRPs) with notifications and include in the assignment details on dates, required assets and ability to view progress • The system must allow a Program Manager to assign design projects to specific Project Managers and assign detailed estimates to be completed, and track the time required to complete the work • The system must allow cash flow for the various planning cycles and scenarios and allow carry forward opening balances to the next fiscal year • The system must allow identification of inspection tasks in work orders and the ability to submit inspections after necessary changes and report on the aggregate work completed
Customer Connections Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system should provide a workflow to calculate the Net Present Value (NPV) and provide form templates to support user requests for NPV calculations • The system must auto-populate the Offer to Connect (OTC) form with Toronto Hydro's account number in the event customer sends funds via Electronic Funds Transfer (EFT) • The system should allow designers to create a job quotation and secure necessary approvals using a system-based workflow • The system should manage a feeder load request process that considers the work assignment, feeder hierarchy, asset data, costs and basic power flow analysis • The system must evaluate project estimates and accruals at a granular level, calculate NPV, retain an audit trail of estimates with parameter changes, timestamps, and user name
Event Management Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance	• The system must provide the ability to record and release Confined Space Hold Off requests against a work order • The system must gather claims data along with the ability to store files and notify when payment is due

Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must allow work orders to capture time, over-time, cost, materials, notes and link work orders together with ability to report on work orders completed • The system must allow for options to share electronic content within Toronto Hydro and with vendors, customers and the City of Toronto • The system must allow user to schedule planned reactive and planned work orders against crew (vehicle, labour, and time) capacity, and skills • The system must generate reports to view the daily, weekly, and monthly performance of planned and unplanned events by crew • The system must allow the crew to record field work completed, with details on OTO, notes, materials, tools, and equipment needed, and assign notifications, delivery dates and follow up work • The system must allow the user to define and assign forestry work to specific crews, prioritize the jobs and allow the assignee to report back on progress • The system must allow multiple planned work notifications to be scheduled and issued to crews piecemeal with consideration for priority for any unplanned work and for follow up work
Human Capital Management Pillar: Innovation Topic(s): Enablement User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must pre-populate employee timesheets with schedule and approved absences and must trigger appropriate workflows and notification on submission of timesheets and capture comments, where appropriate • The system must allow consideration and functionality for overtime pre-approval, employee hierarchy for approvals, emergency declaration and exceptions for timesheet submission, per terms of employment and basic timesheet rules • The system must integrate with SAP Concur and map the appropriate general ledger accounts with SAP Concur • The system should process payroll based on the timekeeping records for the pay period and consider the pay codes, tax implications and garnishments, including the retirees, non-Toronto Hydro employees per the applicable business rules
Meter to Cash Pillar: Innovation Topic(s): Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must calculate the monthly interest due to customers for deposits and process bills or refund customers for the expansion deposits • The system must accept billing financial transactions from Customer Information System and General Ledger (GL) interface and make the necessary adjustments in the GL • The system should calculate the late payment charge for customer accounts and keep a record of applicable late charge rates • The system must apply customer EFT and cheque payments to an invoice and process customer refunds

	• The system should estimate and prepare the bill for customer demand work with consideration for taxes
Record to Report Pillar: Innovation Topic(s): User Experience Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must allow for General Ledger account analysis that supports comments, workflows, attachments • The system must enable deposits against projects with capital contributions and link them to assets and project WBS. • The system must complete calculations to support capital contributions, costs (life to date), deposit balance • The system must generate reports to recognize excess key finances such as excess capital, deferred revenue, contributions realized, deposits, as they pertain to projects and reporting periods • The system must allow user to define Asset Retirement Obligation (ARO) assets with linkages to asset categories and sub-ledgers and support calculation of liability with reports as they pertain to capitalization and derecognition or decommissioning • The system must store and report on Accounts Receivable aging by customer class and groups with trends of balances, revenue and cash flow • The system must have workflows with approvals for elimination and consolidation transactions for journal entries and balances, and report on them • The system must maintain Fixed Asset Continuity and support reports for deferral accounts, regulatory balances, tax assets and liabilities, variances, expenses and recovery • The system must maintain Other Post Employment Benefits (OPEB) liability with opening balance and end liability with expenses, benefits and adjustments, including reports to support analysis • The system must have a template to pole removal that ties to WBSs, accruals, actuals and estimates, that allows for transactions and supports reports for analysis • The system must be able to build a "Road Cut" template to capture specifications from accruals, receipting and invoicing, City Permits and other processes • The system must enable the quarterly schedule of unreconciled differences (SUDs) process with appropriate workflows and audit checks, and reporting capability • The system must support the Allowance for Funds Used During Construction (AFUDC) rules and AFUDC process for projects and support the reports to govern the AFUDC process • The system should manage the end to end debt issuance lifecycle with key inputs and calculations from a tax standpoint and allow for reports to ensure governance

	• The system should estimate preliminary distribution revenue based on rates and regulatory assumption, estimate medium and longer term debt rates, and estimate operational and maintenance expense. • The system must calculate and report on eligible capital expenditures for capital contributions and tax related expenditures such as Capital Cost Allowance (CCA) • The system must provide the ability to calculate effective tax rate. • The system should estimate and allocate corporate shared services based on a number of parameters such as number of purchase orders (POs), payroll, occupancy and provide the option to manually adjust the estimates • The system should track and report the asset lifecycle from procurement to installation to retirement for all asset ty pes including the associated financials records for assets, labour and equipment • The system must identify major assets and support their capitalization while considering the project cost structure • The system must enable asset retirement obligation (ARO) functionality and reporting with calculation of associated liability, discount rate and cost allocations and assess the impact from changes to underlying rates and adjustments • The solution should accept summary values for billing and cash from the Customer Information System and define the schedule to close the inventory sub-ledger • The system must allow a user to build a forecast from existing plans, while maintaining version and applying standard allocation and distribution business rules, and secure the necessary approvals • The system must provide reports that compare actuals versus plan versus historical trends with supporting narrative comments for variances and provide the user multiple views of the data • The system must provide the ability to perform a depreciation simulation with capital contribution amortization, including software and leased assets, and issue exception reports • The solution should track and report the asset lifecycle when it is removed against the plan, and consider the impact to the general ledger accounts, capital contribution, and depreciated derecognition value, as needed • The system must have the ability to record the proceeds of disposition of specific assets and account for downstream effects to the relevant account codes, general ledger code and tax • The system must use data from the Customer Information System billing data interface to update the revenue / cost of power general ledger accounts at a customer class level and allow for reporting to validate the accuracy and completeness

	• The system must maintain a separate tax ledger and allow workflows to track documents, adjustments, approvals and reviews. The system must generate reports to support the process • The system must enable reporting of services, goods and invoices that did not charge harmonized sales tax (HST) • The system must provide the ability to produce internal & external financial statements including but not limited to balance sheets, statement of income, statement of comprehensive income, statement of change in equity, statement of cash flows and summary financial information (ratios) with financial data • The system must support the integration with Workiva (i.e. a financial external reporting system) to enable automation for external reporting • The system must allow setup and reporting of deferral accounts to support Ontario Energy Board (OEB) reporting requirements • The system must allow intercompany invoicing, settlements, transactions journal entries, asset transfers and interests administered through workflows to secure necessary and appropriate approvals • The system must provide the daily cash position based on integration with data from Customer Information System, bank information and build a forecast considering business rules on accounts receivable (AR) and accounts payable (AP) parameters • The system should provide the ability to centralize the operational and capital budgeting process through all stages, allowing for multiple iterations • The system must provide the ability to process property tax payable for each Toronto Hydro property in installments per the City of Toronto invoice • The system must be able to identify and estimate the tax treatment based on the location of the supplier, type of service, and location where service was provided, and provide applicable reports • The system must provide the ability to pay provincial payment in lieu of property tax in installments and be able to estimate the first installment payment • The system must incorporate closing (actual) gross fixed assets, undepreciated capital cost (UCC) and accumulated depreciation into the planning process and allow to run different scenarios for tax and financial purposes • The system should be able to calculate and forecast liability by ARO category using inflation rate, discount rate, accretion, payments and adjustment and use budgeted payments to lower liability • The system must allow to account for the following variables in the calculation of electricity revenue for the planning model: cost of power, retailer settlement variance account, rate riders

	• The system must capture and consolidate quantity, vintage and functional locations / region of assets by class to be decommissioned by each business unit, such that each asset is identified and asset quantity is adjusted accordingly • The system should calculate planned HST by month from net income, gross revenue and operational expenditure & capital expenditure numbers entered by the planning team and secure approval via a workflow prior to posting • The system should allow manual or calculated input of pre-capitalized inventory to book the change in pre-capitalized balance • The system should identify the property and estimate future property tax and secure necessary approvals prior to posting • The system must cascade impact from disposition of assets to ARO, capital contribution, revenue recognition of capital contribution • The system must be able to determine the value at cost of meters and transformers held in inventory • The solution must provide the ability to identify all regulatory deferral account (RDA) accounts by category, by nature and by regulatory status and calculate the change from the prior period and apply the changes against specific profit and loss (P&L) accounts, and provide reports to support analysis • The system should transact in multiple currency and revalue balance sheet accounts and maintain foreign exchange (FX) rate in Canadian dollars • The system must download detailed bank transactions and apply them gains GL bank transactions and interface Customer Information System cash receipts to the SAP GL • The system should identify contracts with pre-paid conditions subject to business rules associated with PO, contract, renewals, receipting etc. • The system must apply industry standards to the creation, modification, deletion, backup, restore and other such operations to financial data, records, artefacts and transactions • The system must identify and report, for City of Toronto and its affiliates as vendors or customers, with respect to deposits, payments, accruals, journal entries, revenue, capital contributions etc. • The system must produce reports on Canadian Electricity Association (CEA), total payment to governments, OEB's recordkeeping and reporting requirements, annual statistics Canada, capital expenditure and financial information • The system must support the calculation of a number of key financial metrics on costs, revenue, expenses, rate of return and interest rates to enable strategic planning

	• The system must allow for transfer of assets with the necessary approvals, retain traceability, move the depreciation with the assets and allow for asset re-evaluations
Source to Pay Pillar: Innovation Topic(s): User Experience Enablement Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must capture detailed information on accruals, invoicing, ledgers, sub-ledgers, operating lease information, goods and services receipted in terms of suppliers, dates, responsibility center (RC), accountant, and district, dates • The user must be able to easily fetch reports to support the month and quarter end analysis with filters such as aging, thresholds, systems (e.g. Customer Information System), Independent Electricity System Operator (IESO) advancements, and to provide a longer term multi-year outlook • The system must allow an authorized user to create and modify POs, PO lines, the approved purchase spend, deliver address and dates with comments and version changes • The system must determine and calculate Engineering and Administration Reclassifications (EAR) eligbility and allow allocation to projects. The system must support reporting of EAR, such as allocation percentage • The system must enable end to end vehicle maintenance, with building plans, modifying them, taking into account skillset, demand and forecasts and reporting • The system must enable the equipment failure tracking process with creation of logs of failure that include time stamps, locations, equipment data, warranties and supporting documentation • The system must provide reports to compare plan vs forecast vs actuals with attributes such as RC, vendors, notes etc. and bring aging inventory and other materials into the forecast • The system must capture vehicle master records, maintenance plans, vehicle parts and maintenance plans, correlate charges against maintenance plans and issue invoices as needed • The system must link a contract to its upstream activity and capture key contract details, electronic signatures, attach POs to the contract • The system must generate a PO for inventory and non-inventory items with linkages to the underlying contract / request for proposal / request for quote / Request for Information (RFX) and report on PO aging and amount remaining on contracts • The system must allow a user to book a vehicle and capture necessary user information. The user must be presented with vehicle attributes and business rules must be applied at the time of the booking • The system must allow the process to decommission vehicles with appropriate inspection submissions and WBSs / IOs

	• The system must allow inventory to be defined by a number of attributes, such as source, lead times, and package details, to manage effectively and to allow complete individual and bulk updates across a number of inventory attributes • The system must allow creation of sales orders, delivery notes and invoices for the sale of scrap material and administering the disposal of other material such as vehicles. • The system must receive an extract of the transactions from the vending machines with transfer of costs to the appropriate charge code and vendor cost administration • The system must provide a framework to capture and manage the vehicle assignment and vehicle collection process • The system must provide a framework to accept vehicle return, administer the inspection, and, lastly, ensure charges are applied against the correct work order • The system must allow users to create / update / delete / define business partners with the appropriate approvals and authorization • The system must allow users with appropriate authorization to define and organize master data with ability to search fields and complete bulk updates • The system must provide the ability to populate vendor scorecard templates with metrics on exceptions, issues, transactions and overall data. • The system must allow for payment of invoices with and without POs applying three way matching where applicable subject to a tolerance factor, facilitate discounts and non-payment when needed, and eliminate risk of duplicate payments • The system must manage debit, credit memo, and update cheque and vendor records based on bank files • The system must allow the administration of holdbacks per the terms in the PO and ensure appropriate approvals and reasons are secured prior to applying the holdback and releasing payment • The system must allow the user to request vehicle maintenance and receive a notification on completion of the work order with start and end times • The system must have the ability to view reservations in terms of forecast, planned and actuals for the different vehicle categories, estimate the depreciated or lease value and ensure appropriate approvals are secured in case of purchase and sale and generate reports for analysis • The system should build a schedule of assets and assist with receipting them. The system should also provide some indicators of the process health and opportunities to flag exceptions

	• The system must prevent double receipting and potential double payment, and it must allow to drop shipped assets directly on site through inventory and non-inventory conversion • The system must allow creation of purchase requisitions consistent with Toronto Hydro's Procurement Policy with the ability to assign it to a vendor, RFQ or RFP process, leverage appropriate workflows to capture approvals and report on key metrics and health of the process • The system must allow the transmission and receipt of electronic documentation with electronic confirmation • The system must enable Ariba to perform RFX related activities and provide necessary organization information to govern the process • The system must enable centralized vendor setup with minimum required information by specific roles and setup must take into account standard terms and those unique to the vendor • The system must report on Key Performance Indicators (KPIs) to monitor performance for the following functions: fleet uptime, facilities response to tickets, warehouse, supply chain • The system must support analytics including spend consolidation opportunities, spend history with ability to drill down into details, view upcoming contract renewals and flag entries that could breach policy • The system must provide the ability to capture any invoiced costs associated with a return order including but not limited to assessment, shipping, refurbishment and warranty costs
Other Requirements Pillar: Innovation Topic(s): User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases	• The system must allow all the attributes associated with the following data to be appropriately ported over and verified: accounts payable, accounts receivable, journal entry, cost center accounting data, asset and equipment master data, functional location data, WBS and internal order (IO) data, material and vendor master data, purchase order, contract and project data • The system must continue to integrate with other systems such as Customer Information System, Intelex, Remedy, and Royal Bank of Canada to ensure ongoing uninterrupted service • The system should support the industry best practices associated with the document lifecycle and its management in the Meter to Cash process. This would include items such as, quotations, billing, etc.

5.2 Technical Requirements

To address the business requirements, the new S/4 HANA system will need to adhere to the technical requirements below:

Categories	Technical Requirements
Infrastructure Components Pillar: Innovation Topic(s): Alignment with Toronto Hydro's IT Standards User Experience Pillar: Maintenance Topic(s): Vendor Support Control of Product Feature TH Releases IT Reliability	• The system must meet Tier 1 Service Level Agreements (SLA). • The system must have high availability with an uptime of 99.95 percent and targeted Return Time Objective (RTO) of equal or less than 4 hours and targeted Return Point Objective (RPO) of up to 4 hours of data loss • The infrastructure must adhere to the applicable Toronto Hydro standard for server, Storage Area Network (SAN), backup, database and middleware
Cyber Security Pillar: Innovation Topic(s): Enablement Alignment with Toronto Hydro's IT Standards User Experience Pillar: Maintenance Topic(s): Vendor Support Cyber Security Risks IT Reliability Control of Product Feature	• User accounts should be authenticated using Toronto Hydro's corporate active directory • User authorizations should be implemented using role-based user groups stored in active directory • User authorizations, existing roles and profiles from SAP ERP need to be migrated to S4 HANA • The system must handle single sign on with the applicable Toronto Hydro standard technology • The at rest data in the databases must be encrypted • Data in the lower environments must be scrambled or masked • The system must adhere to the standards for internal access, external supplier access, security technology, application security, network security and vulnerability management

LOAD AND CUSTOMERS

1. INTRODUCTION

This exhibit provides information on Toronto Hydro's revenue load forecast used in developing rates for 2025 to 2029. This exhibit also provides information on the utility's revenues, customer counts, historical annual loads and the incorporation of conservation demand management ("CDM") into the load forecast. This exhibit also describes the methodology used to incorporate the impacts of electric vehicles ("EVs") and distributed energy resources ("DERs") in the revenue load forecast for the period 2025 to 2029.

Toronto Hydro's total load, customer, and revenue forecast is summarized in Table 1. The revenue forecast is calculated based on proposed distribution rates, excluding commodity charges, rate riders, and all other non-distribution rates.

Table 1: Total Load, Revenues, and Customers

		Total Normalized GWh	Total Normalized MVA	Total Distribution Revenue ($Million)	Total Customers
2018	Actual	24,701.0	39,823.2	736.6	770,333
2019	Actual	24,429.6	39,126.0	766.2	777,369
2020	Actual	23,674.7	36,813.7	727.8	781,374
2021	Actual	23,575.0	36,638.0	761.8	786,258
2022	Actual	23,990.1	37,648.0	786.5	790,699
2023	Bridge	23,678.6	37,199.3	834.3	794,025
2024	Bridge	23,676.2	36,993.9	874.3	797,318
2025	Forecast	23,458.7	36,384.5	972.4	800,374
2026	Forecast	23,416.5	36,063.4	1,019.7	803,344
2027	Forecast	23,389.6	35,698.8	1,059.1	806,017

		Total Normalized GWh	Total Normalized MVA	Total Distribution Revenue ($Million)	Total Customers
2028	Forecast	23,498.8	35,507.1	1,151.0	808,731
2029	Forecast	23,458.5	35,093.4	1,185.1	811,245

1. Total Normalized GWh are purchased GWh (before losses) and are weather normalized to the Test Year heating and cooling degree day assumptions.
2. Total Normalized MVA are weather normalized MVA.
3. Total Distribution Revenue is weather normalized and includes an adjustment for the Transformer Allowance.
4. Total Customers are an annual average and exclude street lighting devices and unmetered load connections.

Toronto Hydro's detailed revenue load forecast by rate class, customer forecast by rate class and forecast of distribution revenues by rate class (OEB Appendix 2-IB) are shown in Exhibit 3, Tab 1, Schedule 2.

The information provided for this exhibit has been prepared in accordance with of the OEB's Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022).

2. CUSTOMER FORECAST

The customer base within Toronto Hydro's service territory has displayed continuous growth over the past five years, driven mainly by Residential and Competitive Sector Multi-Unit Residential ("CSMUR") customer additions.

Table 2 shows a summary of the historical and forecasted customer numbers:

Table 2: Customer Numbers by Rate Class

Year		Residential	Competitive Sector Multi-Unit Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000-4,999 kW	Large Use	Street Lighting	Unmetered Load	Total
2018	Actual	612,262	75,028	71,266	10,470	427	42	1	839	**770,333**
2019	Actual	614,206	79,882	71,515	10,444	455	40	1	827	**777,369**
2020	Actual	614,229	83,686	71,899	10,213	480	44	1	824	**781,374**
2021	Actual	614,181	88,478	72,408	9,846	482	45	1	819	**786,258**
2022	Actual	614,926	92,126	72,614	9,731	461	42	1	799	**790,699**
2023	Bridge	615,795	94,391	72,871	9,672	455	47	1	793	**794,025**
2024	Bridge	616,778	96,411	73,152	9,685	453	46	1	793	**797,318**
2025	Forecast	617,563	98,427	73,396	9,699	451	45	1	793	**800,374**
2026	Forecast	618,292	100,404	73,632	9,712	462	48	1	793	**803,344**
2027	Forecast	618,985	102,150	73,857	9,725	460	47	1	793	**806,017**
2028	Forecast	619,849	103,674	74,165	9,740	463	46	1	793	**808,731**
2029	Forecast	620,742	104,994	74,455	9,754	461	46	1	793	**811,245**

In the 2020-2024 rate application decision, the OEB directed Toronto Hydro to enhance its approach to forecasting the number of customers by incorporating economic and demographic conditions.[1] In response to the OEB's direction, Toronto Hydro considered economic, demographic, market knowledge, and reclassification as it developed the forecast for the 2025-2029 period.

The utility enhanced its forecasting methodologies by using stepwise regression techniques where applicable. Numerous explanatory variables were tested with the ultimate model being determined based on model statistics and expert judgment. The methodology was used for the Residential, General Service ("GS") <50 kW, and GS 50-999 kW rate classes. The customer forecast for these rate classes considers customer population, employment, customer trends, and lagged variables.[2] The forecasts of Toronto's employment and population are based on the Conference Board of Canada forecasts.[3] Exhibit 3, Tab 1, Schedule 1, Appendix H contains the historical and forecast customer and input variable details. The model statistics for each class model are shown in Exhibit 3, Tab 1, Schedule 1, Appendix I.

The customer forecast for GS 1000-4999 kW, Large Use, CSMUR, and Street Lighting rate classes are based on market knowledge of construction in Toronto Hydro's service area, as well as an application of expert judgement. Toronto Hydro regularly communicates with developers, municipal representatives and commercial and residential associations to identify new larger connection projects and their expected connection years. Large

[1] EB-2018-0165 Decision and Order, (December 19, 2019) at page 126.
[2] To account for the influence of the previous period's customer numbers, in what is known as an autoregression. This is a way to avoid error terms reflecting a systematic pattern (Gujarati, 2004); and rid the model of autocorrelation (Keele and Kelly, 2006.)
[3] Conference Board of Canada, *Major City Insights – Toronto Census Metropolitan Area* (February 2023).

connection types include data centres, transit electrification, and commercial and residential buildings.

Toronto Hydro's detailed forecast of customers by rate class is found in Exhibit 3, Tab 1, Schedule 2 (OEB Appendix 2-IB).

3. HISTORICAL LOADS

Toronto Hydro's historical total system load (actual and weather-normalized) is illustrated in Figure 1 below.

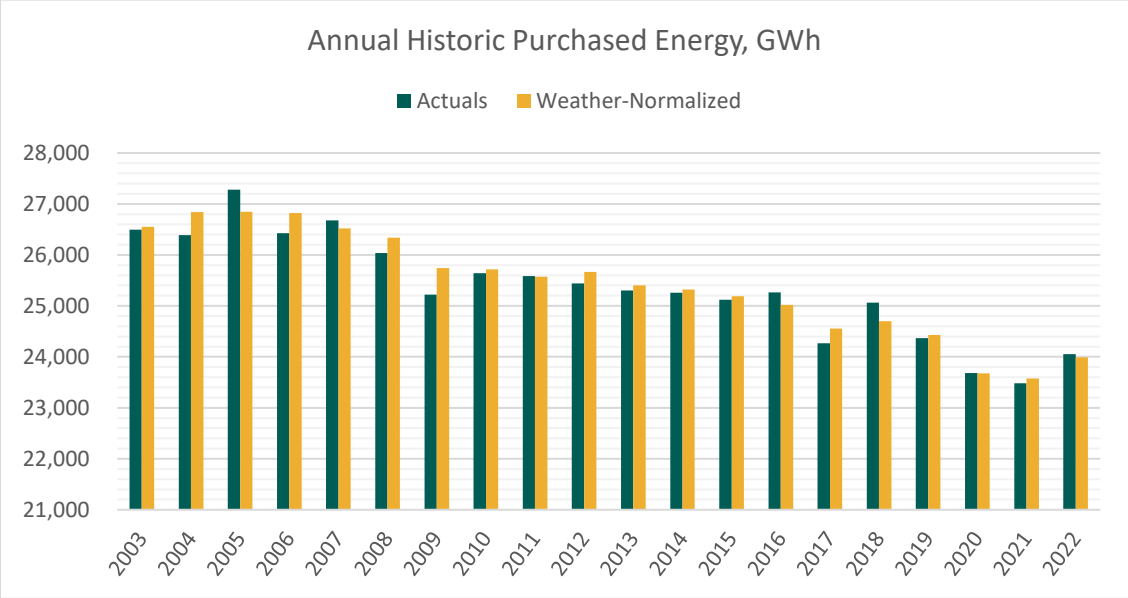


Figure 1: Historical Purchased Energy

Since 2006, Toronto Hydro has experienced a significant decrease in total energy consumption. The flat growth over the 2004-2006 period has been replaced by declining loads over the 2007-2022 period. Conservation activities – both program driven and

naturally occurring – are likely continuing to impact the overall load change, as supported by the statistical significance of the CDM explanatory variable in the regression models.

Table 3, below, shows a summary of the total historical normalized annual loads and growth.

Table 3: Historical Annual Load

Year	Total Normalized GWh	Growth GWh	Percentage Change (%)
2003	26,550.6		
2004	26,839.3	289	1.1%
2005	26,845.7	6	0.0%
2006	26,823.2	(22)	-0.1%
2007	26,519.9	(303)	-1.1%
2008	26,341.1	(179)	-0.7%
2009	25,744.0	(597)	-2.3%
2010	25,720.1	(24)	-0.1%
2011	25,573.2	(147)	-0.6%
2012	25,665.6	92	0.4%
2013	25,401.4	(264)	-1.0%
2014	25,323.7	(78)	-0.3%
2015	25,188.6	(135)	-0.5%
2016	25,021.5	(167)	-0.7%
2017	24,557.7	(464)	-1.9%
2018	24,701.0	143	0.6%
2019	24,429.6	(271)	-1.1%
2020	23,674.7	(755)	-3.1%
2021	23,575.0	(100)	-0.4%
2022	23,990.1	415	1.8%

4. BASE REVENUE LOAD FORECAST

Toronto Hydro developed separate load forecasts for each rate class. For rate classes whose billing units are monthly peak demand, the forecasted monthly non-coincident peak by class is forecast based on historical relationships between energy and demand; The summation of the individual rate class loads is referred to as the base revenue load forecast. The impacts of EVs and DERs was accounted for using an integration model described below in Section 10 to arrive at the total load revenue forecast. Revenues are determined by applying the proposed distribution rates to the rate class billing determinants for the forecast period.

4.1 Multivariate Regression Model

Toronto Hydro's process of developing a model of energy usage for each rate class involves estimating multifactor regression models using different input variables to determine the best fit. Different models were fit based on reasoned assumptions about which input variables impact energy use. Using stepwise regression techniques, numerous explanatory variables were tested with the ultimate model being determined based on model statistics and experience.

The models are developed separately for each rate class. This approach allows for greater detail in modelling loads and allows for the different interactions to be modelled independently. All of Toronto Hydro's regression models use monthly kWh per day as the dependent variable and monthly values of independent variables from July 2002 through to the latest actual values (December 2022) to determine the monthly regression coefficients.

The main drivers of energy consumption over time are weather and energy conservation activities (both program and naturally occurring), as well as calendar, economic, and demographic conditions.

5. WEATHER

The primary driver of consumption variance between years is weather. Weather impacts on load are apparent in both the winter heating season and in the summer cooling season. For that reason, both Heating Degree Days ("HDD" – a measure of coldness in winter) and Cooling Degree Days ("CDD" – a measure of summer heat) are captured in the multifactor regression model for all classes except Streetlighting and Unmetered Scattered Load. In previous rate filings, Toronto Hydro had demonstrated that the standard definition of HDD, which uses 18 degrees Celsius as the point at which loads start to be impacted by temperature, was not as effective as a measure which uses 10 degrees Celsius as the "balance point" for the HDD measure. This methodology is consistent with previous Toronto Hydro rate applications (EB-2014-0116 and EB-2018-0165).

Figure 2, below, shows the relationship between temperatures and loads for the period of July 2002 to December 2022. It is clear that the relationship between heating loads and temperature changes at 10 degrees Celsius.

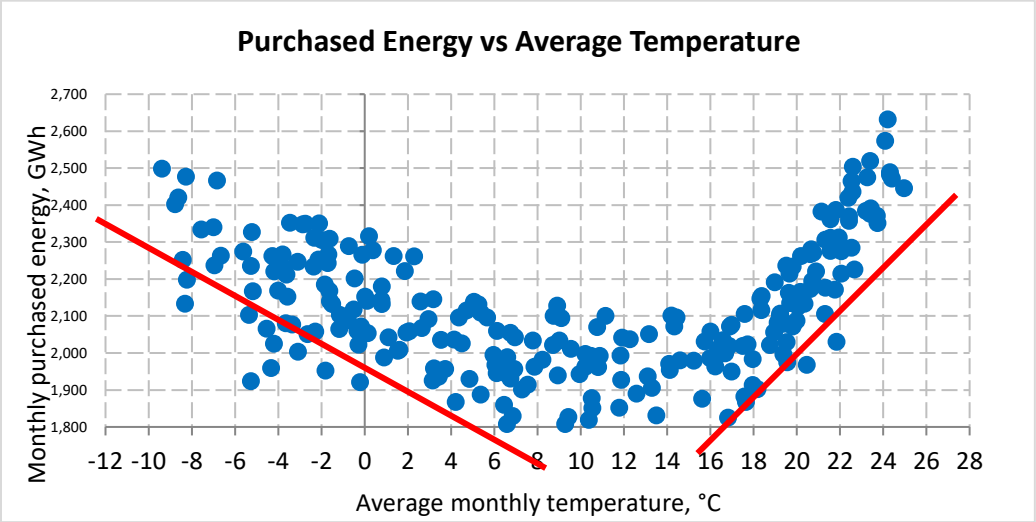


Figure 2: Purchased Energy vs Average Temperature

Positive dew point temperature is another type of weather factor included as an explanatory variable for the CSMUR, GS <50 kW, GS 50-999 kW, and GS 1000-4999 kW customer classes. This variable captures the impact of humidity on consumption and shows the positive impact of temperature on loads during summer months.

The forecast for heating and cooling degree-days, and positive dew point temperature inputs is based on a ten-year historical average of HDD, CDD, and positive dew point. Toronto Pearson International Airport station was used as the climatological measurement point for establishing monthly HDD and CDD.

5.1 Weather Normalization Methodology

Toronto Hydro's forecasts are future (out-of-sample) estimates of monthly load, obtained by extrapolating patterns and relationships from historical (in-sample) observations. These data points are monthly energy (load) purchases that get weather-normalized through adjustments for any deviations relative to the amount of energy that would have

been purchased under normal weather conditions. Specifically, any energy amounts either in excess or below what would be purchased under normal weather conditions, are subtracted or added to the purchases of a given month. Calculations are made by using regression coefficients as quantitative measures of the effect of weather conditions on load purchases. In other words, a regression is estimated to model load variations as a function of explanatory variables including weather conditions such as HDD, CDD, and positive dew point temperature. The "beta" or slope coefficients thus obtained are used to measure load increases or decreases resulting from a unit increase in each of those weather determinants. To illustrate the process, if, for example a given summer month was much hotter compared to normal historical actual patterns then the process would involve: a) that month's number of CDD is subtracted from the number of CDD one would observe in an average year; and b) the difference is multiplied by the partial effect, or beta coefficient of CDD, in order to calculate the effect attributable to that weather-related determinant. This is done for all the weather determinants, thus allowing Toronto Hydro to re-calculate load net of abnormal weather effects. This is referred to as a weather normalized load.

6. CONSERVATION AND DEMAND MANAGEMENT (CDM)

Consistent with its previously approved load forecasts in EB-2014-0116 and EB-2018-0165, Toronto Hydro has included CDM activities and their impacts into its forecast for the 2025 to 2029 period. Changes to the availability of CDM savings forecasts and results has necessitated a change in Toronto Hydro's methodology for accounting for CDM.

As noted in the OEB's Chapter 3 filing requirements, on March 20, 2019, the Minister of Energy, Northern Development and Mines issued separate directives to the OEB and the Independent Electricity System Operator ("IESO") in respect of CDM programs. The

directive to the IESO concluded the Conservation First Framework ("CFF") effective immediately. New CDM program activity has since been provincially-centralized under the IESO's Interim Framework and 2021-2024 CDM Framework. As a result, the IESO is no longer providing CDM savings forecasts or program results for distributors' service territories.

The latest CDM guidelines for Electricity Distributors (EB-2021-0106) state that distributors may choose to include CDM as a variable in a multivariate regression, based on the historical and forecast level of savings from applicable CDM activities in a given year. Toronto Hydro has moved towards including CDM as a multivariate regression variable to represent conservation that occurs through both CDM program delivery and naturally. The utility previously used a three-step process that explicitly considered cumulative historical and forecast CDM impacts that were added to metered loads (gross of CDM), forecasted based on regression modelling, and then subsequently deducted to derive the load forecast (net of CDM).

Incorporating CDM as a multivariate regression variable allows Toronto Hydro to account for conservation activities through regression techniques with the limited LDC-level information available. Due to the change in methodology, the metered loads are no longer manually adjusted for CDM impacts. The CDM regression variable reflects the declining customer usage from conservation activities, as well as avoids any double-counting of savings. Section 6.1 provides a detailed explanation of the CDM savings used to develop the CDM variables.

Toronto Hydro is currently not planning to establish a Lost Revenue Adjustment Variance Account (LRAMVA) threshold for the 2025-2029 period.[4]

6.1 CDM Multivariate Variables

Toronto Hydro incorporated CDM variables into the multivariate regression: a residential CDM variable for the Residential class, and a business CDM variable for the General Service classes. Both variables are based on the cumulative historical and forecast level of savings from 2006 to 2029, and separated by residential and business program savings for each variable respectively. The variables were found to be statistically significant in the Residential, GS <50 kW, GS 50-999 kW, GS 1000-4999 kW, and Large Use class models. The calculations for each CDM variable are shown in Exhibit 3, Tab 1, Schedule 1, Appendix C.

Toronto Hydro's historical and forecasted annual CDM savings for the 2006 to 2029 period are determined in four separate components:

1) Verified historical savings (2006 to 2017);
2) Post-CFF historical savings (2015 to 2022);
3) 2021-2024 CDM Framework forecast savings (2021 to 2024); and
4) Forecast savings beyond the 2021-2024 CDM Framework (2025 to 2029).

Verified Historical Savings (2006 to 2017)

Toronto Hydro's CDM savings include impacts of historical CDM achievement. The annual impacts of CDM completed between 2006 and 2017 have been verified by the IESO, and represent the full suite of energy efficiency and demand response programs offered to Toronto Hydro's residential and business customer segments.

[4] EB-2021-0106, Ontario Energy Board, *Conservation and Demand Management Guidelines for Electricity Distributors* (December 20, 2021) at page 23-24.

Post-CFF Historical Savings (2015 to 2022)

The second component includes unverified 2015 - 2022 achievements, as well as an extrapolation of CDM savings from the IESO's provincial CDM program delivery. In the absence of final verified annual CDM program results and CDM Plan, Toronto Hydro used the following additional information to determine these savings:

- the IESO's Participation and Cost Reports for January 1, 2018 through April 2019; these reports include incremental first-year energy savings;
- third-party Measurement and Verification Reports for specific projects under the Process and System Upgrades Program, which is not captured in the IESO's Participation and Cost Reports;
- for savings to December 31, 2022 that are related to CFF programs, project-level savings for projects that were completed within the 2015-2022 period which a distributor is contractually obligated to finish. For the Retrofit Projects, energy savings and demand reductions are based on the list of projects for which Toronto Hydro paid incentives to customers and which had their status updated to "Project Closed" in CDM-IS system post March 1, 2019. For non-Retrofit CFF Projects, savings are based on the list of projects for which Toronto Hydro has paid incentives and submitted project-level details to the IESO; and
- IESO's 2019-2020 Interim Framework for the province, extrapolated for savings in Toronto Hydro's service area. The extrapolation is based on Toronto Hydro's 2015-2017 historic ratio of LDC program savings to provincial savings under CFF.

Exhibit 3, Tab 1, Schedule 1, Appendix D contains the summary of 2015 to 2022 Post-CFF historical savings. Exhibit 3, Tab 1, Schedule 1, Appendix F contains the IESO's 2019-2020

Interim Framework CDM plan for the province; the extrapolation for savings in Toronto Hydro's service area are shown in Exhibit 3, Tab 1, Schedule 1, Appendix E.

2021-2024 CDM Framework Forecasted Savings (2021 to 2024)

The third component is based on the IESO's 2021-2024 Conservation and Demand Management Framework for the province, extrapolated for savings in Toronto Hydro's service area. The extrapolation is based on Toronto Hydro's 2015-2017 historic ratio of distributor program savings to provincial savings under CFF. For newer programs that did not exist under CFF, the historic ratio is based on the total sector savings (residential or business).

Exhibit 3, Tab 1, Schedule 1, Appendix G contains the IESO's 2021-2024 CDM plan for the province; the extrapolation for savings in Toronto Hydro's service area are shown in Exhibit 3, Tab 1, Schedule 1, Appendix E.

Forecast savings beyond the 2021-2024 CDM Framework (2025 to 2029)

Toronto Hydro's annual forecasted savings for 2025 to 2029 were developed based on the assumption that there will be a continuation of CDM program delivery by the IESO. In the absence of a new framework, the projected impact is based on the anticipated "status quo" CDM delivery objectives and expectations assigned for the post-2024 conservation planning period. Toronto Hydro has determined this to be the best estimate at this time given the absence of conservation planning detail for this period. This method is consistent with Toronto Hydro's previous application methodology.

7. OTHER MULTIVARIATE VARIABLES

The multivariate regression model captures a number of other multivariate variables in addition to CDM impacts, including demographic and economic conditions, COVID-19 pandemic impacts, time trends and calendar factors.

Demographic and economic conditions are captured within the model by using customer numbers, the Toronto unemployment rate, the Toronto employment numbers, Toronto gross domestic product ("GDP") and time trend variables discussed below. The Toronto unemployment rate, employment numbers and GDP reflect the level of economic fluctuations, and were found to be statistically significant in the Residential, CSMUR, GS <50 kW, GS 50-999 kW, GS 1000-4999 kW, and Large Use class models. Customer variables capture overall levels of demographic fluctuations, and were found to be statistically significant in the CSMUR, GS <50 kW, GS 50-999 kW, and Large Use class models. The forecasts of Toronto's unemployment rate, employment numbers and GDP are based on the Conference Board of Canada forecasts.[5]

Load impacts from the COVID-19 pandemic are captured through a lockdown binary variable. This variable is based on the provincial lockdown periods announced during the pandemic in 2020-2021. Additional load impacts from the pandemic are captured through the economic variables used in the model, such as GDP. The lockdown binary variable was found to be statistically significant in the Residential, GS <50 kW, GS 50-999 kW, and Large Use class models.

The time trend variables used in the model are designed to capture trends which are not otherwise explained by the other driver variables, as well as to improve the overall model

[5] *Supra* note 3.

fit over the period. The Residential, GS<50 kW, and Large Use classes use a linear spline time trend in the 2012 to 2022 period, the General Service 1,000-4,999 kW class uses a linear spline time trend in the 2018 to 2022 period, and the GS 50-999 kW uses a simple time trend over historical period 2018 to 2022.

One additional factor determining energy use in the monthly model are "calendar factors." For example, the number of business days in a month will impact total monthly load. To capture the different number of days in the calendar months, the modelling of purchased energy was performed on a per-day basis. To reflect different numbers of business days in the month and, consequently, different number of peak hours, business day percentage was used in those class models. A binary variable was also included to reflect the impact of the 2003 August blackout on energy use in that month.

Exhibit 3, Tab 1, Schedule 1, Appendix A contains the historical and forecast load and input variable details. The model statistics for each class model are shown in Exhibit 3, Tab 1, Schedule 1, Appendix B.

From the regression models, the forecast of energy usage is determined by applying the model coefficients to forecasts of the input variables.

Table 4 summarizes the variables included in each of the rate class energy models.

Table 4: Regression Variables by Rate Class

Residential	Competitive Sector Multi-Unit Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000-4,999 kW	Large Use	Street Lighting	Unmetered Load
HDD 10 per day	HDD 10 per day	HDD 10 per day	HDD 10 per day	HDD 10 per day	HDD 10 per day	Average use per device	Simple extrapolation
CDD per day	CDD per day	CDD per day	CDD per day	CDD per day	CDD per day		
Blackout binary variable	Number of CSMUR customers	Number of GS<50 kW customers	Number of GS 50-999 kW customers	Business days percent	Number of Large Use customers		
Time trend	Positive dew point temp	Lockdown binary variable	Lockdown binary variable	Business CDM Variable	Lockdown binary variable		
Unemployment rate	Unemployment rate	Business CDM Variable	Business CDM Variable	Time trend	Business CDM Variable		
Residential CDM variable		Time trend	Time trend	GDP	Time trend		
		GDP	Employment	Positive dew point temp	GDP		
			Positive dew point temp		Positive dew point temp		
			Business days percent		Business days percent		
			Blackout binary variable				

8. ALIGNMENT WITH PEAK DEMAND FORECAST

Toronto Hydro prepares forecasts in addition to the revenue load forecast for other important purposes, including a peak demand forecast.[6] Where the revenue load forecast provides a view of customer consumption and demand over the coming rate period, the peak demand forecast shows the anticipated peak demand at all transformer station buses that supply Toronto Hydro's distribution grid. The peak demand forecast and the revenue load forecast have important differences. The peak demand forecast focuses on the sufficiency of the distribution system's capacity to serve the potential draw on the grid by aggregations of customers at singular points in time, while the revenue load forecast focuses on projecting customer consumption within billing cycles.

The peak demand forecast is a 10-year weather-adjusted peak demand forecast prepared to assist with the planning of capital work programs mainly at the distribution station level (e.g., feeder level) to meet capacity need. The peak demand forecast considers localized growth and density intensification from new high-rise developments, EVs, and other large connections that are driving the need for investments. The forecast is dependent on historical peak load at the bus level as well as bus weather sensitivity. The peak demand forecast is also used to help inform the IESO's regional forecasting process and, internally, in long-term planning. Please see Exhibit 2B, Section B – Coordinated Planning, Appendix A for the Toronto Region System Needs Assessment Report.

In contrast to the peak demand forecast, the revenue load forecast provides an outlook of customer consumption and demand. The revenue load forecast is dependent on monthly historic billing consumption by rate class (as a dependent variable) as well as independent variables from external sources. As described above in section 6,

[6] Exhibit 2B, Section D4.

conservation activities continue to contribute to the overall decline in customer load and demand.

Toronto Hydro ensures alignment between the two forecasts through the use of common growth base inputs, including large connections and electrical vehicles. The large connection projections are based on market knowledge of construction in Toronto Hydro's service area, including confirmed connection agreements. Toronto Hydro developed a forecast of EV uptake as an input to these forecasts. The EV forecasts are inputs in both the load forecast and peak demand forecast for determining their respective outputs. More information on the electrical vehicles is available in Section 10.

9. CLASS DEMAND (kVA) FORECAST

Toronto Hydro's forecast of monthly peak demand by customer class, which is used to determine revenue for those customers billed on a demand basis (GS 50-999 kW, GS 1000-4999 kW, Large User, and Street Lighting), is established using historical relationships between energy and demand. The utility uses the latest five-year average growth of this relationship for forecasting purposes. The resulting kW demand forecast is explicitly converted based on average power factors to determine the peak kVA demand forecast.

10. ELECTRIC VEHICLES AND DISTRIBUTED ENERGY RESOURCES

Toronto Hydro incorporated EVs and DERs into its load forecast. Toronto Hydro expects to see increased use of these technologies as the energy transition unfolds over the 2025-2029 forecast period. It is necessary, therefore, to develop distinct forecasts for these technologies because they are expected to exceed historical market adoption levels.

Given this anticipated acceleration, the base revenue load forecast does not account for the anticipated future load impacts of these technologies.

Toronto Hydro engaged Clearspring Energy Advisors, LLC ("Clearspring") to help develop an approach to including the expected impacts of EVs and DERs into the 2025 to 2029 period. Clearspring developed an integration model for this purpose. The objective of the integration model is to forecast the impacts on energy and billing demand by rate class resulting from the forecasted changes in the adoption of EVs and DERs. These impacts are then aggregated to the base revenue load forecast developed through multivariate regression modelling. Clearspring also produced an analysis on the changes to the rate class load profiles resulting from the EV and DER forecasts that is used as an input in the cost allocation model by Toronto Hydro for rate setting purposes.

The Clearspring integration model used the following forecast inputs, provided by Toronto Hydro, to forecast the impacts of EVs and DERs onto the billing components of energy and demand:

1) Light-duty electric vehicles ("LDEVs"),
2) Medium-duty electric vehicles ("MDEVs"),
3) Heavy-duty electric vehicles ("HDEVs"),
4) Customer-owned renewable DERs ("Renewables"),
5) Customer-owned non-renewable DERs ("Non-Renewables"), and
6) Customer-owned energy storage resources

The integration model estimates the incremental load of these technologies from their 2022 adoption levels to the 2029 forecasted levels.

The six technology inputs were aggregated to the base revenue load forecast to determine the net forecast after accounting for these technologies. The load impacts vary between the technologies as EVs will increase energy and billing demand, whereas DERs will lower energy and billing demand. The forecasted load impacts as a percentage of the total revenue load forecast are provided annually in Table 5 below.

Table 5: Annual Forecasted Energy and Billed Demand Impacts

Year	Incremental Energy (kWh) % Increase	Incremental Billed Demand (kVA) % Increase
2023	-0.1%	-0.1%
2024	-0.2%	-0.2%
2025	0.1%	0.0%
2026	0.7%	0.5%
2027	1.5%	1.1%
2028	2.5%	1.7%
2029	3.4%	2.4%

10.1 Electric Vehicles

Toronto Hydro developed the EV forecast as an input to Clearspring's integration model. The forecast was developed in reference to the three vehicle types: LDEV (battery and plug-in electric), MDEV, and HDEV.

The EV forecast was developed to be consistent with the City of Toronto's EV Strategy targets:[7]

- 2025 – 15% of new vehicle sales and 5% of total light duty vehicles be classified as EVs; and
- 2030 – 40% of new vehicles sales and 20% of total light duty vehicles be classified as EVs, totalling 220,000 LDEVs.

[7] City of Toronto, Electric Vehicle Strategy: https://www.toronto.ca/wp-content/uploads/2020/02/8c46-City-of-Toronto-Electric-Vehicle-Strategy.pdf.

The LDEV forecast was developed by using historical Light-Duty Vehicles ("LDV") population in Ontario, as well average annual growth rates, for which an extrapolation for Toronto and LDEV forecasts were created. The number of new LDV and LDEV registrations in Ontario were obtained from StatsCan. The reported values were used to estimate the number of new LDVs and LDEVs registered each year in Toronto. It is estimated that approximately 12.7 percent of new vehicles registered in Ontario each year are registered in Toronto. To maintain consistency with the City's EV Strategy the same 11-year average vehicle age was used, which results in approximately 9.1 percent of the vehicle population retiring each year. These factors were used to develop an accounting of the number of LDVs registered in Toronto at the end of each year.

An estimation of the LDV growth in Toronto was created based on the levels seen in 2017-2019 (pre-COVID) from Stats Canada. Toronto's share of Ontario's new vehicles is assumed to be constant over time at 12.7 percent. The forecast of new LDEV registration and total LDEV registered each year was built up to achieve the 220,000 in 2030 EV target provided by the City of Toronto, which would represent 20 percent of the total LDV fleet. The methodology estimates 1.1M LDVs registered in Toronto by 2030, with an annual growth of 1 percent during the forecast period.

The MDEV and HDEV forecasts were also developed using the historical vehicle population in Ontario, as well average annual growth rates, for which an extrapolation for Toronto and EV forecasts were created. With the annual growth rate of both vehicle classes, a provincial wide population forecast was derived. Toronto accounts for approximately 20% of the provincial medium and heavy-duty vehicle population. The HDEV forecast also includes vehicle growth from the Toronto Transit Commission ("TTC"). The TTC's Green Bus Replacement program is key to the City's TransformTO action plan

and outlines the transition of the TTC bus fleet to zero-emission vehicles by 2040.[8] An adoption rate was then developed to establish how rapidly MDEVs and HDEVs would need to be adopted to meet the City's EV Strategy Target. A materialization factor was also added to the MDEV and HDEV forecasts as an adjustment to account for delayed adoption. Internal analysis shows that commercial customers typically have delayed completion dates compared to their original estimated completion dates. Internal analysis was based on energization project materialization between estimated and actual completion dates.

Table 6, 7 and 8 below show the summaries of EV forecasts, consumption and billed demand by vehicle type. Please refer to Clearspring's report in Exhibit 3, Tab 1, Schedule 1, Appendix J for further details.

Table 6: EV Forecasts by Vehicle Type

Year	LDEVs	MDEVs	HDEVs
2023	26,408	1,673	1,651
2024	38,615	2,811	2,769
2025	52,764	3,686	3,622
2026	75,653	4,862	4765
2027	105,249	6,057	5,922
2028	142,460	6,982	6,809
2029	179,770	8,215	7,992

[8] Green Bus Replacement Program, Toronto: Toronto Transit Commission, 2022.

Table 7: EV Consumption (MWh) by Vehicle Type

Year	LDEVs	MDEVs	HDEVs	Total EV Load	% of Total Load Forecast
2023	23,643	9,892	30,174	**63,709**	**0.3%**
2024	60,312	26,688	81,282	**168,281**	**0.7%**
2025	106,482	47,219	143,575	**297,276**	**1.3%**
2026	172,215	72,064	218,716	**462,996**	**2.0%**
2027	264,559	101,434	307,251	**673,244**	**3.0%**
2028	381,971	131,035	396,087	**909,093**	**4.0%**
2029	511,753	160,524	484,126	**1,156,402**	**5.1%**

Table 8: EV Billed Demand (kVA) by Vehicle Type

Year	LDEVs	MDEVs	HDEVs	Total EV Billed Demand	% of Total Billed Demand Forecast
2023	3,449	17,741	60,372	**81,561**	**0.2%**
2024	8,799	47,848	162,964	**219,611**	**0.6%**
2025	15,537	84,644	288,185	**388,366**	**1.1%**
2026	25,127	129,176	439,102	**593,405**	**1.6%**
2027	38,602	181,812	617,072	**837,486**	**2.3%**
2028	55,736	234,851	795,856	**1,086,443**	**3.1%**
2029	74,680	287,698	972,887	**1,335,264**	**3.8%**

10.2 Distributed Energy Resources

DER forecasts, developed by Toronto Hydro (see Exhibit 2B, Section E5.1), were provided to Clearspring as an input to the integration model.

The DER forecasts were developed in reference to three technology types:

- **Renewables** – consists of DER based on renewable technologies, such as solar photovoltaic.

- **Energy Storage** – refers to DER related to the capture of energy, such as batteries.
- **Non-Renewables** – refers to conventional fossil-fuel based DER, such as natural gas generators and combined heat and power.

Tables 9, 10 and 11 below show the summaries of DER forecasts, consumption and billed demand by technology type. Please refer to Clearspring's report in Exhibit 3, Tab 1, Schedule 1, Appendix J for further details.

Table 9: DER Forecasts by Technology Type and Installed Capacity (kW)

Year	Renewables	Energy Storage	Non-Renewables
2023	126,443	56,579	198,186
2024	133,449	60,042	212,056
2025	143,426	73,359	215,566
2026	155,110	77,378	218,717
2027	168,502	81,407	221,597
2028	183,601	85,436	224,297
2029	200,407	89,485	226,817

Table 10: DER Consumption (MWh) by Technology Type

Year	Renewables	Energy Storage	Non-Renewables	Total DER Load	% of Total Load Forecast
2023	-4,166	0	-90,664	**-94,830**	**-0.4%**
2024	-9,374	0	-209,470	**-218,844**	**-1.0%**
2025	-14,764	0	-257,450	**-272,214**	**-1.2%**
2026	-21,551	0	-276,758	**-298,309**	**-1.3%**
2027	-29,396	0	-294,254	**-323,650**	**-1.4%**
2028	-38,299	0	-310,463	**-348,762**	**-1.5%**
2029	-48,260	0	-325,623	**-373,883**	**-1.6%**

Table 11: DER Billed Demand (kVA) by Technology Type

Year	Renewables	Energy Storage	Non-Renewables	Total DER Billed Demand	% of Total Billed Demand Forecast
2023	-5,109	0	-124,299	**-129,408**	**-0.3%**
2024	-11,452	0	-288,041	**-299,493**	**-0.8%**
2025	-18,039	0	-354,245	**-372,284**	**-1.0%**
2026	-26,325	0	-380,823	**-407,147**	**-1.1%**
2027	-35,901	0	-404,905	**-440,806**	**-1.2%**
2028	-46,769	0	-427,214	**-473,983**	**-1.3%**
2029	-58,928	0	-448,079	**-507,007**	**-1.4%**

10.3 Integration Model

The integration model's purpose is to convert the EV and DER forecasts into consumption and billing demand outputs for the total load forecast. The model undertakes a four-step process to convert these technologies into consumption and billing demand outputs as follows:

- The model calculates the change in technology forecasts from 2022;
- The technology changes are then allocated by 6 rate classes (Residential, CSMUR, GS <50kW, GS 50-999 kW, GS 1000-4999 kW, Large User);
- The monthly energy impacts of each technology are estimated by rate class in 2025 through 2029; and
- The monthly billing demand impacts of each technology are estimated for the applicable rate classes in 2025 through 2029 (GS 50-999 kW, GS 1000-4999 kW, Large User).

The resulting outputs are aggregated to the base revenue load forecast. Exhibit 3, Tab 1, Schedule 1, Appendix J contains Clearspring's report on the integration of EVs and DERs for revenue forecasting that was designed and developed for Toronto Hydro.

11. HEAT PUMPS

Heat pumps (i.e. the electrification building heating) are another technology associated with the energy transition. In preparing the revenue load forecast for the 2025-2029 period, Toronto Hydro determined that the impact of heat pumps on overall load and demand is not yet material. As such, the potential load impacts of heat pumps were not separately incorporation into the load forecast. Existing heat pump loads are captured, however, in the multivariate regression models.

12. ACCURACY OF FORECAST AND VARIANCE ANALYSES

Table 12 summarizes the variances between Toronto Hydro's actual loads and the last OEB-approved loads (filed in Toronto Hydro's EB-2018-0165 rate filing).

Table 12: Forecast versus Actual Purchased Energy

Year	Board-Approved Load Forecast	Actual Load		Weather Normalized Actual	
	GWh	GWh	Variance	GWh	Variance
2020	24,044.00	23,681.30	-1.51%	23,674.74	-1.54%
2021	23,763.36	23,480.00	-1.19%	23,574.99	-0.79%
2022	23,650.99	24,054.52	1.71%	23,990.12	1.43%

Year to year variances in Toronto Hydro's historical loads reflect the impacts of COVID-19 pandemic, weather, economic conditions, CDM, and normal customer growth. For the forecast periods, year to year variances in loads reflect the impact of model driver variables.

Table 13 summarizes the variances between Toronto Hydro's actual number of customers and the last OEB-approved number of customers (filed in Toronto Hydro's EB-2018-0165 rate filing).

Table 13: Forecast versus Actual Number of Customers

Year	Board-Approved Customer Forecast	Actual Number of Customers	Variance
2020	784,279	781,374	-0.37%
2021	791,003	786,258	-0.60%
2022	799,341	790,699	-1.08%

Tables showing Toronto Hydro's year-over-year actual loads and customers can be found in Exhibit 3, Tab 1, Schedule 2 (OEB Appendix 2-IB).

Making a Difference

Energy Efficiency in Ontario

2019-2020 Interim Framework Results



ieso
Connecting Today.
Powering Tomorrow.

SAVE ON ENERGY™
POWER WHAT'S NEXT

Save on Energy celebrates 10 years in 2021. More than 250,000 Ontario residents and businesses have relied on Save on Energy programs to better manage their energy use.

10 YEARS OF SAVE ON ENERGY™











Everyone benefits from energy efficiency

It helps:

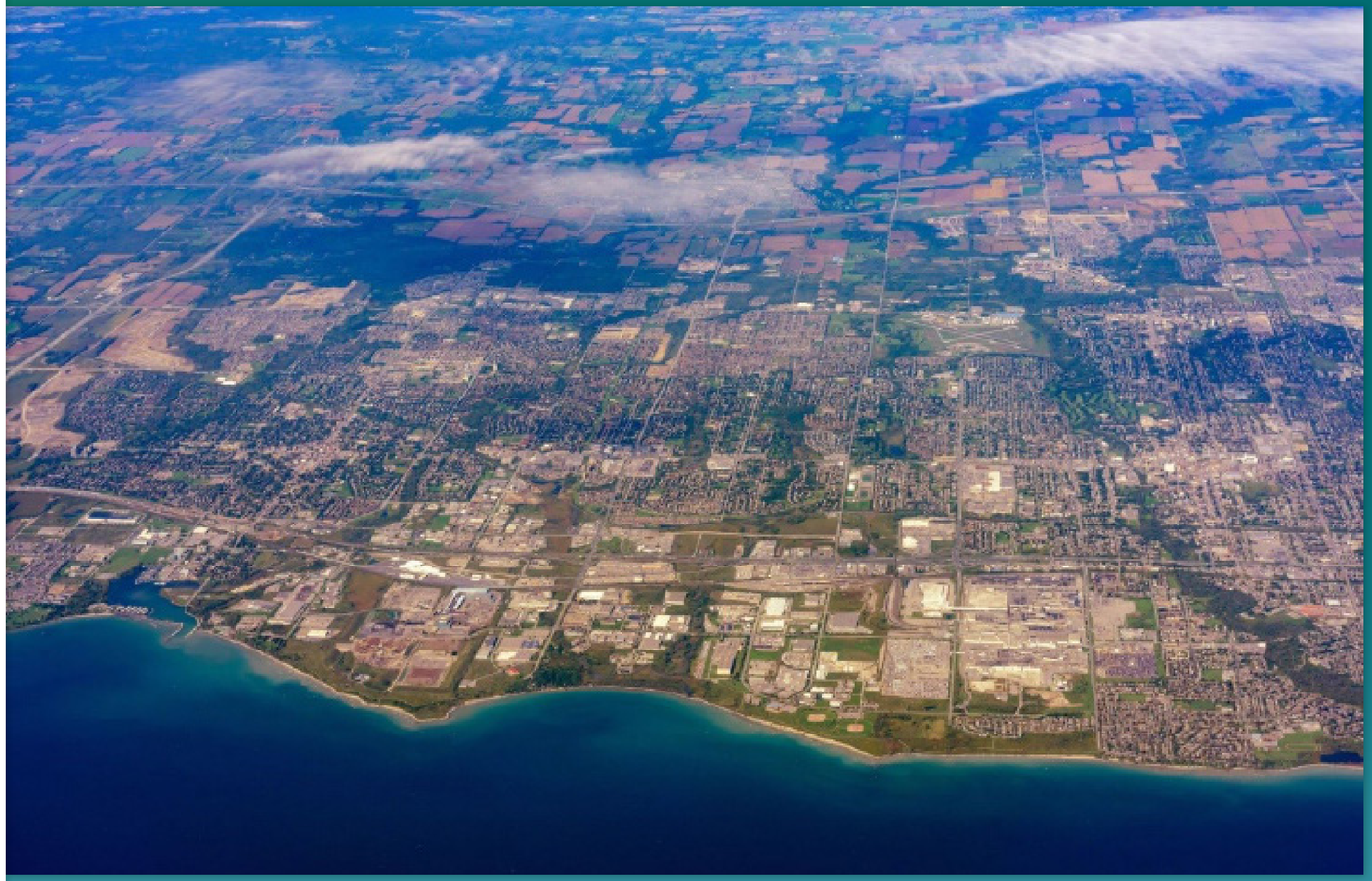
- enable consumers to better manage their electricity bills
- support businesses in their efforts to stay competitive
- drive economic prosperity
- defer building new power plants and transmission lines
- lower electricity system costs

2019-2020 Save on Energy highlights

$353 M
Invested in Energy Efficiency Projects

1.5 TWh
Total Electricity Savings

186.4 MW
Total Demand Savings



The electricity saved is equivalent to powering a city the size of Oshawa for one year

2019-2020 Save on Energy Programs

- Retrofit
- Small Business Lighting
- Energy Manager
- Process and Systems Upgrade Program
- Energy Performance Program
- Home Assistance Program
- First Nation Programs
- Local Program Fund



Retrofit program

2019-2020 RESULTS:

11,128
Businesses Supported

1.2 TWh
Total Electricity Savings

144.7 MW
Total Demand Savings

Helping business unlock energy savings and improve productivity, employee comfort and customer experience



Case Study:
Dream Office



"The IESO has been an important partner for us to achieve our sustainability goals. Leveraging the Save on Energy program enabled a pathway to smarter, more efficient and higher performing buildings."

LEE HODGKINSON
VP, Technical Services, Sustainability & ESG
Dream Office

Dream retrofitted the lighting at 11 office buildings in downtown Toronto, replacing inefficient incandescent and fluorescent bulbs and magnetic ballasts with new energy-efficient and long-lasting LED lighting.

Dream is one of Canada's leading real estate companies, focused on impact investing and sustainable buildings

2M+
Square feet of existing office space retrofitted in a major lighting program

Through direct IESO funding, Dream also hired a full-time Energy Manager to identify energy-saving capital projects and make operational improvements

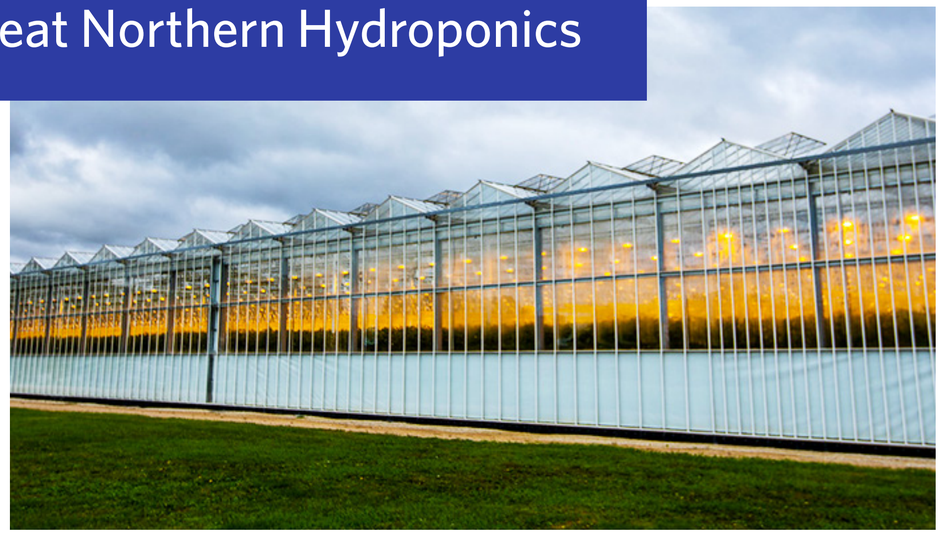
Through the incentives received from Save on Energy, Dream was able to justify a larger investment and retrofit scope, including a smart lighting control system that can be controlled using a mobile device and provides human-centric lighting

4,947 MWh
Total Electricity Savings

945 kW
Total Demand Savings

Case Study:

Great Northern Hydroponics



"We were the first tomato grower to light a crop commercially in this area. If it's a clear sky, the lighting requirement goes down to 50 per cent."

GUIDO VAN HET HOF
President and General Manager
Great Northern Hydroponics

This project is part of an energy-efficiency strategy that also includes measures such as energy curtains and an automation system to control light and heat, which adjusts according to available sunlight.

70-acre
Facility located in Kingsville, Ontario

10
Varieties of tomatoes

$150,000
Expected annual savings in energy costs by replacing half their high pressure sodium (HPS) lights with high-performance LED fixtures

Small Business Lighting program

2019-2020 RESULTS:

6,826
Businesses Supported

47.2 GWh
Total Electricity Savings

11.6 MW
Total Demand Savings

Providing small businesses with up to $2,000 to increase visibility and safety and help reduce energy costs



Energy Manager program

The Energy Manager program is the largest of its kind in North America, with trained energy-efficiency professionals helping large organizations save energy and drive Ontario's competitiveness

2019-2020 RESULTS:

195
Employed

46.6 GWh
Total Electricity Savings

5.0 MW
Total Demand Savings



Other specialized support for large energy consumers



Energy Performance Program:
performance-based incentives to drive change and deliver results



Process and Systems Upgrade:
support for complex industrial projects

Case Study:

Peel District School Board



"The IESO's energy incentive programs have helped PDSB reduce our energy costs and our carbon footprint, as well as make progress on our environmental and social equity goals."

SHAHID NAEEM P.ENG. PMP
Manager, Energy & Sustainability
Peel District School Board

The Energy and Sustainability department has been utilizing the Save on Energy incentive programs to help fund energy efficiency projects for several years, including the Energy Performance Program.

155,000
Students in kindergarten to grade 12

12 GWh
Total electricity savings over three years

259
Schools operate in the municipalities of Brampton, Caledon and Mississauga

Work included the installation of LED lighting, lighting controls and building automation system upgrades, among other things

41
Participating sites/buildings

Case Study:
Newmont Corp.



"With support from Save on Energy, we achieved an industry-first advanced electrification, and are on our way to eliminating diesel particulate matter from the underground environment. The project benefits will help us reduce energy costs and protect employee health while minimizing impacts to the environment."

JOHN MULLALLY
Country Manager and Senior Director, Sustainability and External Relations
Newmont Corp.

Borden's entire fleet of underground vehicles and heavy equipment will be either electric or battery-powered in place of conventional diesel-powered equipment and features state-of-the-art health and safety controls, and digital mining technologies and processes.

Located near Chapleau, Ontario, Newmont's Borden mine came into production in October 2019

Newmont received support from the IESO's Save on Energy programs

9 GWh

Expected annual energy savings resulting from an innovative "Ventilation On Demand" project that limits ventilation to when and where it is required

Home Assistance Program

Support for income-eligible consumers to reduce bills and increase home comfort with energy-saving upgrades at no cost to the participant

2019-2020 RESULTS:

22,859
Homes Supported

19.6 GWh
Total Electricity Savings

1.9 MW
Total Demand Savings



First Nations Conservation Program

Save on Energy offers First Nation communities specialized programs that reduce costs, improve home comfort and reduce reliance on fossil fuels

2019-2020 RESULTS:

823
Homes Supported

500 MWh
Total Electricity Savings





Support for Indigenous communities

Focused support for Indigenous communities through the First Nations Conservation Program and the Remote First Nation Energy Efficiency Pilot Program helps make electricity more affordable and improve health, safety and comfort

The Remote Pilot Program served four communities in 2019-2020:

- Kasabonika Lake First Nation
- Wunnumin Lake First Nation
- North Caribou Lake First Nation
- Sachigo Lake First Nation

12 more communities will be eligible in 2021

Local Program Fund

In addition to the suite of Save on Energy programs, communities are benefiting from tailored programming funded through the Local Program Fund and designed and delivered by local distribution companies. These programs help meet the needs of local areas and include incentives to businesses and residents for programs involving refrigeration, smart thermostats, block heater timers and more.

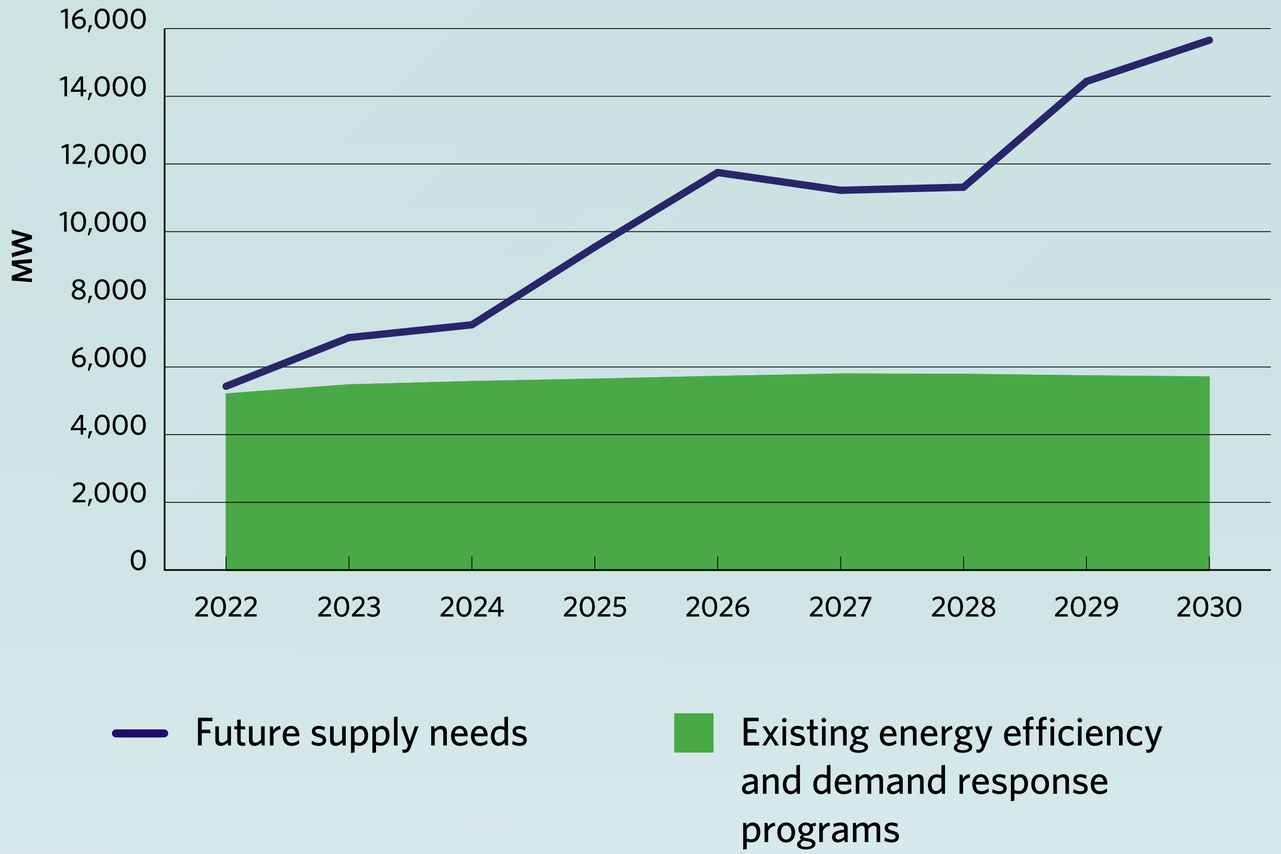
10
Local Programs Approved (2019-2020)



Why energy efficiency matters

At less than two cents per kilowatt-hour, it's Ontario's most cost-effective and enduring energy resource.

Consumers managing energy more efficiently will help address new supply needs with the potential for greater contributions as the IESO develops new approaches to energy efficiency.



Energy savings represented by the green shading is inclusive of the cumulative impacts from existing Save on Energy programs (including the current framework), Codes and Standards, Industrial Conservation Initiative (ICI), and other demand response programs.



Support for greenhouse owners

Energy efficiency is part of a broader solution to address increasing energy needs in southwestern Ontario.

The adoption of energy-efficient processes and technologies by businesses and communities has helped to reduce peak demand in the region by 10 MW.*

* Includes savings from 2015 Save on Energy programs and projects implemented with support from the IESO Grid Innovation Fund.

The current framework for energy efficiency

The IESO's 2021-2024 Conservation and Demand Management Framework will invest almost $700 million to reduce peak demand by 440 MW and consumption by 2.7 TWh.

2021-2024 CDM programs focus on those who need them most, including businesses, First Nation communities and Income-eligible residents.



The future of energy efficiency is rapidly evolving to:

- enable customer-focused solutions
- competitively procure energy efficiency to ensure cost-effectiveness
- respond to changing needs, particularly in vulnerable communities
- contribute to Ontario's post-pandemic economic recovery, particularly for small businesses
- deliver even greater electricity system resiliency and ratepayer value



Learn more today:

[Current Save on Energy programs]

[First Nations Conservation Program]

[Ontario's energy needs]

[Energy Efficiency Auction]

[Grid Innovation Fund]

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Independent Electricity System Operator

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Save on Energy

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SaveOnEnergy.ca

Appendix:
Program Progress

Save on Energy programs contributed to 1.5 TWh of electricity savings and 186.4 MW of demand reduction from 2019 to 2020. The results demonstrate the value that energy efficiency provides for the electricity system and customers, and helps inform the future of conservation and demand management programs in the province. The data below includes customer participation and net-unverified contracted costs and savings. Totals include both committed and in-service project savings.

Final reported results will be provided later this fall with the posting of the Evaluation, Measurement and Verification (EM&V) reports. The EM&V process assesses the resource savings, cost-effectiveness and market impacts of each program. The reports will be available on the IESO website.

Program	Electricity Savings (GWh)	Demand Savings (MW)	Project Costs ($M)	Incentive Costs ($M)	Participation
Retrofit Program	1,187.9	144.7	47.7	145.3	11,128 projects
Small Business Lighting Program	47.2	11.6	3.7	11.2	6,826 projects
Energy Manager Program	46.6	5.0	1.3	14.0	195+ energy managers
Process and Systems Upgrade Program	196.5	20.2	4.7	46.0	106 projects
Energy Performance Program	9.9	1.2	0.4	1.1	22 facilities
Home Assistance Program	19.6	1.9	4.8	30.2	22,859 homes
Indigenous Programs	0.5	0.0	n/a	7.1	823 homes
Local Program Fund	8.7	1.8	n/a	18.0	44,779 projects*
IESO Central Services	n/a	n/a	18.0	n/a	
Total	**1,516.9**	**186.4**	**80.6**	**272.9**	
Interim Framework CDM Plan Target	**1,429.4**	**189.5**	**80.5**	**272.9**	
Actual vs. Target	**106%**	**98%**	**100%**	**100%**	

*756 projects from Refrigeration Efficiency Program, 42,621 homes from Community Conservation Program and 1,402 projects from Swimming Pool Efficiency Program

Changes to building codes and product standards help contribute to the province's conservation savings. These savings are covered in the IESO's Annual Planning Outlook.

Support for customers

In response to the COVID-19 pandemic, in-person interactions between Save on Energy representatives and customers were temporarily suspended on March 16, 2020, including visits to home and businesses. Participants of the Home Assistance Program, Small Business Lighting, and First Nations Conservation Program were placed on wait lists and were contacted for appointments once it was safe to visit homes and businesses. Participation targets set in the CDM Plan by program were impacted due to the ongoing pandemic, but overall, the IF energy targets were achieved. New programs under the 2021-2024 CDM Framework will continue to provide opportunities to help those who need them most and can contribute to reduced energy costs as businesses and residents recover from the impacts of COVID-19.

Learn more at saveonenergy.ca/en/FAQs





2021-2024 Conservation and Demand Management Framework

Update to 2021-2024 Conservation and Demand Management Framework Program Plan

The Conservation and Demand Management (CDM) Framework Program Plan is an overview of the CDM programs to be delivered by the IESO, under the Save on Energy brand, from January 2021 to December 2024. The plan sets out forecast budgets and, where applicable, savings targets and estimated cost-effectiveness for the portfolio of CDM programs.

The IESO reports on program participation, expenditures against budget, and progress towards demand and energy savings targets, greenhouse gas emission reductions, and additional achievements of the Energy Affordability Program and on-reserve First Nations programs, on an annual and quarterly basis. The IESO has undertaken a mid-term review of the framework; this updated plan reflects the actual spending and savings to date as well as the forecasted activity for the latter part of the framework, including the implementation of the new and enhanced initiatives planned as a result of the Minister's Amending Directive of October 4, 2022.

2021-2024 CDM Framework Overview

Electricity demand in Ontario is expected to grow rapidly in the coming years as a result of economic development and electrification of various sectors of the economy. At the same time, Ontario is seeing the retirement of generation assets resulting in growing system needs. In the midst of these needs, conservation demand management (CDM) initiatives will continue to offer ratepayer value as energy efficiency continues to be counted on as a clean, reliable and cost-effective approach to ensuring the reliability of the grid.

The current suite of programs was launched in 2021, following a directive from the Government of Ontario to develop a new four-year electricity CDM framework. The 2021-2024 CDM Framework focuses on cost-effectively meeting the needs of electricity consumers and Ontario's electricity system through the delivery of programs and opportunities to enable electricity consumers – including industrial, commercial, institutional, on-reserve First Nations, low-income and income-eligible residential consumers - to improve the energy efficiency of their homes, businesses and facilities.

Since the launch of the framework in 2021, the government has taken additional action with a directive to enhance the 2021-2024 Framework. The IESO is pursuing enhancements to various Save on Energy programs (including those focused on income-eligible and First Nations customers) to address system and customer needs. This includes moving forward to launch four new or enhanced CDM programs in 2023 to increase energy efficiency contributions to emerging system needs.

Additional focus areas of the framework include:

- Achieving provincial peak demand reductions and implementing targeted approaches to address regional/local system needs using demand-side solutions as cost-effective alternatives to traditional infrastructure investments
- Leveraging competitive mechanisms to drive cost efficiencies and support innovative customer-based solutions.

Details about the various incentives offered through each program and how to apply is available at SaveOnEnergy.ca.

Budget and Targets:

The plan, which is subject to changes and revisions over time, allocates the 2021-2024 Conservation and Demand Management Framework budget of up to $1.034 billion over the suite of programs and is forecasted to achieve 725 MW of peak demand savings and 3.8 TWh of electricity savings by 2026. These savings are expected to persist for 10 to 20 years from the implementation of the measure.

Reporting:

As part of its responsibilities, the IESO will publish the verified results of its evaluation, measurement and verification (EM&V) of the savings resulting from the 2021-2024 CDM Framework, as well as costs related to its activities in support of the programs such as audits, capability building and training. The IESO will publish verified program results on an annual basis, as well as quarterly program updates, to inform the sector on the progress to meeting the targets. The 2021 Verified Results are available at IESO.ca.

Cost Effectiveness:

Program cost-effectiveness under the 2021-2024 CDM Framework for the CDM Plan is assessed using forecasted program participation and supply-side avoided costs, which estimate the cost of supplying that same amount of energy from the current electricity generation mix. The IESO Cost-Effectiveness Guide is available on the IESO website. Cost effectiveness in this plan is based on avoided supply costs developed in the IESO's 2021 Annual Planning Outlook and has been updated to reflect changes in the province's planning outlook.

2021-2024 CDM Framework Summary Tables:

The following tables outline the associated budget, electricity and demand savings, and cost-effectiveness of the programs delivered under the 2021-2024 CDM Framework.

Budget

Program	Budget ($M)			
	2021	2022	2023	2024
Retrofit Programs	57.3	78.7	93.9	122.1
Small Business	4.1	1.8	6.8	15.8
Energy Performance	2.2	2.1	8.3	8.4
Energy Management	0.4	7.0	6.0	13.6
Industrial Energy Efficiency	0.0	0.0	29.0	41.0
Targeted Greenhouse	0.0	0.0	68.0	68.0
Local Initiatives	0.0	0.0	69.6	70.1
Residential Demand Response	0.0	0.0	10.3	14.6
Total Business & Residential Programs	**64.0**	**89.6**	**291.8**	**353.5**
Energy Affordability Program	10.8	13.8	41.7	87.0
First Nations Programs	1.3	0.1	18.1	16.4
Total Support Programs	**12.0**	**13.9**	**59.8**	**103.4**
Total All Programs	**76.0**	**103.5**	**351.7**	**456.9**
Customer Education and Tools	0.0	0.3	0.4	0.5
Central Services -- Business	2.7	4.3	17.3	17.6
Central Services -- Support	0.0	0.2	1.3	1.3
Total IESO Services	**2.7**	**4.8**	**19.0**	**19.4**
Total Annual Budget	**78.7**	**108.3**	**370.7**	**476.3**
CDM Framework Total				**1,034.0**

Peak Demand and Energy Savings

	Peak Demand Savings (MW)				Energy Savings (GWh)			
Program	**2021**	**2022**	**2023**	**2024**	**2021**	**2022**	**2023**	**2024**
Retrofit Programs	49.5	89.8	96.5	127.9	322	570	359	560
Small Business	1.5	0.6	3.0	9.0	10	4	20	65
Energy Performance	1.8	1.8	8.4	8.4	16	20	50	54
Energy Management	0.1	1.8	8.0	25.1	1	15	29	96
Industrial Energy Efficiency	0.0	0.0	20.0	22.0	0.0	0.0	165	165
Targeted Greenhouse	0.0	0.0	1.4	1.3	0.0	0.0	333	333
Local Initiatives	0.0	8.0	43.0	45.4	0.0	61	161	181
Residential Demand Response	0.0	0.0	84.0	123.0	0.0	0.0	3	7
Total Business & Residential Programs	**52.9**	**101.9**	**264.3**	**362.1**	**349**	**670**	**1,120**	**1,462**
Energy Affordability Program	0.7	1.1	7.5	14.5	7	14	49	97
First Nations Programs	0.0	0.0	2.0	2.0	1	0	15	16
Total Support Programs	**0.7**	**1.1**	**9.5**	**16.5**	**8**	**14**	**64**	**113**
Total Annual Savings	**53.6**	**103.0**	**273.8**	**378.6**	**357**	**684**	**1,184**	**1,575**
CDM Framework Total				**725.0**				**3,800**

*Values may not add up precisely due to rounding

Notes:

- 2022 values are estimates based on available preliminary results and forecasts
- For Residential Demand Response the Peak Savings value is the estimated peak demand impact for the year of operation and does not persist over time. The Total Peak Demand Savings of 725 MW includes the Residential Demand Response peak impact only in 2024 to avoid double counting of savings.
- Retrofit Programs include: Retrofit Prescriptive, Midstream Lighting, Custom Lighting, and Custom Non-Lighting

- Energy Management Programs include: Energy Manager Program, Strategic Energy Management, and Existing Building Commissioning
- Targeted Greenhouse is estimated to provide 2.7 MW of provincial peak demand reduction while also reducing the Southwestern Ontario local peak demand by approximately 225 MW
- Local Initiatives include: Local Initiatives and Enhanced Local Initiatives

Program Cost-Effectiveness

	Cost Effectiveness		
Program	**Program Administrator Cost (PAC) Ratio**	**Levelized Unit Energy Costs ($/MWh)**	**Levelized Unit Capacity Costs ($'000/MW-yr)**
Retrofit Programs	2.3	25	126
Small Business	1.2	39	308
Energy Performance	2.7	20	138
Energy Management	1.6	39	143
Industrial Energy Efficiency	1.9	28	218
Targeted Greenhouse	2.3	21	n/a
Local Initiatives	1.6	41	173
Residential Demand Response	1.0	n/a	112
All Business & Residential Programs	**2.0**	**27**	**144**

Technical Notes:

- Peak demand savings are calculated in accordance with the IESO Evaluation, Measurement and Verification Protocols and Requirements. Peak demand savings and energy savings persist to 2026 and assumes the Residential Demand Response program will continue beyond the current Framework.
- Budgets are funds committed in the calendar year; energy and demand savings in a calendar year are those resulting from the budget commitment.
- Cost effectiveness is calculated in accordance with the IESO's Cost Effectiveness Guide. Avoided supply costs are based on the IESO's 2021 Annual Planning Outlook and has been updated to reflect changes in the province's planning outlook.
- As per the September 30, 2020, Ministerial Directive, the Support Programs are not required to meet cost-effectiveness thresholds as these programs provide significant non-energy benefits not captured through cost-effectiveness analysis.

Integration of Revenue Forecast with Electric Vehicle and Distributed Energy Resource Forecasts

PREPARED BY:

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Clearspring Energy Advisors LLC

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1 Executive Summary

Toronto Hydro-Electric System Limited ("Toronto Hydro" or "Company") engaged Clearspring Energy Advisors, LLC ("Clearspring") to develop a model ("Integration Model") that integrates the Company's revenue forecast for the years 2025 to 2029 with forecasts for electric vehicles ("EVs") and distributed energy resources ("DERs"). The lead model developer is Mr. Steven A. Fenrick. Mr. Fenrick has developed models, provided research reports, and expert witness testimony before the Ontario Energy Board in several applications including Toronto Hydro's previous distribution rate application. Mr. Fenrick and Clearspring have been involved in several load forecasting studies. In recent years, many of these studies have begun to incorporate EV and DER forecasting into the analysis. A copy of Mr. Fenrick's summary *curriculum vitae* is attached in Appendix B.

The objective of the Integration Model is to forecast the impact on energy and billing demand by rate class resulting from the forecasted changes in EVs and DERs. Clearspring also produced an analysis on the changes to the rate class load profiles resulting from the EV and DER forecasts that is used as an input in the cost allocation model by Toronto Hydro for rate setting purposes.

The base revenue forecast is produced by Toronto Hydro. Toronto Hydro also provided Clearspring with the historical data and forecasts for the number of EVs and the nameplate capacity of DERs on its system along with other assumptions on EV consumption and DER production. Clearspring's research focused not on the EV and DER forecasts themselves but rather on building a model that estimates the impacts of those forecasts onto the billing determinants of energy and demand.

The Integration Model and the forecasted impact of the technologies onto the base revenue forecast is discussed in Sections 1 through 8. Please see Section 9 for a summary of the cost allocation model ("CAM") analysis.

1.1 Forecast Inputs

Electric vehicles and distributed energy resources are emerging technologies that have the potential to significantly influence the energy delivered by utilities and the peak demands they need to plan for. The overall impact on the kilowatt hours ("kWhs") and the timing of charging or production is relevant for forecasting the energy and demand billing determinants. EVs will increase electricity consumption and demand, whereas DERs will tend to decrease them.

Our study uses the following forecast inputs, provided by Toronto Hydro, to forecast the impacts of EVs and DERs onto the billing components of energy and demand:

1. Light-duty electric vehicles ("LDEVs")
2. Medium-duty electric vehicles ("MDEVs")
3. Heavy-duty electric vehicles ("HDEVs")
4. Customer-owned ground-mounted and roof-mounted solar photovoltaic panels ("Renewables")
5. Customer-owned non-renewable distributed energy resources ("Non-Renewable")

6. Customer-owned energy storage resources

The base revenue forecast is produced and was provided to Clearspring by Toronto Hydro's staff.[1] It is Clearspring's understanding that the dataset used to inform the econometric models of the base forecast has an end year of 2023. Therefore, the Integration Model estimates the incremental load of these technologies from their 2023 adoption levels to the forecasted levels of the future custom incentive regulation years of 2025 to 2029.

The incremental energy and billing demand from 2023 of LDEVs, MDEVs, HDEVs, Renewable, Non-Renewable DER, and energy storage are forecasted by the Integration Model and are to be added to the base revenue forecast. The technology forecasts are required because these technologies are expected to exceed historical market adoption levels. Given this anticipated acceleration, the base revenue forecast does not satisfactorily account for the anticipated future load impacts of these technologies.

1.2 Forecast Summary of EVs and DERs

The six technology inputs can be aggregated to the base revenue forecast to determine the expected forecast after accounting for these technologies. There is a balancing of impacts between the technologies as EVs will increase energy and billing demand, whereas DERs will lower energy and billing demand.

The net forecasted impacts as a percentage of the base revenue forecast on a total system basis are provided below annually.[2] Please see Appendix A for monthly breakdowns of the energy and billing demand impacts of the technology forecasts by rate class.

Table 1: Annual Forecasted Energy and Billing Demand Impacts

Year	Incremental Energy (kWh) % Increase	Incremental Billing Demand (kVA) % Increase
2025	-0.1%	-0.3%
2026	0.3%	-0.1%
2027	0.8%	0.2%
2028	1.4%	0.6%
2029	2.1%	1.0%

The net impacts are forecasted to have a minimal impact on the base revenue forecast in 2025 but this impact is projected to increase to 2.1% for energy and 1.0% for billing demand by 2029 as EV technologies mature and market adoption accelerates.

[1] The base forecast results and methodology are described in Exhibit 3.

[2] The forecasts are integrated monthly as the base revenue forecast is monthly, but we display annual impacts here for display purposes.

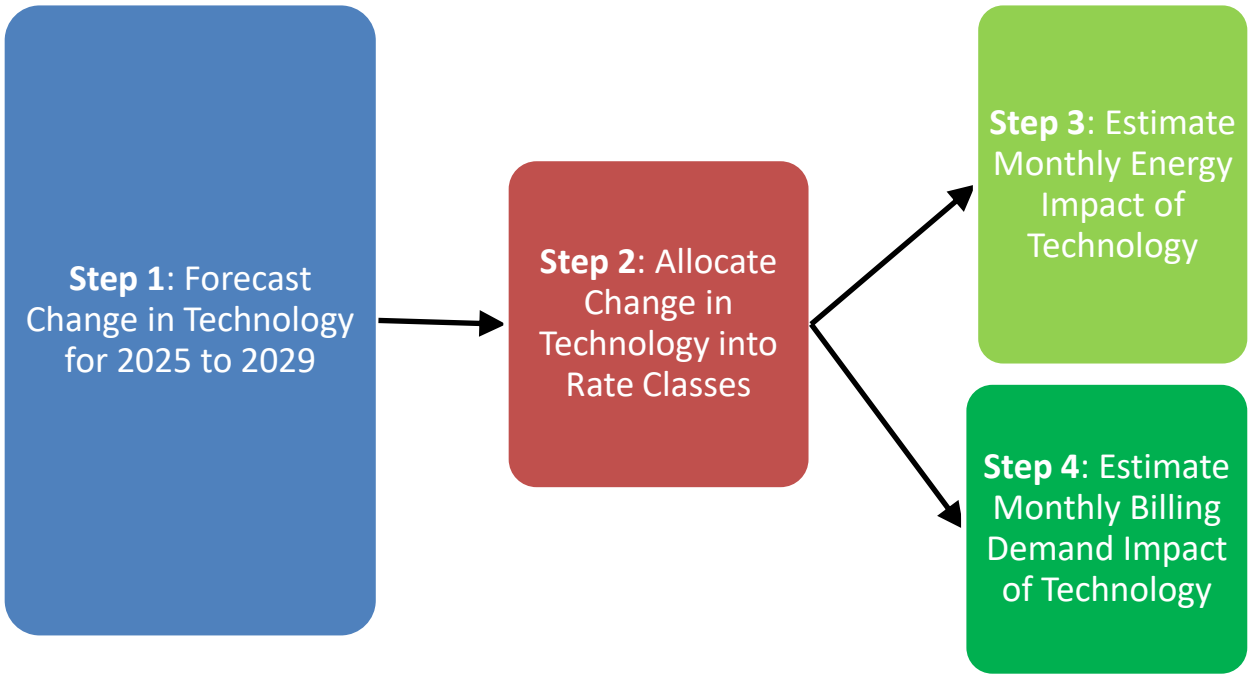
2 Integration Forecast Methodology

The 2025-2029 forecasts for the EV counts and DER nameplate capacities are provided by Toronto Hydro. The forecasts appear to be reasonable expectations of near-term technology adoption based on our experience with other clients in forecasting EVs and renewable resources.

After being provided with the forecasts for the technology counts/capacities on a system-wide basis, the Integration Model undertakes a four-step process to translate the forecasted technology count/capacity into incremental energy and billing demand.

The four steps are:

1. Calculate the change in the count/capacity forecasts from 2023.
2. Allocate the change from 2023 to a specific rate class.
3. Estimate the monthly energy (kWh) impact of each technology for the rate class in 2025 through 2029.
4. Estimate the billing demand (kVA) impact of each technology for the three rate classes that contain a billing demand component in 2025 through 2029.



2.1 Forecast Change in Technology Count

The objective of the research is to forecast how much energy and billing demand should be added to the base revenue forecast to account for the changes in the technologies included in the study. The base revenue forecast sample dataset goes through the year 2023. The load effects for each technology through 2023 will be embedded within the data used to calculate the base forecasting models.

It is, therefore, the incremental loads from their 2023 values that will drive a change to the base revenue forecast for the upcoming years of 2025 to 2029. The Integration Model calculates the change in each technology for these upcoming years from the 2023 value. These new loads will drive an incremental change in energy and billing demand to the base revenue forecast.

2.2 Allocate Incremental Change to the Rate Classes

Integrating the technology forecasts with the revenue forecast requires allocating the technology count/capacity into appropriate rate classes. The six rate classes that we allocated EVs and DERs to are:

- Residential
- CSMUR
- GS<50 kW
- GS50-999 kW
- GS 1-5 MW
- Large Use

Three of the rate classes also have a billing demand component that is calculated based on the customer's highest kVA reading during the month. The three classes with a demand rate component are the larger customer classes of GS50-999 kW, GS 1-5 MW, and Large Use. For these three rate classes, the Integration Model forecasts the impact on billing demands from the incremental additions of EVs and DERs using hourly interval data specific to individual customers within each rate class and layered on technology hourly load profiles to estimate the impact on billing demand resulting from the presence of the technology. This process is discussed further below in Step 4.

Technologies were allocated by the Integration Model to rate classes based on where the technology is most likely to be used and installed. LDEVs are more likely to be owned and charged at residences and have higher concentrations in the residential rate class, whereas HDEVs are more likely to be owned and charged at larger businesses and be concentrated in the general service or Large Use rate classes.

The following list summarizes the technology and the information used in the Integration Model to allocate each technology to the six rate classes.

Technology	Rate Class Allocation Method
Light-Duty EVs (LDEVs)	The Integration Model uses an estimate of 91% of home charging, placing 91% of LDEVs in the residential rate class.[3] The remaining 9% was apportioned to the other five rate classes based on the percentages of Level 2 EV chargers at Toronto Hydro.
Medium-Duty EVs (MDEVs)	The Integration Model uses the rate class percentage of kWh usage in the Manufacturing and Warehouse industry sector at Toronto Hydro.
Heavy-Duty EVs (HDEVs)	Same as the MDEV method but TTC kWh usage is added to the percentages.
Renewable DER	The Integration Model uses Toronto Hydro's records of customers on the net metering program and the installed kW capacity of Solar by rate class.
Non-Renewable DER	The Integration Model uses the current Non-Renewable installed nameplate capacity by rate class at Toronto Hydro.
Energy Storage	The Integration Model uses the current energy storage by nameplate capacity by rate class.

2.3 Estimate Monthly Energy Impact

Estimating the energy contribution of each technology by month to each rate class involves multiplying the expected energy required to charge the EV (or the expected production of the DER) in each month by the forecasted number of EVs/DERs in each rate class. The energy usage for EVs will vary due to temperatures impacting the battery efficiencies of the vehicles. Cold temperatures reduce battery efficiency relative to milder temperatures. The Integration Model uses a differential assumption of +/- 10 percent to adjust for this reality.[4] [5] Renewable DERs tend to produce far more energy in the summer months when sunlight is more direct than during winter months. The Integration Model inputs capacity factors for Renewables that are specific to winter and summer months. The model makes no seasonal adjustment for Non-Renewable DERs.

The average daily EV energy consumption was provided by Toronto Hydro. For LDEVs, Toronto Hydro estimated an average daily consumption of 9.4 kWh per LDEV. For MDEVs, Toronto Hydro estimated

[3] USDRIVE, Summary Report on EVs605 at Scale and the U.S. Power System, Grid Integration Tech Team and Integrated Systems Analysis Tech Team, 2019.

[4] Cold Temperatures Affect an Electric Vehicle's Driving Range - Consumer Reports

[5] May through September are designated as summer months and are reduced by 10 percent and the remaining months designated as winter months and are increased by 10 percent.

103.56 kWh per MDEV use per day. For HDEVs, Toronto Hydro estimated 319.87 kWh per HDEV use per day. Clearspring then multiplied these daily estimates by the number of days in each month and adjusted for summer/winter seasonal differences.

The Renewable and Non-Renewable average hourly capacity factors are provided by Toronto Hydro. The capacity factors are summed to estimate the daily energy production. This daily production is multiplied by the number of days in each month. The Renewable capacity factors are specific to summer and winter. Energy storage is assumed to not be actively charged and discharged, due to a current lack of evidence regarding how energy storage may be used at customer sites, and so will not have an impact on the results.

2.4 Estimate Monthly Billing Demand Impact

Three of Toronto Hydro's rate classes are billed on peak demand,[6] which is calculated as the highest kVA demand for that customer in each month. Billing demand times and amounts will vary from customer to customer and from month to month. The presence of EV charging will put upward pressure on billing demand and that pressure is a function of the number of EVs being charged at the premise, the load profiles of those EVs, and the base load profile for that customer. DERs will also have an impact on billing demand, but in the opposite direction. However, the mechanics of forecasting the change in the Integration Model are the same.

The Integration Model accounts for these factors by using hourly load profiles of the EVs and hourly capacity factors of the DERs, receiving smart meter hourly interval data for customers from Toronto Hydro from the three rate classes with a billing demand component, and then examining how the estimated number of EVs or DERs would impact billing demand for each general service customer. A load profile that estimates the hourly charging requirements (or production expectations) of an EV/DER at the general service customer premise is necessary for the analysis.[7] The load profiles are based on either Toronto Hydro analysis or external sources and are scaled to match the energy assumptions found in Step 3.[8]

[6] These rate classes are GS 50-999, GS 1-5MW, and Large Users. The remaining rate classes do not have a billing demand rate component.

[7] Since only the three general service rate classes have a billing demand component, it is only a general service load profile that needs to be calculated. Residential home charging can be ignored when estimating billing demand impacts.

[8] The LDEV hourly profile was derived from the U.S. Department of Energy Alternative Fuels Data Center. More details on the LDEV hourly profiles are provided in Section 3. The MDEV, HDEV, and DER hourly load profiles are provided by Toronto Hydro.

The following table shows the seasonal hourly load profiles used for each EV technology in the billing demand analysis of Step 4.

Table 2: Seasonal Hourly Load Profiles by EV Technology

Hour Beginning	Summer LDEV	Winter LDEV	Summer MDEV	Winter MDEV	Summer HDEV	Winter HDEV
0	0.0	0.1	4.0	4.9	29.0	35.4
1	0.0	0.0	4.1	5.0	25.2	30.8
2	0.0	0.0	3.7	4.5	19.4	23.7
3	0.0	0.0	4.4	5.3	14.8	18.0
4	0.1	0.1	4.1	5.0	14.2	17.3
5	0.1	0.2	3.6	4.4	12.1	14.8
6	0.4	0.5	3.2	3.9	12.8	15.6
7	0.9	1.1	2.9	3.5	11.9	14.6
8	1.3	1.6	0.9	1.0	2.4	3.0
9	1.3	1.5	1.0	1.2	8.7	10.6
10	0.9	1.1	1.8	2.2	10.5	12.8
11	0.7	0.8	2.1	2.5	13.7	16.7
12	0.5	0.6	4.1	5.0	11.7	14.3
13	0.4	0.5	3.7	4.5	10.3	12.6
14	0.4	0.1	3.6	4.4	10.9	13.4
15	0.4	0.4	4.8	5.8	9.5	11.6
16	0.3	0.4	5.7	7.0	9.2	11.2
17	0.2	0.3	5.2	6.3	8.8	10.7
18	0.2	0.2	4.9	6.0	6.4	7.8
19	0.1	0.1	5.0	6.1	5.8	7.1
20	0.1	0.1	5.8	7.1	4.4	5.4
21	0.1	0.1	5.8	7.1	4.0	4.9
22	0.1	0.1	5.1	6.3	3.3	4.0
23	0.0	0.1	4.0	4.9	29.0	35.4

The following table displays the capacity factors for the DERs. A value of -0.5 means that the model assumes the DER will produce 0.5 kWh for every 1 kW of nameplate capacity in that hour.[9]

Table 3: Seasonal DER Capacity Factors

Hour Beginning	Solar Summer	Solar Winter	Energy Storage Summer	Energy Storage Winter	Non-Renewable Summer	Non-Renewable Winter
0	0	0	0	0	-0.66	-0.66
1	0	0	0	0	-0.65	-0.65
2	0	0	0	0	-0.65	-0.65
3	0	0	0	0	-0.65	-0.65
4	0	0	0	0	-0.65	-0.65
5	0	0	0	0	-0.65	-0.65
6	0	0	0	0	-0.66	-0.66
7	-0.03	-0.01	0	0	-0.67	-0.67
8	-0.13	-0.02	0	0	-0.67	-0.67
9	-0.22	-0.04	0	0	-0.67	-0.67
10	-0.28	-0.05	0	0	-0.67	-0.67
11	-0.32	-0.06	0	0	-0.67	-0.67
12	-0.33	-0.06	0	0	-0.67	-0.67
13	-0.35	-0.07	0	0	-0.67	-0.67
14	-0.34	-0.06	0	0	-0.68	-0.68
15	-0.33	-0.06	0	0	-0.68	-0.68
16	-0.32	-0.06	0	0	-0.68	-0.68
17	-0.28	-0.05	0	0	-0.67	-0.67
18	-0.2	-0.04	0	0	-0.67	-0.67
19	-0.09	-0.02	0	0	-0.67	-0.67
20	0	0	0	0	-0.67	-0.67
21	0	0	0	0	-0.66	-0.66
22	0	0	0	0	-0.66	-0.66
23	0	0	0	0	-0.66	-0.66

The Integration Model inputs 2019 hourly smart meter data for customers in the three rate classes with a billing demand component. The year of 2019 is used since 2020 and subsequent hourly load data was influenced by the Covid-19 pandemic. Using this data provides 8,760 hourly observations for each customer included in the analysis. For the rate classes of GS 1-5MW and Large Use, Clearspring received and processed the 2019 interval data for all the customers in the rate classes. Given the large number of customers in the GS 50-999 rate class, Clearspring extracted a sample of the data for that rate class to conduct the billing demand impact analysis.

Using the hourly interval data, the monthly billing demands in 2019 can be calculated for every customer in the three samples. The Integration Model adds the technology load profile to the customer load profile

[9] We assume zero for energy storage as there is not yet evidence available on if energy storage will be used to avoid billing demand or other peak demands or only be used for resiliency.

in every single hour of the year. The revised customer load profile with the new technology loads added is used to calculate what the billing demand would have been if the technology had been present for each customer.

The before and after billing demand differences for every customer are averaged in each rate class to produce an estimate of how much billing demand is predicted to change from adding the technology at the customer premise. This is used to produce the average kW impact per EV (or per DER nameplate) in each month. The average kW estimate is multiplied by the forecasts for the technology count/capacity in each rate class to determine the kW impacts for each rate class by each month. The kW estimate impacts are escalated by an assumption of a 0.95 power factor to translate from kW to kVA.[10]

Layering estimated technology load profiles to customer hourly interval data enables the analysis to adjust for when each customer is actually consuming its peak demand for the month, since customers incur their billing peaks at varying times of day. This procedure enables the model to estimate how the technology will influence the load that is specific to that specific customer's peak time. This is important since EVs are not charged uniformly through the day, nor do Renewable DERs have a constant production curve.

The second advantage of this procedure is that it gives the model flexibility to adjust the peak time after the new loads are added. The addition of EV load (or DER production) may move the peak time to an entirely different hour and the analysis accounts for this possibility.[11]

The steps in the billing demand analysis can be summarized as follows:

1. Estimate the technology hourly load profile.
2. Process the 2019 hourly interval customer data in each of the three rate classes.
3. Calculate the average billing demand in each rate class in 2019.
4. Add the technology hourly load profiles to the customer hourly interval data for every hour in the year.
5. Calculate the average billing demand in each rate class after the addition of the technology hourly load profiles.
6. Take the difference in the before and after billing demand to estimate a per unit billing demand impact for the technology.
7. Multiply the per unit billing demand impact for the rate class by the forecasted number of EVs or DER nameplate capacity for that rate class.

[10] This assumption was provided to Clearspring from Toronto Hydro.

[11] The more EVs or DER capacity at a given customer site, the more likely it will be that the presence of the technology will shift the billing peak time to a different time that day or to a separate day. The Integration Model accounts for this by adding more EVs and more DER capacity for the larger rate class customers (GS 1-5 MW and Large Use) who are likely to have a higher number of EVs or DERs on site than those customers GS 50-999 kW.

3 Light-Duty Electric Vehicle Forecasts

Vehicles classified as Light-Duty Vehicles ("LDVs") weigh less than 4,535 kilograms according to Statistics Canada. There are two major types of Light-Duty Electric Vehicles ("LDEVs") on the market today: battery electric vehicles ("BEV") and plug-in hybrid electric vehicles ("PHEV"). For the purposes of the Integration Model, we do not distinguish between these two types of LDEVs. Given that most driving and the necessary charging will occur due to relatively short driving distances in or near the City of Toronto, both BEVs and PHEVs will add similar electric demand profiles to the grid.

The market adoption rate of LDEVs has grown but continues to be low relative to future expectations. The maturation of the technology, decreasing prices relative to internal combustion engines ("ICE"), and increasing charging opportunities are increasing sales of EVs as a percentage of total sales. However, recent supply chain issues caused by COVID have slowed down adoption rates.[12]

The LDEV forecast was provided by Toronto Hydro. The forecasts appear to be reasonable expectations of near-term technology adoption based on our experience with other clients in forecasting EVs.[13] Historic LDEV data was estimated by Toronto Hydro and is small compared to the future forecasts of LDEVs.

The electric vehicles will mostly be charged at the owner's residence. However, some of the LDEVs will be charged at alternate locations, typically at the place of work. The energy required for home charging will add to residential energy use and the alternate locational charging will add to the general service rate classes. Integration of the LDEVs into the revenue forecast requires an assumption on the rate class split of where charging will occur.

The Integration Model assumes 91% of LDEV charging in Toronto will occur at home.[14] The remaining 9% of LDEV charging is allocated to the other five rate classes based on Toronto Hydro data on the percentage of Level 2 EV chargers in those five rate classes.

For display purposes, the following table displays the annual LDEV counts for each rate class after allocating 91% to the residential class and divvying up the remaining 9% based on Level 2 EV chargers. The

[12] 'Unprecedented' global chip shortage pushing electric vehicle delays into years - National | Globalnews.ca.

[13] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=48-AEO2023&cases=ref2023&sourcekey=0.

[14] USDRIVE, Summary Report on EVs605 at Scale and the U.S. Power System, Grid Integration Tech Team and Integrated Systems Analysis Tech Team, 2019.

model is, however, monthly, with the LDEV counts escalating to the annual numbers in December of each year.

Table 4: Number of LDEVs by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2019	6,772	43	143	342	128	14
2020	9,023	57	190	456	171	19
2021	11,960	76	252	604	227	25
2022	19,520	123	411	986	370	41
2023	29,972	189	631	1,514	568	63
2024	43,635	275	918	2,204	826	92
2025	59,429	375	1,251	3,001	1,126	125
2026	76,411	482	1,608	3,859	1,447	161
2027	96,006	606	2,020	4,849	1,818	202
2028	117,339	741	2,469	5,926	2,222	247
2029	140,303	886	2,952	7,086	2,657	295

3.1 LDEV Energy Forecast

Estimating the energy contribution of each LDEV by month for each rate class involves multiplying the expected energy required to charge each LDEV in each month by the forecasted number of LDEVs in each rate class. The charging energy required is a function of the average kilometres ("km") driven each day and the average EV efficiency factor. The EV efficiency factor measures how many kilowatt hours ("kWh") of electricity are required per kilometre of driving.

$$kWh\ per\ day\ for\ LDEV = average\ km\ driven\ per\ day\ (km) * EV\ efficiency\ factor\ (kWh\ /\ km)$$

Toronto Hydro estimated that an average Toronto LDEV driver will average 40.3 km/day. The EV efficiency factor is estimated by Toronto Hydro at .233 kWh/km. Multiplying these two components together produces the estimate of each LDEV requiring 9.4 kWh per day, which appears reasonable to Clearspring based on our experience and other external sources.[15]

[15]https://ecocostsavings.com/average-electric-car-kwh-per-mile/.

The following table displays the forecasted annual LDEV energy contribution for each rate class.

Table 5: Annual LDEV Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2019	2,168,435	13,689	45,630	109,512	41,067	4,563
2020	27,822,885	175,641	585,471	1,405,131	526,924	58,547
2021	36,954,088	233,285	777,617	1,866,281	699,855	77,762
2022	55,886,731	352,804	1,176,013	2,822,430	1,058,411	117,601
2023	87,660,678	553,387	1,844,625	4,427,100	1,660,162	184,462
2024	130,109,415	821,359	2,737,865	6,570,875	2,464,078	273,786
2025	181,707,014	1,147,087	3,823,622	9,176,693	3,441,260	382,362
2026	238,948,815	1,508,445	5,028,149	12,067,558	4,525,334	502,815
2027	303,011,373	1,912,861	6,376,204	15,302,889	5,738,583	637,620
2028	374,527,806	2,364,333	7,881,109	18,914,661	7,092,998	788,111
2029	451,895,366	2,852,741	9,509,138	22,821,931	8,558,224	950,914

The forecasts are translated into monthly forecasts using the monthly LDEV counts found in Table 4 and multiplying the average daily kWh charging by the number of days in each month. An additional monthly adjustment is made to account for the reality that EV batteries perform worse in cold temperatures.[16] To adjust for this, the Integration Model adds 10 percent to the energy totals in winter months and subtracted 10 percent to the energy totals in summer months.[17]

To integrate the LDEV forecasted energy into the revenue forecast, the incremental load of LDEVs for each rate class from their 2023 adoption levels are added to the revenue forecast. The incremental load in each month in 2025 to 2029 is the difference between that month's forecasted LDEV load and the same month in 2023.

For display purposes, the following table displays the annual LDEV incremental energy impact from 2023 levels for each rate class. The model is, however, monthly. Also shown is the average increase in LDEV energy from the base revenue forecast for each rate class.

Table 6: Annual Incremental Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	94,046,336	593,699	1,978,997	4,749,593	1,781,097	197,900
2026	151,288,137	955,057	3,183,524	7,640,458	2,865,172	318,352
2027	215,350,695	1,359,474	4,531,579	10,875,789	4,078,421	453,158
2028	286,867,128	1,810,945	6,036,484	14,487,561	5,432,835	603,648
2029	364,234,688	2,299,354	7,664,513	18,394,831	6,898,062	766,451

[16] https://cleantechnica.com/2022/12/19/how-temperature-affects-electric-car-range-charging-performance/.

[17] Summer months are defined as May through September with the remaining months designated as winter months.

3.2 LDEV Billing Demand Forecast

A load profile that estimates the hourly charging requirements of an LDEV at the general service customer premise is necessary to forecast the impact of LDEVs on billing demand.[18] Most of this charging will be from commuters who are working at the place of business. The Integration Model uses a load profile that estimates "at work" charging behavior per LDEV from the U.S. Department of Energy (DOE) Alternative Fuels Data Center.[19]

The DOE profile is scaled to match the LDEV energy charging assumptions that were provided to Clearspring by Toronto Hydro. The model scales the profile to match the energy use estimate of 9.4 kWh and adjusts for summer and winter differences in battery efficiency. The winter and summer LDEV load profiles for "at work" charging used in the analysis are provided in the following table.

[18] Since only the three general service rate classes have a billing demand component, it is only a general service load profile that needs to be calculated. Residential home charging can be ignored when estimating billing demand impacts.

[19] The DOE profile tool can be found here: https://afdc.energy.gov/evi-pro-lite/load-profile/. The profile used a location of Chicago, which is also on a Great Lake and has similar weather to Toronto, and 25 commuting miles.

Table 7: Summer and Winter LDEV Work Charging Load Profile

Hour	Summer LDEV Load	Winter LDEV Load
0	0.04	0.05
1	0.03	0.04
2	0.03	0.03
3	0.02	0.02
4	0.05	0.06
5	0.14	0.18
6	0.41	0.50
7	0.88	1.08
8	1.33	1.62
9	1.25	1.53
10	0.94	1.15
11	0.65	0.80
12	0.47	0.57
13	0.42	0.52
14	0.40	0.14
15	0.35	0.43
16	0.29	0.35
17	0.22	0.27
18	0.16	0.19
19	0.12	0.14
20	0.08	0.10
21	0.06	0.07
22	0.05	0.07
23	0.05	0.06

For display purposes, the following table displays the annual LDEV incremental billing demand impact from 2023 levels for each rate class. The model is, however, monthly.

Table 8: Incremental Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	10,594	4,076	412
2026	17,043	6,557	663
2027	24,260	9,334	944
2028	32,316	12,434	1,258
2029	41,032	15,788	1,597

Shown in the following table is the average percentage increase in LDEV billing demand from the base revenue forecast for each rate class.

Table 9: LDEV Percentage Increase from Base Demand by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.0%
2026	0.1%	0.1%	0.0%
2027	0.1%	0.1%	0.0%
2028	0.1%	0.1%	0.0%
2029	0.2%	0.2%	0.0%

4 Medium-Duty and Heavy-Duty Electric Vehicle Forecasts

Vehicles classified as Medium-Duty Vehicles ("MDVs") weigh between 4,535 and 11,793 kilograms according to Statistics Canada. Vehicles classified as Heavy-Duty Vehicles ("HDVs") weigh more than 11,793 kilograms. Medium-Duty Electric Vehicles ("MDEVs") and Heavy-Duty Electric Vehicles ("HDEVs") are forecasted separately by Toronto Hydro.

The MDEV and HDEV count forecast was provided to Clearspring by Toronto Hydro. The forecasts appear to be reasonable expectations of near-term technology adoption based on our experience with other clients in forecasting EVs.

The table below provides the historic and forecasted MDEVs and HDEVs in Toronto.

Table 10: Forecast for the Number of MDEVs and HDEVs in Toronto

Year	Total MDEVs in Toronto	Total HDEVs in Toronto
2022	0	0
2023	82	147
2024	210	479
2025	413	964
2026	674	1,560
2027	1,007	2,284
2028	1,502	3,095
2029	2,120	3,908

The MDEVs and HDEVs count forecasts for Toronto Hydro are allocated to the rate classes. The Integration Model uses the Manufacturing and Warehouse kWh usage percentages by rate class provided by Toronto Hydro to allocate the MDEVs by rate class. For the HDEV rate class allocations, the model uses the same Manufacturing and Warehouse kWh usage percentages plus the Toronto Transit Commission ("TTC") garage kWh usage. The TTC garage usage, which was provided by Toronto Hydro, and was added to the HDEV allocations because of TTC's Green Bus Program, is forecasted to purchase and add several electric buses to its fleet, which would be classified as HDEVs.

For display purposes, the following table displays the annual MDEV counts for each rate class. The model is, however, monthly with the MDEV and HDEV counts escalating to the annual numbers in December of each year.

Table 11: Forecasted Number of MDEVs by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-000 kW	GS 1-5 MW	LU
2022	0	0	0	0	0	0
2023	0	0	6	28	25	22
2024	0	0	16	73	64	56
2025	0	0	32	144	127	111
2026	0	0	51	235	207	181
2027	0	0	77	351	309	270
2028	0	0	115	523	461	403
2029	0	0	162	739	651	569

The following table displays the annual HDEV counts for each rate class.

Table 12: Forecasted Number of HDEVs by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-000 kW	GS 1-5 MW	LU
2022	0	0	0	0	0	0
2023	0	0	11	51	45	40
2024	0	0	36	166	145	132
2025	0	0	72	334	293	266
2026	0	0	116	540	474	430
2027	0	0	170	791	693	630
2028	0	0	230	1,072	940	854
2029	0	0	290	1,353	1,186	1,078

4.1 MDEV & HDEV Energy Forecast

Estimating the energy contribution of each MDEV and HDEV by month for each rate class involves multiplying the expected energy required to charge each vehicle in each month by the forecasted number of MDEV and HDEVs in each rate class. The Integration Model assumes that MDEVs require 103.56 kWh per day and HDEVs require 319.87 kWh of electricity per day. Both of these assumptions were provided from Toronto Hydro.

The following table displays the forecasted annual MDEV energy contribution for each rate class.

Table 13: Annual MDEV Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2022	0	0	0	0	0	0
2023	0	0	92,292	421,300	371,586	324,412
2024	0	0	315,744	1,441,332	1,271,252	1,109,863
2025	0	0	669,510	3,056,232	2,695,591	2,353,377
2026	0	0	1,159,758	5,294,152	4,669,433	4,076,634
2027	0	0	1,787,311	8,158,854	7,196,095	6,282,528
2028	0	0	2,667,883	12,178,551	10,741,461	9,377,799
2029	0	0	3,843,691	17,545,972	15,475,517	13,510,852

The following table displays the forecasted annual HDEV energy contribution for each rate class.

Table 14: Annual HDEV Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2022	0	0	0	0	0	0
2023	0	0	498,747	2,326,961	2,039,258	1,853,621
2024	0	0	2,052,675	9,576,983	8,392,895	7,628,877
2025	0	0	4,661,915	21,750,688	19,061,454	17,326,262
2026	0	0	8,091,377	37,751,224	33,083,701	30,072,043
2027	0	0	12,274,950	57,270,151	50,189,328	45,620,519
2028	0	0	17,126,372	79,905,004	70,025,630	63,651,094
2029	0	0	22,234,906	103,739,441	90,913,202	82,637,239

The energy forecasts are translated into monthly forecasts using the monthly MDEV and HDEV counts found in Table 11 and multiplying the average daily kWh charging by the number of days in each month. Similar to LDEVs, an additional monthly adjustment is made to account for the reality that EV batteries perform worse in cold temperatures. To adjust for this, the Integration Model adds ten percent to the energy totals in winter months and subtracted ten percent to the energy totals in summer months.

To integrate the MDEV/HDEV forecasted energy into the revenue forecast, the incremental load of MDEV and HDEVs for each rate class from their 2023 adoption levels are added to the revenue forecast. The incremental load in each month in 2025 to 2029 is the difference between that month's forecasted MDEV/HDEV load and the same month in 2023. The incremental load is used since the base revenue forecast uses a dataset through 2023 and, therefore, already has the 2023 MDEV/HDEV load embedded into the forecast.

Tables 16 and 17 below display the annual MDEV and HDEV incremental energy impacts from 2023 levels for each rate class. The model is, however, monthly.

Table 15: Annual MDEV Incremental Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0	0	577,219	2,634,931	2,324,005	2,028,965
2026	0	0	1,067,467	4,872,852	4,297,847	3,752,222
2027	0	0	1,695,020	7,737,553	6,824,509	5,958,116
2028	0	0	2,575,591	11,757,251	10,369,875	9,053,387
2029	0	0	3,751,400	17,124,672	15,103,931	13,186,440

Table 16: Annual HDEV Incremental Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0	0	4,163,168	19,423,726	17,022,196	15,472,641
2026	0	0	7,592,630	35,424,263	31,044,442	28,218,421
2027	0	0	11,776,202	54,943,190	48,150,070	43,766,898
2028	0	0	16,627,625	77,578,043	67,986,372	61,797,472
2029	0	0	21,736,159	101,412,480	88,873,944	80,783,617

Shown in Tables 18 and 19 are the average percentage increase in MDEV and HDEV energy from the base revenue forecast for each rate class.

Table 17: Annual Percentage MDEV Impact from Revenue Base Forecast by Rate Class

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%
2026	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%
2027	0.0%	0.0%	0.1%	0.1%	0.2%	0.3%
2028	0.0%	0.0%	0.1%	0.1%	0.3%	0.5%
2029	0.0%	0.0%	0.2%	0.2%	0.4%	0.7%

Table 18: Annual Percentage HDEV Impact from Revenue Base Forecast by Rate Class

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.2%	0.2%	0.4%	1.0%
2026	0.0%	0.0%	0.3%	0.4%	0.8%	1.8%
2027	0.0%	0.0%	0.5%	0.6%	1.2%	2.9%
2028	0.0%	0.0%	0.7%	0.8%	1.7%	4.2%
2029	0.0%	0.0%	0.9%	1.1%	2.3%	5.8%

4.2 MDEV & HDEV Billing Demand Forecast

MDEVs and HDEVs will put upward pressure on Toronto Hydro's three rate classes with billing demand, and that pressure is a function of the number of EVs being charged at the premise, the load profiles of those EVs, and the base load profile for that customer. The model accounts for these factors by using hourly load profiles of the MDEV and HDEVs, analyzing smart meter interval data for customers from Toronto Hydro, and then examining how the estimated number of MDEV and HDEVs would impact billing demand for each general service customer.

The following table displays the hourly load profile used for MDEVs and HDEVs for both the summer and winter. This load profile is layered onto the customer-specific hourly interval data to calculate the difference in the before and after technology billing demands.

Table 19: Summer and Winter MDEV and HDEV Charging Load Profiles

Hour Beginning	Summer MDEV	Winter MDEV	Summer HDEV	Winter HDEV
0	4.023	4.917	28.98	35.42
1	4.113	5.027	25.236	30.844
2	3.663	4.477	19.35	23.65
3	4.356	5.324	14.76	18.04
4	4.104	5.016	14.166	17.314
5	3.6	4.4	12.141	14.839
6	3.177	3.883	12.798	15.642
7	2.862	3.498	11.907	14.553
8	0.855	1.045	2.421	2.959
9	1.008	1.232	8.694	10.626
10	1.8	2.2	10.467	12.793
11	2.052	2.508	13.653	16.687
12	4.086	4.994	11.673	14.267
13	3.663	4.477	10.332	12.628
14	3.564	4.356	10.944	13.376
15	4.761	5.819	9.459	11.561
16	5.697	6.963	9.171	11.209
17	5.166	6.314	8.784	10.736
18	4.932	6.028	6.417	7.843
19	5.013	6.127	5.823	7.117
20	5.778	7.062	4.419	5.401
21	5.805	7.095	4.032	4.928
22	5.13	6.27	3.285	4.015
23	4.023	4.917	28.98	35.42

For display purposes, the following table displays the annual MDEV incremental billing demand impact from 2023 levels for each rate class.

Table 20: MDEV Incremental Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2023	-	-	-
2024	1,996	1,584	1,408
2025	5,156	4,091	3,637
2026	9,538	7,567	6,721
2027	15,147	12,015	10,668
2028	23,014	18,257	16,213
2029	33,525	26,592	23,607

For display purposes, the following table displays the annual HDEV incremental billing demand impact from 2023 levels for each rate class.

Table 21: HDEV Incremental Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2023	-	-	-
2024	14,434	12,280	13,100
2025	38,730	32,947	35,149
2026	70,696	60,137	64,160
2027	109,695	93,310	99,554
2028	154,940	131,796	140,617
2029	202,618	172,350	183,889

Shown in the following table is the average percentage increase in MDEV billing demand from the base revenue forecast for each rate class.

Table 22: MDEV Percentage Demand Impact from Revenue Forecast by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.1%
2026	0.0%	0.1%	0.2%
2027	0.1%	0.2%	0.3%
2028	0.1%	0.2%	0.5%
2029	0.2%	0.3%	0.7%

Shown in the following table is the average percentage increase in HDEV billing demand from the base revenue forecast for each rate class.

Table 23: HDEV Percentage Demand Impact from Revenue Forecast by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	0.2%	0.4%	0.9%
2026	0.3%	0.7%	1.7%
2027	0.5%	1.2%	2.7%
2028	0.7%	1.7%	4.0%
2029	1.0%	2.2%	5.5%

5 Renewable DER Forecast

Toronto Hydro provided the Renewable nameplate capacity forecast, and historical, data to Clearspring. It is Clearspring's understanding that the Renewable forecast is entirely driven by solar. The forecasts appear to be reasonable expectations of near-term technology adoption based on our experience with other clients in forecasting solar resources.[20]

The table below provides the 2022 to 2029 forecast for the Renewable capacity for Toronto Hydro.

Table 24: Annual Renewable Capacity Forecast by Year

Year	Total Renewable Nameplate kW
2022	100,366
2023	110,610
2024	117,616
2025	127,593
2026	139,278
2027	152,669
2028	167,768
2029	184,574

The Renewable capacity forecasted for Toronto Hydro is allocated to the different rate classes. The Integration Model uses the 2022 participation percentages in Toronto Hydro's net metering program by rate class to estimate the rate class allocations.

The following table displays the annual Renewable Capacity for each rate class.

Table 25: Forecasted Renewable Capacity by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-000 kW	GS 1-5 MW	LU
2022	14,262	0	11,141	66,302	8,662	0
2023	15,718	0	12,278	73,069	9,546	0
2024	16,713	0	13,055	77,697	10,150	0
2025	18,131	0	14,163	84,288	11,011	0
2026	19,791	0	15,460	92,007	12,020	0
2027	21,694	0	16,946	100,853	13,175	0
2028	23,840	0	18,622	110,828	14,478	0
2029	26,228	0	20,488	121,930	15,929	0

5.1 Renewable Energy Forecast

Renewables are not able to produce the same amount of electricity continuously and consistently during every hour of the day. For instance, solar will produce substantially more electricity during summer

[20] https://www.iea.org/reports/renewables-2022/renewable-electricity#abstract

months and during the mid-day while sunlight is most direct. Toronto Hydro provided the hourly capacity factors to Clearspring for both summer and winter months. The table below provides the hourly capacity factors of a one kW nameplate capacity solar array for both summer and winter.

Table 26: Summer and Winter Renewable Production Hourly Profiles

Hour Beginning	Summer	Winter
0	0	0
1	0	0
2	0	0
3	0	0
4	0	0
5	0	0
6	0	0
7	-0.03	-0.01
8	-0.13	-0.02
9	-0.22	-0.04
10	-0.28	-0.05
11	-0.32	-0.06
12	-0.33	-0.06
13	-0.35	-0.07
14	-0.34	-0.06
15	-0.33	-0.06
16	-0.32	-0.06
17	-0.28	-0.05
18	-0.20	-0.04
19	-0.09	-0.02
20	0	0
21	0	0
22	0	0
23	0	0

The hourly capacity factors can be summed to estimate the average production per day of a one kW solar array.[21] In the summer, the sum of the production factors is -3.22, meaning that for every one kW nameplate capacity, a solar array will have an average production of 3.22 kWh's during the summer months. In the winter, the sum of the production factors is -0.60, meaning a 0.6 kWh production expectation during winter months. The Integration Model multiplies the average daily production by the number of days in each month to estimate the energy contribution of Renewables based on the estimated nameplate capacity in each rate class.

[21] These production factors are for "average" summer and winter days. Cloudy days will have lower production and clear days will have higher production.

The table below provides the annual Renewable energy contribution by rate class and year. The annual totals are provided below for display purposes; however, the model disaggregates the forecasts into monthly contributions to match and integrate with the base revenue forecast.

Table 27: Annual Renewable Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LS
2022	-8,761,942	0	-6,844,303	-40,732,855	-5,321,292	0
2023	-9,353,911	0	-7,306,714	-43,484,823	-5,680,806	0
2024	-10,093,938	0	-7,884,779	-46,925,089	-6,130,238	0
2025	-10,859,950	0	-8,483,142	-50,486,158	-6,595,452	0
2026	-11,824,330	0	-9,236,457	-54,969,403	-7,181,138	0
2027	-12,939,083	0	-10,107,236	-60,151,711	-7,858,148	0
2028	-14,204,210	0	-11,095,477	-66,033,082	-8,626,484	0
2029	-15,619,711	0	-12,201,181	-72,613,517	-9,486,144	0

To integrate the Renewable forecasted energy into the revenue forecast, the incremental production of Renewables for each rate class from their 2023 adoption levels are added to the revenue forecast. The incremental production forecasted in each month in 2025 to 2029 is the difference between that month's forecasted production and the same month in 2023. The incremental production is used since the base revenue forecast uses a dataset through 2023 and, therefore, already has the 2023 Renewable production embedded into the forecast.

Table 28: Annual Incremental Renewable Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	-1,818,949	0	-1,420,854	-8,456,000	-1,104,682	0
2026	-2,783,328	0	-2,174,169	-12,939,244	-1,690,368	0
2027	-3,898,081	0	-3,044,947	-18,121,552	-2,367,378	0
2028	-5,163,208	0	-4,033,189	-24,002,924	-3,135,713	0
2029	-6,578,709	0	-5,138,893	-30,583,358	-3,995,374	0

Shown below is the average percentage impact from Renewables from the base revenue forecast for each rate class.

Table 29: Renewable Energy Percentage of Base Forecast by Rate Class

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	-0.1%	-0.1%	0.0%	0.0%
2026	-0.1%	0.0%	-0.1%	-0.1%	0.0%	0.0%
2027	-0.1%	0.0%	-0.1%	-0.1%	-0.1%	0.0%
2028	-0.1%	0.0%	-0.2%	-0.3%	-0.1%	0.0%
2029	-0.1%	0.0%	-0.2%	-0.3%	-0.1%	0.0%

5.2 Renewable Billing Demand Forecast

Renewables will put downward pressure on Toronto Hydro's three rate classes regarding billing demand, and that pressure is a function of the nameplate capacity producing at the premise, the production profiles of those Renewables (provided in the table in the prior subsection), and the base load profile for that customer. The Integration Model accounts for these factors by using the hourly Renewable capacity factors, analyzing smart meter interval data for customers from Toronto Hydro, and then examining how the estimated production of the Renewables would impact billing demand for each general service customer.

The following table provides the forecasted incremental billing demand reductions by rate class of Renewables.[22]

Table 30: Incremental Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	(12,821)	(2,816)	-
2026	(19,614)	(4,309)	-
2027	(27,465)	(6,034)	-
2028	(36,375)	(7,991)	-
2029	(46,344)	(10,182)	-

Shown below is the average percentage impact from Renewables from the base revenue forecast for each rate class.

Table 31: Renewable Billing Demand Percentage of Base Forecast by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	-0.1%	0.0%	0.0%
2026	-0.1%	0.0%	0.0%
2027	-0.1%	-0.1%	0.0%
2028	-0.2%	-0.1%	0.0%
2029	-0.2%	-0.1%	0.0%

[22] The forecast is monthly but annual numbers are provided for display purposes.

6 Non-Renewable DER Forecast

Toronto Hydro provided the behind-the-meter Non-Renewable nameplate capacity forecast and historical data to Clearspring. It is Clearspring's understanding that these Non-Renewable DERs will be actively dispatched by the IESO. The forecasts increase substantially until 2024 and then grow by less than two percent thereafter.

The table below provides the 2022 to 2029 forecast for Non-Renewable capacity for Toronto Hydro.

Table 32: Annual Non-Renewable Capacity Forecast by Year

Year	Total Nameplate kW
2022	170,013
2023	198,186
2024	212,056
2025	215,566
2026	218,717
2027	221,597
2028	224,297
2029	226,817

The Non-Renewable capacity forecasted for Toronto Hydro is then allocated to the different rate classes. The Integration Model uses the current nameplate capacity of non-renewable generation by rate class to estimate the rate class allocations.

For display purposes, the following table displays the annual Non-Renewable capacity for each rate class.

Table 33: Forecasted Non-Renewable Capacity by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-000 kW	GS 1-5 MW	LU
2022	0	0	95	32,026	70,748	67,145
2023	0	0	110	37,333	82,471	78,271
2024	0	0	118	39,946	88,243	83,749
2025	0	0	120	40,607	89,704	85,135
2026	0	0	122	41,201	91,015	86,379
2027	0	0	123	41,743	92,214	87,517
2028	0	0	125	42,252	93,337	88,583
2029	0	0	126	42,726	94,386	89,579

6.1 Non-Renewable DER Energy Forecast

Unlike Renewables, Non-Renewables can continuously and consistently produce the same amount of electricity in any hour of the day and are not significantly impacted by winter/summer conditions. Toronto Hydro provided the capacity factors by hour for the existing Non-Renewable generation on its system that

are dispatched by the IESO. These capacity factors are for an average day and are the same for both winter and summer months.

The table below provides the hourly production factors of a one kW Non-Renewable nameplate capacity.

Table 34: Non-Renewable Production Hourly Profile

Hour Beginning	Non-Renewable
0	-0.66
1	-0.65
2	-0.65
3	-0.65
4	-0.65
5	-0.65
6	-0.66
7	-0.67
8	-0.67
9	-0.67
10	-0.67
11	-0.67
12	-0.67
13	-0.67
14	-0.68
15	-0.68
16	-0.68
17	-0.67
18	-0.67
19	-0.67
20	-0.67
21	-0.66
22	-0.66
23	-0.66

The hourly capacity factors can be summed to estimate the average production per day of a one kW Non-Renewable resource. The sum of the production factors is -15.96. This means that on an average day, for every one kW of Non-Renewable nameplate capacity, 15.96 kWh's will be generated. The Integration Model multiplies this sum by the number of days in each month to estimate the energy contribution of Non-Renewables based on the estimated nameplate capacity in each rate class. The table below provides the annual Non-Renewable energy contribution by rate class and year.

The annual Non-Renewable energy contributions by rate class are provided below for display purposes; however, the model disaggregates the forecasts into monthly contributions to match and integrate with the base revenue forecast.

Table 35: Annual Non-Renewable Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LS
2022	0	0	-550,179	-186,298,506	-411,547,347	-390,586,651
2023	0	0	-600,616	-203,377,196	-449,275,454	-426,393,211
2024	0	0	-666,709	-225,757,248	-498,714,663	-473,314,410
2025	0	0	-693,400	-234,795,282	-518,680,357	-492,263,223
2026	0	0	-704,142	-238,432,497	-526,715,237	-499,888,875
2027	0	0	-713,875	-241,728,342	-533,996,005	-506,798,824
2028	0	0	-722,892	-244,781,589	-540,740,858	-513,200,151
2029	0	0	-731,325	-247,637,294	-547,049,324	-519,187,318

To integrate the Non-Renewable forecasted energy into the revenue forecast, the incremental production of Non-Renewables for each rate class from their 2023 adoption levels are added to the revenue forecast. The incremental production forecasted in each month in 2025 to 2029 is the difference between that month's forecasted production and the same month in 2023.

Table 36: Annual Incremental Non-Renewable Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0	0	-92,784	-31,418,086	-69,404,903	-65,870,012
2026	0	0	-103,526	-35,055,300	-77,439,783	-73,495,664
2027	0	0	-113,259	-38,351,145	-84,720,552	-80,405,613
2028	0	0	-122,276	-41,404,393	-91,465,404	-86,806,940
2029	0	0	-130,709	-44,260,098	-97,773,870	-92,794,107

Shown below is the average percentage impact from Non-Renewables from the base revenue forecast for each rate class.

Table 37: Non-Renewable Energy Percentage of Base Forecast by Rate Class

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.0%	-0.3%	-1.7%	-4.1%
2026	0.0%	0.0%	0.0%	-0.4%	-1.9%	-4.6%
2027	0.0%	0.0%	0.0%	-0.4%	-2.1%	-5.2%
2028	0.0%	0.0%	0.0%	-0.4%	-2.3%	-5.8%
2029	0.0%	0.0%	0.0%	-0.5%	-2.5%	-6.6%

6.2 Non-Renewable DER Demand Forecast

Non-Renewables will put downward pressure on billing demand and is a function of the nameplate capacity producing at the premise, the production profiles of those Non-Renewables (provided in the table in the prior subsection), and the base load profile for every customer. The Integration Model accounts for these factors by using the hourly Non-Renewable capacity factors provided by Toronto Hydro, receiving smart meter interval data for customers from Toronto Hydro, and then analyzing how the estimated production of the Non-Renewables would impact billing demand for each general service customer.

The following table provides the forecasted incremental billing demand reductions by rate class of Non-Renewables.[23]

Table 38: Incremental Non-Renewable Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	-43,383	-95,783	-90,780
2026	-48,397	-106,855	-101,272
2027	-52,941	-116,887	-110,778
2028	-57,150	-126,180	-119,585
2029	-61,087	-134,871	-127,822

Shown below is the average percentage impact from Non-Renewables from the base revenue forecast for each rate class.

Table 39: Non-Renewable Billing Demand Percentage of Base Forecast by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	-0.2%	-1.1%	-2.3%
2026	-0.2%	-1.3%	-2.5%
2027	-0.2%	-1.4%	-2.9%
2028	-0.3%	-1.5%	-3.2%
2029	-0.3%	-1.7%	-3.6%

[23] The forecast is monthly but we show annual numbers for display purposes.

7 Energy Storage Forecast

Energy storage can be used for multiple purposes. One viable option may be for back-up power when outages are encountered. Another possible purpose is to reduce billing peaks or shift energy use from on-peak to off-peak. If energy storage is actively used to reduce billing demands, this could have the impact of reducing demands but increasing energy use at the premise through energy losses that result from the inefficiency in the discharge/charging cycle. Under the back-up option, there would be minimal impacts on demand and energy.

It is unclear how energy storage will be used in the future on Toronto Hydro's system. There is no evidence yet that reveals how energy storage may be used on the system and if its presence will result in meaningful energy or billing demand changes. Given this current lack of evidence, it is assumed that energy storage will only be used for back-up power through the forecast period meaning that energy storage is assumed to have zero kWh and zero kW impacts.

The forecasted energy storage nameplate kW, provided by Toronto Hydro, are presented in Table 40 below.

Table 40: Annual Energy Storage Nameplate kW

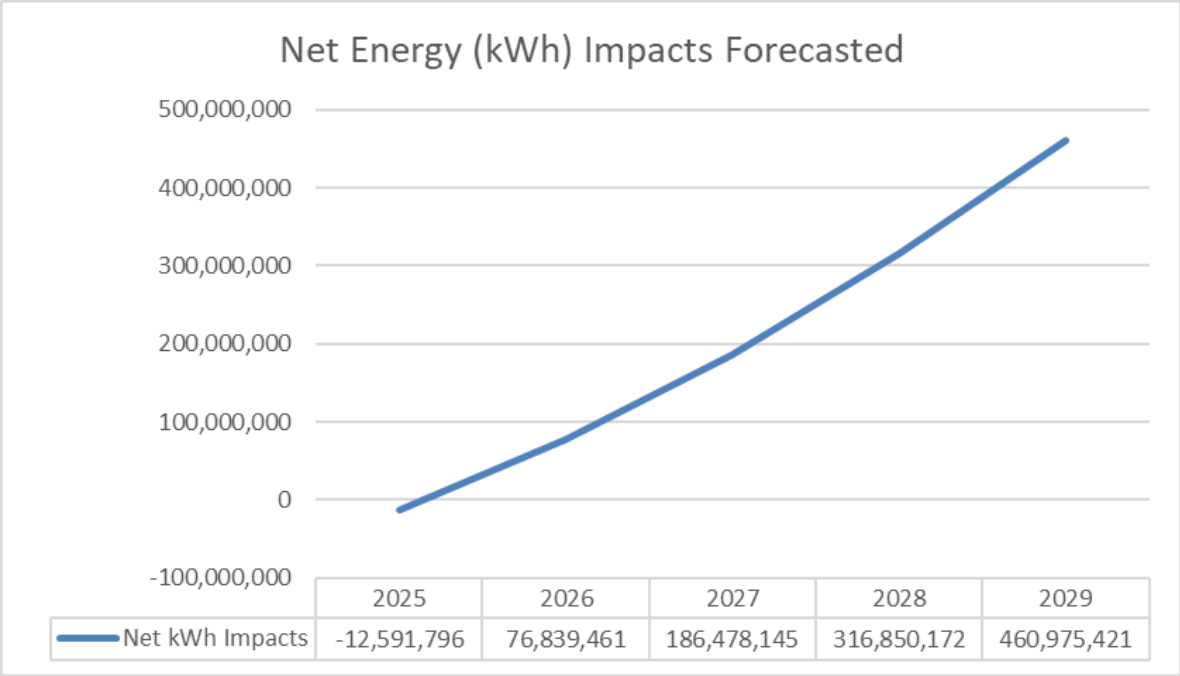
Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LS
2019	12	0	0	803	3,338	4,926
2020	24	0	0	1,553	6,457	9,531
2021	25	0	0	1,609	6,692	9,876
2022	25	0	0	1,656	6,883	10,159
2023	77	0	0	5,003	20,800	30,699
2024	82	0	0	5,309	22,073	32,578
2025	100	0	0	6,487	26,969	39,804
2026	105	0	0	6,842	28,446	41,984
2027	111	0	0	7,198	29,927	44,171
2028	116	0	0	7,554	31,408	46,357
2029	122	0	0	7,912	32,897	48,553

8 Net Results

The six technology inputs can be aggregated and layered onto the base revenue forecast to determine the expected forecast after accounting for the incremental impacts of the technologies. There is a balancing of impacts between the technologies, as EVs will increase energy and billing demand, while DERs will lower energy and billing demand.

The net forecasted energy impacts are provided below annually.[24]

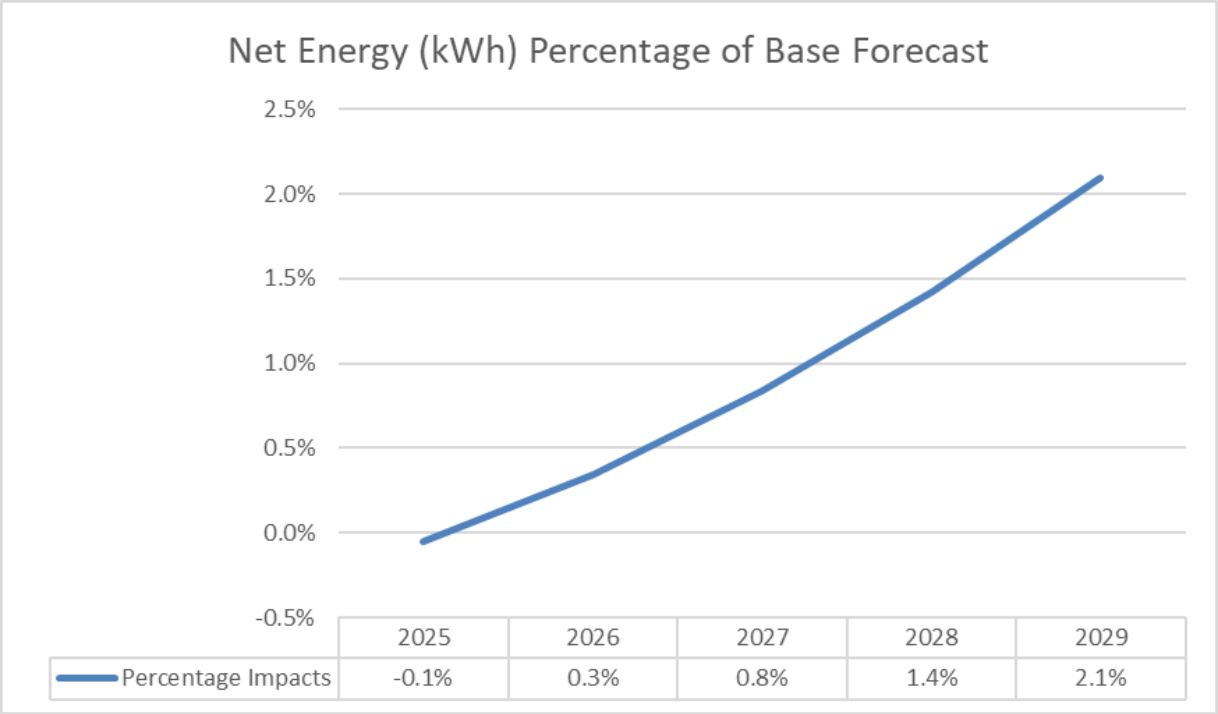
Figure 1: Net Energy Impacts Forecasted for Six Technologies



[24] The forecasts are integrated on a monthly basis as the base revenue forecast is monthly, but we display annual impacts here for display purposes.

The following graph displays the percentage difference of the net energy impacts, in kWh's, relative to the total energy for that same year in the base revenue forecast.

Figure 2: Net Energy Percentage of Base Forecast for Six Technologies



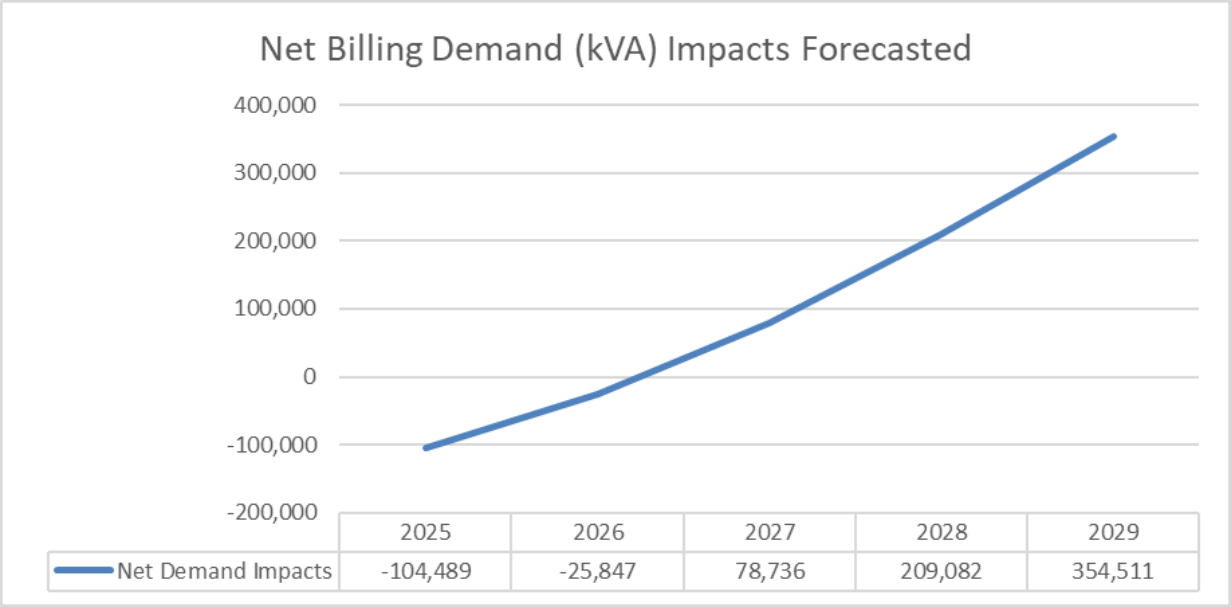
The following table displays, annually, the forecasted net energy by rate class that is projected to be added in 2025 to 2029.

Table 41: Annual Incremental Net Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	92,227,387	593,699	5,205,746	-13,065,835	-49,382,286	-48,170,506
2026	148,504,808	955,057	9,565,925	-56,972	-40,922,689	-41,206,668
2027	211,452,614	1,359,474	14,844,594	17,083,835	-28,034,931	-30,227,441
2028	281,703,920	1,810,945	21,084,234	38,415,539	-10,812,035	-15,352,432
2029	357,655,979	2,299,354	27,882,469	62,088,527	9,106,692	1,942,401

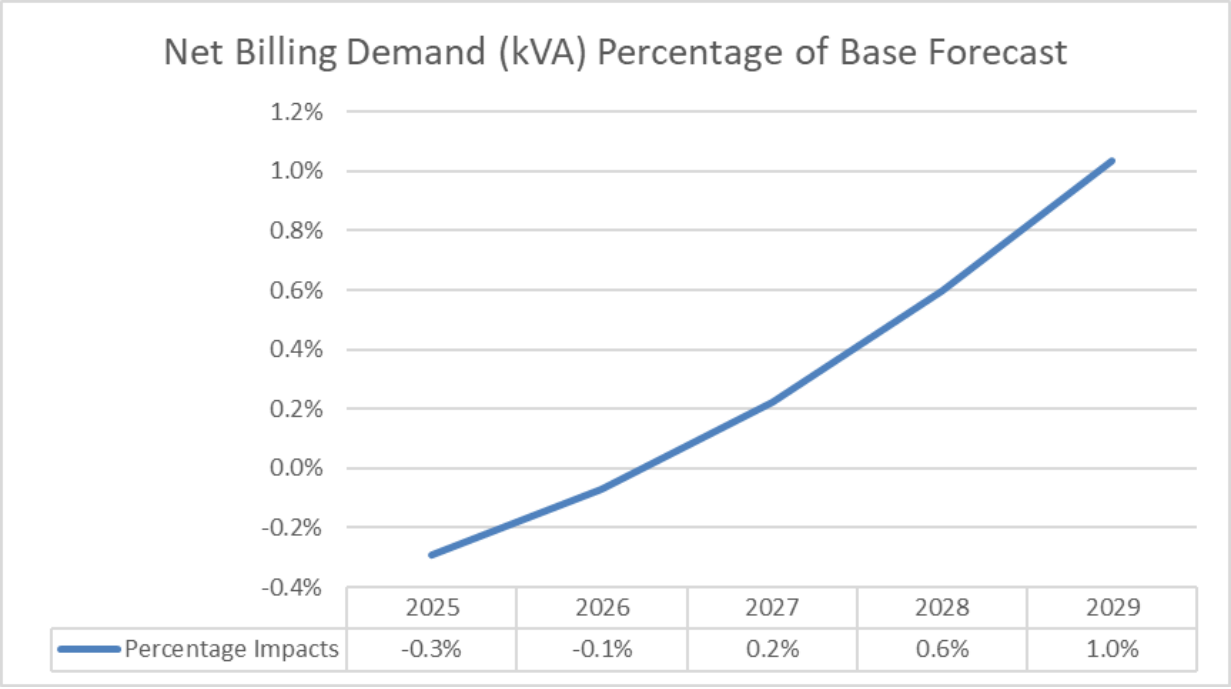
The net forecasted billing demand impacts are provided below annually.

Figure 3: Net Billing Demand Impacts Forecasted for Six Technologies



The following graph displays the percentage difference of the net demand impacts, in kVA, relative to the total billing demand in the base revenue forecast.

Figure 4: Net Billing Demand Percentage of Base Forecast for Six Technologies



The following table displays, annually, the forecasted net billing demand by rate class that is projected to be added in 2025 to 2029.

Table 42: Annual Incremental Net Billing Demand by Rate Class (kVA)

Year	GS50-999 kW	GS 1-5 MW	LU
2025	587	-55,536	-49,540
2026	33,489	-33,339	-25,997
2027	75,266	-2,718	6,188
2028	126,111	36,214	46,757
2029	182,172	80,147	92,192

9 Load Profiles

To assist with the cost allocation model ("CAM") study used for rate setting purposes by Toronto Hydro, Clearspring performed a detailed comparison between hourly 2019 rate class load profiles and hourly 2019 load profiles modified with 2025 EV and DER forecasted load impacts (LDEVs, MDEVs, HDEVs, Renewable, and non-renewable DERs). This analysis provides Toronto Hydro with the changes in the rate class allocators used within the CAM due to the anticipated changes in the technologies studied in the Integration Model.

The 2025 hourly EV/DER loads were constructed by multiplying the expected LDEV, MDEV, and HDEV counts by the same kW load profiles used in the Integration Model. Similarly, for Renewable and Non-Renewable DERs, the 2025 loads were forecasted by multiplying the total nameplate capacities by the kW load profiles used in the Integration Model.

One load profile needed to be added to the analysis: a residential LDEV load profile. For the Integration Model, it was not necessary to include a residential LDEV load profile because billing demand is not a component of residential rates. However, how LDEV's may impact the cost allocations between the residential and other classes in the CAM is pertinent.

The residential LDEV load profile assumed that EV owners would typically "smart charge" their vehicles in response to time-of-use pricing such as the Ultra-Low Overnight ("ULO") rate offering. The ULO provides a steep reduction in the electricity rate if consumers use electricity during off-peak, night-time hours. Our analysis assumes that consumers are typically charging vehicles during this time by using an LDEV load profile derived from the Alternative Fuels Data Center of the U.S. Department of Energy ("DOE") that estimates the load shape of residential LDEVs in the presence of smart charging.[25] This DOE load shape was then scaled to match the energy assumptions for the City of Toronto used in the Integration Model. The seasonal adjustment of adding ten percent for winter months and subtracting ten percent for summer months consistent with the Integration Model is also implemented for the CAM analysis.

[25] https://afdc.energy.gov/evi-pro-lite/load-profile/. The load shape used Chicago as the target city, 25 miles of travel per day in a shoulder month, and Level 1 charging.

The following table displays the residential LDEV load profiles used for the analysis.

Table 43: Residential, Smart Charging LDEV Load Profile for Toronto Hydro

Hour Beginning	Summer LDEV	Winter LDEV
0	1.319	1.612
1	1.023	1.250
2	0.782	0.956
3	0.587	0.717
4	0.390	0.476
5	0.251	0.306
6	0.141	0.173
7	0.086	0.105
8	0.057	0.070
9	0.043	0.052
10	0.041	0.050
11	0.047	0.057
12	0.052	0.064
13	0.059	0.072
14	0.085	0.104
15	0.124	0.151
16	0.170	0.208
17	0.217	0.265
18	0.245	0.299
19	0.271	0.332
20	0.295	0.360
21	0.307	0.375
22	0.305	0.373
23	1.556	1.902

The CAM input tables are compiled by calculating the yearly, quarterly, and monthly noncoincident ("NCP") and coincident peaks ("CP") and comparing the percent differences between the peaks that did not include the impacts of the six technologies and the peaks that did have the 2025 loads added.[26] Ultimately, adding the EV and DER loads to 2019 load data increases the NCP and CPs for the residential, CSMur, and GS<50 rate classes, while it decreases the NCP and CPs for the GS50-999, GS1-5MW, and LU rate classes. The increases are due to EVs having a larger impact on peaks for the lower-use rate classes, whereas the forecasted increase in DERs by 2025 causes peaks to drop for the larger use rate classes.

[26] The NCP or CP impacts of the CAManalysis will not match the demand impacts found in the Integration Model because of the different definitions of demand being analyzed. In the Integration Model, it is billing demand that is relevant which is based on each individual customer's own peak during the month. For the CAM analysis, the relevant peak demand is either the rate class non-coincident peak or the system coincident peak.

The following table displays the annual, quarterly, and monthly NCPs for the 2019 data prior to adding 2025 technology impacts and then the NCPs after adding in the impacts.[27]

Table 44: NCPs Before and After 2025 Technology Impacts by Rate Class

	RES	CSMUR	GS<50	GS50-999	GS1-5MW	LU	SL	USL	**Total**
1NCP: 2025Baseline	1,202,242	81,697	642,970	1,577,135	645,935	310,050	31,389	6,323	**4,497,741**
1NCP: 2025Net	1,212,328	81,797	642,961	1,566,120	625,420	290,411	31,389	6,323	**4,456,749**
% Increase	0.8%	0.1%	0.0%	-0.7%	-3.2%	-6.3%	0.0%	0.0%	-0.9%
4NCP: 2025Baseline	4,364,424	300,589	2,502,247	6,194,492	2,516,961	1,195,740	121,365	24,249	**17,220,066**
4NCP: 2025Net	4,410,788	300,966	2,502,763	6,152,751	2,432,341	1,115,494	121,365	24,249	**17,060,716**
% Increase	1.1%	0.1%	0.0%	-0.7%	-3.4%	-6.7%	0.0%	0.0%	-0.9%
12NCP: 2025Baseline	10,817,700	831,752	6,753,047	17,271,260	6,912,953	3,347,378	348,075	70,127	**46,352,293**
12NCP: 2025Net	10,981,253	832,870	6,763,953	17,168,462	6,666,153	3,115,743	348,075	70,127	**45,946,635**
% Increase	1.5%	0.1%	0.2%	-0.6%	-3.6%	-6.9%	0.0%	0.0%	-0.9%

The following table displays the annual, quarterly, and monthly CPs for the 2019 data prior to adding 2025 technology impacts and then the CPs after adding in the impacts.

Table 45: CPs Before and After 2025 Technology Impacts by Rate Class

	RES	CSMUR	GS<50	GS50-999	GS1-5MW	LU	SL	USL	**Total**
1CP: 2025Baseline	884,507	46,895	642,970	1,571,419	641,174	290,102	-	4,429	**4,081,498**
1CP: 2025Net	913,274	48,766	638,780	1,551,590	615,798	255,329	-	4,437	**4,027,973**
% Increase	3.3%	4.0%	-0.7%	-1.3%	-4.0%	-12.0%		0.2%	-1.3%
4CP: 2025Baseline	3,551,046	218,023	2,344,649	6,117,966	2,355,768	1,037,809	28,111	19,135	**15,672,506**
4CP: 2025Net	3,603,754	220,065	2,341,719	6,064,921	2,266,427	942,752	28,111	19,142	**15,486,890**
% Increase	1.5%	0.9%	-0.1%	-0.9%	-3.8%	-9.2%	0.0%	0.0%	-1.2%
12CP: 2025Baseline	8,757,869	644,093	6,321,104	16,957,736	6,682,659	3,037,182	140,169	59,368	**42,600,180**
12CP: 2025Net	8,891,672	646,676	6,324,315	16,834,621	6,425,229	2,781,677	140,169	59,376	**42,103,735**
% Increase	1.5%	0.4%	0.1%	-0.7%	-3.9%	-8.4%	0.0%	0.0%	-1.2%

[27] The following tables include metered and unmetered street lighting but there are zero impacts of the technologies assumed on those rate classes.

Appendix A: Monthly Projected Impacts by Technology by Rate Class from the Integration Model

The following tables provide the forecasted monthly impacts for each technology resulting from the Integration Model.

LDEV Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	7,864,340	49,646	165,488	397,170	628	148,939	326	16,549	33
Feb-25	7,232,014	45,655	152,182	365,236	921	136,964	352	15,218	29
Mar-25	8,149,405	51,446	171,486	411,567	1,086	154,338	352	17,149	38
Apr-25	8,024,456	50,657	168,857	405,257	1,034	151,971	328	16,886	32
May-25	6,900,930	43,564	145,215	348,516	803	130,693	288	14,521	32
Jun-25	6,791,175	42,872	142,905	342,973	744	128,615	329	14,291	33
Jul-25	7,134,165	45,037	150,123	360,295	720	135,110	316	15,012	36
Aug-25	7,250,782	45,773	152,577	366,184	706	137,319	311	15,258	38
Sep-25	7,129,742	45,009	150,030	360,071	854	135,027	318	15,003	31
Oct-25	9,147,132	57,744	192,481	461,955	993	173,233	357	19,248	39
Nov-25	8,989,998	56,752	189,175	454,019	1,084	170,257	376	18,917	31
Dec-25	9,432,197	59,544	198,480	476,351	1,022	178,632	422	19,848	39
Jan-26	12,953,184	81,771	272,571	654,171	1,034	245,314	537	27,257	55
Feb-26	11,857,010	74,851	249,505	598,811	1,510	224,554	577	24,950	48
Mar-26	13,301,624	83,971	279,903	671,768	1,773	251,913	574	27,990	62
Apr-26	13,041,139	82,327	274,422	658,613	1,681	246,980	533	27,442	51
May-26	11,168,233	70,503	235,011	564,026	1,299	211,510	466	23,501	52
Jun-26	10,945,913	69,100	230,333	552,798	1,199	207,299	531	23,033	54
Jul-26	11,453,320	72,303	241,010	578,423	1,155	216,909	507	24,101	58
Aug-26	11,595,864	73,203	244,009	585,622	1,129	219,608	497	24,401	61
Sep-26	11,359,749	71,712	239,041	573,698	1,361	215,137	507	23,904	49
Oct-26	14,521,162	91,670	305,566	733,358	1,576	275,009	566	30,557	61
Nov-26	14,221,337	89,777	299,257	718,216	1,714	269,331	595	29,926	50
Dec-26	14,869,601	93,869	312,898	750,955	1,611	281,608	665	31,290	61
Jan-27	18,460,325	116,537	388,457	932,296	1,474	349,611	766	38,846	78
Feb-27	16,894,190	106,650	355,501	853,202	2,152	319,951	823	35,550	69
Mar-27	18,948,238	119,617	398,724	956,937	2,525	358,851	818	39,872	88
Apr-27	18,573,091	117,249	390,830	937,991	2,394	351,747	759	39,083	73
May-27	15,902,305	100,389	334,629	803,109	1,849	301,166	664	33,463	74
Jun-27	15,582,489	98,370	327,899	786,958	1,707	295,109	756	32,790	76
Jul-27	16,301,506	102,909	343,029	823,270	1,644	308,726	722	34,303	83
Aug-27	16,501,106	104,169	347,229	833,350	1,606	312,506	708	34,723	87
Sep-27	16,161,974	102,028	340,093	816,223	1,937	306,084	721	34,009	70
Oct-27	20,655,931	130,398	434,658	1,043,180	2,242	391,193	806	43,466	87
Nov-27	20,225,697	127,682	425,605	1,021,452	2,438	383,045	847	42,561	70
Dec-27	21,143,844	133,478	444,925	1,067,821	2,290	400,433	946	44,493	87
Jan-28	24,780,945	156,438	521,460	1,251,504	1,978	469,314	1028	52,146	105
Feb-28	22,645,026	142,954	476,514	1,143,635	2,884	428,863	1103	47,651	92
Mar-28	25,361,613	160,104	533,679	1,280,830	3,380	480,311	1095	53,368	118
Apr-28	24,824,465	156,713	522,376	1,253,702	3,200	470,138	1015	52,238	98
May-28	21,225,502	133,993	446,644	1,071,945	2,468	401,979	886	44,664	99
Jun-28	20,770,692	131,122	437,073	1,048,976	2,276	393,366	1007	43,707	102
Jul-28	21,700,594	136,992	456,641	1,095,938	2,189	410,977	961	45,664	110
Aug-28	21,938,140	138,492	461,640	1,107,935	2,135	415,476	941	46,164	116
Sep-28	21,460,341	135,476	451,585	1,083,805	2,572	406,427	957	45,159	93
Oct-28	27,393,950	172,934	576,445	1,383,468	2,974	518,801	1069	57,645	116
Nov-28	26,791,242	169,129	563,762	1,353,030	3,229	507,386	1122	56,376	93
Dec-28	27,974,618	176,599	588,664	1,412,793	3,030	529,798	1252	58,866	115
Jan-29	31,655,232	199,834	666,114	1,598,674	2,527	599,503	1313	66,611	134
Feb-29	28,893,361	182,399	607,997	1,459,192	3,680	547,197	1407	60,800	117
Mar-29	32,322,924	204,049	680,164	1,632,395	4,308	612,148	1396	68,016	151
Apr-29	31,603,326	199,507	665,022	1,596,053	4,073	598,520	1292	66,502	124
May-29	26,992,323	170,398	567,994	1,363,185	3,139	511,194	1127	56,799	126
Jun-29	26,385,939	166,570	555,234	1,332,561	2,891	499,710	1280	55,523	129
Jul-29	27,538,617	173,847	579,489	1,390,774	2,778	521,540	1219	57,949	140
Aug-29	27,811,764	175,571	585,237	1,404,569	2,707	526,713	1193	58,524	147
Sep-29	27,178,946	171,576	571,921	1,372,610	3,257	514,729	1212	57,192	118
Oct-29	34,659,849	218,802	729,340	1,750,416	3,763	656,406	1352	72,934	146
Nov-29	33,864,866	213,783	712,611	1,710,267	4,082	641,350	1418	71,261	118
Dec-29	35,327,541	223,017	743,390	1,784,136	3,827	669,051	1581	74,339	145

MDEV Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	0	0	42,318	193,177	405	170,382	314	148,751	260
Feb-25	0	0	39,992	182,560	417	161,018	316	140,576	281
Mar-25	0	0	46,236	211,063	415	186,157	336	162,524	284
Apr-25	0	0	46,641	212,909	430	187,786	357	163,946	319
May-25	0	0	41,036	187,322	366	165,218	308	144,243	273
Jun-25	0	0	41,263	188,360	397	166,134	293	145,042	264
Jul-25	0	0	44,241	201,956	440	178,125	314	155,511	262
Aug-25	0	0	45,844	209,273	426	184,579	337	161,146	280
Sep-25	0	0	45,917	209,603	424	184,870	338	161,400	313
Oct-25	0	0	59,950	273,664	532	241,372	464	210,729	392
Nov-25	0	0	59,912	273,491	603	241,219	465	210,595	435
Dec-25	0	0	63,868	291,550	571	257,147	465	224,501	465
Jan-26	0	0	82,427	376,269	789	331,869	611	289,737	507
Feb-26	0	0	77,037	351,663	804	310,166	609	270,790	542
Mar-26	0	0	88,154	402,414	791	354,928	641	309,869	542
Apr-26	0	0	88,082	402,083	812	354,637	673	309,615	602
May-26	0	0	76,812	350,639	684	309,263	577	270,001	510
Jun-26	0	0	76,602	349,678	737	308,416	544	269,261	490
Jul-26	0	0	81,498	372,030	811	328,129	579	286,472	482
Aug-26	0	0	83,841	382,725	779	337,563	616	294,708	512
Sep-26	0	0	83,404	380,730	770	335,803	614	293,172	569
Oct-26	0	0	108,200	493,920	960	435,636	838	380,331	708
Nov-26	0	0	107,481	490,637	1,082	432,741	835	377,803	780
Dec-26	0	0	113,927	520,064	1,019	458,696	829	400,463	830
Jan-27	0	0	133,663	610,157	1,280	538,157	991	469,837	822
Feb-27	0	0	124,378	567,770	1,298	500,773	983	437,198	875
Mar-27	0	0	141,745	647,049	1,271	570,696	1,031	498,245	872
Apr-27	0	0	141,083	644,028	1,301	568,031	1,078	495,918	964
May-27	0	0	122,586	559,588	1,092	493,556	920	430,898	815
Jun-27	0	0	121,831	556,143	1,173	490,517	865	428,244	779
Jul-27	0	0	129,198	589,773	1,285	520,179	918	454,140	764
Aug-27	0	0	132,504	604,865	1,232	533,490	974	465,762	809
Sep-27	0	0	131,429	599,959	1,213	529,163	967	461,984	896
Oct-27	0	0	170,031	776,172	1,508	684,582	1,317	597,672	1,113
Nov-27	0	0	168,457	768,985	1,696	678,244	1,308	592,138	1,223
Dec-27	0	0	178,113	813,064	1,593	717,121	1,296	626,080	1,298
Jan-28	0	0	200,435	914,959	1,919	806,992	1,486	704,542	1,232
Feb-28	0	0	187,023	853,735	1,952	752,993	1,478	657,398	1,316
Mar-28	0	0	213,687	975,455	1,917	860,350	1,554	751,126	1,314
Apr-28	0	0	213,207	973,261	1,967	858,415	1,630	749,436	1,457
May-28	0	0	185,678	847,597	1,654	747,579	1,394	652,671	1,234
Jun-28	0	0	184,935	844,205	1,780	744,587	1,312	650,060	1,182
Jul-28	0	0	196,521	897,094	1,955	791,235	1,396	690,785	1,162
Aug-28	0	0	201,942	921,842	1,877	813,063	1,484	709,842	1,233
Sep-28	0	0	200,675	916,055	1,853	807,959	1,477	705,386	1,369
Oct-28	0	0	260,071	1,187,192	2,307	1,047,101	2,014	914,169	1,702
Nov-28	0	0	258,094	1,178,168	2,599	1,039,142	2,005	907,220	1,874
Dec-28	0	0	273,324	1,247,688	2,445	1,100,459	1,989	960,752	1,992
Jan-29	0	0	297,632	1,358,654	2,850	1,198,331	2,207	1,046,199	1,830
Feb-29	0	0	276,609	1,262,686	2,887	1,113,687	2,186	972,301	1,946
Mar-29	0	0	314,859	1,437,293	2,824	1,267,690	2,289	1,106,752	1,937
Apr-29	0	0	313,038	1,428,979	2,888	1,260,357	2,393	1,100,351	2,140
May-29	0	0	271,707	1,240,307	2,421	1,093,949	2,040	955,069	1,806
Jun-29	0	0	269,762	1,231,430	2,596	1,086,119	1,914	948,233	1,724
Jul-29	0	0	285,801	1,304,648	2,843	1,150,697	2,030	1,004,613	1,689
Aug-29	0	0	292,849	1,336,818	2,722	1,179,071	2,152	1,029,385	1,787
Sep-29	0	0	290,222	1,324,828	2,679	1,168,496	2,136	1,020,151	1,979
Oct-29	0	0	375,153	1,712,527	3,328	1,510,446	2,905	1,318,690	2,455
Nov-29	0	0	371,387	1,695,336	3,740	1,495,283	2,885	1,305,452	2,697
Dec-29	0	0	392,380	1,791,166	3,510	1,579,805	2,855	1,379,244	2,860

HDEV Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	-	-	293,308	1,368,463	3,124	1,199,268	2,464	1,090,097	2,708
Feb-25	-	-	279,647	1,304,722	2,989	1,143,408	2,745	1,039,322	2,981
Mar-25	-	-	325,909	1,520,565	3,370	1,332,564	2,727	1,211,258	2,854
Apr-25	-	-	331,170	1,545,112	3,509	1,354,076	2,869	1,230,812	3,004
May-25	-	-	293,326	1,368,545	2,641	1,199,340	2,254	1,090,162	2,473
Jun-25	-	-	296,770	1,384,615	2,656	1,213,422	2,364	1,102,963	2,365
Jul-25	-	-	319,999	1,492,992	2,777	1,308,400	2,565	1,189,294	2,802
Aug-25	-	-	333,336	1,555,215	2,824	1,362,930	2,637	1,238,860	2,667
Sep-25	-	-	335,489	1,565,263	3,052	1,371,735	2,695	1,246,864	2,885
Oct-25	-	-	440,011	2,052,920	4,057	1,799,099	3,582	1,635,324	3,775
Nov-25	-	-	441,591	2,060,294	4,976	1,805,561	3,788	1,641,198	4,282
Dec-25	-	-	472,611	2,205,021	4,794	1,932,395	3,992	1,756,486	4,204
Jan-26	-	-	579,105	2,701,881	6,169	2,367,823	4,865	2,152,276	5,347
Feb-26	-	-	542,642	2,531,756	5,799	2,218,732	5,327	2,016,758	5,784
Mar-26	-	-	622,459	2,904,150	6,437	2,545,084	5,209	2,313,401	5,450
Apr-26	-	-	623,357	2,908,341	6,606	2,548,756	5,399	2,316,739	5,655
May-26	-	-	544,755	2,541,617	4,906	2,227,374	4,185	2,024,613	4,592
Jun-26	-	-	544,346	2,539,706	4,871	2,225,700	4,336	2,023,091	4,338
Jul-26	-	-	580,226	2,707,110	5,035	2,372,406	4,650	2,156,442	5,082
Aug-26	-	-	597,962	2,789,857	5,066	2,444,922	4,730	2,222,357	4,784
Sep-26	-	-	595,836	2,779,939	5,421	2,436,230	4,786	2,214,456	5,124
Oct-26	-	-	774,195	3,612,095	7,138	3,165,499	6,302	2,877,339	6,642
Nov-26	-	-	770,199	3,593,448	8,679	3,149,158	6,607	2,862,485	7,468
Dec-26	-	-	817,549	3,814,364	8,292	3,342,760	6,905	3,038,464	7,272
Jan-27	-	-	930,161	4,339,771	9,908	3,803,206	7,814	3,456,995	8,588
Feb-27	-	-	865,251	4,036,925	9,247	3,537,804	8,495	3,215,752	9,223
Mar-27	-	-	985,752	4,599,135	10,193	4,030,502	8,250	3,663,600	8,631
Apr-27	-	-	980,852	4,576,274	10,394	4,010,468	8,496	3,645,390	8,898
May-27	-	-	852,007	3,975,135	7,672	3,483,654	6,546	3,166,532	7,183
Jun-27	-	-	846,531	3,949,586	7,575	3,461,263	6,743	3,146,179	6,746
Jul-27	-	-	897,491	4,187,342	7,788	3,669,624	7,193	3,335,572	7,860
Aug-27	-	-	920,232	4,293,446	7,796	3,762,608	7,280	3,420,093	7,362
Sep-27	-	-	912,555	4,257,628	8,303	3,731,219	7,330	3,391,561	7,848
Oct-27	-	-	1,180,319	5,506,909	10,882	4,826,040	9,608	4,386,719	10,126
Nov-27	-	-	1,169,143	5,454,765	13,174	4,780,344	10,030	4,345,182	11,336
Dec-27	-	-	1,235,909	5,766,273	12,535	5,053,337	10,438	4,593,324	10,993
Jan-28	-	-	1,352,787	6,311,580	14,410	5,531,223	11,364	5,027,708	12,490
Feb-28	-	-	1,250,830	5,835,889	13,368	5,114,346	12,280	4,648,779	13,334
Mar-28	-	-	1,416,909	6,610,746	14,652	5,793,400	11,858	5,266,018	12,406
Apr-28	-	-	1,402,229	6,542,254	14,859	5,733,376	12,146	5,211,459	12,721
May-28	-	-	1,211,752	5,653,564	10,912	4,954,563	9,310	4,503,542	10,215
Jun-28	-	-	1,198,049	5,589,629	10,720	4,898,533	9,542	4,452,613	9,547
Jul-28	-	-	1,264,215	5,898,336	10,971	5,169,072	10,132	4,698,524	11,072
Aug-28	-	-	1,290,446	6,020,722	10,933	5,276,326	10,209	4,796,015	10,323
Sep-28	-	-	1,274,205	5,944,944	11,593	5,209,917	10,236	4,735,650	10,958
Oct-28	-	-	1,641,334	7,657,827	15,132	6,711,021	13,361	6,100,107	14,081
Nov-28	-	-	1,619,414	7,555,558	18,248	6,621,396	13,892	6,018,641	15,702
Dec-28	-	-	1,705,455	7,956,992	17,298	6,973,198	14,404	6,338,417	15,169
Jan-29	-	-	1,822,353	8,502,390	19,412	7,451,163	15,308	6,772,873	16,826
Feb-29	-	-	1,674,971	7,814,766	17,900	6,848,557	16,444	6,225,122	17,855
Mar-29	-	-	1,886,513	8,801,736	19,508	7,713,498	15,788	7,011,327	16,518
Apr-29	-	-	1,856,703	8,662,653	19,675	7,591,612	16,083	6,900,536	16,843
May-29	-	-	1,596,005	7,446,339	14,372	6,525,681	12,262	5,931,639	13,455
Jun-29	-	-	1,569,921	7,324,644	14,048	6,419,032	12,504	5,834,698	12,510
Jul-29	-	-	1,648,499	7,691,258	14,305	6,740,319	13,212	6,126,738	14,437
Aug-29	-	-	1,674,747	7,813,718	14,189	6,847,638	13,249	6,224,287	13,398
Sep-29	-	-	1,646,123	7,680,172	14,977	6,730,603	13,223	6,117,907	14,156
Oct-29	-	-	2,111,073	9,849,446	19,463	8,631,670	17,184	7,845,916	18,111
Nov-29	-	-	2,074,019	9,676,566	23,371	8,480,165	17,792	7,708,203	20,110
Dec-29	-	-	2,175,233	10,148,791	22,063	8,894,005	18,372	8,084,371	19,348

Renewable Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	(46,909.61)	0	(36,642.98)	(218,075.22)	(401)	(28,489.09)	(66)	0	0
Feb-25	(43,558.79)	0	(34,025.51)	(202,497.79)	(403)	(26,454.07)	(67)	0	0
Mar-25	(49,541.99)	0	(38,699.23)	(230,312.74)	(373)	(30,087.78)	(70)	0	0
Apr-25	(49,217.60)	0	(38,445.84)	(228,804.68)	(446)	(29,890.77)	(76)	0	0
May-25	(280,002.48)	0	(218,721.15)	(1,301,686.39)	(1,534)	(170,050.76)	(426)	0	0
Jun-25	(277,805.84)	0	(217,005.27)	(1,291,474.58)	(1,977)	(168,716.71)	(446)	0	0
Jul-25	(294,129.59)	0	(229,756.40)	(1,367,361.08)	(1,924)	(178,630.43)	(442)	0	0
Aug-25	(301,193.15)	0	(235,274.03)	(1,400,198.42)	(1,981)	(182,920.26)	(461)	0	0
Sep-25	(298,312.95)	0	(233,024.19)	(1,386,808.81)	(2,114)	(181,171.06)	(492)	0	0
Oct-25	(58,755.33)	0	(45,896.14)	(273,144.06)	(659)	(35,683.22)	(93)	0	0
Nov-25	(58,133.73)	0	(45,410.58)	(270,254.34)	(472)	(35,305.71)	(88)	0	0
Dec-25	(61,387.71)	0	(47,952.40)	(285,381.58)	(537)	(37,281.91)	(90)	0	0
Jan-26	(73,655.97)	0	(57,535.63)	(342,414.72)	(630)	(44,732.65)	(103)	0	0
Feb-26	(68,056.42)	0	(53,161.59)	(316,383.32)	(629)	(41,331.94)	(105)	0	0
Mar-26	(77,040.39)	0	(60,179.33)	(358,148.35)	(580)	(46,788.08)	(109)	0	0
Apr-26	(76,192.84)	0	(59,517.28)	(354,208.22)	(690)	(46,273.34)	(117)	0	0
May-26	(431,613.14)	0	(337,150.31)	(2,006,499.95)	(2,365)	(262,126.77)	(656)	0	0
Jun-26	(426,478.72)	0	(333,139.60)	(1,982,630.82)	(3,035)	(259,008.54)	(684)	0	0
Jul-26	(449,776.20)	0	(351,338.20)	(2,090,937.08)	(2,943)	(273,157.54)	(676)	0	0
Aug-26	(458,857.73)	0	(358,432.15)	(2,133,155.64)	(3,018)	(278,672.92)	(703)	0	0
Sep-26	(452,844.44)	0	(353,734.93)	(2,105,200.84)	(3,209)	(275,020.94)	(747)	0	0
Oct-26	(88,885.86)	0	(69,432.31)	(413,216.04)	(997)	(53,982.05)	(140)	0	0
Nov-26	(87,656.20)	0	(68,471.77)	(407,499.54)	(712)	(53,235.26)	(133)	0	0
Dec-26	(92,270.28)	0	(72,076.01)	(428,949.67)	(807)	(56,037.48)	(135)	0	0
Jan-27	(104,914.56)	0	(81,952.96)	(487,730.87)	(897)	(63,716.58)	(147)	0	0
Feb-27	(96,629.61)	0	(75,481.26)	(449,215.50)	(893)	(58,684.98)	(149)	0	0
Mar-27	(109,051.02)	0	(85,184.12)	(506,960.60)	(821)	(66,228.73)	(154)	0	0
Apr-27	(107,534.75)	0	(83,999.70)	(499,911.75)	(974)	(65,307.88)	(165)	0	0
May-27	(607,439.46)	0	(474,495.28)	(2,823,888.14)	(3,328)	(368,909.40)	(924)	0	0
Jun-27	(598,586.09)	0	(467,579.56)	(2,782,730.25)	(4,260)	(363,532.58)	(960)	0	0
Jul-27	(629,638.45)	0	(491,835.81)	(2,927,087.71)	(4,119)	(382,391.26)	(946)	0	0
Aug-27	(640,737.95)	0	(500,506.07)	(2,978,687.49)	(4,214)	(389,132.20)	(981)	0	0
Sep-27	(630,810.44)	0	(492,751.29)	(2,932,536.07)	(4,470)	(383,103.03)	(1,041)	0	0
Oct-27	(123,528.62)	0	(96,493.16)	(574,264.67)	(1,385)	(75,021.25)	(195)	0	0
Nov-27	(121,545.34)	0	(94,943.93)	(565,044.71)	(987)	(73,816.77)	(184)	0	0
Dec-27	(127,665.08)	0	(99,724.31)	(593,494.40)	(1,117)	(77,533.40)	(187)	0	0
Jan-28	(140,685.38)	0	(109,894.98)	(654,023.66)	(1,203)	(85,440.87)	(197)	0	0
Feb-28	(129,278.37)	0	(100,984.51)	(600,994.33)	(1,195)	(78,513.19)	(200)	0	0
Mar-28	(145,573.88)	0	(113,713.58)	(676,749.50)	(1,096)	(88,409.75)	(205)	0	0
Apr-28	(143,243.35)	0	(111,893.11)	(665,915.24)	(1,298)	(86,994.38)	(220)	0	0
May-28	(807,481.41)	0	(630,756.07)	(3,753,850.96)	(4,424)	(490,398.63)	(1,228)	0	0
Jun-28	(794,127.95)	0	(620,325.14)	(3,691,772.87)	(5,652)	(482,288.83)	(1,274)	0	0
Jul-28	(833,716.35)	0	(651,249.23)	(3,875,812.97)	(5,454)	(506,331.61)	(1,252)	0	0
Aug-28	(846,833.82)	0	(661,495.81)	(3,936,793.97)	(5,569)	(514,298.09)	(1,297)	0	0
Sep-28	(832,210.93)	0	(650,073.28)	(3,868,814.49)	(5,897)	(505,417.33)	(1,374)	0	0
Oct-28	(162,683.62)	0	(127,078.69)	(756,289.93)	(1,824)	(98,800.82)	(256)	0	0
Nov-28	(159,801.16)	0	(124,827.09)	(742,889.86)	(1,298)	(97,050.25)	(242)	0	0
Dec-28	(167,572.12)	0	(130,897.29)	(779,015.77)	(1,466)	(101,769.70)	(246)	0	0
Jan-29	(180,968.43)	0	(141,361.69)	(841,293.08)	(1,548)	(109,905.53)	(254)	0	0
Feb-29	(166,002.70)	0	(129,671.35)	(771,719.79)	(1,534)	(100,816.56)	(256)	0	0
Mar-29	(186,608.97)	0	(145,767.74)	(867,515.03)	(1,406)	(113,331.13)	(263)	0	0
Apr-29	(183,318.62)	0	(143,197.51)	(852,218.71)	(1,661)	(111,332.84)	(282)	0	0
May-29	(1,031,739.02)	0	(805,932.66)	(4,796,388.42)	(5,652)	(626,594.49)	(1,569)	0	0
Jun-29	(1,013,104.31)	0	(791,376.35)	(4,709,758.69)	(7,210)	(615,277.29)	(1,625)	0	0
Jul-29	(1,062,009.90)	0	(829,578.46)	(4,937,112.87)	(6,948)	(644,978.57)	(1,595)	0	0
Aug-29	(1,077,145.34)	0	(841,401.35)	(5,007,475.09)	(7,083)	(654,170.60)	(1,649)	0	0
Sep-29	(1,057,045.91)	0	(825,700.89)	(4,914,036.11)	(7,490)	(641,963.85)	(1,745)	0	0
Oct-29	(206,350.85)	0	(161,188.91)	(959,291.84)	(2,314)	(125,320.75)	(325)	0	0
Nov-29	(202,423.66)	0	(158,121.23)	(941,034.98)	(1,644)	(122,935.69)	(307)	0	0
Dec-29	(211,991.38)	0	(165,594.96)	(985,513.78)	(1,854)	(128,746.35)	(311)	0	0

Non-Renewable Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	0	0	(11,006)	(3,726,862)	(5,028)	(8,232,918)	(11,117)	(7,813,604)	(10,545)
Feb-25	0	0	(9,430)	(3,193,191)	(4,778)	(7,053,998)	(10,548)	(6,694,728)	(10,000)
Mar-25	0	0	(9,875)	(3,343,775)	(4,513)	(7,386,648)	(9,972)	(7,010,436)	(9,450)
Apr-25	0	0	(9,009)	(3,050,546)	(4,256)	(6,738,884)	(9,406)	(6,395,663)	(8,915)
May-25	0	0	(8,744)	(2,960,687)	(4,010)	(6,540,379)	(8,850)	(6,207,268)	(8,397)
Jun-25	0	0	(7,914)	(2,679,816)	(3,757)	(5,919,913)	(8,280)	(5,618,403)	(7,841)
Jul-25	0	0	(7,612)	(2,577,599)	(3,492)	(5,694,109)	(7,697)	(5,404,100)	(7,299)
Aug-25	0	0	(7,047)	(2,386,055)	(3,234)	(5,270,974)	(7,129)	(5,002,515)	(6,764)
Sep-25	0	0	(6,272)	(2,123,720)	(2,973)	(4,691,457)	(6,558)	(4,452,514)	(6,197)
Oct-25	0	0	(5,915)	(2,002,967)	(2,714)	(4,424,704)	(5,984)	(4,199,347)	(5,673)
Nov-25	0	0	(5,177)	(1,752,990)	(2,442)	(3,872,486)	(5,409)	(3,675,255)	(5,123)
Dec-25	0	0	(4,784)	(1,619,879)	(2,188)	(3,578,434)	(4,833)	(3,396,179)	(4,577)
Jan-26	0	0	(11,964)	(4,051,229)	(5,466)	(8,949,468)	(12,085)	(8,493,659)	(11,463)
Feb-26	0	0	(10,288)	(3,483,641)	(5,212)	(7,695,625)	(11,507)	(7,303,675)	(10,910)
Mar-26	0	0	(10,816)	(3,662,548)	(4,943)	(8,090,844)	(10,923)	(7,678,765)	(10,351)
Apr-26	0	0	(9,912)	(3,356,331)	(4,683)	(7,414,385)	(10,349)	(7,036,760)	(9,808)
May-26	0	0	(9,668)	(3,273,868)	(4,434)	(7,232,219)	(9,786)	(6,863,872)	(9,286)
Jun-26	0	0	(8,801)	(2,980,188)	(4,178)	(6,583,459)	(9,208)	(6,248,154)	(8,719)
Jul-26	0	0	(8,521)	(2,885,188)	(3,908)	(6,373,595)	(8,615)	(6,048,979)	(8,170)
Aug-26	0	0	(7,947)	(2,690,847)	(3,647)	(5,944,283)	(8,040)	(5,641,532)	(7,628)
Sep-26	0	0	(7,135)	(2,415,975)	(3,382)	(5,337,069)	(7,460)	(5,065,244)	(7,050)
Oct-26	0	0	(6,799)	(2,302,167)	(3,120)	(5,085,659)	(6,878)	(4,826,639)	(6,520)
Nov-26	0	0	(6,024)	(2,039,832)	(2,841)	(4,506,142)	(6,295)	(4,276,638)	(5,962)
Dec-26	0	0	(5,651)	(1,913,486)	(2,584)	(4,227,035)	(5,709)	(4,011,746)	(5,407)
Jan-27	0	0	(12,825)	(4,342,739)	(5,859)	(9,593,436)	(12,954)	(9,104,828)	(12,287)
Feb-27	0	0	(11,060)	(3,745,047)	(5,603)	(8,273,088)	(12,371)	(7,851,728)	(11,728)
Mar-27	0	0	(11,665)	(3,949,864)	(5,331)	(8,725,546)	(11,780)	(8,281,141)	(11,163)
Apr-27	0	0	(10,727)	(3,632,349)	(5,068)	(8,024,130)	(11,200)	(7,615,450)	(10,615)
May-27	0	0	(10,505)	(3,556,989)	(4,817)	(7,857,656)	(10,633)	(7,457,454)	(10,089)
Jun-27	0	0	(9,604)	(3,252,147)	(4,559)	(7,184,236)	(10,049)	(6,818,333)	(9,515)
Jul-27	0	0	(9,344)	(3,164,115)	(4,286)	(6,989,766)	(9,448)	(6,633,767)	(8,959)
Aug-27	0	0	(8,764)	(2,967,677)	(4,022)	(6,555,821)	(8,867)	(6,221,924)	(8,413)
Sep-27	0	0	(7,920)	(2,681,845)	(3,754)	(5,924,396)	(8,281)	(5,622,658)	(7,826)
Oct-27	0	0	(7,604)	(2,574,802)	(3,489)	(5,687,931)	(7,693)	(5,398,237)	(7,292)
Nov-27	0	0	(6,797)	(2,301,644)	(3,206)	(5,084,503)	(7,102)	(4,825,542)	(6,727)
Dec-27	0	0	(6,444)	(2,181,928)	(2,947)	(4,820,041)	(6,510)	(4,574,550)	(6,165)
Jan-28	0	0	(13,614)	(4,609,782)	(6,219)	(10,183,354)	(13,751)	(9,664,701)	(13,043)
Feb-28	0	0	(11,769)	(3,984,984)	(5,962)	(8,803,128)	(13,163)	(8,354,772)	(12,480)
Mar-28	0	0	(12,445)	(4,214,111)	(5,687)	(9,309,287)	(12,568)	(8,835,151)	(11,909)
Apr-28	0	0	(11,478)	(3,886,718)	(5,423)	(8,586,051)	(11,984)	(8,148,752)	(11,358)
May-28	0	0	(11,277)	(3,818,440)	(5,172)	(8,435,220)	(11,414)	(8,005,602)	(10,830)
Jun-28	0	0	(10,347)	(3,503,811)	(4,912)	(7,740,180)	(10,826)	(7,345,962)	(10,251)
Jul-28	0	0	(10,108)	(3,422,769)	(4,636)	(7,561,153)	(10,221)	(7,176,052)	(9,692)
Aug-28	0	0	(9,524)	(3,224,933)	(4,371)	(7,124,119)	(9,635)	(6,761,278)	(9,142)
Sep-28	0	0	(8,651)	(2,929,449)	(4,100)	(6,471,373)	(9,046)	(6,141,777)	(8,548)
Oct-28	0	0	(8,355)	(2,829,262)	(3,834)	(6,250,052)	(8,453)	(5,931,728)	(8,013)
Nov-28	0	0	(7,520)	(2,546,542)	(3,547)	(5,625,502)	(7,858)	(5,338,987)	(7,442)
Dec-28	0	0	(7,187)	(2,433,591)	(3,286)	(5,375,985)	(7,261)	(5,102,178)	(6,876)
Jan-29	0	0	(14,353)	(4,860,048)	(6,557)	(10,736,209)	(14,497)	(10,189,398)	(13,751)
Feb-29	0	0	(12,432)	(4,209,767)	(6,298)	(9,299,691)	(13,906)	(8,826,045)	(13,184)
Mar-29	0	0	(13,176)	(4,461,580)	(6,021)	(9,855,965)	(13,306)	(9,353,986)	(12,609)
Apr-29	0	0	(12,182)	(4,124,851)	(5,755)	(9,112,106)	(12,718)	(8,648,013)	(12,054)
May-29	0	0	(11,999)	(4,063,113)	(5,503)	(8,975,721)	(12,146)	(8,518,574)	(11,524)
Jun-29	0	0	(11,043)	(3,739,238)	(5,242)	(8,260,257)	(11,554)	(7,839,550)	(10,940)
Jul-29	0	0	(10,822)	(3,664,646)	(4,964)	(8,095,476)	(10,943)	(7,683,162)	(10,377)
Aug-29	0	0	(10,234)	(3,465,412)	(4,697)	(7,655,354)	(10,354)	(7,265,456)	(9,824)
Sep-29	0	0	(9,335)	(3,160,818)	(4,424)	(6,982,483)	(9,760)	(6,626,855)	(9,223)
Oct-29	0	0	(9,057)	(3,066,945)	(4,156)	(6,775,110)	(9,163)	(6,430,044)	(8,686)
Nov-29	0	0	(8,196)	(2,775,204)	(3,865)	(6,130,634)	(8,564)	(5,818,392)	(8,111)
Dec-29	0	0	(7,881)	(2,668,477)	(3,604)	(5,894,866)	(7,962)	(5,594,632)	(7,540)

Appendix B: Summary Curriculum Vitae

STEVEN A. FENRICK

SUMMARY OF EXPERIENCE AND EXPERTISE

- I have directed project teams and engaged in research in the fields of performance based regulation, performance benchmarking, DSM, load research and forecasting, and survey design and implementation.
- I have been a expert witness in a number of cases involving incentive regulation and other utility research topics.

PROFESSIONAL EXPERIENCE

Clearspring Energy Advisors, LLC (2019 to Present)

Principal Consultant

Responsible for providing consulting services and expert witness testimony to utilities and regulators in the areas of reliability and cost benchmarking, productivity studies and other empirical aspects of performance-based ratemaking and incentive regulation. Direct activities in the areas of demand-side management programs, peak time rebate programs, load forecasting, and market research.

Power System Engineering, Inc.– Madison, WI (2009 to 2018)

Director of Economics

Responsible for providing consulting services to utilities and regulators in the areas of reliability and cost benchmarking, incentive regulation, value-based reliability planning, demand-side management including demand response and energy efficiency, ran peak time rebate programs, load research, load forecasting, end-use surveys, and market research.

Pacific Economics Group – Madison, WI (2001 - 2009)

Senior Economist

Co-authored research reports submitted as testimony in numerous proceedings in several states and in international jurisdictions. Research topics included statistical benchmarking, alternative regulation, and revenue decoupling. Managed and supervised PEG support staff in research and marketing efforts.

EDUCATION

University of Wisconsin - Madison, WI

Bachelor of Science, Economics (Mathematical Emphasis)

University of Wisconsin - Madison, WI

Master of Science, Agriculture and Applied Economics

Publications & Papers

- "Peak-Time Rebate Programs: A Success Story", *TechSurveillance*, July 2014 (with David Williams and Chris Ivanov).
- "Demand Impact of a Critical Peak Pricing Program: Opt-In and Opt-Out Options, Green Attitudes and other Customer Characteristics:, *The Energy Journal*, January 2014. (With Lullit Getachew, Chris Ivanov, and Jeff Smith).
- "Evaluating the Cost of Reliability Improvement Programs", *The Electricity Journal*, November 2013. (With Lullit Getachew)
- "Expected Useful Life of Energy Efficiency Improvements", Cooperative Research Network, 2013 (with David Williams).
- "Cost and Reliability Comparisons of Underground and Overhead Power Lines", *Utilities Policy*, March 2012. (With Lullit Getachew).
- "Formulating Appropriate Electric Reliability Targets and Performance Evaluations, *Electricity Journal*, March 2012. (With Lullit Getachew)
- "Enabling Technologies and Energy Savings: The Case of EnergyWise Smart Meter Pilot of Connexus Energy", Utilities Policy, November 2012. (With Chris Ivanov, Lullit Getachew, and Bethany Vittetoe)
- "The Value of Improving Load Factors through Demand-Side Management Programs", Cooperative Research Network, 2012 (with David Williams and Chris Ivanov).
- "Estimation of the Effects of Price and Billing Frequency on Household Water Demand Using a Panel of Wisconsin Municipalities", *Applied Economics Letters*, 2012, 19:14, 1373-1380.
- "Altreg Rate Designs Address Declining Average Gas Use", *Natural Gas & Electricity*. April 2008. (With Mark Lowry, Lullit Getachew, and David Hovde).
- "Regulation of Gas Distributors with Declining Use per Customer", *Dialogue*. August 2006. (With Mark Lowry and Lullit Getachew).
- "Balancing Reliability with Investment Costs: Assessing the Costs and Benefits of Reliability-Driven Power Transmission Projects." April 2011. *RE Magazine*.
- "Ex-Post Cost, Productivity, and Reliability Performance Assessment Techniques for Power Distribution Utilities". Master's Thesis.
- "Demand Response: How Much Value is Really There?" *PSE whitepaper.*
- "How is My Utility Performing" *PSE whitepaper*.
- "Improving the Performance of Power Distributors by Statistical Performance Benchmarking" *PSE whitepaper*.
- "Peak Time Rebate Programs: Reducing Costs While Engaging Customers" *PSE whitepaper*.
- "Performance Based Regulation for Electric and Gas Distributors" *PSE whitepaper*.
- "Revenue Decoupling: Designing a Fair Revenue Adjustment Mechanism" *PSE whitepaper.*

Expert Witness Experience

- Docket EB-2021-0110, Hydro One Networks, Joint Rate Application for Transmission and Distribution. Custom Incentive Regulation Benchmarking and Productivity research.
- Case No. 2020-00299, Big Rivers Electric Corporation, Integrated Resource Plan. Testimony on load forecast research.
- Docket EB-2019-0261, Hydro Ottawa, Custom Incentive Regulation Application.
- Docket EB-2019-0082, Hydro One Networks Transmission, TFP and Econometric Benchmarking research.
- Docket EB-2018-0165, Toronto Hydro Electric System Limited, Econometric Benchmarking research.
- Docket EB-2018-0218, Hydro One Transmission Sault St. Marie, TFP and Econometric Benchmarking research.
- Docket EB-2017-0049, Hydro One Distribution, TFP and Benchmarking research.
- Docket EB-2015-0004, Hydro Ottawa, Custom Incentive Regulation Application.
- Docket 15-SPEE-357-TAR, Application for Southern Pioneer Electric Cooperative, Inc., Demand Response Peak Time Rebate Pilot Program.
- Docket EB-2014-0116, Toronto Hydro, Custom Incentive Regulation Application.
- Docket EB-2010-0379, The Coalition of Large Distributors in Ontario regarding "Defining & Measuring Performance".
- Docket No. 6690-CE-198, Wisconsin Public Service Corporation, "Application for Certificate of Authority for System Modernization and Reliability Project".
- Expert Witness presentation to Connecticut Governors "Two Storm Panel", 2012.
- Docket No. EB-2012-0064, Toronto Hydro's Incremental Capital Module (ICM) request for added capital funding.
- Docket No. 09-0306, Central Illinois Light rate case filing.
- Docket No. 09-0307, Central Illinois Public Service Company rate case filing.
- Docket No. 09-0308, Illinois Power rate case filing.

Recent Conference Presentations

- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2019.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2018.
- Panel Moderator at WPUI conference on cost allocation and innovative rate designs at Madison WI. June 2018.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2017.
- Wisconsin Manager's Meeting, "Reliability Target Setting Using Econometric Benchmarking". November 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2016.

- Wisconsin Electric Cooperative Association (WECA) Conference, "An Introduction to Peak Time Rebates". September 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2015.
- EUCI conference chair, 2015. "Evaluating the Performance of Gas and Electric Distribution Utilities."
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2014.
- Cooperative Exchange Conference, Williamsburg VA. "Smart Thermostat versus AC Direct Load Control Impacts". August 2014.
- EUCI conference chair in Chicago. "The Economics of Demand Response". February 2014.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2013.
- EUCI conference chair in Chicago. "Evaluating the Performance of Gas and Electric Distribution Utilities." August 2013.
- Presentation to the Ontario Energy Board, "Research and Recommendations on 4th Generation Incentive Regulation".
- Presentation to the Canadian Electricity Association's best practice working group. 2013
- Conference chair for EUCI conference in March 2013 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."
- Presentation to the board of directors of Great Lakes Energy on benchmarking results, December 2012.
- Presentation on making optimal infrastructure investments and the impact on rates, Electricity Distribution Association, Toronto, Ontario. November 2012.
- Conference chair for EUCI conference in August 2012 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Reliability Target Setting and Performance Evaluation".
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Making the Business Case for Reliability-Driven Investments".
- Conference chair for EUCI conference in 2012 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". St. Louis.
- Conference chair for EUCI conference in 2012 titled, "Demand Response: The Economic and Technology Considerations from Pilot to Deployment". St. Louis.
- 2012 Presentation in the Missouri PSC Smart Grid conference entitled, "Maximizing the Value of DSM Deployments". Jefferson City.
- 2011 conference chair on a nationwide benchmarking conference for rural electrical cooperatives. Madison.
- 2011 presentation on optimizing demand response program at the CRN Summit. Cleveland.
- Conference chair for EUCI conference in 2011 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". Denver.
- 2010 presentation on cost benchmarking techniques for REMC. Wisconsin Dells.

OTHER REVENUE

1. INTRODUCTION

In addition to revenues recovered through distribution rates, Toronto Hydro earns other revenue from non-distribution related services, property and facility rentals, specific service charges, and short-term investments. Toronto Hydro also receives income and recoveries from shared services that it provides to its affiliates. Together, these revenues constitute Toronto Hydro's Other Revenue and reduce the utility's revenue requirement recovered through distribution rates. Other Revenue is broken out into the sub-categories summarized in Table 1 below.

Table 1: Other Revenue Summary

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Specific Service Charges	2.7	3.4	3.3	3.5	3.5	3.5	3.5	3.6	3.7	3.8
Late Payment Charges	2.1	1.7	3.5	4.9	4.6	3.9	4.0	4.1	4.2	4.2
Other Operating Revenues	26.4	27.4	27.5	26.5	27.3	28.1	28.7	29.3	29.9	30.5
Other Income or Deductions	8.1	7.5	13.1	11.3	11.5	12.4	12.6	12.8	13.0	13.3
Total	**39.3**	**40.0**	**47.4**	**46.2**	**46.9**	**47.9**	**48.8**	**49.8**	**50.8**	**51.8**

A complete breakdown of the Other Revenue accounts is shown in OEB Appendix 2-H – Other Operating Revenue (Exhibit 3, Tab 2, Schedule 2).

2. REVENUE FROM SPECIFIC SERVICE CHARGES

Toronto Hydro charges OEB-approved user fees for certain services. Some of these services, such as account set-up, are provided at the customer's request. Other fees result from Toronto Hydro's business operations, such as customers' non-payment of bills.

2020-2021 Variance Explanation

The historical variance between 2020 and 2021 actuals from $2.7 million to $3.4 million is primarily due to an increase in account setup charges driven by a higher volume of customer account set-up requests.

2021-2022 Variance Explanation

The historical variance between 2021 and 2022 actuals from $3.4 million to $3.3 million is primarily due to a decrease in account setup charges driven by a lower volume of customer account set-up requests.

2022-2025 Variance Explanation

The revenue from 2022-2025 is expected to remain stable in accordance with historical volumes of services driving specific service charges.

2025-2029 Variance Explanation

Between 2025 and 2029, revenue from specific service charges is expected to increase by $0.4 million, or an average of $0.1 million per year, in accordance with the growth of Toronto Hydro's customer base and concomitant growth in the volumes of services driving specific service charges.

3. LATE PAYMENT CHARGES

Toronto Hydro applies late payment charges on overdue customer balances in accordance with all applicable legislative and regulatory requirements.

2020-2021 Variance Explanation

The historical variance between 2020 and 2021 actuals from $2.1 million to $1.7 million is primarily due to Toronto Hydro's voluntary reduction of late payment charges as part of the relief provided to customers during the COVID-19 pandemic.[1]

2021-2022 Variance Explanation

The historical variance between 2021 and 2022 actuals from $1.7 million to $3.5 million is primarily due to the resumption of the standard late payment charge rate as the relief measures for customers were lifted by the end of COVID-19 pandemic.

2022-2025 Variance Explanation

Between 2022 and 2025, revenue from late payment charges is expected to significantly increase relative to previous years, as the arrears that customers accumulated over the COVID-19 pandemic cumulatively generate higher amounts of late payment charges. Toronto Hydro expects the increase in late payment charges to stabilize by 2025 as the utility's resumed collections efforts take effect and rein in the arrears caused by the pandemic.

2025-2029 Variance Explanation

Between 2025 and 2029, revenue from late payment charges is expected to increase by $0.3 million, or an average of less than $0.1 million per year, in accordance with the growth of Toronto Hydro's customer base and concomitant volumes of late or unpaid accounts.

[1] Refer to the Customer Care program in Exhibit 4, Tab 2, Schedule 14 for more information on Toronto Hydro's collections and disconnection for non-payment policies during the COVID-19 pandemic.

4. OTHER OPERATING REVENUES

Other Operating Revenues include revenues from Standard Supply Service ("SSS") administration charges, retail service charges, and maintenance of third-party facilities located within Toronto Hydro. It also includes revenues allocated from Toronto Hydro's contract with the City of Toronto for the maintenance of streetlighting assets.

2020-2021 Variance Explanation

The historical variance between 2020 and 2021 actuals from $26.5 million to $27.4 million is primarily due to an increase in revenues related to streetlighting assets and increased costs of streetlighting operations.

2021-2022 Variance Explanation

The historical variance between 2021 and 2022 actuals from $27.4 million to $27.5 million is primarily due to an increase in revenues related to streetlighting assets and increased costs of streetlighting operations.

2022-2025 Variance Explanation

Between 2022 and 2025, other operating revenues are expected to increase by $0.4 million, or an average of $0.1 million per year, in accordance with the growth of Toronto Hydro's customer base and concomitant growth in the volumes of services driving other operating revenues.

2025-2029 Variance Explanation

Between 2025 and 2029, other operating revenues are expected to increase by $2.3 million, or an average of $0.6 million per year, in accordance with the growth of Toronto Hydro's

customer base and concomitant growth in the volumes of services driving other operating revenues.

5. OTHER INCOME OR DEDUCTIONS

Toronto Hydro earns revenue by providing services to customers and third parties, through gains on the sale of reclaimed materials from field, and gains on the disposal of utility property. Toronto Hydro also earns income and recoveries by providing shared services to its affiliates and through interest income from the short-term investment of idle cash balances.

Toronto Hydro divides its Other Income or Deductions into the following categories:

- Merchandise and Jobbing;
- Gains from Sale of Utility Properties;
- Shared Services Revenues and Expenses from Non-Rate-Regulated Utility Operations;
- Miscellaneous Non-Operating Income; and
- Interest Income from Short-Term Investment.

5.1 Merchandise and Jobbing

Toronto Hydro offers some services to customers and third parties for a fee. These services generally exclude those covered by the various OEB-approved specific service charges and are comprised of the following activities:

- Customer requests for isolations, protection, and temporary removals of lines to allow work on customer equipment;
- Repair of damaged distribution plant to be reimbursed by third parties (accident claims);

- Toronto Hydro's make-ready work and permit review for pole and duct attachments and rentals;
- Gains on sale of reclaimed materials from field; and
- Revenues from sale of inventory to third parties.

The revenues and expenses from Merchandise and Jobbing vary significantly from year to year, depending on the number and type of activities requested by customers. As such, forecast of the activities, revenues and expenses from 2023-2025 are based primarily on historical trends, 2025-2029 revenues and expenses forecasted in accordance with the growth of Toronto Hydro's customer base and concomitant volumes of merchandise and jobbing activities.

Toronto Hydro also generates income from the sale of reclaimed materials from field (e.g. scrap metals, reclaimed transformers, cables, etc.). These reclaimed materials are sold at market rates and any revenue depends on the strength of the market commodity prices at the time of disposition and the volume of reclaimed material that is available for processing. Toronto Hydro currently outsources the processing and selling of reclaimed materials to a third party. Proceeds of the sale net of the vendor's cost of disposing the reclaimed materials are remitted to Toronto Hydro.

5.2 Gains from Sale of Utility Properties

Toronto Hydro periodically disposes of surplus facilities, vehicles, and equipment. Over the 2020 to 2022 period, total net gains from sales were $3.6 million, of which the utility has recorded $1.6 million in the Gain on Sale of Property Variance Account in accordance with the OEB's decision from Toronto Hydro's 2020-2024 rate application.[2] For the forecast

[2] EB-2018-0165, Decision and Rate Order (February 20, 2020), Schedule C at pages 2-3. See Exhibit 9, Tab 1, Schedule 1 for more information on the Gain on Sale of Property Variance Account.

period of 2025 - 2029, Toronto Hydro forecasts gains on sale of utility properties of $1.8 million, which is in line with historical averages.

5.3 Shared Services Revenues and Expenses from Non-Rate-Regulated Utility Operations

Toronto Hydro provides shared services to its affiliates and receives income and recoveries through transfer prices determined based on Affiliate Relationship Code ("ARC") requirements. Further details on shared services are provided in Exhibit 4, Tab 5, Schedule 1.

5.4 Interest Income from Short-Term Investment

Toronto Hydro invests its working capital cash balances at a competitive market rate with its cash management bank to generate additional interest income. The interest earned from these short-term investment activities are an offset to Toronto Hydro's interest expense, which reduce the overall distribution revenue requirement and result in lower distribution rates, benefitting ratepayers.

5.5 Other Income or Deduction Year-over-Year Variance Analysis

2020-2021 Variance Explanation

The historical variance for other income or deductions between 2020 and 2021 actuals from $8.1 million to $7.5 million is due to:

- Decrease of $3.3 million in merchandising and jobbing primarily due to lower volume for accident claims, customer and temp services which was partially offset by higher revenues from sale of reclaimed materials.

These variances were partially offset by:

- Increase in gain on sale of property of $2.2 million,

- Increase in gain on foreign exchange and interest income from short-term investment of $0.6 million.

2021-2022 Variance Explanation

The historical variance for other income or deductions between 2021 and 2022 actuals from $7.5 million to $13.1 million is due to:

- Increase of $5.8 million in merchandising and jobbing primarily due to higher volume for customer and temp services and accident claims;
- Increase of $2.0 million primarily due to HST recovery from the Canada Revenue Agency relating to prior rate periods. Toronto Hydro expects this to be a one-time occurrence.

These variances were partially offset by:

- $2.3 million lower gain on sale of properties.

2022-2025 Variance Explanation

Between 2022 and 2025, other income or deductions are expected to be relatively lower by $0.7 million, or an average of $0.2 million per year, given that the peak in Other Income due to the one-time HST recovery is not expected to continue into 2023 or beyond. In addition, Toronto Hydro expects the revenues from merchandising and jobbing and gain on sale of properties to stabilize by 2023.

2025-2029 Variance Explanation

Between 2025 and 2029, other income or deductions are expected to increase by $0.9 million, or an average of $0.2 million per year, in accordance with the growth of Toronto Hydro's customer base and concomitant growth in the volumes of services driving other operating revenues.

OPERATIONS, MAINTENANCE & ADMINISTRATION ("OM&A") OVERVIEW

Toronto Hydro's 2025-2029 Custom Incentive Rate Framework set out in Exhibit 1B, Tab 2, Schedule 1 includes a mechanism to enable multi-year rate funding for operational investments as well as capital expenditure needs. The proposed 2025-2029 Operations, Maintenance & Administration ("OM&A") plan represents the minimum investments necessary to deliver the Distribution System Plan ("DSP") outlined in Exhibit 2B and achieve key outcomes valued by customers and the OEB under the Renewed Regulatory Framework ("RRF").

In addition to enabling Toronto Hydro to attract and retain the necessary resources to carry out its DSP and deliver customer outcomes in next rate period and beyond, the OM&A plan addresses other key operational requirements, including:

- integrating cloud computing and non-wires solutions into operations;
- responding to evolving policy and customer expectations to connect behind-the-meter technologies such as electric vehicles, solar panels, and energy storage;
- protecting customers' data and the grid against intensifying cyber security threats driven by rapid technology advancements and changing geopolitical dynamics;
- complying with new or expanded legal and regulatory requirements, including customer service, safety, and environmental obligations;
- maintaining safe, reliable, and effective operations across a multitude of key utility functions including Emergency Response, Supply Chain, Fleet, Facilities, and Information Technology ("IT");
- addressing a variety of externally-driven costs, including insurance premiums, bad debt expenses, and regulatory costs; and

- keeping up with asset maintenance requirements to ensure the grid remains safe and reliable for customers.

This schedule provides an overview of Toronto Hydro's current 2020-2024 and future 2025-2029 OM&A plan. The drivers underpinning Toronto Hydro's OM&A plan are specific, tangible, and urgent, with the most pressing needs highlighted in section 5 of this schedule, and detailed evidence supporting the entire plan provided in Exhibit 4, Tab 2. Tables 1 and 2 below provide breakdowns of Toronto Hydro's OM&A expenditures by program for the historical and bridge years (2020-2024), and forecast years (2025-2029), respectively.

Table 1: Historical and Bridge Year OM&A Expenditures by Program ($ Millions)[1]

Programs	Actual			Bridge	
	2020	2021	2022	2023	2024
Preventative and Predictive Overhead Line Maintenance	5.8	6.2	5.7	7.2	7.9
Preventative and Predictive Underground Line Maintenance	5.1	4.4	5.7	6.3	6.1
Preventative and Predictive Station Maintenance	5.9	6.4	5.5	6.5	7.0
Corrective Maintenance	23.1	26.5	23.5	24.9	25.6
Emergency Response	22.1	23.0	22.0	20.4	23.1
Disaster Preparedness Management Program	6.0	5.5	4.9	1.3	1.8
Control Centre Operations	7.6	6.0	6.5	7.4	7.9
Customer Operations	9.3	7.5	9.0	12.6	12.8
Asset and Program Management	13.4	11.9	13.1	13.5	14.0
Work Program Execution	11.0	14.2	17.3	14.3	15.2
Fleet and Equipment Services	9.3	8.5	7.8	8.7	9.1
Supply Chain Services	15.8	12.9	13.8	16.7	18.8
Facilities Management	24.3	26.0	25.0	26.0	27.9

[1] Numbers may not sum due to rounding.

Programs	Actual			Bridge	
	2020	2021	2022	2023	2024
Customer Care	55.7	39.3	39.3	44.9	48.4
Human Resources, Environment and Safety	15.5	17.6	16.7	18.9	21.3
Finance	16.4	17.9	18.4	20.9	22.9
Information Technology	48.0	50.6	53.5	57.5	61.1
Legal and Regulatory	18.5	19.0	19.2	24.7	28.0
Charitable Donations and LEAP	1.0	1.0	1.0	1.3	1.4
Common Costs and Adjustments	(0.2)	(0.3)	(1.0)	(1.1)	(0.9)
Allocations and Recoveries	(25.5)	(26.6)	(26.5)	(31.4)	(33.9)
Total OM&A	**288.1**	**277.5**	**280.4**	**301.5**	**325.5**

Table 2: Forecast Year OM&A Expenditures by Program ($ Millions)[2]

Programs	Forecast				
	2025	2026	2027	2028	2029
Preventative and Predictive Overhead Line Maintenance	9.1	9.2	9.6	9.5	9.4
Preventative and Predictive Underground Line Maintenance	6.8	7.0	6.7	7.1	7.0
Preventative and Predictive Station Maintenance	8.0	7.6	7.7	8.6	8.8
Corrective Maintenance	29.5	30.7	31.0	32.0	33.6
Emergency Response	25.9	26.4	27.2	27.9	28.6
Disaster Preparedness Management Program	1.9	1.9	2.0	2.1	2.2
Control Centre Operations	8.3	9.0	9.5	10.0	10.5
Customer Operations	12.7	13.1	13.7	14.1	14.6
Asset and Program Management	14.2	15.8	16.6	17.9	18.7
Work Program Execution	16.0	16.8	17.9	18.5	19.4
Fleet and Equipment Services	9.3	9.6	9.8	10.0	10.3
Supply Chain Services	21.5	23.5	24.9	25.5	27.1
Facilities Management	27.9	28.4	28.9	29.6	30.3
Customer Care	48.6	51.6	52.5	54.4	56.1

[2] Numbers may not sum due to rounding.

Programs	Forecast				
	2025	2026	2027	2028	2029
Human Resources, Environment and Safety	22.6	23.2	24.2	25.3	26.3
Finance	24.4	26.2	27.6	29.4	31.1
Information Technology	63.3	65.8	68.7	71.7	75.1
Legal and Regulatory	29.9	30.9	32.0	33.2	34.2
Charitable Donations and LEAP	1.5	1.6	1.7	1.8	1.9
Common Costs and Adjustments	(0.9)	(0.9)	(0.8)	(0.8)	(0.8)
Allocations and Recoveries	(37.5)	(39.4)	(41.2)	(42.3)	(44.8)
Total OM&A	**343.0**	**358.0**	**370.2**	**385.5**	**399.6**

The programs that constitute Toronto Hydro's plan are largely a continuation of its 2020-2024 OM&A programs, which are critical to the safe and reliable operation of the distribution system, delivering timely and effective customer-facing services, and fulfilling critical corporate functions that allow the utility to operate in a financially responsible and legally-compliant manner. However, the utility is not operating in a stable state as detailed in the discussion of the funding need in the Rate Framework in Exhibit 1B, Tab 2, Schedule 1, and discussed in brief below. Instead, these operational programs must be delivered in an environment of increased volume and increased complexity of work driven by evolving customer needs, requirements, and expectations.

The information presented in this OM&A overview schedule is organized as follows:

- Section 1 contextualizes Toronto Hydro's OM&A investment plan;
- Section 2 outlines historical productivity and benchmarked efficiency trends;
- Section 3 presents the workforce needs and challenge underpinning the plan;
- Section 4 describes Toronto Hydro's business planning process;
- Section 5 identifies key drivers necessitating forecast OM&A expenditures; and

- Section 6 sums up the preceding information with a macro level causal track analysis showing the variance drivers from the 2020 OEB-approved OM&A budget to the 2025 test year and 2029 forecast year.

1. THE OM&A PLAN IN CONTEXT

In the current rate period, Toronto Hydro's operating parameters shifted from a relatively linear and stable environment to a more dynamic, growth-oriented context, predicated on significant increases in future customer demand driven by an unprecedented energy transition that is creating new and expanded roles for electricity within the economy. The DSP in Exhibit 2B outlines in detail the capital investments required to address these new imperatives, while also sustaining existing infrastructure in accordance with good utility practices. However, asset readiness is only part of the solution required to meet the needs of customers and the system in an electrified future state. Toronto Hydro must also invest in human capital and other operational priorities to deliver the increasing and evolving capital plan and ensure that customers are not underserved in the next decade as the pace of the energy transition intensifies.

As the utility takes least-regrets actions to expand and modernize the grid to be ready and equipped for a once-in-a century transformation of the energy system, it similarly needs to invest in resources with new and enhanced skill sets to get the work done safely and cost-effectively. However, not all of these resources can be capitalized under existing accounting standards and practices, nor do all the solutions to expand and modernize the grid entail capital investments. Technological advancements offer new digital tools and smart grid solutions to address system needs and deliver cost-effective customer services. Taking advantage of these opportunities requires investment in both capital assets (i.e. hard infrastructure like sensors, switches, and reclosers, and intangibles like software

systems) and in operational programs where approximately 50 percent of the costs related to human capital typically reside.

Since 2015, Toronto Hydro has served the needs of a growing city, evolving customer and policy demands, and an aging and deteriorating system, while addressing intensifying challenges—brought on by factors such as urban development and densification, more frequent instances of extreme weather, and evolving cyber security threats—with a staffing complement that is essentially flat from 2015 to 2024. After nearly a decade of realizing sustained efficiencies and managing complex operations with a flat headcount, Toronto Hydro requires incremental funding to hire and retain necessary resources without compromising the utility's financial viability.

Entering the next rate term, it is no longer possible nor prudent for Toronto Hydro to meet its obligations without additional resources. From 2024 through to 2029, Toronto Hydro's workforce is expected to grow by roughly 25 percent to sustain the foundations of a safe and reliable grid while also meeting the imperatives of an urban city and customers who are increasingly relying on electricity to expand, digitize, and decarbonize their footprint. Relative to the increase in the capital plan that the utility must deliver to get the grid ready and achieve outcomes for customers during this transformational time, the pace of workforce growth and related OM&A increases demonstrates Toronto Hydro's ongoing commitment to be efficient and productive. Specifically, the linear trends in Figure 1 below shows that from 2015-2029 (a 14-year period spanning three custom incentive rate cycles) Toronto Hydro has delivered, and intends to continue delivering, a larger capital program with an increase in resourcing and related OM&A costs that is comparatively much lower than the rate of growth in the capital program.

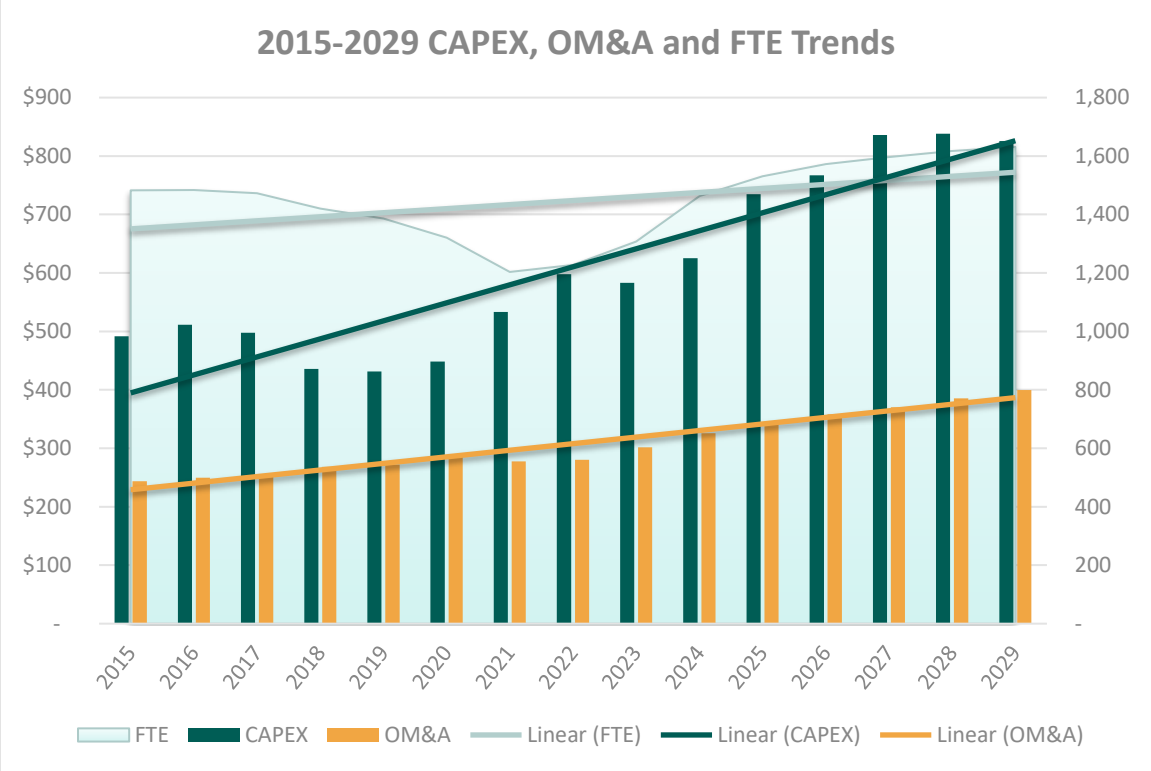


Figure 1: Comparing 2014-2029 Linear Trends in CAPEX, OM&A and FTEs

The full-time employee ("FTE") and OM&A trends identified in Figure 1 above reflect the continuation of a productivity journey in the last decade that has produced a demonstrably lean staffing complement. Notably, benchmarking shows that relative to other large and mid-sized distributors in Ontario, Toronto Hydro's workforce is well below the average when compared using various key ratios such as of net fixed assets ("NFA") per FTE, FTEs by system load (MWh), and FTEs per km of line. This benchmarking data is presented and further detailed in section 2 below.

1.1 Key Themes and Trends

Toronto Hydro's 2025-2029 OM&A plan is forecasted at approximately $1,856 million, representing a 26 percent increase over the current 2020-2024 period, compared to a 44

percent proposed increase in capital investment, as outlined in the DSP in Exhibit 2B. Efficient deployment of operational funding and staffing costs over the last decade, as further discussed below, has enabled Toronto Hydro to bring forward in this application an operational plan that (i) supports the execution of a larger capital program necessary to expand and modernize the grid for the future, while (ii) continuing to deliver high performance on service quality metrics, with (iii) an increase in operational budgets that is comparatively lower than the capital program.

In 2025, the first year of the next rate period, Toronto Hydro's forecasted OM&A budget is approximately $343 million, representing a compound annual growth rate of 5.16 percent from the utility's approved OM&A in the 2020 rebasing application (EB-2018-0165). On a per customer basis, the compound annual growth rate ("CAGR") from the 2020 approved to the 2025 proposed budget is approximately 4.66 percent. Over the same period (2020 to 2025), Toronto Hydro's OM&A costs per FTE (a measure of workforce productivity per OEB Appendix 2-L),[3] are increasing at a CAGR of 2.1 percent, which is less than the average rate of inflation over this period, per the OEB's parameters for 2021-2024,[4] and assuming a return to stable pre-pandemic inflation levels of 2 percent in 2025, consistent with the Bank of Canada's economic outlook.[5] Inflation is a measure that reflects the increasing cost of input prices, including labour. The fact that operational expenses per FTE are growing at a rate less than inflation shows that input prices related to labour are being managed efficiently through the utility's compensation and staffing

[3] OEB Filing Requirements for Electricity Distribution Rate Applications Chapter 2 – Cost of Service (December 15, 2022), s. 2.4.2 "OM&A Summary and Cost Driver Tables".
[4] OEB Letter Re: *2021 Inflation Parameters* (November 9, 2020); EB-2021-0212, OEB Decision and Order, *2022 Input Price Index Generic Proceeding* (November 18, 2021); OEB Letter re*: 2023 Inflation Parameters* (October 20, 2022); OEB Letter re: *2024 Inflation Parameters* (June 29, 2023).
[5] Bank of Canada, *Monetary Policy Report* (October 2023), online: <https://www.bankofcanada.ca/wp-content/uploads/2023/10/mpr-2023-10-25.pdf> at page 1.

strategy. Table 3 below details the facts and trends outlined above, which are also presented in OEB Appendix 2-L at Exhibit 4, Tab 1, Schedule 5.

Table 3: 2020-2025 OM&A Trends

	2020 Test	2021 Actuals	2022 Actuals	2023 Bridge	2024 Bridge	2025 Test	2020-24 CAGR
OM&A ($M)	266.7[6]	277.5	280.4	301.5	325.5	343.0	**5.16%**
OM&A per Customer ($)	341.3	352.9	354.6	379.7	408.2	428.5	**4.66%**
OM&A per FTE ($)	201,892	230,673	228,524	230,680	222,488	224,036	**2.10%**

Over the next rate period, from 2025 to 2029, Toronto Hydro forecasts OM&A costs to increase at a CAGR of 3.89 percent with a corresponding growth in OM&A per customer of 3.54 percent and OM&A per FTE of 2.26 percent, as shown below in Table 4.

Table 4: 2025-2029 OM&A Trends

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2025-29 CAGR
OM&A ($M)	343.0	358.0	370.2	385.5	399.6	**3.89%**
OM&A per Customer ($)	428.5	445.6	459.3	476.7	492.6	**3.54%**
OM&A per FTE ($)	224,036	227,735	231,954	238,404	245,003	**2.26%**

The growth trends observed in Tables 3 and 4 above are subject to important considerations regarding workforce-related and customer-correlated costs.

[6] In EB-2018-0165, the OEB approved a 2020 OM&A budget of $272.2 million and directed Toronto Hydro to amend the presentation of shared services within Other Revenue, under USoA Accounts 4375 and 4380 for revenues and expenses of non-rate regulated utility operations. Normalized for this change, the 2020 OEB-approved OM&A budget was $266.7 million.

1.1.1 Workforce Related Costs

Despite workforce being a key driver of the OM&A plan, staffing-related costs (as measured by OM&A per FTE metrics) are growing at a lower rate than the overall plan. Over both rate periods, from 2020 through to 2029, the OM&A CAGR is 4.6 percent whereas OM&A per FTE CAGR is roughly 2.17 percent. Additionally, the OM&A per FTE growth rate over this period is lower than the rate of inflation, which averages at 3.5 percent using OEB parameters for 2021-2024 and a 2 percent outlook for 2025-2029, assuming a return to stable pre-pandemic inflation levels of 2 percent, consistent with the Bank of Canada's economic outlook.[7]

Toronto Hydro requires a custom rate funding solution to secure the human capital necessary to deliver the 2025-2029 investment plan safely and efficiently, maintain the high-service quality performance improvements achieved in the last decade,[8] and achieve other important outcomes that customers need and value such as improving the resilience of the grid.[9] Neither cutting compensation costs nor cutting headcount are viable strategies to manage these key objectives within a standard IRM funding framework. Managing workforce-related costs downwards to live within a standard IRM funding paradigm would entail a reduction to Toronto Hydro's overall staffing complement of up to 200 resources by the end of the rate period, putting total FTEs below 2015 levels. Since Toronto Hydro already has a demonstrably lean workforce compared to other distributors in the province, as evidenced by the benchmarking results in section 2, such a reduction to its staffing complement is not possible or prudent because it would put resourcing at precariously low levels and compromise the utility's performance with

[7] *Supra* note 5.
[8] Exhibit 1B, Tab 3, Schedule 2.
[9] Exhibit 1B, Tab 3, Schedule 1.

respect to a multitude of outcomes and risks that pose significant consequences for customers, as further detailed in sections 3 and 5.1 below.

Similarly, reducing compensation costs per employee is not a viable strategy to live within standard IRM funding for OM&A. The Mercer Compensation Benchmarking study at Exhibit 4, Tab 4, Schedule 5 and similar benchmarking studies filed in past rate applications show that Toronto Hydro's compensation strategy consistently yields costs (i.e. salary and wages) that are market-competitive at the 50th percentile within both the energy sector and general industry. A material reduction to compensation costs per employee, which would have to be implemented by effectively freezing salaries and wages over the 2025-2029 period, would put Toronto Hydro out of compliance with its collective agreement obligations and place the utility's compensation below market levels, compromising its ability to attract and retain the talent it needs to serve customers.

1.1.2 Customer-Correlated Costs

The other key observation to point out with respect to the cost per customer trends observed in Tables 3 and 4 above is that operating in Canada's densest and fastest (vertically) growing city, Toronto Hydro serves far more end-use customers through bulk-metering and competitive sub-metering arrangements than its actual customer count would otherwise indicate. Based on self-declarations submitted by multi-unit residential buildings for the purposes of Regulated Price Plan elections and the Ontario Electricity Rebate ("OER") program, Toronto Hydro estimates that it serves approximately 340,000 end-consumers or more behind bulk meters. As the sub-metering market has become more mature in Toronto over the last decade, a greater share of new multi-unit buildings

opt for bulk-metering service connections.[10] The practical effect of operating in this urban environment with a deregulated sub-metering market is a slower rate of formally reported customer growth from 2015 to 2029, which is putting artificial upward pressure on cost performance metrics like OM&A per customer, as shown in Figure 2 below.

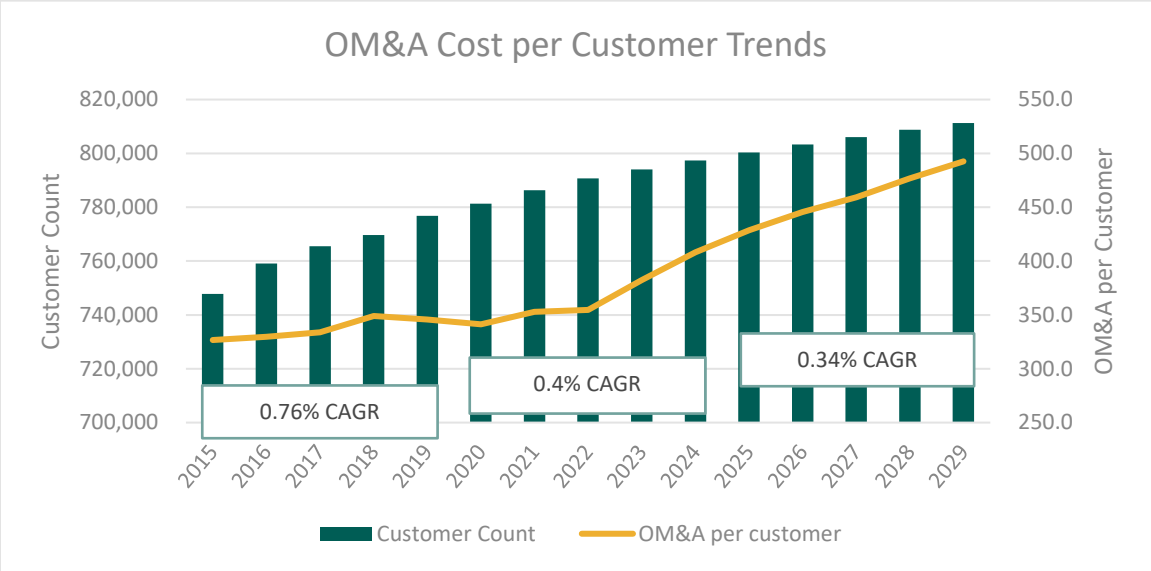


Figure 2: 2015-2029 OM&A Cost per Customer Trends

1.2 Service Quality and Performance Outcomes

Toronto Hydro's OM&A expenditures contribute to the achievement of the Renewed Regulatory Framework ("RRF") outcomes,[11] as measured by the Electricity Distributor Scorecard ("EDS") and Electricity Service Quality Requirements ("ESQRs") outlined in Exhibit 1B, Tab 3, Schedule 2. Each OM&A program enables outcomes that Toronto Hydro

[10] Toronto Hydro estimates that its market share for suite metering new multi-unit buildings is now approximately 30 percent, compared to approximately 70 percent in 2013.
[11] Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, (October 18, 2012), at page 57.

expects to be attained as a result of the proposed investment and are categorized into the four outcome categories under the RRF; namely, Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance.[12] This approach underscores the customer value generated by the proposed OM&A programs.

Over the last decade, Toronto Hydro managed operational funding efficiently, as further discussed below, while delivering notable improvements in service quality and other performance metrics for its customers. For example, Toronto Hydro improved its performance on first contact resolution, a key measures of customer experience and satisfaction, from 77 percent in 2013 to 92 percent in 2022. Similarly, the utility improved connections-related performance, as measured by the metric New Residential and Small Business Services Connected on Time, from 94 percent in 2013 to 99 percent in 2022.[13]

Over the 2025-2029 rate period, Toronto Hydro intends to maintain these performance improvements and make targeted improvements in other areas such as: (i) strengthening protection against physical and digital security threats, (ii) improving efficiency outcomes through the use of non-wires solutions to avoid or defer the need for traditional capital investments, and (iii) strengthening resilience through proactive investments in modern grid technology as outlined in the Grid Modernization Strategy in Exhibit 2B, Section D5. These and other key performance objectives are outlined in Toronto Hydro's 2025-2029 Custom Scorecard in Exhibit 1B, Tab 3, Schedule 1.

[12] The outcomes listed in each program are directly connected to, and dependent on, the forecasted funding needs for the program. Any change in overall rates funding for the term of the plan would require Toronto Hydro to reforecast cost allocation to each program and re-examine the corresponding outcomes.
[13] Please refer to Exhibit 1B, Tab 3, Schedule 2 for more information about the utility's historical performance.

The OM&A programs detailed in Exhibit 4, Tab 2 work together with the capital programs outlined in Exhibit 2B, Section E to enable the achievement of the key performance commitments across four areas of performance in the 2025-2029 Custom Scorecard: (1) System Reliability and Resilience; (2) Customer Experience and Service; (3) Environment, Safety, and Governance; and (3) Efficiency and Financial Performance. Investments in operational programs as detailed herein and importantly, the resources that underpin these programs, are essential to meeting the performance targets outlined in Exhibit 1B, Tab 3, Schedule 1.

2. Productivity & Benchmarking

Using publicly available data,[14] the historical benchmarking analysis presented in this section demonstrates that Toronto Hydro (i) has a lean workforce compared to its Ontario peers and (ii) is a strong OM&A cost performer compared to other large and mid-sized distributors in the province.[15] Toronto Hydro's efficient OM&A and staffing cost management to date positions the utility well to address a growing need for investments in operations and resourcing without creating undue cost burdens and rate increases for customers in the next rate term.

2.1 OM&A Metrics

Figures 3 and 4 below compare OM&A expenditures against capital expenditures and system load (MWh), respectively, over the 2016 to 2022 period for Toronto Hydro and the identified distributor peer group. When comparing OM&A expenditures to capital

[14] Using publicly available data that utilities including Toronto Hydro reported to the OEB under the Electricity Reporting and Record Keeping Requirements ("RRR").

[15] The peer group consists of the large and mid-sized Ontario distributors: Hydro One, Hydro Ottawa, Alectra Utilities, Elexicon Energy, London Hydro, EnWin Utilities, and Enova Power. With the exception of Elexicon and Hydro One, these distributors serve the top 10 cities in Ontario (by population size). Hydro One was included in the peer group because it serves approximately 90 percent of the service territory in the province, and Elexicon Energy was included because it is the fourth largest municipally owned electricity distributor in the province.

expenditures (Figure 3), Toronto Hydro spends considerably less OM&A relative to capital in comparison to the peer group, in many years showing an OM&A-to-CAPEX ratio of less than half that of the peer group. Toronto Hydro's OM&A per MWh of load (Figure 4) is more comparable to that of other large distributors, but remains lower than that of the peer group for all years analyzed.

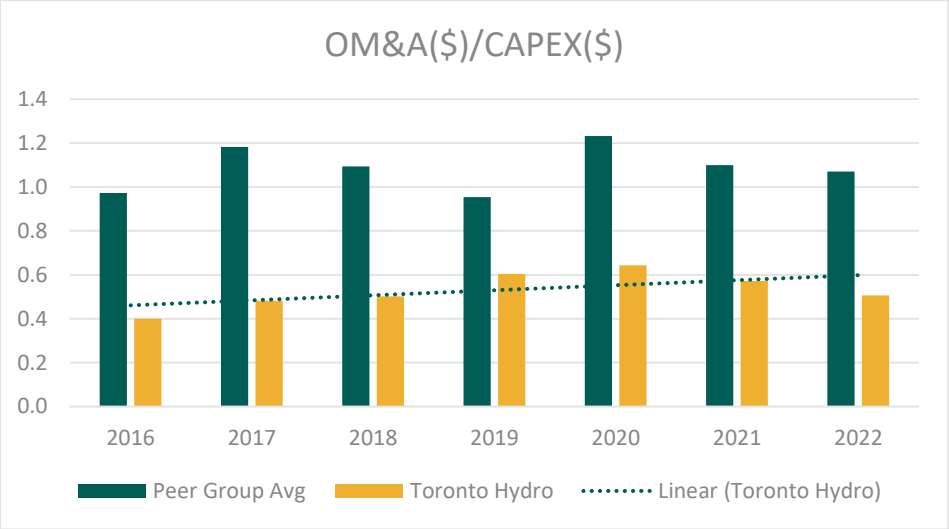


Figure 3: OM&A relative to Capital Expenditures

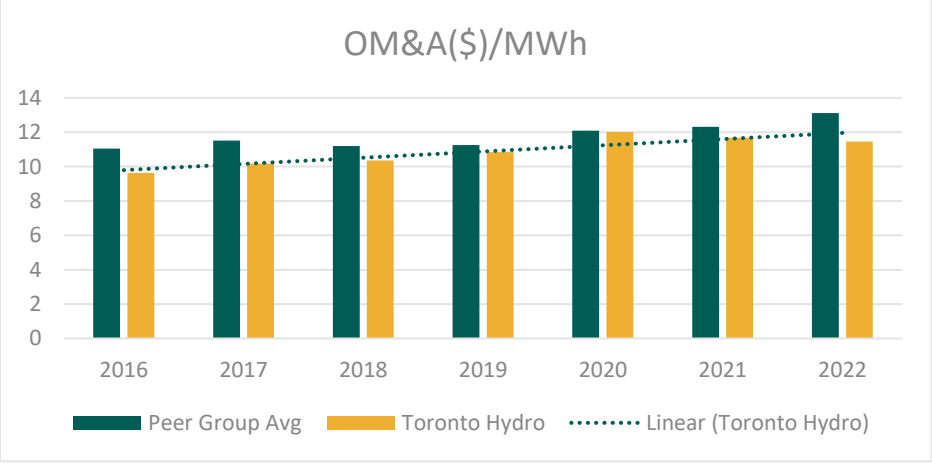


Figure 4: OM&A Expenditure per MWh of Load

2.2 FTE Metrics

Figures 5, 6, and 7 below compare total FTEs against capital expenditures, load (GWh), and circuit-km over the 2016 to 2022 period for Toronto Hydro and the identified distributor peer group. Toronto Hydro has a considerably lower FTE per $1 million in capital expenditures relative to the peer group, staffing an average of 2.86 FTE per $1 million in capital expenditure, compared to an average of 7.5 FTE for the peer group. Similarly, there is a noticeable gap between Toronto Hydro and the peer group with respect to the number of FTEs per GWh of load and per circuit-km.

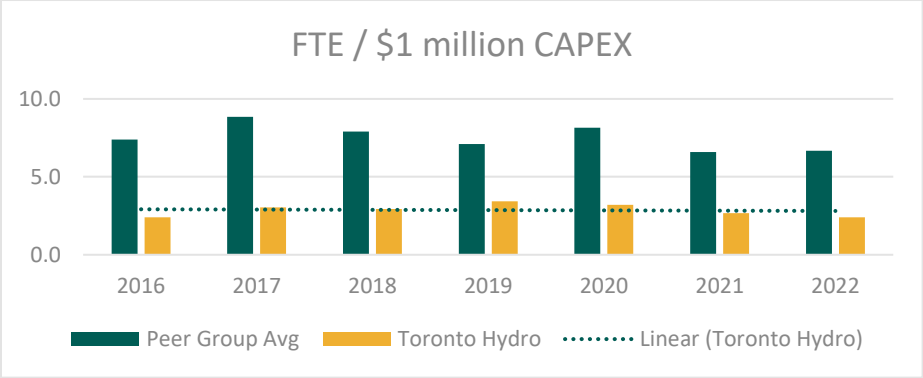


Figure 5: FTE per $1 million Capital Expenditures

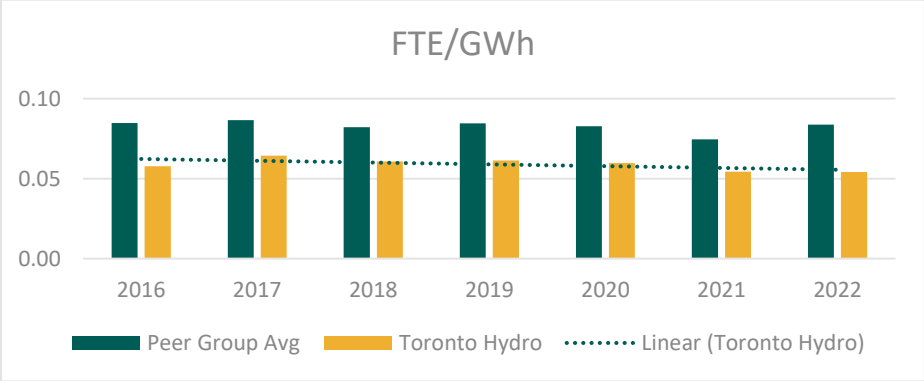


Figure 6: FTE per GWh of Load

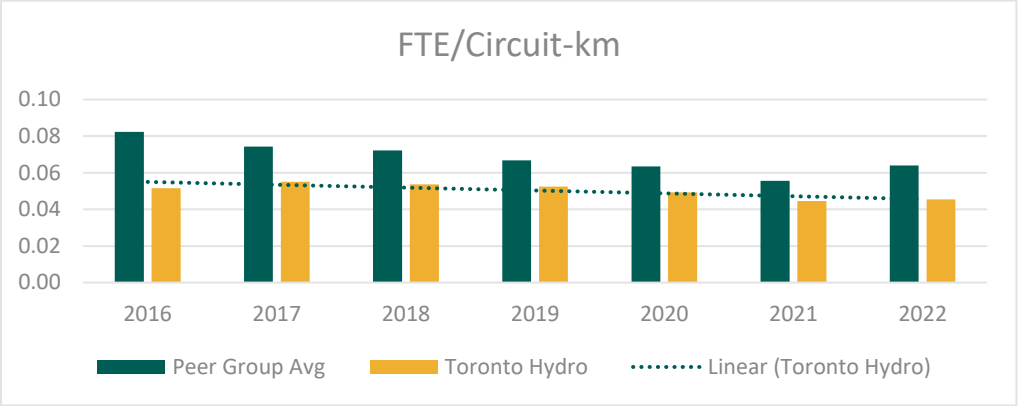


Figure 7: FTE per Circuit-Km

2.3 Customer Metrics

Figures 8, 9, and 10 below compare FTEs, OM&A expenditures, and MWh of load relative to customer count over the 2016 to 2022 period for Toronto Hydro and the identified distributor peer group. Subject to the practical caution articulated above in subsection 1.1.2, customer metrics provide another tool for assessing Toronto Hydro's performance against its peers. With respect to FTE per customer, Toronto Hydro's staffing is consistent with or better than the peer group. At first glance, Toronto Hydro appears slightly "behind" the average of other large Ontario distributors when examining OM&A per customer, but closer examination shows that Toronto Hydro requires more system capacity, more assets and hence more resources per customer than other large or mid-size distributors in Ontario. In part, this is driven by Toronto Hydro customers serviced behind bulk meters, which skews the evaluation of performance against customer count. Examination of MWh of load relative to customer count demonstrates this reality, with Toronto Hydro providing an average of 31.8 MWh per customer, approximately 35 percent more load per customer relative to the peer group multi-year average of 23.6 MWh.

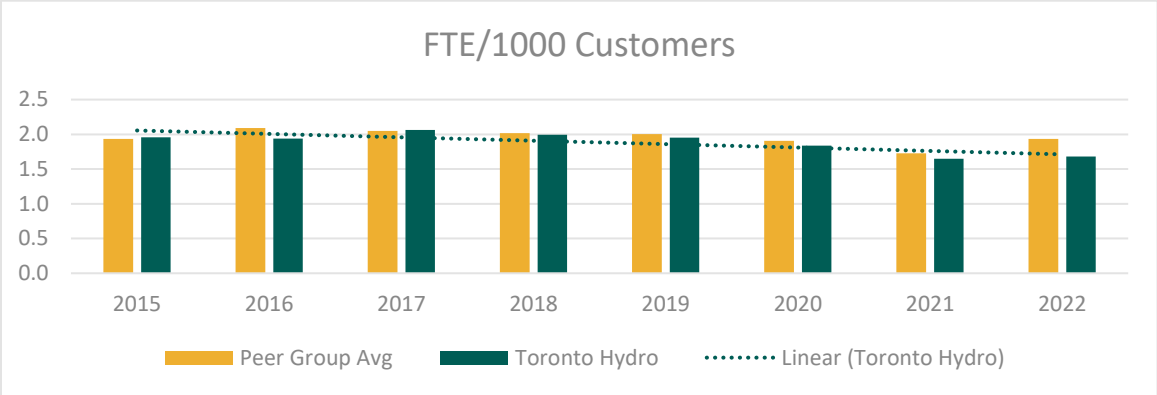


Figure 8: FTE per 1,000 Customers

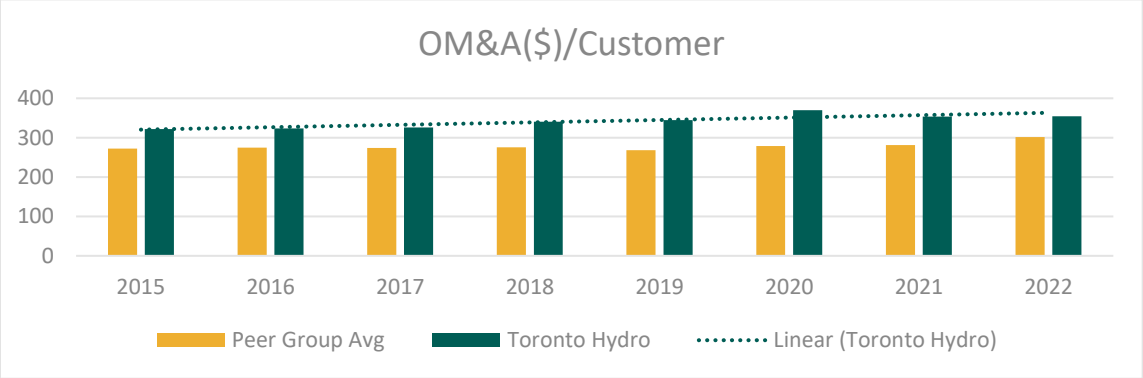


Figure 9: OM&A Expenditure per Customer

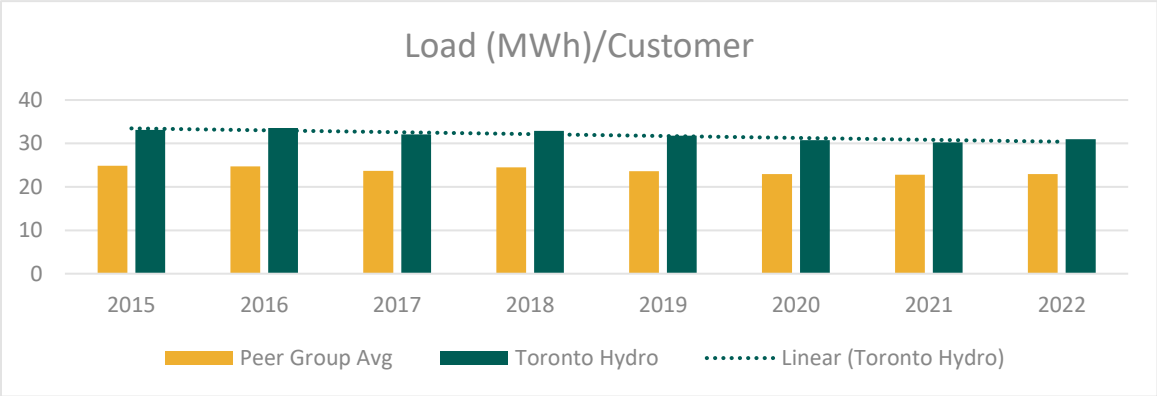


Figure 10: MWh of Load per Customer

3. WORKFORCE NEEDS AND CHALLENGES

With compensation costs representing a large portion of the utility's 2025-2029 OM&A budget, the need for resources and the ability to fund prudent costs to attract and retain those resources is the biggest driver of the multi-year OM&A need.

Figure 11 below shows the overall profile of Toronto Hydro's FTEs from 2015 to 2029, consistent with data provided in the current and previously filed iterations of Appendix 2-K, which excludes students as they are temporary resources.

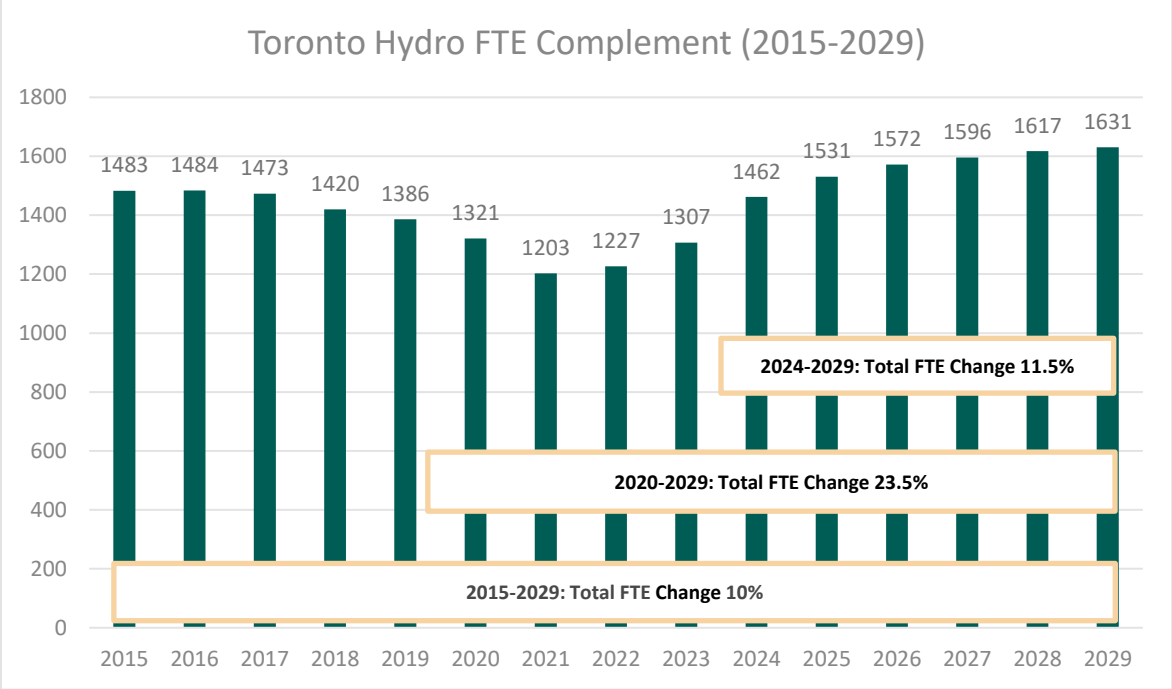


Figure 11: 2015-2029 FTE Complement (Appendix 2-K)

From 2015 to 2029 Toronto Hydro expects total FTEs to increase by 10 percent. This FTE count overlays a period of time in which Toronto Hydro's annual capital expenditure plan is growing by roughly 70 percent, while the customer count is expected to grow by approximately 8.5 percent, including the addition of larger and more complex customers

such as data centres and transit systems. A growing customer base and expanding capital program both place constraints on staff resources, with distinct tasks increasing in volume as the utility serves more (and larger) customers and executes more individual capital projects.

In the 2020-2024 rate application (EB-2018-0165), Toronto Hydro brought forth a workforce plan that was responsive to the circumstances of the day, being a more stable and linear operating environment. Despite significant disruption caused by the COVID-19 pandemic, the utility expects to successfully implement its resource plan over the current rate period. However, fundamental shifts have taken place since EB-2018-0165 which have material implications for Ontario's energy sector and Toronto Hydro's business, and require responsive action over the 2025-2029 rate period.

As the worst of the COVID-19 pandemic subsided, customers, governments, and markets began to coalesce around a need to accelerate the energy transition to mitigate the existential and economic impacts of climate change. Fueled by technology trends including the declining cost of solar photovoltaic and battery technologies, government policies encouraging climate action, and financial markets driving a greater focus on ESG imperatives, customer needs and expectation for electricity are rapidly evolving. As customers electrify previously non-electric energy uses (e.g. transportation, heating) and increase participation in clean energy production and management, these actions will have fundamental long-term implications for Toronto Hydro and its system, including—but not limited to—being ready to serve a future demand for electricity that is expected to roughly double over the next two decades.[16]

[16] As shown in the Future Energy Scenarios report filed at Exhibit 2B, Section D4, Appendices A and B.

Given its fundamental obligation to connect customers who want to access the distribution grid, Toronto Hydro cannot enter this period of significant change unprepared to handle increased demand and consumption, bi-directional power flows, increased societal reliance on electricity, and enhanced customer expectations that naturally flow from these evolutions. Due to the long lead time required for investment in both grid and human capital, to meet these needs Toronto Hydro must begin work today to be prepared for an accelerated energy transition in the next decade.

Toronto Hydro's response to changing circumstances began in earnest in 2022 after COVID-19 related disruptions in 2020 and 2021 brought its staffing contingent to a low point of 1,203 FTEs in 2021. As seen in the Employee Costs and Compensation Table (Appendix 2-K) filed in Exhibit 4, Tab 4, Schedule 2, from 2022 through 2023 Toronto Hydro has been primarily "catching up" to the staffing levels projected in the 2020-2024 rate application. Yet, because the external environment has changed, these catch-up efforts are also a foundational step towards a future-ready plan that includes investments in resourcing capacity (headcount) and capabilities (enhanced skills) that are necessary to deliver the 2025-2029 DSP and key outcomes outlined in Exhibit 1B, Tab 3, Schedule 1.

As Toronto Hydro prepares to enter its next rate period, staffing levels are forecasted to grow by 25 percent over the 2024 through 2029 period. Due to the necessity of long lead time investments in human capital (see below), this growth is higher in the beginning years and more gradual over the rest of the period, focused on scaling teams that require additional resources and expanded skills to plan, design and execute capital and operations work programs.

Just as it takes years to build new transformer station or convert an area of the city served by legacy infrastructure to modern standards, human capital investments require long lead times, with the average employee undergoing two years training and development before becoming a fully competent contributor due to the specialized nature of the skills and experience required to work in this sector. For certain trades, it takes anywhere from four and a half to six and a half years to train a new certified and skilled tradesperson, plus a minimum additional one to two years to develop a new frontline leader post-apprenticeship.

Toronto Hydro often hires capable, but relatively inexperienced employees, with the intention to develop them in-house through on-the-job training and mentoring by tenured staff who can ensure effective knowledge and skill transfer to the next generation of employees. Combining this practice with continued pace of baby-boomer retirements, Toronto Hydro's workforce has an average age of 40, having declined by 14 percent over the last decade.

A key part of Toronto Hydro's talent strategy is a trade school for field trades such as Power Line Technicians and Distribution System Technologists to develop them from apprentices to journeypersons. This talent strategy is fuelled by partnerships with colleges and universities for direct recruiting and collaborative curriculum building. The relationships with academic institutions extend to other areas of technical expertise, including engineers, engineering technologists and technicians, computer systems developers and programmers, software developers and programmers, cyber security specialists, database analysts, data administrators, accountants, lawyers, and human resources ("HR") professionals. The utility's development program ensures it has both a strong workforce today and a healthy pipeline of talent for the future.

An expanded workforce means that compensation costs must also increase to keep pace. From 2024 to 2029, as the utility's workforce grows by approximately 11.5 percent, total compensation expenses are expected to increase by compound annual growth rate of 6.9 percent. Total cash compensation per FTE is forecast to increase at rate of 3.7 percent over the 2020 to 2029 period, consistent with economic assumptions in section 4.2.6 and in the Compensation evidence.[17] The Mercer compensation benchmarking study filed at Exhibit 4, Tab 4, Schedule 5 and similar benchmarking studies filed in past rate applications affirm that Toronto Hydro's compensation philosophy continues to deliver good value for the utility and its customers, concluding that Toronto Hydro's total compensation is positioned within a market competitive median.

4. Business Planning

This section describes Toronto Hydro's business planning process to arrive at the operational plan summarized in this schedule and detailed throughout Exhibit 4.

4.1 Planning Process

Toronto Hydro leveraged its established integrated business planning process to produce a 2023-2029 operational plan that enables the delivery and complements the priorities and outcomes of the capital plan, while maintaining the safety and reliability of the distribution system, enabling non-wires solutions, enhancing customer experience in accordance with broader societal trends, keeping the utility abreast of all applicable policy, legislative, and regulatory developments, and equipping support functions with the tools and resources required to enable these outcomes.

[17] For more information about Compensation costs please refer to Exhibit 4, Tab 4, Schedule 4.

As discussed in Exhibit 2B, Section E2, Toronto Hydro began its business planning process in 2022 by obtaining feedback about customers' needs and priorities with respect to the 2025-2029 planning period (Phase 1 Customer Engagement).[18] Customers expressed that price, reliability, and investing in new technology are their top priorities, with reliability increasing in relative importance compared to previous engagements. Customers also expressed that they expect Toronto Hydro to invest in system capacity to ensure that growth does not decrease reliability and to support their electrification objectives. This feedback enabled Toronto Hydro to develop a capital plan organized around four investment priorities: 1) Sustainment and Stewardship; 2) Modernization; 3) Growth; and 4) General Plant.

The utility used customer feedback, along with other business and technical inputs such as asset health demographics, system constraints, safety and environmental risk assessments, business conditions and risks, legislative and regulatory requirements, cost inputs for materials, and labour and external services, to produce the capital and system maintenance plans through the Investment Planning and Portfolio Reporting ("IPPR") process described in Exhibit 2B, Sections D1 and D3.

Following the development of the capital and maintenance plan, the utility determined the workforce complement, external services, equipment, materials, and other operational resources that it will need to execute the capital plan and keep up with growing customer requirements, changing technologies, and evolving policy expectations. Through a series of iterative engagements between operational leaders, system planners, and specialists from support services such as Finance and Human

[18] For more detailed information about the Customer Engagement process that Toronto Hydro followed, please refer to Exhibit 1B, Tab 5, Schedule 1.

Resources, Toronto Hydro produced an operational plan (inclusive of workforce requirements) that was integrated with the capital and maintenance plans.

As further detailed in Exhibit 2B, Section E2, to guide the development of the plan in a way that balances price and service quality outcomes, Toronto Hydro set a strategic planning direction which included a price limit of 7 percent per year on the average annual distribution rate increase for residential customers. This price limit translated into an upper budget limit of $1.9 billion for the operational plan over the 2025-2029 rate period.

Various iterations and refinements took place over the course of planning process, as leaders across the organization worked cross-functionally to align, optimize, and stress-test capital and operational expenditure levels to ensure compatibility between objectives and strike balance between price and service quality outcomes. These engagements produced a multi-year workforce plan which aims to ensure that Toronto Hydro has the necessary capacity (headcount) and capabilities (skillsets) to execute the investment plan.

Once a draft plan was produced that aligned with the strategic planning direction, Toronto Hydro took the draft plan back to customers for feedback via a comprehensive customer engagement process (Phase 2), whereby customers provided input on seven key investment options, by indicating their preferences on whether to increase, maintain, or reduce the pace of investment, and the specific trade-offs between price and other outcomes for each area. The utility used the results of the Phase 2 Customer Engagement, as well as other salient information such as 2022 year-end actual data, to finalize the capital and operational plans. The assumptions underpinning the operational plan,

including the headcount plan, were refined alongside the capital plan, resulting in the $1,856 million OM&A plan summarized in this schedule and detailed in Exhibit 4, Tab 2.

4.2 Planning Inputs

Toronto Hydro relied on a broad variety of inputs to ensure that its operational plan aligns and supports the priorities of the capital plan, and delivers customer-valued outcomes, while prudently controlling costs. In producing the operational plan, the utility applied an inflationary increase approach to existing budgets and then layered on incremental requirements and priorities derived from the planning inputs summarized below.

4.2.1 Customer Needs and Priorities

Toronto Hydro's operational plan for the 2025-2029 rate period was informed by extensive application-specific, as well as ongoing customer engagement activities undertaken in the normal course of business. As discussed briefly in section 4.1 above and in greater detail in Exhibit 1B, Tab 5, Schedule 1, the utility undertook a two-phase application-specific customer engagement to learn about customers' needs and priorities to build a draft plan that is responsive to those needs and priorities, and obtain customer feedback on the draft plan across key investment areas. The plan is also informed by extensive ongoing customer and stakeholder engagement activities undertaken in the normal course of business as part of the utility's robust and sophisticated customer research and response model, as described below in section 3 of Exhibit 1B, Tab 5, Schedule 1.

Ongoing and application-specific research reveals that customer behaviour and attitudes are evolving, and there is a shift in terms of customers needs and priorities. These include:

- Reliability and investment in new technology have become increasingly important to customers, and are almost on par with price.
- Customers are looking for information to improve their understanding of climate change, decarbonization and electrification, as well as an understanding of Toronto Hydro's role in these initiatives, while at the same time looking for opportunities to reduce their overall energy costs.
- Many customers have strong expectations for Toronto Hydro to commit to environmental initiatives and lessen environmental impact.
- Customers have evolving communication preferences – email is the preferred method of contact for all communications and younger Torontonians, in particular, have above-average preference for SMS communications.
- Customers have shown more concern for the future of the electricity system and the grid than in past years.

As key sectors of the economy shift towards electrification, the volume and complexity of customer needs and inquiries are expected to increase. Toronto Hydro's customer response model is becoming more efficient at understanding and responding to customer requirements quickly, and improving customers' self-service experience through the introduction of various self-service tools (such as an improved online self-service portal and a new mobile application). Yet, the utility needs more resources with the necessary knowledge and skills to maintain an agile and robust customer research and response model as the energy transition unfolds. The 2025-2029 operational plan reflects Toronto Hydro's drive to meet these needs in the next rate period and beyond.

4.2.2 Asset Maintenance Requirements

Toronto Hydro determines asset maintenance requirements, including system response and customer-driven work activities, through its annual Investment Planning and Portfolio Reporting ("IPPR") process, detailed in Exhibit 2B, Sections D1 and D3 whereby the utility: (i) establishes asset management policies, goals, and objectives, as informed by corporate strategies and customer needs, expectations, and feedback; (ii) assesses the current state of assets based on asset demographics and condition; (iii) identifies the required expenditure levels to manage risk and achieve intended outcomes; and (iv) tracks execution status and expenditures to inform future projects.

Toronto Hydro also considers asset management and maintenance considerations for general plant infrastructure, namely vehicle fleet, facilities, and IT assets and systems, which serve as the backbone for all capital and operational programs. The safe, reliable, and efficient operation of these assets is crucial to Toronto Hydro's successful and cost-effective delivery of the outcomes expected by customers and mandated by the OEB, and the protection of the distribution grid from physical and digital threats.

4.2.3 Workforce Requirements

Toronto Hydro's leaders identified the workforce needs to execute work in their programs in terms of both capacity (i.e. headcount) and capabilities (i.e. skillsets). This included consideration of Toronto Hydro's hiring plans that were already in place but had been delayed in implementation due to the COVID-19 pandemic. In this regard the utility prioritized resourcing in a number of key areas of the plan, which are discussed in further detail in section 5.1. These areas include:

- Resources to support modernization objectives across a number of portfolios, including System Planning, Control Centre, and Information Technology.

- Staff in customer-interfacing functions such as Customer Connections, Key Accounts, Customer Care, and Community and Public Relations to align with growing volumes of work and increasing service expectations in these portfolios.
- Skilled trades, and technical and other resources in work program execution-related functions to enable the delivery of a larger capital program, including back-end support functions such as Supply Chain, Finance, and Legal Services.

4.2.4 Legislative and Regulatory Obligations

The 2020-2024 rate period saw a significant increase in the volume of legislative and regulatory requirements and policy engagements emanating from the Government of Ontario, the OEB, and the IESO. Examples include major infrastructure policy initiatives embodied in legislation such as the *Building Transit Faster Act, 2020*, the *Building Broadband Faster Act, 2021*, and the revised *Ontario Underground Infrastructure Notification System Act, 2012*, consumer-oriented initiatives such as the Ultra Low Overnight TOU rate[19] or Green Button,[20] and 10 rounds of amendments to OEB codes and 28 OEB Staff Bulletins to give effect to these and other requirements. Examples of policy engagements include the Framework for Energy Innovation, the Reliability and Power Quality Review, Electric Vehicle Integration, and Distribution Sector Resilience, Responsiveness & Cost Efficiency.[21] These requirements and engagements have added to volumes of work for both Toronto Hydro's legal and regulatory professionals and operational business units implementing the relevant outcomes, generating additional business processes that will last into the 2025-2029 rate period.

[19] Ontario Regulation 633/21 under the *Electricity Act, 1998* SO 1998 c. 15, Sched A.
[20] Ontario Regulation. 95/05 under the *Ontario Energy Board Act, 1998* SO 1998 c. 15, Sched B.
[21] EB-2021-0118, EB-2021-0307, EB-2023-0071, and EB-2023-0003, respectively.

4.2.5 Internal and External Benchmarking

Toronto Hydro also relied on comparative analyses, as detailed in section 2 above, and expert benchmarking studies to situate the utility's historical performance and future expenditure plans with comparable peers across various jurisdiction and operational areas. These studies are summarized in Exhibit 1B, Tab 3, Schedule 3.

4.2.6 Economic Assumptions

Toronto Hydro used both general and specific cost and economic assumptions in its forecast of 2025-2029 OM&A costs. In preparing its 2023 to 2029 forecasts, Toronto Hydro considered, and the forecasts reflect, the following inputs: (i) Toronto Hydro's obligations under collective agreements, (ii) relevant labour market data (where available),[22] and (iii) the utility's projections of outcomes of future rounds of collective bargaining that will take place throughout the forecast period. More specifically, in the absence of objective market indicators to forecast compensation increases over the 2025-2029 forecast period, the utility (in consultation with its compensation expert Mercer Canada and based on experience) relied on a historical rolling-average (in addition to the factors noted above) as the best information available to predict reasonable future compensation levels. For more information on compensation costs, see Exhibit 4, Tab 4, Schedules 2 and 4. Otherwise, a general inflation factor of 2.0 percent was applied, consistent with the Bank of Canada's economic outlook to return the economy to stable inflation by 2025.[23]

[22] For example, the results of Mercer Canada's *August 2023 QuickPulse™ Canada Compensation Planning Survey* show total salary increases of 3.7 percent, online: <https://www.imercer.com/ca/ARTICLEDETAIL/annual-increase-budget-canada>

[23] *Supra* note 5.

5. KEY DRIVERS

5.1 Staffing

As further described below, the execution of increased volumes of work is a key driver of the workforce requirements across a number of functions and roles within the utility's operations, which are summarized herein and further detailed in the underlying programmatic evidence. The challenge of increasing volumes of work is further compounded by more complex workloads. Priorities such as grid modernization, increased receipt and use of data, pursuit of non-wires solutions to defer or displace the need for traditional infrastructure, intensifying cyber security threats, and increased connection and management of distributed energy resources, all add to the complexity of work completed by Toronto Hydro staff. Some of these developments have created situations of incremental workload for Toronto Hydro staff relative to historical status quo, while others have increased the complexity of existing tasks. These workloads ultimately produce better outcomes for customers through provision of safe and reliable service, while relying on a more intelligent grid with enhanced capabilities to manage outages and handle two-way power flows.

Figure 12 below highlights material areas of growth in Toronto Hydro's workforce plan, with implications for OM&A funding required over the 2025 to 2029 rate period. The sections that follow address each of these areas, articulating the specific workload requirements that drive the need for incremental staffing.

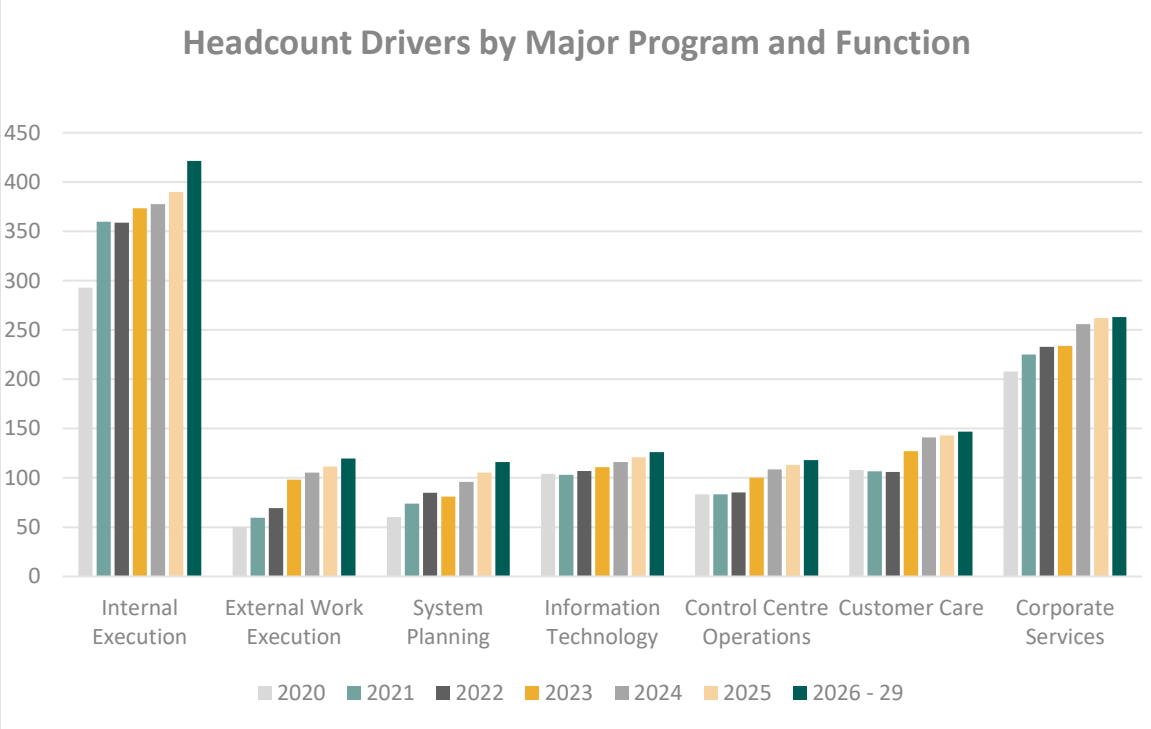


Figure 12: 2020-2029 Headcount Drivers by Major Program and Functions[24]

The key areas of investment in incremental resources are summarized as follows:

- **Internal Work Execution**: Increases to the complement of Certified and Skilled Trades critical to the execution of Toronto Hydro's capital and operations programs, including the utility's Grid Modernization Strategy, at a pace that allows for the extended lead-time required to safely train new workforce entrants.
- **External Work Execution**: Increases to the number of contract managers and project management staff to ensure the utility is able to effectively manage external contractors as the capital program grows.

[24] Figure 12 is aligned with Appendix 2-K (Exhibit 3, Tab 4, Schedule 2) in that it excludes students, which are temporary resources.

- **System Planning:** This segment is driven by the amount of capital (system access, renewal, and service) and maintenance work, and associated scopes of work that must be developed. Additional resources are required to analyze distribution system performance and needs, develop the utility's asset management strategy, develop the utility's grid modernization plan, manage record keeping and develop the DSP and scopes of work for executing the DSP.
- **Control Centre Operations:** As more distribution assets and DERs are connected to Toronto Hydro's grid and the utility modernizes system operation through the implementation of advanced grid management systems and more sophisticated data analysis and automation, this program will require more staff, both to handle increasing volumes of work and acquire specialized skills and knowledge made necessary by the evolution of Control Centre operations to support the Grid Modernization Strategy and Non-Wires Solutions program.
- **Information Technology**: The utility will need a robust staffing complement to effectively manage core business IT processes, as well as cyber security enhancements, cloud implementation, and major IT projects.
- **Customer Care:** Additional workers skilled in data analytics are required to enable the utility to respond to more complex customer inquiries, implement and optimize automated call centre quality management, powered by artificial intelligence and machine learning technologies, as well as gain insights on customer behaviour in interacting with the increasing number of communication channels (e.g. live chat and mobile application).
- **Corporate Services:** Financial professionals administering the utility's financial and accounting records and process will need to keep pace with the increasing volume of work; Higher work volumes (such as offers to connect), evolving legal, regulatory and policy requirements and changing business conditions necessitate

highly-skilled and experienced staff to address legal, regulatory and public affairs matters; and the utility's talent acquisition, management, and retention services, compensation, and performance management frameworks will need to oversee the human resources needed to execute Toronto Hydro's investment plan.

5.1.1 External Work Execution

As further described in Exhibit 4, Tab 2, Schedule 10, the External Work Execution segment administers and oversees capital and maintenance work performed by external contractors and is the primary point of contact between Toronto Hydro and external contractors. The tasks completed by this group include evaluating and administering competitive tenders for contractor services, providing oversight of the resulting contracts, and administering support of the specific projects assigned to external contractor crews, such as: job package development and issuance; liaising with system planners to address specific design matters; field issues management; liaising with customers directly and through the community relations team; ordering materials; facilitating changing of project scopes; monitoring contractor safety practices; invoicing and receipting; and inspection of newly constructed assets.

Given the nature of the workload completed by the External Work Execution segment, Toronto Hydro must increase the number of contract managers and project management staff to ensure the utility is able to effectively manage external contractors as the capital program grows. From the end of 2022 to 2029, Toronto Hydro intends to increase resourcing in this area by 74 percent from 69 to 120 staff. In Toronto Hydro's experience, an appropriate resource level has each manager, with a supporting analyst, executing approximately $11 to 13 million in capital projects annually. As shown in Figure 12, Toronto Hydro's plan ensures sufficient resources to support these execution levels.

If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility would face execution risks due to a smaller contingent of frontline managers, analysts, and other staff being required to manage a larger capital portfolio per employee; allowing staff significantly less capacity to tend to the needs of each individual project relative to best practice and historical norms. These execution risks include a slower pace of work, compromises from quality and less time for internal coordination across projects.

A decrease in External Work Execution resources would slow the pace of execution, jeopardizing the completion of required and planned capital projects. Reduction in the number of projects being executed in a given year would put renewal of assets and upgrade or expansion of the distribution system at risk. This would introduce the risk of reduced reliability due to aged assets or the inability for customers (residential and business) to expand as needed to accommodate growth and/or energy conversion for climate action purposes. A decrease in resources may also result in less time available per project. This could lead to less capacity to ensure best practices are followed, and may compromise customer experience in terms of reliability. As well, strained resources and time per projects can lead to reduced time for internal coordination across projects, with less consideration for efficiencies in terms of optimal construction window or calendarization which can lead to lost opportunities for project cost reduction. For example, field manager understaffing may result in inadequate field quality assurance/control during pre-construction. Field managers assist project execution managers with field “walk-downs” prior to construction. Not being able to undertake these may lead to unnecessary delays during construction that could have been identified earlier by a field manager that has years of “hands-on” experience.

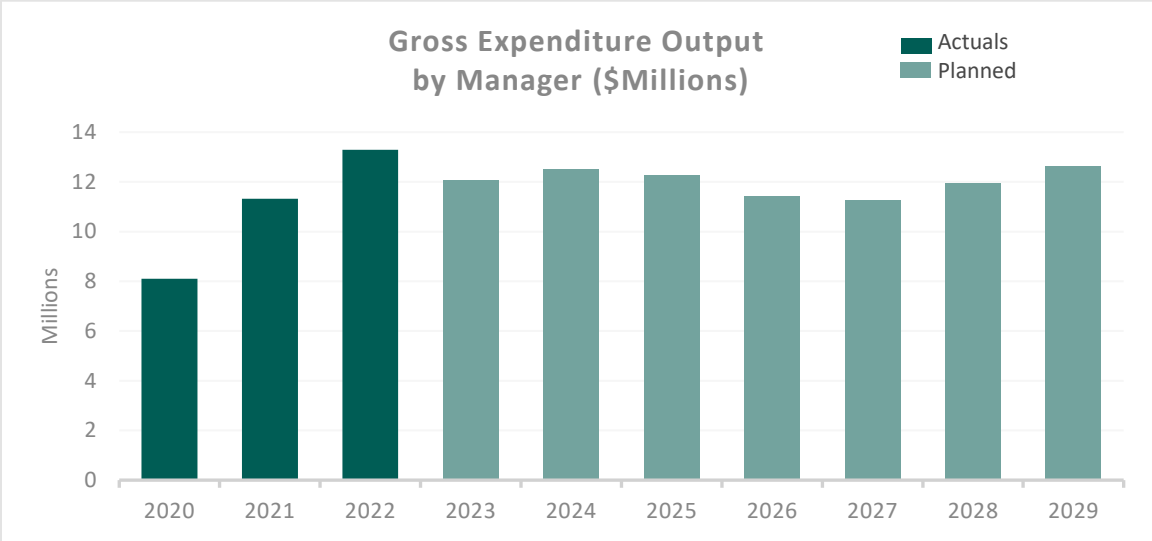


Figure 13: Gross Expenditure Output by Manager ($ Millions)

5.1.2 Internal Work Execution

The Internal Work Execution segment, as described in Exhibit 4, Tab 2, Schedule 10, captures the non-capitalized expenditures associated with work performed by Toronto Hydro's skilled trades' apprentices, including the training costs associated with the utility's trade school which is further described in Exhibit 4, Tab 4, Schedule X. Certified and skilled trades are critical resources in the execution of Toronto Hydro's capital and maintenance programs. Over time, Toronto Hydro has strengthened the workforce to prepare for retirements and unplanned exits as necessary, and allow for the extended lead-time required to safely train new workforce entrants, considering that apprentice programs run from four and a half to six and half years in length. From the end of 2022 to 2029, Toronto Hydro intends to increase resourcing in this area by 17 percent from 360 to 421 staff.

A steady complement of certified and skilled trades is critical to the execution of Toronto Hydro's capital and operations programs. One of the key areas that certified and skilled

Trades will support is Toronto Hydro's Grid Modernization Strategy (Exhibit 2B, Section D5). This strategy addresses emerging challenges and opportunities arising from electrification, distributed energy resource proliferation, and worsening climate change in a manner that leans first and foremost into the deployment of proven technologies (e.g. reclosers, switches, smart meters, analytics), which will deliver benefits to customers in the near-term (e.g. improved reliability), while laying the foundation for more advanced use cases that will be required in 2030 and beyond. Distribution System Technologists—who operate, install, commission, construct, repair, maintain, and decommission all types of, protective relay and control systems, distribution automation equipment, and SCADA systems—are key to implementing the Grid Modernization Strategy as the equipment and systems installed and maintained by these resources are key components and enablers of the Intelligent Grid that lies at the heart of this strategy.

If Toronto Hydro were forced to scale back this program to manage within a reduced level of funding over the 2025-2029 rate period, the utility would face a decreased ability to meet legislated training targets, thereby becoming exposed to unnecessary safety and legal risks. Furthermore, reduced investment in the certified and skilled trades enabled by this program would results in notable execution risks with respect to the capital and maintenance plans detailed in this application and beyond, due to lack of support and decrease in recruitment of skilled tradespeople.

5.1.3 System Planning

The System Planning segment (Exhibit 4, Tab 2, Schedule 9) enables Toronto Hydro to analyze distribution system performance and needs, develop the utility's asset management strategy, develop the utility's grid modernization plan, develop the DSP and scopes of work for executing the DSP, and manage record keeping. Toronto Hydro

intends to increase resources in this area to by 37 percent from 85 to 116 staff between the end of 2022 and 2029. The System Planning segment is driven by the volumes of distribution system capital and maintenance work that the utility needs to plan and design, and associated scopes of work that must be developed. Growth and electrification, system studies and development planning need, and distributed energy resource ("DER") connections will require incremental studies, forecasts, and planning, and the deployment of Intelligent Grid, Energy Storage technologies, and Non-Wires Solutions.

The work done through the System Planning segment is divided into four functional areas:

- **The Investment Planning function** undertakes analytical work related to reliability, asset condition assessments, and risk assessment (e.g. environment, safety, customer, and legal claims). This work forms the basis of the development of Toronto Hydro's DSP presented in Exhibit 2B.
- **The Capacity Planning and Grid Innovation function** is responsible for planning the distribution system's future load requirements driven by customer growth and the requisite connection capacity to accommodate current and forecasted levels of DERs, as well as identifying opportunities for adopting non-wires solutions.
- **The Integrated Planning and Grid Modernization function** is responsible for facilitating the development, integration, and strategic oversight of Toronto Hydro's long-term Grid Modernization Strategy, in addition to providing market intelligence and strategic forecasting of future electricity system needs and opportunities, and change management support capacity to help accelerate innovation initiatives.

- **The Records Management function** involves the maintenance and upkeep of digital records of Toronto Hydro's distribution system. The utility must maintain up-to-date records to enable efficient and effective system planning and operations.

If Toronto Hydro were forced to deliver the System Planning segment with a reduced level of funding over the 2025-2029 rate period, the utility could face compliance risks and inefficiencies, including ineffective system planning, inability to manage risks around growth and electrification, failing to maximize benefits of new technologies connected to modernization initiatives, and significant safety and reliability risks if records and data updates are not synchronized with equipment or system configuration changes.

5.1.4 Control Centre Operations

The Control Centre Operations program (Exhibit 4, Tab 2, Schedule 7) facilitates the safe and reliable operation of the utility's distribution grid through real-time system control and monitoring activities and coordinates system switching and restoration work through the utility's Control Centre to mitigate the effects of outages on customers and enable safe load transfers for capital and maintenance work. The program also plays a critical role in the integration of both customer-owned and utility-owned DERs into Toronto Hydro's distribution system, the significance of which will only increase over the 2025-2029 period, as the energy transition takes hold and the utility's Non-Wires Solutions program expands.[25] The Control Centre is also one of the key executors and enablers of Toronto Hydro's Grid Modernization Strategy[26]—as the utility adds more distribution assets and modernizes its system operations through more sophisticated data analysis

[25] Exhibit 2B, Section E7.2.
[26] Exhibit 2B, Section D5.

and automation, this program will require more staff both to handle increasing volumes of work and acquire specialized skills and knowledge, made necessary by technologies the utility plans to implement in the 2025-2029 rate period such as Network Condition Monitoring & Control,[27] Advanced Metering Infrastructure 2.0,[28] Fault Location, Isolation, and Service Restoration,[29] and the Advanced Distribution Management System.[30]

Toronto Hydro intends to increase resources in this area to by 39 percent from 85 to 118 staff between the end of 2022 and 2029. The Control Centre program's staffing needs is driven by a variety of tasks and business processes such as the volumes of new distribution system operation assets installed in the grid, growth in the volume of DER connections, incremental and more complex system data modelling requirements, and support for the implementation of IT/OT infrastructure projects and internal and external planning and policy engagements.

For example, as shown in Table 5 below, the number of assets connected to Toronto Hydro's Supervisory Control and Data Acquisition ("SCADA") system is going to increase significantly—by over tenfold in some cases—over the 2025-2029 rate period as part of the investments under the Contingency Enhancement segment of the System Enhancements program.[31]

Table 5: SCADA-connected Assets

Asset Type	2020-2024	2025-2029
Switches	33	299
Reclosers	49	220

[27] Exhibit 2B, Section E7.3.
[28] Exhibit 2B, Section E5.4.
[29] Exhibit 2B, Section D5.
[30] Exhibit 2B, Section E8.4, Appendix A.
[31] Exhibit 2B, Section E7.1.

Asset Type	2020-2024	2025-2029
Feeders for Distribution Automation	15	63

Similarly, growth in the volume of DERs driven by both Toronto Hydro and its customers more broadly will increase the workload of the Control Centre Operations program. By 2029, the expansion of the Non-Wires Solutions program will require the Energy Centre function of the Control Centre to support the procurement of up to 30 MW of capacity under the Flexibility Services initiative (compared to 10 MW in the 2020-2024 period) and manage the operation of nine Toronto Hydro-owned battery energy storage systems ("BESS") (compared to only one in the 2020-2024 period).[32]

In addition, the utility forecasts total DERs installed on the grid to increase by approximately 67 percent from 2023 to 2029,[33] which is driving investments in the Generation Protection, Monitoring and Control program.[34] Each additional device installed in the system pursuant to these programs requires oversight from Control Centre Operations personnel for: 1) commissioning and testing in the field to reliably communicate with the SCADA system, and 2) daily operations and troubleshooting (e.g. responding to alarms or asset management tasks). Headcount increases in this area are essential to enabling the utility to safely and reliably accommodate these utility- and customer-driven changes to its grid.

Technological advancements and the modernization of system operation tools is another area that will require the Control Centre Operations program to upskill and enhance its workforce. For example, the advanced applications that Toronto Hydro will adopt as part

[32] Exhibit 2B, Section E7.2.
[33] Exhibit 2B, Section E3 at page 3.
[34] Exhibit 2B, Section E5.5.

of the Advanced Distribution Management System ("ADMS") Upgrade will require the utility to significantly improve data modelling in the Network Management System ("NMS") to enable the self-healing grid and other automation functions through modernization projects such as Fault Location, Isolation, and Service Restoration ("FLISR").[35] This is because the operation of FLISR will depend on not only traditional types of data relating to connectivity attributes of distribution equipment, but also engineering attributes, such as device limits, impedances, and power transformer data, representing an increase in data point types from 13 to 36. Adequate staffing for the Control Centre Operations program to gather these additional types of data and input them into modelling systems will be essential for the successful and timely implementation and daily operation of modernization initiatives such as FLISR.

Finally, Control Centre Operations staff act as subject matter experts for a number of internal and external activities. Internally, program staff support investments in cellular SCADA upgrades under the Communication Infrastructure segment of the Information Technology and Operational Technology ("IT/OT") Systems program, where the expertise of Control Centre operators is crucial to the timely and reliable completion of critical infrastructure upgrades.[36] Externally, Control Centre Operations staff support Toronto Hydro's participation in industry forums and working groups such as the Electric Power Research Institute ("EPRI") Distribution Operations & Planning Group,[37] and the IESO's Transmission-Distribution Coordination Working Group.[38] The operational expertise that Control Centre operators bring to these engagements benefits both Toronto Hydro, by enabling the utility to expand its knowledge of the industry through connections with

[35] Exhibit 2B, Section E8.4, Appendix A.
[36] Exhibit 2B, Section E8.4.
[37] EPRI, *Distribution Operations and Planning,* online: <https://www.epri.com/portfolio/programs/108271> .
[38] IESO, *Transmission-Distribution Coordination Working Group* online: <https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Transmission-Distribution-Coordination-Working-Group> .

stakeholders, and the industry, by contributing to policy design and development with Toronto Hydro's unique experience as a large urban distributor.

If Toronto Hydro were forced to deliver work under the Control Centre Operations program with a reduced level of funding over the 2025-2029 rate period, the utility would be unable to resource the critical functions discussed above, resulting in a number of risks relating to the successful execution of capital plans relating to the distribution system and IT/OT projects; the efficient and effective modernization of Toronto Hydro's operations in accordance with customer and stakeholder expectations and the continued transition to new and diverse energy resources; and the productive development of industry policies.

5.1.5 Information Technology ("IT")

The IT OM&A program (Exhibit 4, Tab 2, Schedule 17) supports all aspects of Toronto Hydro's business. The IT infrastructure, cyber security controls, business applications and services supported and delivered by this Program enable efficient operations of the utility and play a critical role in achieving Toronto Hydro's objective to provide safe, secure and reliable electricity. Adequate resourcing for this area is key to supporting the execution of the 2025-2029 investment plan. Toronto Hydro intends to increase resources in this area by 18 percent from 107 to 126 staff between the end of 2022 and 2029.

As discussed in Exhibit 2B, Section E8.4, Toronto Hydro needs to invest in IT/OT hardware, software, and communications infrastructure over the 2025-2029 rate period to maintain relevant assets and systems in reliable operating condition, renew assets at end-of-life or vendor support, implement and maintain robust controls against increasing and more sophisticated cyber security threats, and contribute to the utility's capacity to

accommodate growth and modernization journey in the context of the broader energy transition. The IT program requires a larger staff complement and the appropriate mix of skillsets to execute and support these initiatives, as each project requires subject matter experts, technical staff, and project managers to effectively and efficiently achieve the planned outcomes. The increasing prominence of cloud solutions intensifies these demands, as IT solutions that were traditionally on-premises and may have required a particular skillset and/or complement of resources may now require a significantly different skillset and resource mix where the utility relies on a cloud-based application.

Cyber security controls must be periodically refreshed and enhanced to maintain the reliability and availability of systems to support core operations, mitigate against potential vulnerabilities and threats, and minimize the risks of system failure. Investments in this area constitute a significant part of Toronto Hydro's IT plan for the 2025-2029 rate period,[39] and to execute this work and keep up with the shifting cyber security landscape and controls, Toronto Hydro needs additional IT staff with enhanced skillsets.

In addition, Toronto Hydro has observed the following workload trends driving the program's resourcing needs:

- From 2020-2024 to 2025-2029, an increase of 6 percent in the number of endpoint devices supported by the program;
- From 2020-2024 to 2025-2029, an increase of 18 percent in the number of complex systems operated and maintained by the program;
- From 2020 to 2023, an increase of 22 percent in IT service requests handled by the program; and
- From 2020-2024 to 2025-2029, an increase of 9 percent in cyber security systems and controls overseen by the program.

[39] Exhibit 2B, Section E8.4 and Exhibit 4, Tab 2, Schedule 17.

If Toronto Hydro were forced to deliver this program with a reduced level of funding or staffing over the 2025-2029 rate period, the utility could face various cyber security risks and suffer from a significant loss in business efficiency due to a decline in the quality and availability of IT solutions and tech support.

5.1.6 Customer Care

As the electricity industry evolves, Toronto Hydro's customer service functions must keep up with broad changes in customer needs and preferences driven by the energy transition and adapt to handle evolving customer behaviour and more complex information. As discussed in Exhibit 4, Tab 2, Schedule 14, the utility is already observing these trends even with respect to traditional customer interactions. For example, a high bill inquiry now often requires a frontline representative to consider more factors than before, such as the customer's choice of available pricing plans (e.g. tiered, Time of Use, Ultra-Low Overnight Time of Use) or the customer's usage of electricity-intensive devices such as electric vehicle chargers or heat pumps. These trends are even more pronounced with respect to services that have been historically niche areas, but are gradually becoming more commonplace, such as DERs. For example, the billing of net metered accounts is an order of magnitude more complex than regular load accounts, due to the calculation of generation credits and the treatment of Harmonized Sales Tax.

In this environment, customers' expectations are also continually reshaped by all service providers they interact with, not just utilities. As online services and electronic transactions are gradually becoming the norm for the majority of small and large businesses, customers are coming to expect the same standard of service from their electricity distributor as table stakes.

Toronto Hydro's customer-interfacing operations are adapting to these trends by increasing the variety of communication channels available to customers, with a focus on self-service. In 2022, the number of such channels increased from seven to nine, with the addition of live chat and Toronto Hydro's mobile application.[40] As a result, customers are currently able to perform a broad variety of online transactions, such as registering for electronic bills ("eBills"), requesting move-ins or move-outs, downloading consumption information for their rental property,[41] registering for pre-authorized debits, or reporting streetlight outages. While each channel adds to customer convenience, managing interactions through different channels requires different staff skills to operate and perform analytics for gaining insights on customer behaviour and each channel's effectiveness and efficiency.

From the end of 2022 to 2029, Toronto Hydro intends to increase resourcing in this area by 39 percent from 106 to 147 staff. Against the trends discussed above, Toronto Hydro plans to transfer certain customer-interfacing functions from its external contact centre vendor to internal staff, in order to build, preserve, and diversify in-house knowledge and expertise of core functions, and leverage the same for modernization initiatives and projects or business processes borne out of regulatory compliance requirements.

Parallel to the insourcing effort, the utility plans to hire new staff to replace retiring staff and/or fill vacant positions. The addition of new and relatively inexperienced staff drives the need for more training time and quality assurance ("QA") work. In order to increase the effectiveness of QA processes, Toronto Hydro plans to increase its reliance on technology and data analytics—for example, deploying speech analytics tools to transcribe and analyze customer interactions, assess indicators of customer sentiment

[40] The previously existing seven channels are telephone, email, fax, Toronto Hydro's website, interactive voice response ("IVR") through the Contact Centre function, and the online customer self-service portal.
[41] Pursuant to Ontario Regulation 389/10, under the *Energy Consumer Protection Act, 2010*, SO 2010, c 8.

and intent, and identify call drivers. The application of such techniques and strategies to quality management, powered by artificial intelligence and machine learning technologies, enables evaluation of customer service performance based on more robust empirical data. In order to leverage and unlock the full potential of these capabilities, Toronto Hydro must invest in human capital with the necessary data analytics skillsets.

Knowledge management is another area driving resourcing needs in Customer Care. As the complexity of service offerings and customer interactions grows, either through new legislative and regulatory requirements or evolving customer needs and technologies, it is becoming more important to keep knowledge management databases current. The utility needs dedicated staff for maintaining consistent and current information and making it accessible to customers and staff across all engagement channels.

5.1.7 Corporate Services

Corporate services provide organization-wide support in the areas of Finance, Public, Legal, and Regulatory Affairs ("PLRA"), and Human Resources, Environment and Safety ("HRES"). From the end of 2022 to 2029, resources in corporate services are forecasted to increase by 13 percent from 233 to 263 staff. As the volume and complexity of Toronto Hydro's capital investments and operations increase in the 2025-2029 period, corporate services require a highly skilled and dedicated workforce to perform all of these functions in a timely and effective manner.

The Finance program (Exhibit 4, Tab 2, Schedule 16) supports Toronto Hydro's operations through financial planning, management reporting, capital planning and reporting, payroll and disbursements, corporate tax, treasury, insurance, and internal audits, as well as external reporting and financial regulatory and revenue management. Toronto Hydro

needs an adequate complement of finance professionals to administer the utility's complex financial and accounting processes and records in the face of increasing volumes of work (i.e. projects and transactions) borne out of the capital program.

The PLRA program (Exhibit 4, Tab 2, Schedule 18) provides specialized legal, regulatory, government and public relations professional services to the utility and its affiliates. Higher work capital volumes (such as offers to connect), evolving legal, regulatory, and policy requirements (as noted above in section 4.2.4) and changing business conditions necessitate highly-skilled and experienced staff to address complex and consequential legal, regulatory, and public affairs matters. These needs are most cost-effectively addressed by internal resources with the necessary skills and experience to provide the required services in a holistic manner that is integrated with other business functions. Attracting and retaining talent in this area of corporate services is a particular challenge because the utility competes with law firms and large sophisticated organizations such as banks that often offer more attractive compensation packages.

The HRES program (Exhibit 4, Tab 2, Schedule 15) provides comprehensive human resource management services ranging from employee lifecycle, labour relations, employee communications and engagement, governance of health and safety and environmental management systems, and human resources technology management. All of these activities are carried out within a culture of ensuring employees' health and safety, and environmental sustainability. Looking ahead to 2025-2029, the utility's talent acquisition, management, and retention services, compensation, and performance management frameworks must be equipped to serve the human resource needs of a growing organization that is challenging itself (through its greatest asset—people) to

maintain a record of high-performance and deliver incremental outcomes to customers during a time of unprecedented change and transformation.

Without sufficient funding to maintain its Corporate Services functions, the utility could be exposed to a number of risks, including legal, compliance, and customer-related risks and drawbacks, all of which would compromise its ability to deliver outcomes that customers value and expect. These consequences include: reduced governance and oversight of financial planning and management activities, leading to a greater risk of errors and omissions; ineffective or unfavourable negotiation of contract terms, resulting in substandard performance by contracted parties or foregone recourse to appropriate remedies, reducing the value and increasing costs to ratepayers; non-compliance or inadequate implementation of new requirements resulting in increased customer complaints and barriers to achieving public policy objectives; a reduced ability to successfully recruit and develop the skilled and specialized resources that Toronto Hydro requires to execute its investment plan; and increased likelihood of safety-related incidents or incidents with an adverse environmental impact.

5.2 Other Key Drivers

Expenditures in OM&A are also driven by factors in addition to staffing levels. Below is an overview of the key, non-staffing related drivers.

5.2.1 Asset Maintenance Requirements

Toronto Hydro's distribution system consists of approximately 61,000 distribution transformers, 17,000 primary switches, 15,600 kilometres of overhead conductors, and 13,800 kilometres. Toronto Hydro leverages its reliability centred maintenance

framework, in combination with the OEB's minimum inspection requirements,[42] and continuous monitoring and assessment of asset performance to maintain equipment in good working order throughout its expected serviceable life, and where possible, to increase the useful life for enhanced value. This includes conducting inspections and maintenance tasks on a fixed (or variable) cycle as necessary, as well as completing corrective work to address asset deficiencies and risks that jeopardize system safety and reliability. The Corrective Maintenance program, in particular requires significant investments to address a number of incremental drivers: [43]

- **Corrective Work Requests:** Toronto Hydro uses a prioritization framework that classifies asset deficiencies into four categories, depending upon the urgency/severity of the deficiency. Since 2019, the utility observed a rise in the volume of corrective work in the "P3" category requiring resolution within 180 days due to the proportion of assets exhibiting deteriorating conditions and exceeding their expected lives. These asset deficiencies elevate the risk of failure and must be managed to keep the system safe and reliable for customers.
- **Electrical Safety Authority ("ESA") Requirements:** Toronto Hydro plans its maintenance programs with a view to achieving and maintaining compliance with electrical distribution safety requirements under Ontario Regulation 22/04,[44] in accordance with directives and guidelines issued by the ESA from time to time. This includes work such as the disconnection and grounding of unused lines, and responding to ESA directives and flash notices identifying hazards and risks that must be addressed. A recent example of such ESA-directed work is "Delta to Wye" conversions based on a 2018 flash notice to distributors and which is expected to continue driving work volumes into the 2025-2029 rate period.

[42] OEB, *Distribution System Code*, Appendix C, (August 2, 2023).
[43] Exhibit 4, Tab 2, Schedule 4.
[44] Ontario Regulation 22/04, under the *Electricity Act, 1998* SO 1998, c 15, Sched A.

- **Emergency Response:** Corrective work may also be required as a result of emergencies or unplanned system events, including asset failures and deficiencies identified outside of Toronto Hydro's daily (planned) operations (including ESA field inspections) but requiring follow-up remediation in order to permanently restore power or eliminate safety or environmental risks. The emergence of such issues and the extent of the work (and costs) required to address them are unpredictable. As the distribution system becomes more heavily utilized due to electrification, the emergence of such compliance issues is expected to grow.

Toronto Hydro must address asset maintenance requirements in a timely manner in order to: (i) remain compliant with the Distribution System Code, (ii) satisfy electrical distribution safety requirements under Ontario Regulation 22/04, and (iii) maintain a safe and reliable system for customers in alignment with good utility practice. Without sufficient funding for asset maintenance, all of these critical outcomes are placed at risk.

5.2.2 Cloud Computing

Cloud solutions equip the utility with dynamic and cost-effective software tools to support the automation and modernization of business processes and protect the system against increasing cyber security threats. Toronto Hydro invests cloud computing solutions in accordance with the utility's IT Investment Strategy outlined in Exhibit 2B, Section D8. Costs to implement cloud-based solutions typically include project initiation, planning, execution (e.g. configuration, development, testing, customization, etc.), monitoring and control, and deployment. Recent drivers of cloud computing expenses include:[45]

- The implementation of new applications such as Oracle Field Services Cloud ("OFSC"), an upgrade to the mobile workforce management system for Grid

[45] Exhibit 4, Tab 2, Schedule 17.

Emergency Management, which replaced the legacy on-premises in-house solution. OFSC allows dispatchers and grid response crews to collaboratively manage outage events with respect to assembling crews, managing priorities, and communicating across different groups to respond to an unplanned outage events in a timely and effective manner.

- Cyber security maintenance and subscription fees as a result of new investments into cloud-based, artificial intelligence-enabled threat prevention, detection, and response solutions to ensure that cyber security processes and controls are capable of adequately responding to the evolving threat landscape.

Cloud-based solutions increase the range of IT solutions available to Toronto Hydro and provide the utility more flexibility in designing and implementing IT systems and controls. However, the shift from the traditional perpetual software licensing model to cloud subscription and maintenance fees is driving incremental OM&A expenditures as more IT vendors move towards a subscription model for both cloud-based and on-premises systems. In fact, many vendors are adopting "cloud only" solutions that rely solely on cloud technologies instead of providing an option to host a solution on-premises.

Toronto Hydro requires sufficient funding for cloud solutions to: (i) serve growing technology requirements across the business driven by modernization imperatives and innovation opportunities; (ii) adequately protect its grid and systems against cyber security threats; and (iii) retain flexibility in a more dynamic technology environment.

5.2.3 Non-Wires Solutions (Local Demand Response)

Toronto Hydro's Non-Wires Solutions ("NWS") program was established in the 2015-2019 Distribution System Plan to address capacity constraints through local demand response

("LDR").[46] Building on its existing LDR experience, Toronto Hydro identified further opportunities to use LDR in the 2025-2029 rate term to avoid and defer capital investments in load transfers, and set an ambitious goal to expand the reach of the LDR program in the next rate term. Toronto Hydro intends to procure 30 MW of flexible system capacity to displace and defer the need for load transfers in the Horseshoe North area during the 2025-2029 period. Load transfers in this area are currently necessary to alleviate capacity constraints at a number of stations, including Finch TS and Bathurst TS. The goal is to use LDR to defer or displace certain load transfers by procuring flexible system capacity from third-party or customer-owned DERs.

5.2.4 Insurance Premiums

Insurance premium costs are included in the Finance program.[47] The utility anticipates an upward trend in insurance costs through to 2029 that is attributable to higher rates on the existing insurance program policies for property, liability, cyber, directors and officers ("D&O"), and crime. In particular, cyber security insurance premiums are increasing in correlation with growing and more acute cyber security threats that affect large organizations such as Toronto Hydro each year. In addition, Toronto Hydro's rate base is expected to increase from $4.9 billion in 2022 to $7.6 billion in 2029 which has a direct impact on the future property and liability insurance premiums. Without sufficient funding for insurance costs, Toronto Hydro may face challenges securing financing for its work programs, risk contravention of covenants contained in existing debt issuances, and be exposed to compliance risks vis-à-vis relevant tax laws, rules, and regulations.

[46] Exhibit 2B, Section E7.2.
[47] Exhibit 4, Tab 2, Schedule 16.

6. Variance Analysis

In the last rebasing application (EB-2018-0165), the OEB approved a 2020 OM&A budget envelope of $272.2 million,[48] and directed Toronto Hydro to amend the presentation of costs attributable to shared services.[49] In accordance with that directive, Toronto Hydro reclassified $5.5 million of shared services costs from 2020 OM&A to other revenues and expenses,[50] resulting in an OEB-approved 2020 OM&A budget of $266.7 million.[51]

Toronto Hydro's actual OM&A expense for 2020 was $288.1 million. However, this amount includes approximately $21.1 million in one-time expenses related to the COVID-19 pandemic; specifically bad debt expense,[52] and non-routine emergency costs such as additional personal protective equipment and increased health services resources.[53] Adjusted for these one-time COVID-19 related expenses, Toronto Hydro's actual OM&A expense for 2020 is $267.0 million, which is aligned with the OEB-approved 2020 OM&A test year of $266.7 million.

Figures 14 and 15 below respectively show the major drivers of OM&A cost increases from the adjusted 2020 actual to the 2025 test year and from the 2025 test year to the 2029 forecast year. Consistent with applicable OEB guidance,[54] detailed year-over-year variance analyses by OM&A program and segment can be found OEB Appendix 2-JB (Recoverable OM&A Cost Driver Table) and in Exhibit 4, Tab 2, Schedules 1 to 21.

[48] EB-2018-0165, Decision and Order (December 19, 2019) at page 140.
[49] EB-2018-0165, Decision and Order (December 19, 2019) at page 131.
[50] Exhibit 3, Tab 2, Schedule 2 (OEB Appendix 2-H).
[51] Exhibit 4, Tab 1, Schedule 3 (OEB Appendix 2-JB).
[52] Exhibit 4, Tab 2, Schedule 14 at page 29.
[53] Exhibit 4, Tab 2, Schedule 6 at pages 17-18.
[54] Including, for example, OEB Filing Requirements for Electricity Distribution Rate Applications, Chapter 2 (December 15, 2022), s. 2.4; and the Handbook for Utility Rate Applications (October 13, 2016) at page 19.

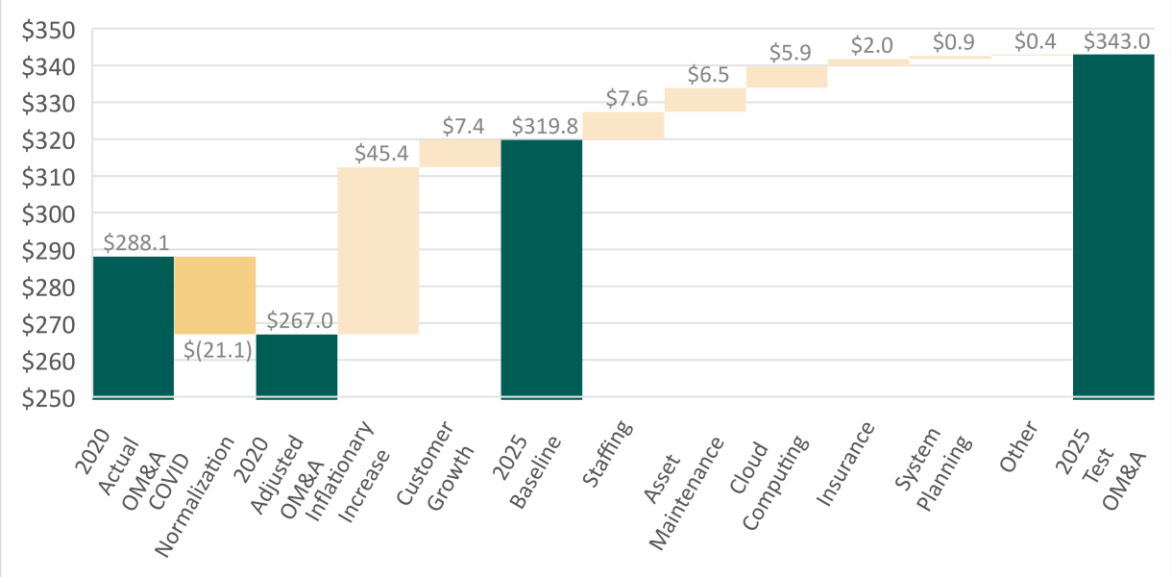


Figure 14: OM&A Causal Track Analysis 2020 Test versus 2025 Test ($ Millions)

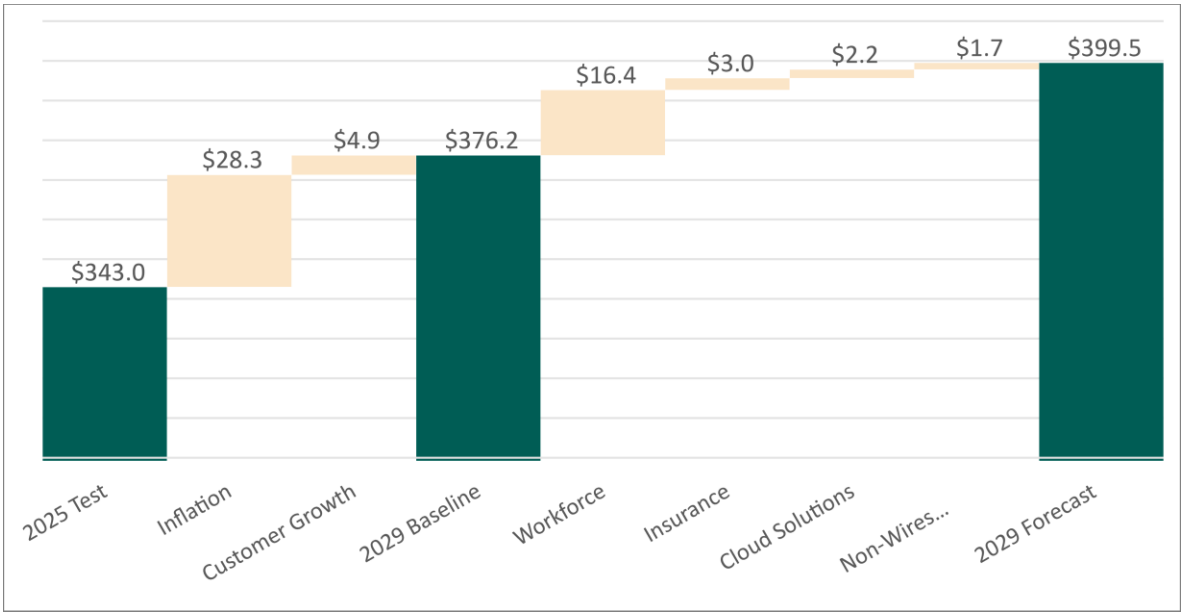


Figure 15: OM&A Causal Track Analysis 2025 Test versus 2025 Forecast ($ Millions)

PREVENTATIVE AND PREDICTIVE OVERHEAD LINE MAINTENANCE

1. OVERVIEW

Table 1: Preventative and Predictive Overhead Line Maintenance Program Summary

Preventative and Predictive Overhead Line Maintenance Program									
Outcomes: Operational Effectiveness - Reliability, Environment, Operational Effectiveness - Safety, and Customer Focus									
Segments: • Overhead Line Patrols & Pole Inspections • Overhead Switch Maintenance & Insulator Washing • Vegetation Management • Metering Services									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
5.8	6.2	5.7	7.2	7.9	9.1	9.2	9.6	9.5	9.4

The Preventative and Predictive Overhead Line Maintenance program (the "Program") funds Toronto Hydro's maintenance activities on: (i) Toronto Hydro's overhead line assets; and (ii) metering assets and associated communication systems that enable meter data collection and tracking to ensure compliance with applicable legislative and regulatory requirements. This Program involves inspection and maintenance tasks typically conducted on a fixed cycle, including inspection of equipment for indications of potential failure. The segments in this Program are focused on preserving and maximizing the performance of assets over their expected useful life while mitigating a wide variety of system risks. The Program is also designed to minimize overall asset lifecycle costs, account for factors such as the safety of Toronto Hydro work crews and the public,

responsible environmental stewardship and associated obligations, and compliance with statutory and regulatory requirements.[1]

The Preventative and Predictive Overhead Line Maintenance program is comprised of the following four segments:

- **Overhead Line Patrols & Pole Inspections:** This segment funds periodic line patrols to inspect all overhead distribution equipment, including pole-mounted transformers, switches, auxiliary equipment, and conductor wire. In addition to line patrols, the segment also includes dedicated pole inspections and wood pole treatment as well as inspections of poles to assess the need for additional guying for reinforcement during storm events;
- **Overhead Switch Maintenance & Insulator Washing**: This segment funds two general sets of maintenance activities on the overhead distribution system: (i) the periodic maintenance of overhead switches such as SCADA-Mate and Three Phase Gang-Operated Switches; and (ii) the washing of porcelain insulators located at high-risk locations prone to contamination build-up;
- **Vegetation Management**: This segment funds the trimming of vegetation near overhead feeders to minimize the impact of tree-caused power interruptions on system reliability;
- **Metering Services:** This segment funds the inspection and maintenance of metering assets and associated communication technologies to ensure proper functionality and compliance with applicable legislative and regulatory requirements;

[1] Ontario Energy Board, Distribution System Code (August 2, 2023) Appendix C.

By preserving and maximizing the performance of overhead line and metering assets and ensuring these assets are fully operational, this Program contributes to maintaining safety, environmental stewardship, and overall system reliability at reasonable costs to Toronto Hydro's customers. In addition, the Program contributes to customer experience and satisfaction by facilitating: (i) the tracking of accurate and timely electricity consumption information for customer billing purposes; and (ii) the use of up-to-date communication technology that enables remote reading and processing of customer meter information.

2. OUTCOMES AND MEASURES

Table 2: Preventative and Predictive Overhead Line Maintenance Program Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contribute to the overall system performance and reliability – as measured by performance metrics like SAIFI, SAIDI, Customers Interrupted ("CI"), and Customer Hours Interrupted ("CHI") – by promptly identifying potential asset failure or assets in substandard conditions before failure occurs, through planned inspections in compliance with the Ontario Energy Board's ("OEB") Distribution Systems Code ("DSC").
Environment	• Contribute to reducing the environmental impact of Toronto Hydro's distribution system by proactively identifying transformers exhibiting signs of oil deficiencies for replacement, thereby reducing the likelihood of oil spills into the environment.
Operational Effectiveness - Safety	• Contribute to Toronto Hydro's safety objectives (including compliance with Ontario Regulation 22/04, and safety performance as reflected by metrics like the Serious Electrical Incidents Index and Total Recordable Injury Frequency through proactive inspections to identify and reduce the likelihood of equipment malfunction (e.g. porcelain switch breaking) and asset failures (e.g. collapse of a pole or flashovers on electrical equipment) which, if not prevented, may lead to injury of the general public and/or Toronto Hydro's crews.

Customer Focus	• Contribute to Toronto Hydro's customer focus objectives by ensuring the accurate billing of all smart metered customers based on actual usage, and mitigating the risk of meter seals expiring before their testing and re-validation (which also supports compliance with applicable regulatory requirements like the *Electricity and Gas Inspection Act,*[2] and the *Weights and Measures Act*).[3]

3. PROGRAM DESCRIPTION

The Preventative and Predictive Overhead Line Maintenance program funds all maintenance activities with respect to Toronto Hydro's overhead distribution system and metering assets, including meters and communication systems that enable meter data collection and tracking. This Program involves inspection and maintenance tasks typically conducted on a fixed cycle and inspection of equipment for predetermined conditions indicative of a potential failure. The segments in the Program focus on preserving and maximizing the performance of assets over their expected useful life while mitigating a variety of system risks. The Program is also designed to minimize overall costs and account for factors such as the safety of Toronto Hydro's work crews and the public, responsible environmental stewardship and associated obligations, and compliance with applicable statutory and regulatory requirements.

The Preventative and Predictive Overhead Line Maintenance program is comprised of the following four segments:

- **Overhead Line Patrols & Pole Inspections**: this segment funds periodic line patrols to inspect and assess the condition of all overhead distribution equipment including pole-mounted transformers, switches, auxiliary equipment, and

[2] RSC 1985, c. E-4. ["*Electricity and Gas Inspection Act"]*
[3] RSC 1985, c. W-6. ["*Weights and Measures Act"].*

conductor wire. In addition, this segment also includes dedicated pole inspections of all wood, concrete, and steel poles as well as wood pole treatments, and inspections of poles to assess the need for additional guying for reinforcement during storm events.

- **Overhead Switch Maintenance & Insulator Washing:** this segment funds two general sets of maintenance activities on the overhead distribution system: (1) the periodic maintenance of overhead switches such as SCADA-Mate and Three Phase Gang-Operated Switches, and (2) the washing of porcelain insulators located at high-risk locations prone to contamination build-up.
- **Vegetation Management:** this segment funds the trimming of vegetation near overhead feeders to minimize the impact of tree-caused power interruptions on system reliability.
- **Metering Services:** this segment funds the inspections and maintenance of metering assets and associated communication technologies to ensure proper functionality and compliance with applicable legislative and regulatory requirements. Metering maintenance activities include: meter audits to verify meter accuracy; verifying, testing and troubleshooting wholesale meters installed at transmission grid supply points; investigating communication issues; and installing reused meters following accuracy testing.

4. PROGRAM COSTS

In 2025, Toronto Hydro requires $9.1 million in rate funding for the Preventative and Predictive Overhead Line Maintenance program, which represents an increase of $3.3 million over the 2020-2024 rate application.

Over the 2025-2029 rate period, the utility expects the cost of this program to increase by a compounded annual growth rate of 1.0 percent, which is necessary to address overhead line maintenance needs and deliver the customer outcomes enabled by this program.

The Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for each segment are summarized in Table 3 below.

Table 3: Overhead Maintenance Program Expenditures by Segment ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Overhead Line Patrols & Pole Inspections	0.5	0.5	0.5	0.5	0.6	0.8	0.8	0.9	0.9	0.9
Overhead Switch Maintenance & Insulator Washing	1.4	1.6	1.3	1.6	1.7	2.4	2.4	2.5	2.6	2.6
Vegetation Management	2.8	3.4	3.5	3.5	3.8	4.0	4.1	4.2	4.3	4.4
Metering Services	1.1	0.7	0.4	1.6	1.8	1.9	1.9	2.0	1.7	1.5
Total	**5.8**	**6.2**	**5.7**	**7.2**	**7.9**	**9.1**	**9.2**	**9.6**	**9.5**	**9.4**

4.1 Cost Drivers

Cost variances are partly attributed to varying numbers of units scheduled for inspections each year based on their inspection cycle. For example, from 2020 to 2021 overhead line patrols and infrared thermography scans increased from 5,862 km to 7,576 km. Other cost drivers include:

- The adjustment of inspection frequencies for wood poles from ten years to eight years, and the implementation of a new inspection program for concrete and steel poles starting in 2025;
- The increase in the annual volumes of overhead switches maintained to achieve a six-year maintenance cycle starting in 2025;

- An increase in vegetation management costs to address an ever-growing tree canopy and reduce potential outages caused by tree-related contacts; and
- Increases in metering services costs due to the growing number of suite metering units driven by the growing population of condominium residents, as well as changes in the volume of meters due to be tested and resealed each year.

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

Toronto Hydro has a competitive bid process with a wide range of contractors involved in bidding for our contracted work, which helps keep costs competitive across vendors and provides more options.[4]

For the Overhead Line Patrol segment, starting in 2019 Toronto Hydro has tracked the exact number of kilometers of overhead distribution patrolled each year in order to ensure it is more accurately charged for areas patrolled.

For the Vegetation Management segment, planned trimming activities are expected to reduce the number of areas requiring reactive spot trimming, which can cost as much as 50 percent more than planned trimming; the bundling of feeders from the same station whenever possible will yield further costs savings; and the piloting of new technologies such as LiDAR and satellite imagery is expected to further improve the efficiency of the program.

[4] Exhibit 4, Tab 2, Schedule 15.

For Toronto Hydro's Insulator Washing segment, the reduced number of poles with porcelain insulators, as they are phased out of the system will directly yield cost savings due to fewer poles insulators needing to be washed.

4.2.2 Productivity

Toronto Hydro has placed significant emphasis on achieving greater output for the same or reduced input in each of the segments within the Preventative and Predictive Overhead Line Maintenance program. Toronto Hydro continues to rely on a Reliability Centered Maintenance ("RCM") approach and adjusts maintenance tasks and frequencies based on RCM and Condition-based Maintenance principles. Toronto Hydro also does the following:

- Standardize the maintenance cycles of overhead switches to align with station maintenance cycles wherever possible to minimize the need for multiple equipment outages and significant switching resources, enable efficient execution of more maintenance work per outage, and minimize the need for multiple visits to work on particular sites;
- Implement "find and fix" protocols whereby crews that identify minor asset deficiencies address the deficiencies (e.g. replacing equipment nomenclature or addressing missing or defective guy guards and pole ground wires) onsite, as opposed to only logging the deficiencies for future action under the Corrective Maintenance program;[5]
- Issue longer-term inspection maintenance contracts to third party service providers to keep unit costs stable and increase service quality levels over time (i.e. as result of accumulated service provider experience and familiarity with identifying deficiencies on Toronto Hydro's distribution system); and

[5] Exhibit 4, Tab 2, Schedule 4.

- Introduce new tools or making greater use of existing technology such as Infrared Thermography, Electronic Maintenance Sheets, Online Partial Discharge Testing, LiDAR, and satellite imagery; and,
- Migrate from phone line based communication to more reliable communication technology (i.e. wireless), reducing costs associated with on-site investigations and troubleshooting.

The following sections describe each of the segments in the Preventative and Predictive Overhead Line Maintenance program.

5. OVERHEAD LINE PATROLS AND POLE INSPECTIONS SEGMENT

5.1 Segment Description

Toronto Hydro conducts line patrols to inspect its overhead lines – approximately 4,100 circuit kilometres of primary and 11,500 circuit kilometres of secondary distribution lines – every three years. Infrared thermography scans are also performed annually on all primary lines and nearby secondary lines. The three-year inspection cycles for line patrols are as mandated by the OEB's Minimum Inspection Requirements (under Appendix C of the DSC).[6]

Line patrols cover all overhead distribution equipment including poles, conductor wires, pole-mounted transformers, switches, lightning arrestors, line insulators, and other peripheral attachments. Approximately 139,000 poles, 30,700 overhead transformers, and 7,350 overhead switches are inspected through line patrols.

Toronto Hydro also conducts dedicated pole inspections for its wood poles which are currently conducted on a ten-year cycle. All wood poles are either butt or full length

[6] *Supra* note 1.

treated against rot. For the reasons discussed below, beginning in 2025, Toronto Hydro plans to adjust this cycle for wood poles to every eight years and also to begin inspecting all concrete and steel poles on a ten-year cycle. In addition, Toronto Hydro also conducts inspections to identify poles that are in need of additional guying for reinforcement during storm events and undertakes condition based maintenance for poles by targeting certain poles found to be in poor condition or at a higher risk of failure more frequently. Toronto Hydro has approximately 105,000 wood poles, 29,700 concrete poles and 3,600 steel poles.

Overhead line patrols are designed to identify visible deficiencies (such as signs of leaking transformers, loose or broken attachments (e.g. cross-arms, insulator brackets), and damaged poles), as well as deficiencies that can be identified through infrared thermography. This technology identifies thermal anomalies, such as a significant increase in temperature at the secondary connection point of the pole-mounted transformer shown in Figure 1. If undetected and not addressed, such a deficiency can lead to a failure of the connection over time and result in safety and environmental risks due to arcing, which can lead to a transformer fire and release of oil into the environment. The Institute of Electrical and Electronics Engineers ("IEEE"), American National Standards Institute ("ANSI") and the International Electrotechnical Commission ("IEC") all publish standard temperature ratings for assets, which are used to determine if an electrical component has a temperature above the recommended value. Thermography is an accepted and encouraged practice in the utility industry as evidenced by the National Fire Protection Association's standard 70B: Recommended Practice for Electrical Equipment Maintenance.[7]

[7] National Fire Protection Association, Standard for Electrical Equipment Maintenance (2023).

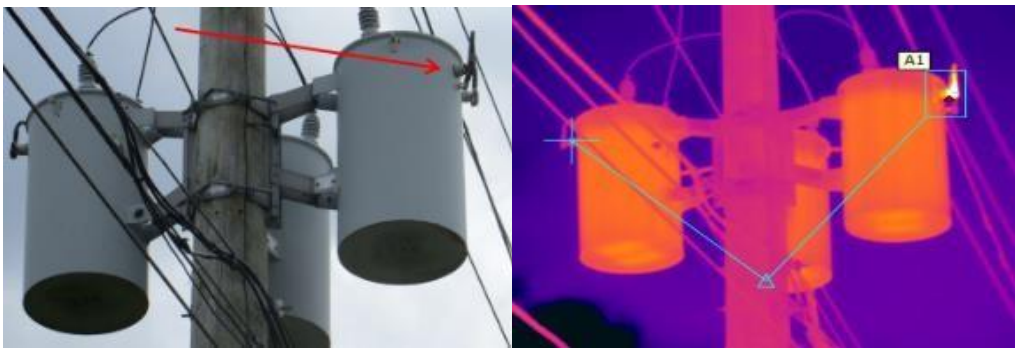


Figure 1: Secondary Connection on Pole-Mounted Transformer (Left) with an Infrared Thermography Image of the Same Asset Denoting a Hot Spot at A1 (Right)

Wood pole inspections involve a visual assessment of each pole and a sounding test using a hammer to check for internal cavities, which can indicate an infested or internally decayed pole. Based on the results of this assessment, one or more of the following steps may be taken:

- A bore test (using a 12 millimetre diameter bit to drill into the pole) to assess the condition of the shavings from the interior;
- A resistograph test (using a 2 millimetre diameter needle drill bit and an electronic resistance measurement device to drill into the pole) to determine the presence of wood decay, stages of rot, and hollow areas;
- Treatment using a boron glass rod or copper-boron glass rod wood preservative;
- Treatment using an external copper napthenate wrap; and
- Treatment using an internal fumigant.

Beginning in 2025, Toronto Hydro is adjusting the inspection cycle for wood poles from ten to eight years to better manage the growing volume of wood poles past their useful life and in HI4 and HI5 condition based on the asset condition assessment ("ACA") as shown in Figure 2 below. This adjustment will also allow Toronto Hydro to better inform

its wood pole ACA and support planning of system renewal investments with more timely inspection data of poles in poor condition.

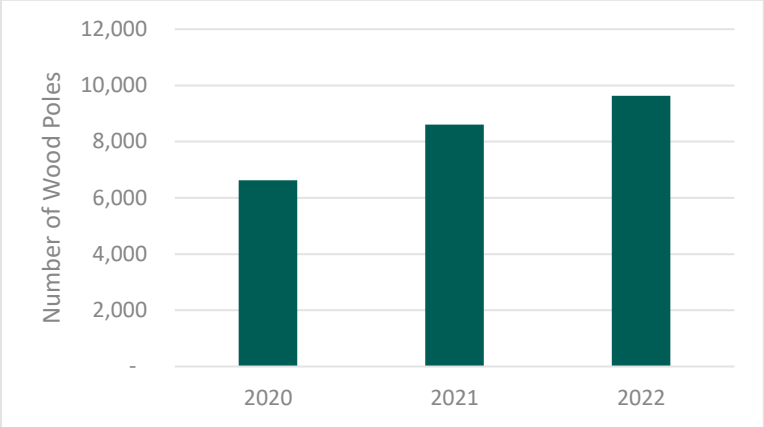


Figure 2: Wood Poles in HI4 & HI5 from 2020-2022

From 2025 onward, Toronto Hydro will begin to inspect concrete and steel poles in addition to wood poles as part of its dedicated pole inspection program on a ten-year cycle. Inspections of these poles are supported by the Canadian Securities Administrators (CSA) Standard C22.3. Inspections of these poles will allow Toronto Hydro to improve decisions on planned renewal investments for these assets. Further, this is expected to reduce the burden on reactive capital by proactively identifying poles with substandard conditions and scheduling them for replacement before they require costly reactive intervention. Toronto Hydro had originally planned to conduct inspections for these assets in 2020, however Toronto Hydro postponed this initiative until 2025 to give flexibility in the short-term budgeting for this segment and more time to plan ahead for the implementation of inspections for these assets.

Overhead line patrols and pole inspections serve to assess asset conditions and identify overhead asset deficiencies resulting from aging assets or exposure to weather, animals, trees, or other environmental elements. Condition and deficiency information gathered

during these activities is utilized to plan and prioritize capital and corrective maintenance work, so that public and employee safety, environmental, system reliability, and financial risks can be mitigated. Pole treatment activities are undertaken to extend the life of the pole and mitigate the risk of decay.

During 2020-2022, Toronto Hydro identified on average approximately 7,100 deficiencies annually during line patrols. Deficiencies identified include loose or deteriorated connections, missing guy guards, tracking insulators, rusted equipment, oil leaks, vegetation interference, damaged conductors and conductor splices, which are all addressed in the Corrective Maintenance or Reactive and Corrective Capital programs.[8] Identifying and addressing these issues reduces the likelihood of a component failure and the associated risks. For example, an aging conductor splice that fails could result in a live conductor dropping to the ground, which would create a serious safety risk to the public and Toronto Hydro employees and cause a power interruption that may impact hundreds of customers. Thermography is used to mitigate this risk as it allows such deficiencies in splices to be identified.

Dedicated pole inspections identify poles that have lost their mechanical strength and are likely to fail, endangering the crews working on them and possibly resulting in collapse if they remain in service.

For wood poles, the primary indicator of health and remaining life is mechanical strength, given that the main function of poles is to act as support structures. As a natural material, a wood pole undergoes a different degradation process than most other distribution assets. The degradation processes are primarily biological and cumulative with age. They

[8] Exhibit 4, Tab 2, Schedule 4 and Exhibit 2B, Section E6.7.

consist of insect infestation, moisture ingress, and bird or fungi attacks. Decay causes a wood pole to lose its strength and functionality, which increases the risk of a structural failure. Poles often support and withstand significant static loads such as transformer banks and conductors, and dynamic loads such as climbing workers or high winds. They typically fail with the onset of age and the loss of structural strength.

As further illustrated in Figures 3 and 4 below, deficiencies such as rot and excessive cracking are common causes of pole failures. Between 2020 and 2022, Toronto Hydro condemned on average over 190 wood poles annually.



Figure 3: Rot at Base of a Pole



Figure 4: (Left) Cracked Wood Pole, (Right) Surface Rot on Pole

For steel poles, the most common cause of degradation is corrosion as illustrated in Figure 5. The corrosion protection system for steel poles can be compromised by mechanical

degradation of the coating due to external impacts by foreign objects or abrasion, adverse weather conditions, and loss of coating due to age.



Figure 5: Corrosion on Steel Pole Base

Concrete poles can begin to deteriorate from weather events or mechanical damage by external factors such as vehicle impacts. Cracks on concrete poles can either be circumferential (around the pole) or longitudinal (along the length of the pole), with the latter type typically being more serious in nature as shown in Figure 6 below. Longitudinal cracks can be caused by reinforcing steel being overly close to the surface of the concrete pole or degradation due to weather events such as freeze-thaw conditions.



Figure 6: (Left) Longitudinal Crack on Pole, (Right) Cracked Concrete Base

During the 2020-2022 period, approximately 26 concrete poles were replaced reactively on average annually.

Poles are found predominantly along sidewalks, roadways, and other areas of high pedestrian and vehicular traffic. Without routine inspection, there is an unacceptable risk that poles and associated attachments could collapse onto sidewalks, roadways, and even residences. The collapse of a pole can also cause oil spills from ruptured transformer tanks, electrical arcs, flashovers, and fires, which pose serious environmental risks and safety risks to the public and Toronto Hydro employees. Minimizing the likelihood of a pole failure will mitigate these risks. Moreover, pole inspection activities, and in particular wood pole treatments (e.g. application of boron rods, copper naphthenate wraps, and internal fumigant) extend the life of poles and allow for a more efficient and structured capital pole replacement program.

Between 2020 and 2022, there were on average approximately 130 incidents of overhead asset failures (excluding major event days) each year. These failures were primarily

attributed to overhead transformers, switches, conductors, insulators, lightning arrestors and poles, and caused in excess of 117,000 CIs and 75,000 CHI's annually. Line patrols and pole inspection activities are in place to identify deficiencies that, if left unaddressed, may lead to incidents that impact system reliability.

5.2 Overhead Line Patrols and Pole Inspections Segment Costs

Table 4 below provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025) expenditures for this segment.

Table 4: Overhead Line Patrols and Pole Inspections Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Overhead Line Patrols & Pole Inspections	0.5	0.5	0.5	0.5	0.6	0.8	0.8	0.9	0.9	0.9

5.3 Overhead Line Patrols and Pole Inspections Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

There is no material variance during this rate period.

2021 – 2022 Variance Explanation

There is no material variance during this rate period.

2022 – 2025 Variance Explanation

Between 2022 and 2025, expenditures are expected to increase by approximately $0.3 million, or an average of approximately $0.1 million per year, primarily due the adjustment of the inspection frequency for wood poles from ten to eight years and the addition of inspections for concrete and steel poles in 2025.

2025 – 2029 Variance Explanation

Between 2025 and 2029, expenditures are forecasted to increase by approximately $0.1 million, which is primarily attributed to inflationary pressures. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks, including:

- Reduced ability to comply with applicable legislative and regulatory requirements such as the OEB's Minimum Inspection Requirements.[9]
- Increased frequency of equipment malfunctions or failures due to unidentified deficiencies or lack of maintenance leading to increased:
    - safety risks from incidents such as the collapse of a pole onto a roadway, sidewalk or residence, or flashovers on electrical equipment;
    - environmental risk from oil leaks resulting from unidentified equipment deficiencies such as corrosion on the transformer tank; and
    - reliability risks from the failure of overhead equipment, which can result in outages.
- Decreased ability to extend the life of wood poles through treatment.

6. OVERHEAD SWITCH MAINTENANCE AND INSULATOR WASHING

6.1 Segment Description

This segment includes two general sets of maintenance activities on the overhead distribution system: (i) maintenance of overhead switches; and (ii) washing of porcelain overhead line insulators.

- **Overhead Switches:** Toronto Hydro maintains overhead switches on a variable cycle greater than 6 years and beginning in 2025 will adjust the cycle to six-years. There are two main types of switches on Toronto Hydro's distribution system:

[9] *Supra* note 1.

- Supervisory Control and Data Acquisition ("SCADA") Switches (or SCADA-Mate Switches): These switches are motorized, and can be operated remotely from the Control Room via wireless communication, or operated locally by field crews. To enable communication and remote operation during a system failure, the switches and related equipment utilize a battery system that is capable of providing power for switch operation and communication. Maintenance of SCADA switches involves verifying the switch's remote and local operation along with lubrication of the pivot points on the visible air-gap isolation mechanism. It also includes battery replacements for the switch and repeater radio (in accordance with manufacturer's recommendations), and Remote Terminal Unit ("RTU") testing to verify proper communication with the Control Room. Figure 7 below shows a typical SCADA switch.



Figure 7: SCADA-Mate Switch

- Three Phase Gang-Operated Switches: These switches are found throughout Toronto Hydro's overhead system and unlike the SCADA switches, are not capable of remote operation. While some have motorized controls, the vast majority are manually operable at the physical switch location. The scope of work to maintain these switches involves

verifying correct blade alignment, blade penetration, travel stops, arc interrupter operation, and mechanical operation. The contacts are cleaned and greased and the switch is tested for correct operation. Figure 8 below shows a gang-operated switch.



Figure 8: Manual Gang-Operated Switch

In total, Toronto Hydro maintains approximately 2,200 overhead switches comprising of approximately 1,300 SCADA switches and 900 Three Phase Gang-Operated Switches.

Due to resourcing and operational constraints, Toronto Hydro has historically found achieving the four-year maintenance cycle of its overhead switches noted in its 2020-2024 rate application to be challenging, instead attaining variable cycles generally greater than 6 years. In order to maximize existing resources, starting in 2023, condition-based maintenance principals have been used to target switches that pose a greater risk of failure. To further alleviate constraints, beginning in 2025, Toronto Hydro will be maintaining overhead switches on a six-year inspection cycle at a minimum. This approach is supported by an independent assessment of Toronto Hydro's overhead switch maintenance practices.

- **Insulator Washing:** Conductors and switches used on the overhead distribution system have historically been attached to poles and structural infrastructure using

porcelain insulators (rather than the current standard of polymer insulators). Porcelain insulators have a high dielectric strength and good mechanical properties, including hardness and resistance to chemical erosion and thermal shock. However, porcelain has poor resistance to contamination build-up, which causes tracking (i.e. leakage of electricity across the insulator). The accumulation of dirt and salt, combined with moisture (during misty or foggy days), reduces the effective insulation levels, and can lead to insulator tracking, flashover, and potential pole fires. To mitigate the risk of contamination and insulator tracking, insulators at the highest risk locations are washed twice a year. Insulator washing is performed using a high-pressure intermittent water jet while lines are energized. Figure 9 shows an example of a porcelain insulator being washed.



Figure 9: Porcelain Insulator Washed Using a High Pressure Water Jet

Overhead switch maintenance and insulator washing serve to mitigate public and employee safety, system reliability, and financial risks. Manual overhead switching is a common and high-risk activity undertaken by Toronto Hydro crews. Switches that are not

regularly maintained can be difficult to operate, which has led to strains and injuries for crew members. Regular maintenance enables the detection and prediction of common failure modes, including the failure of a switch's insulator as shown in Figure 10 below, which can result in an arc flash that can seriously injure crew members.



Figure 10: Broken Switch Insulator

A second common failure mode is corrosion of switch metal blades. This naturally occurs from contaminants such as road salt and water settling on the switch blades. It can result in excessive heating of the blade and, over time, can lead to the blade failing to conduct electricity. Contaminants and corrosion on a switch blade during a load break operation may also cause the electrical arc to elongate, which causes additional damage to the blade and can lead to blade failure. Associated safety risks include burns from an arc-flash and overexertion injuries to an employee (i.e. if a switch requires a significant amount of force to operate).

Other common failure modes include switch seizure due to the drying out of lubrication, excessive arcing due to the misalignment of blades, and in the case of SCADA switches, failure of batteries – all of which can lead to switch malfunction, and pose a risk of injury to Toronto Hydro employees.

Between 2020 and 2022, Toronto Hydro identified on average 38 switch-related deficiencies annually. These deficiencies are addressed by overhead switch maintenance activities such as identifying and correcting deteriorated insulators and corroded switch blades, ensuring blades are properly aligned, lubricating switches, and replacing batteries proactively. Deficiencies requiring further follow-up action or replacement of the switch are addressed in the Corrective Maintenance or Reactive and Corrective Capital programs.[10]

From a system reliability perspective, reducing the likelihood of switch failures can reduce the number of CIs and CHIs. Between 2020 and 2022, Toronto Hydro's distribution system experienced on average approximately 30 power interruptions per year due to switch failures, which resulted in more than 46,000 CIs and 24,000 CHIs annually. Switches are designed to isolate line sections from the distribution system when a fault occurs or for the purposes of undertaking planned work. Their function and impact on system reliability can be illustrated using the example in Figure 11 below.

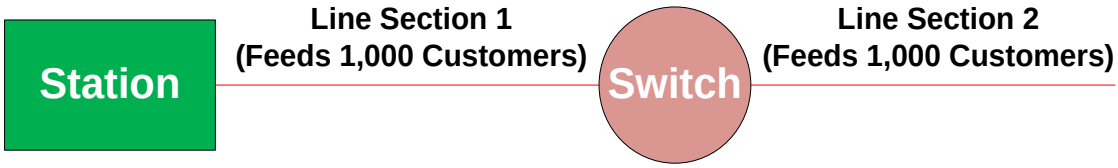


Figure 11: Example of Overhead Switch Impact on System Reliability

Depicted above is a feeder that serves 2,000 customers, divided into two line sections using a switch, with each section serving 1,000 customers. When a fault occurs on Line Section 2, the switch can be operated to isolate that line section such that the station can continue to supply the customers on Line Section 1. Without an operable switch, 2,000 CIs would result, as the feeder would be isolated in its entirety from the station.

[10] *Supra* note 8.

Maintaining the switch in good working order has the potential to reduce that number to 1,000 CIs as only Line Section 2 would be isolated. Assuming in this theoretical example a fault is equally likely to occur on Line Section 1 or Line Section 2, an operable switch would improve system reliability by 33 percent.

Approximately 2,500 locations contain porcelain insulators, which are at an increased risk of contamination as they are close to industrial areas and busy arterial roads and highways (such as the 401, 400, 427, and the Don Valley, Allen, and Gardiner Expressways), where salt used to melt snow or ice in the winter months becomes airborne through "salt spray" and deposits on the insulators.

Removing contamination through insulator washing reduces the risk of electrical tracking, pole fires, and insulator failures. From a safety perspective, pole fires and insulator failures in Toronto's dense urban areas can cause injury to individuals at ground level and crew members working near the insulators. The primary failure mode for porcelain equipment is cracking, which may start as a hairline crack, but has the potential to lead to a catastrophic failure with shards of debris falling to the ground and striking anyone in the vicinity and an arc flash risk to workers nearby. Figure 12 below shows a close-up view of a porcelain insulator damaged by electrical tracking over time.



Figure 12: Close-up of Damaged Porcelain Insulator Showing Tracking

From a system reliability perspective, insulator failures, depending on where they occur on a feeder, will cause a power interruption for tens to possibly thousands of customers. On March 3, 2015, Toronto Hydro experienced an all-time high of 121 pole fires, caused by a freezing rain storm event. These pole fires impacted approximately 107,000 customers and resulted in approximately 292,000 CHI's. The cause of the fires was a combination of the higher moisture levels caused by freezing rain and the build-up of salt used on roads, which became airborne and accumulated on the insulators. This combination of factors can significantly increase the risk of a pole fire. See Figure 13 below.



Figure 13: Pole fire on December 22nd, 2017

From a financial perspective, pole fires resulting from insulator tracking necessitate emergency response, equipment replacement, and in some instances, the payment of damage claims. Emergency response costs incurred by Toronto Hydro for the March 3, 2015 freezing rain event totalled $1.5 million.

In response to this event, Toronto Hydro developed a reactive insulator washing program, which involves additional system wide insulator washing of all high risk pole locations on a reactive basis, based on weather patterns and road salt usage trends. This work is funded through the Corrective Maintenance program.[11] Since this Program began, Toronto Hydro has not seen pole fires at 2015 levels. From 2020-2022, Toronto Hydro has been averaging approximately 20 pole fires per year which represents a significant reduction from the total number of poles fires in 2015.

Given the risks associated with contaminated porcelain insulators (including public and employee safety, system reliability, and financial risks), routine insulator washing is a necessary and prudent means of reducing the likelihood of contingencies resulting from debris build-up on insulators. Reductions in the amount of insulator washing could result in increased incidents of insulator tracking and poles fires.

As porcelain insulators are naturally phased out of the system and replaced with polymer insulators, the need for insulator washing is expected to diminish in the long-term, as polymer insulators are hydrophobic and are not susceptible to the same failure mode due to contamination. In the short-term however, continued insulator washing is expected to be required.

6.2 Overhead Switch Maintenance and Insulator Washing Segment Costs

Table 5 below provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for this segment.

[11] *Supra* note 5.

Table 5: Overhead Switch Maintenance and Insulator Washing Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Overhead Switch Maintenance & Insulator Washing	1.4	1.6	1.3	1.6	1.7	2.4	2.4	2.5	2.6	2.6

6.3 Overhead Switch Maintenance and Insulator Washing Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

Expenditures increased by approximately $0.2 million from 2020 to 2021, which was primarily attributed to an increase in unit prices to maintain all overhead switches and an increase in switch batteries replaced.

2021 – 2022 Variance Explanation

Expenditures decreased by approximately $0.2 million from 2021 to 2022, which was primarily attributed to a decrease in the number of switch batteries replaced.

2022 – 2025 Variance Explanation

Between 2022 and 2025, expenditures are expected to increase by approximately $1.1 million, or an average of $0.4 million per year, which is primarily attributed to an increase in the number of overhead switches scheduled for maintenance in order to achieve a six-year inspection cycle.

2025 – 2029 Variance Explanation

Between 2025 and 2029, expenditures are expected to increase by approximately $0.2 million, or an average of less than $0.1 million per year, primarily due to inflation partially

offset by decreases in the number of insulators to be washed. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks, including:

- Reduced ability to comply with applicable legislative and regulatory requirements such as the OEB's Minimum Inspection Requirements.[12]
- Increased frequency of equipment malfunctions or failures due to unidentified deficiencies or lack of maintenance leading to increased:
    - safety risks from incidents such as the collapse of a pole onto a roadway, sidewalk or residence, or flashovers on electrical equipment;
    - environmental risk from oil leaks resulting from unidentified equipment deficiencies such as corrosion on the transformer tank; and
    - reliability risks from the failure of overhead switches or other equipment, which result in outages or interruptions caused by overgrown trees, which can result in outages.

7. VEGETATION MANAGEMENT

7.1 Segment Description

Toronto Hydro performs vegetation management on over 860 overhead primary feeders extending almost 4,800 circuit kilometres along Toronto's arterial thoroughfares, rights-of-way, and residential streets. These feeders co-exist with the City of Toronto's mature and dense tree canopy, which includes about 600,000 City-owned "street trees" and thousands of trees located on customer properties. In total, there are over ten million trees in the City of Toronto. Over 125,000 of these street trees are adjacent to primary overhead feeders, and their overgrowth can potentially interfere with the safe and reliable distribution of electricity.

[12] *Supra* note 1.

Planned vegetation management activities are executed by contractors with support from Toronto Hydro's internal resources. Trees and branches are pruned according to minimum clearance standards based on American National Standards Institute ("ANSI") A300 – Standard Practices for Trees, Shrubs and other Woody Plant Maintenance,[13] and the City of Toronto Forestry Pruning Guidelines. In addition to the minimum clearance standards, Toronto Hydro considers other factors such as:

- **Species and growth patterns of a tree**: Fast-growing trees are trimmed more and slow-growing trees are trimmed less;
- **Natural trimming practices**: Branches are pruned back to a natural point of growth in the crown of the tree and leaders are "trained" (shaped) to grow away from the lines;
- Distance of major limbs that exhibit minimal growth, versus minor branches that can exhibit aggressive growth;
- **Directional pruning practices**: Maintenance of tree shape and branch patterning;
- Overall aesthetics and balance of the tree;
- Removal of dead limbs; and
- **Storm hardening**: Select removal of branches within the canopy to minimize the possible effects of wind and severe weather, but maintain the overall tree appearance.

Toronto Hydro avoids the practice of "tree topping", which is the indiscriminate removal of branches to reduce the size of the tree crown. As a result, and given the above-noted factors, Toronto Hydro mandates the use of certified utility arborists for vegetation

[13] American National Standards Institute, *American National Standard for Tree Care Operations — Tree, Shrub, and Other Woody Plant Maintenance — Standard Practices (Pruning)*, (A300 (Part 1) -2001).

management activities with training, knowledge, and certification in the practice of arboriculture.

Vegetation management mitigates the risk of vegetation interference by pruning trees near Toronto Hydro's overhead feeders. Each year, Toronto Hydro identifies the feeders in greatest need of tree pruning based on prioritization criteria such as feeder reliability history, number of customers supplied by each feeder, and the amount of time that has elapsed since the trees surrounding the feeder were last pruned. The prioritization process results in pruning trees surrounding feeders once every two to five years, with the system average being approximately three years. On average, Toronto Hydro pruned 1,399 circuit kilometres and approximately 47,000 trees annually between 2020 and 2022.



Figure 14: Tree Trimming of an Overhead Feeder

Vegetation interference is one of the most common causes of power interruptions, as overhead feeders are prone to tree branch contacts. Trees may make contact with distribution feeders as a result of natural growth, or when severe weather causes branches to break and fall onto lines or to bend and make intermittent contact. Conductors on feeders can also naturally stretch and sag due to ice and snow build-up, heavy loading or warm weather, bringing the lines closer to tree limbs. Branch contacts with lines result in a new path for current to travel, causing the branch to become energized, and posing a safety risk.

Vegetation-related power interruptions have a significant impact on system reliability and are among the leading causes of system outages. Statistics from 2020 to 2022 show that tree contacts are responsible for nearly 100 power interruptions a year, and cause approximately 116,000 CIs and 117,000 CHIs annually. When all interruptions are considered, over the period of 2020-2022, trees accounted for approximately nine percent of all CIs and 16 percent of all CHIs annually on average. These statistics exclude interruptions that occurred on major event days. During such days, the distribution system is particularly vulnerable to tree contacts and costly tree damage.

As more time passes since the last tree pruning for a particular feeder, it becomes more likely that tree contacts will occur and associated risks will increase (including system reliability, financial, and safety risks). These risks can be effectively mitigated through tree trimming.

From a reliability standpoint, Figure 15 illustrates the average number of sustained outages per feeder relative to time elapsed since the last pruning and trimming activities. This figure shows that the more time that passes from when a feeder was last trimmed, the higher the number of sustained outages are observed for that feeder, which is forecasted to continue to increase as more time elapses from the last trimming.

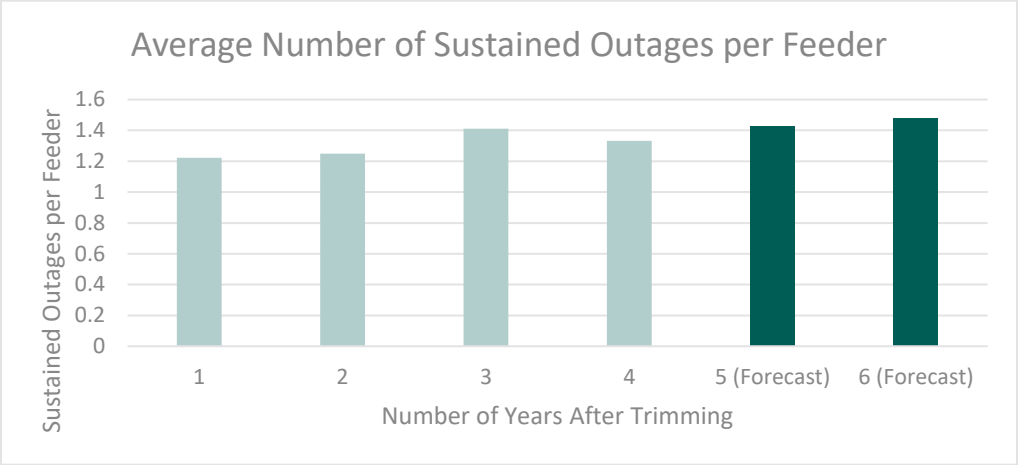


Figure 15: Average Number of Sustained Outages Per Feeder

Vegetation management is also a widely accepted means of effectively "storm-hardening" a system (i.e. proactively mitigating against storm damage and associated system reliability risks). Storm hardening involves selectively removing portions of a tree canopy to reduce the "sail effect" of branches during high winds and to reduce the likelihood that broken branches will make contact with lines. As such, more frequent tree pruning further reduces risks posed by severe weather.

Toronto Hydro's system is susceptible to severe weather and storm damage, as evidenced by the 2013 ice storm and more recently the May 21st, 2022 wind storm. In many cases, the effects of these storms continue well after the storm has passed. Broken and weakened trees and tree limbs continue to pose a threat to overhead lines until the next tree pruning date. From a financial perspective, planned vegetation management is expected to reduce reactive expenditures from corrective and emergency responses.

In addition to system reliability and financial risks, vegetation management serves to mitigate safety risks, including as a result of trees and vegetation that grows or is blown

into power lines. This vegetation can become energized, and in certain situations, can cause fires or step and touch potential risks to the general public. Another safety risk stems from branches or trees that bring energized conductors to the ground when they fall, which pose significant safety hazards to the public. Vegetation management is expected to mitigate these risks.

Under the City's Strategic Forest Management Plan, the City's tree canopy cover is expected to grow from 28 percent to 40 percent. The outcome of this initiative is evident from Toronto Hydro's Vegetation Management program (see Figure 16), where the number of trees trimmed for the same feeders has increased by approximately 61 percent from 2018 to 2022. The growing tree canopy will only increase the need for a robust Vegetation Management program in order to maintain tree growth and mitigate the risk of tree contacts with overhead distribution lines.

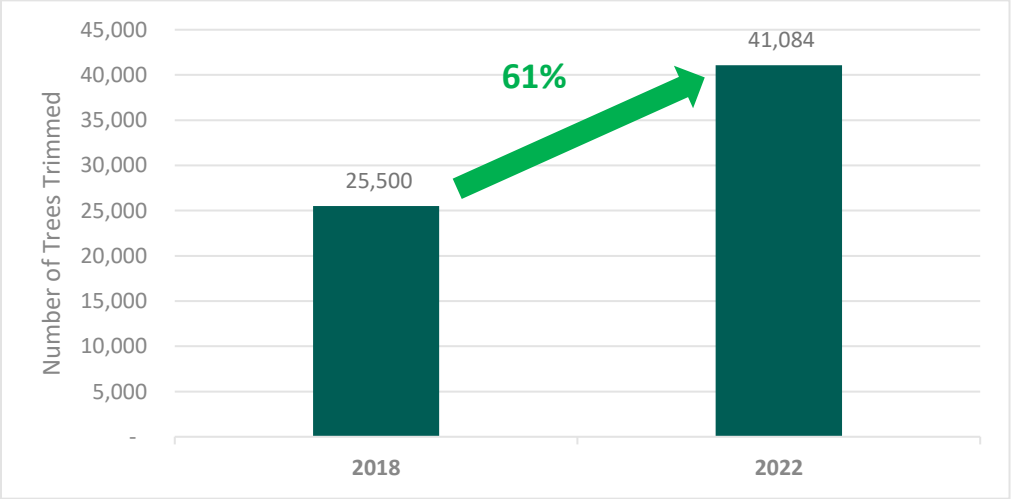


Figure 16: Tree count for feeders trimmed in 2018 versus the same feeders trimmed in 2022

Toronto Hydro is piloting multiple technologies, such as LiDAR and satellite imagery to assess vegetation encroachment near overhead primary conductors. The objectives of

these pilots is to reduce vegetation-related outages by adopting a data and condition-based approach for feeder-based tree trimming.

7.2 Vegetation Management Segment Costs

Table 6 below provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for this segment.

Table 6: Vegetation Management Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Vegetation Management	2.8	3.4	3.5	3.5	3.8	4.0	4.1	4.2	4.3	4.4

7.3 Vegetation Management Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

Expenditures increased by approximately $0.6 million from 2020 to 2021, which was primarily attributed to an increase in the number of kilometers of feeder trimmed.

2021 – 2022 Variance Explanation

Expenditures increased by approximately $0.1 million from 2021 to 2022, which was primarily attributed to an increase in the number of kilometers of feeder trimmed.

2022 – 2025 Variance Explanation

Between 2022 and 2025, expenditures are expected to increase by approximately $0.5 million, or an average of $0.2 million per year, primariliy due to inflationary pressures.

2025 – 2029 Variance Explanation

Between 2025 and 2029, expenditures are forecast to increase by $0.4 million, or an average of $0.1 million per year, due to inflationary pressures. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks, including:

- Reliability risks from interruptions caused by overgrown trees;
- Extreme weather related risks due to inability to storm harden the system by reducing likelihood that broken branches will make contact with lines during high winds;
- Safety risks due to branch contacts with lines causing branches to become energized, potentially causing fires and step and touch potential risks; and
- Financial risks due to increased spending on corrective or emergency responses.

8. METERING SERVICES SEGMENT

8.1 Segment Description

Toronto Hydro and its customers rely on metering equipment to accurately measure and provide on a timely basis electricity consumption information for customer billing and market settlement purposes. The Metering Services segment is responsible for maintaining this equipment to ensure proper functionality and compliance with applicable legislative and regulatory requirements.

Toronto Hydro's metering assets include both meters and the communication systems that enable meter data collection and tracking. The maintenance of metering equipment is critical to ensuring the ongoing accuracy of meter reads and the associated billing and settlement data. Moreover, meter testing is a requirement under the *Electricity and Gas*

Inspection Act administered by Measurement Canada. [14] Metering Services maintains Toronto Hydro's 798,000 smart and suite meters and 222 wholesale meter installations, examples of which are illustrated in Figures 17 and 18 below.



Figure 17: Smart Meter Installation at Customer Location.



Figure 18: Wholesale Meter Installation at Transformer Station.

Metering Services activities consist of three major functional categories: (i) Meter Sampling & Testing; (ii) Wholesale Meter Maintenance; and (iii) Field Response.

8.1.1 Meter Sampling and Testing

Toronto Hydro is required to comply with the metering requirements set out in and pursuant to legislation administered by Measurement Canada, which requires that all meters must be resealed at specific intervals in order to ensure that customers' electricity use is metered accurately. The Toronto Hydro meter sampling and testing program verifies the accuracy of meters, ensuring compliance with applicable requirements under the *Electricity and Gas Inspection Act* and the *Weights and Measures Act.*[15] These statutes

[14] *Supra* note 2.
[15] *Supra* note 2 and 3.

permit the use of meters for a set period of time, also referred to as a "seal period", before they must be either tested (i.e. re-verified) or replaced. For smart meters, this time span is typically ten years. When meters are tested and re-verified for accuracy, the seal period is extended.

For meter testing purposes, Measurement Canada permits utilities to form isolation lots (i.e. groups of meters with homogeneous meter characteristics), and test only a small number (called the sample group) from the isolation lot. Typically, 2-5 percent of randomly selected meters from each isolation lot form the sample group. For smaller homogeneous lots, the sampling rate could be as high as 50 percent. These sampling rates are allowed given the large number of meters in-service. The number of meters to be tested is determined in accordance with Measurement Canada's specification S-S-06, *Sampling Plans for the Inspection of Isolated Lots of Meters in Service*.[16] The seal period of the isolation lot of meters can be extended if the accuracy statistics for the sample group meet tolerances stipulated in Measurement Canada's specification. Some unique meters do not belong to any isolation lot and must be removed from service and tested individually before their seal periods expire. Table 7 lists the number of meters with a seal period that will expire during the 2025-2029 rate period. It also lists the number of meters that will need to be sampled or re-verified so as to comply with Measurement Canada's requirements. The sampling units accounts for meters that will be replaced through capital investments in the Metering program, including through Toronto Hydro's Advanced Metering Infrastructure ("AMI") 2.0 initiative.[17]

[16] See Annex C, Table 2, Limiting Quality 3.15.
[17] Exhibit 2B, Section E5.4.

Table 7: Number of Seal Expiring Meters in 2025-2029 and Sampling Units

Year	Seal-Expiring Meters	Sampling/Re-verification units
2025	196,127	10,464
2026	155,463	13,201
2027	70,968	14,783
2028	68,151	15,396
2029	28,242	11,311
Total	**518,951**	**65,155**

In conducting meter testing, Toronto Hydro relies on field crews to remove meters that are part of a sample group and return them to Toronto Hydro's accredited service provider for testing. Test results are forwarded to Toronto Hydro for documentation and further actions based on the test results. A pass will result in an update to the meter records and the extension of seal periods, based on the tested accuracy levels. For the utility's smart meters with a ten-year initial seal period, provided the meters pass testing, the seals will be extended for all of the meters within the group by an additional eight years.

8.1.2 Wholesale Meter Maintenance

Wholesale meters, including instrument transformers, are installed at transmission grid supply points to measure electricity supplied from Hydro One Networks Inc. ("Hydro One") to Toronto Hydro. Wholesale meter maintenance involves re-verifying (i.e. testing every eight years) and troubleshooting wholesale meters, and ensuring compliance with all applicable regulations, such as the requirement to notify the Independent Electricity System Operator ("IESO") of Meter Trouble Reports within 48 hours pursuant to the IESO's Market Rules and Market Manual.

Meter Trouble Reports are issued if there is any failure in data communication or if the data is suspected to contain errors. Data communication failures can arise from issues

with Toronto Hydro's wireless 4G private network, the meter itself, or the modem. If such a failure occurs, Toronto Hydro attempts to resolve the issue remotely. If remote resolution is unsuccessful, Toronto Hydro deploys field crews to the site of the particular wholesale meter to address the issue directly.

8.1.3 Field Response

The third category of activities within Metering Services is Field Response, which includes activities such as:

- Testing the accuracy of large user meter installations;
- Converting legacy flat rate services (e.g. Water heaters) into metered activities; and
- Installing reused meters following accuracy testing.

Toronto Hydro's 691,000 smart meters have a failure rate of 0.9 percent (i.e. approximately 6,200 units annually). Toronto Hydro's 94,000 suite meters have a failure rate of 2 percent (i.e. approximately 1,700 annually). The majority of the failures are related to: (i) the use of radio frequency mesh technology for smart meters; (ii) powerline carrier for suite meters, to deliver the meter reading data back to Toronto Hydro's centralized meter reading software and (iii) hardware failure of suite meters. As failures occur, staff and field crews must investigate failure causes and restore communications in a timely manner, as well as perform on-site interval energy data downloads to maintain time sensitive billing (time-of-use).

Overall, a significant portion of the work undertaken by Metering Services is not discretionary because it is either driven by statutory or regulatory obligations, or a need to resolve a meter issue in the field on a reactive basis.

8.2 Metering Services Segment Costs

Table 8 below provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for this segment.

Table 8: Metering Services Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Metering Services	1.1	0.7	0.4	1.6	1.8	1.9	1.9	2.0	1.7	1.5

8.3 Metering Services Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

Expenditures decreased by approximately $0.4 million from 2020 to 2021, primarily due to obsolete meter models that could not be reused and therefore were not sampled or reverified.

2021 – 2022 Variance Explanation

Expenditures decreased by approximately $0.3 million from 2021 to 2022, mainly due to lower maintenance activities for transformer station metering and reduced number of reused meter changes as obsolete meter models were being replaced with new meters.

2022 – 2025 Variance Explanation

Between 2022 and 2025, expenditures are expected to increase by $1.5 million, or an average of $0.5 million per year, primarily due to higher volumes of suite maintenance activities and meter testing and resealing and operational costs related to Toronto Hydro's AMI 2.0 initiative.

2025 – 2029 Variance Explanation

Between 2025-2029, expenditures are forecast to decrease by $0.4 million, or an average of $0.1 million per year, primarily due to lower meter sampling costs and reduced operational costs. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks, including:

- Reduced ability to comply with applicable legislative and regulatory requirements such as Measurement Canada's metering requirement; and
- Worsening customer service performance due to inaccurate or delayed billing of customers based on usage.

PREVENTATIVE AND PREDICTIVE UNDERGROUND LINE MAINTENANCE

1. OVERVIEW

Table 1: Preventative and Predictive Underground Line Maintenance Program Summary

Preventative and Predictive Underground Line Maintenance Program									
Outcomes: Operational Effectiveness - Reliability, Environment, and Operational Effectiveness – Safety									
Segments: • Below-Grade Equipment Maintenance • Padmounted Equipment Maintenance • Cable Diagnostic Testing • Contact Voltage Scanning									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
5.1	4.4	5.7	6.3	6.1	6.8	7.0	6.7	7.1	7.0

The Preventative and Predictive Underground Line Maintenance program (the "Program") funds maintenance activities on Toronto Hydro's underground assets. This Program involves inspection and maintenance tasks typically conducted on a fixed cycle and inspection of equipment for predetermined conditions indicative of a potential failure. The activities comprising the individual segments in this Program are focused on preserving and maximizing the performance of assets over their expected useful life while mitigating a wide variety of system risks. This Program is also designed to minimize overall costs and account for other factors such as the safety of Toronto Hydro's work crew and the public, and statutory and regulatory requirements.[1] The Preventative and Predictive Underground Line Maintenance program is comprised of the following four segments:

[1] *Distribution System Code*, Appendix C (August 2, 2023).

- **Below-Grade Equipment Maintenance:** this segment includes the periodic inspection and maintenance of all underground vaults such as network vaults, compact radial distribution ("CRD") vaults, underground residential distribution ("URD") vaults, submersible vaults, cable chambers, and equipment housed within them.
- **Padmounted Equipment Maintenance:** this segment includes the periodic inspection of padmounted equipment (e.g. transformers, switches), which form part of Toronto Hydro's underground distribution system.
- **Cable Diagnostic Testing:** this segment involves performing diagnostic testing on cables installed in Toronto Hydro's underground system to provide a more accurate assessment of the condition of underground cables, splices, joints, and terminations.
- **Contact Voltage Scanning**: this segment addresses includes the periodic scanning of Toronto Hydro's distribution system for contact voltage, which results from an unintentional connections between structures or surfaces (e.g. bus shelters, surfaces above buried distribution equipment) and Toronto Hydro's distribution system. The main activity in this segment involves using vehicle mounted mobile scanning tools to scan for stray voltages from electrical connections and terminations that potentially energize poles, bus shelters etc., due to exposure to weather elements, thereby creating public safety hazards.

By preserving and maximizing the performance of underground assets, and reducing risks associated with its operation, this Program contributes to maintaining safety, environmental responsibility, and overall system reliability at a reasonable cost to Toronto Hydro's customers.

2. OUTCOMES AND MEASURES

Table 2: Preventative and Predictive Underground Line Maintenance Program Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contribute to maintaining existing levels of system reliability – as measured by performance metrics like SAIDI, SAIFI, Customers Interrupted ("CI"), and Customer Hours Interrupted ("CHI") – through the effective inspection and maintenance of underground assets for deficiencies in compliance with the Ontario Energy Board's ("OEB") Distribution Systems Code ("DSC").
Environment	• Contribute to reducing the environmental impact of Toronto Hydro's distribution system by proactively identifying transformers exhibiting signs of oil deficiencies or padmounted switches leaking SF_6 gas for replacement, thereby reducing the likelihood of these contaminants from entering the environment.[2]
Operational Effectiveness - Safety	• Contribute to Toronto Hydro's safety objectives (including compliance with Ontario Regulation 22/04, and safety performance as measured through the Serious Electrical Incidents Index) by:[3] o minimizing public exposure to contact voltage by finding and eliminating energized (4.5 volts or greater) surfaces and structures on Toronto Hydro's distribution system; and o minimizing exposure to blown cable chamber lid incidents through prompt identification and resolution of failing cables that can result in electrical faults leading to these incidents.

3. PROGRAM DESCRIPTION

The Preventative and Predictive Underground Line Maintenance program funds maintenance activities on Toronto Hydro's underground assets. This Program involves inspection and maintenance tasks typically conducted on a fixed cycle and inspection of equipment for predetermined conditions indicative of a potential failure. The activities comprising the individual segments in this Program are focused on preserving and

[2] Approximately 600 oil deficiencies (e.g. leaking underground transformers) were found and reported between 2020 and 2022.
[3] Ontario Regulation 22/04: Distribution System Safety, under *Electricity Act,* SO 1998, Ch 15, Schedule A.

maximizing an the performance of assets over their expected useful life while mitigating a wide variety of system risks. Tasks in this Program are also designed to minimize overall costs and account for factors such as the safety of Toronto Hydro crews and the public, and statutory and regulatory requirements.

Maintenance activities include vault and cable chamber inspections to assess the condition of civil structures and the equipment housed inside (e.g. transformers, switches, and cables), inspections of padmounted transformers and switches; cable diagnostic testing for underground cables; and contact voltage scanning for stray voltages across the distribution system.

- **Below-Grade Equipment Maintenance:** this segment funds the periodic inspection and maintenance of all underground vaults such as network vaults, compact radial distribution ("CRD") vaults, underground residential distribution ("URD") vaults, submersible vaults, cable chambers, and equipment housed within them.
- **Padmounted Equipment Maintenance:** this segment funds the periodic inspections of padmounted equipment (e.g. transformers, switches).
- **Cable Diagnostic Testing:** this segment funds the diagnostic testing on cables installed in Toronto Hydro's underground system to provide a more accurate assessment of the condition of underground cables, splices, joints, and terminations.
- **Contact Voltage Scanning:** this segment funds the periodic scanning of Toronto Hydro's distribution system for contact voltage, which results from an unintentional connections between structures or surfaces (e.g. bus shelters, surfaces above buried distribution equipment etc.) and Toronto Hydro's distribution system. The main activity in this segment is the use of vehicle

mounted mobile scanning tools to scan for stray voltages from electrical connections and terminations that potentially energize poles, bus shelters etc. due to exposure to weather elements, thereby creating public safety hazards.

4. PROGRAM COSTS

In 2025, Toronto Hydro requires $6.8 million in rate funding for the Preventative and Predictive Underground Line Maintenance program, which represents an increase of $1.7 million over the previous rate period in 2020.

Over the 2025-2029 rate period, the utility expects the cost of this program to increase by a compounded annual growth rate of 1.1 percent, which is necessary to address underground line maintenance needs and deliver the customer outcomes enabled by this program.

The Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for each segment are summarized in Table 3 below.

Table 3: Preventative and Predictive Underground Line Maintenance Program Expenditures by Segment ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Below-Grade Equipment Maintenance	2.5	2.9	3.0	3.5	3.2	3.5	3.6	3.3	3.5	3.5
Padmounted Equipment Maintenance	0.6	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6
Cable Diagnostic Testing	-	0.3	0.4	0.6	0.6	0.7	0.8	0.8	0.8	0.8
Contact Voltage Scanning	2.0	0.7	1.8	1.7	1.8	2.0	2.0	2.0	2.2	2.1
Total	**5.1**	**4.4**	**5.7**	**6.3**	**6.1**	**6.8**	**7.0**	**6.7**	**7.1**	**7.0**

4.1 Cost Drivers

Cost variances are partly attributed to varying numbers of units scheduled for inspections each year based on their inspection cycle. For example, in the Below–Grade Equipment Maintenance segment, the number of submersible vaults due for maintenance increased from 2,500 locations in 2021 to 3,244 locations in 2022 (an increase of 30 percent). Similarly, in the Padmounted Equipment Maintenance segment, Toronto Hydro inspected more padmounted transformers, from 2,157 units in 2021 to 2,422 units in 2022. In the Cable Diagnostic Testing segment, costs are increasing as this is a relatively new segment and testing is steadily ramping up.

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

Toronto Hydro continually looks to optimize its work coordination process. For example, Toronto Hydro's Cable Diagnostic Testing program in the downtown core aims to coordinate testing with station maintenance cycles. As the program matures, multiple feeders will be able to be coordinated at the same station for testing to eliminate the need for additional outages and site visits, thereby reducing costs.

As of 2027, Toronto Hydro's network vaults will have sensors providing remote monitoring and control through the Network Condition Monitoring and Control ("NCMC") program.[4] Network monitoring will complement the inspections of network vaults and will reduce the number of on-site inspections required, yielding costs savings from the adjustment of maintenance cycles for the civil structure of network vaults from 6 months to 1 year.

[4] Exhibit 2B, Section E7.3.

For the Contact Voltage segment, Toronto Hydro adjusted the inspection cycle to be performed on a per ward basis, implementing risk-based maintenance principles. Instead of scanning the entire city on an annual basis, only wards deemed to be higher risk are scanned each year. The remaining lower risk wards, i.e. those located outside of downtown and with fewer historical voltage contact hits, are scanned every three years. This change has yielded direct cost savings from the reduction in overall scanning activity each year.

4.2.2 Productivity

Toronto Hydro has placed significant emphasis on achieving greater output for the same or reduced input in each of the segments within the Preventative and Predictive Underground Line Maintenance program. Toronto Hydro continues to rely on its Reliability Centered Maintenance ("RCM") approach, pursuant to which it adjusts maintenance tasks and frequencies based on RCM and Condition-Based Maintenance ("CBM") principles. Examples of these adjustments include:

- Continuously updating inspection forms and implementing CBM to allow for the capturing of greater details about substandard conditions or deficiencies found during inspections. These updates enable better prioritization and determination of the most appropriate corrective action for each deficiency to better mitigate public and employee safety, as well as environmental, system reliability, and financial risks.
- Standardizing the scheduling of outage-based activities to align with station maintenance cycles wherever possible to minimize the need for multiple outages (and significant switching resources), enable bundling of maintenance work, and minimize the need for multiple trips to particular sites.

- Implementing "find and fix" protocols whereby crews that identify minor asset deficiencies also address the deficiencies on site (through actions such as lubricating components, replacing faulted circuit indicators, replacing sump pumps, clearing drains, caulking ducts and roof slabs, and replacing defective locks, hinges or handles) as opposed to only logging the deficiencies for the Corrective Maintenance program.
- Introducing new tools or making greater use of technology such as 3D imaging and modelling of underground structures, Cable Diagnostic Testing, Contact Voltage Scanning, Infrared Thermography, Electronic Maintenance Sheets, and Online Partial Discharge Testing.
- Improve the method of selecting assets for inspections through the adoption of CBM principles based on an asset's health and condition history.

The following sections describe and discuss the drivers of each of the segments within the Preventative and Predictive Underground Line Maintenance program.

5. BELOW-GRADE EQUIPMENT MAINTENANCE SEGMENT

5.1 Segment Description

This segment covers the inspection and maintenance of underground vaults and cable chambers and the equipment housed within them. These below-grade structures are constructed out of concrete or reinforced or un-reinforced concrete and house transformers, switches, cables, and other electrical distribution equipment. Inspections and maintenance activities are conducted on various types of below-grade structures including network vaults, compact radial distribution ("CRD") vaults, underground residential distribution ("URD") vaults, submersible vaults, and cable chambers.

Constructed in the 1950s and 1960s, network vaults are primarily located in the downtown core of Toronto. These vaults are the largest of the below-grade structures, and house interconnected electrical equipment used for the secondary network system that provides reliable supply to large and critical customers in the city's dense downtown core. The four main electrical components within network vaults are: (i) primary switches, which isolate supply to transformers; (ii) transformers; (iii) network protectors, which open when reverse power flow is sensed, preventing the secondary grid from feeding a primary side fault; and (iv) fuse panels, which protect the cables feeding the secondary grid. The transformer and the network protector are referred to as a network unit, an example of which is illustrated in Figure 1. Toronto Hydro has over 1,040 network vaults and 1,700 network units that require inspection and maintenance.

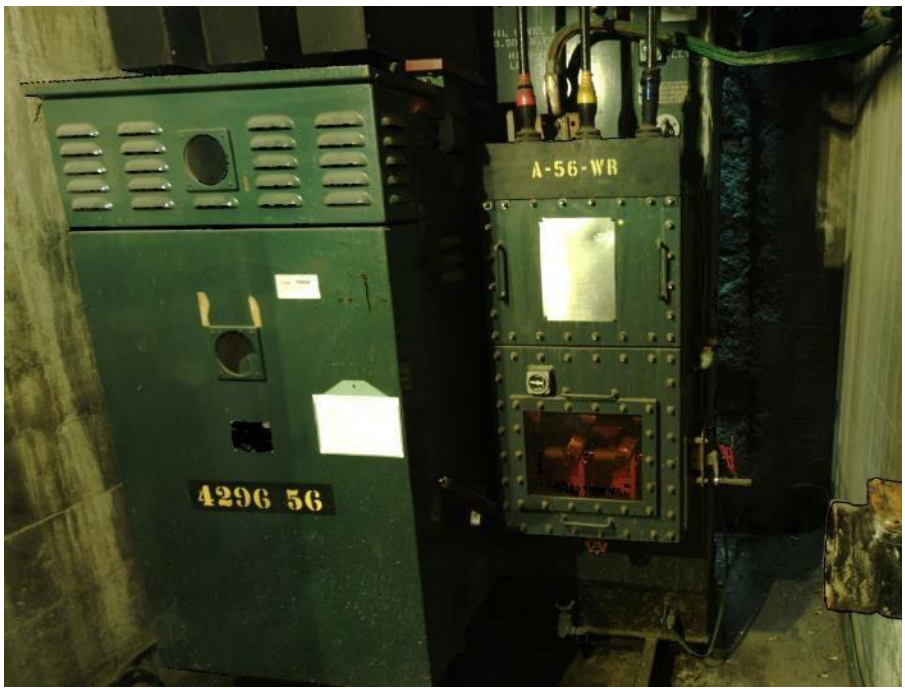


Figure 1: A Network Unit

The civil structures of network vaults is are currently inspected on a six-month cycle and the electrical assets are inspected annually. Beginning in 2027, the inspection cycle for

the civil structures of network vaults will be adjusted from six months to annual. This extended cycle is appropriate because all network vaults will be equipped with sensors installed as part of the NCMC program. The NCMC program is expected to complement the network inspections by providing remote monitoring and control for the network distribution system. The real-time remote sensing capabilities will provide live operating data for parameters such as temperature and water level within the vault, network transformer oil temperature and oil levels, and network protector operation status, as well as water levels inside the protector. With the implementation of NCMC across the network distribution system, the real-time condition and loading data will allow Toronto Hydro to proactively monitor operating conditions and effectively respond and proactively address any potential hazards that are detected. Network protectors are also inspected, cleaned, and functionally tested to ensure operability on a four-year cycle for high voltage protectors, and a five-year cycle for low voltage protectors.

Toronto Hydro's CRD and URD systems were constructed in the early 1990s and 2000s, respectively. CRD vaults were designed to be a cheaper lower-cost alternative to network vaults because of their simpler design, and are typically used to supply small retail, apartment, and commercial office buildings. URD vaults were built for 4 kV to 13.8 kV conversion projects and are primarily used to power small residential or commercial buildings. Toronto Hydro has a total of 780 CRD and URD vaults, which are inspected annually.

Submersible vaults are small civil structures installed on public road allowances, or private properties, and are used for residential distribution. These vaults contain submersible transformers,[5] switches, loop-through primary conductors, and secondary circuits. The

[5] Submersible transformers are designed to function submerged under water for extended periods (but not indefinitely), although Toronto Hydro aims to keep water out of the submersible vaults through inspections.

vaults are sized to accommodate a transformer and secondary connections only. The over 8,700 submersible transformer vaults in Toronto Hydro's distribution system are inspected on a three-year cycle. Figure 2 illustrates a submersible vault.



Figure 2: Submersible Vault

Cable chambers are civil structures are typically installed on public road allowances, and contain primary and secondary cables, cable splices, and in many cases, third party installations such as Toronto Transit Commission ("TTC") power cables, television cables, and phone lines. Located along the routes of underground feeders, cable chambers facilitate cable installation in underground ducts. Toronto Hydro has over 11,400 cable chambers that are inspected on a ten-year maintenance cycle. Beginning in 2025, Toronto Hydro will be implementing condition-based maintenance for cable chambers in poor condition as well as locations found to have deficiencies reported from Cable Diagnostic Testing.

The Below-Grade Equipment Maintenance segment includes, for all types of vaults or chambers, visual inspections of the civil infrastructure and electrical equipment, thermographic scans, partial discharge testing, drainage, and sump pump tests.

The inspection cycles in this segment are designed to meet or exceed mandated cycles specified by the OEB's Minimum Inspection Requirements (Appendix C to the Distribution System Code).[6]

The useful life of below-grade structures (including all types of vaults described above and cable chambers) is 60-65 years. The roofs of those structures however are expected to last for only 25 years, due to greater exposure to the environment and dynamic loads such as pedestrian and vehicular traffic. The equipment housed within below-grade structures is expected to have an average life between 30 and 40 years depending on the type of equipment.

The ages of Toronto Hydro's vaults vary from the relatively new URD and CRD vaults to the older network vaults in the downtown areas of the city. Over 28 percent of all network vaults will reach the end of their expected life within the next ten years, and the vast majority of network vault roofs are already beyond their useful life. In addition, over 55 percent of cable chamber roofs are past their useful life.

As below-grade structures age, the greatest concern becomes structural strength. Structural deficiencies affecting vaults include degradation of concrete and corrosion of supports such as beams and rebar. Once degradation and corrosion set in, conditions can deteriorate rapidly and in many cases from one season to the next. Of particular concern

[6] *Supra* note 1.

is the winter season when moisture and water (often containing road salt) enter below-grade structures and freeze and thaw. Figures 3 and 4 depict structural deficiencies that are common in older vaults.



Figure 3: Crumbling Vault Roof with Exposed Rebar



Figure 4: Corroded I-Beams

Below-Grade Equipment Maintenance mitigates the risks that the deterioration of civil and electrical assets poses, including public and employee safety, financial, environmental, and system reliability risks. Toronto Hydro mitigates these risks by identifying deficiencies in below-grade structures before they cause a failure. As illustrated in Figure 5 below, Toronto Hydro has identified on average over 25,000 deficiencies each year between 2020 and 2022. This is an increase over the average number of deficiencies found in the distribution system over 2015-2017 (approximately 12,000 deficiencies per year), which is partly attributed to enhancements made to

inspection forms in order to capture greater details and enable more informed decision-making on follow-up actions and the inclusion of deficiencies that are repaired during inspection.[7] Toronto Hydro reviews these deficiencies to determine appropriate correction actions, and those that require corrective actions are addressed under the Corrective Maintenance and Reactive and Corrective Capital programs.[8][9]

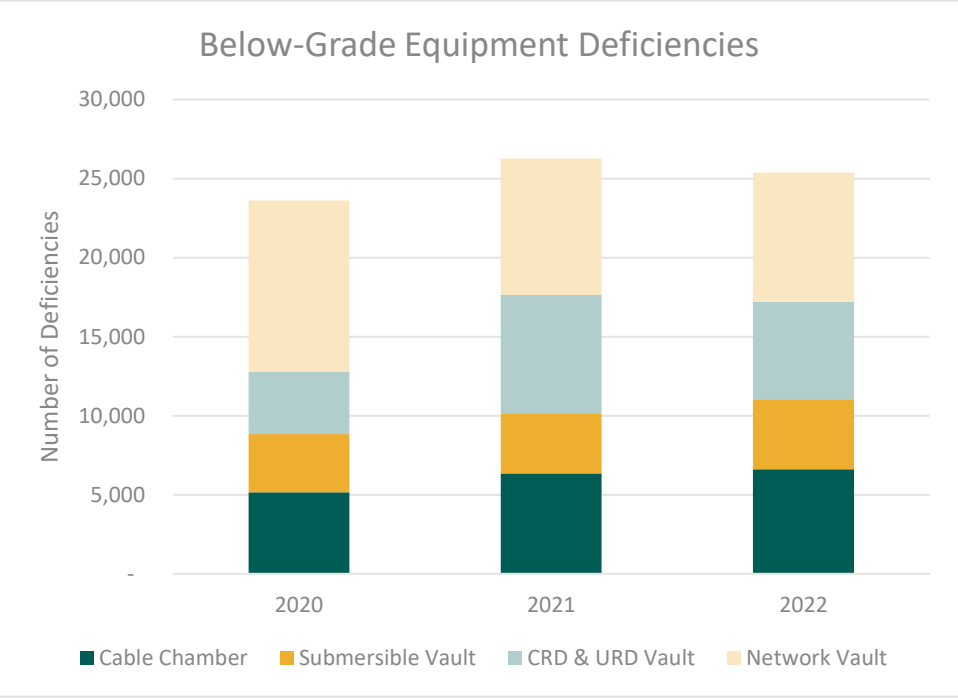


Figure 5: Below-Grade Equipment Deficiencies Identified Between 2020 and 2022

Below-grade structures are typically installed underneath roadways, pedestrian walkways and in residential neighbourhoods. Given their locations, it is important to identify and correct structural defects and potential failures proactively to mitigate potential safety risks to the public, such as trip hazards due to uneven elevation grading.

[7] The average annual deficiencies for 2015-2017 did not include deficiencies fixed during inspections, which accounted for approximately 3,600 deficiencies per year over 2020-2025.
[8] Exhibit 4, Tab 2, Schedule 4
[9] Exhibit 2B, Section E6.7

In addition to the importance of their structural integrity, vaults must be maintained in a relatively clean state, and contain appropriate nomenclature, functional lighting, and drainage systems. Oil barrier devices installed in vault drains are also inspected and replaced as required. Vaults are naturally ventilated using grates to ensure uninterrupted ventilation. However, debris can enter over time, and, if not addressed, create slip and fall hazards for employees.

From a financial risk perspective, inspections and maintenance mitigate the risk of costly failures. For example, identifying a vault with significant dirt and debris (such as the one depicted in Figure 6) enables corrective action to be taken and reduces the risk that the debris will catalyse asset corrosion as shown in Figure 7, or potentially result in an arc flash or fire.



Figure 6: Vault Full of Dirt and Debris



Figure 7: Corrosion on Top of a Transformer

When equipment failures occur, emergency response and equipment replacement can result in tens of thousands or even hundreds of thousands of dollars in costly repairs costs. For example, a network transformer emergency replacement can cost in excess of $180,000, which is approximately 1.4 times the cost of a planned replacement, and a structural rebuild of a vault can exceed $500,000. These expenditures can be mitigated through proactive maintenance activities.

In addition to safety and financial risks, below-grade equipment maintenance mitigates environmental risks. For example, inspections enable the early identification of corroded equipment before an oil leak develops, potentially washing into the drainage system, which could result in regulatory penalties and environmental restoration costs. Figure 8 below depicts an oil leak within a vault. This type of deficiency is addressed by cleaning activities, as shown in Figure 9.



Figure 8: Oil Leaking from a Transformer Base Inside a vault



Figure 9: Crews Cleaning a Vault that had a Transformer Oil Leak

In addition to the value provided by mitigating the aforementioned safety, financial, and environmental risks, below-grade equipment maintenance provides value to customers by mitigating system reliability risks associated with civil infrastructure or electrical equipment failures. Between 2020 and 2022, the distribution system experienced approximately 50 incidents of below-grade equipment failures annually, which resulted in more than 46,000 customer interruptions and 39,000 customer hours of interruption annually.

Between 2020 and 2022, Toronto Hydro experienced an average of almost 6 incidents of cable chamber lid ejections annually as a result of failing cables within the cable chambers igniting gases and creating a shock wave.[10] Failures also occured in CRD, URD, and submersible vaults, where Toronto Hydro replaced over 300 defective or failed submersible transformers over the 2020-2022 period. These failures pose system reliability risks (e.g. interruptions to tens and even hundreds of customers).

The risk of equipment failure and the related system reliability risks are not only mitigated through routine visual inspections, but also by thermographic scanning. Thermographic or infrared scanning identifies thermal anomalies in the target equipment, and is an effective predictor of equipment failure. Figure 10 below shows an example of a thermographic photograph of cable splices inside a cable chamber. The deficiency, as evidenced by an 80°C increase in temperature on one of the splices, is not visually evident (see picture on the left), but is easily identified using the infrared image (see picture on the right) so it can be corrected before failure.

[10] Exhibit 2B, Section E6.3.

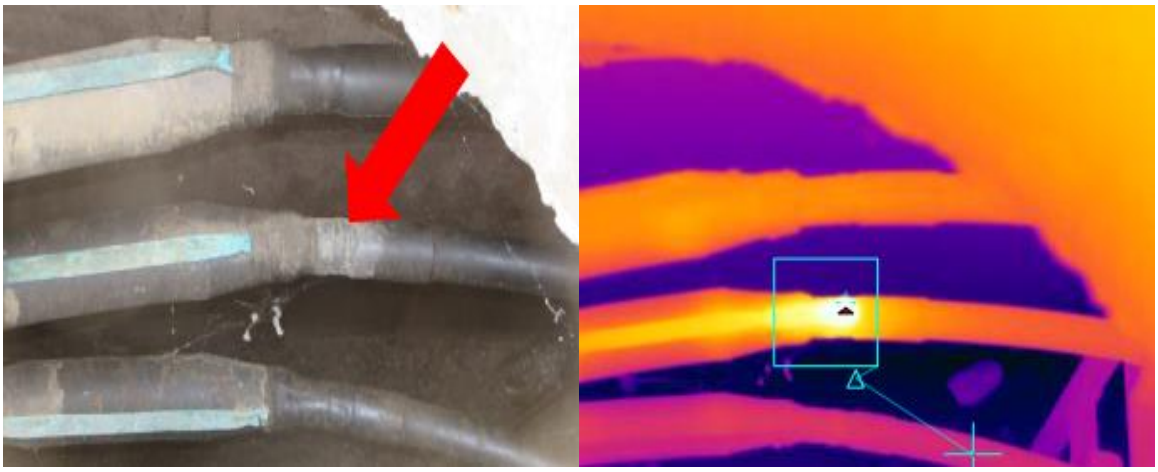


Figure 10: Cables Inside a Cable Chamber (Left) with an Infrared Thermography Image of the Same Cables Denoting a Hot Spot (Right)

5.2 Below-Grade Equipment Maintenance Segment Costs

Table 4 provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for this segment.

Table 4: Below-Grade Equipment Maintenance Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Below-Grade Equipment Maintenance	2.5	2.9	3.0	3.5	3.2	3.5	3.6	3.3	3.5	3.5

5.3 Below-Grade Equipment Maintenance Segment Year-over-Year Variance Analysis

2020-2021 Variance Explanation

From 2020 to 2021, expenditures increased by approximately $0.4 million, which was primarily due to an increase in the number of network protectors overhauled as well as an increase in the number of cable chambers inspected in order to reduce a backlog of overdue units.

2021-2022 Variance Explanation

From 2021 to 2022, expenditures increased by approximate $0.1 million which was primarily attributed to an increase in the number of network protector overhauls and an increase in the number of submersible transformer vaults due for inspection.

2022-2025 Variance Explanation

Between 2022 to 2025, expenditures are forecasted to increase by approximately $0.5 million, or an average of $0.2 million per year, due to:

- an increase in the number of network protectors scheduled for overhauls; and
- an increase in the total number of vaults due for inspection.

2025-2029 Variance Explanation

Between 2025 and 2029, costs in this segment are not expected to materially change as inflationary pressures are offset by a reduced number of network vault inspections. Year-to-year fluctuations are due to varying numbers of submersible, CRD, and URD vaults due for inspection. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks, including:

- Compliance risks associated with statutory and regulatory requirements.[1]
- Implementation risks, such as the inability to carry out the cyclical inspections necessary to maintain assets and prevent the below risks;
- Failure risks, such as increased numbers of failures and associated outages on the system due to a reduction in below-grade asset inspections and maintenance;
- Public and employee safety risks, such as the inability to mitigate exposure to blown cable chamber lid incidents due to the lack of prompt identification and resolution of failing cables that can result in electrical faults leading to these incidents;

- Financial risks, such as the inability to mitigate failures and the costs associated with emergency response and equipment replacement; and
- Environmental risks, such as the inability to prevent or mitigate the release of underground transformer oil into the environment.

6. PADMOUNTED EQUIPMENT MAINTENANCE SEGMENT

6.1 Segment Description

Padmounted transformers and switches (collectively referred to as "padmounted equipment") are metal-clad enclosures with lockable cabinet doors located on top of concrete pads within road allowances or on private properties. These assets are found on the underground distribution system where cables enter underground equipment through the pad. Padmounted transformers (see Figure 11) supply residential areas or commercial buildings and padmounted switches (see Figure 12) enable the sectionalizing of underground feeders. Toronto Hydro owns approximately 8,200 padmounted transformers and 1,280 padmounted switches.



Figure 11: Padmounted Transformer



Figure 12: Padmounted SF6-Insulated Switch

This segment also funds annual inspections for concrete tap box locations that are located in high traffic pedestrian zones along Yonge Street. These tap boxes may contain both primary and secondary circuits along with their associated connectors and splices. They are located within the public road allowance in the sidewalks, boulevards, and roadways. As a result, they are exposed to several external elements such as road snow and sidewalk plows which can cause damage to these structures, posing potential safety hazards to the public.

Padmounted Equipment Maintenance includes: visual inspection of pads and protective bollards for damage or deterioration; visual inspection of the elevation of the pad in relation to the grade; removal of overgrown vegetation that may be encroaching on the pad; and a visual inspection and verification of equipment labels and safety signs. Visual inspections focus on both the mechanical components (e.g. doors, locks, hinges, handles, latches, and paint) and electrical components (e.g. terminations, bushings, elbow connectors, transformer tank, primary and secondary switches, fuses, disconnects, barriers, fault indicators, relays, oil levels). In addition, maintenance includes thermographic scans and partial discharge testing of electrical connections.

The following additional maintenance activities are carried out for padmounted switches:

- Batteries in SCADA switches are replaced once every three years;
- Gas levels are verified on units that are filled with SF_6 gas;
- Cable duct entries are inspected to ensure they are sealed, and ultrasonic testing is conducted to identify any partial discharge; and

- Air-insulated switches that have significant dirt build-up on their insulators, show evidence of tracking, or have exposed electrical terminations, are scheduled for CO_2 cleaning.

CO_2 cleaning is performed as part of the Corrective Maintenance program, to remove dirt and other contaminants from the switch to prevent tracking, which can lead to an arc flash and equipment failure. [11]

Toronto Hydro carries out the above noted activities on a three-year cycle for padmounted transformers and annually for padmounted switches. Regular maintenance cycles ensure Toronto Hydro is able to comply with applicable inspection requirements and properly maintain padmounted equipment. [12]

The average useful life of padmounted transformers and switches are 30 and 40 years, respectively. As padmounted transformers and switches age, the likelihood of failure increases as a result of current surges, ingress of moisture, dirt, and salt leading to excessive corrosion, mechanical damage, and the degradation of insulating barriers for equipment.

As illustrated in Figure 13 below, Toronto Hydro's inspection activities identified over 4,000 padmounted equipment deficiencies per year on average between 2020 and 2022. Identifying those deficiencies that require corrective action and addressing them through the Corrective Maintenance and Reactive and Corrective Capital programs serve to

[11] Exhibit 4, Tab 2, Schedule 4
[12] *Supra* note 1.

mitigates a wide variety of safety, environmental and system reliability risks, primarily in residential areas.[13][14]

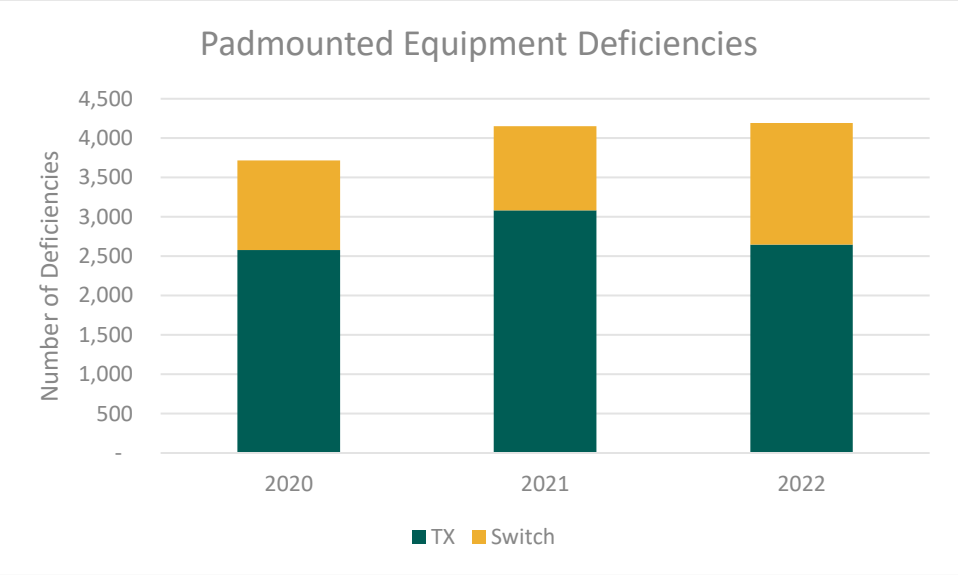


Figure 13: Padmounted Equipment Deficiencies Identified Between 2020 and 2022

An example of risk mitigation is promptly identifying a corroding enclosure as illustrated in Figure 14 below. If not identified and addressed, corrosion (which may also be present on internal components) can give rise to significant environmental, safety, and reliability risks. Through maintenance activities, Toronto Hydro also rectifies switches with rusted coil springs (as shown in Figure 15 below), which may break during activation and prevent the switch from opening and closing. If undetected, this condition can result in an arc flash and endanger employees operating the switch.

[13] Exhibit 4, Tab 2, Schedule 4
[14] Exhibit 2B, Section E6.7.



Figure 14: Padmounted Transformer with Surface Corrosion



Figure 15: Padmounted Switch with Rusted Coil Spring

Another example of risk mitigation is identifying and addressing excessive vegetation growth near equipment. If unaddressed, overgrown vegetation not only hinders access to the transformer during an emergency, but can also pose a safety and fire risk. Electricity can arc or flashover to nearby vegetation, even without physical contact. Figure 16 below illustrates an example of excessive vegetation growth.



Figure 16: Padmounted Transformer Requiring Vegetation Removal

Transformers also require maintenance where locks, hinges, or warning signage have been vandalized, broken, or removed. If unaddressed, these conditions can lead to serious safety-related incidents if someone inadvertently comes into contact with padmounted equipment.

Padmounted unit failures also impact Toronto Hydro's system reliability, potentially affecting anywhere from several residential and commercial customers (when a transformer fails), to hundreds of customers in the case of a switch failure. When a switch unit fails, multiple feeders can experience a power interruption, as switches often act as a tie point for multiple feeders. Maintenance activities are designed to mitigate the risk of such failures and ensure SCADA switches do not contain failed batteries that render switches inoperable remotely. Between 2020 and 2022, the distribution system experienced over 1,600 customer interruptions and 700 customer hours of interruption annually due to failures of padmounted equipment.

6.2 Padmounted Equipment Maintenance Segment Costs

Table 5 below provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for this segment.

Table 5: Padmounted Equipment Maintenance Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Padmounted Equipment Maintenance	0.6	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6

6.3 Padmounted Equipment Maintenance Segment Year-over-Year Variance Analysis

2020-2021 Variance Explanation

From 2020 to 2021, expenditures decreased by approximately $0.1 million which was primarily attributed to a decrease in the number of padmounted equipment inspected.

2021-2022 Variance Explanation

From 2021 to 2022, expenditures did not materially change.

2022-2025 Variance Explanation

Between 2022 and 2025, costs in this segment are expected to increase by approximately $0.1 million due to inflationary pressures.

2025-2029 Variance Explanation

Between 2025 and 2029, expenditures are not expected to materially change. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks, including:

- Compliance risks associated with statutory and regulatory requirements.[1]
- Implementation risks, such as the inability to carry out the cyclical inspections necessary to maintain padmounted equipment and prevent the below risks;
- Failure risks, such as increased numbers of failures and associated outages on the system due to a reduction in padmounted asset inspections and maintenance;
- Public and employee safety risks, such as the inability to mitigate safety hazards associated with padmounted equipment;
- Financial risks, such as the inability to mitigate costly failures; and
- Environmental risks, such as the inability to prevent or mitigate the release of SF_6 from leaking padmounted switches into the environment.

7. CABLE DIAGNOSTIC TESTING SEGMENT

7.1 Segment Description

Since 2015, Toronto Hydro has been performing diagnostic testing on select newly installed underground primary cables and cables at high risk locations (locations that exhibited underground faults based on reliability data). As of 2020, the utility has expanded this type of work into a dedicated maintenance program for performing diagnostic testing on cables installed in Toronto Hydro's underground system to provide a more accurate assessment of the condition of underground cables, splices, joints and terminations. Diagnostic testing is expected to support the delivery of more reliable service to customers, and allow more effective capital allocation by providing a stronger basis for informed underground project planning and prioritization.

Toronto Hydro intends to test all newly installed cables being commissioned as part of its regular practice. In addition, the utility plans to test high-risk feeders in the Downtown Core on a four-year cycle in alignment with downtown station maintenance cycles so as to minimize additional costs for outages and site visits. In addition, select subdivisions in the Horseshoe area will be chosen for testing to assist with making capital investment decisions with more condition-based data and to address areas with poor reliability.

The two most common types of cables installed in Toronto Hydro's underground system are Paper Insulated Lead-Covered ("PILC") and Cross-Linked Polyethylene ("XLPE"), as shown in Figure 17.

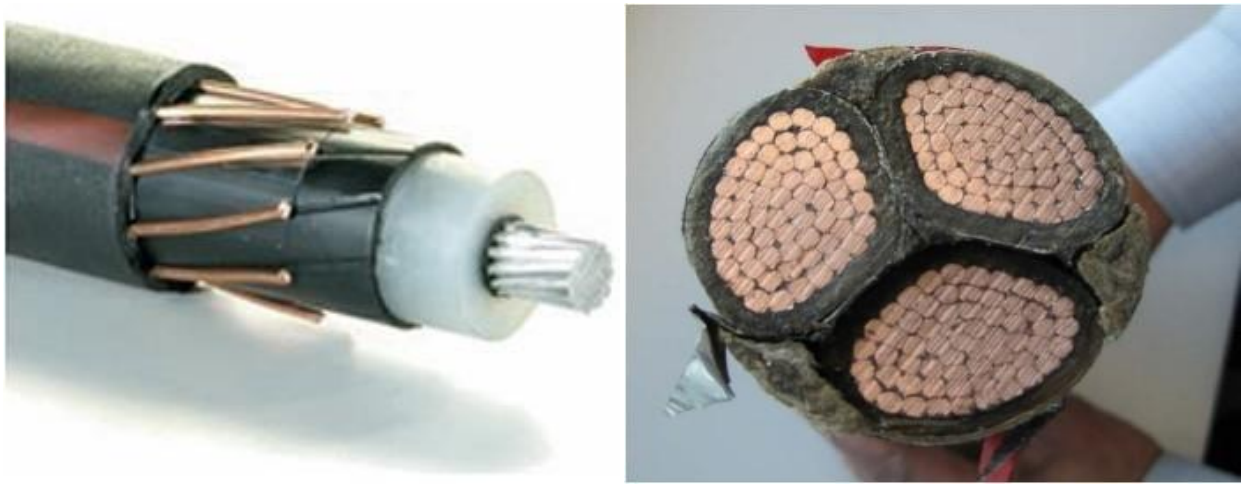


Figure 17: Example of XLPE Cable (Left) and PILC Cable (Right)

Toronto Hydro has approximately 1,030 circuit kilometres of PILC cables, and over 4,500 circuit kilometres of XLPE cable.

In the past, asset data such as age, historical failures, and number of joints etc. were used to determine appropriate replacement strategies for these cables. Utilizing cable diagnostic testing provides a more accurate assessment of the condition of underground cables, splices, joints, and terminations. It enables predictive analysis and allows Toronto Hydro planners and engineers to effectively determine the cables that currently are, or will soon be, at risk of failure.

Cable diagnostic testing is an accepted practice industry-wide and used in numerous other electrical utilities in Canada and the United States. Toronto Hydro follows industry standards that support and provide guidelines for cable testing in the field, including IEEE 400-2012, IEC 60060, IEC 60085, and IEC 60502.

The expected life of underground cable varies by type and construction. The expected life of XLPE cable is 40 years for jacketed direct-buried ("DB") cable, 20 years for un-jacketed DB cable, and 50 years for cable in concrete duct installations. The expected life of PILC cable is 65 years. A majority of the PILC and XLPE cable populations (which were installed in the beginning in the early 1900s and 1950s, respectively) have reached their expected useful lives.

As cables age, the likelihood of failure increases as a result of water treeing, electrical treeing, and insulation breakdown for cables.[15]

In addition, cables will experience aging differently depending on the following factors:

- Manufacturing quality;
- Damage during installation and workmanship issues;
- Installation environment (e.g. areas with high moisture levels result in water penetration of the insulation (or water treeing) and thereby causing insulation failure);
- Operating temperature and loading (e.g. higher loading and resulting temperatures accelerate the aging process); and
- Ambient temperature of the installation environment (e.g. higher temperatures accelerate the aging process).

Defective primary cables and cable accessories accounted for approximately 73 percent of all customer interruptions and 75 percent of all customer hours of interruption for underground equipment between 2020 and 2022. On average, over the same period, approximately 130 interruptions a year were related to defective underground primary

[15] Water ingress into the cable insulation in the presence of an electrical field causes microscopic tears called "water treeing." Over time, continued moisture penetration and the presence of electrical stresses causes these water trees to become electrical trees (whereby the tears become carbonized and can conduct electricity).

cables, which resulted in over 131,000 customers interrupted and 116,000 customer hours of interruption annually.

Based on Toronto Hydro's experience, when a cable fails once, repeated failures are very likely. Cables prone to failure not only impact system reliability, but also entail safety and environmental risks. Figures 18 depicts a leaking cable splice.



Figure 18: Oil Leakage from Cable Lead Splice

Cable Diagnostic Testing performed from 2021-2022 identified deficiencies as shown in Figure 19 below.

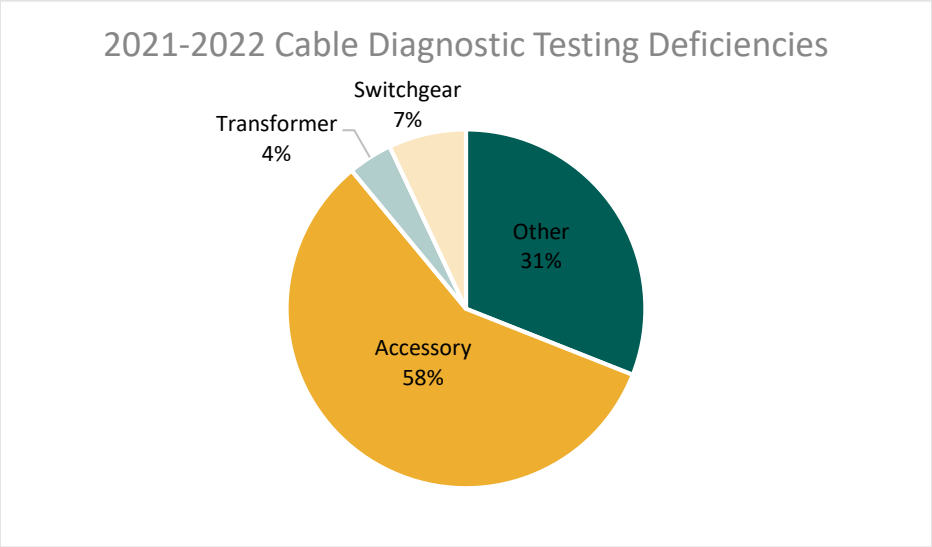


Figure 19 Cable Diagnostic Testing Deficiencies Identified Between 2021 and 2022

This program has helped identify deficiencies, such as accessory-related issues related to poor workmanship, incorrectly installed faulted circuit indicators, and hot spots or partial discharge on elbows, terminations and splices, enabling appropriate corrective work to be issued to mitigate failure risk.

As this program continues to mature, the diagnostic data available on cables will continue to grow and will allow Toronto Hydro to better understand how cables degrade over time, evaluate the variation between cable types, and provide feedback to system planning, standards, and quality groups to make improvements for future cable installations. The data collected from the tests will be used to help predict cables at risk of degradation and help in identifying problematic locations in the system with a higher degree of accuracy.

7.2 Cable Diagnostic Testing Segment Costs

Table 6 below provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for this segment.

Table 6: Cable Diagnostic Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Cable Diagnostic Testing	-	0.3	0.4	0.6	0.6	0.7	0.8	0.8	0.8	0.8

7.3 Cable Diagnostic Testing Segment Year-over-Year Variance Analysis

2020-2021 Variance Explanation

From 2020 to 2021, expenditures increased by approximately $0.3 million which was primarily due to an increase in the number of Horseshoe area feeders tested.

2021-2022 Variance Explanation

From 2021 to 2022, expenditures increased by approximately $0.1 million which was primarily due to an increase in the number of downtown feeders tested.

2022-2025 Variance Explanation

Between 2022 and 2025, expenditures are forecasted to increase by approximately $0.3 million, or an average of $0.1 million per year, due to the increasing number of feeders tested as this segment continues to ramp up.

2025-2029 Variance Explanation

Between 2025 and 2029, expenditures are expected to increase by approximately $0.1 million, due to inflationary pressures. The Cable Diagnostic Testing Segment is relatively new and as a result, is continuing to evolve with each additional year of testing. The expenditures and volume of work proposed over the 2025-2029 rate period are based on Toronto Hydro's estimate of feeder segment unit costs using 2020-2022 actuals. However, the volume of work executed can vary significantly as a result of the complexity of each feeder segment based on length, accessibility, and number of terminations along

the feeder segment. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks, including:

- Risk of missed opportunity to identify and correct deficiencies to mitigate failure risk for biggest source of defective equipment related outages on underground system (i.e. cable and cable accessories); and
- Risk of not leveraging source of data and insights into cable degradation and failures to improve project planning and prioritization and future cable installations.

8. CONTACT VOLTAGE SCANNING SEGMENT

8.1 Segment Description

Most of Toronto Hydro's electrical distribution equipment is exposed to environmental elements, including wide seasonal temperature variations and accumulation of dirt or debris. This may result in the partial or total failures of electrical distribution equipment, and can lead to live wires making contact with nearby structures (poles, bus shelters, concrete housing etc.).

These issues can give create a public safety hazard known as contact voltage, which has the potential to cause electric shock. A typical example of a contact voltage hazard is an exposed secondary voltage wire in a sidewalk handwell or inside a street lighting pole that energizes the sidewalk or pole. Contact voltage endangers the public, workers, and pets that may come into contact with the energized surface.

The main activity in this segment is the use of a mobile scanning tool (i.e. a voltage detection system) mounted onto a vehicle to scan for contact voltage throughout Toronto

Hydro's service area. Data is collected and analyzed to determine the location and nature of the fault. Based on the results, a repair crew is dispatched to further investigate and eliminate the fault.[16]

Previously Toronto Hydro scanned the entire distribution system on a one-year cycle. However, to save costs without compromising safety, the utility now takes a risk-based approach. Of the total 25 wards that make up Toronto, the utility continues to scan 11 of them annually. These 11 wards include all high-risk wards that exhibit a higher amount of contact voltage incidents and wards in the downtown region which have a higher density of objects that may have contact voltage such as traffic lights, bus shelters, street light poles, and handwells. The remaining 14 wards, which are all in the Horseshoe area and have a lower average number of contact voltage incidents, are scanned once every three years.

The mobile scanning tool locates assets with contact voltages greater than 1 volt. Toronto Hydro uses the Third Harmonic ("3HD") as a guideline (as recommended by the IEEE Working Group on "Voltages at Publicly and Privately Accessible Locations") to prioritize corrective action for contact voltages found. If a contact voltage equal to or greater than 10 volts is found, the scanning crew will identify and barricade the relevant area and remain on site until a follow-up emergency response crew arrives to make permanent repairs. With respect to a contact voltage between 4.5 volts and 10 volts, the incident is analyzed and corrective action is issued. Notices are issued to affected parties if the contact voltage is found on customer or third party owned equipment. Contact voltage incidents less than 4.5 volts are reported to Toronto Hydro for review, and notices are

[16] The contract for the Contact Voltage Scanning program ended in March, 2021 and a new contract was not completed in time in order to continue the program for the rest of the year which led to a much lower number of contact voltage hits being reported in 2021.

issued to affected parties (where the contact voltage was found on customer or third party owned equipment).

Figure 20 below shows the volume of contact voltage incidents (>4.5 volts) identified between 2020 and 2022.

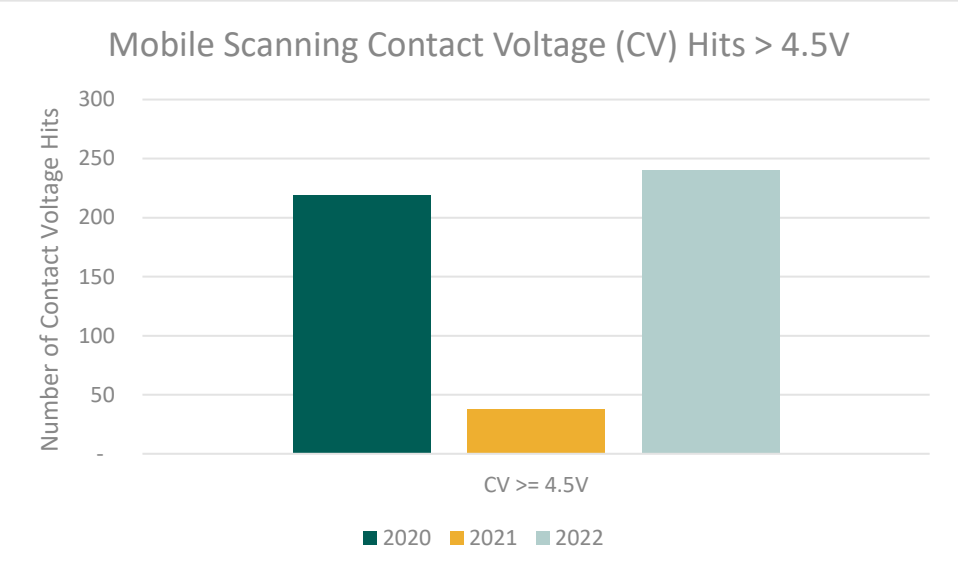


Figure 20: Contact Voltage Hits (>4.5 V) (2020-2022)

Traffic lights, bus shelters, street light poles, and handwells have been the primary sources of contact voltages throughout the City of Toronto in recent years as shown in Figure 21.

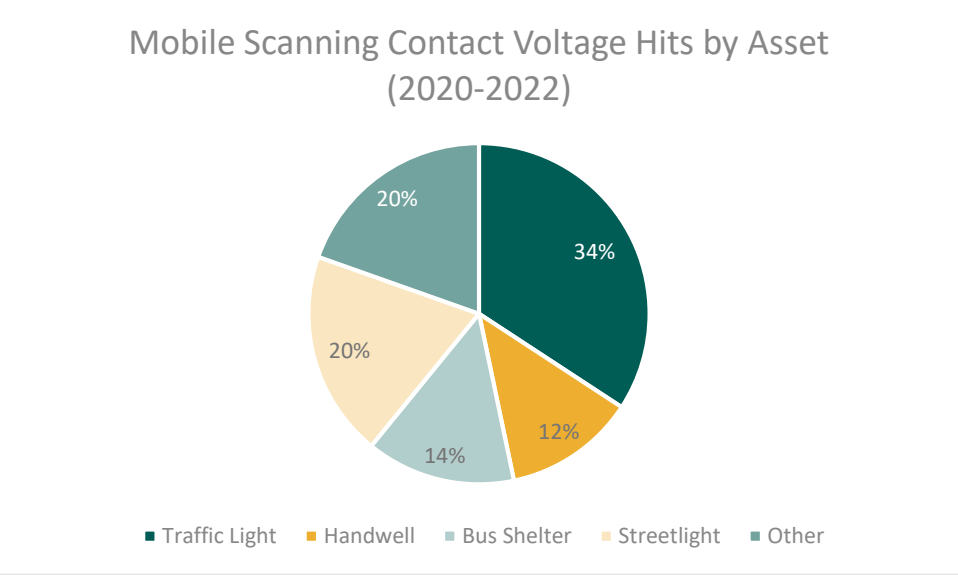


Figure 21: Contact Voltage Hits by Asset (2020-2022)

Scanning is performed during the months of January to March and September to December as Toronto Hydro's previous experience of scanning throughout the entire year indicated that most cases of contact voltage occur during the winter months. Underlying causes include aging infrastructure, freezing/thawing conditions, and vibrations at or below grade (which can cause wires to dislodge).

Contact voltage remains a risk for pedestrians and pets in the City of Toronto. By scanning for contact voltages across the city and addressing defective equipment through the Corrective Maintenance or Reactive and Corrective Capital program, the number of contact voltage related safety incidents can be reduced.

8.2 Contact Voltage Segment Costs

Table 7 provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for this segment.

Table 7: Contact Voltage Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Contact Voltage Scanning	2.0	0.7	1.8	1.7	1.8	2.0	2.0	2.0	2.2	2.1

8.3 Contact Voltage Segment Year-over-Year Variance Analysis

2020-2021 Variance Explanation

From 2020 to 2021, expenditures decreased by approximately $1.3 million, due to the lower number of wards scanned. In 2021, the contract for this work ended in March and was not re-signed in time for scanning to be done over September to December.

2021-2022 Variance Explanation

From 2021 to 2022, expenditures increased by approximately $1.1 million to fund the scanning of all high-risk wards on an annual cycle, with the remaining wards scanned on a three-year cycle.

2022-2025 Variance Explanation

Between 2022 and 2025, expenditures are expected to increase by approximately $0.2 million, or an average of $0.1 million per year, due to inflationary pressures.

2025-2029 Variance Explanation

Between 2025 and 2029, expenditures are forecasted to increase by approximately $0.1 million due to inflationary pressures. Year-to-year fluctuations are due to varying numbers of wards due for scanning. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks, including:

- Public safety risks, such as the inability to prevent safety hazards such as electrical shocks caused by contact voltage which endanger the public, workers, and animals that may come into contact with energized surfaces.

PREVENTATIVE AND PREDICTIVE STATION MAINTENANCE

1. OVERVIEW

Table 1: Preventative and Predictive Station Maintenance Program Summary

Preventative and Predictive Station Maintenance Program									
Outcomes: Operational Effectiveness - Reliability, Environment, and Operational Effectiveness – Safety									
Segments: • Customer Location Maintenance • Station Inspections and Auxiliary Equipment Maintenance • Station Switchgear Maintenance • Station Equipment Maintenance									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
5.9	6.4	5.5	6.5	7.0	8.0	7.6	7.7	8.6	8.8

The Preventative and Predictive Station Maintenance program (the "Program") addresses maintenance activities on Toronto Hydro's: (i) station assets; and (ii) assets located at customer-owned buildings or dedicated areas on customer premises. This Program involves inspection and maintenance tasks of equipment to identify and address predetermined conditions indicative of a potential failure. The activities comprising the individual segments in this Program are focused on preserving and maximizing the performance of assets over their expected useful life while mitigating a wide variety of system risks.

This Program is also designed to minimize overall costs and account for other factors such as the safety of Toronto Hydro's work crews and the public, and ensures compliance with

statutory and regulatory requirements.[1] The Station Maintenance Program is comprised of the following four segments:

- **Customer Location Maintenance:** A subset of Toronto Hydro's customers is supplied by electrical equipment, such as transformers and switches, located within customer-owned buildings (vaults) or dedicated areas on customer premises. The activities in this segment are aimed at inspecting and maintaining this equipment. In addition, the inspection and maintenance of primary Automatic Transfer Switches ("ATS"), communication systems for vaults located deep underground, and Distributed Energy Resource ("DER") sites, are conducted under this segment.
- **Station Inspections and Auxiliary Equipment Maintenance:** This segment focuses on two sets of work: (i) the periodic inspection of all Transformer Stations ("TS") and Municipal Stations ("MS") and associated equipment, as well as battery Energy Storage Systems ("ESS"); and (ii) maintenance of auxiliary equipment housed or used at stations, including station batteries, air compressors, and testing equipment.[2]
- **Station Switchgear Maintenance:** This segment includes the testing and maintenance of Toronto Hydro owned switchgear units and circuit breakers located at TSs and MSs across the utility's service territory.
- **Station Equipment Maintenance:** This segment includes the maintenance of equipment located at 23 TS and 139 MS locations, including 183 station transformers. Maintenance activities include the inspection, testing, cleaning, and calibrating of assets such as power transformers and their auxiliary equipment.

[1] Ontario Energy Board, *Distribution System Code*, Appendix C (August 2, 2023).
[2] Transformer stations are points of power supply from the Hydro One Networks Inc. ("Hydro One") transmission system which step down supply voltages.

By preserving and maximizing the performance of station assets and assets located in customer-owned buildings, this Program contributes to maintaining safety and the environment, and overall system reliability at reasonable costs to Toronto Hydro's customers.

2. OUTCOMES AND MEASURES

Table 2: Preventative and Predictive Station Maintenance Program Outcomes and Measures Summary

Operational Effectiveness – Reliability	• Contributes to maintaining existing levels of system reliability (SAIDI/SAIFI) by inspecting station assets for deficiencies in compliance with the Ontario Energy Board's ("OEB") Distribution Systems Code ("DSC").
Environment	• Operate in an environmentally responsible manner and Rreduces the environmental impact of Toronto Hydro's distribution system by proactively identifying station equipment for replacement, such as transformers exhibiting signs of oil deficiencies or circuit breakers leaking SF_6 gas, for replacement and minimizing the likelihood of these associated contaminants from entering the environment.
Operational Effectiveness – Safety	• Contributes to Toronto Hydro's public safety performance (as measured by the OEB's distributor scorecard safety metrics), employee safety performance, and compliance with applicable safety requirements (including Ontario Regulation 22/04, the Ontario Fire Code, and the *Occupational Health and Safety Act*) by proactively performing inspections to reduce the risk of asset failures that may otherwise endanger the general public and Toronto Hydro crews (e.g. failure of a vault transformer, station power transformer or switchgear which can result in a fire).[3]

3. PROGRAM DESCRIPTION

The Preventative and Predictive Station Maintenance program funds maintenance activities in respect of: (i) Toronto Hydro's station assets; and (ii) Toronto Hydro's assets

[3] Ontario Regulation 213/07: Fire Code made under the *Fire Protection and Prevention Act, 1997,* SO 1997, Chapter 4.

located at customer-owned buildings or dedicated areas on customer premises. This Program involves inspection and maintenance tasks typically conducted on a fixed cycle and inspection of equipment for indications of potential failure. The activities comprising the individual segments in this Program are focused on preserving and maximizing the performance of assets over their expected useful life while mitigating a wide variety of system risks. This Program is also designed to minimize overall costs and account for other factors such as the safety of Toronto Hydro work crews and the public, and ensure compliance with statutory and regulatory requirements.

Maintenance activities in this Program include inspections to assess the condition of customer location building vault structures and the equipment housed inside (including transformers, switches, and cables), as well as inspections of station facilities and station assets (including power transformers, switchgear, and auxiliary station equipment). The Station Maintenance Program is comprised of the following four segments:

- **Customer Location Maintenance:** A subset of Toronto Hydro's customers is supplied by electrical equipment such as transformers and switches that are located within customer-owned buildings (vaults) or dedicated areas on customer premises. The activities in this segment are aimed at inspecting and maintaining this equipment. In addition, the inspection and maintenance of primary Automatic Transfer Switches ("ATS"), communication systems for vaults located deep underground, and Distributed Energy Resource ("DER") sites, are conducted under this segment.
- **Station Inspections and Auxiliary Equipment Maintenance:** This segment funds two types of work: (i) periodic inspection of all TSs and MSs and the associated equipment, as well as battery Energy Storage Systems ("ESS"); and (ii)

maintenance of auxiliary equipment housed or used at stations including station batteries, air compressors, and testing equipment.

- **Station Switchgear Maintenance**: This segment includes the testing and maintenance of Toronto Hydro owned switchgear units and circuit breakers located at TSs and MSs across the utility's service territory.
- **Station Equipment Maintenance** – This segment includes the maintenance of equipment located at 23 TS and 139 MS locations, including 183 station transformers.

Detailed descriptions of the segments are provided in sections 5-8 below.

4. PROGRAM COSTS

In 2025, Toronto Hydro requires $8.0 million in rate funding for the Preventative and Predictive Station Maintenance program, which represents an increase of $2.1 million over the previous rate period in 2020.

Over the 2025-2029 rate period, the utility expects the cost of this program to increase by a compounded annual growth rate of 2.7 percent, which is necessary to address station maintenance needs and deliver the customer outcomes enabled by this program.

The Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for each segment are summarized in Table 3 below.

Table 3: Stations Maintenance Program Expenditures by Segment ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Customer Location Maintenance	1.3	1.1	1.3	1.6	1.6	1.5	1.7	1.6	2.0	1.5
Station Inspections and Auxiliary Equipment Maintenance	1.1	1.1	1.2	1.1	1.1	1.3	1.2	1.2	1.3	1.6
Stations Switchgear Maintenance	2.7	3.2	2.4	2.8	3.4	4.1	3.6	3.6	4.2	4.5
Station Equipment Maintenance	0.8	1.0	0.6	1.0	0.9	1.1	1.1	1.3	1.1	1.2
Total	**5.9**	**6.4**	**5.5**	**6.5**	**7.0**	**8.0**	**7.6**	**7.7**	**8.6**	**8.8**

4.1 Cost Drivers

Year-over-year cost variances in this Program tend to be primarily driven by differences in the volume and complexity of units inspected and maintained. For example, air blast circuit breakers and switchgear with a higher number of circuits are generally more expensive to maintain on a per unit basis. Other recent cost drivers in this Program include the addition of new activities such as ESS site maintenance and Deep Vault Communication testing.

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

The sales, decommissioning, and conversions of stations and their equipment such as 4kV MS stations will in turn yield direct cost savings from the elimination of the inspection and maintenance of assets at these locations. Additional savings will be realised from the reduction in maintenance activities for station air compressors serving the TTC whose ownership is transferred to the TTC, and the elimination of legacy air blast circuit breakers.

Not all stations are equal and will vary in size and number of assets. This has resulted in a varying amount of labour and costs required in order to maintain all equipment in a given

year. Work is being undertaken to reduce this variability in order to balance the amount of resources and costs required to maintain all station assets year over year.

In addition, in order to keep labour costs down, Toronto Hydro conducts analysis to determine the lowest cost resource (e.g. internal vs. external contractor) and allocates maintenance to the most cost effective resource.

4.2.2 Productivity

Toronto Hydro has placed significant emphasis on achieving greater output for the same or reduced input in each of the segments within the Preventative and Predictive Station Maintenance program. Toronto Hydro continues to rely on the Reliability Centered Maintenance ("RCM") approach and adjusts its maintenance tasks and frequencies based on RCM, Condition-Based Maintenance, and continuous improvement principles. Examples of these adjustments include:

- Continuously updating inspection forms to allow for the capturing of greater details about substandard conditions or deficiencies found during inspections. These updates enable better prioritization and determination of the most appropriate corrective action for each deficiency to better mitigate public and employee safety, as well as environmental, system reliability, and financial risks.
- Standardizing the scheduling of outage-based activities to align with station maintenance cycles wherever possible to minimize the need for multiple equipment outages (and significant switching resources), enable bundling of maintenance work, and minimize the need for multiple trips to particular sites.
- Implementing "find and fix" protocols whereby crews that identify minor asset deficiencies address the deficiencies by replacing them onsite instead of only logging the deficiencies for the Corrective Maintenance program.[4]

[4] Exhibit 4, Tab 2, Schedule 4.

- Issuing longer-term inspection maintenance contracts to third-party service providers to help keep unit costs stable and increases service quality levels over time as retaining the same service provider increases their experience and familiarity with identifying deficiencies on Toronto Hydro's distribution system.
- Introducing new tools or making greater use of technology such as Infrared Thermography, Electronic Maintenance Sheets, Furan Sampling, Doble Testing, Dissolved Gas Testing, Online Partial Discharge Testing, and Enhanced Battery Testing.

The following sections discuss the drivers of each of the segments that make up the Preventative and Predictive Station Maintenance program.

5. CUSTOMER LOCATION MAINTENANCE SEGMENT

5.1 Segment Description

A subset of Toronto Hydro's customers is supplied by electrical equipment, such as transformers and switches, that is located within customer-owned buildings (vaults) or dedicated areas on customer premises. These sites are found in or adjacent to industrial or commercial buildings, hospitals, schools, apartments, and condominiums, and are secured to prevent unauthorized access to energized equipment.

The equipment contained in these sites, including over 12,000 transformers, is owned by Toronto Hydro and requires regular inspection and maintenance. There are approximately 4,413 customer-owned locations where Toronto Hydro is obligated to maintain or inspect equipment. For maintenance purposes, these 4,413 locations are divided into two subsets based on customer load requirements: (i) 4,042 Customer

Building Vaults which possess transformation capacity less than 2,000 kVA; and (ii) 371 Customer Substations, which have transformation capacity of 2,000 kVA or above.

Toronto Hydro maintains Customer Building Vaults on a three-year cycle, in compliance with the OEB's Minimum Inspection Requirements (Appendix C of the DSC). Maintenance of Customer Building Vaults includes a visual inspection of the vault and equipment, thermographic scans and partial discharge testing of all electrical equipment and connections to detect thermal anomalies and corona, and general cleaning to reduce contamination build-up and electrical tracking. Deficiencies that are noted during inspections are either addressed immediately or subsequently addressed through corrective maintenance. The condition of the customer's civil structure is also assessed and any identified deficiencies are communicated to the customer for remediation.

Customer Substations are inspected annually and maintained every four years. Inspections ensure that ventilation, access, and drainage systems are operating as required and that equipment is not leaking, defective, or corroded. Maintenance includes visual inspections, thermographic scans, functional tests, oil testing, and general cleaning.

Through Customer Location Maintenance, Toronto Hydro identifies deficiencies in electrical equipment and verifies the integrity and security of the structures that house the equipment at Customer Building Vaults and Customer Substations. Identifying and addressing deficiencies minimize the likelihood of equipment failure, mitigating risks relating to public and employee safety, the environmental, financial impacts, and system reliability. As illustrated in Figure 1 below, since 2020, Toronto Hydro has identified on average over 5,700 deficiencies at Customer Locations each year. Those deficiencies

requiring corrective action that cannot be addressed immediately are addressed as part of the Corrective Maintenance and Reactive Capital programs.

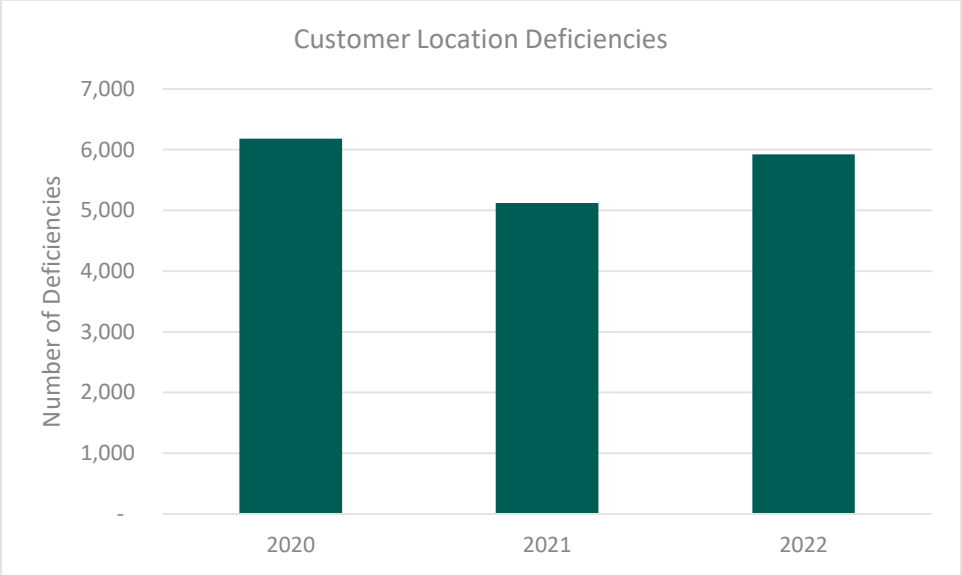


Figure 1: Customer Location Deficiencies Identified Between 2020 and 2022

Specific examples of deficiencies identified and their associated risks include:

- Dirty vaults that require cleaning to reduce the risks of flashover caused by contamination build-up and premature equipment failure, which can result in injury to employees, customers, and members of the public that are near these vaults, as well as property damage;
- Corrosion of equipment, locks and doors (as illustrated in Figure 2 below), which can result in unauthorized entry and pose a safety risk if individuals make contact with energized equipment;
- Oil leaking from cables or transformers (as illustrated in Figure 3 below), which if not addressed in a timely manner, can result in oil entering the drainage system and potentially spilling into environmentally sensitive areas;

- "Hot spots" on equipment identified using a thermographic cameras before excessively high temperatures cause burnt insulation and electrical faults, which pose serious safety risks (e.g. vault fire); and
- Degradation of a transformer's insulating oil properties due to the concentrations of certain gases (e.g. hydrogen, carbon monoxide, methane, and acetylene), which can be identified via transformer oil testing as indications of an elevated risk of transformer failure.

Beyond inspections of the electrical equipment, Customer Location Maintenance activities include inspections of the civil infrastructure housing the equipment. Such civil infrastructure is owned by Toronto Hydro's customers, who are responsible for repairs. Nevertheless, it is prudent for Toronto Hydro to continue inspections and issue follow-up Customer Action Forms given the risk that customers may fail to carry out necessary repairs in a timely manner. It is not uncommon for structural elements to be in poor condition to the point that walls (as illustrated in Figure 4 below) and roofs are at risk of collapsing on Toronto Hydro's equipment.

In addition, improperly maintained landscaping and vegetation at or near outdoor customer locations can pose safety risks (e.g. vegetation becoming energized and possibly catching fire) and prevent Toronto Hydro crews from entering the sites to carry out required work (as illustrated in Figure 5 below). Such serious deficiencies are communicated to customers so that they can be addressed.



Figure 2: Rusted Door



Figure 3: Transformer Leaking Oil



Figure 4: Cracked Walls



Figure 5: Vegetation Overgrowth

By preventing equipment failures and non-electrical deficiencies, Customer Location Maintenance activities also prevent power interruptions. A failure at a Customer Building Vault will typically impact one or more customers for a prolonged period of time depending on the type of failure. Failures at Customer Substations have a greater impact as more than 2,000 kVA of load may be interrupted for similar durations.

Beginning in 2020, Toronto Hydro began inspecting vaults containing primary ATS every three years. These switches are designed to automatically switch over to a standby feeder when the normal feeder has power interrupted and require functional testing to ensure they are operable. This program was created in response to a failure from an ATS for the Rouge Valley hospital back in 2018, which resulted in a prolonged outage.

Beginning in 2022, Toronto Hydro also initiated a Deep Vault Communication program to test radio antennas installed at vaults located in underground garages at P2 level or lower with poor radio signals. These antennas are installed in order to amplify radio signals and this equipment needs to be tested periodically to ensure the safety of crews working at these vaults.

Beginning in 2023, Toronto Hydro is piloting inspections of renewable and non-renewable Distributed Energy Resource ("DER") sites, which are electrical generation and storage sites connected to Toronto Hydro's distribution system. DER sites could potentially introduce safety or reliability issues to the grid. In order to mitigate this, the monitoring and control equipment installed at these sites require inspection and maintenance in order to ensure the safe and reliable disconnection and monitoring of DER sites.

The Electrical Safety Authority ("ESA") has identified that 3-Phase 3 Wire solidly grounded customer services to be a potential safety hazard. If the customer has a supply from a grounded wye connected transformer, a short circuit on the customer side could pose a potential fire hazard as the short circuit current tries to find a ground path through pipes or other metal structures. In response to this, Toronto Hydro developed an initiative under this segment in 2018 to inspect all of these locations (to be completed by the end

of 2023) and take corrective measures (under the Corrective Maintenance program) to fix potential hazards by the end of 2025.

5.2 Customer Location Maintenance Segment Costs

Table 4 provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for this segment.

Table 4: Customer Location Maintenance Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Customer Location Maintenance	1.3	1.1	1.3	1.6	1.6	1.5	1.7	1.6	2.0	1.5

5.3 Customer Location Maintenance Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

From 2020 to 2021, expenditures decreased by approximate $0.2 million which was primarily attributed due to a reduction in the number of customer substations due for inspection.

2021 – 2022 Variance Explanation

From 2020 to 2021, expenditures increased by approximate $0.2 million which was primarily due to an increase in the number of customer substations due for inspection and the start of inspections of communication systems located in vaults deep underground.

2022 – 2025 Variance Explanation

Between 2022 and 2025, expenditures are expected to increase by approximately $0.2 million, or an average of approximately $0.1 million per year, primarily due to the

introduction of inspections of DER sites. Higher costs in 2023 and 2024 are due to the number of customer locations due for inspection and the completion of Delta-Wye inspections in 2023.

2025 – 2029 Variance Explanation

Between 2025 and 2029, expenditures are not expected to materially change. Year-to-year fluctuations are primarily due to varying numbers of customer locations due for inspection. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks, including:

- Reduced ability to comply with applicable legislative and regulatory requirements such as the OEB's Distribution System Code;
- Increased safety risks from unauthorized access to energized equipment and faulty communication equipment used by crews in vaults;
- Increased frequency of equipment failures due to unidentified deficiencies or lack of maintenance leading to increased:
    - public and employee safety risks, such as from flashovers or vault fires;
    - environmental risks from oil leaks resulting from unidentified equipment deficiencies such as transformers and cables; and
    - reliability risks from interruptions due to equipment failures.

6. STATION INSPECTIONS AND AUXILIARY EQUIPMENT MAINTENANCE SEGMENT

6.1 Segment Description

Toronto Hydro owns equipment at 23 TSs and 139 MSs throughout the City of Toronto.[5] Equipment is located either inside buildings or outside in fenced yards. The Station

[5] Toronto Hydro's distribution system is serviced by 37 Terminal Stations. However, it only owns and operates assets at 23 of these stations.

Inspections and Auxiliary Equipment Maintenance segment funds the following two categories of work:

- Periodic inspections of all TSs, MSs, and battery stations and the associated equipment; and
- Maintenance of auxiliary equipment housed or used at stations including station batteries, air compressors, and testing equipment.

Figures 6 and 7 below show a typical MS found in a residential neighbourhood, and Figure 8 below shows a TS yard.



Figure 6: Residential Area MS (front view)



Figure 7: Residential Area MS (rear view)



Figure 8: The Station Yard at Cavanagh TS

Periodic inspections of stations are conducted either monthly or semi-annually. During semi-annual inspections, crews look for any signs of transformer oil leaks, confirm transformer cooling fan operation, check battery electrolyte levels, verify the condition of equipment alarms, and look for any visual signs of equipment deterioration or imminent failure. In addition, adjustments to heating and ventilation systems are performed during the spring and fall to ensure assets are protected from damage due to temperature (e.g. turning on or turning off control cabinet heaters) and in the fall, oil samples are collected from power transformers for testing. During monthly inspections, crews also look for deficiencies in station fences, gates, doors, building walls, roofs, danger signs, and lighting.

Beginning in 2022, Toronto Hydro began performing maintenance activities for Toronto Hydro owned Energy Storage Systems ("ESS"). ESS can be used to provide distribution-level grid support. Toronto Hydro's Bulwer BESS project has helped the utility develop processes for monitoring and controlling BESS assets on a daily basis, as well as gain experience with creating baselines and measuring peak-shaving success at the feeder level. The implementation of an ESS maintenance program will assist in upkeeping the ESS connected through the Energy Storage System capital segment.[6] The ESS maintenance activities are focused on inspecting, testing, and cleaning the assets related to the ESS annually. These assets include batteries, transformers, Power Conversion Systems ("PCS") Inverters, disconnect switches, fire suppression system, pad structures, and HVAC systems. Failure of such equipment can result in fire, oil leaks, significant emergency response, equipment replacement costs, reliability, and power quality issues. Maintenance activities are vital for mitigating the risk of such failures and associated consequences. These inspections will support the safe and reliable functioning of the ESS

[6] Exhibit 2B, Section E7.2

until it reaches its end of life. The inspections of ESS units is a relatively new activity and is expected to grow as more units are installed.

In addition to inspections, this segment includes the maintenance of station auxiliary equipment. This equipment provides a support or service function and can be described as being peripheral to station power and protection and control equipment. Station auxiliary equipment includes: (i) Battery Banks; (ii) Station Protection Systems; (iii) Station Compressed Air Systems; and (iv) other miscellaneous station apparatus, including station buses, specialized environmental protection systems, and testing equipment. This equipment is described as follows:

- **Battery Banks:** The protection and control equipment in stations is powered by a direct current ("DC") supply from battery banks that are similar to those depicted in Figure 9 below, and are charged by station rectifiers (chargers). Stations typically have lead-acid or nickel cadmium batteries. Specialized inspections and tests on these battery banks are conducted every six months for MS and monthly for TS and include cleaning, measurements of specific gravity, voltage, electrolyte level, and temperature, inspection for corrosion on terminals, connections, battery racks and cabinets, and load cycle testing.
- **Station Protection Systems:** TS and MS stations are equipped with alarms to monitor and ensure proper functioning of various assets in stations including buildings, batteries, compressors, switchgear, and service transformers. Maintenance includes assessing the physical and mechanical conditions of the alarms and coordinating with the control room to perform functional tests. This work is carried out on a one-year cycle.
- **Compressed Air Systems:** These systems are required to supply dry compressed air for the operation of air blast circuit breakers as depicted in Figure 10. Air blast

circuit breakers use compressed air to open their arcing contacts, and to extinguish the electrical arc that forms during breaker operation. There are approximately 14 air compressors used in Toronto Hydro's 4.16 kV and 13.8 kV stations. These assets are inspected and maintained twice a year.



Figure 9: Station Battery System at George and Duke MS



Figure 10: Air Compressor System

Station Inspections and Auxiliary Equipment Maintenance are undertaken to address two broad sets of needs: (i) the need to mitigate the risks posed by deficient or failed equipment and components, including public and employee safety, environmental, financial, and system reliability risks; and (ii) the need to ensure compliance with applicable regulatory requirements such as the Ontario Fire Code and the *Occupational Health and Safety Act, 1990*.[7]

6.1.1 Station Inspections

Over 2020-2022, Station Inspections identified over 800 deficiencies on average annually. Identified deficiencies requiring corrective action were addressed through the Corrective

[7] SO 1990, Ch O.9., [*"Occupational Health and Safety Act"].*

Maintenance program, or equipment replacement programs as discussed in the Stations Renewal program. [8,9]

From a safety perspective, deficiencies at stations within urban and residential settings can pose significant risks. For example, deficiencies at access points such as gates, doors, fences, signs, and other security infrastructure can result in a station becoming accessible to the general public. Such deficiencies can arise due to structural degradation or other common causes including vandalism and wildlife, and can contribute to risk of injury to the general public. Frequent inspections are critical to maintaining secure station sites in a densely populated environment.

From an employee safety perspective, inspections identify deficiencies with station safety features such as alarms, emergency lightning, burn kits, eyewash stations, first aid kits, and fire extinguishers. This equipment is critical in protecting employees during emergency situations such as station fires. Inspections also enable Toronto Hydro to remain compliant with the Ontario *Fire Protection and Prevention Act* which requires, among others, fire extinguishers to be inspected monthly.[10]

From an environmental perspective, inspections allow for the identification of equipment that is leaking oil (an example of a leaking transformer is depicted in Figure 11). Leaking transformers or cables pose environmental risks, where oil can enter waterways, ground water and potentially sensitive ecological areas. Frequent inspections can identify signs of oil leaks, which can indicate assets that are at risk of failing. Based on such findings, Toronto Hydro can address the leak and prevent equipment failures.

[8] *Supra* note 5.
[9] Exhibit 2B, Section E6.6
[10] S.O. 1997, c. 4, [*"Fire Protection and Prevention Act"].*



Figure 11: Oil Leak on a Station Transformer

Inspections also identify vegetation concerns and damage to grading and landscaping as depicted in Figure 12. Failure to address these deficiencies can result in customer complaints, damage to stations (i.e. due to poor drainage), and safety risks for employees including accessibility risks from vegetation overgrowth and slip-and-fall risks from poor landscaping.



Figure 12: Damaged Landscaping

In addition to identifying deficiencies to mitigate safety and environmental risks, Station Inspection work involves the oil sampling and the testing of power transformers in order to mitigate financial and system reliability risks. Industry-standard oil tests are performed

to identify poor conditions and abnormalities that cannot otherwise be detected without a complete disassembly of the transformer. Such tests include: (i) Dissolved Gas Analysis; (ii) Furan analysis; and (iii) tests for acid levels, moisture levels, and other oil quality attributes.

Oil testing is particularly valuable because it allows Toronto Hydro to identify transformers that may be at a high risk of failure and to schedule corrective action such as oil reclamation or replacement before a catastrophic event occurs. Consequences of such an event can include oil spills, fire, emergency response, substantial equipment replacement costs, and a prolonged power interruption.

6.1.2 Auxiliary Equipment Maintenance

As discussed above, Auxiliary Equipment Maintenance is performed to mitigate a variety of risks. Maintenance of station backup battery systems reduces the risk that a station's protection and control system will not operate as required during a power interruption. During such an event, the system's DC power source allows all station protection and control equipment to function and communicate normally. Loss of the backup power supply can have consequences ranging from loss of communication and remote operation capability, to failure of a protecting device to function posing both safety and system reliability risks.

Maintenance of protection systems ensures the operability and dependability of alarms at station facilities so that Toronto Hydro can be notified and proactively respond to defective equipment before they lead to failure, which in turn can pose safety, environmental, and system reliability risks.

The maintenance of compressed air systems is designed to ensure that air blast circuit breakers are available to operate as designed when required. Without a certain pressure and volume of compressed air available, the circuit breakers will not close or trip. Failure to operate during fault conditions will expose employees to the risk of severe burns from arc flashes. When this occurs, protection devices upstream of the circuit breaker would need to operate resulting in outages to a far greater number of customers than would otherwise occur. For example, the failure of an air blast circuit breaker to clear a fault in July 2012 at George MS and Duke MS resulted in interruptions to 6,500 customers for nearly eight hours. Replacement costs for an air blast circuit breaker can range from $60,000 to $200,000 depending on factors including breaker type, voltage rating, and location. As Toronto Hydro eliminates these legacy assets from the system, this risk will be minimized.[11] Maintenance tasks that mitigate the risks described above include inspections of all components for deficiencies, cleaning of filters, replacement of pressure relief valves and pump-up time testing which is used to determine their correct operation.

6.2 Station Inspections & Auxiliary Equipment Segment Costs

Table 5 below provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for this segment.

Table 5: Station Inspections & Auxiliary Equipment Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Station Inspections and Auxiliary Equipment Maintenance	1.1	1.1	1.2	1.1	1.1	1.3	1.2	1.2	1.3	1.6

[11] Exhibit 2B, Section E6.6.

6.3 Station Inspections & Auxiliary Equipment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

There is no material variance during this period.

2021 – 2022 Variance Explanation

From 2021 to 2022, expenditures increased by approximately $0.1 million which is primarily attributed to the introduction of maintenance for ESS units and an increase in costs for semi-annual stations inspections.

2022 – 2025 Variance Explanation

Between 2022 and 2025, expenditures are expected to increase by approximately $0.1 million primarily due an increase in the number of ESSs and a higher volume of auxiliary equipment maintenance, offset by a reduction in the total number of stations requiring inspection and maintenance.

2025 – 2029 Variance Explanation

Between 2025 and 2029, expenditure are expected to increase by approximately $0.3 million, or an average of approximately $0.1 million per year, primarily due to inflationary pressures and an increase in the number of ESSs. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks, including:

- Reduced ability to comply with applicable legislative and regulatory requirements such as the OEB's Distribution System Code, Ontario Fire Code, and *Occupational Health and Safety Act* requirements.
- Increased frequency of station equipment malfunctions or failures due to unidentified deficiencies or lack of maintenance leading to increased:

- public safety risks from deficiencies at station access points and other security infrastructure,
- environmental risks from oil leaks resulting from unidentified equipment deficiencies such as transformers and cables, and
- reliability risks from the failure of station backup battery systems operating as required during power interruption.

7. STATION SWITCHGEAR MAINTENANCE SEGMENT

7.1 Segment Description

Station Switchgear Maintenance includes testing and maintenance of Toronto Hydro's switchgear units and circuit breakers that are located at TSs and MSs across the utility's service territory. A switchgear unit is a combination of switching devices and their associated controls, measuring, protection, and regulating equipment. Assemblies of these devices and equipment, with associated interconnections, accessories, enclosures and supporting structures, are found at Toronto Hydro's distribution stations. There are approximately 235 switchgears installed within the distribution system and they collectively contain over 1,800 circuit breakers.

Switchgears and circuit breakers must operate quickly and reliably when an electrical interference or equipment failure causes a fault on the distribution system. Switchgear maintenance activities mitigate the risk that the equipment will malfunction during a contingency, failing to protect the downstream feeders and equipment and possibly leading to a safety incident involving the public or Toronto Hydro employees.

Toronto Hydro owns and maintains two types of switchgears:

- The exposed bus type, used mainly for outdoor installations; and

- The enclosed type, further subdivided into metal clad, metal-enclosed, and brick structures, which are mainly used for indoor installations.

Examples of switchgear are illustrated in Figure 13 below.



Figure 13: (Left) Outdoor Enclosure Housing Metal clad Switchgear. (Right) Indoor Metal clad Switchgear

Station Switchgear Maintenance includes three sets of activities.

1) **Circuit Breaker Maintenance**: Circuit breakers (Figure 14) use various mediums to extinguish the electric arc that forms during an interruption operation. Toronto Hydro owns the following types of circuit breakers: air magnetic, air blast, Sulphur Hexafluoride ("SF_6"), oil, and vacuum units, which are maintained every four years. Circuit breaker maintenance work includes a visual inspection and verification of the integrity of the mechanical and electrical components in circuit breakers, functional testing of the unit, and replacement of worn components.



Figure 14: (Left) KSO Oil Circuit Breaker, (Right) Vacuum Circuit Breaker

2) **Protection & Control ("P&C") Maintenance**: P&C equipment maintenance includes inspection and testing of sensing devices and relays that monitor the magnitude and flow of electrical power. In the event of a fault on the distribution system, the protective relays detect the fault and trigger interrupting devices, such as circuit breakers, to operate and isolate the circuit, protecting the system from further damage. A protective relay system has to be periodically tested and verified to ensure that the system remains protected, the settings are appropriate for the current state and loads, and a failure event does not result in cascading outage events. More specifically, maintenance activities involve verifying the AC voltage and current to the fault detecting relay, testing the operating characteristics of the relay, validating relay settings, verifying the operation of auxiliary relays, and verifying output functions such as alarms and annunciations. This equipment is maintained every four years.

3) **Thermography and Ultrasonic Testing**: A thermographic scan of a switchgear unit provides Toronto Hydro with an advanced warning of developing electrical faults by identifying thermal anomalies on the equipment. Ultrasonic testing identifies high-frequency noise associated with surface tracking and corona, which are also

indicators of impending failure. All load break switches, disconnect switches, and bolted electrical connections undergo thermographic scans and ultrasonic tests every four years.

Maintenance activities are designed to reduce the likelihood of switchgear or breaker failure and to mitigate the associated risks. One way that this is accomplished is by identifying deficiencies that can lead to common switchgear failure modes. These deficiencies include worn components, loose connections, degradation, corrosion, and contamination. Examples of these are shown in Figures 15 and 16, which illustrate a corroded switchgear enclosure and pest infestation inside an outdoor switchgear.



Figure 15: Rusted Switchgear Enclosure



Figure 16: Pests Inside Outdoor Switchgear

Figure 17 below shows an example of an internal arc fault, which can be destructive and pose a risk of injury because of the energy levels reached within the confined compartment.



Figure 17: Impact of Internal Arc Fault in a Switchgear

Toronto Hydro has identified over 1,700 deficiencies on switchgear assets during between 2020 and 2022.

The likelihood of deficiencies existing and leading to a failure increases as switchgear and breakers age and approach their end-of-life. The average expected lives of switchgear enclosures and circuit breakers are 50 and 45 years, respectively.

Of particular concern are the high numbers of air magnetic, air blast, and oil breakers that have exceeded their expected life. The likelihood of failure increases for these assets due to wear and tear caused by high occurrences of operations, contamination, loose connections, and corrosion.

Toronto Hydro's Asset Condition Assessment indicates that over 35 percent of the population of switchgear have moderate to material deterioration and are at an increased

likelihood of failure.[12] A failure of one of these assets has the potential to lead to a catastrophic fire, release harmful contaminants into the environment (e.g. oil spills, combustion by-products), and safety risks in the form of debris or arc-flashes that can cause injury and property damage. The replacement of worn and corroded components, the alignment of switch blades, the lubrication of switches, and the removal of dirt and other contamination during maintenance mitigates the risk of failures and associated employee safety, financial, environmental, and system reliability risks that are associated with switchgear failure.

An example of a catastrophic station failure occurred at Station J in East York in 2009. The station was over 50 years old at the time, and a fire broke out following a switchgear failure and subsequent fault. The switchgear had surpassed its expected life and the fault resulted in the destruction of Station J. Maintenance, including thermographic scans and ultrasonic tests, serves to prevent similar occurrences by detecting defective components (e.g. closing coil, pallet switch, closing spring, and relay systems) and incipient faults in loose connections, contacts, and insulators that could develop into a catastrophic failure from the failure of a protection and control asset to operate and clear a fault.

The financial consequences of failures of switchgear and circuit breakers are also significant. The replacement of a circuit breaker can exceed $100,000 and approach $1 million depending on various factors including breaker type, voltage rating, and location. The total replacement cost of a transformer station switchgear, including the costs of the enclosure and circuit breakers, is approximately $6 million and can take over 3 years to design and construct. These costs significantly exceed the annual cost of switchgear

[12] Exhibit 2B, Sections D1 and D3

maintenance activities. As such, the prevention of even one catastrophic failure over a multi-year period will offset the planned maintenance expenditures during the period.

In addition to mitigating safety, environmental, and financial risks, Switchgear Maintenance provides customer value by mitigating system reliability risks. A failure of station switchgear or a circuit breaker can result in a large number of customer interruptions and long interruption durations. Between 2020 to 2022, Toronto Hydro experienced four incidents on average annually that were related to switchgear failures, which resulted in an average of over 2,900 customers interruptions and 3,300 customer hours of interruption annually on average.

Not all switchgear failures are catastrophic in nature and some are as small as the failure of a breaker to open and close. This was the case on May 3rd, 2019, when a vacuum circuit breaker failed to trip and clear a fault, which resulted in over 4,400 customer interruptions and 17,000 customer hours of interruption. Nevertheless, these failures impact system reliability, as protection systems are designed to coordinate with each other, with the intent of isolating the fault or failure to the smallest possible area within the distribution system. If a protection device were to fail to function, a protection device located further upstream would operate. Such a scenario results in outages impacting greater numbers of customers and system assets as well as increasing the safety risks to employees and members of the public in proximity to the stations. Failure of protection devices on the distribution system could also result in the fault migrating to the transmission system, leading to even larger outages. Maintenance tasks are designed to ensure protection devices operate as designed. During maintenance, crews verify and correct improper settings onsite, including: (i) verifying that the voltage and current settings on the fault detecting relays are correct for the system element being protected;

(ii) verifying that the operating characteristics of the fault detecting relays are correct for the applied setting; and (iii) verifying that the operation of auxiliary relays and output functions, such as circuit breaker tripping and annunciation, are correct.

7.2 Station Switchgear Maintenance Segment Costs

Table 6 below provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for this segment.

Table 6: Station Switchgear Maintenance Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Stations Switchgear Maintenance	2.7	3.2	2.4	2.8	3.4	4.1	3.6	3.6	4.2	4.5

7.3 Station Switchgear Maintenance Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

From 2020 to 2021, expenditures increased by approximately $0.5 million which was primarily attributed to higher unit costs due to the complexity of the units maintained and higher material costs due to global supply chain issues.

2021 – 2022 Variance Explanation

From 2021 to 2022, expenditures decreased by approximately $0.8 million which was primarily attributed to maintaining fewer and less complex units.

2022 – 2025 Variance Explanation

Between 2022 and 2025, expenditures are expected to increase by approximately $1.7 million, or an average of $0.6 million per year, primarily due to inflationary pressures and the lower complexity of units maintained in 2022.

2025 – 2029 Variance Explanation

Between 2025 and 2029, expenditures are forecast to increase by approximately $0.4 million, or an average of $0.1 million per year, primarily due to inflationary pressures. Year-to-year fluctuations are due to differences in the relative volume and complexity of units maintained each year. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks, including:

- Increased frequency of station switchgear or circuit breaker malfunctions or failures due to unidentified deficiencies or lack of maintenance leading to increased:
  - public or employee safety risks from fire, debris, or arc flashes;
  - environmental risks from release of contaminants such as oil or combustion byproducts;
  - financial risks from high cost to replace station switchgear; and
  - reliability risks from the switchgear or circuit breaker malfunction during a contingency leading to additional outages.

8. STATION EQUIPMENT MAINTENANCE SEGMENT

8.1 Segment Description

The Station Equipment Maintenance segment addresses equipment located at 23 TS and 139 MS locations, including 183 station power transformers. TSs are points of power supply from the Hydro One transmission system to Toronto Hydro's distribution system. These stations step down supply voltages from 230 kV or 115 kV to 27.6 kV or 13.8 kV, utilizing transformers that, with two exceptions, are owned by Hydro One.[13] MSs are stations within Toronto Hydro's distribution system that are supplied by Toronto Hydro

[13] Copeland TS and Cavanagh TS.

feeders, at 27.6 kV or 13.8 kV, and step down voltage to 13.8 kV or 4.16 kV. Toronto Hydro owns and maintains all equipment at MSs, including the transformers, and while Toronto Hydro's distribution system is supplied by 37 TSs, it owns and maintains a large number of equipment at 23 TSs.

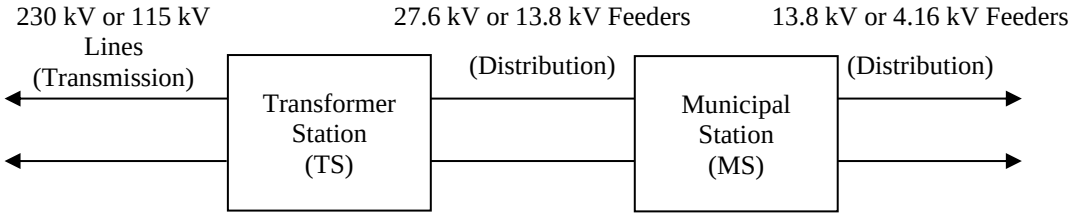


Figure 18: System Configuration

Figures 19 and 20 below depict examples of station power transformers at Toronto Hydro's stations.



Figure 19: Power Transformer at Cavanagh TS



Figure 20: Power Transformer at Neilson Dr. MS

Station power transformers are essential components of every station and a large number have exceeded their expected useful lives. A majority of Toronto Hydro's transformers

were installed in the 1950s through the 1970s. The average useful life of these units is 45 years and over half of the entire population is beyond its useful life.

As transformers age, maintenance becomes increasingly important to ensure that the core and windings continue to function within acceptable parameters, insulating properties do not deteriorate excessively, and auxiliary equipment such as gauges and alarms are functioning properly to detect and provide early warnings of problems such as oil leakage, gases in the oil, and overheating.

Maintenance activities are focused on inspecting, testing, and cleaning assets, including power transformers and their auxiliary equipment, current transformers, potential transformers, station service transformers, DC batteries, chargers, disconnect switches, load break switches, fuses, interconnect cables, and remote terminal units. Failure of such equipment, and in particular, the failure of power transformers, can result in station fires, oil leaks, significant emergency response and equipment replacement costs, and power interruptions impacting a large number of customers. Maintenance activities are vital for mitigating the risk of such failures and associated consequences. Maintenance activities also help to extend the useful life of equipment by promptly identifying failing insulation, deterioration of insulating oil, and transformer winding irregularities such as shorted turns, all of which can cause catastrophic equipment failure if not addressed in a timely manner.

The Station Equipment Maintenance segment does not include maintenance of station switchgear, which is captured in the dedicated Station Switchgear Maintenance segment. Examples of activities that are undertaken as part of Station Equipment Maintenance are:

- Comprehensive transformer testing including winding resistance and power factor testing to evaluate the insulation integrity of the core and windings;
- Cleaning of power transformer bushings to remove contamination that can lead to tracking and flashovers;
- Inspections and calibrations of transformer auxiliary equipment such as relays, temperature and oil gauges, and alarms;
- Verifying the integrity of all clamped and bolted connections on primary feeders, insulators, bushings, secondary feeders and buses;
- Cleaning and testing of on-load tap changers, which are devices used to regulate voltage; and
- Testing of transfer trip relays between a MS transformer (at 4 kV) and the upstream 13.8 kV or 27.6 kV supply feeder.

Station Equipment Maintenance, including the aforementioned activities, requires planned outages and is scheduled on a four-year cycle. In this regard, preventative and predictive tools and tests are employed during maintenance to prevent and identify deterioration on equipment that can lead to failures and associated consequences.

As illustrated in Figure 21 below, Toronto Hydro has identified on average 44 deficiencies on station equipment each year since 2020.

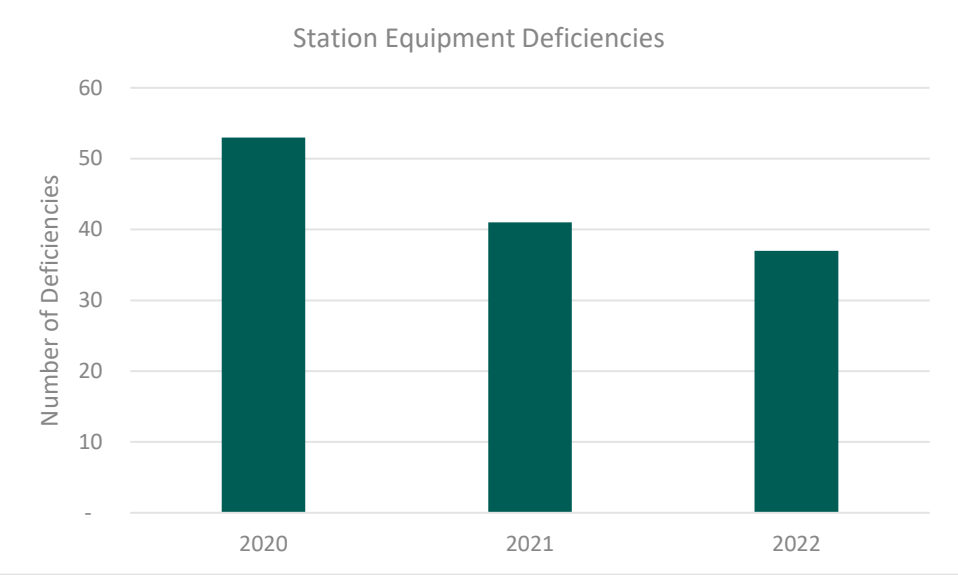


Figure 21: Station Equipment Deficiencies Identified Between 2020 and 2022

When equipment failures occur (e.g. on a power transformer), they pose significant safety, environmental, financial, and system reliability risks. An example of a transformer failure is one that occurred at Dupont MS in 2003. The 49-year old transformer failed and resulted in a fire that caused damage to two other power transformers at the station and caused oil and fluids to spill into the station. This event interrupted 5,675 customers, resulting in over 23,341 customer hours interrupted. The entire outage lasted for 6.6 hours. Figures 22 to 24 show the damage caused by this incident.



Figure 22: Failed Power Transformer



Figure 23: Damages to the MS Wall



Figure 24: Leaking Fluids from Failed Transformer

The safety risks associated with a failure of this nature include station fires and flashovers which can cause injury to employees in a station. Further, associated environmental risks include the spillage of oil from ruptured transformer oil tanks which can contaminate ground water, soil and environmentally sensitive locations, as well as the release of hazardous combustion by-products.

During 2020-2022, Toronto Hydro experienced seven outage incidents cause by failed station transformer equipment. Fortunately, none of these incidents were of the magnitude of the failure at Dupont MS in 2003; however, they did cause over 8,200 customer interruptions and 13,200 customer hours of interruption over the three-year period and thousands of dollars in emergency response costs. From a financial perspective, transformer failures can result in emergency response and equipment replacement expenditures that are estimated to range between $0.2 million and $4 million. Given these figures, the mitigation of even one costly failure can result in savings that substantially offset the cost of the Station Equipment Maintenance program.

Although power transformer failures pose the greatest risk within stations, it is important to note that Station Equipment Maintenance mitigates failures on various other types of station equipment which can also cause significant safety, environmental, financial and system reliability risks. One example is load break switches, which are used to supply and isolate the primary voltage feed to a power transformer at MSs. These switches are installed in outdoor enclosures at 27.6 kV. A failure of such a switch can cause a station outage and significant safety risks as these switches are often operated manually. To ensure the successful operation of a switch during fault conditions, maintenance activities include cleaning insulators, lubricating contacts and gears, checking blade alignment, and conducting electrical tests such as contact resistance, insulation resistance and fuse resistance tests. Another example is station service equipment, which supplies batteries, ventilating systems, lighting, and cranes. A failure of this equipment can result in the loss of power to station protection equipment, the loss of remote communication and control functions, overheating of switchgear, and various other risks. Maintenance mitigates the risk of these failures occurring.

8.2 Station Equipment Maintenance Segment Costs

Table 7 below provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for this segment.

Table 7: Station Equipment Maintenance Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Station Equipment Maintenance	0.8	1.0	0.6	1.0	0.9	1.1	1.1	1.3	1.1	1.2

8.3 Station Equipment Maintenance Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

From 2020 to 2021, expenditures increased by approximately $0.2 million due to a greater number and complexity of units maintained and higher material costs due to global supply chain issues.

2021 – 2022 Variance Explanation

From 2021 to 2022, expenditures decreased by approximately $0.4 million due to a decrease in the number and complexity of units maintained.

2022 – 2025 Variance Explanation

Between 2022 and 2025, expenditures are expected to increase by approximately $0.5 million, or an average of $0.2 million per year, primarily due to inflationary pressures and the lower complexity of units maintained in 2022.

2025 – 2029 Variance Explanation

Between 2025 and 2029, expenditures are forecast to increase by approximately $0.1 million due to inflationary pressures. Year-to-year fluctuations are due to differences in

the relative volume and complexity of the units maintained. . If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks, including:

- Increased frequency of station equipment, such as power transformers or load break switches, malfunctions or failures due to unidentified deficiencies or lack of maintenance leading to increased:
    - safety risks due to fires or flashovers;
    - environmental risks from oil leaks or combustion by-products resulting from unidentified equipment deficiencies;
    - reliability risks from power interruptions impacting a large number of customers; and
    - financial risks from emergency response and equipment replacement costs.

CORRECTIVE MAINTENANCE

1. OVERVIEW

Table 1: Corrective Maintenance Program Summary

Corrective Maintenance Program									
Outcomes: Operational Effectiveness - Safety, Environmental, and Operational Effectiveness – Reliability									
Segments: • Corrective Maintenance									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
23.1	26.5	23.5	24.9	25.6	29.5	30.7	31.0	32.0	33.6

As part of the Corrective Maintenance program (the "Program"), the utility undertakes actions to address deficiencies or substandard conditions across the distribution system that are identified during the normal course of operations. This includes deficiencies or substandard conditions identified through activities undertaken as part of the Preventative and Predictive Maintenance programs or the Emergency Response program. [1] Corrective Maintenance activities are generally high priority, cover short planning horizons (given the risks that deficiencies and substandard conditions can pose if left unaddressed), and involve repairing/restoring assets to their normal operating conditions through maintenance, refurbishment, and/or minor component replacements, which include but are not limited to colour harmonization for Station breakers, Faulted Circuit Indicator ("FCI") replacement, and many more. This program also addresses Electrical Safety Authority ("ESA") related compliance issues, such as delta-wye corrective work and cap and grounding of unused lines above 750 volts for both the overhead and underground systems.

[1] Exhibit 4, Tab 2, Schedule 5.

Toronto Hydro's primary objective for this Program is to contribute to maintaining safety, environmental integrity, and overall system reliability by correcting or repairing deficiencies or substandard conditions on the distribution system. Additionally, where feeders are performing particularly poorly and are at risk of exceeding thresholds set for FESI-7 (Feeders Experiencing Sustained Interruptions of 7 or more), or FESI-6 Large Customer (Key Account Feeders Experiencing Sustained Interruptions of 6 or more), line patrols are conducted by field crews to assess the condition of equipment on the feeder and identify quick, targeted actions that yield immediate reliability improvements. Any capital work identified through these line patrols is addressed through the Worst Performing Feeder segment within the Reactive and Corrective Capital program.[2]

There has been a rise in the volume of corrective work requests attributed to deteriorating asset condition and asset-related safety risks to crews or the general public. Furthermore, the increase in corrective work requests is due to enhanced inspection forms and introducing new inspection work, such as cable diagnostic testing,[3] which identifies additional deficiencies that may need to be addressed. This results in approximately $20 million worth of backlog for the lower priority ("P3", requiring resolution within 180 days) work requests, which will need to be addressed before the issues worsen and cause a system fault which may lead to a power outage, or other safety incidents. Hereafter, any reference to backlog is for P3 deficiencies only. To help manage this risk, the corrective work requests in the backlog have been further prioritized by level of risk (e.g. High, Medium and Low) within P3 priority, and by the primary and secondary impact (e.g. Environmental, Safety, Reliability, Operations) of the deficiency so that Toronto Hydro can target the work that address the greatest risk. An example of a high-risk deficiency includes, but is not limited to, extensive rotting on a crossarm which need

[2] Exhibit 2B, Section E6.7.
[3] Exhibit 4, Tab 2, Schedule 2.

to be replaced or a leaning pole that will need to be straightened to avoid reliability and safety issues. A low-risk example includes, but is not limited to, replacing a cracked phase barrier or removing graffiti.

With aging assets and the enhancements of Toronto Hydro's Preventative and Predictive Maintenance programs,[4] and ramp up of newer inspection programs such as cable diagnostic testing, additional deficiencies are expected to be identified, resulting in a continuous overall increase in corrective follow-up work as reflected in the proposed 2025-2029 expenditures for the Corrective Maintenance program.

2. OUTCOMES AND MEASURES

Table 2: Corrective Maintenance Program Outcomes and Measures Summary

Operational Effectiveness - Safety	• Contributes to Toronto Hydro's public and employee safety objectives by:
	  • Promptly repairing high-risk assets approaching imminent failure.
	  • Eliminating risks such as trip hazards caused by sink holes on sidewalks, lack of pole guy(s) and/or washing insulators located in high contamination areas to prevent flashover and pole fires.
	  • Detecting and eliminating energized stray/contact voltage (4.5 volts or greater), on surfaces and structures within Toronto Hydro's distribution system.

Environment	• Contributes to Toronto Hydro's environmental objectives by:
	  • Repairing cables and splices exhibiting signs of oil deficiency to prevent oil spills into the environment.
	  • Preventing excessive corrosion by cleaning oil-filled equipment and applying corrosion inhibiting coatings.

[4] Exhibit 4, Tab 2, Schedules 1-3.

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7, FESI-6 Large Customer) by: • Repairing and restoring assets through corrective maintenance to acceptable operating conditions. Examples include but are not limited to, FCI replacement, animal guard installation, spot tree trimming and crossarm replacement due to rotting.

3. PROGRAM DESCRIPTION

Toronto Hydro's primary objective for this program is to contribute to maintaining the safety of Toronto Hydro's work crew and general public, environmental integrity, and overall system reliability. This is accomplished by correcting or repairing deficiencies or substandard conditions on the distribution system. Furthermore, this program addresses ESA compliance issues, such as the cap and grounding of unused lines above 750 volts for both overhead and underground systems and the delta-wye program.

Deficiencies or substandard conditions across Toronto Hydro's distribution system are identified through the normal course of field operations, which include line patrols conducted on poorly performing feeders (Worst Performing Feeders, or "WPF"), the Preventative and Predictive Maintenance programs, the Emergency Response program and/or customer communication, as shown in Figure 1 below. Identified deficiencies or substandard conditions are subsequently addressed through a variety of programs: [5]

- Corrective Maintenance program;
- Reactive and Corrective Capital program[6];

[5] Exhibit 2B, Section D3.
[6] *Supra* note 2.

- Preventative and Predictive Maintenance programs; when non-critical deficiencies are identified and are feasible to repair on-site, they are addressed as part of the "find it and fix it" practices.

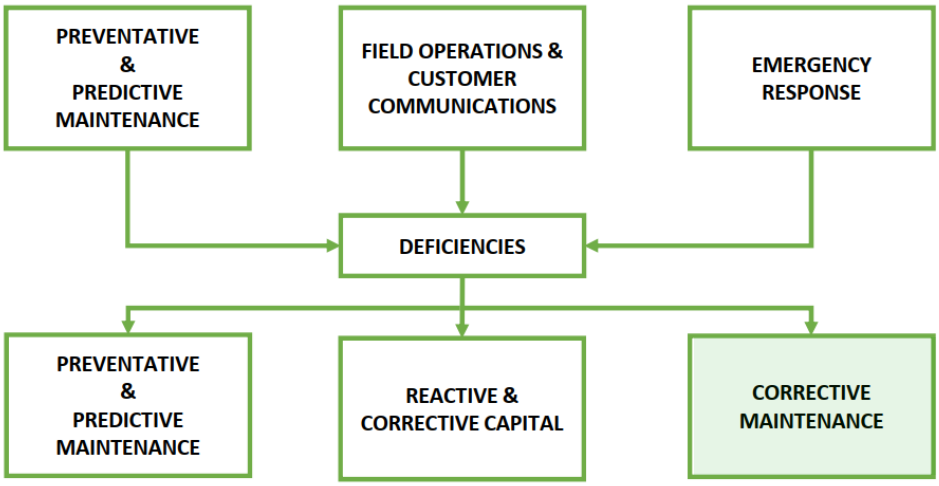


Figure 1: Deficiency Capturing Process

- **Preventative & Predictive Maintenance Activities:** Field crews identify asset failures and deficiencies as part of scheduled maintenance inspection activities. The inspection cycle depends on the maintenance program as per Reliability Centered Maintenance ("RCM"). The RCM framework is a comprehensive approach to the lifecycle maintenance of distribution system assets. RCM enables Toronto Hydro to leverage a methodological approach to preserve the asset's function by implementing failure management practices that target the potential functional failure.

- **Field Operations & Customer Communication:** Corrective work can also be triggered by sources outside scheduled/planned maintenance activities. These include, but are not limited to:

- Phone calls from customers to Toronto Hydro;
- External emails to Toronto Hydro;
- Observations by field crews during the normal course of operations;
- Customer inquiries requiring field assessment and follow up;
- Line patrol for Worst Performing Feeder Program.

- **Emergency Response:** Corrective work can also be required as a result of emergencies or unplanned system events. These include asset failures and deficiencies identified outside of Toronto Hydro's daily (planned) operations but requiring follow-up remediation in order to permanently restore power or eliminate safety or environmental risks.

All deficiencies from the above sources are reviewed to validate the need for reactive intervention, assess the nature of reactive intervention required (Capital versus Maintenance), and the priority level to be assigned to each deficiency request. For the Corrective Maintenance Program, Toronto Hydro uses a prioritization framework that classifies asset deficiencies into four categories and addresses the deficiencies by generating a work request notification:[7]

(i) P1 requires resolution within 15 days;
(ii) P2 requires resolution within 60 days;
(iii) P3 requires resolution within 180 days; and
(iv) P4 which indicates that conditions are to be monitored.

The scope of the corrective maintenance work includes all overhead and underground assets, municipal and transformer stations. It also includes other work, such as stations

[7] Work requests are forms issued to assign and schedule corrective work to be performed by Toronto Hydro crew.

decommissioning, work required to address ESA Compliance issues, and temporary follow-up repairs to assets during an emergency event, but excludes emergency repair work managed under the Emergency Response program. More specifically, the Corrective Maintenance program consists of the following activities:

- **Distribution Overhead Maintenance:** Corrective restoration of equipment and replacement of components that are part of the overhead distribution system, including conductor, conductor splices, insulators, brackets, surge arresters, pole-mounted transformers, and overhead switches. Work includes, but is not limited to:
    - Vegetation management in response to off-cycle requests; spot trimming needs identified by Toronto Hydro crews or direct customer communication, such as dying or damaged tree limbs and branches, major storm damages, or excessive tree growth that threatens overhead distribution lines or poses system reliability risks;
    - Installing missing animal guards, guy guards, ground wire and/or surge arresters; and
    - Patrols and spot maintenance of poorly performing feeders, which targets non-Key Account feeders that are at risk of experiencing seven or more sustained outages (FESI-7) or Key Account feeders that are at risk of experiencing 6 or more sustained outages (FESI-6 Large Customer) over a rolling 12-month period. Typical work includes installation of insulated drop leads, animal guards, and replacement of vintage porcelain cut-out switches mounted on steel brackets at overhead transformer locations that are prone to tracking.

- **Distribution Underground Maintenance:** Restoration of equipment that is part of the underground and network distribution system, including cables, cable splices, vaults, ducts, vents, hatchways, transformers, and switchgears. Work includes, but is not limited to:
    - Leveling surfaces to eliminate tripping hazards;
    - Installing or replacing FCIs and/or fuses; and
    - Equipment CO_2 washing, which cleans excessive dirt, debris, and contamination from energized equipment in below-grade and pad-mounted installations to prevent arcing and flashover risks.

- **Stations Maintenance:** Corrective repairs to station equipment such as transformers, tap changers, cooling systems, switchgear, bus-bars, air compressors, circuit breakers, relays, remote terminal units, and SCADA systems. Work includes, but is not limited to:
    - Repairing battery charger, breakers, alarms, gauge, fuses, RTU and repeater radio;
    - Installing ground, locks or barriers; and
    - Replacing arrester, FCI, sensor and/or silica gel.

These activities are critical to maintaining distribution lines and stations assets, as assets are exposed to normal degradation processes (e.g. corrosion, water ingress, heavy loading) and external forces (e.g. adverse weather, tree contacts, foreign interference) that cause deficiencies and accelerate asset deterioration. The Preventative and Predictive Maintenance program sets out the number of deficiencies that Toronto Hydro

identifies annually for a variety of assets.[8] Figure 2 below shows a breakdown of the number and types of corrective work issued and the P3 backlog between 2019 and 2022.

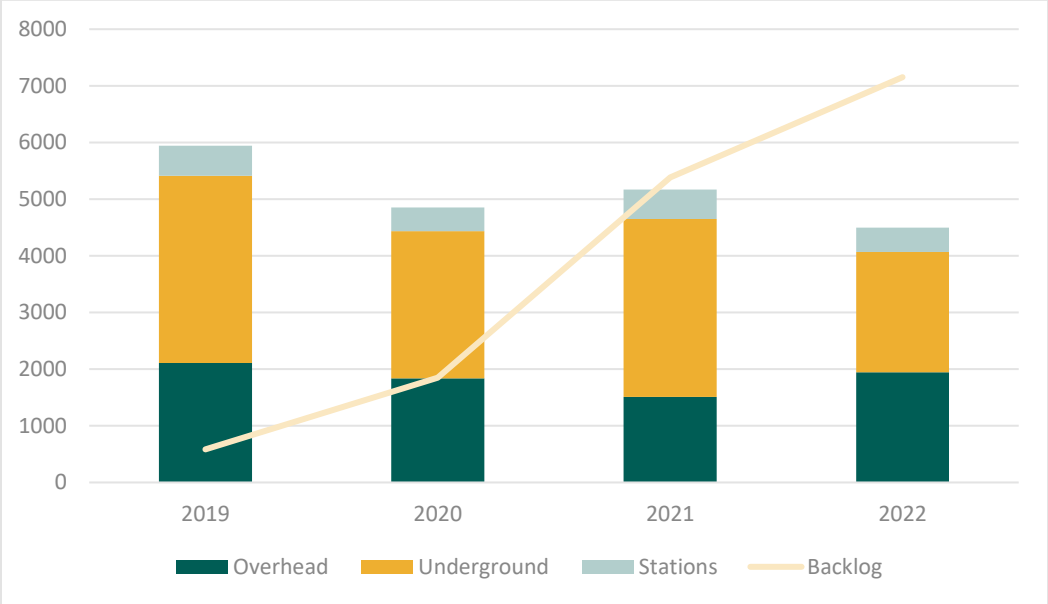


Figure 2: Historical Corrective Work Requests Issued and P3 Backlog

As shown in Figure 2, there has been a rise in the volume of corrective work in the P3 backlog due to the proportion of assets exhibiting deteriorating conditions and exceeding their expected lives, thereby elevating the risk of failure across the distribution system.

Toronto Hydro also enhances inspection forms when required, which contributes to capturing greater details about substandard conditions found during inspections and therefore increasing the P3 backlog volume. As a result of these updates, Toronto Hydro continuously improves its process for capturing deficiencies and determining the appropriate corrective action. This provides the utility with greater visibility into asset health and allows for more effective condition assessment and risk mitigation.

[8] Exhibit 4, Tab 2, Schedules 1-3.

Consequently, the number of deficiencies reported from Preventative and Predictive maintenance activities increased significantly for deficiencies such as trip hazards, vault grounding, rack repair, and nomenclatures which contributed to the higher volume of corrective work requests and the P3 backlog.

There is approximately $20 million in the P3 backlog, of which the medium and high risks items make up approximately 35 percent and will need to be resolved before a fault in the system occurs that could lead to a bigger issue. However, even for the low-risk deficiencies, there is still a possibility of the deficiency worsening over time. For example, a damaged pole anchor may be considered a medium risk initially, but if not addressed over time then it could lead to the pole leaning and subsequently breaking, which will affect safety and reliability. Similarly, for a low-risk deficiency such as replacement of primary cable rack, if left unaddressed for too long could lead to cable damage which can cause an outage. For this reason, Toronto Hydro needs to invest in reducing the P3 backlog, and manage it moving forward.

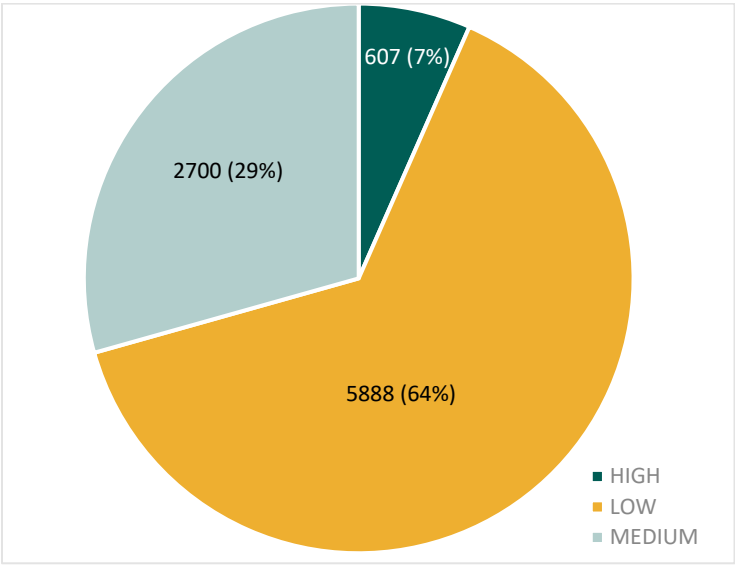


Figure 3: Risk Levels for P3 Backlog of Work Requests

On average, approximately 8,000 corrective work requests were generated each year between 2019-2021, which increased to over 11,000 requests in 2022, with the majority targeting underground system assets such as vaults, cable chambers, and pad-mounted equipment. In general, corrective maintenance needs tend to vary both in the volume and type of work required from year to year.

From a safety perspective, corrective maintenance addresses deficiencies that, if ignored, could endanger members of the public and/or Toronto Hydro employees. For example, a deficiency that is routinely found during overhead line patrols, using infrared thermography, is a thermal anomaly (or "hot spot") on a conductor splice. Hot spots are evidence of over-heating within the splice and, if not addressed in a timely manner, could result in a live conductor failing, falling to the ground, and energizing the surrounding area. Such a condition presents an unacceptable risk that must be mitigated through corrective maintenance in a timely manner. Other examples may include trip hazards on sidewalk due to unlevel ground around Toronto Hydro owned assets, which contributes to the total number of Public Incident Risks or presence of stray voltage which can impact public safety.

From an environmental perspective, corrective maintenance mitigates the risk of oil leaks and premature equipment failures. For example, a cable splice leaking oil must be repaired promptly to prevent oil from entering the soil, drains, and waterways. Furthermore, an oil-filled transformer that is at risk of corroding should be maintained in a clean state, free of contaminants that can act as catalysts for corrosion. As part of the Corrective Maintenance program, Toronto Hydro cleans dirty vaults and padmounted installations and applies corrosion inhibiting coatings to equipment to prevent excessive corrosion and the possibility of subsequent oil leaks. Corrective maintenance activities

directed at corrosion prevention also serves to mitigate financial risks. Over recent years, greater emphasis has been placed on identifying the year manufactured on underground transformers to confirm potential risk of PCB containing assets, and identifying corrosion at the base of the transformer. In 2021, inspection questions were modified to include the manufactured year for all transformers.

From a reliability perspective, corrective maintenance addresses deficiencies that, if ignored, will result in unnecessary interruptions for customers and affect reliability metrics such as SAIDI, SAIFI, FESI-7 or FESI-6 Large Customer. For example, depending on the specific location of a spliced conductor (e.g. main trunk, lateral, sub-lateral), there may be a power interruption to hundreds of customers and key customers (e.g. hospitals) if the splice fails due to a hot spot. Other deficiencies that pose similar system reliability risks include, but are not limited to, deteriorated components such as insulators, mounting brackets, cross-arms, broken ground wire, guy wires, overgrown vegetation, failed surge arresters and/or conductor clearance issues (e.g. excessive conductor sag). In aggregate, these individual deficiencies pose significant reliability risks.

As part of Customer Engagement,[9] "Reliable Service" was identified as a top customer need, and ranked in the top three needs for residential, small business, commercial and industrial for both Key Account and non-key account customers. When asked specifically about their top three reliability priorities, the frequency of power outages was identified across all customer classes. This program is intended to address these needs, among others, by ensuring essential work is issued in a timely manner to reduce unnecessary interruptions.

[9] Exhibit 1B, Tab 3, Schedule 1.

Corrective maintenance work can extend the life of assets and defer the need for capital equipment replacement expenditures. An example is caulking which is applied to civil infrastructure such as underground vaults. Caulking seals cracks in concrete and minimizes damage from moisture ingress. If caulking is not applied, cracks can grow to threaten the structural integrity of civil infrastructure and result in expensive vault rebuilds which can increase the cost of repair from hundreds of dollars to thousands of dollars to repair. Water ingress can also accelerate corrosion of equipment, leading to premature failure and associated costs.

Toronto Hydro needs to address any ESA Compliance issues as they are identified, and this type of work is funded by this Program. Two recent examples of work Toronto Hydro has been doing in this Program to address such issues are cap and grounding unused lines above 750 volts and 'Delta-Wye' corrective work. Unused primary lines above 750 volts are required to be removed completely and, if the removal is not feasible, then the cable is required to be deenergized, disconnected, and grounded at each end in order to provide permanent protection and compliance with ESA requirements and Section 11 of Ontario Regulation 22/04. The unused lines are found both overhead and underground, such as in submersible vaults, URD (Underground Residential Design), CRD (Compact Radial Design), and building vaults.

Regarding Delta-Wye corrective work, the ESA has identified potential fire and shock hazard posed by 3-phase grounded wye-connected secondary transformation with no grounded neutral conductor between the transformer's secondary neutral terminal and the customer's service entrance equipment. When there is a phase-to-ground fault, there is no defined path for the fault current to follow. A fire hazard could be present where the fault current tries to find an alternate path (e.g. metallic gas pipe, communication

cable, etc.). The ESA issued a Flash Notice in 2018 to ensure that utilities have a path forward to address these issues and ensure compliance with the ESA requirements under Ontario Regulation 22/04.

The emergence of such compliance issues and the extent of the work (and costs) required to address them are unpredictable. If anything, as the complexity of the distribution system increases with the energy transition and electrification, the emergence of such compliance issues is likely to grow. Toronto Hydro must address these risks in a timely manner, and without sufficient funding in this Program, this could compromise the utility's ability to complete other work and lead to an increased backlog of unaddressed deficiencies and their associated risk.

4. PROGRAM COSTS

In 2025, Toronto Hydro requires $29.5 million in funding for the Corrective Maintenance program, which represents an increase of $6.4 million over the last rate application in 2020.

Over the 2025-2029 rate period, the utility expects the cost of this program to increase by a compounded annual growth rate of 3.3 percent, which is necessary to address forecast corrective work request volumes, high risk deficiencies in the P3 backlog, and emerging compliance issues, and deliver the customer outcomes enabled by this program.

The Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures are summarized in Table 3 below.

Table 3: Corrective Maintenance Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Corrective Maintenance	23.1	26.5	23.5	24.9	25.6	29.5	30.7	31.0	32.0	33.6
Total	**23.1**	**26.5**	**23.5**	**24.9**	**25.6**	**29.5**	**30.7**	**31.0**	**32.0**	**33.6**

4.1 Cost Drivers

As discussed above, corrective maintenance needs tend to vary both in the volume and type of work required from year to year. Toronto Hydro continues to process increasing volumes of corrective work requests to address identified deficiencies. Overall, the observed variances are primarily attributable to:

- The type of work addressed each year (e.g. overhead, underground and stations);
- Gradual increase in corrective work due to greater deficiencies found via enhanced inspection forms;
- High volume of P3 backlog work that needs to be addressed to avoid issues across the system;
- Introducing new inspection programs such as cable diagnostic testing and DERs; and
- Increased volume of emergency corrective work for defective equipment.

Toronto Hydro's 2025-2029 forecast program expenditure of $29.5 million is based on historical spending levels and work request volumes and accounts for the high-risk P3 backlog of work and ESA compliance work.

4.2 Cost Control and Productivity Measures

Corrective maintenance expenditures are driven largely by work request volumes and the types of repairs required. Toronto Hydro has taken steps to manage costs and improve work processes in this Program.

- Toronto Hydro enhances the inspection forms when necessary to capture more objectively quantifiable and measurable facts from field inspections. The revised inspection forms provide greater visibility into asset health and allow for more effective condition assessment and risk mitigation.
- Toronto Hydro also continues to emphasize "find it and fix it" practices in the Preventative and Predictive Maintenance programs, which promotes the on-site repair of minor deficiencies as they are identified. Examples of minor deficiencies and associated corrective actions include but are not limited to, replacing nomenclature, replacing faulted circuit indicators and/or installing missing guy guards. This eliminates the need to create a separate work request and additional travel time for a different crew to complete repair, resulting in savings of approximately $700,000 per year.
- Toronto Hydro has introduced the prioritization of the high volume of P3 backlog to further determine risk level (e.g. High, Medium or Low) and classify the deficiency impact (e.g. safety, environmental, reliability) which will contribute to issuing work effectively based on available budget.
- The work request process has been improved in several ways in recent years, including through the introduction of the Asset Deficiency Automated Prioritization Tool ("ADAPT") process in March 2021, which reduced manual reviews and improved processing time. See Figure 4 below.

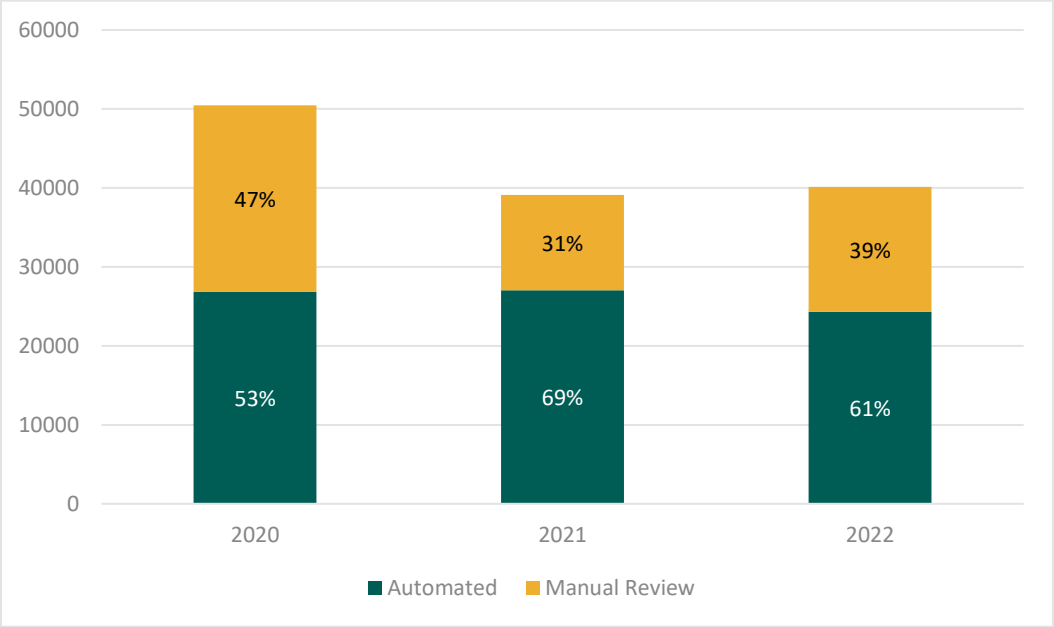


Figure 4: Manual vs. Automated Review of Work Requests

- The work request process has also been improved by introducing a mass creation process for notifications submitted to the work request desk mailbox. Improved tracking and reporting by eliminating multiple, redundant Excel master lists through the adoption of the SAP system, Netezza warehouse data/table and subsequent enhancements in managing work requests. This has improved the process time of each work request as well as increasing data accuracy and traceability. The Work Request Desk ("WRD") workflows are linked directly to Netezza data warehouse. This has resulted in a 20 percent reduction in the time taken to create a notification.
- Improved quality of submission requests via the Asset Deficiency Web Portal using standardized forms to submit work requests when deficiencies are identified. This ensures higher accuracy, completeness, and consistency when submitting requests thereby reducing the need for follow-ups.

- Better communication and coordination within Toronto Hydro (e.g. Supply Chain) to ensure material availability to support effective work execution and completion in compliance with the priority assigned.
- Under the Delta-Wye ESA compliance work, transformers that were scoped for replacement through capital projects were automatically removed from the inspection list, thus saving inspection and corrective costs.
- Lastly, deficiency and work request reviews are currently performed electronically via Electronic Red Construction Folder ("eRCF"). This leads to efficient records keeping, easier accessibility and better visibility of returned eRCFs from crews.

4.3 Corrective Maintenance Program Variance Analysis

2020 – 2021 Variance Explanation

The costs from 2020 to 2021 increased by approximately $3.4 million due to increased corrective work required to support environmental and safety risks, including station decommissioning, Delta-Wye corrective work, and cap and grounding of unused primary lines. The increase was also driven by a higher number of deficiencies identified through inspections programs such as overhead line patrols and cable diagnostic testing.

2021 – 2022 Variance Explanation

The costs from 2021 to 2022 decreased by approximately $3.0 million, primarily due to the significant progress that was made in 2021 in the capping and grounding of unused lines, requiring less of this work in 2022. This decrease was partially offset by increased spending on work such as stations decommissioning and addressing the backlog of P3 work requests.

2022 – 2025 Variance Explanation

Between 2022 and 2025, costs are expected to increase by $6.0 million, or an average of $2.0 million per year, due to:

- The need to address the P3 deficiency backlog;
- Expected increases related to spot tree trimming and corrective work for Distributed Energy Resource ("DER") sites (pilot inspections of these sites are starting in 2023);
- Remediation work required for Copeland Station (Phase 1); and
- The need to replace obsolete FCIs.

2025 – 2029 Variance Explanation

Between 2025 and 2029, costs are forecast to increase by $4.1 million, or an average of $1.0 million per year, to address forecast work request volumes, continue to mitigate the P3 deficiency backlog, and ensure that the utility has the ability to address emerging compliance issues in a timely manner without compromising other corrective work. If Toronto Hydro was forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks, including:

- Reduced ability to address deficiencies that pose safety risks to the public and Toronto Hydro employees such as hot spots on conductor splices and/or trip hazards on sidewalks due to underground assets;
- Reduced ability to address failed or corroded equipment that could negatively impact the environment through oil leaks;
- Reduced ability to address deficiencies that pose risks to system reliability such as deteriorated or failed components, overgrown vegetation, and/or rotting crossarms;

- Increased need for capital expenditures to replace equipment that otherwise could have been deferred through maintenance such as caulking of civil infrastructure or installing animal guards;
- Reduced ability to address high volume of P3 backlog which may contribute to worsening problems if left unaddressed;
- Reduced ability to mitigate outages on poorly performing feeders caused by systemic issues, such as animal contacts at overhead transformer locations due to lack of animal guards; and
- Reduced ability to address any emerging ESA compliance issues.

EMERGENCY RESPONSE

1. OVERVIEW

Table 1: Emergency Response Program Summary

Emergency Response Program Summary									
Outcomes: Customer Focus, Public Policy Responsiveness, Operational Effectiveness - Reliability and Operational Effectiveness - Safety									
Segments: • Emergency Response Program									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
22.1	23.0	22.0	20.4	23.1	25.9	26.4	27.2	27.9	28.6

The Emergency Response program (the "Program**"**) entails the provision of emergency response and restoration services related to unplanned and urgent events affecting Toronto Hydro's distribution system. The Program ensures that the utility is able to comply with applicable Distribution System Code ("DSC") requirements regarding emergency response, maintain customer service and system reliability, and address urgent public safety risks.

The Program consists of three major functions:

- Dispatch Logistics;
- Grid Response; and,
- Storm and Major Event Restoration.

2. OUTCOMES AND MEASURES

Table 2: Emergency Response Program Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: o Improving communications in relation to urgent events and emergency response, including urgent planned events which customers have identified as a priority for them; and o Maintaining timely and accurate outage restoration time.
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by responding to police, fire and ambulance calls, where necessary, with qualified staff within 60 minutes, 80 percent of the time as prescribed by section 7.9 of the DSC.
Operational Effectiveness - Reliability	• Contribute to Toronto Hydro's system reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by ensuring crews are available 24/7/365 to respond to power system events and minimizing outage restoration times.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's public and employee safety objectives and performance (as measured via metrics like Total Recordable Injury Frequency) by: o Ensuring timely response to failing assets and cascading asset failures, to mitigate the risk of injury to the City of Toronto's emergency first responders, the general public and Toronto Hydro crews; and o Remaining compliant with Electrical Distribution Safety Regulation O. Reg. 22/04 (particularly, section 4 – safety standards) by ensuring that Toronto Hydro facilities present no undue hazard to the public).

3. PROGRAM DESCRIPTION

3.1 Purpose and Need:

The primary purpose of the Emergency Response Program is to provide 24/7 emergency response and restoration services for unplanned and urgent distribution system events. The program also ensures that Toronto Hydro remains compliant with sections 4.5 (Unplanned Outages and Emergency Conditions) and 7.9 (Emergency Response) of the

DSC while responding to and restoring services during and following these events. The Program includes three main functions:

- **Dispatch Logistics**: This function involves communications intake (e.g. telephone calls, email, social media, web chat, and online outage submissions) from external stakeholders (e.g. customers, government authorities), information collection about events on the distribution system, and field resource assignment and dispatch for the purposes of investigating and resolving abnormal conditions and safety issues, and other customer service related deficiencies.
- **Grid Response**: This function is executed by specialized field crews that are dispatched in response to emergency situations, including compromised or failing distribution assets, primary and secondary service interruptions, power quality issues, and other customer service related deficiencies.
- **Storm and Major Event Restoration:** This function involves the efforts to restore power after major events, extended loss of supply, and damage and safety hazards arising from severe weather-related events.

Emergency response may be required for a variety of reasons, including: (i) response to requests for support from Toronto Emergency Management Services ("EMS") (i.e. police, firefighters, and paramedics) or the public; (ii) equipment failure; (iii) events related to severe weather; (iv) motor vehicle accidents (shown in Figure 1, below); (v) power quality issues; and (vi) reactive equipment isolations.

Due to the unpredictable nature of severe weather systems and large-scale events, Toronto Hydro cannot forecast the number of events requiring the mobilization of the Program's resources. However, to ensure preparedness to address events 24/7/365, the Program engages: (i) specialized grid response crews working on shift around the clock

for immediate response, making temporary repairs, and restoring power where possible, (ii) reactive and standby crews for emergency repair and re-construction, and (iii) dispatchers to communicate with stakeholders, collect information, and coordinate emergency responses.

The City of Toronto's dense urban environment impacts the Program's operations and crew response. For example, high pedestrian and vehicle traffic can affect crew travel times to emergency events, and can increase the risk to the public. In addition, due to the diversity and vintage of different parts of Toronto Hydro's distribution system, grid response crews have to be prepared to work with a wide variety of equipment.



Figure 1: Crews were engaged to respond to a motor vehicle accident with a Distribution Pole (2022)

3.1.1 Dispatch Logistics

Dispatchers address inbound communications from internal and external stakeholders:

- External stakeholders include customers, members of the public, EMS, the City of Toronto, and other utilities; and,
- Internal stakeholders include field crews and other staff which include Toronto Hydro employees and external contractors.

Customers and other stakeholders are using increasingly diverse methods to convey information to Toronto Hydro. The utility serves a large customer base with a diverse set of needs and expectations that continue to evolve. Customers and other stakeholders expect to be able to report a power system concern through a variety of methods and receive a timely response and resolution. As a result, the utility is modernizing the Program to meet these ever-evolving needs

Toronto Hydro's dispatch staff address a wide variety of inbound communications. On a given shift, a dispatcher can attend to concerns reported through inbound calls, web chat engagement, social media requests, and online outage reports. For each method of communication, a dispatcher must interpret the nature of the event that has occurred, validate the veracity of the concern (for example, confirming that the reported incident is related to assets owned by Toronto Hydro or otherwise within the utility's responsibility to address), prioritize the event, confirm that it has not been already queued for response, and dispatch the most appropriate resource. In addition to attending to inbound communications from external stakeholders, dispatchers also engage in inbound and outbound communications with field resources to respond to emergency events.

From 2018-2022 the dispatch logistics function received an average of 81,000 inbound calls per year from external and internal stakeholders, including 54,000 external customer interactions from social media, outage web chat, and online outage reporting. Although customer calls typically constitute the majority of external customer interactions, social media report and outage web chat volumes increased in 2021 and 2022.

Call volumes in 2018 were substantially higher due to an increased volume of significant events than in subsequent years. While call volumes vary depending on system conditions, the volume of inbound calls from crews steadily declined year over year between 2019-2022 thanks to the new system and resource monitoring tools that Toronto Hydro continues to implement during the current rate period, as discussed in greater detail below under Section 4.2, Cost Control and Productivity. This decline has been partially offset by an increase in calls from external stakeholders during the same time period (Figure 2).

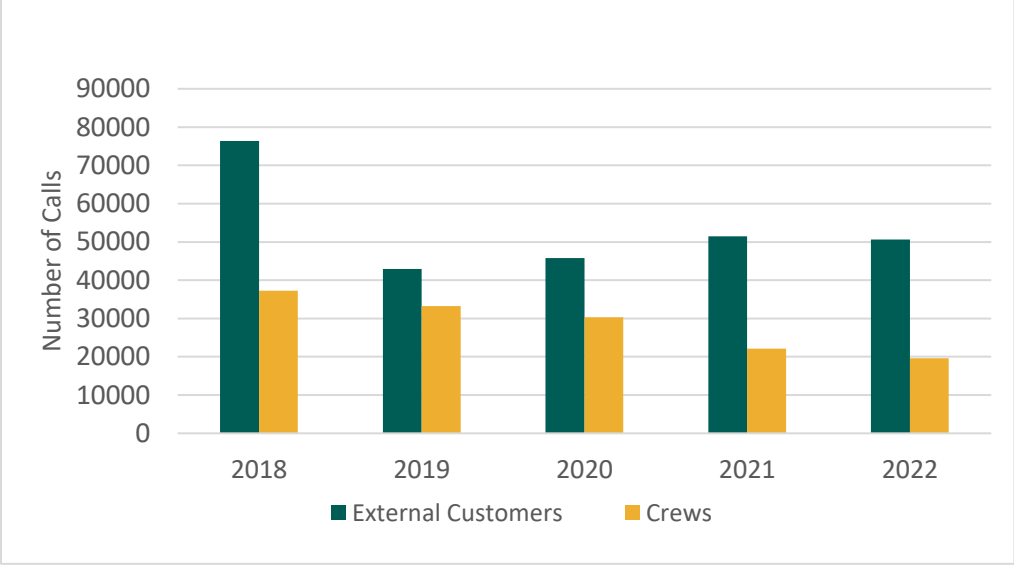


Figure 2: Total inbound calls received by dispatch between 2018-2022.

Toronto Hydro experienced a relatively lower volume of Major Event Days between 2019-2022 compared prior years. Furthermore, during the height of the COVID-19 pandemic in 2020 and part of 2021, many residents worked from home, businesses were closed, and public events were disrupted, resulting in decreased traffic volume in the City of Toronto. Event volumes in 2020 and 2021 were lower than those in the pre-pandemic years of 2018 and 2019. Nonetheless, customer interactions with the dispatch logistics function continued to increase from 2019 to 2022 (Figure 3).

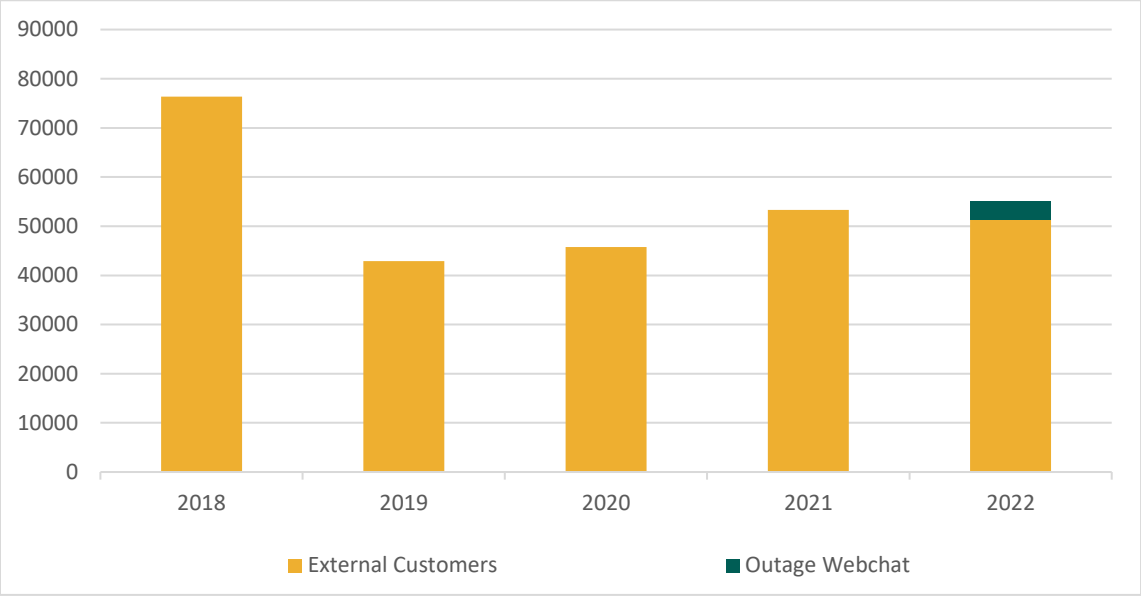


Figure 3: shows total inbound customer interactions dispatch received 2018-2022

Customers also have the option to submit outage reports online, through Toronto Hydro's website. Dispatchers validate these online outage reports using multiple tools at their disposal, including communicating directly with the customer, if necessary. After determining the nature of a customer's outage report, re-prioritizing or cancelling the event if required, dispatch will assign appropriate resources to respond to the event. To accomplish this, dispatchers gather the required information and interact with relevant Toronto Hydro systems, as described in Section 3.1.2 below. Between 2018-2022, there

were an average of 25,000 online outage submissions and after validation was completed, dispatchers submitted 2,800 unique outage tickets, for execution (Figure 4).

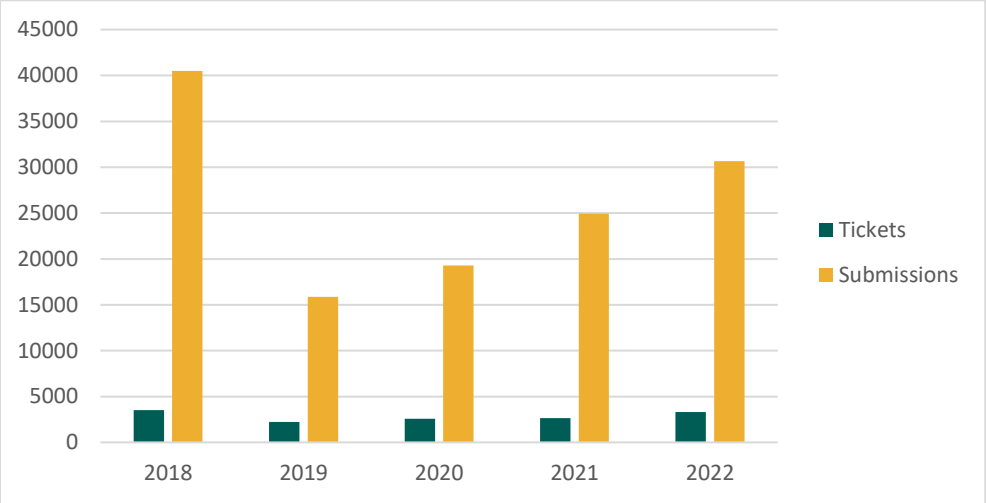


Figure 4: Online outage report submissions and tickets created 2018-2022

As further detailed in Section 3.1.2 below, dispatchers manage daily power system events using two applications, the Outage Management System ("OMS") function of the Network Management System ("NMS"), and Oracle Field Service Cloud ("OFSC").

3.1.2 Grid Response

Over the 2018-2022 period, approximately 20,000 events were created per year that required crew dispatch. The total number of events requiring crew dispatch represents approximately one quarter of the total communications intake dispatchers addressed, as discussed in the previous section.

Toronto Hydro classifies events that require crew dispatch into four main categories:

- **Emergency Events**: Emergency calls reported by Toronto EMS or members of the public may involve significant public health and safety risks. Pursuant to the section 7.9 of the Distribution System Code, a crew must arrive at the location of

the event within one hour of being notified, 80 percent of the time. Of the approximately 3,000 emergency events logged annually over the 2018-2022 period, over 1,100 were from Toronto EMS or validated reports by members of the public.

- **Power Off (Primary):** "Power off" calls attributed to power interruptions on primary facilities (i.e. on the primary high voltage side of the distribution transformer). Primary "power off" events involve power disruptions to sizeable loads and large numbers of customers, typically requiring coordinated switching, load transfers, and often direct engagement with customer building superintendents and operations staff on location.
- **Power Off (Secondary):** "Power off" calls attributed to interruptions on secondary facilities (i.e. the distribution transformer or equipment on the secondary low voltage side of transformer), and "power on" events where power has not been interrupted but an issue has been identified on primary facilities such as voltage fluctuations or flickering lights.
- **Other**: Situations such as sparking wires, objects on wires, feeder patrol findings,[1] and planned outages.

[1] Results of visual inspections of feeder assets that Toronto Hydro crews/contractors perform in accordance with section 4.4 of the Distribution System Code.

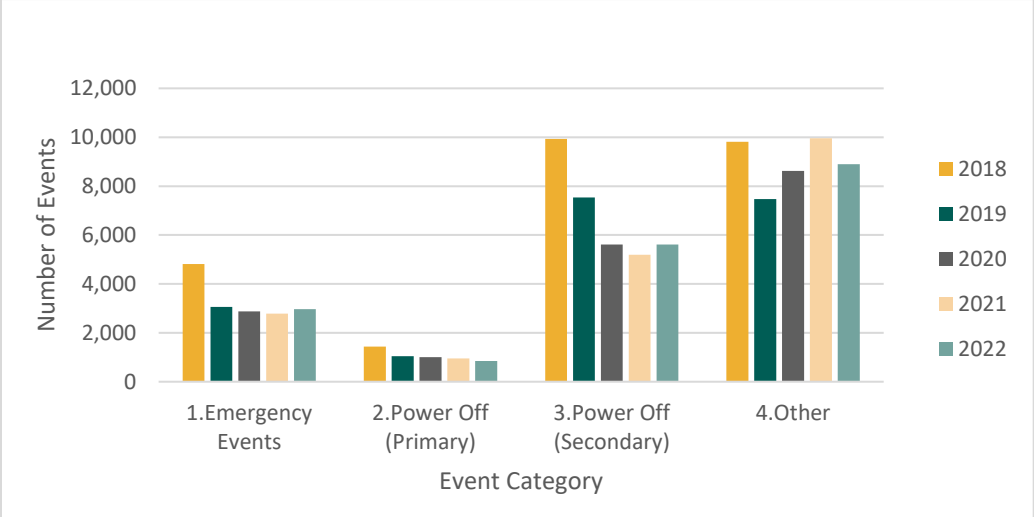


Figure 5: shows the number of events by category during the 2018-2022 period

Categories 1 and 2 constitute the highest priority events for dispatchers and grid response resources.

Category 3 and 4 events represent the largest number of calls and typically involve power interruptions to a small number of customers or lower risk situations. These events, which occur daily as part of the utility's routine operations, require timely response by crews that are properly equipped and trained to address repairs on high voltage equipment that can pose safety risks. Due to the frequency of these events, Toronto Hydro assigns dedicated crews to the grid response function, which typically involves:

- An emergency crew restoring power to all customers and making all necessary permanent repairs (e.g. when current-limiting fuses have ruptured, primary or secondary conductors are down, or insulators or arrestors have failed);
- An emergency crew restoring power to all customers but only making temporary repairs or isolating the deficiency (necessitating follow-up repairs, usually commencing the next day); or

- An emergency crew arriving on site and, after assessing the situation and making the area safe for the public and employees, determining that the scope of the repair is beyond that crew's capabilities and that construction or civil crews are required to fully address the situation (Figure 6).



Figure 6: shows a leaning distribution pole Grid Response crews attended to and forwarded for permanent reactive repair (2021)

The grid response function also addresses deficiencies in equipment or components that are identified in the course of planned activities and that require immediate attention. For example, a subset of deficiencies found from Toronto Hydro's Preventative and Predictive Maintenance programs are directed to grid response for immediate action on an emergency basis to address any unacceptable safety/public safety, environmental, or system reliability risks. This process is used to create a diverse mix of work to ensure 24/7 crew productivity and response time to emergency events as they arise.

Given the nature of the events that the grid response function attends to, the vast majority of its work is non-discretionary. Restoration efforts after power interruptions, for example, are expected to be expedient to minimize customer outage time and maintain system reliability. As previously noted, the DSC mandates timely responses to EMS calls. Therefore, the utility must respond to serious equipment deficiencies to mitigate potential public safety, environmental, and system reliability risks. Such deficiencies may include, for example, damaged poles that could collapse and harm members of the public or oil leaks from a transformer that could contaminate residential or environmentally sensitive areas (Figure 7).



Figure 7: shows an Overhead Transformer taken down by a falling tree, spilling oil onto the roadway and sidewalk (2022)

To assist with situational reporting requirements such as event clearances or estimated time of restoration updates and situational awareness, the grid response and dispatch logistics functions interact with the following Toronto Hydro systems: Outage Management System ("OMS"), Distribution Management System ("DMS"), Oracle Field Service Cloud ("OFSC"), Oracle Customer Care & Billing (i.e. Toronto Hydro's customer

information system or "CIS"), Geo Electrical Mapping Records Viewer ("GEAR"), GeoTab, Work Management Tool ("WMT"), Batch Request Tool ("BRT") for meter pinging, and Toronto Hydro's enterprise resource planning system ("SAP") for emergency maintenance work order creation.

3.1.3 Storm and Major Event Restoration

The grid response function also attends to outages and public safety hazards on major or significant event days,[2] including significant storm damage. Severe weather systems and large-scale events (e.g. loss of upstream supply from Toronto Hydro's transmitter Hydro One Networks Inc.) can necessitate significant crew efforts on a number of days each year. The effort is typically in response to widespread damage on the distribution system and power interruptions to customers. The largest of these events are referred to as "major events".

While severe weather and significant events are inherently unpredictable, any resulting increase in customer calls and system issues can produce a tangible increase in event volumes year over year. Severe weather such as high wind or freezing rain can result in fallen trees knocking down power lines (Figure 8), broken poles, and pole fires. During the 2018-2022 period, Toronto Hydro experienced seven major event days, with five occurring in the spring and summer of 2018, impacting a total of 624,000 customers. There was one major event day in July 2020, with wind gusts reaching 119km/h and impacting 54,000 customers. In May 2022, extreme weather resulted in a major event

[2] Major Event Days are defined in accordance with the IEEE 1366 Standard as: "a day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold value". The OEB's Electricity Reporting and Record Keeping Requirements defines a "Major Event" as an event that is beyond the control of the distributor and is a) unforeseeable, b) unpredictable, c) unpreventable, or d) unavoidable.

day impacting 142,000 customers. Table 3, below shows Extreme Weather events in the city of Toronto between January 2020 through March 2023.

Table 3: Extreme Weather (January 2020 through May 2022)

Event	Description of Impact
High Winds Storm (May 2022)	• 142,052 Customers impacted at its peak • 5 days to restore power to all customers
Flash Storm (August 2021)	• 20,000 customers impacted at peak • 2 days to restore power to impacted customers
Thunderstorm High Volume Event (July 2021)	• A line of thunderstorms with windspeeds in excess of 75 km/h. • 12,000 customers were impacted at its peak • Service restored for the majority of customers within 2 days
High Wind Event (April 2021)	• Wind expected to reach ~95hm/hr • 22,000 customers impacted at its peak • 1 day to restore power to impacted customers
High Wind Event (November 2020)	• Winds in excess of 100 km/h • Estimated 8000 customers impacted and 101 outages at its peak
Flash Storm (July 2020)	• Approximately 50-70mm of rain • 50,000 customers impacted at peak • Impacted customers restored within 2 days
Adverse Weather (January 2020)	• Approximately 60mm of rain, 5-15mm of ice and 90 km/h winds • 4900 customers impacted at its peak • Impacted customers restored within 3 days

Since 2012, there have been a total of 21 Major Event Days in Toronto Hydro's service territory and 81 percent have resulted from inclement weather, of which 57 percent occurred between March and August.



Figure 8: Crews respond to a fallen tree on power lines due to a wind storm event (2021)

During a storm, shift managers and dispatchers will support the event response by coordinating all available field resources to repair the damage and restore power, scaling up resource levels as required. A shift manager will assign team members to different areas of focus. For example, some dispatchers address customer calls and some dispatchers focus on field crew communications. Assigning dispatchers to more specific tasks during storm response allows for the more effective management of increased event and call volumes.

When there is a substantial influx of outage and hazard reports in a short period, duplicate events are likely. The dispatch logistics function also heavily focuses on ensuring the information in the work agenda is accurate, removing redundant events to ensure field resources are effectively used. For very large events such as the 2013 ice storm or the May 2022 weather event that caused tremendous, widespread damage, Toronto Hydro utilizes all available internal and external resources, which are funded through the

Emergency Response Program. In such situations, grid response resources are complemented by resources typically deployed for planned work, such as re-purposed design and construction crews to address widespread damage on the distribution system and power interruptions to customers.

Toronto Hydro's approach to Major Event Days and other incidents is largely driven by the need to ensure that critical infrastructure and services such as EMS facilities, transit, hospitals, and water pumping stations remain functional and to restore power to customers as quickly as possible. This approach is also reinforced by the need to mitigate risks associated with storm damage and major events to public and employee safety (e.g. from hazards posed by downed conductors or damaged poles), system reliability (e.g. to prevent unreasonably long durations of customer interruptions), and the environment (e.g. from failed transformers leaking oil).

4. PROGRAM COSTS

In 2025 Toronto Hydro requires $25.9 million in rate funding for Emergency Response Program, which represents an increase of $3.8 million over the last rebasing in 2020.

Over the 2025-2029 rate period, the utility expects the cost of the Program to increase by annual growth rate of 2.5 percent which is necessary to address the emergency response needs and deliver the customers outcomes enabled by this Program.

Table 4 provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for each of the Program's segments.

Table 4: Emergency Response Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Emergency Response	22.1	23.0	22.0	20.4	23.1	25.9	26.4	27.2	27.9	28.6
Total	**22.1**	**23.0**	**22.0**	**20.4**	**23.1**	**25.9**	**26.4**	**27.2**	**27.9**	**28.6**

4.1 Cost Drivers

Year-over-year variances in historical actual costs are primarily attributable to storm events.

Due to the nature of the events addressed by the Program, the costs incurred are completely demand driven and can vary from year to year, with Major Event Days and smaller storms as the major cost drivers.

Toronto Hydro determines its complement of grid response and dispatch logistics staff in accordance with the utility's obligations to meet emergency response requirements on a 24/7/365 basis. The utility continually monitors and optimizes complement and shift arrangements to ensure requisite resources are available to support the level of response and volume of work.

4.2 Cost Control and Productivity

4.2.1 Dispatch Logistics

Toronto Hydro's implementation of various technological solutions between 2019-2022 to improve event validation by dispatchers contributed to a decrease in average event volumes over the same period, which in turn helped the utility reduce truck rolls and save on deployment costs. Dispatchers interact with a number of systems throughout a

given shift to assist in validating a reported concern and deciding the appropriate course of action:

- Network Management System (OMS and DMS): Dispatchers log events to the OMS work agenda. In addition, dispatchers can confirm whether there is an outage at a customer's smart meter using NMS' Advanced Metering Infrastructure ("AMI") functionality. During emergencies, dispatchers use NMS to support damage assessment and wire guarding activities, as the system provides a view of all devices and asset types in the field from a single screen, facilitating the accurate determination of the devices impacted, customer counts, and boundaries to set event priority and send the event to the appropriate field resources.

- Oracle Field Service Cloud ("OFSC"): OFSC allows dispatchers the ability to view pending events, traffic, and real-time crew locations on a single display. This interface assists in logistical decision making, reducing crew travel time between events. Incoming smart dispatching functionality will factor in crew location, traffic, estimated duration, event priority, device type, and crew qualification when used for emergency dispatch functionality. Toronto Hydro also expects additional cost-savings and productivity improvements from the planned go-live of NMS-SAP integration in summer 2023. The utility's dispatchers currently create 20,000 emergency maintenance work orders per year. SAP integration will allow dispatchers to create an emergency maintenance work order directly from the NMS work agenda. This process improvement will streamline the day-to-day work order creation process for field crews to charge costs against when completing system events, resulting in considerable time savings annually and presenting an opportunity for dispatchers to take on additional duties during their shifts. In addition, OFSC provides a chat feature

where dispatchers and field staff can communicate electronically, which has the potential to mitigate phone queue wait times in high-volume scenarios and communicate important safety messaging to all electronic crews without the need for a phone interaction. Toronto Hydro expects to leverage future phases of OFSC to introduce a more automated, productive platform that can assign events to the most appropriate qualified resources.

- Batch Request Tool ("BRT"): Dispatchers use the BRT to confirm if there is voltage to a customer's meter using AMI functionality. All initial outage reports are validated with the use of BRT, allowing dispatchers to assign confirmed outages to crews in the field. If a customer is shown to have full power after pinging their meter, dispatchers correspond with the customer and reprioritize or cancel the event accordingly, optimizing the use of field resources.

- Geo Electrical Mapping Records Viewer ("GEAR"): Since a significant part of work under the Program involves attending to asset damage reports, such as wires down situations, dispatchers use GEAR to determine asset ownership in the field and confirm that Toronto Hydro is responsible for corrective or reactive actions. The consistent use of the GEAR viewer saves costly truck rolls in regards to issues involving non-Toronto Hydro assets such as telecommunications wires or customer-owned equipment.

- Work Management Tool ("WMT"): WMT is a database of all electronic system response reports, including pictures and files crews upload with their event clearances. In 2021, Toronto Hydro leveraged the OFSC implementation to enhance WMT to allow for enhanced documentation, photos and files to be uploaded.

Dispatchers use WMT to understand the historical context of a customer concern. For example, if there is a recurrent issue in a particular location or repeated inquiries from a customer, dispatchers are able to review previous event clearance details and possibly forward the event to another work group for follow up if the issue no longer falls under the Program. The enhancements allow for improved documentation when follow up or research is required.

To ensure optimal resource utilization during low event volume periods, dispatchers and crews attend to planned work that supports overall system health, such as planned customer isolations, inspections, and maintenance tasks.

Toronto Hydro dispatchers work on a shift schedule that the utility has optimized based on current staffing levels and to enable compliance with applicable legislative and regulatory requirements, as well as providing timely response to internal and external stakeholder concerns. In the event of a sudden influx of call and event volumes, a 24/7 standby complement is available to scale up and manage higher call and event volumes. This scalability allows dispatch logistics to generally handle a significant event in an end-to-end manner before having to engage the Disaster Preparedness Management program under Exhibit 4, Tab 2, Schedule 6.

4.2.2 Grid Response

Predicting the number and timing of system events, and the severity and frequency of adverse weather with a high level of accuracy is generally not practical. However, Toronto Hydro's capital investments through the System Renewal programs help mitigate the risk of asset failure by renewing assets in poor condition and improving

overall asset performance.[3] In addition, the utility's continuous improvement in engineering and the work of its standards committees, as well as preventative and predictive maintenance programs (including vegetation management and storm hardening) all contribute to the resilience of the distribution system. [4] Collectively, these efforts are expected to improve the overall resiliency of the distribution system and help alleviate cost pressures in the Program over the long term.

Toronto Hydro goes through a competitive bid process to tender out the operations in grid response function and ensure that costs for these services are in line with market rates. The nature of the services requires highly trained and experienced field workers who can efficiently and safely troubleshoot distribution system problems, identify the necessary repairs and execute the work under all weather conditions while working under pressure. Currently, work is split between two independent service providers. Each provider has crews working 24 hours, 7 days a week. To account for the ever-changing needs of Toronto Hydro's distribution system, the grid response function continues to assess and review the shift complements on an ongoing basis and adjusts schedules accordingly to balance performance with costs. Crews are also cross-trained and set up in a way to enable the combination of two trouble crews to complete reactive work as required and avoid the need to call in a standby construction crew on overtime, resulting in reduced costs.

When event volumes are relatively low, the grid response function assigns less urgent maintenance work under the Corrective Maintenance and Preventative and Predictive Maintenance programs to maximize labour utilization and improve system reliability. [5]

[3] Exhibit 2B, Section E6.
[4] Exhibit 4, Tab 2, Schedules 1-4.
[5] *Ibid*.

In addition, through the use of the systems discussed under Section 4.2.1, Toronto Hydro assesses and monitors the number of crews on shift throughout each day of the week to optimize available resources. For example, the utility staggers crew start and stop times and prioritizes events to increase the number of events responded to per crew shift.

4.3 Emergency Response Program Year-over Year Variance Analysis

2020 – 2021 Variance Explanation

Between 2020 and 2021 there was an increase of $0.9 million due to multiple high wind storm events over the months of March, May, August, October, and December.

2021 – 2022 Variance Explanation

Between 2021 and 2022 there was a decrease of $1 million. Compared to the previous year, 2022 had less severe and milder storm event days, with the exception of the May storm which resulted in a Major Event Day ("MED").

2022-2025 Variance Explanation

Between 2022 and 2025, costs in this segment are expected to increase by $3.9 million, or an average of $1.3 million per year due the increased cost of providing emergency services as a result of inflationary cost pressures including increased labour and vehicle costs. In addition, a new contract for external resources will become effective in 2025.

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $2.7 million, or an average of $0.7 million per year, to maintain the resourcing capacity and capabilities required to support the volume and complexity of work discussed above. If

Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various legal compliance risks and drawbacks, including:

- Potential non-compliance with the Distribution System Code service quality requirement for emergency response,
- Delayed responses to safety and environmental risks, which would increase customer and crew exposure to unsafe conditions and the potential for fines or penalties by federal, provincial and municipal regulatory bodies for failure to report and or mitigate environmental spills in a timely manner,
- Extended customer outage durations,
- More frequent and longer outage durations, adversely affecting the health of distribution assets and increasing the likelihood of more prolonged outages, and
- Delayed responses to urgent customer and stakeholder concerns.

DISASTER PREPAREDNESS MANAGEMENT

1. SUMMARY

Table 1: Disaster Preparedness Management Summary

Disaster Preparedness Management Program									
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Operational Optimization									
Segments: • Disaster Preparedness Management									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
6.0	5.5	4.9	1.3	1.8	1.9	1.9	2.0	2.1	2.2

The Disaster Preparedness Management program (the "Program") entails the implementation of a robust and comprehensive disaster preparedness framework for Toronto Hydro. The Program is comprised of activities to prepare for, respond to, and recover from disasters or large-scale emergencies (e.g. severe storms, major system/facility disruptions) at both the distribution system and corporate levels. It delivers the requisite governance, planning, and training that enables Toronto Hydro to mobilize and deploy its resources rapidly and effectively during and following disasters in order to mitigate the public safety, reliability, and financial risks that can materialize at such critical times. The Program also uses those same methodologies to prepare an effective response to internal disruptions of normal operations by identifying critical work and prioritizing the necessary supporting resources such as workspace, equipment, technology, people, etc.

As the largest city in Canada, Toronto is home to over 3 million people and 190,000 active businesses including the country's largest financial institutions, leading medical and

research facilities, educational institutions, major transportation hubs, and federal, provincial and municipal government offices. [1] In addition, the City frequently hosts events of regional, national, and international significance. Extended power disruptions within Toronto Hydro's service territory can have significant impacts on these important organizations and events, causing far-reaching social and economic consequences. In addition, with the energy transition leading to increased electrification—including the electrification of heating and transportation—as well as the widespread adoption of work from home and hybrid working models, it will be even more important for residents and businesses to have consistent and reliable access to electricity.

Accordingly, it is essential that Toronto Hydro respond quickly and effectively to minimize disaster-related power disruptions. The urgency of this need is further heightened given the growing likelihood and intensity of extreme weather events and deliberate threats (e.g., cyber-attacks).

This Program is a continuation of the activities described in the Disaster Preparedness Management Program from Toronto Hydro's 2020-2024 Rate Application.[2] The Program is necessary to ensure the continued implementation of a comprehensive and industry-leading disaster readiness program that satisfies customer expectations, maintains adequate service levels, ensures public and employee safety during and following disasters, and enables the utility to comply with applicable legislative and regulatory requirements.

[1] City of Toronto, *Toronto Economic Dashboard, Labour Demographics*, online: <https://www.toronto.ca/city-government/data-research-maps/toronto-economy-labour-force-demographics/toronto-economic-dashboard/>.
[2] EB-2018-0165, Exhibit 4A, Tab 2, Schedule 6.

2. OUTCOMES AND MEASURES

Table 2: Program Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: o Establishing and communicating accurate estimated outage restoration times for disaster incidents; o Coordinating effectively with impacted customers, particularly those identified as key customers; and o Restoring customers efficiently and effectively, using all available internal and external resources (e.g. through the utilization of mutual aid assistance as necessary).
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (ex. SAIDI, SAIFI, FESI-7) by: o Responding efficiently (including through the effective utilization of available resources) to major disruptions; o Reducing response times by conducting regular assessments to understand the utility's exposure to hazards and align preparatory activities based on expected event outcomes; o Maximizing and expanding potential resources for disaster response and restoration by building mutual assistance relationships with external partners; and o Using digital and physical damage assessment capabilities to enable more effective and informed prioritization of restoration efforts, in alignment with industry best practices. • Ensuring compliance with Section 39 of the *Electricity Act, 1998* and Chapter 5, Section 11 of the Independent Electricity System Operator ("IESO") Market Rules that aim to alleviate the effects of an emergency on the electricity system by preparing and implementing emergency plans. • Ensures minimal impacts following an internal disruption by implementing a corporate business continuity program to assess and prioritize supporting resources for critical work process.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF"), by: o Responding to disasters in a timely manner and mitigating the public health and safety risks.

	○ Adjusting the number of staff on duty to maintain a perimeter for safety or risk hazards following a disaster event. ○ Providing clear role assignment and training with respect to disaster and emergency incident response. ○ Ensuring all employees know their role and expectations, so that the appropriate actions can be taken to limit the scope and duration of an incident.



Figure 1: Damage caused by derecho wind storm in May 2022

3. PROGRAM DESCRIPTION

Disruptions and disasters are unpredictable in timing or scope, but are virtually certain to affect a distribution system as large and complex as that of Toronto Hydro. The Program aims to increase the reliability of grid operations by implementing mechanisms to more effectively and efficiently restore operations in response to disaster events and

disruptions. This is consistent with legislative and regulatory requirements regarding market participants' obligations to prepare and plan for disasters.[3]

Customers also expect the utility to deliver services safely and provide accurate and timely communications of restoration times during outages. However, providing electricity distribution services to a city as large and complex as Toronto already presents a host of operational challenges even under normal operating conditions. These challenges are drastically amplified during events such as severe storms, pandemics, and critical system disruptions. Table 3 below outlines several recent examples of incidents that exceeded the utility's standard response practices and triggered the deployment of additional planning and response resources under the Program.

Table 3: Examples of Recent Events in the City of Toronto

Event	Description
COVID-19 Pandemic Response (Mar 2020 – Oct 2022)	• A Level 2 Emergency Declaration led to the establishment of an Incident Management Team and supporting response infrastructure in March 2020. • Toronto Hydro needed to quickly pivot to remote and social distancing work for all employees when lockdowns began. • Personal protective equipment (PPE) including masks, face shields, disinfectant wipes needed to be procured, warehoused and distributed to protect working staff. • Social distancing rules prevented shared vehicle use, increasing mileage and vehicle utilization. • All employees, vendors and contractors were directly impacted by necessary measures. • Zero cases of at-work COVID-19 transmission were recorded.

[3] Independent Electricity System Operator Market Rules for the Ontario Electricity Market, Chapter 5, Section 11.

Event	Description
Derecho Wind Storm (May 2022)	• Wind storm struck in a line from southern Ontario to Quebec City. • High winds of 120+ km/h were recorded at Pearson International Airport. • ~142,000 Toronto Hydro customers experienced an outage at peak. • 98% of customers were restored within 24 hours, 99% after 48 hours.
Mutual Aid Deployment to Ottawa (May-Jun 2022)	• Hydro Ottawa ("HO") requested assistance on May 23 through the Ontario Mutual Aid Group ("OnMAG") following the May Derecho Wind Storm. • HO experienced 110,000 customer outages. • Following the stand-down of internal response, Toronto Hydro deployed 26 employees on May 25 to aid HO's restoration efforts. • Deployment continued until June 5.

Climate change is a significant factor influencing Toronto Hydro's planning and operations. Scientists worldwide overwhelmingly agree that the planet is warming. [4] A warmer climate is expected to lead to more frequent and severe extreme weather events. Toronto Hydro also expects an increase in deliberate hazards including cyber-attacks and transnational threats to critical infrastructure Both weather incidents and deliberate hazards can rapidly escalate in scope, cross jurisdictional lines, and result in significant losses. In this regard, the risk exposure of Canadian utilities – particularly those in the country's largest City – is a complex and urgent issue that could materialize in far-reaching social and economic consequences at the local, regional, and national levels. In this context, it is imperative for Toronto Hydro to implement a comprehensive disaster

[4] Toronto Hydro engaged Stantec for a report titled Climate Change Vulnerability Assessment Update, which was completed on November 18, 2022.

preparedness framework that underpins its multi-faceted approach to planning, response, operations, and recovery.

Temperatures in Toronto are expected to increase in the coming decades. For example, by 2050, the average number of daily maximum temperatures of 25°C are expected to occur 110 times per year compared to 86 times per year currently. A warmer climate is expected to lead to more frequent and severe extreme weather events. In addition to extreme weather events, Toronto experiences a wide range of weather conditions that may not be classified as extreme, but nevertheless have the potential to adversely affect the distribution system at various times during the year including heat, high winds, heavy rainfall, and heavy snowfall. As customers come to rely more on electricity to meet their energy needs, it will become even more important for Toronto Hydro to have systems in place to ensure reliability and that power is restored quickly following storms.

In addition, the COVID-19 pandemic highlighted the potential impact of non-grid events on Toronto Hydro's capabilities. The pandemic significantly affected normal operating procedures of in-office work and close-contact working conditions in the field. A robust incident management system and business impact analyses allowed Toronto Hydro to efficiently pivot to a work-from-home system and social distancing measures in the field. Toronto Hydro continued to reliably distribute electricity to its customers while protecting the safety of its employees, contractors, and the public.[5]

[5] An incident management system is comprehensive system for incident management that can be used to coordinate a structured incident response of any scale. The Province of Ontario provides a standard Incident Management System (IMS 2.0), which has been implemented by Toronto Hydro. Government of Ontario, *Incident Management System (IMS) Guidance Version 2.0* (March 31, 2021) online: <https://files.ontario.ca/solgen-ims-guidance-version-2.0-en-accessible.pdf>.

Overall, the Program enhances the utility's capacity for effective planning, communications, and response activity coordination in anticipation of, during, and following disasters that result in significant and widespread supply interruptions and threats to public safety. It does this through two complementary disciplines: emergency management ("EM") and business continuity ("BC"). Planning under the Program is calibrated to reflect Toronto Hydro's current risk profile and relevant standards and best practices.[6]

The Program consists of the following three functions:

1. Hazard and Risk Profiling & Disaster Planning;
2. Program Implementation and Evaluation; and,
3. Maintenance and Improvement.

Each function is summarized below.

3.1 Hazard/Risk Profiling & Disaster Planning

Hazard or risk profiling and disaster planning is the primary and largest function of the Program. This component encompasses Hazard Identification Risk Assessment, Business Impact Analysis, Response Planning, and External Partnerships Management.

3.1.1 Hazard Identification Risk Assessment ("HIRA")

HIRA entails the identification of specific hazards and risks to Toronto Hydro's operations. Through HIRA, the utility determines how frequently such hazards can materialize, the

[6] The Program follows the Canadian Standards Association's Z1600 Emergency and Continuity Management Program (CSAZ1600) standard. CSAZ1600 outlines requirements for emergency and continuity management programs that address disaster prevention, mitigation, preparedness, response, and recovery. Canadian Standards Association, *Emergency and continuity management program,* (2017).

severity of the potential impact, and which hazards pose the greatest threat to distribution system operations. HIRA findings enable the utility to prepare for worst-case scenarios and most likely risks, and efficiently allocate resources to hazards that may occur within its service territory.

Toronto Hydro has fully operationalized a sustainable enterprise-wide HIRA framework. This framework has improved the utility's understanding of its up-to-date hazard exposure profile and has enabled the development of hazard risk models by correlating anticipated external events (e.g. weather forecasts) to power system impacts, enhancing operational decision-making. For example, thanks to this system, Toronto Hydro's ability to anticipate and respond to weather events has improved during the 2020-2024 rate period, through the use of dedicated forecasting tools. In addition, the implementation, training, and use of incident management system procedures has allowed for a more effective response architecture when emergencies or incidents occur.

3.1.2 Business Impact Analysis ("BIA")

Through BIAs, the utility predicts the consequences of a temporary loss of key business functions and gathers the information needed to develop business recovery strategies. BIA results show how operational disruption will impact the reliable distribution of electricity and enables Toronto Hydro to identify which key services, facilities, and equipment are of the highest criticality and what resources it needs to secure to ensure key services can continue at acceptable levels.

In 2020, Toronto Hydro initiated an expansion into business continuity planning ("BCP"), which included hiring qualified staff and securing a BCP software platform. The utility is currently conducting initial BIAs for all departments, which will allow the prioritization of

critical processes and implementation of a standardized approach to BCP across the entire organization. This will allow Toronto Hydro to monitor for gaps and plan remediation, and test its capabilities in the coming years. By the end of 2024, Toronto Hydro will have a full business continuity management program with BIAs completed and reviewed on annual cycles, feeding to updates of BCPs and validated by testing and exercises covering all aspects of Toronto Hydro. This Program will ensure Toronto Hydro has a robust response infrastructure to manage internal disruptions and complement the Emergency Response program discussed in Exhibit 4, Tab 2, Schedule 5.

3.1.3 Response Planning

Toronto Hydro adopts an all-hazards approach to disaster preparedness, which involves the identification and integration of common disaster response elements across all hazard types (e.g. severe storms, cyber-attacks, large-scale system failures, etc). The utility accomplishes this through the use of the Ontario Incident Management System approach to emergency management, which includes recommendations on how personnel, facilities, equipment, procedures, and communications should be coordinated during an incident. This approach increases planning efficiency, improves the utilization of internal resources, and ensures a standardized and efficient response if and when the utility must react rapidly. It also streamlines processes and improves the utility's ability to focus on unique response requirements for specific hazards and risks.

The Program produces and houses key disaster preparedness frameworks, including planning documents covering corporate disaster preparedness governance, emergency management, hazard-specific planning in respect of system damage and restoration strategies, Toronto Hydro's role in participating in a province-wide, black-start restoration of the provincial grid, planning for the management of supply chain, purchasing, and

material distribution during emergencies, and the utility's approach to effectively engaging with customers and external stakeholders during emergencies.

In addition, public authorities and organizations hosting events or responding to situations in the city frequently approach Toronto Hydro to provide assurance in the form of contingency plans for specific events (e.g. the 2019 Toronto Raptors victory parade, support for mass vaccination clinics in 2021-2022, "trucker protests" blockading downtown areas in February 2022) that bring together thousands of attendees. Each of these events and situations is unique in nature, requiring custom response plans that are tailored in scope and approach relative to the existing grid emergency plans.

3.1.4 External Partnerships

The utility collaborates closely with electricity sector partners (e.g. Ontario Power Generation, Hydro One Networks Inc., the Independent Electricity System Operator, Electricity Canada) to ensure consistent response and collaborative restoration.

Toronto Hydro is an active participant in the working groups of the departments, agencies, and corporations ("DACs") of the City of Toronto, contributing to both the Extreme Winter Weather Working Group and the Extreme Heat Emergencies Working Group. This work highlights the foundational nature of the utility's line of business, and how critical its resiliency is to the social and infrastructure work the other DACs conduct, as without power they cannot effectively operate.

In addition, through mutual assistance ("MA") agreements with other utilities, Toronto Hydro has access to "at cost" crews, equipment, supplies, or expertise following a disaster. Toronto Hydro is an active member of the North Atlantic Mutual Assistance

Group and a founding member of the Ontario Mutual Assistance Group, which enables the utility to leverage assistance from a number of neighbouring jurisdictions when the need arises.



Figure 4: Repair Work by Toronto Hydro Crews Deployed to Hydro Ottawa Territory (May 2022)

The Program includes planning for the deployment and onboarding of MA crews. MA can give rise to operational challenges and requires significant planning and coordination to be leveraged safely and efficiently. To ensure the safety of external crews assisting Toronto Hydro during disasters, the utility needs to undertake significant research, negotiation, and planning to implement the necessary MA arrangements and derive the maximum benefits of such arrangements. Jurisdiction-specific legislative and regulatory regimes, along with different operating standards and system configurations, can limit the host utility's ability to take full advantage of MA within a short timeframe. While the

adoption of the common Utility Worker Protection Code has simplified some matters, operational complications associated with differences in safety practices, construction standards and restoration practices and lack of familiarity with the requesting utility's system may result in MA crews being assigned simpler, non-critical tasks, which ultimately leads to longer restoration timelines and prevents the full utilization of highly qualified resources. Furthermore, the difficulties encountered in the deployment of mutual aid resources can lead to an increase in overall restoration costs without proper advance planning and coordination. During the 2025-2029 plan period, the utility will update and expand on its plan for sourcing, onboarding, and utilizing non-Toronto Hydro crews following a potential disaster event.

3.2 Program Implementation and Evaluation

This Program function entails the delivery of required workforce training and the execution of approved plans and processes during a disaster incident. The Program provides employees with training on updated disaster preparedness frameworks and processes, emergency roles, and incident management. It also integrates emergency response and preparedness requirements into corporate IT systems. This shows Toronto Hydro's commitment to plan ahead and ensure resiliency is integrated into core processes and systems.

The Program evaluates ongoing disaster planning and procedures through testing, exercises, and reviews of actual events (e.g. through after-action reviews and Major Event Day reporting). Toronto Hydro conducted an after-action review after an incident to gather the lessons learned from direct experience and enable their incorporation into business practices. Relevant incident commander(s) then draft and signed off on an after-action report ("AAR") and present it to the Disaster Planning Forum ("DPF") at the next

opportunity.[7] Smaller scale actions resulting from the AARs are implemented without delay. For large scale actions, recommendations are made to the DPF members to determine if large-scale changes to corporate practices are necessary.

In addition, using simulation techniques (e.g. drills, system tests, etc.), the utility is able to identify gaps in its disaster planning including with respect to training, internal and external coordination, communications, and resource availability. For example, since 2020 Toronto Hydro has:

- Participated in a continent-wide industry response validation (GridEx VI 2021);[8]
- Conducted 3 rounds of incident management software (Disaster LAN) exercises to practice and validate knowledge of the tool across the corporation;
- Used Disaster LAN to manage roll-out of Utility Work Protection Code in 2021/22 across Toronto Hydro; and
- Validated and tested the incident management system processes and capabilities in numerous potential and actual disruptions.

During the 2025-2029 rate period, Toronto Hydro expects to build and enhance a comprehensive exercise and testing program for disaster preparedness. It will continue to design and conduct disaster simulations and tests that identify program gaps with a view to informing adjustments and improvements in the overall disaster planning framework and supporting plans and procedures.

[7] The Disaster Planning Forum is a forum for leadership from across Toronto Hydro to review and provide feedback on the utility's Disaster Preparedness Program.
[8] This is a voluntary continent-wide exercise is focused on cyber- and infrastructure-attacks on critical grid components, and participants' capabilities to respond and cooperate. The IESO coordinated participation among Toronto Hydro and other Ontario participants. Toronto Hydro intends to participate in GridEx VII in November 2023.

3.3 Program Maintenance & Improvement

This function consists of reviewing all elements of the Program including hazard and risk assessment, planning, business continuity planning, and exercises and testing, in order to maintain a current framework that meets the utility's needs and risk profile. Given the unique characteristics of disaster events and the need to respond efficiently and effectively in each case, dedicated resources and processes are required in order to research, identify, evaluate, and implement adjustments and enhancements to existing practices.

Toronto Hydro aims to maintain and improve the effectiveness of the Program on an ongoing basis through the use of both internal and external reviews and assessments. For the 2025-2029 rate period the utility intends to continue its systematic reviews of the Program by gathering feedback from internal personnel involved in disaster response and impacted stakeholders through the previously discussed AAR process.

In addition, the Program will ensure continued alignment with applicable legislative and regulatory requirements and industry standards. Toronto Hydro intends to align its business procedures with the tenets of the Canadian Standards Association Z1600 body of guidelines, which provide best practices for emergency and continuity management. Toronto Hydro currently aligns to 88 percent of Z1600 components and has a target of increasing alignment to above 95 percent by the end of 2023. This is an ongoing effort that will require continuous programmatic maintenance. To date, the utility has observed an improvement in incident response across departments through greater familiarity with the incident management system. This is a direct result of the Program's training and information sessions and efforts to promote habitual conformance to standards when responding to disruptions. A strong example of the effectiveness of this work was the

rapid and relatively smooth response by Toronto Hydro management and operations to the storm of December 22-24, 2022. The utility declared a Level 2 Emergency in advance of the forecasted heavy winter weather and the incident management team was rapidly rostered and deployed to manage the event, while Emergency Response and Control Centre Operations ramped up operations to provide enhanced coverage.[9]

Where appropriate, Toronto Hydro uses third-party consultants to ensure that its disaster planning processes are robust and effective. Accordingly, in addition to training program development and facilitation, the utility requires funding to retain auditors and emergency management consultants to periodically evaluate and provide recommendations as the Program evolves.

4. PROGRAM COSTS

In 2025 Toronto Hydro requires $1.9 million in rate funding for the Disaster Preparedness Management Program, which represents a decrease of $4.1 million over the last rebasing in 2020.

Over the 2025-2029 rate period, the utility expects the cost of this Program to increase by annual growth rate of 4.4 percent which is necessary to address the disaster and disruption planning needs and deliver the customers outcomes enabled by this Program.

[9] For more information on the latter two functions, please refer to Exhibit 4, Tab 2, Schedules 5 and 7.

Table 4: Disaster Preparedness and Management Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Disaster Preparedness Management Program	6.0	5.5	4.9	1.3	1.8	1.9	1.9	2.0	2.1	2.2
Total	**6.0**	**5.5**	**4.9**	**1.3**	**1.8**	**1.9**	**1.9**	**2.0**	**2.1**	**2.2**

For 2020-2022, many non-routine operational and emergency expenses related to the COVID-19 response were attributed to the Program. These expenses are itemized in Table 1 and include:

- Incremental facilities, vehicle and equipment signage;
- Personal protective equipment (PPE);
- Additional health services resources to support contact tracing and monitor employee quarantine, testing, etc.
- Equipment rental including trailers and vehicles to support the ongoing execution of operating and capital programs while ensuring social distancing and the safety of our employees;
- Incremental facility costs such as increased cleaning services, supplies, trailer rentals, etc.
- IT support and incremental costs related to ensuring business continuity including the transition to and working from home (e.g. conference call WebEx, support to the control room, etc.);
- Unproductive time due to employee quarantine;
- Support to the implementation of customer relief programs including the new Time of Use rates for customers during the pandemic;
- Incremental outage costs and time incurred resulting from the execution of work during a pandemic (e.g.: compensation to customers such as gift cards, etc.); and
- Costs related to the administration of vaccines to employees.

Table 1: Itemized list of Corporate Costs attributed to DPM Budget

COVID-19 response costs	2020 Actual	2021 Actual	2022 Actual
Facilities modification (physical distancing measures, cleaning, protective equipment, etc.)	2.1	2.7	3.2
Health services support (testing, contact tracing, etc.)	0.6	0.7	0.2
Business continuity and remote work enablement	0.5	0.1	0.2
Lost productivity due to employee sickness and quarantine	0.3	0.1	0.2
Time of Use (TOU) implementation costs	0.1	-	-
Miscellaneous	0.3	-	-
Total	**3.9**	**3.6**	**3.8**

4.1 Cost Drivers

The variances are attributable to the following factors:

- **Reduction in unplanned COVID-19 costs:** As discussed above, costs incurred by Toronto Hydro as a result of the COVID-19 pandemic were attributed to the Disaster Preparedness Management budget, resulting in the appearance of significantly higher Program costs for the years 2020-2022.
- **Increase in net payroll/labour costs and employee expenses:** These costs are associated with the recruitment, training, and development of employees who are skilled, knowledgeable, and qualified in the fields of emergency management, business continuity, and utility operations. Effective development and sustainment of the Program require dedicated employees with specialized skills and knowledge in utility operations and emergency management. Due to a period of employee turn-over the Program has been operating with reduced staffing levels throughout 2022 and 2023. The utility plans to restore staff levels, which will result in concurrent increases in payroll costs.
- **External testing and assessment costs:** Ongoing evaluation through testing and exercises provides insight into the effectiveness of the Program. The consulting

costs for the 2025-2029 rate period are associated with external auditing and benchmarking to maintain the Program's efficacy and continued alignment with industry best practices. This portion of the budget will also be allocated for conducting large scale emergency response exercises across the utility.

4.2 Cost Control and Productivity Measures

The Program aims to maintain an up-to-date and robust utility-wide disaster preparedness framework while utilizing cost control and productivity initiatives to manage costs. For example, Program staff proactively review administrative costs, such as contracted software access, to ensure that adequate benefits are derived to justify the expense.

In addition, the Program facilitates efficient use of internal resources with a view to controlling external labor costs and aims to leverage existing emergency response capabilities within the utility by assigning Toronto Hydro employees to emergency functions. The Program trains employees on the utility's emergency structure and the emergency roles they will need to fulfill to assist with system operation and restoration. Finally, in partnering with other utilities via MA agreements, Toronto Hydro has access to "at cost" crews, equipment, supplies, and expertise following a disaster event. These initiatives enable the utility to significantly and rapidly increase the number of resources available for disaster response without an increased reliance on external resources and other labor costs.

Since 2020, Toronto Hydro has continued to utilize a number of tools, processes and related improvements in support of Program execution during actual events, including:

- Full utilization of the Ontario Incident Management System, which is the response system used by the vast majority of responders in the Province. The adoption of this system positions Toronto Hydro for collaborative response with other utilities (e.g. Enbridge), public safety organizations (e.g. Toronto Police, Fire, and Paramedic Services) and municipal and provincial governments. This provides the utility with access to all levels of emergency management and response organizations (e.g. municipal public works and forestry crews) during disaster response;
- Implementation of statistical and comprehensive damage assessment tools aimed at enabling more rapid and effective estimation of restoration times following a disaster event. This increases Toronto Hydro's understanding of which areas of the system have been most significantly impacted and require the most immediate attention, enabling the utility to plan its resource allocation more effectively, focusing restoration efforts on areas requiring immediate response and those which will most positively impact the greatest number of customers and the impacted community; and
- Use of dedicated and deep weather forecasting feeds that provide an enhanced view on potential storm events, a primary cause of disruptions to grid operations. Daily updates on weather conditions and modelling predictions allow Toronto Hydro to be proactive in resource planning (i.e. placing response crews on standby).

4.3 Disaster Preparedness Management Program Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

Program costs decreased by $0.5 million from 2020 to 2021 due to a reduction in COVID-19 costs, namely the procurement, warehousing and distribution of PPE and other health measures, and a decrease in compensation costs.

2021 – 2022 Variance Explanation

Program costs decreased by $0.6 million from 2021-2022 reduction of headcount and consulting costs which was partially offset by an increase in the COVID-19 response costs.

2022 – 2025 Variance Explanation

Between 2022 and 2025, costs in this segment are expect to decrease by $3 million, or an average of $1 million per year due to:

- ending COVID-19 response and commensurate spend;
- This is partly offset by:
    - inflationary pressures; and
    - Increased headcount to support improving and implementing the functions of the Program.

2025 – 2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $0.3 million, or an average of $0.1 million per year, to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work discussed above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks and drawbacks, including:

- Reduced disaster preparedness and response activities, potentially leading to longer outage restoration times during disaster events;
- Adoption of an ad-hoc, reactive approach to disaster management (compared to a modern, proactive, systematic approach that includes ongoing risk/hazard assessments) that will prolong disruptions, increase emergency response costs, and overall expose customers to worse reliability and customer service levels;
- Reduced ability to adequately perform drills and testing on current disaster frameworks;
- Reduced ability to retain internal expertise required to continuously improve the Program and bring it in line with industry best practices;
- Reduced ability to provide essential disaster preparedness training to employees; and
- Potential impediment of the utility's efforts to render its distribution system more responsive and resilient.

CONTROL CENTRE OPERATIONS

1. OVERVIEW

Table 1: Control Centre Program Summary

Control Centre Program									
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Customer Focus, Public Policy Responsiveness									
Segments: • Control Centre Program									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
7.6	6.0	6.5	7.4	7.9	8.3	9.0	9.5	10.0	10.5

Toronto Hydro's Control Centre Operations program (the "Program") facilitates the safe and reliable operation of the utility's distribution grid through real-time system control and monitoring activities on a 24/7, 365-day basis. The Program coordinates system switching and restoration work through the utility's Control Centre to mitigate the effects of outages on customers and to enable safe load transfers for capital and maintenance work. The Program further leverages the Control Centre to monitor the flow of electricity and asset performance across Toronto Hydro's distribution system to provide real-time information and system condition data for future use in system planning activities. The Control Centre plays a critical role in enabling and supporting the growth of the utility's distribution system and ensuring that core operational services continue to be delivered in an efficient and reliable manner. The Program includes the following functions:

- **Distribution System Operations:** Real-time, 24/7 operation of the distribution grid to monitor system conditions, respond to outages, enable field crews to safely work on the distribution system, and coordinate operations with third parties such

as Hydro One Networks Inc. (Toronto Hydro's transmitter), and the Independent Electricity System Operator ("IESO");

- **Work and Outage Scheduling/Coordination**: Review and approval of work on the distribution system and scheduling system outages or work to minimize system and customer impact;
- **Grid Analytics**: Reliability reporting and grid analysis to monitor risks, performance, and project design of approved construction;
- **Supervisory Control and Data Acquisition ("SCADA") System Maintenance and Support**: Maintenance, configuration and troubleshooting of the utility's SCADA system, which enables power system controllers to monitor and operate distribution system equipment remotely and in real time; and
- **Energy Centre**: The operation of Toronto Hydro-owned energy storage systems and the monitoring of grid impacts from customer-owned distributed energy resources.

The Program is a continuation of the activities described in the Control Centre Operations program in Toronto Hydro's 2020-2024 Rate Application.[1] The utility expects the size and scope of the Program to evolve as the nature and needs of distribution system users (such as load, electricity generation, and storage customers) change in accordance with broader industry preferences and trends as part of the energy transition. Toronto Hydro accordingly plans to increase the workforce capacity of the Program to modernize its Control Centre functions during the 2025-2029 rate period.

[1] EB-2018-0165, Exhibit 4A, Tab 2, Schedule 7.

2. OUTCOMES AND MEASURES

Table 2: Control Centre Operations Program Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: o Responding to system disruptions on a 24/7/365 basis and, in conjunction with field crews, taking the necessary actions to restore service in a safe and expedient manner; o Supporting and enabling the successful execution of the distribution system's capital and maintenance investment programs; o Maintaining the integrity of the registry database that pertains to system asset quantity and type, which is used for planned and reactive distribution system work; and o Ensuring compliance with all legislative and regulatory requirements related to grid emergency preparedness and business continuity, including emergency preparedness requirements outlined in Section 39 of the *Electricity Act, 1998* and IESO's Market Rules relating to emergency preparedness planning and system restoration planning.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety objectives measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by: o Providing seamless visibility over the distribution system, including load management and control over inadvertent energizing of equipment; o Administers application of the Utility Work Protection Code, which is a critical tool for eliminating electrical hazards for working on distribution plant; and o Ensuring compliance with electrical distribution safety regulations through timely reporting of serious electrical incidents involving Toronto Hydro infrastructure.

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: o Receiving and responding expeditiously to trouble calls from customers and/or external stakeholders; o Maintaining the capability to effectively manage, prioritize and resolve multiple concurrent system issues impacting customers; and o Providing relevant and timely outage information for customers, such as estimated outage restoration times and other situational information relating to system outages.
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy objectives by ensuring compliance with: o Emergency response-related service quality requirements of the Distribution System Code ("DSC") by ensuring the utility responds to emergency calls within sixty minutes, 80 percent of the time;[2] o DSC requirements governing the connection and integration of distributed energy resources to the distribution system through the development and implementation of necessary tools and processes; and o Electricity Reporting and Record Keeping Requirements relating to Major Event Day reporting by efficiently communicating with external and internal parties, prioritizing system alarms, external and internal reports, and dispatching resources effectively.

3. PROGRAM DESCRIPTION

3.1 Control Centre Functions

3.1.1 Distribution System Operations

The Control Centre is responsible for the safe and efficient operation of the distribution system. This includes monitoring the status and operational state of the distribution system on a 24/7/365 basis. Power system controllers maintain a real-time model and

[2] *Distribution System Code* (August 2, 2023).

record of switch positions, device states, power flows, loading, work-in-progress, trouble alarms and abnormal system events across all 1,700+ circuits.

To support these functions, power system controllers utilize a wide range of processes and specialized tools, such as directly opening and closing remotely operable switches to redirect the flow of electricity, instructing field crews with respect to the operation of locally operable switches, and administering the Utility Work Protection Code ("UWPC") to ensure that work on, or in proximity to, Toronto Hydro's infrastructure can be conducted safely. Power system controllers are responsible for identifying the necessary steps to safely complete the work and minimize interruptions to customers, instructing field crews regarding the execution of these steps, and maintaining records of which steps have been completed and which workers are actively working on the system.

Between 2018 and 2020, UWPC was implemented across Toronto Hydro. UWPC implementation was a company-wide strategic initiative led by the Control Centre team to adopt the provincial standard work protection code. It involved process development, modifications to core operating platforms, and the training of all power system controllers and electrical field workers. Previously, Toronto Hydro utilized its own unique work protection code. The purpose of this initiative was to align Toronto Hydro's practices more closely with those of other Ontario utilities and with provincial Electrical Utility Safety Rules. This alignment has reduced barriers to mutual aid, reduced onboarding requirements for crews to work on Toronto Hydro's distribution system, and mitigated compliance risks.

Other processes administered by the Control Centre include the preparation of switching sequences and the issuance of "hold-offs." Switching sequences are documented as

"Order to Operate" ("OTO") safety documents. Each OTO is comprised of a list of switching instructions that enable operations crews to safely transfer customer load and establish suitable work protection over a specified range of system devices. A hold-off is a condition applied to a device by the controlling authority that prevents equipment operations for the duration of time that a field crew is working in proximity to Toronto Hydro's infrastructure. Power system controllers record the location of workers within proximity of electrical equipment (e.g. working on energized apparatus) to limit the possibility that other concurrent activities may increase the risk of equipment damage. Application of hold-offs for certain activities are a requirement of the Electrical Utility Safety Rules and Toronto Hydro's work procedures, and failure to apply hold-offs can result in equipment damage and create extended outages should an incident occur in the physical or electrical proximity to the work site.

The Control Centre also plays a significant role with respect to outage restoration. When a feeder circuit breaker trips, the Control Centre is notified immediately through the SCADA system. Power system controllers take immediate action to isolate the issue, restore power where possible by switching to alternate supplies, coordinate with grid response crews to identify the specific location of the fault, make repairs, and plan the final restoration. The Control Centre will relay known situational information such as outage boundaries, numbers of customers affected, and estimated restoration times to the Communications and Public Affairs team for dissemination to the public.[3] Similarly, the Control Centre is the direct point of contact for the IESO and Hydro One in situations where issues on the transmission system impact supply to Toronto Hydro's system, or for the coordination of restoration efforts following a major disruption to the provincial electricity grid.

[3] Exhibit 4, Tab 2, Schedule 18.

The Program relies on highly sensitive and secure systems that can only be accessed by authorized individuals who are physically located at the designated facilities. By the end of 2023, Toronto Hydro will have two fully functional Control Centre facilities upon completion of the Control Operations Reinforcement Program as described in the utility's 2020-2024 rate application.[4] Each of these facilities is designed to be capable of supporting full operations for an indefinite period of time, ensuring that the Control Centre will maintain full capability even in the event that the alternate location is unavailable due to unanticipated circumstances. Such circumstances could include a fire in the building or in the immediate vicinity, flooding, civil unrest, extreme traffic congestion, or any other situation that prevents or constrains access to a Control Centre facility or otherwise impedes operations. This arrangement will also further mitigate operational risk in the event of another pandemic that necessitates physical distancing or restrictions on interpersonal contact. The additional Control Centre space will also support the delivery of training programs and enable the maintenance of IT hardware and software assets and facility systems with minimal interruption to 24/7 operations.

In the longer term, the increased Control Centre capacity will provide flexibility to the future expansion of Toronto Hydro's real-time operational capabilities in scale and scope. For example, such an evolution could be necessary due to a significant increase in the scale of the distribution system resulting from customers' drive for electrification and decarbonization, or as an outcome of potential future developments in public and regulatory policies and various IESO engagements focused on market renewal and grid innovation. Under the scenarios that are currently being considered, Toronto Hydro could have a need to provide new real-time operational services related to energy management, market operations and distributed energy resource management. The

[4] EB-2018-0165, Exhibit 2B, Section E8.1.

utility does not anticipate that the implementation of the alternate Control Centre facility will have a material impact on ongoing operational costs under the Program.

3.1.2 Work and Outage Coordination

The Control Centre acts as a central authority for the operational assessment of designs, scheduling, and coordination of work on the distribution system. All construction work involving modifications to the distribution system is submitted to the Control Centre for review. Control Centre engineers and technicians consider the operational impacts and safety of the proposed designs and provide feedback and approval. Prior to work initiation, execution groups also submit work requests to the Control Centre for planning and coordination purposes. This information is used to develop a plan that eliminates conflicts between jobs, identifies synergies (e.g. the grouping of work requiring similar isolations to reduce the number of switching activities), and allows the work execution groups and the Control Centre to coordinate and optimize the use of shared field switching resources.

The Control Centre is also responsible for planning service isolations and restorations at the request of customers who require these services to safely work on their electrical systems.

3.1.3 Grid Analytics

The Control Centre analyzes system performance, calculates reliability statistics, reviews outage restoration performance, and plays a role in processing system record changes following the completion of work in the field. In addition, Control Centre engineers and technicians maintain the outage reporting and tracking system, which stores data related to outages, including impacted devices/circuits, the duration of customer outages, the

number of customers impacted, and the restoration sequence. From this database, the team compiles system performance statistics for reporting to internal and external stakeholders. The group also conducts in-depth reviews of outages on a case-by-case basis to assess performance and identify continuous improvement opportunities.

Toronto Hydro's distribution grid is in a state of perpetual change as new customers connect to the system and capital projects make modifications to the permanent physical design and configuration of the grid. The Control Centre requires access to the most current information in order to effectively and safely carry out its work. Therefore, the Program plays an important role in ensuring that system records are consistently and expediently updated by maintaining a real time record of distribution system changes and driving the change request process to permanently update record systems following completion of projects. This work helps protect Toronto Hydro crews and customers from exposure to unsafe conditions and ensures that switching and other Control Centre activities achieve planned results without compromising system integrity and reliability.

3.1.4 SCADA System Maintenance and Support

As Toronto Hydro's SCADA system is integral to the efficient operation of the Control Centre, a team of specialized engineers oversee the activities related to maintaining, improving, and modifying it to maintain cyber security and facilitate system operation efficiency. The SCADA team consists of trained engineers and technicians that possess specific skill sets in SCADA and similar industrial control systems. Their efforts facilitate remote system monitoring and control, and help ensure that decisions and orders from the Control Centre are quickly and efficiently executed. When Toronto Hydro installs new system monitoring and control equipment, it relies on SCADA engineers to configure and

enable these devices to work seamlessly with the existing equipment and applications. Figure 1 shows the SCADA display of a typical Toronto Hydro Station.

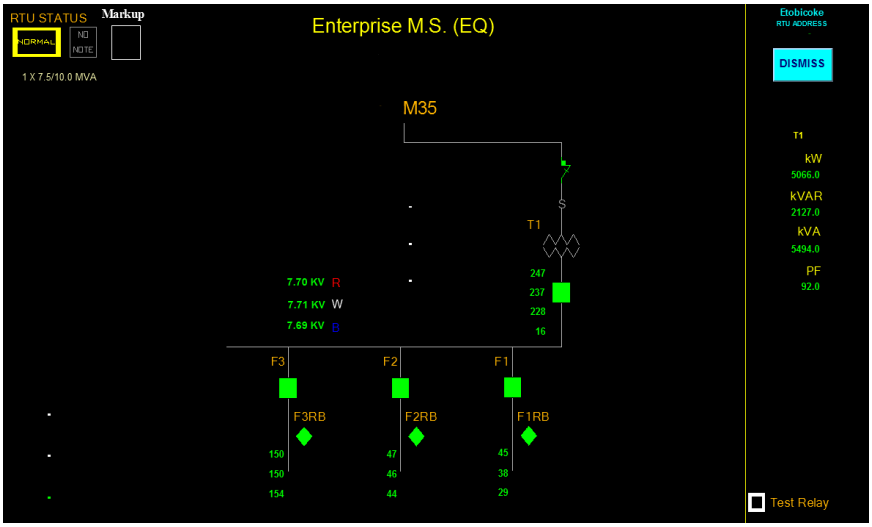


Figure 1: SCADA Display of a Typical Toronto Hydro Station

3.1.5 Energy Centre

In recent years, Toronto Hydro has experienced an increase in the volume and scale of distributed energy resources ("DERs") connected to the grid. This trend is expected to continue and will likely result in a significant increase in DER penetration over the coming years as governments and private organizations adopt policies to significantly reduce their greenhouse gas emissions. In addition, Toronto Hydro intends to continue to pursue the development of energy storage resources, local demand response programs and advanced grid pilots.[5]

A greater prevalence of distribution-connected energy sources and non-traditional distribution infrastructure necessitates a shift in the way distribution systems are

[5] Exhibit 2B, Sections E3 and E7.2.

operated. Rather than being geared primarily towards energy delivery, operators must also consider the importance of energy management as it relates to the safe and efficient operation of the distribution system. Historical processes and tools are not always well suited to account for this growing consideration and distribution system operators must introduce new processes and tools to ensure that future needs are met and customer expectations are fulfilled.

Examples of emerging functions that may need to be developed and implemented at scale include energy resource dispatching, scheduling, aggregation, and settlement. Such resources may also require more active management of short circuit levels, system voltages, and advanced protection schemes. To this end, in 2019, Toronto Hydro implemented a Distributed Energy Resource Management System ("DERMS") to enhance its capability to manage energy flows. Figure 2 below shows the DERMS system display for a battery storage site. This platform is currently used to directly operate Toronto Hydro-owned battery storage sites and to monitor and manage grid-level impacts of customer-connected DERs. As the need for these functions grows, Toronto Hydro intends to continue to develop and integrate energy management tools and processes into core Control Centre functions.

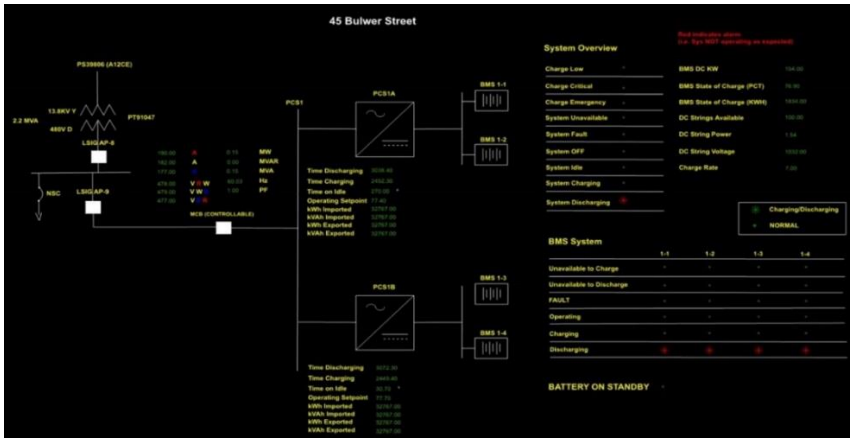


Figure 2: Energy Centre Display of a Battery Storage Site

3.2 Control Centre Priorities

3.2.1 Renewal, Development, and Sustainment of Skilled Resources

The Control Centre is primarily staffed by power system controllers, power system controller apprentices and distribution grid operations managers who work on a 24/7/365 shift schedule. The Control Centre is also supported by a team of technical staff.

Control Centre functions require a highly trained, skilled and knowledgeable workforce. The density and uniqueness of Toronto Hydro's urban setting adds additional complexities and challenges. For example, in downtown Toronto there are several unique legacy distribution configurations that are generally not found at the same scale elsewhere in the province, including the secondary network, underground residential distribution assets, and various underground radial configurations for supplying large loads. Each of these systems requires highly specialized knowledge and experience to operate efficiently and safely, and to effectively respond to unplanned outages. The impacts of any potential outages in these systems would be significant, which includes infrastructure critical to Canada's largest city (e.g. subways, streetcars, major hospitals, emergency services facilities, community support centres, telecommunications hubs, and financial institutions).

Power system controller qualifications are primarily developed through a combination of in-class training and on-the-job experience. Power system controller apprentices, irrespective of educational backgrounds and prior experience, are required to complete a 4.5-year apprentice program, which involves the assignment of progressively more complex responsibilities, to substantially familiarize themselves with Toronto Hydro's system and become fully qualified power system controllers.

The sustainment and development of this workforce possessing highly specialized knowledge and skills is critical to ensure that Toronto Hydro has the capability to realize the outcomes listed in Table 2 and to ensure that the Control Centre is well positioned to embrace and overcome the challenges associated with the evolution of the nature and needs of users on the utility's distribution system and its impact on roles, responsibilities, and systems. Toronto Hydro needs to continuously and proactively renew its Control Centre workforce in order to offset the impacts of natural attrition. Toronto Hydro mitigates these impacts with its workforce renewal program and in-house apprentice development program. The Control Centre's current staffing levels are anticipated to remain generally constant; however, hiring for backfill purposes may occur 1-2 years prior to anticipated retirements.

The Control Centre team also requires the support of a team of technical staff whose duties include work scheduling, design review, system analysis, energy management, reporting, and maintenance/development of core operating technology platforms and tools (SCADA, Energy Centre, Network Management System, etc.) Over the next several years, Toronto Hydro expects a significant increase in workload associated with these functions to support increased distribution system automation, the development and sustainment of energy management functions, distribution system growth (load and connection volumes), and the expansion of the SCADA system to enable more remote and autonomous operational capabilities.

For example, as shown in Table 3 below, the number of assets connected to Toronto Hydro's SCADA system is going to increase significantly—by approximately tenfold in

some cases—over the 2025-2029 rate period as part of the investments under the Contingency Enhancement segment of the System Enhancements program.[6]

Table 3: Increase in Number/Volumes of SCADA-connected Assets across 2020-2024 and 2025-2029 rate periods

Asset Type	2020-2024	2025-2029
Switches	33	299
Reclosers	49	220
Feeders to Meet Minimum Requirement for Distribution Automation (DA)	15	63

Similarly, growth in the volume of DERs driven by both Toronto Hydro and its customers more broadly will increase the workload of the Program. By 2029, the expansion of the Non-Wires Solutions program will require the Energy Centre function of the Program to support the procurement of up to 30 MW of capacity under the Flexibility Services initiative (compared to 10 MW in the 2020-2024 period) and manage the operation of nine Toronto Hydro-owned battery energy storage systems ("BESS") (compared to only one in the 2020-2024 period).[7]

In addition, the utility forecasts total DERs installed on the grid to increase approximately 67% to 2029,[8] which is driving investments in the Generation Protection, Monitoring and Control program.[9] Each additional device installed in the system pursuant to these programs requires oversight by Control Centre personnel for: 1) commissioning and testing devices in the field to reliably communicate with the SCADA system, and 2) daily

[6] Exhibit 2B, Section E7.1.
[7] Exhibit 2B, Section E7.2.
[8] Exhibit 2B, Section E3.
[9] Exhibit 2B, Section E5.5.

operations and troubleshooting, e.g. when responding to alarms or asset management tasks. Therefore, headcount increases in this area will be essential to enabling Toronto Hydro to safely and reliably accommodate these utility- and customer-driven changes to its grid.

Technological advancements and the modernization of system operation tools is another area that will require the Program to upskill and enhance its workforce. For example, the advanced applications that Toronto Hydro will adopt as part of the Advanced Distribution Management System ("ADMS") Upgrade will require the utility to significantly improve data modelling in the Network Management System ("NMS") to enable the self-healing grid and other automation functions through modernization projects such as Fault Location, Isolation, and Service Restoration ("FLISR").[10] This is because the operation of FLISR will depend on not only traditional types of data relating to connectivity attributes of distribution equipment, but also engineering attributes, such as device limits, impedances, and power transformer data, representing an increase in data point types from 13 to 36. Adequate staffing for the Control Centre Operations program to gather these additional types of data and input them into modelling systems will be essential for the successful and timely implementation and daily operation of modernization initiatives such as FLISR.

Finally, Program staff act as subject matter experts for a number of internal and external activities. Internally, program staff support investments in cellular SCADA upgrades under the Communication Infrastructure segment of the Information Technology and Operational Technology ("IT/OT") Systems program,[11] where the expertise of Control

[10] Exhibit 2B, Section E8.4, Appendix A.
[11] Exhibit 2B, Section E8.4.

Centre operators is crucial to the timely and reliable completion of critical infrastructure upgrades. Externally, Program staff support Toronto Hydro's participation in industry forums and working groups such as the Electric Power Research Institute ("EPRI") Distribution Operations & Planning Group and the IESO's Transmission-Distribution Coordination Working Group. [1213] The operational expertise that Control Centre operators bring to these engagements benefits both Toronto Hydro, by enabling the utility to expand its knowledge of the industry through connections with stakeholders, and the industry, by contributing to policy design and development with Toronto Hydro's unique experience as a distributor.

To collectively address these needs, Toronto Hydro forecasts a significant increase in the headcount of technical staff supporting Control Centre functions between 2023 and 2029.

3.2.2 Workforce Management

The Toronto Hydro Control Centre operates under a 24/7 supervision model whereby Control Centre managers work a rotating schedule of twelve-hour shifts. The schedule ensures that at least one manager is present in the Control Centre at all times and ensures effective outage response, communication with customers, and the protection of public safety. As power system controllers coordinate with field crews to analyze, plan, execute and resolve public safety incidents or restore power outages, accurate customer-centric information must be available in a timely manner. The 24/7 supervision model supports consistent operational decision-making, more accurate and timely dissemination of information to customers, and increased service for customer

[12] Electric Power Research Institute, *Distribution Operations and Planning* (June 8, 2023) online: <https://www.epri.com/portfolio/programs/108271>.
[13] Independent Electricity System Operator, *Transmission-Distribution Coordination Working Group* (November 17, 2023), online: <https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Transmission-Distribution-Coordination-Working-Group> .

escalations. Having a manager present also provides support for more junior apprentices as they develop their skills and knowledge and helps them benefit from leadership guidance for public safety incidents and customer communication escalations. Consistent management oversight also allows operators to focus on their individual responsibilities for managing system events, while the manager monitors the overall situation, aligns priorities and strategies across the team, communicates to interested stakeholders, and activates additional resources as necessary to resolve the situation.

4. PROGRAM COSTS

In 2025 Toronto Hydro requires $8.3 million in rate funding for the Control Centre Program, which represents an increase of $0.7 million over the last rebasing period in 2020. Over the 2025-2029 rate period, the utility expects the cost of this Program to increase by an annual growth rate of 6.0% which is necessary to address the Program needs and deliver the customers outcomes enabled by this Program. The Program's costs are comprised almost entirely of payroll.

Table 4 provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for the Program.

Table 4: Control Centre Operations Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Control Centre Operations	7.6	6.0	6.5	7.4	7.9	8.3	9.0	9.5	10.0	10.5
Total	**7.6**	**6.0**	**6.5**	**7.4**	**7.9**	**8.3**	**9.0**	**9.5**	**10.0**	**10.5**

4.1 Cost Drivers

As noted previously, the costs of the Program are primarily driven by payroll, which is partially offset by departmental labour recoveries, whereby a portion of Control Centre payroll is allocated to capital projects supported by the Control Centre. Minor cost drivers include temporary contract labour, which is typically used where there is a limited term need for specialized expertise and knowledge (such as training), and an allocation for the procurement of technical analysis and research on an as-needed basis.

4.2 Cost Control and Productivity Measures

A functional and efficient Control Centre is critical to meeting operational objectives, sustaining reliability performance and enabling delivery of the capital and maintenance work programs. Productivity improvements in Control Centre operations typically translate to productivity opportunities for field crews, and/or enable a greater throughput of work without a comparable increase in resource compliment. On an ongoing basis, Toronto Hydro monitors several key areas of Control Centre performance and productivity, as described below.

4.2.1 Hold-offs

Each hold-off requires a power system controller to research the work location, prepare documentation, apply a condition to the circuit breaker, and verbally issue the hold-off to the requestor. Toronto Hydro issues over 21,500 hold-offs each year, most of which are requested between 6:30 am and 9:00 am on weekdays. In order to efficiently deliver this work and minimize delays in the field, several years ago Toronto Hydro implemented a planned hold-off process whereby requests are researched and prepared a day in advance. This has resulted in an average transaction time of approximately 3 minutes per hold-off, down from approximately 29 minutes in 2014, which allows crews to spend less

time waiting for hold-offs to be issued and more time on their responsibilities in the field. Toronto Hydro continuously assesses and revises Control Centre processes to optimize resourcing for the delivery of hold-offs and to ensure continuous improvement in performance.

4.2.2 Switching Orders

Most planned distribution system work requires power system controllers to prepare and check multiple switching orders, also referred to as PC17A forms. These documents prescribe the steps necessary to eliminate and/or control electrical hazards in the field. An individual PC17A can be anywhere from one step to over 100 steps, depending on the complexity of the distribution system. In 2021, Toronto Hydro issued almost 7,500 PC17A forms to field stakeholders, accounting for a total of nearly 185,000 individual switching steps. In order to schedule and execute field work efficiently, field crews need to have their switching documentation issued prior to the planned start of their work. Control Centre managers monitor PC17A production relative to work volume and allocate resources accordingly. In 2022, 80% of PC17As were issued two or more days in advance of the requested work start date, helping to ensure that field crews can start their work on time.

4.2.3 Call Queuing

Nearly all work on or in proximity to the distribution system requires at least one transaction with the Control Centre. In 2021, the Control Centre handled over 92,000 individual calls. Depending on the volume of crews calling in at any given time, the Control Centre is at risk of becoming a bottleneck for work execution in the field. Recognizing this, in 2019 Toronto Hydro harmonized the primary mode of communication between the field and the Control Centre by establishing the phone system as the primary method.

This ensured that all transactions are received through the same communication channel and enabled the implementation of a phone queuing software which provides managers and power system controllers real-time visibility of crew wait times. This insight enables managers to dynamically allocate resources based on actual need, reducing wait times for field crews. The phone queuing system also provides historical data with respect to call volumes and wait times, enabling performance reporting and process optimization. In 2021, over 94 percent of calls had a wait time of less than 10 minutes.

4.2.4 Other Initiatives

Table 5 below provides examples of other productivity initiatives under the Program. Note that the future implementation of the Advanced Distribution Management System ("ADMS") project will be a prerequisite for the successful implementation of many of these initiatives. [14]

[14] *Supra* note 8.

Table 5: Examples of Control Centre Productivity Initiatives

Initiative	Timing	Outcomes and Benefits
Development of Apprentice Programs	Ongoing	Enhancement of specialized skill sets in power system controllers, which will enable efficiencies in performance. Harmonization of processes and practices across the workforce results in fewer errors and more efficient operating decisions. As apprentices progress and are qualified to take on more responsibility, it allows for more resilient shift scheduling, reducing overtime and improving day-to-day capacity of the Control Centre accommodate work without delay.
Network Management System Updates	Ongoing	Multiple times a year, the Control Centre updates the core network management system platform used by power system controllers to operate and mimic the distribution system. Changes are focused on stability, cyber security, and productivity improvements such as data validation, streamlining work flows, and automating repetitive tasks.
Supervisory Control and Data Acquisition (SCADA) System	Ongoing	The SCADA system controls approximately 4,000 field devices and is a critical operating tool for power system controllers. Power system controllers work closely with SCADA engineers to ensure that system improvements incorporate automation and streamline critical information flow to optimize outage restoration and system monitoring. Upgrades and enhancements are required for field personnel safety, improved system stability, cyber security resilience, and productivity improvements.
Automated Model Build	2023 - 2024	This initiative will provide the ability to automatically extract distribution system changes and implement them into the Network Management System ("NMS"), reducing record update latency and the amount of effort required to maintain the NMS network model.
Fault Localization, Isolation & Service Restoration (FLISR)	Ongoing	Refers to the implementation of automated fault location and system restoration following an outage. This project is intended to improve reliability and productivity by using technology to automate initial outage restoration steps and enable a self-healing grid. Work will be comprised of two major segments: the first with the Information Technology group and the second with the Control Centre's engineering team.

Initiative	Timing	Outcomes and Benefits
Work Request Tool	2022 - 2025	Implementation of a single software tool to manage all operational work requests with integration to core systems (GEAR, [15] NMS, and SAP).[16] This project will result in the retirement of several legacy databases and platforms, and enable efficiencies in scheduling and administering distribution system work requests (work protection, planned outages, hold-offs, design review, etc.).
Operational Analytics	Ongoing	Enhances access to operational data that eliminates several manual reports and enables advanced reporting and analytics. These changes enable more efficient storm event reporting and more informative system condition reporting. In the future, it will also eliminate the need for manual outage reporting currently undertaken by power system controllers. Currently each outage requires a controller to enter outage details and restoration steps into a stand-alone outage tracking platform. In a typical year, controllers enter approximately 2,200 individual reports. The Operational Analytics program will modernize reliability calculation processes and enable auto-generation of outage reports based on restoration actions recorded in the NMS.
Digitization	2020	In 2020, partially motivated by operational constraints arising from the COVID-19 pandemic, the Control Centre completed the digitization of virtually all paper-based processes in the Control Centre. This initiative enhanced business continuity and ensured that critical operational information is readily available to all power system controllers and managers in real time.

[15] GEAR refers to the Geospatially Enabled Asset Registry, a geospatial information system used by Toronto Hydro that provides a graphic representation of distribution assets and their relationship to other assets within Toronto Hydro's network.
[16] SAP is Toronto Hydro's Enterprise Resource Management (ERP) system.

Initiative	Timing	Outcomes and Benefits
UWPC	2020	UWPC implementation was a company-wide strategic initiative led by the Control Centre team to adopt the provincial standard work protection code and involved process development, modifications to core operating platforms, and the training of all power system controllers and electrical field workers. Previously, Toronto Hydro utilized its own unique work protection code. The purpose of this initiative was to align Toronto Hydro's practices more closely with those of other Ontario utilities and with provincial Electrical Utility Safety Rules. This alignment has reduced barriers to mutual aid, reduced onboarding requirements for crews to work on Toronto Hydro's distribution system, and mitigated compliance risks

4.3 Control Centre Operations Program Year-over-Year Variance Analysis

2020-2021 Variance Explanation

Costs decreased by $1.6 million from 2020 to 2021. This variance is attributable to:

- a higher department labour recovery rate in 2021 compared to 2020 (i.e. a higher portion of labour costs were allocated to capital projects);
- higher one-time costs in 2020 directly related to the implementation of the Utility Work Protection Code ("UWPC") across the organization.[17] The one-time costs of $1.1 million incurred in 2020 were primarily driven by workforce training and the re-tagging of field devices pursuant to UWPC.

2021-2022 Variance Explanation

Costs increased by $0.5 million from 2021 to 2022. This variance is primarily attributable to higher compensation costs.

2022-2025 Variance Explanation

Between 2022 and 2025, costs in this segment are expected to increase by $1.8 million, or an average of $0.6 million per year due to:

- Normal-course compensation increases; and,
- Increased headcount including additional technical and management staff to fill vacant positions and support a growing volume of work related to continued implementation of the intelligent grid, automation, and energy transition.

[17] UWPC implementation was a company-wide strategic initiative led by the Control Centre team to adopt the provincial standard work protection code and involved process development, modifications to core operating platforms, and the training of all power system controllers and electrical field workers. Previously, Toronto Hydro utilized its own unique work protection code. The purpose of this initiative was to align Toronto Hydro's practices more closely with those of other Ontario utilities and with provincial Electrical Utility Safety Rules. This alignment has reduced barriers to mutual aid, reduced onboarding requirements for crews to work son Toronto Hydro's distribution system, and mitigated compliance risks.

Increases in headcount are necessary to support grid modernization, analytics, and the development of energy centre capabilities.

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $2.2 million, or an average of $0.6 million per year, to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work discussed above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, Toronto Hydro will be unable to resource this critical function in an optimal and sustainable manner. Such a scenario would result in a number of operational risks, including:

- Inability to successfully execute the capital and maintenance investment programs due to Control Centre-related constraints and delays in administering field work;
- Significantly longer restoration times for outages resulting from Control Centre capacity constraints;
- Inability to efficiently and effectively modernize Toronto Hydro's operations to meet customer and stakeholder expectations with respect to the continued transition to new and diverse energy resources;
- Less effective coordination with Hydro One and the IESO with respect to bulk system issues, resulting in prolonged outages for customers and possible non-compliance with relevant legislative and regulatory requirements;
- Less effective dissemination of outage information to support customer communications, including estimated times of restoration;
- Reduced operating efficiency and higher safety risks as a result of the reduced ability to manage data on changing system configuration in a timely manner; and

- Persistence of abnormal system configurations, which can cause additional or prolonged outages.

CUSTOMER OPERATIONS

1. OVERVIEW

Table 1: Customer Operations Program Summary

Customer Operations Program									
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Operational Effectiveness - Safety									
Segments: • Customer Connections • Key Accounts • Public Safety and Damage Prevention • Customer Owned Equipment Services									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
9.3	7.5	9.0	12.6	12.8	12.7	13.1	13.7	14.1	14.6

The Customer Operations program (the "Program") delivers services that respond to requests from customers. The specific activities under this Program include field work and support functions to safely, efficiently, and promptly meet customer requests. This work is categorized into four segments as follows:

- Customer Connections;
- Key Accounts;
- Public Safety and Damage Prevention; and
- Customer-Owned Equipment Services.

2. OUTCOMES AND MEASURES

Table 2: Customer-Driven Work Program Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's compliance with legislative and regulatory requirements (including Ontario Energy Board-mandated Electricity Service Quality Requirements (ESQR) measures[1]) on customer connections, appointments, written responses to enquiries, and the provision of information concerning the location of the utility's underground infrastructure, pursuant to the *Ontario Underground Infrastructure Notification System Act, 2012*[2]. • Contributes to meeting Toronto Hydro's customer service objectives by providing customers access to customer-owned vaults (including of one free vault access per 12-month period in accordance with the utility's Conditions of Service). • Contributes to meeting Toronto Hydro's obligations for customer connections (including Ontario Energy Board mandated ESQR measures) by ensuring sufficient planning staff and required tools or resources are available to efficiently plan and design service connections and meet service request volumes • The Key Accounts team ensures enquiries from large customers, developers, and key accounts are resolved appropriately and in a timely manner
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's reliability objectives (e.g. SAIFI, SAIDI, FESI-7) by working with customers to ensure customer-owned civil structures containing distribution equipment on customer property are adequately maintained and protected to prevent any risk of damage or interruption to parts of the distribution system.

[1] More specifically, Toronto Hydro's customer connection-related obligations include obligations under the following sections of the DSC: Connection of New Services (7.2) Appointment Scheduling (7.3), Appointments Met (7.4), Written Response to Enquiries (7.8).
[2] SO 2012, c 4.

Operational Effectiveness - Safety	• Contributes to Toronto Hydro's public and employee safety performance and objectives (as measured via metrics like Total Recordable Injury Frequency) by: ○ Providing underground infrastructure locates in a timely manner and providing timely and accurate information to excavators, to reduce the likelihood of damage to energized underground distribution assets and consequent safety hazards to the public; ○ Providing vault safety agents (VSAs) during vault access appointments to ensure customer access does not cause any safety risks and that safe limits of approach are maintained; and, ○ Disconnecting and reconnecting (also known as "isolating") customers' service connections upon request to enable electrical work on the customer side of the demarcation point with minimal safety risk.[3]

3. PROGRAM DESCRIPTION

Most of the activities in the Program are driven by legislative and regulatory requirements, including the *Electricity Act, 1998*,[4] the Ontario Energy Board's Distribution System Code ("DSC"), the *Ontario Underground Infrastructure Notification System Act, 2012* ("OUINSA"),[5] the O. Reg. 213/91 ("Construction Projects") under the *Occupational Health and Safety Act*,[6] and other applicable requirements governing building and fire safety standards.

The Program covers the interactions between Toronto Hydro's customers and its distribution system with a focus on the safe completion of work in proximity of Toronto

[3] The costs of this program include isolations for low-voltage isolations requested by eligible low-income customers only. See section 6.1.3 of this Schedule for more information.
[4] SO 1998, c 15, Sch A
[5] SO 2012, c 4
[6] RSO 1990, c O.1

Hydro equipment, improving the customer experience for requests for access to the grid and meeting the unique needs of Toronto Hydro's largest customers. More specifically, the four Program segments are:

- **Customer Connections:** Focuses on enhancing the experience for customers requesting access to the grid by providing a dedicated team to communicate and manage connection requests from initial contact through completion. This segment also includes the administrative and unrecovered costs associated with the investigative engineering, design, and field work to facilitate customer connection requests in accordance with applicable customer service and regulatory obligations. Most of the activities in the Program are driven by legislative and regulatory requirements, including the *Electricity Act*, 1998, and the Ontario Energy Board's Distribution System Code ("DSC");
- **Key Accounts:** Manages the utility's relationships with large electricity consumers (i.e. 1MW and greater and other critical customers) across all business sectors. Key Accounts collaborates across internal departments to provide an integrated customer experience while building trust, meeting the unique needs of large customers and delivering value;
- **Public Safety and Damage Prevention:** Which aims to provide the general public, other utilities, and Toronto Hydro's capital projects crews with timely information regarding the location of Toronto Hydro's underground infrastructure in accordance with applicable legislative and regulatory requirements; and
- **Customer-Owned Equipment Services**: Which aims to provide customers the means to safely access and service their equipment operating on the distribution system, through services such as vault access and isolations.

4. PROGRAM COSTS

In 2025, Toronto Hydro requires $12.7 million in rate funding for the Customer Operations program, which represents an increase of $3.4 million over the last rate application in 2020.

Over the 2025-2029 rate period, the utility expects the cost of this program to increase by annual growth rate of 3.4 percent which is necessary to address the program needs and deliver customers outcomes enabled by this program.

Table 3 provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for each of the Program's segments.

Table 3: Customer Operations Expenditures by Segment ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Customer Connections	3.7	1.6	1.6	3.2	3.6	3.2	3.3	3.5	3.6	3.8
Key Accounts	-	0.5	0.8	0.9	1.2	1.5	1.5	1.7	1.8	1.9
Public Safety & Damage Prevention	4.7	4.4	5.4	7.3	6.8	6.7	6.9	7.0	7.2	7.3
Customer-Owned Equipment Services	0.9	1.0	1.2	1.2	1.2	1.3	1.4	1.5	1.5	1.6
Total	**9.3**	**7.5**	**9.0**	**12.6**	**12.8**	**12.7**	**13.1**	**13.7**	**14.1**	**14.6**

4.1 Cost Drivers

The largest drivers of cost increases in the Program are attributable to underground infrastructure locates under the Public Safety and Damage Prevention segment. Specifically, these drivers are the proliferation of large multi-unit segment locates and the effects of the more stringent locate compliance requirements introduced by Bill 93.[7] Both drivers are discussed in greater detail below.

[7] *Getting Ontario Connected Act, 2022*, SO 2022, c 9, formerly known as Bill 93.

The variances in the Customer Connections segment are attributable to the complexity of the initial investigation required prior to making an offer to connect. As both the number and complexity of expansion projects have been increasing over time, it is expected that the overall time and administrative burden involved in these investigations will also increase. Projects that do not proceed are not capitalized. Any unfunded costs (including administrative resources) relating to such investigation are funded through this Program.

Key Accounts was previously a function within the Customer Care segment. It was separated out as a segment in 2021 to reflect the evolution of Toronto Hydro's Key Accounts strategy. The variances in Key Accounts segment for the 2020 – 2024 period reflect the development of this team. Costs are expected to remain relatively flat for the 2025-2029 period.

The variances in the Public Safety and Damages Prevention segment are attributable to a significant increase in the volumes of construction and development in the city of Toronto which has led to an unprecedented increase of construction projects requiring large, "multi-unit segment" locates, whereas a "single unit" locate typically relates to a single property or premises, multi-unit segment locates are often requested by developers working on projects with large geographic footprints such as building complexes or subdivisions and require the identification of underground infrastructure in a much larger area or in greater numbers. Therefore, multi-unit segment locates are more complicated and require more time or greater numbers of resources to complete, and therefore require the utility to incur greater costs. As of 2023, the proportion of multi-segment locates are almost doubled compared to April 2022.

In addition, in April 2022, Bill 93*, Getting Ontario Connected Act, 2022*, received royal assent. This legislation resulted in major changes to the *Ontario Underground Infrastructure Notification System Act, 2012* ("OUINSA"), which governs the mandatory identification of underground infrastructure ("locates") in Ontario. The new legislative framework is significantly more onerous on utilities and other infrastructure owners due to mandatory, penalty-backed, and increased compliance obligations, intended to impose stricter performance standards with respect to the timeliness and accuracy of locates. The legislative amendments also enhanced the powers of the Ontario One Call Corporation to monitor and enforce compliance. Collectively, these developments have greatly increased the demand for locate services and consequently, demand for workers with the appropriate qualifications. However, it will take the construction industry time and effort to ramp up service levels since low wages for personnel performing locate work had historically constrained the supply of such qualified labour.[8] As the industry raises wages to attract, train, and retain more personnel, labour costs have been increasing since April 2022.

Toronto Hydro expects the cost increases resulting from the above developments to persist beyond 2023 as it adapts its locate service levels to achieve and sustain the compliance targets and performance requirements imposed by the amended legislation over the 2025-2029 rate period. Specifically, the following factors will likely continue to drive increased costs:

- Increased operational costs to comply with the stricter compliance targets for locate service providers and infrastructure owners (i.e. increased work

[8] For example, prior to 2022 the average hourly wage for locators in Toronto was less than $25. <https://www.toronto.ca/wpcontent/uploads/2023/03/8d36-2022-Utility-FW-Sched.pdf>.

management processes, incremental costs for the extension of shifts, including into holidays and weekends and bringing in resources from other geographical areas to manage peak volumes, stricter requirements to reschedule appointments in writing, which previously could be done verbally).

- Incremental costs to ensure resources are available to manage peak capacity requirements and contingencies. Locate request volumes are typically seasonal, in alignment with overall construction activity. However, the locate request submission process administered by Ontario One Call does not require excavators to submit tickets in advance, regardless of the complexity of the locate work, which significantly constrains the utility's resource and work planning and optimization. The new compliance requirements under OUINSA also make no allowance for inclement weather, emergency situations, or force majeure, and therefore the utility is required to rapidly deploy incremental capacity to handle such scenarios or catch up from delays within the required timelines to ensure full compliance.

- Administrative monetary penalties will be in place as of April 1, 2024. In order to achieve compliance targets and mandated performance requirements under OUINSA, Toronto Hydro will be obligated to meet customer driven and fluctuating work demands at all times, as the utility's ability to forecast volumes is limited. This will require external contractors providing locate services to maintain a sufficient complement of rapid response resources.

- Increased locate request volumes due to increased awareness and compliance obligations across the construction industry, including the greater incentive for

excavators' compliance due to penalties that Ontario One Call could levy under the amended legislation.

- Process and system enhancements, including changes to process and technology, for Toronto Hydro and its locate service providers to efficiently monitor and manage increased volumes of locate work.

The cost forecasts in the Public Safety & Damage Prevention segment include increased labour costs and other types of costs known at the time of filing. However, there is still a great degree of uncertainty regarding the full extent of locates-driven costs that Toronto Hydro may need to incur in the 2025-2029 period to achieve compliance with OUINSA. For example, the Government of Ontario delayed the effective date of administrative monetary penalties ("AMPs") pursuant to Ontario Regulation 87/23 under OUINSA until April 1, 2024. Furthermore, through a joint letter by the Minister of Public and Business Service Delivery and Minister of Energy issued on May 11, 2023, the Government of Ontario signalled that it will consult on additional enhancements to locate delivery requirements under the OUINSA, which may result in future legislative and regulatory changes affecting demand for locate services and accompanying costs. If there are any additional material developments that may affect the 2025-2029 cost forecasts for the Public Safety & Damage Prevention segment while the evidentiary record is open during this rate application proceeding, Toronto Hydro will adduce additional evidence as required.

On October 31, 2023, the Ontario Energy Board established the Getting Ontario Connected Act ("GOCA") Variance Account to allow utilities to record the incremental

costs of locates resulting from the implementation of Bill 93.[9] Given the ongoing uncertainty regarding the incremental costs, Toronto Hydro requests the continuation of this variance account for the 2025-2029 rate period. This approach is in the best interests of ratepayers, as it allows Toronto Hydro to adequately fund the locates work, which is non-discretionary, in compliance with the utility's legislative and regulatory obligations during the next rate term. Further details on this variance account can be found in Exhibit 9, Tab 1, Schedule 1.

The primary driver of cost increases under the Customer-Owned Equipment Services segment over the 2025-2029 rate period is the increase in customer demand for vault access services. Currently, approximately 30 percent of customers who own vaults containing distribution equipment access their vaults every year. Access requests are increasing due to a number of factors, including an increase in the effectiveness of the Customer Action Form process (detailed under subsection 6.1.2 below) for requiring customers to address deficiencies, which in turn drives repeat customer requests. Moreover, the growth of the city of Toronto's buildings naturally increases the number of vaults present and the subsequent requests for access.

[9] EB-2023-0143 Decision and Order (October 31, 2023).

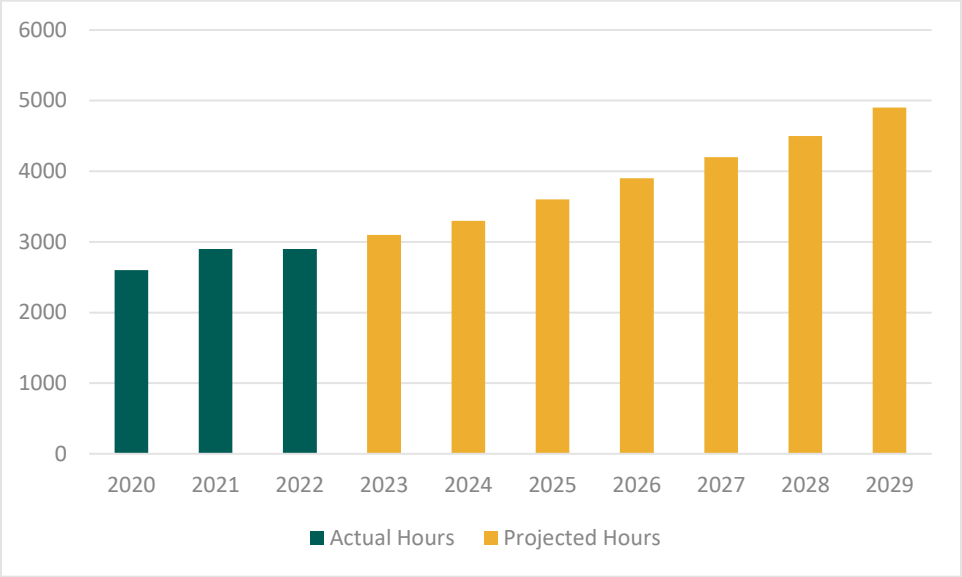


Figure 1 – Actual and Projected Vault Access Hours

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

Toronto Hydro undertakes a number of measures to control costs in this Program. Under the Customer Connections segment, Toronto Hydro reviews pre-payment values on a project basis to ensure they cover a reasonable portion of the initial investigation work and mitigate financial risks should the project not proceed.

At the end of 2023, Toronto Hydro is expected to launch the Service Request Form Enhancements on the Customer Connections Portal. This portal will allow customers to submit service request forms online, including with attachments, for new and existing services. These enhancements will streamline the process and increase efficiency for customers by having unique forms for different kinds of requests ensuring that the appropriate information is collected, minimizing back and forth with the customer. The

online portal will also improve data collection and reporting for regulatory and governance purposes, which will also assist with future capacity planning.

Under the Key Account segment, the Key Accounts team integrates data from numerous sources which allows for a more complete understanding and timely analysis of customer issues and requirements.

For the Public Safety and Damage Prevention segment, the utility is working with its locate service providers ("LSPs") to streamline the "clear" process, which indicates to customers and excavators that their work will be clear of any Toronto Hydro equipment. The "clear" process is when a locate request is screened in office by a trained worker prior to being sent out for field locating. This process eliminates the need for an LSP to spend time and effort verifying the location of Toronto Hydro assets where they do not exist and allows LSPs to focus on locates that require physical presence. LSPs perform this process at a lower rate due to the fact that the locate does not require a vehicle rollout or field resources to attend the excavation site, improving Toronto Hydro's compliance with OUINSA requirements and saving the cost associated with dispatching LSP resources to the field to conduct a physical locate.

Under the Customer-Owned Equipment Services segment, Toronto Hydro provides customers vault access at its expense, recognizing that the utility gains safety and reliability benefits from doing so, including the identification of potential hazards and deficiencies, and ensuring that customers access the vault in a safe manner with appropriate supervision to prevent damage to the utility's distribution equipment. Toronto Hydro limits free access to one 4-hour appointment per 12-month period per

customer.[10] Customers requiring access to vaults more than once per year or for durations longer than four hours are responsible for the incremental costs of access, such as VSA time. This incentivizes customers to be efficient with their free access appointment and better plan and optimize their paid access appointments.

In addition, to facilitate customers' interactions with the vault access program, Toronto Hydro is investing in a Customer Connections Portal which will allow customers to book and pay for vault access appointments online. This initiative will improve customer experience by increasing the convenience of booking vault access appointments and reduce the administrative costs of the program by reducing manual work for appointment scheduling and payment processing.

4.2.2 Productivity

Customer Connections

In 2021, Toronto Hydro integrated its Customer Offers and Sustainment group and Execution team with the Distribution Projects East and West teams (designers, construction teams and managers) into one team enabling any project (capital or connections) to be executed by this team. Previously, these groups were separated and dedicated to either capital or connections projects. This change allows the team to better coordinate customer connection work with capital work in order to find efficiencies because the designers have more direct information about the planned projects in each category. This change also enables the designers to adapt to variable volumes of work between capital and connections projects.

[10] The appointment length is based on the average historical appointment duration that customers have required to complete their vault access visits.

In 2022, Toronto Hydro created two new teams – the customer intake team and the pre-design team – to streamline the customer connection process and ensure an efficient allocation of resources:

- **Customer Intake team:** Improves the customer experience by creating a single point of contact for all customer inquiries related to connections. Previously, customers could initiate a connection request through several different channels creating the risk of inefficiencies and an inconsistent customer experience. By having a single point of contact, Toronto Hydro ensures that all connection-related requests are directed to the appropriate teams. The intake team also ensures that customer application forms are complete and contain accurate information.
- **Pre-Design team:** Acts a single point of contact for customers to ensure all the information required by the design teams for large connections (i.e. requiring expansion) is collected before moving forward to the design phase. This team also performs administrative functions previously handled by designers, such as collecting and reviewing pre-payment values. As a single point of contact, the pre-design team avoids the need for customers to repeat information through out the process and minimizes delays with proceeding with the project due to lack of required information. By assisting with administrative functions, the Pre-Design team frees up capacity for the design team to stay focused on design work.

Key Accounts

Key Accounts has continued to mature since formation in 2021 and now carries out an important role in managing large connections projects during the design and construction phases, acting as a single point of contact to the customer. By performing this function, it improves the customer experience by streamlining responses, and allows technical

resources to focus their efforts on value added activities, rather than managing the overall project.

Public Safety and Damage Prevention

Toronto Hydro is working with the Locate Alliance Consortium ("LAC"), through which utilities and other infrastructure owners coordinate in purchasing locate services in specific geographical areas and share costs accordingly. This approach allows a single LSP to perform locates on behalf of all participating utilities within a geographical area, which streamlines the quality, timing, and efficiency of the locate process compared to multiple LSPs individually performing a locate for each infrastructure owner. This approach is also environmentally friendlier as fewer vehicles are required to attend the job site and conduct each locate.

Toronto Hydro is also working with other infrastructure owners and Ontario One Call to reduce the amount of unjustified locate requests, i.e. where an excavator requests a locate without the intent of excavating within the statutory validity period of 60 days. Early and unjustified locate requests in this manner result in the utility having to complete multiple locates for the same work, increasing costs without providing any benefits to the excavator or other stakeholders. By working to educate excavators and the general public on appropriate locate use, Toronto Hydro expects to encourage more prudent and efficient locate requests in order to minimize excavators' wasteful mobilization of locate resources.

Customer-Owned Equipment Services

When possible, Toronto Hydro schedules VSA appointments to multiple addresses in clusters to ensure one VSA can cover numerous appointments in a single day. As requests

are received Toronto Hydro staff also optimize the scheduling and planning of vault access requests by considering the relevant vault locations and access times to reduce travel time for VSAs between appointments. In addition, the utility coordinates with customers who own multiple vault locations to schedule a single VSA for a day to maximize the efficiency of the customer's vault access.

5. CUSTOMER CONNECTIONS SEGMENT

5.1 Segment Description

The Customer Connections segment is driven by customer requests to connect to Toronto Hydro's distribution system or service upgrades for existing customers. Serving one of the fastest growing cities in North America, Toronto Hydro receives a high volume of requests for connections and upgrades for residential and commercial developments each year.

The Customer Connections segment is responsible for handling all communications with customers relating to connection and upgrade requests. The team manages a project from intake through to closure providing a single point of contact for all customer requests and communications related to a connection. This ensures a consistent and efficient customer experience.

Requests for connection vary in location, load requirements and the complexity of underlying planning or construction work. In accordance with its regulatory obligations, Toronto Hydro must connect a customer to its distribution system within prescribed timelines if that customer and the associated connection meet all technical requirements outlined in the DSC (Section 7.2) and the utility's Conditions of Service. Customer connections can be in the form of a basic connection, or a connection requiring expansion

work. The types of connections Toronto Hydro performs can generally be divided into two categories as follows:

- **Low Voltage Requests:** These requests primarily relate to residential and small commercial customers that utilize existing Toronto Hydro transformation for their connection. As shown in Figure 1, the high volume of requests presents challenges as they require extensive project coordination and administrative oversight. The level of work is typically seasonal and has a relatively short turnaround time. To meet its service obligations, Toronto Hydro works with customers to provide options for a new connection or service upgrade.
- **High Voltage Requests:** These requests primarily relate to larger residential and commercial developments with dedicated transformation on customer property. These customers typically engage Toronto Hydro years before service is required. Figure 2 provides a year-over-year comparison of the volume of new formalized High Voltage requests that Toronto Hydro receives on an annual basis.

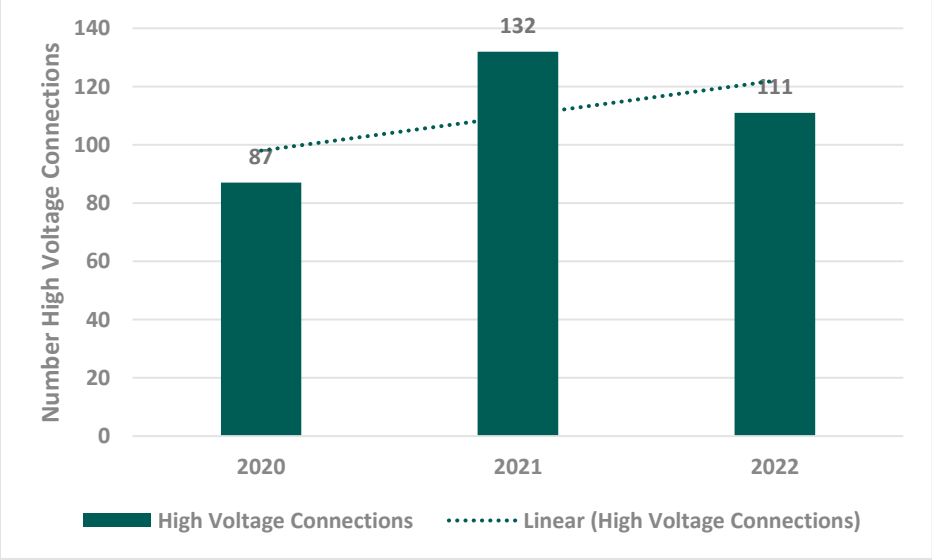


Figure 2: High Voltage Connection Requests (2020-2022)

Following the receipt of a connection request, Toronto Hydro works with prospective customers to develop an appropriate connection design, calculate the design pre-payment, and establish a mutually satisfactory construction schedule. Given the high density of Toronto's urban core, there could be instances of localized capacity constraints at many of the utility's Transformer Stations and Municipal Stations as well as spatial restrictions of existing underground or overhead easements. As such, Toronto Hydro may be required to undertake expansion and enhancement work to enable safe and reliable power. Projects with expansion work typically require connections that extend beyond the closest pole or cable chamber, resulting in work on various sections of the circuit or sometimes the entire circuit. Such work is complicated and requires a specialized team (including designers and distribution and stations engineers) to plan the system to accommodate the connection. Customer jobs requiring expansion work entail significantly more resources to prepare an offer to connect.

Figure 3 illustrates the year-over-year volumes of Offers to Connect requiring expansion projects. Over the past three years, both the volume and average complexity of expansion work remains high.

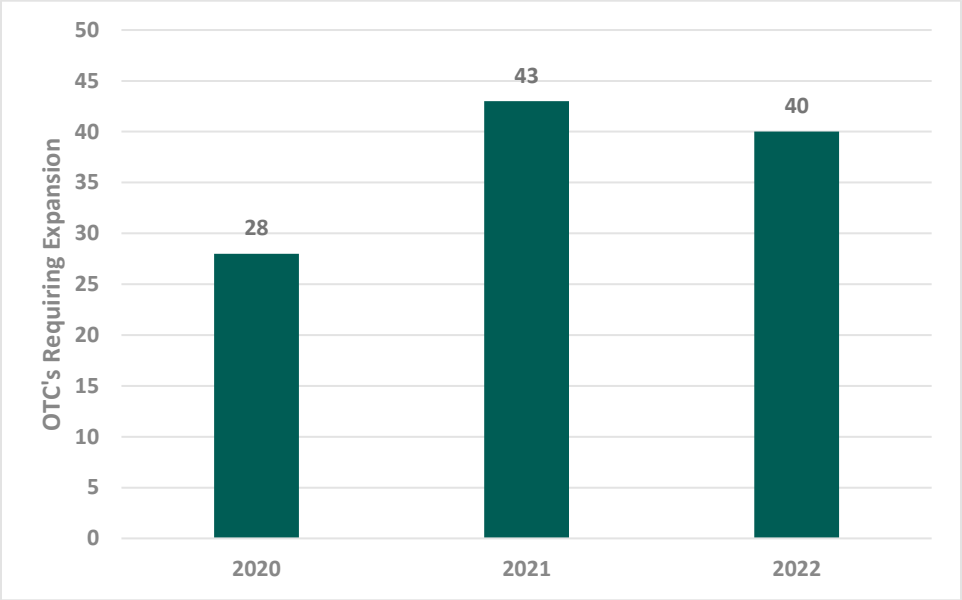


Figure 3: Number of Connections Requiring Expansion Work (2020-2022)

Given the current pace of Toronto's growth and the volume of large connection requests, Toronto Hydro identifies and addresses areas where insufficient connection capacity exists or is projected to materialize in the near or medium term. In this regard, the utility's customer connection work also entails an analysis of development plans prepared by provincial and municipal agencies and private development firms. Toronto Hydro incorporates the results of this analytical work into its load forecasts, system upgrade, and expansion plans.

Throughout the duration of connection planning and design activities, Toronto Hydro maintains frequent communications with prospective customers to effectively manage their expectations and accommodate their evolving requirements or concerns, where applicable. This includes the Key Accounts team which supports existing and new key account customers. If planned or ongoing connection work may temporarily affect service quality, reliability or otherwise cause disruptions for existing Toronto Hydro customers,

the utility endeavours to ensure that affected customers receive timely notifications and are able to provide input regarding the scheduling of planned activities.

The utility recovers eligible costs associated with the planning and execution of connection work from the requesting customers in accordance with the DSC and other relevant Ontario Energy Board and internal policies. The remainder of the costs are either capitalized or recovered through operating costs as described below.

Finally, operating costs related to customer connection work also include Program support costs such as tools and equipment, information technology, vehicle and occupancy costs.

5.2 Customer Connections Segment Costs

Toronto Hydro requires approximately $3.5 million each year during the 2025 to 2029 period to execute the functions in this segment.

Table 4 provides the Actual (2020-2022), Bridge (2023-2024), and Forecasted (2025-2029) expenditures for the Customer Connection segment.

Table 4: Customer Connections Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Customer Connections	3.7	1.6	1.6	3.2	3.6	3.2	3.3	3.5	3.6	3.8

The 2025-2029 forecast represents an increase of $0.8 million over Toronto Hydro's 2020-2024 average annual cost of $2.7 million.

5.3 Customer Connections Segment Variance Analysis

2020-2021 Variance Explanation

The costs from 2020 to 2021 decreased by $2.1 million due to restructuring of the customer connections team and costs being allocated to other teams.

2021-2022 Variance Explanation

There was no variance from 2021 to 2022.

2022-2025 Variance Explanation

Between 2022 and 2025 costs in this segment are expected to increase by $1.6 million or an average of $0.5 million per year due to:

- Increased headcount to address increased volumes and complexity of connections activity to support increased growth and electrification in the city of Toronto;
- Normal course compensation increases;
- the creation and ramping of two new teams, the Customer Intake Team and Pre-Design team;
- This is offset by slight decreases due to expected retirements.

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $0.6M, or an average of $0.2M per year, to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work discussed above. If Toronto Hydro was forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks and drawbacks, such as a reduced ability to provide potential customers safe and reliable connection options in a timely manner. An in-depth analysis is required to determine the impact of a new customer on

the grid to ensure system integrity, and insufficient funding could compromise the ability to properly conduct this analysis;

6. KEY ACCOUNTS

6.1 Segment Description

Toronto Hydro's Key Account customers are those customers who have critical loads, including:

- Customers who have electricity use greater than 1MW at a single site or combined across a number of sites – this is increasingly including data centres and large developments;
- Priority loads such as hospitals and financial institutions;
- Essential public services including the TTC and schools; and
- Developers.

Many of these customers are critically important to the economic and social fabric of Toronto. These customers often have distinct needs and priorities including:

- **Power quality and reliability:** Generally, a top priority for these large customers. Depending on the nature of their operations, even momentary interruptions can incur high costs due to loss of product or create health and safety issues in the operation of critical infrastructure.
- **Complex Connections and Expansions:** Many Key Account customers have large or complex connections, such as data centres and real estate developments, which require additional support and resources through all phases of their projects.

- **Environmental Social & Governance (ESG) goals**: Many Key Account customers are already planning for the energy transition towards decarbonization and may have their own ESG goals to meet.

- **Behind-the-Meter (BTM) energy solutions:** Many Key Account customers are interested in adopting BTM energy solutions to address a range of issues from back up supply, ESG targets and cost management through peak shaving and load shifting.

Because of these unique needs, Key Account customers require a tailored level of customer service. The Key Accounts team proactively engages with these customers on a wide range of topics (described below) to ensure that work is coordinated with customers and Toronto Hydro's crews can complete work in a timely and efficient manner. Specifically, Key Accounts acts as a single point of contact within Toronto Hydro for work related to these customers, including:

- Facilitating and assisting with scheduling and planning for major capital and maintenance projects, operational requirements, and regulatory compliance;
- Liaising with departments across Toronto Hydro including: engineering, design and construction, and operations;
- Meeting with customers to resolve billing issues, coordinate planned outages, and provide business-specific updates during unplanned outages;
- Resolving issues related to reliability and power quality;
- Discussing opportunities for reducing emissions and meeting decarbonization goals;
- Partnering with the IESO to support the delivery of Local Incentive Programs;[11] and,

[11] Under previous Conservation and demand Management frameworks, the Key Accounts function worked with large customers to access provincial funding for energy efficiency programs.

- Providing account and sector specific information through various channels such as direct mail, newsletters, workshops, and association outreach.

As the needs of large customers continue to evolve, the Key Accounts function has also evolved to emphasize more proactive engagement with these customers. The Key Accounts team had 490 meetings with customers in 2021. In 2022, the Key Accounts team had 1139 engagements with customers, including 723 customer meetings, as well as emails and phone calls.

Through regular outreach and structured meetings with developers and current and future customers, the Key Accounts team is able to obtain information and insight into development and growth plans across the City of Toronto and gain insight into connections much earlier in the planning process. This can include projects that are contemplated for ten or 20 years in the future. Where necessary, the Development Planning team will be involved, along with the Key Accounts team, to provide technical information and ensure that relevant information is incorporated into future forecasting information.[12] Traditionally, Toronto Hydro would not be engaged until much later in the development process –approximately a year or two before the project was set to begin – which provided less opportunity to efficiently integrate necessary expansions into system-level planning.

Key Accounts is also engaged by the Customer Connections team when large connection requests are received, validated, and pre-design payments are made. This is the beginning of the relationship that Key Accounts has with the customer (or a continuation in the case of an existing Key Account customer). Through initial meetings, the team understands the

[12] See Exhibit 2, Sections E7.4 Stations Expansions and E5.3 Load Demand.

customers' goals, and shares a high-level overview of the connections process that the customer will experience. Engagements continue with the customer throughout the life cycle of the project, ensuring a streamlined customer experience. A significant area of value that Key Accounts delivers is in ensuring timely handoffs between internal teams; when cross-departmental decisions must be made pertaining to connections, the team coordinates meetings and ensures internal alignment before communicating with customers.

Key Accounts also works with customers to understand their energy management needs, including supporting customers with their decarbonization goals. If customers are considering incorporating new technologies[13], the Key Accounts team consults with customers to ensure that new technologies meet Toronto Hydro standards and Conditions of Service, generally with support from the appropriate teams internally.

Key Accounts leverages its relationships to support the distribution system more broadly including through the procurement of demand response and other flexibility services to the benefit of both key account customers and the grid as a whole. In addition, by engaging early with Key Account customers, Toronto Hydro is provided with insight into areas of growth and changing customer needs which allows Toronto Hydro to better plan for future system needs.[14]

6.2 Key Account Segment Costs

Table 5 provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for this segment.

[13]For example, electrification of space and water heating, electric vehicles, energy efficiency and demand management, or installation of behind the meter solar and/or battery systems.
[14] For more information see Exhibit 2B, Section B3 – Coordinated Planning.

Table 5: Key Account Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Key Accounts	-	0.5	0.8	0.9	1.2	1.5	1.5	1.7	1.8	1.9

6.3 Key Accounts Segment Costs Variance Analysis

2020-2021 Variance Explanation

The costs from 2020 to 2021 increased by $0.5 million due to team formation and onboarding of resources midyear.

2021-2022 Variance Explanation

The costs from 2021 to 2022 increased by $0.3 million due to this being the first full year of resource expenditures.

2022-2025 Variance Explanation

The costs from 2022 to 2025 are expected to increase by $0.7 million or an average of 0.2 million per year due to increases in headcount to ramp up operations of the team and inflationary increases.

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $0.4M, or an average of $0.1 million per year, to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work discussed above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks and drawbacks, including:

- Limited opportunity for ongoing interactions and collaborative relationships with large customers to identify and meet their unique needs; and
- Potentially becoming a barrier to customer choice for electrification and other new technologies for large customers who may require additional support and coordination in order to execute electrification strategies.

7. PUBLIC SAFETY AND DAMAGE PREVENTION SEGMENT

7.1 Segment Description

The Public Safety and Damage Prevention segment consists of the governance, oversight, and execution of work to ensure public safety and prevent potential damage to Toronto Hydro's distribution equipment when customers (or their contractors) perform work in proximity to the utility's assets. The primary activity in the segment is identifying the location of Toronto Hydro's underground infrastructure (commonly referred to as "locates") pursuant to the OUINSA. The utility responds to locate requests forwarded through Ontario One Call by identifying and marking the location of its underground infrastructure in accordance with applicable statutory requirements.

The OUINSA mandates all excavators in Ontario, who may be homeowners, contractors working for property and infrastructure owners, developers, or other utilities, to use the Ontario One Call service to request a utility locate to confirm that the work area does not contain any underground infrastructure. The locate process is intended to ensure public safety and prevent damage to underground infrastructure. As previously discussed, following the enactment of Bill 93 in April 2022, the OUINSA incorporates strict compliance requirements for both infrastructure owners and excavators, and provides recourse for both sides in the event that a party suffers losses or expenses due to another's failure to fulfill statutory obligations. Therefore, Toronto Hydro is required by

law to comply with the OUINSA framework and is responsible for the costs of performing requested locates its service territory.

The utility outsources the locate function to LSPs, who process requests received through Ontario One Call and identify the location of Toronto Hydro's underground infrastructure. The utility currently provides locate services upon request at no charge to the requesting excavator and recovers the costs through its distribution revenue requirement. This encourages widespread use of the service, which yields significant public safety and reliability benefits from properly locating underground infrastructure and enabling safe excavation practices. By avoiding damage to distribution equipment and infrastructure, the risk of outages and the likelihood of safety hazards for construction and utility workers and the public are significantly reduced.

As an infrastructure owner and thus a "member" under the OUINSA, Toronto Hydro is required to pay Ontario One Call for the locate request intake services and general oversight the latter provides. The utility must also cover the costs of LSPs performing the actual locate work. The cost of an individual locate varies depending on the nature of work requested and the timeline for its execution.

Segment activities also include the planning and execution of alternate locate agreements ("ALAs") with any excavator that meets Toronto Hydro-specified requirements. ALAs allow excavators who use the hydrovac excavation method to excavate without the requirement of a utility locate because the excavation method presents a significantly lower risk of damage to utility infrastructure. Through an ALA, the utility assigns the excavator a blanket locate clearance through a contractor identification number. This identification number allows Ontario One Call to filter related locate requests out of the general intake of locate requests and into the ALA clearance process, allowing the

excavator to obtain immediate approval to perform shallow excavation. Through this approach, excavators are able to commence excavation work earlier than the standard five-day turnaround time for locates and Toronto Hydro is able to minimize the costs associated with completing the locate. As a result, ALAs lead to higher customer satisfaction, require less coordination and oversight from Toronto Hydro, and enable cost efficiencies.

7.2 Public Safety and Damage Prevention Segment Costs

Table 6 provides the Historical (2020-2022), Bridge (2023-24), and Forecast (2025-2029) expenditures for this segment.

Table 6: Public Safety and Damage Prevention Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Public Safety & Damage Prevention	4.7	4.4	5.4	7.3	6.8	6.7	6.9	7.0	7.2	7.3

As discussed in section 4.1 above, this cost forecast includes increased labour costs and other types of segment costs known at the time of filing, although there remains a great degree of uncertainty regarding the full extent of locates-driven costs that Toronto Hydro may need to incur in the 2025-2029 period to achieve compliance with OUINSA. Therefore, if there are any additional material developments that may affect the 2025-2029 segment cost forecasts while the evidentiary record is open during this rate application proceeding, the utility will adduce additional evidence as required. To enable adequate funding of locates work, which is non-discretionary, while ensuring compliance with the utility's legislative and regulatory obligations during the next rate term, Toronto Hydro also requests continuation of the GOCA Variance Account to record the incremental costs of locates resulting from the implementation of the OUINSA, as discussed in Exhibit 9, Tab 1, Schedule 1.

Alternatively, if the OEB were to approve neither the forecasted costs laid out in Table 6 above nor the request for continuation of the GOCA variance account, Toronto Hydro would have to provision in its forecast of 2025-2029 rates for a higher recovery of locates costs that the utility would have to incur to achieve 100 percent compliance with OUINSA during the 2025-2029 rate period. Table 7 below shows the estimated costs for this scenario.

Table 7 Public Safety and Damage Prevention Segment Expenditures Provisioning for Lack of Continued Availability of the GOCA Variance Account ($ Millions)

2025	2026	2027	2028	2029
10.4	11.4	12.3	13.4	13.9

7.3 Public Safety and Damage Prevention Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

There was a decrease of $0.3 million between 2020 and 2021 due to continued impacts on the construction industry from COVID-19 shutdowns, reducing volumes of locates. During COVID-19 shutdowns, locates were mainly driven by excavations related to large projects, essential services, and critical infrastructure.

2021 – 2022 Variance Explanation

There was an increase of $1 million between 2021 and 2022 primarily driven by inflationary labour costs and an increase in the volume of costlier multi-segment locate requests.

2022 – 2025 Variance Explanation

Between 2022 and 2025 costs in this segment are expected to increase by $1.3 million or an average of $0.4 million due to:

- Cost increases arising from stricter locate performance standards imposed by Bill 93 including:
    - Increased labor costs due to Toronto Hydro new contract with the LSPs; and,
    - Cost increases arising from stricter locate performance standards (including increased volumes);
- Annual inflationary cost increases;
- Increased volumes due to general growth;

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $0.6M, or an average of $0.2M per year, to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work discussed above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks and drawbacks, including:

- Digs by excavators without proper information about the location of underground infrastructure, which could potentially result in damage to distribution assets, system outages, and major safety risks to field workers or the public;
- Reduced performance in providing locate information in a timely manner, resulting in administrative monetary penalties and other compliance enforcement actions by Ontario One Call; and,
- Inability to comply with stricter locate performance standards imposed by Bill 93.

8. CUSTOMER-OWNED EQUIPMENT SERVICES SEGMENT

8.1 Segment Description

The work comprising this segment enables Toronto Hydro's commercial, industrial and multi-unit residential building customers to safely perform periodic maintenance activities on their (customer-owned) civil infrastructure and other equipment, and facilitates the notification of deficiencies, thereby improving the reliability and safety of the distribution system.

8.1.1 Vault Access

Customers are responsible for supplying, maintaining, repairing, and otherwise modifying all civil assets located on their property, and any civil infrastructure located on public road allowances that serve unmetered connections. The applicable infrastructure includes poles, cable chambers, transformer rooms, transformer vaults, hand wells, junction boxes, and other equipment housing or supporting Toronto Hydro's connection assets. The most common type of customer equipment access relates to transformer vaults located on customers' property. In the interest of public safety, the utility places locks on transformer vault doors, to ensure that only qualified personnel have access to these rooms and the high-voltage electrical equipment they contain. From time to time, Toronto Hydro customers require access to vaults for periodic maintenance and inspections, or to perform repairs identified as necessary during prior site visits, e.g. through the Customer Action Form process described below in subsection 6.1.2.

There are over 8,600 customer-owned vaults in Toronto Hydro's service territory that contain distribution equipment. Where required, a customer-owned vault may contain fire detection equipment, which must be inspected annually in accordance with the applicable legislative and regulatory requirements. During vault inspections by customers

and/or third parties, Toronto Hydro requires qualified staff, i.e. a vault safety agent ("VSA") to attend for safety purposes and to prevent damage to the utility's assets. VSAs ensure that access to the customer-owned vault is completed safely by all who enter by ensuring that limits of approach are maintained and proper personal protective equipment ("PPE") is worn. VSAs are authorized to refuse to commence or end an appointment if safety practices are not being maintained. When Toronto Hydro identifies structural deficiencies with or within the vault structure, access doors, grounding equipment, drainage, or other physical attributes, it provides the customer with a completed Customer Action Form, which explains the nature of the deficiencies and recommends corrective steps, as discussed in the next subsection.

8.1.2 Customer Action Form ("CAF") Process

Toronto Hydro issues customers and property owners a CAF when any electrical or civil deficiencies are found in the field on customer-owned equipment or structures. Customers are responsible for replacing or repairing their defective electrical equipment and those that own a transformer vault are responsible for inspecting, maintaining, repairing and replacing their vault when necessary.[15] As unaddressed deficiencies may cause damage to equipment or expose them to other risks (such as weather exposure, flooding, or premature deterioration of asset conditions), corrective work by customers is necessary to maintain the safety and reliability of both utility-owned and customer-owned electrical equipment and civil infrastructure, and mitigate the risk of potential outages. In addition, the Electrical Safety Authority ("ESA") requires distributors to address deficiencies with customers to ensure public safety and Toronto Hydro's CAF process plays the primary role in fulfilling this obligation. The utility issues approximately

[15] Examples of such electrical equipment or civil assets include electrical meter bases, stand pipes, transformer vaults that house high voltage equipment, etc.

2,000 electrical and 1,500 civil defect CAFs each year. The vault access process discussed above in section 6.1.1 is key to enabling many customers' compliance with the requirements of CAFs.

Toronto Hydro continues to improve upon its rigorous CAF process to ensure that customers are clearly made aware of their deficiencies and corrective obligations and are able to easily communicate with the utility. This supports the repair or mitigation of noted deficiencies and contributes to the continued safe and reliable operation of the distribution system. For example, where a customer increases the frequency of debris removal from their vaults and drain cleaning in response to a CAF, the risk of flooding within the vault decreases, which in turn reduces the risk of transformer and vault equipment damage and corrosion.

8.1.3 Low-Voltage Isolations

Toronto Hydro currently provides eligible low-income customers ("ELIC")[16] one free disconnection and reconnection ("isolation") per 12-month period. The utility's rationale for this approach is to encourage repairs to address deficiencies identified in CAFs and other customer-side work that may otherwise remain incomplete and jeopardize safety or grid reliability, as the cost of isolations may be prohibitive for this group of customers. In addition, this approach reduces the cost barrier for these customers where they require an isolation for service modifications or upgrades, including for electrification purposes, such as installing solar panels or electric vehicle chargers. It is estimated that approximately two percent of customers who request low-voltage isolations are designated as ELICs.

[16] As defined in the Distribution System Code.

8.2 Customer-Owned Equipment Services Segment Costs

Table 8 provides the Historical (2020-2023), Bridge (2024-2025), and Forecast (2025-2029) expenditures for the Customer-Owned Equipment Services segment.

Table 8: Customer-Owned Equipment Services Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Customer-Owned Equipment Services	0.9	1.0	1.2	1.2	1.2	1.3	1.4	1.5	1.5	1.6

8.3 Customer-Owned Equipment Services Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

There was an increase of 0.1 million between 2020 and 2021 due to increases in vault access volumes, as well as inflation.

2021 – 2022 Variance Explanation

There was an increase of 0.2 million between 2021 and 2022 due to increases in vault access volumes as well as inflation.

2022 – 2025 Variance Explanation

Between 2022 and 2025, costs in this segment are expected to increase by $0.1 million due to increases in vault access volumes as well as inflation.

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $0.3M, or an average of $0.1 million per year to maintain the resourcing capacity and capabilities required to support the volume and complexity of work discussed above. If Toronto Hydro

were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various risks and drawbacks, including:

- Inability to provide free access in a timely manner to customer-owned equipment and vaults, reducing customers' ability to maintain their equipment and civil infrastructure, and potentially jeopardizing public safety and the reliability of Toronto Hydro's system; and
- Inability to work with customers for the timely resolution of deficiencies and hazards through the Customer Action Form process, resulting in increased safety and reliability risks.

ASSET AND PROGRAM MANAGEMENT

1. OVERVIEW

Table 1: Asset and Program Management Program Summary

Asset and Program Management Program									
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Operational Effectiveness - Safety, Public Policy Responsiveness, and Environment									
Segments: • System Planning • Standards and Policies • Flexibility Services • Program Management and Support									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
13.4	11.9	13.1	13.5	14.0	14.2	15.8	16.6	17.9	18.7

Toronto Hydro's Asset and Program Management program (the "Program") encompasses a wide range of asset management functions to support the reliable and safe operation of the utility's electricity distribution system.

The functions in this Program are performed under four segments: (i) System Planning; (ii) Standards and Policies; (iii) Flexibility Services;[1] and (iv) Program Management and Support. The activities performed in these segments include:

- Equipment, materials and standards research;
- Stations and distribution system planning;
- Forecasting customer and system needs;
- Outage investigations and reliability planning;

[1] Previously referred to as Local Demand Response in Toronto Hydro's 2020-2024 Rate Application (EB-2018-0165).

- Integration of new technologies into the utility's system;
- Asset Information Management and Records;
- Flexibility services programs targeted at reducing system constraints at times of maximum demand in targeted grid areas to defer or avoid the need for specific distribution or transmission projects at a lower total resource cost;[2] and
- Program strategy, planning, budgeting, scheduling, resourcing, tracking and reporting of Toronto Hydro's distribution-related programs

The key outputs of the Program are long and short-term plans and scopes of work, organized in annual work programs, for capital and maintenance investments all aimed at maintaining and improving Toronto Hydro's distribution system performance. While a portion of the associated costs are capitalized (i.e. for work directly related to capital planning and the execution of capital programs), this Program funds the remaining costs through operational expenditures.

2. OUTCOMES AND MEASURES

The most significant output of this Program is the Distribution System Plan ("DSP") and Maintenance Plans, and their annual updates.[3] As such, the outcomes detailed in the DSP are indirectly enabled by this Program. The following table summarizes specific outcomes directly attributable to this Program.

[2] Exhibit 2B, Section E7.2.
[3] Exhibit 2B.

Table 2: Asset and Program Management Program Outcomes and Measures Summary

Customer Focus	• Contributes to meeting Toronto Hydro's obligations for customer connections (including Ontario Energy Board mandated ESQR measures)[4] by: ○ Processing and executing, in a timely manner, customer connection requests and offers to connect (both load and generation customers) as prescribed in section 7.2 of the Distribution System Code ("DSC"), ○ Routinely meeting with, engaging, and responding to customer and stakeholder requests and concerns.
Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: • Maintaining and actively managing Toronto Hydro's system and customer-specific reliability performance, • Ensuring ongoing stewardship of the distribution system and its ability to safely and reliably function in the long-term by maintaining asset records, scheduling maintenance activities, and developing capital investment scopes of work, and • Maximizing the usage of existing assets by conducting asset condition assessments.
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by: ○ Ensuring regular inspection of assets to, at a minimum, comply with Appendix C of the DSC, ○ Responding to the Ontario Energy Board's direction for utilities to consider and leverage non-wires alternatives where possible to drive rate-payer value, and

[4] Toronto Hydro's customer connection-related obligations include:
(i) completing low and high voltage connections within five and ten business days respectively at least 90 percent of the time, as measured pursuant to the OEB's new connection metrics and section 7.2 of the DSC;
(ii) completing customer appointments in accordance with the OEB's Appointment Scheduling and Appointments Met metrics 90 percent of the time, as per sections 7.3 and 7.4 of the DSC; and
(iii) responding to inquiries requiring a written response within ten business days at least 80 percent of the time, as measured pursuant to the OEB's Written Response metric and section 7.8 of the Distribution System Code.
Ontario Energy Board, *Distribution System Code* (August 2, 2023).

	○ Developing long-term plans for grid investment and capability-building that are responsive to the emerging pressures of electrification and the energy transition.
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's public and employee safety objectives by: ○ By reviewing inspection findings, scheduling timely corrective work to address deficient equipment and infrastructure, and planning asset renewal investments over the medium to long-term thereby mitigating safety risks, ○ Monitoring system capacity conditions to minimize the risk of operating the system in violation of applicable design parameters through load transfer or capacity expansion projects, and ○ Actively reviewing, researching, and updating material and standards documentation related to system assets and operating procedures.
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by: ○ Actively mitigating system risks that can result in costly failures and associated restoration work, and ○ Enabling deferral or avoidance of capital investment where demand is uncertain to optimize capital allocation.

3. PROGRAM DESCRIPTION

The Asset and Program Management program encompasses all functions supporting Toronto Hydro's asset management work and its coordination through the following segments:

- **System Planning:** This segment enables Toronto Hydro to analyze distribution system performance and needs, develop the utility's asset management strategy, develop the utility's grid modernization plan, develop the DSP and scopes of work for executing the DSP, and manage record keeping.
- **Standards and Policies**: This segment entails the development of all design and construction standards, Conditions of Service documents, management of the

utility's quality programs, and facilitation of load connections through the offer to connect process.

- **Flexibility Services**: Flexibility Services refers to programs that address localized distribution issues through targeted procurements with customers or other third-parties.[5]
- **Program Management and Support**: This segment funds activities that enable the planning, budgeting, scheduling, resourcing, and tracking and reporting of Toronto Hydro's distribution-related programs. It also manages changes throughout the lifecycle of capital and maintenance projects.

4. PROGRAM COSTS

In 2025 Toronto Hydro requires $14.2 million in rate funding for Asset and Program Management program, which represents an increase of $0.8 million over the last rebasing in 2020. When normalized for shared services recoveries outlined in Exhibit 4, Tab 5, Schedule 1, the expected increase in this program is $1.2 million.

Over the 2025-2029 rate period, the utility expects the cost of this program to increase by an annual growth rate of 7.1 percent which is necessary to address the program needs (e.g. Planned Capital and Maintenance Work, Integrated Planning & Grid Modernization, and, Work Program Management) and deliver the customers outcomes enabled by this program.

Table provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Years (2025-2029) expenditures for each of the Program's segments.

[5] *Supra* note 2.

Table 3: Asset and Program Management Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Planning	5.6	6.1	7.5	8.1	8.1	8.4	9.1	9.5	10.0	10.3
Standards and Policies	4.7	4.5	4.3	2.8	3.0	3.2	3.2	3.3	3.4	3.5
Flexibility Services	0.4	0.2	0.2	0.8	0.8	0.2	0.9	1.1	1.6	1.9
Program Management and Support	2.7	1.1	1.1	1.8	2.1	2.4	2.6	2.7	2.9	3.0
Total	**13.4**	**11.9**	**13.1**	**13.5**	**14.0**	**14.2**	**15.8**	**16.6**	**17.9**	**18.7**

4.1 Cost Drivers

The high-level cost drivers are described below. Specific variance explanations can be found under the detailed description of each Program segment in the sections below.

4.1.1 Planned Capital and Maintenance Work

The Program is driven by the amount of capital (system access, renewal, and service) and maintenance work, and associated scopes of work that must be developed. The costs of work that is required to support these programs is generally proportional to their magnitude. For example, expenditures in system access, renewal and service will increase by approximately 30 percent in the period. Furthermore, growth and electrification, system studies and development planning need and distributed energy resource ("DER") connections will require incremental studies, forecasts and planning, and the deployment of Intelligent Grid, Energy Storage technologies, and Non-Wires Solutions.

4.1.2 Reactive Capital and Maintenance Work

Costs are driven by the number of deficiencies identified through maintenance and inspections, and these costs are expected to increase as a result of the growing volume of deficiencies and reactive and corrective work requests generated through planned maintenance programs as well as through normal course of operations.

4.1.3 Integrated Planning & Modernization

Costs in the Integrated Planning & Modernization segment are driven by the need to administer the annual Investment Planning and Portfolio Reporting ("IPPR") process, continuous improvement of the Asset Management System (including ISO 55001 alignment and certification), Grid Modernization Strategy research, development and implementation, and Future Energy Scenarios modelling. There are also opportunities for leveraging advanced analytics to enable data-driven decision making for applications like predictive asset management, grid planning and optimization, load forecasting, etc. which will require the development of additional skillsets and capabilities and greater efforts to ensure accurate, up-to-date, and accessible asset information and records. These programs are essential to ensure future reliability, security and cost efficiency.

4.1.4 Standards Change Requests

Costs in the Standards and Policies segment are driven by the number of standards change requests submitted and required, including an anticipated increase in Standards change requests to meet the needs of electrification demands.

4.1.5 Evolving Design Standards

The Standards and Policies segment costs are also driven by the need to comply with applicable requirements, including Ontario Regulation 22/04 ("Electrical Distribution Safety Regulation").[6] For instance, all installation work must be based on standard design drawings and specifications, and all electrical equipment installed on the distribution system must be approved pursuant to that regulation. With revisions to industry standards, including Canadian Securities Administrators ("CSA") standards on Overhead and Underground Distribution Lines, standard design drawings and specifications are

[6] Ontario Regulation 22/04, under the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A.

subject to change to ensure that safety standards as per the Electrical Distribution Safety Regulation are met. In addition, as Toronto Hydro continues to explore the use of new technologies in its distribution system to improve reliability and operational efficiency, and reduce overall operating costs, standard designs will also need to evolve to reflect industry best practices.[7]

4.2 Cost Control and Productivity Measures

Toronto Hydro expects cost control and productivity measures within the Program to enable cost savings and increased efficiency throughout the rate period. The overall costs of the program are projected to increase throughout the rate period, but these measures moderate the rate of increase.

In the System Planning segment, there is a large increase in workload due to multiple new initiatives including: development of the grid modernization roadmap, support in implementation of Asset Investment Planning ("AIP"), and broader technical support for the customer care function that interfaces with customers considering electrification activities. Despite an increased workload due to expanded scope of planning, Toronto Hydro plans to manage these increasing costs through continuous improvement measures, including:

- Leveraging existing and new analytics tools to improve data quality within Toronto Hydro;
- Providing licenses to more employees for existing tools, such as Alteryx Designer to improve productivity; [8]
- Implementing centralized online tools including:

[7] *Supra* note 5.
[8] Alteryx Designer is a software application used for advanced data analysis, including data preparation, blending, reporting, predictive analytics and data science.

- A new Microsoft SharePoint page which will be used as a central platform for the System Studies team to receive submissions, complete reviews and track requests;
- Integrating Toronto Hydro's station relay and asset data into a consolidated database and management platform developed for Toronto Hydro. This database acts as a central location to store and track all settings used for maintenance and construction activities at our Municipal Substations and Transformer Stations, improving record keeping for all Toronto Hydro stakeholders; and

- Strategic usage of records service providers to more cost effectively update and maintain asset records within core systems such as the GIS, ERP, and document management systems.

In the Standards and Policies segment, Toronto Hydro expects to maintain segment expenditures below 2020-2024 levels as a result of continuous improvement measures which will reap benefits in the 2025-2029 period, including:

- Implementing the Intelex Quality Management module replacing Excel workbooks and Access databases. The module improves productivity over previous tools and creates a seamless workflow to manage end to end defect investigation, and provide transparency and visibility of defect investigation progress to all stakeholders;
- Leveraging analytic tools (Alteryx) to automate the information extraction process necessary for an Equipment Failure Analysis; Outputs from the workflow are displayed through interactive dashboards (Tableau); This was implemented over the 2020-2024 rate period.

- Redesigning Toronto Hydro's priority decision framework, and implementing a new tool, Asset Deficiency Assessment Priority Tool ("ADAPT"), resulting in a significant reduction in manual engineering reviews. Specifically, between 2020 and 2021, the quantity of manual engineering reviews for major assets was reduced by approximately 40 percent and escalations by crews was reduced by 25 percent;
- Launching the Asset Deficiency Web Portal - This portal allows internal personnel to submit reactive work requests when deficiencies are identified. When this portal was launched, Toronto Hydro also standardized the processes of gathering information, and creating and reporting work request information back to the requester and affected stakeholders. Standardization allows consistency and limits the number duplicate work request, reducing the overall process time; and
- Migrating the Product Change requests database from Microsoft Access to Customer Relationship Management ("CRM"), resulting in a centralized work platform to manage Product Change requests and better communication among teams involved. This was implemented in 2020. The migration to CRM also resulted in drastic improvement of classification of Product Change requests, resulting in better reporting and process efficiency;

In addition, much of the work performed in this segment is initiated through formal change requests (e.g. change a construction standard to accommodate new equipment) or informal requests for support (e.g. technical clarification regarding a design policy). All instances of such services provided by this segment are tracked and categorized. The data is then used to identify trends and recurring issues, and opportunities for improvement and efficiency gains.

Please see section Exhibit 2B, Section E7.2 for details of the Flexibility Services Program productivity and efficiencies.

In the Program Management and Support segment, productivity and operational efficiencies are gained through broad productivity enhancements including:

- Developing a number of workflows using Alteryx data processing to automate complex data analytics tasks, allowing staff to focus on other value-add tasks. For example, the Preventative Maintenance Units Tracking workflow, developed in 2022, translates Plant Maintenance order status from SAP to maintenance unit attainments. This workflow resulted in approximately 300 hours of time saved per year. Overall, the total recorded 69 workflows within Program Management and Support segment are estimated to have saved approximately $420,000 saved per year;
- Implementing an electronic red construction folder system to replace a physical red construction folder. It is estimated that this resulted in a savings of $276,000 in 2022. In addition, this contributed to significant operational benefits including, decreased time to release and complete work, efficiency in searching for and retrieving electronic documents, and improved access capabilities to internal and external users;
- Establishing a Weekly Switching Work Plan process that ensures that the feeder switching,[9] necessary to complete the planned Capital and Maintenance program, are delivered. Toronto Hydro uses synergies or bundling to reduce the number of times a feeder is removed from service, leading to savings on switching costs, reduced risk of not completing capital and maintenance programs on time,

[9] Feeder Switching creates a safe work zone for field crews by de-energization of feeder to complete work

reduced exposure to high-voltage equipment and improved customer reliability. From 2019 to 2022, approximately 2606 switching hours per year were saved through bundling of outages;

- Enhancing SAP Business Planning and Consolidation ("BPC") tool that delivers planning, budgeting, forecasting, reporting and financial consolidation capabilities. The new enhancements, which were implemented in July 2022, aim to address gaps in the current planning process through automation of existing manual efforts and processes, reduction in offline data, and use of an integrated solution with a central repository, to execute end to end planning cycles between finance and operations.
- Introducing new software to more efficiently track project information and associated change management.

5. SYSTEM PLANNING SEGMENT

5.1 Segment Description

The work done through the System Planning segment is divided into four functional areas:

- Investment Planning;
- Capacity Planning & Intelligent Grid;
- Integrated Planning and Grid Strategy; and
- Records Management.

Together, these functional areas enable Toronto Hydro to analyze the distribution system's performance and needs, develop the utility's asset management strategy, and produce the DSP as well as scopes of work for DSP execution.

5.1.1 Investment Planning

The Investment Planning function allows Toronto Hydro to monitor and analyze performance measures for its distribution system, identify system needs, and develop the capital portions of the DSP. The analytical work undertaken includes:

- **Reliability Analysis**: System power outage data is analyzed to: (i) identify performance patterns and trends related to specific types of equipment or geographical areas, and (ii) develop reliability forecasts based on investment scenarios. Outage data captured in specialized outage software is used to conduct detailed analyses of outage events, and identify worst performing areas as well as customers most affected by system outages. The analytical work performed under this function is critical to identifying system needs, informing investment decisions, and prioritizing work in various System Renewal and System Service capital programs. The results of reliability forecasting for the plan based on the DSP are provided in Exhibit 2B, Section E2. This analysis also forms the basis for managing reliability targets for measures such as SAIFI, SAIDI, and FESI-6,[10] both from year to year and over the longer term.
- **Asset Condition Assessment**: This is done at the discrete equipment level and the feeder (or station) levels to identify assets showing signs of significant deterioration and in need of replacement, refurbishment or other forms of intervention. This ensures the continued safe and reliable operation of the distribution system. Further details on the ACA can be found in Section 6.1.2 below. [11]

[10] Exhibit 2B, Section C2
[11] Exhibit 2B, Section D3, Appendix C.

- **Capital System Planning**: Based on the system analysis described above, the planning function creates station and distribution capital work plans for design and construction, to enhance the reliability of the distribution system.

  Other Analyses: The planning function supports the works of engineering groups by assessing risks relating to: environment and safety (e.g. oil leak deficiencies), customers (e.g. customer interruption costs, impact on large account customers), legal (e.g. claims relating to property damage), and corporate brand and reputation (e.g. with respect to various stakeholders, the media, specific communities).

This analytical work, conducted as part of the Investment Planning function, forms the basis of the development of Toronto Hydro's DSP, and contributes to individual projects that together enable the utility to execute its capital and maintenance programs and address reliability, condition, or system risk needs at local levels (e.g. individual equipment, line sections, stations). Insights from the detailed analyses are used to explore feasible mitigation options to determine optimal solutions to specific issues. If the preferred solution for a particular issue is a capital investment, a scope of work is created. Figure 1 below illustrates Toronto Hydro's historic and forecasted capital expenditures initiated by a scope of work. Scoped work represents planned work that requires design, whereas demand program represents work that is reactive in nature, or requested or initiated by customers or a third party.

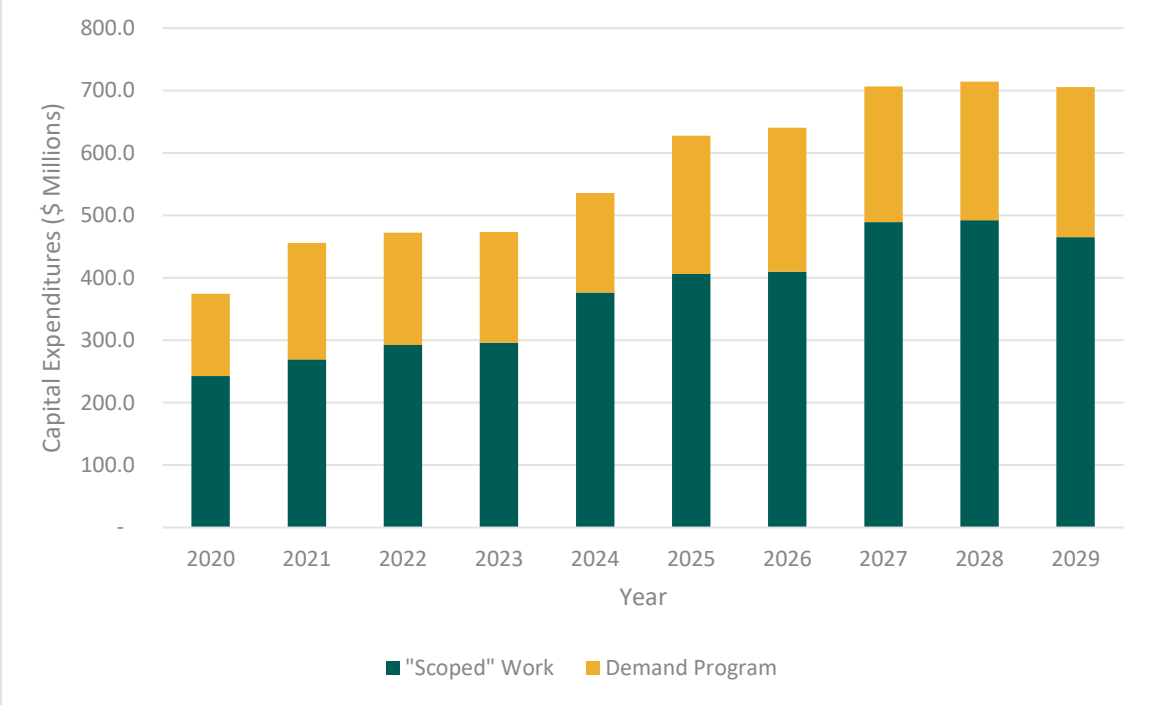


Figure 1: Value of Scopes of Work (Renewal, Service, Access)

5.1.2 Capacity Planning and Grid Innovation

This functional area is responsible for planning the distribution system's future load requirements driven by customer growth, and the requisite connection capacity to accommodate current and forecasted levels of DERs in Toronto Hydro's service area. This group also identifies opportunities for adopting non-wires alternatives (including flexibility services, local demand response) to maximize the use of existing distribution system assets.

Capacity planning work requires constant monitoring of changing system characteristics, such as feeder and transformer station loadings, short-circuit levels and system performance measures. Combining system performance data with past system demand trends and known requests for load and generation connections, Toronto Hydro produces

system demand forecasts to determine what our system demands might be in the future.[12]

Toronto Hydro has a dedicated DER Connections team that works closely with customers to ensure the DER connection process is followed and timelines are met. The Capacity Planning and Grid Innovation function is responsible for the capacity plan in the Customer Connections Program.[13]

5.1.3 Integrated Planning & Grid Modernization

The Integrated Planning function includes staging and administering the annual IPPR process, coordinating the engineering division's Distribution System Plan preparation for regulatory applications, as well as developing and implementing analytics and support tools to drive more effective and efficient investment planning. The function is also responsible for the continuous improvement of the Asset Management System, aligning to best-in-class standards, and developing the long-term asset management strategy.

The Grid Modernization function is responsible for facilitating the development, integration, and strategic oversight of Toronto Hydro's long-term Grid Modernization Strategy and associated roadmaps, in addition to providing market intelligence and strategic forecasting of future electricity system needs and opportunities, and change-management support capacity to help accelerate innovation initiatives. This function has been introduced in recognition of the fact that Ontario's energy system is set to undergo significant long-term changes as it becomes increasingly decarbonized, decentralized and digitized. These demands have established the need for incremental resources, new

[12] Exhibit 2B, Section D2.
[13] Exhibit 2B, Section E5.1

skillsets and additional third-party support within the planning and engineering functions of the utility, with a specific focus on providing the specialized support and strategic inputs necessary to manage a greater pace of change and level of uncertainty.

An early example of these new strategic insights is the Future Energy Scenarios ("FES") model. FES is scenario-based model developed with leadership from the Grid Modernization function and support from an external modelling expert. This model provides granular data on possible future changes to power demand, energy consumption, generation and storage across Toronto due to decarbonization, changing customer behaviours and evolving economic and policy conditions out to 2050. The model also provides an assessment of the potential impacts of these changes on the network. [14]

The 2025-2029 Grid Modernization Strategy, the development of which was coordinated by the Grid Modernization function.[15] Going forward, Toronto Hydro plans to mature and expand the Integrated Planning and Grid Modernization functions to provide the dedicated and specialized support required to deliver and accelerate the associated grid modernization and innovation programs. Given the increasingly long-term and strategic nature of integrated investment planning in the emerging environment, it will be necessary for Toronto Hydro to continue augmenting its traditional, largely project-focused planning and engineering functions with dedicated resources carrying specialized skillsets, including strategic planning, smart grid engineering, cost-benefit analysis, research and development, analytics, change management, and innovation expertise. For

[14] Exhibit 2B, Section D4.
[15] Exhibit 2B, Section D5.

more information on the variety of programs, initiatives, and activities these functions are supporting, refer to the Grid Modernization Strategy.[16]

5.1.4 Records Management

The Records Management function involves the maintenance and upkeep of digital records of Toronto Hydro's distribution system. Toronto Hydro's system is constantly changing due to new customer connections (which results in evolving system capacity and configuration), as well as equipment failures, retirements, additions and reconfigurations. The utility must maintain up-to-date records to enable efficient and effective system planning and operations. Toronto Hydro also maintains records of its distribution asset inspections pursuant to the Electrical Distribution Safety Regulation.[17] When Toronto Hydro installs new assets on its distribution system on a planned or reactive basis, key data management systems must be updated based on relevant installation and inspection records.[18] Approximately 5,500 equipment change-outs are processed annually through the above systems.

Failure to update systems and records when equipment is replaced or reconfigured in the system raises significant safety and reliability risks as this data is referenced and relied on daily by investment planners, system controllers, designers, and trades staff across the organization. The Records Management function plays a crucial role in ensuring the quality and accuracy of data maintained and used at Toronto Hydro.

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[16] *Ibid*.
[17] *Supra* note 6.
[18] For example, Geographic Information System (GIS) – Referred to as GEAR (i.e. Geospatially Enabled Asset Registry), which also serves as the source of information for Toronto Hydro's DMS/NMS, and Enterprise Asset Management System (EAM) – Referred to as SAP.

Toronto Hydro expects the costs in the Records Management function to increase in 2025-2029 to keep pace with the growing investment program and customer demands. Another driver will be an overall increase in the expected quality, availability, and integration of critical asset and system information. As discussed in Exhibit 2B, Sections D1 and D5, unlocking the potential value of advanced analytics and distribution automation will require a higher overall level of data quality and governance, which will place more demands on the Records Management function and associated departments that are responsible for handling critical asset information.

5.2 System Planning Segment Costs

Table 4 provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Years (2025-2029) expenditures for the segment.

Table 4: System Planning Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Planning	5.6	6.1	7.5	8.1	8.1	8.4	9.1	9.5	10.0	10.3

5.3 System Planning Segment Year-over-Year Variance Analysis

2020-2021 Variance Explanation

From 2020 to 2021, costs in this segment increased by $0.5 million. This is attributable to the then new Integrated Planning & Modernization function. Grid Strategy was a new team created in 2021 under Integrated Planning & Modernization for the purpose of development of a Grid Modernization Strategy for Toronto Hydro, development of FES and pursuing ISO 55001 certification for asset management.

2021-2022 Variance Explanation

From 2021 to 2022, costs in this segment increased by $1.4 million. There was a continued ramp up of the new functions initiated in 2021 that contributed to an increase in costs. In particular, the costs related to the development of FES which kicked off in 2022 and a third-party consultant to perform a gap analysis and prepare plan for ISO 55001 certification for Toronto Hydro's Asset Management System.

2022 – 2025 Variance Explanation

Between 2022 and 2025, costs in this segment are expected to increase by $0.9 million, or by an average of $0.3 million per year due to the need to further expand:

- Integrated Planning & Modernization activities to better manage planning uncertainty and accelerate the adoption of value-added digital capabilities. For example, analytical capability to support more rigorous long-term investment plan development in response to energy transition and electrification and the development and implementation of enhanced analytics and decision-support tools; and,
- All increases are also generally affected by inflationary pressures.

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $1.9 million, or an average of $0.5 million per year, to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work discussed above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various legal compliance risks and negative consequences, including:

  - Inefficient and ineffective system planning;

- Inability to support or plan capitalized work due to reduced ability to monitor and analyze distribution system performance measures, identify system needs, or develop the capital portions of the DSP;
- Decreased short- and long-term reliability of the distribution system;
- Inability to manage risks around growth and electrification;
- Inability to capitalize on synergies or maximize the use of existing distribution system assets;
- Sub-optimal coordination with the IESO and regional planning groups, and with customers for purposes of enabling distributed generation ("DER") connections (resulting in potential non-compliance with Ontario Energy Board prescribed processes and timelines);
- Inability to develop and integrate improved analytics capabilities and productivity improvement in planning, and decision support system;
- Inability to manage risks around modernization initiatives. For example, failure to maximize benefits of new technologies due to inadequate training of employees; and
- Significant safety and reliability risks if records and data updates are not synchronized with equipment or system configuration changes (given that such data is relied on by investment planners, system controllers, designers, and trades staff across the organization), incomplete data returned from the field and projects not completed in a timely manner.

6. STANDARDS AND POLICIES SEGMENT

6.1 Segment Description

The Standards and Policies Segment is responsible for the development of the utility's design and construction standards, Maintenance Planning, managing the utility's quality programs, and facilitating load connections through the offer to connect process.

6.1.1 Design and Construction Standards

One of the core functions of the Standards and Policies segment is the development and maintenance of design, construction and equipment standards and specifications for the electrical and civil construction work executed by Toronto Hydro. It is driven by the Electrical Distribution Safety Regulation, which requires distributors to create standard design drawings and specifications for all equipment comprising the distribution system. This function has a significant focus on safety of utility workers in the public. "Safety by design" is a core principle routinely applied in the utility's decision making. Toronto Hydro has more than 1,000 construction standards managed by this function. Changes to these standards are driven by reliability improvements, new technologies, regulatory changes, and industry standards (e.g. CSA standards) revisions. Toronto Hydro processes an average of 550 standard change requests per year.

6.1.2 Maintenance Planning

The Maintenance Planning function includes the analysis and preparation of Toronto Hydro's maintenance plans and schedules for all components of its distribution system. Toronto Hydro uses a Reliability-Centered Maintenance ("RCM") framework as the foundation for its maintenance planning. RCM is an established engineering framework that determines failure management policies for any physical asset in its present operating context to maximize reliability and extend useful life based on the asset's

function and the consequences of functional failure on the distribution system. RCM analyses are critical in scheduling asset maintenance programs and activities. From 2016 to 2018, Toronto Hydro updated the RCM results and analyses for each asset certified to align with RCM best practices.[19] See Exhibit 4, Tab 2, Schedules 1, 2, and 3 for details on Preventative and Predictive Maintenance.

Beginning in 2017, extensive work was performed to update the ACA (based on the most recent inspection results) and adopt a new ACA framework. Toronto Hydro now uses an ACA framework and algorithm adopted from the Common Network Asset Indices Methodology ("CNAIM"). The ACA is crucial to guiding planners in deciding which assets to include in their investment plans. Since 2017, changes have been made to reflect inspection program changes and to model empirical field observations. In addition, Condition-driven Probability of Failure has been developed leveraging ACA data. Over the 2023 to 2024 period, Toronto Hydro is working to leverage its Value Framework initiative to develop a full risk view within the ACA methodology.[20]

The Maintenance Planning function also entails the review of all asset deficiencies identified through maintenance and inspection activities. During the 2020-2022 period, between 30,000 and 50,000 deficiencies were reported annually, and reviewed and categorized for the purposes of formulating corrective and reactive responses (as detailed in Exhibit 4, Tab 2, Schedule 4 Corrective Maintenance). The work undertaken in Maintenance Planning is critical to both the short-term viability (e.g. by addressing

[19] Applicable Standards: SAE JA-1011 (Evaluation Criteria for Reliability-Centered Maintenance (RCM) Processes). Applicable Guideline: SAE JA-1012 (A Guide to the Reliability-Centered Maintenance (RCM) Standard)
[20] For details regarding the ACA model are provided in Appendix C of Exhibit 2B, Section D.

equipment deficiencies) and long-term viability (e.g. by prudently maintaining assets) of the distribution system.

6.1.3 Quality Control

The segment also provides services in the area of quality control throughout the equipment lifecycle. Quality audits, and reviews and investigations are conducted from when equipment and materials are procured from suppliers to when they fail in the field. Root cause analysis is the cornerstone of this segment's quality activities. Corrective and preventative actions, often issued through non-conformance reports to Toronto Hydro's equipment suppliers, drive improvements to standards and equipment. This segment's quality programs play a critical role in ensuring Toronto Hydro receives equipment of the highest quality from its suppliers. Toronto Hydro receives an average of 650 pieces of failed equipment returned from the field per year.

6.2 Standards and Policies Segment Costs

Table provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for the Standards and Policies segment.

Table 5: Standards and Policies Segment Expenditures ($ Million)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Standards and Policies	4.7	4.5	4.3	2.8	3.0	3.2	3.2	3.3	3.4	3.5

6.3 Standards and Policies Segment Year-over-Year Variance Analysis

2020-2021 Variance Explanation

Between 2020 and 2021 costs in this segment decreased by $0.2 million per year. This is primarily attributed to productivity initiatives as noted in Section 4.2.

2021-2022 Variance Explanation

Similarly, between 2021 and 2022 costs in this segment decreased by $0.2 million per year. This is primarily attributed to productivity initiatives as noted in Section 4.2, and organizational restructure.

2022-2025 Variance Explanation

Between 2022 and 2025, costs in this segment are expected to decrease by $1.1 million or an average of $0.4 million per year due to the aforementioned productivity initiatives and associated organizational restructuring.

2025 – 2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $0.3 million, or an average of $0.1 million per year to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work discussed above. [21] If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various legal compliance risks and drawbacks, including:

- Reduced ability to facilitate load connections through the offer to connect process, thus resulting in potential non-compliance with Ontario Energy Board prescribed timelines;
- Risk of not receiving the highest quality equipment from suppliers;
- Less effective management of Toronto Hydro's quality programs; and
- Reduced access to highly specialized engineering expertise.

7. FLEXIBILITY SERVICES SEGMENT

Please see section Exhibit 2B, Section E7.2 for details of the Flexibility Services Program.

8. PROGRAM MANAGEMENT AND SUPPORT SEGMENT

8.1 Segment Description

The work in the Program Management and Support segment can be subdivided into four functional areas:

- Scope Issuance and Tracking
- Work Program Management
- Stations-Based Maintenance and Annual Feeder Scheduling
- Work Execution Support

Together, these activities enable the planning, budgeting, scheduling, resourcing, tracking and reporting of Toronto Hydro's distribution system-related programs. The segment also manages changes throughout the lifecycle of capital and maintenance projects.

Additionally, this function effectively allocates work, identifies and mitigates emerging risks, and coordinates and tracks capital projects and maintenance activities across the utility's service territory.

8.1.1 Scope Issuance and Tracking

The high-level objectives for the Scope Issuance and tracking function are to:

- Receive, audit, issue and track all received scopes from the system planning group;
- Assign and schedule capital projects to support the generation of detailed designs for the construction of projects in the proposed project execution year;

- Ensure that the proposed work has complete details required for resourcing and budgeting prior to its issuance to the operations teams for detailed design and construction;
- Ensure documented budgetary estimates and changes to said estimates for capital construction projects to support budgeting and resource allocation by the work execution management team; and
- Track all issued scopes to completion; capturing cancellations, as well as unassigned scopes to ensure assignment and execution.

8.1.2 Work Program Management

Part of the process of creating the execution work program is to check the resulting project labour requirements against the available labour schedules to make the appropriate resource allocations to discrete projects. Once the individual project-based analysis is complete, the combined program (i.e. a collection of individual projects or demand/unplanned work) is reviewed against available resources and other relevant reference information on an aggregate level, to identify any inconsistencies, deficiencies or sub-optimal resource utilization trends.

In addition to maintaining the program-wide resource balance, Program Management staff track the status of projects in the work program and the roll-up of the projects into programs and portfolios. While tracking project execution progress, Toronto Hydro seeks to proactively identify and monitor known or emerging risks that can impact the successful delivery of the work program, and develop the appropriate mitigation strategies.

Lastly, Program Management staff provide regular reporting to all the stakeholders through monthly reporting of divisional scorecards, meeting updates, program delivery status reporting amongst others, to ensure programs are tracked, reported, risks identified along with mitigation actions and visibility is provided on the executive level.

8.1.3 Project & Work Execution Function Support (E.g. Stations-Based Maintenance and Annual Feeder Scheduling

Program Management also provides various support activities to operational departments that execute capital and maintenance work. One example is annual feeder scheduling. Many projects require feeders to be taken out of service to create a safe work zone in accordance with safety requirements and practices. Each time a feeder is taken out of service in downtown Toronto, a combination of network and customer locations need to be switched. Each of these switching steps requires a crew to visit the location and manually move switch handles. Once a feeder has been switched out, work on the system (such as maintenance or installation of new assets) can be performed.

Toronto Hydro has utilized a "stations-based maintenance" approach to completing its maintenance program dating back to 2016 to help align work requiring outages in the downtown core. Given the cost and safety implications associated with switching feeders on the network system, every effort is taken to combine or synergize work to achieve efficiencies in work coordination.

Program Management and Support staff work with Operations and Control Room Teams to identify synergies on downtown feeders to create safety, reliability, customer, productivity and environmental benefits.

Other key benefits include:

- Higher attainment of capital and maintenance programs;
- Reduced execution costs and feeder outage costs due to smaller amounts of outages required;
- Improved customer reliability due to fewer outages; and
- Enhanced system stability and flexibility with fewer feeders in an abnormal configuration.

Other support functions include:

- Supply and equipment planning;
- Customer connection program analysis;
- Material forecasting, scheduling and management through aligning material requirement with forecasted execution dates and liaising with the procurement team to identify current and future year material requirements to ensure availability;
- Aligning system and capacity planning priorities with the work execution program as required i.e. flagged system priorities due to reliability or regulations are scheduled timely by PMO for execution by the OPS teams;
- Key portfolio reporting and management e.g. NCMC program coordination, management and reporting where PMO coordinates with all stakeholders (Planning, Operations, IT and Control Room) to effectively execute the program; and
- Performance reporting through monthly scorecards for the various departments and divisions to flag required improvements.

During project execution, Toronto Hydro coordinates its work with the anticipated work of other utilities and City of Toronto planners. This is done iteratively, from the inception of a project to its completion. In the City of Toronto, it is especially critical to coordinate projects and obtain permits given the scale of new development, infrastructure renewal and major transit projects currently in development or construction. Work Execution staff maintain the databases and business processes necessary to coordinate the work and facilitate circulation of project data with other utilities. It seeks to maximize collaboration between multiple teams to complete work in the most efficient manner, prevent potential conflicts and reduce potential disruptions from construction projects to Toronto Hydro's customers.

Work Execution staff is responsible for securing timely and accurate approvals for the multiple roadway work permits Toronto Hydro requires throughout a given year. This involves coordination across Toronto Hydro engineers, designers, construction teams and City officials to ensure all relevant documentation is prepared in accordance with Municipal Consent Requirement for the installation of plant within City of Toronto streets.

Finally, the work execution support function provides oversight and governance over project and program management practices. This aims to ensure that business processes, including forecasting, risk identification, change management, continuous improvement, progress tracking and analytics are being used for all applicable projects and programs. Given the number and variety of projects in Toronto Hydro's capital and maintenance work programs, the governance function is critical to ensure the integrity and accuracy of work plans and financial forecasts submitted to the Ontario Energy Board, its shareholders and other neighbouring utilities. Some of these governance functions include; monthly executive and senior management performance reporting, key program

status reporting, change request process management, project variance analysis and numerous metrics to drive process adherence and continuous improvement. In addition to providing oversight, it is also responsible for designing and maintaining procedural documents and project management tools in alignment with industry standards and best practices. This group also has ownership of the governance software systems that support these areas.

8.2 Program Management and Support Segment Costs

Table provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for the Program Management and Support segment.

Table 7: Program Management and Support Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Program Management and Support	2.7	1.1	1.1	1.8	2.1	2.4	2.6	2.7	2.9	3.0

8.3 Program Management and Support Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

The decrease of $1.6 million from 2020 to 2021 is attributable to organizational restructure.

2021 – 2022 Variance Explanation

There is no material variation in this period.

2022 – 2025 Variance Explanation

Between 2022 and 2025 costs in this segment are expected to increase by $1.3 million, or an average of $0.4 million per year due to:

- The Permit Delivery Office moving under the Program Management and Support department;
- Normal course escalation and increases; and
- Headcount increases to support a higher volume of work.

2025 – 2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $0.6 million, or an average of $0.2 million per year, to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work discussed above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various legal compliance risks and drawbacks, including:

- Decreased service levels in respect of customer service connections requests;
- Less efficient use of design and construction labour resources, raising the risk for resource stranding;
- Less effective project coordination, including sub-optimal alignment and integration with third party projects;
- Reduced program delivery and integration across multiple internal stakeholders such as efficient translation of strategic changes, compliance requirements from planning to operations for execution, or facilitating budget creation by Finance;
- Reduced governance and reporting functions that drive crucial elements of project management, such as cost controls, project performance and change management; and
- Decreased risk management during operational phases.

WORK PROGRAM EXECUTION

1. OVERVIEW

Table 1: Work Program Execution Program Summary

Work Program Execution Program									
Outcomes: Operational Effectiveness - Reliability, Operational Effectiveness - Safety, and Financial Performance									
Segments: • External Work Execution • Internal Work Execution									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
11.0	14.2	17.3	14.3	15.2	16.0	16.8	17.9	18.5	19.4

Work Program Execution (the "Program") is responsible for oversight, administrative training, and other functions performed in the process of executing Toronto Hydro's capital and maintenance work programs, which are not eligible for capitalization in accordance with the utility's capitalization policy. The Program consists of the following two segments:

- External Work Execution; and
- Internal Work Execution.

The Program and its constituent segments are a continuation of the activities described in Work Program Execution in Toronto Hydro's 2020-2024 rate application.[1]

[1] EB-2018-0165, Exhibit 4A, Tab 2, Schedule 10.

2. OUTCOMES AND MEASURES

Table 2: Work Program Execution Program Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: o Undertaking oversight, administrative training and other functions performed in the process of executing Toronto Hydro's capital and maintenance work programs; and o Managing the administration associated with external contractors who respond to outages and reactive calls.
Operational Effectiveness – Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF"), by ensuring Toronto Hydro employees receive legislated safety training and possess the requisite tools and Personal Protective Equipment ("PPE") to perform their roles in a safe manner.
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by ensuring that any work completed by external contractors is allocated based on a variety of factors including safety, costs, performance and qualifications. As a result, Toronto Hydro is able to determine the most qualified and cost-efficient contractor for a specific project.

3. PROGRAM DESCRIPTION

The Program encompasses the labour costs for oversight and training activities relating to the execution of Toronto Hydro's capital and maintenance programs. This includes coordination and support of external contractors executing a portion of Toronto Hydro's capital and maintenance programs, the utility's internal design and construction crews, and apprentices. These activities are performed through two segments:

- **External Work Execution**, which covers the costs required to directly administer planning and execution of the portion of Toronto Hydro's capital and maintenance program that is completed by external contractors. This includes the issuance and oversight of capital and maintenance work to meet legislated and regulatory health and safety requirements; and

- **Internal Work Execution**, which covers the administrative and support costs for the portion of Toronto Hydro's capital and maintenance program that is completed by internal labour. This segment includes safety training costs (including training costs associated with the utility's Trade School) for employees, including apprentices, as well as costs for small tools issuances, PPE, logistics, tracking, project-specific planning, and supervisory time not directly attributable to a specific program or project. [2,3]

4. PROGRAM COSTS

In 2025, Toronto Hydro requires $16 million in rate funding for the Work Program Execution program, which represents an increase of $5 million over the previous rate period in 2020. When normalized for shared services recoveries outlined in Exhibit 4, Tab 5, Schedule 1, the expected increase in this program is $4.9 million.

Over the 2025-2029 rate period, the utility expects the cost of this Program to increase by an annual growth rate of 5 percent. This increase is necessary to address the Program needs while delivering the customer outcomes enabled by this Program.

Table 3, below, displays the Historical (2020-2022), Bridge (2023-2024), and Forecast Years (2025-2029) expenditures for the two segments comprising the Program.

[2] Exhibit 4, Tab 4, Schedule 3.
[3] With the exception of Power System Controllers, see Exhibit 4, Tab 2, Schedule 7.

Table 3: Work Program Execution Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
External Work Execution	1.0	1.5	1.1	1.2	1.4	1.5	1.6	1.7	1.8	1.8
Internal Work Execution	10.0	12.7	16.2	13.1	13.8	14.5	15.2	16.2	16.7	17.6
Total	**11.0**	**14.2**	**17.3**	**14.3**	**15.2**	**16.0**	**16.8**	**17.9**	**18.5**	**19.4**

4.1 Cost Drivers

Over the 2025-2029 rate period, Toronto Hydro's capital program is increasing by approximately 47 percent. In addition, the complexity of the utility's work program, particularly in areas of System Access, System Renewal and System Service, is increasing as Toronto Hydro makes investments to lay the foundation for the energy transition by expanding and modernizing the grid to enable customer choice to connect new technologies such as solar panels, heat pumps and electric vehicles. To support Toronto Hydro and its customers on this electrification journey, this Program must keep up with managing increased oversight and training activities. Primarily, this means an increase in headcount in both segments as well as related increases in training costs, tools and safety equipment, and PPE.

For the Internal Work Execution segment, Toronto Hydro anticipates headcount increases for a number of key Certified and Skilled Trades and Designated & Technical Professional positions such as Power Line Technician ("PLT"), Distribution System Technologist ("DST"), Engineers and Engineering Technologist ("ETL"). All of these professions require a minimum number of hours training in order to fulfill their roles.

Engineers and ETL's, for example, are trained on a broad range of technical topics to ensure that their solutions are practical and safe by design. PLT's and DST's are required to complete a number of hands on technical proficiency and legislative courses that

equip them to implement these designs safely and skillfully. These resources together provide Toronto Hydro with the ability to design and construct its capital program. An increase in this population will make it possible for the utility to achieve the increased program anticipated for 2025 to 2029.

For the external segment, Toronto Hydro anticipates headcount increases for a number of roles including field and project managers and project management staff to ensure that Toronto Hydro is able to appropriately manage external contractors and respective capital programs. As capital programs increase in both size and complexity of work, resourcing requirements necessarily increase in order to maintain prioritization of safe work practices, design and construction standards, and overall efficient use of capital budgets. In Toronto Hydro's experience, an appropriate resource level has each manager, with a supporting analyst, executing approximately $11-13 million in capital projects annually.[4] As shown in Figure 1, Toronto Hydro's headcount plan ensures sufficient resources to maintain manager numbers at this level of execution while also maintaining the ratio of supporting analysts at about 1:1.

[4] Gross EWP per year.



Figure 1: Gross EWP Output by Manager ($ Millions)

4.2 Cost Control & Productivity Measures

4.2.1 Cost Management

Toronto Hydro undertakes a number of measures to control costs within this Program, some of which are aimed at reducing training costs. Through the implementation of online training modules, employees now receive a substantial portion of their requisite training online. This eliminates added costs relating to travel time, and affords employees the flexibility to view the training at times that do not interfere with operations and delivery of the work program.

Starting in 2018, Toronto Hydro concentrated annual training for design and construction field crews in two-week blocks. This allows training to be delivered in a more efficient manner, leveraging full consecutive days. This is predominantly done in full crew

compliments to better coordinate planning and minimizing the impact to work execution. Training included in these blocks is based on specific training requirements, as well as any new, timely or emerging requirements. In 2023, this training approach was applied to the station and distribution automation groups, modified to one week based on the department's specific training requirements.

4.2.2 Productivity

Toronto Hydro continues to look for opportunities to improve the overall productivity of this Program.

As all of Toronto Hydro's external contractors have the requisite qualifications and experience to engage in all areas of capital work, the utility has implemented a process whereby work is allocated to specific contractors based on a variety of factors including, safety, costs, performance, qualifications and resourcing capability. As a result, Toronto Hydro is able to determine the most qualified and cost-efficient contractor for a specific project.

With regards to training, Toronto Hydro is trialing virtual reality technologies for equipment-specific tasks. This allows for a risk-free learning environment for the internal work force and is productive, effective and innovative.

Administratively, a move to an online work distribution process has also allowed for some productivity gains in the planning process for the reactive segment of work (supported by both the internal and external work crews).

5. EXTERNAL WORK EXECUTION SEGMENT

5.1 Segment Description

The External Work Execution segment consists of the administration of capital and maintenance work performed by external contractors. This function serves as the primary point of contact between Toronto Hydro and external contractors, including evaluating and administering competitive tenders for contractor services, providing oversight of the resulting contracts, and administering support of the specific projects assigned to external contractor crews, such as:

- Job package development and issuance;
- Liaising with system planners to address specific design matters;
- Field issues management;
- Ordering of materials;
- Facilitating changing of project scopes;
- Monitoring contractor safety practices;
- Invoicing and receipting; and
- Inspection of newly constructed assets.

This segment ensures that Toronto Hydro provides the employees overseeing this function with training, safety equipment, and tools that ensure external contractors are adequately monitored and compliant with legislated, regulatory and safety requirements.

The External Work Execution segment proactively engages with customers through the Community Relations team.[5] This is an integral part of the project management and execution process. In addition to working with the Community Relations team, Project

[5] Exhibit 4, Tab 2, Schedule 18.

Execution Managers may also meet directly with customers on site to address any concerns that customers may have, before, during and after construction.

The External Work Execution segment also includes the administration costs associated with managing external contractors who respond to outages and reactive calls. Since this function is shared with Toronto Hydro employees, costs may also be included in the Internal Work Execution segment depending on the responding crew. Consequently, there are slight year-over-year cost variations depending on the identity of the response crews.

5.2 External Work Execution Segment Costs

Table 4, below, provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Years (2025-2029) expenditures for the External Work Execution segment.

Table 4: External Work Execution Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
External Work Execution	1.0	1.5	1.1	1.2	1.4	1.5	1.6	1.7	1.8	1.8

The costs for this segment can be separated into two categories:

- **Capital and Maintenance**: which includes the Program Support Office and Construction groups; and
- **Reactive Contractor Administration**: which covers the oversight of non-capital reactive work (e.g. digging a splice pit to access a failed cable). This budget is currently under the Internal Work Execution segment and is transferred annually to account for the external assistance for reactive work.

5.3 External Work Execution Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

From 2020 to 2021 costs in this segment increased by $0.5 million due to an increase in work being performed by Toronto Hydro's Energy Services affiliate.[6] While costs incurred appear in this program, they are recovered through the shared services program as set out in Exhibit 4, Tab 5, Schedule 1.

2021– 2022 Variance Explanation

From 2021 to 2022, costs in this segment decreased by $0.4 million. This is attributed to a minor variance in oversight costs of external resources.

2022 – 2025 Variance Explanation

Between 2022 to 2025, costs in this segment are expected to increase by $0.4 million or an average of $0.1 million per year due to:

- A return to baseline in oversight costs following the decrease in 2021;
- headcount increases to support an increasing capital program; and
- inflationary pressures.

2025 – 2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $0.3 million, or an average of $0.1 million per year to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work discussed above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various legal compliance risks and drawbacks, including:

[6] Toronto Hydro Energy Services Inc.

- Execution risks relating to a reduced ability to perform capital and maintenance plans due to a decrease in recruitment of field managers, engineers, project managers and other staff;
- Decreased ability to meet legislated training targets, thereby exposing Toronto Hydro to unnecessary safety and legal risk;
- Reduced productivity due to inadequate tools and equipment; and
- Increased risk of injury to employees resulting from the lack of requisite PPE, clothing and equipment such as hard hats.

6. INTERNAL WORK EXECUTION SEGMENT

6.1 Segment Description

The Internal Work Execution segment includes the administrative support and training costs associated with construction work performed by Toronto Hydro's internal construction and design employees. Among the costs included in this segment are small tools issuance, legislated training costs, including training costs associated with the utility's Trade School, office-related expenditures, as well as time not directly attributable to any specific capital program or project. This Program ensures that Toronto Hydro employees are receiving legislated safety training and possess the requisite tools and PPE to perform their roles in a safe and financially responsible manner.

6.1.1 Safety Training

As described in detail in the Human Resources, Environment and Safety program, employee health and safety are core values at Toronto Hydro.[7] Underlying this commitment is the extensive health and safety awareness and training work conducted throughout the year. Toronto Hydro certified tradespersons and apprentices participate

[7] Exhibit 4, Tab 2, Schedule 15.

in an average of over 8.6 days of health and safety training per year. The training is aimed at providing employees with the tools and knowledge to perform their work safely and efficiently, thereby maximizing the value of their work for the utility and its customers.

In addition, due to the complexity of Toronto Hydro's distribution system and the number of legacy assets that are largely unique to the utility (e.g. paper-insulated lead-covered cable), apprentices are required to complete several years of theoretical and practical training to gain the skills and knowledge required to safely work on Toronto Hydro's distribution system.

6.1.2 Apprenticeships

The Internal Work Execution segment also includes a portion of (non-capitalized) expenditures associated with capital construction work performed by Toronto Hydro's skilled trades' apprentices. Certified and skilled trades are critical resources in the execution of Toronto Hydro's capital and maintenance programs. Over time, Toronto Hydro has strengthened the workforce to prepare for retirements and unplanned exits as necessary, and allow for the extended lead-time required to safely train new workforce entrants (apprentice programs run from 4.5 to 6.5 years in length).

6.2 Internal Work Execution Segment Costs

Table 5, below, provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Years (2025-2029) expenditures for the Internal Work Execution segment.

Table 5: Internal Work Execution Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Internal Work Execution	10.0	12.7	16.2	13.1	13.8	14.5	15.2	16.2	16.7	17.6

The variances are largely attributable to a staged approach to safely absorb and integrate almost 40 individuals to the apprenticeship program during the 2025-2029 timeframe. This approach will facilitate workforce renewal in a safe and effective manner without jeopardizing the utility's objectives or ability to safely and effectively deliver its capital and maintenance work programs.

6.3 Internal Work Execution Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

Between 2020 and 2021, costs in this segment increased by $2.7 million due to an increase in headcount in the apprentice program, and increased payroll costs due to increased sick time.

2021 – 2022 Variance Explanation

Between 2021 and 2022, costs in this segment increased by $3.5 million due to an increase in operational costs due to a higher proportion of sick time compared to 2021 as a result of the omicron wave of the COVID-19 pandemic. Also contributing to this increase is an increase in the apprentice program, as well as an increase in tool repair, PPE and other consumables.

2022 – 2025 Variance Explanation

Between 2022 to 2025, costs in this segment are expected to decrease by $1.7 million, or an average of $0.6 million due to:

- A decrease in operational costs due to an anticipated return to pre-pandemic sick time usage;

- better allocation of costs to other operations, maintenance and administration programs (attributed to the transition to SAP), as well as a decrease in tool repair and PPE costs; and
- This decrease was partially offset by an increase in the headcount to support an increasing capital program, and inflationary pressures.
-

2025 – 2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $3.1 million, or an average of $0.8 million per year, to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work discussed above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various legal compliance risks and drawbacks, including:

- Decreased ability to meet legislated training targets, thereby exposing Toronto Hydro to unnecessary safety and legal risk;
- Reduced productivity due to inadequate tools and equipment;
- Increased risk of injury to employees and the public resulting from the lack of requisite PPE, clothing and equipment such as pylons, barriers, and hard hats; and
- Execution risk relating to a reduced ability to perform capital and maintenance plans due to lack of support and decrease in recruitment of skilled tradespeople.

FLEET AND EQUIPMENT SERVICES

1. OVERVIEW

Table 1: Fleet and Equipment Services Program Summary

Fleet and Equipment Program Summary									
Outcomes: Operational Effectiveness - Reliability, Environment, Operational Effectiveness - Safety, Financial Performance									
Segments: • Fleet and Equipment Services									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
9.3	8.5	7.8	8.7	9.1	9.3	9.6	9.8	10.0	10.3

Toronto Hydro's Fleet and Equipment Services program (the "Program") governs the utility's vehicle and equipment procurement, operation, maintenance, and disposal policies. The primary objective of the Program is to ensure that the utility's vehicle assets and equipment operate safely and reliably at the lowest overall lifecycle cost. To achieve this objective, the Program delivers the services required to maintain Toronto Hydro's 456 vehicle fleet. The Program continues the activities described in Toronto Hydro's 2020-2024 Rate Application Fleet and Equipment Services program. The Program's services ensure that ensures that fleet vehicles are available so that the utility can carry out its electricity distribution activities and meet customer expectations in a safe, reliable, and expedient manner.

The activities administered by this Program are closely governed by legislative and regulatory requirements such as those administered by the Ministry of Transportation (the "MTO"), the Electrical Utility Safety Rules ("EUSR"), and the *Occupational Health and*

Safety Act, 1990 (Ontario) ("OHSA").[1] The majority of the Program's activities are mandatory to meet these legislative and regulatory obligations and must be carried out by certified trade technicians.

2. OUTCOMES AND MEASURES

Table 2: Fleet and Equipment Services Program Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: o Helping to ensure work crews have access to appropriate and sufficient vehicles and equipment to perform distribution work when required; and o Ensuring that the fleet and equipment are in good working order and assets are replaced before critical equipment failures arise that necessitate lengthy and costly offsite repairs.
Environment	• Contributes to Toronto Hydro's environmental objectives by aiming to reduce greenhouse gas ("GHG") emissions associated with fleet fuel consumption by: o Utilizing hybrid and electric vehicles and biofuels where possible; and o Implementing proactive mitigation measures such as anti-idling technology, GPS reporting to drive best practices for driver behaviour, and the use of biofuels.[2]
Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety objectives as measured by metrics like Total Recordable Injury Frequency ("TRIF") by helping to ensure employees are working safely with minimal exposure to hazards by completing vehicle and equipment (e.g. personal protective equipment) safety inspections.

[1] R.S.O. 1900, c. O.1. [*"Occupational Health and Safety Act"].*
[2] The use of technology to drive these results is constrained by funding and classes of vehicles where the return on investment is justifiable.

Financial Performance	• Contributes to Toronto Hydro's financial performance objectives as measured by the total cost and efficiency measures by: o Managing fleet and equipment assets to the lowest overall lifecycle costs; and o Mitigating fuel expenses by aiming to reduce fuel consumption through a combination of utilizing hybrid and electric vehicles; anti-idling technologies; and optimizing vehicle lifespans in accordance with the utility's asset management strategy.

3. PROGRAM DESCRIPTION

The successful execution of the Program's activities enables Toronto Hydro to maintain a safe and reliable fleet that is capable of meeting the utility's safety, reliability and customer service objectives. Activities to fulfill the Program's objectives include:

- Managing the lifecycle of Toronto Hydro's vehicle and equipment assets
- Administering a preventative vehicle maintenance program in accordance with MTO requirements and original equipment manufacturers' ("OEM") guidelines
- Equipping vehicles with the necessary onboard equipment that is optimized to align with each vehicle type. This equipment includes ruggedized laptop mounts, truck grounds, air rescue kits, safety retrieval lines, and telematics systems. This equipment enables fleet operators to perform their duties safely, efficiently, and with minimized wear and tear on vehicles.
- Employing technologies to reduce engine wear and idle time
- Work required to manage vehicle and equipment asset lifecycles, and to test related safety equipment, including executing competitive bids for equipment assets and related services such as fuelling, telematics, washing, lab testing and onboard technology services, and

- Managing contracts and vendors and employing skilled fleet mechanics. Toronto Hydro's fleet mechanics hold a number of specialized licenses and certifications that enable them to perform repairs on utility equipment.

All vehicles, regardless of power source, are part of regular preventative maintenance inspections according to each vehicle's class. Additional reactive maintenance costs may arise at undetermined times and the cost is generally comparable between electric vehicles and internal combustion engine vehicles. The primary difference in repair costs between the two types of vehicles is attributable to potential major repairs. Toronto Hydro factors in these types of repairs into its asset lifecycle analysis, which accounts for the degradation of major vehicle components and the expiry of warranties on major parts such as batteries.

The Program's activities are also aimed towards reducing Toronto Hydro's scope 1 greenhouse gas emissions to achieve Net Zero by 2040, as detailed in Exhibit 2B, Section D6. Sample activities to this end include maintaining equipment to reduce engine idle time and wear in compliance with engine idling reduction by-laws,[3] and using maintenance measures to optimize the fuel efficiency of the utility's internal combustion engine (ICE) vehicles. Finally, the Program employs the services of technicians capable of maintaining and repairing both hybrid and electric vehicles, enabling the utility to maintain its growing complement of low-emissions fleet vehicles.

The Program also governs the administration of services provided by a third-party lab certified by North American Independent Laboratories. This lab acquires, certifies, and tests the safety tools, implements, and employee personal protective equipment ("PPE")

[3] Toronto Municipal Code, Chapter 517, Idling of Vehicles and Boats.

that are mandated by law for utility work. Defective or insufficient safety equipment risks exposing workers to electrocution and to harmful gases within vaults and cable chambers. The faults or failure of this equipment could also compromise grid integrity, thereby reducing the reliability of Toronto Hydro's distribution system. The use of this third-party service provider enables the utility to receive these services as the demand arises without the costs and logistical challenges of continually maintaining skilled staff and infrastructure in-house.

Toronto Hydro also outsources non-core maintenance work to qualified third-party service providers if the work meets the following criteria:

- The work entails greater physical safety risks, such as vehicle suspension work;
- The work does not require the technical expertise of a licensed mechanic, such as tire replacement;
- The work requires specific skills or credentials that Toronto Hydro employees do not possess and which may be sourced through a third-party service provider, such as aerial lift dielectric testing; or
- The work uses equipment not owned by, or not readily accessible by the utility, such as vehicle emissions testing equipment.

Toronto Hydro outsources generic maintenance work to free up its in-house mechanics' time for skilled monthly maintenance work. This enables the utility to allocate high value and specialized work to its internal employees while ensuring that intermittent work that can be easily contracted out to market is completed at optimum efficiency and cost.

4. PROGRAM COSTS

Toronto Hydro is requesting an average of $9.8 million over the 2025-2029 period to efficiently execute the functions in the Fleet and Equipment Services program. The Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for the program are summarized in Table 3 below. Program costs have remained fairly stable since the last rebasing period.

Table 3: Fleet and Equipment Services Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Fleet and Equipment Services	9.3	8.5	7.8	8.7	9.1	9.3	9.6	9.8	10.0	10.3
Total	**9.3**	**8.5**	**7.8**	**8.7**	**9.1**	**9.3**	**9.6**	**9.8**	**10.0**	**10.3**

The Program costs cover the labour, parts, services, and fuel attributable to the core Program functions. The labour costs also involve the services of third-party technicians who maintain, repair, and test all capital assets within the Program (such as vehicles, equipment, and safety tools). The volume and pace of the program's activities, as well as the testing requirements, are influenced by several factors such as applicable legislative and regulatory requirements, and the size and condition of the utility's fleet. Toronto Hydro must complete repairs to equipment in a timely and periodic manner to ensure that vehicles are safe for operators and the public, and test safety tools in a continuous fashion to protect field employees on the job.

The Program also includes the costs for fuelling, parts, tools, licences, and insurance associated with the operation, maintenance, and repair of fleet equipment and with safety programs. These costs are non-discretionary and are required for continued operations under the Program. Other operating costs include compensation for the

Program's managers and employees, who perform a variety of functions including but not limited to, advising on vehicle conditions, administering the centralized vehicle pool, and advising on standard vehicle selections for optimal safety and technical functionality at the lowest available cost.

To manage the costs under the Program, as detailed below under subsection 4.2 Cost Control and Productivity Measures, Toronto Hydro has invested in fuel-saving technologies and opts for electric and hybrid vehicles, where possible, to further save on fuel and engine-related maintenance costs. The utility also decreased its overall fleet size from 588 vehicles in 2017 to 456 in 2023, which reduced the Program's maintenance, repair, and administrative costs.

4.1 Cost Control and Productivity Measures

4.1.1 Cost Management

- **Elimination of Under-Utilized Vehicles:** Toronto Hydro optimizes its fleet size on an ongoing basis, as discussed in detail in Exhibit 2B, Section E8.3, Fleet and Equipment Services (capital). Over the past two rate periods, the utility eliminated some costly and specialized vehicles and equipment that were expensive to repair and where the relevant services could be obtained through outsourcing (e.g: cable trucks and forestry units). Each vehicle reduction results in cost savings by eliminating the need for associated maintenance, repair, licensing, insurance, and fuel costs. On average, each vehicle removed from the fleet reduces operating costs by $2,000 to $7,000 per year. Since 2017, Toronto Hydro's fleet size has decreased by 132 vehicles (a net 22 percent reduction).
- **Fuel Consumption Reduction:** The Program has also achieved an average annual reduction in fuel needs (estimated to be approximately 20,000 litres per year) as

a result of replacing internal combustion engine vehicles with hybrid and fully electric vehicles, in accordance with Toronto Hydro's Decarbonization Strategy discussed in Exhibit 2B, Section D6 and the Fleet and Equipment Services (capital) program discussed in Exhibit 2B, Section E8.3, which contributes to lower fuel costs.

- **Optimization of Vehicle Services:** In 2020, Toronto Hydro eliminated costs attributed to truck-to-truck fuelling services and selected a more cost-competitive mobile wash vendor, which collectively resulted in an annual savings of approximately $0.25 million.
- **Repair Avoidance:** Toronto Hydro has begun a ten-year corrosion prevention pilot project with 18 pickup trucks that were put into service in 2020. The goal of this project is to determine the best form of corrosion protection to minimize repair and replacement costs by extending the life of the vehicles. The pilot includes testing three forms of protection on six vehicles each: (1) a single base protection application of initial oil-based rust inhibitor spray, (2) a single base protection application of initial oil-based rust inhibitor spray plus the installation of a rust inhibitor module, and (3) a single base protection application of initial oil-based rust inhibitor spray plus an annual application of oil-based rust inhibitor spray. Toronto Hydro's aim is to increase the age vehicles can reliably remain in the fleet, as corrosion to critical components of units are one of the primary factors leading to vehicle replacements.
- **Optimization of Program Resources:** The Program's employees improve processes, evaluate service agreements, and make ongoing adjustments where cost savings can be realized without increasing labour requirements. Specific examples include: (i) utilizing GPS data for daily reporting on engine issues to proactively reduce breakdowns and towing; ii) continually evaluating the capacity

of internal resources and determining the appropriate approach to optimize their utilization; and iii) shifting work to externally sourced services where deemed appropriate (in accordance with capacity, specialization, or cost effectiveness needs).

- **Driver Safety Reporting:** From 2018 onwards, Toronto Hydro has leveraged driver safety reporting on speeding, harsh braking, and reversing from parked position to influence improvements in driver safety behaviour, and thus help minimize safety incidents and resulting repair costs. Thanks to these measures, from 2020 to 2022 the number of speeding infractions has decreased by approximately 174 percent.

4.1.2 Productivity

The Program proactively monitors and manages vehicle utilization by continuously evaluating the optimal usage of different types of vehicles according to operational needs and work volumes. For example, vehicles that are not required for dedicated uses by field crews are allocated to a centralized vehicle pool for shared use across the utility. Specialized equipment, such as dump trucks, derricks with augers, and specially equipped trailers are allocated to the pool to eliminate the redundancy that would otherwise result from several crews relying on dedicated use of a particular piece of equipment. For more information on Toronto Hydro's fleet vehicle utilization statistics, please refer to Exhibit 2B, Section E8.3.

4.2 Fleet and Equipment Services Program Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

From 2020 to 2021, costs decreased by $0.8 million. This variance is comprised from:

- Payroll savings of $1.2 million due to significant attrition; and

- An increase in external contractor services of $0.4 million to support the decreased capacity.

2021 – 2022 Variance Explanation

From 2021 to 2022, costs decreased by $0.7 million. This variance is comprised from:

- Continued vehicle reductions that occurred throughout 2021 and 2022, resulting in lower operating and repair costs.

2022 – 2025 Variance Explanation

From 2022 to 2025, costs are expected to increase by $1.5 million. This variance is comprised from:

- Increased headcount and payroll costs due to an increase in hiring mechanics to adequately manage the necessary demands of vehicle repairs within the fleet.
- As well, a larger than average number of vehicles were commissioned at this time requiring support from external service providers.

2025-2029 Variance Explanation

Between 2025 and 2029, costs in this segment are expected to increase by $1 million, or an average of $0.3 million per year. Without the requested funding, Toronto Hydro faces the following risks:

- Reduced ability to procure all parts, services, and fuel required for proper vehicle functionality, which could result in vehicle downtime, impaired ability to perform distribution work, and potentially prolonged outages;
- Reduction in the frequency, scope, and timeliness of vehicle maintenance work, resulting in undetected faults and potential employee and public safety risks, as well as inefficiencies in asset lifecycle management;

- Reduced ability to provide constant availability of certified and tested safety implements and PPE that are required by law;
- Inability to implement technologies and programs that would yield sustained reductions in GHG emissions and compliance with idling by-laws;
- Reduced ability to perform management functions related to the continuous monitoring of and compliance with legislative and regulatory requirements; and
- Increases in costly and complex vehicle and equipment faults as a result of reduced labour capacity to perform routine maintenance.

FACILITIES MANAGEMENT

1. OVERVIEW

Table 1: Facilities Management Program Summary

Facilities Management Program Summary									
Outcomes: Operational Effectiveness - Reliability, Public Policy Responsiveness, Environment, Operational Effectiveness - Safety, and Financial Performance									
Segments: • Facilities Maintenance Services • Rentals & Leases • Utilities & Communications • Property Taxes									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
24.3	26.0	25.0	26.0	27.9	27.9	28.4	28.9	29.6	30.3

Toronto Hydro's Facilities Management program (the "Program") delivers the workspace and property management services that enable the utility's employees to perform their work in optimally configured, safe, and structurally sound surroundings. The Program aims to maintain the utility's facilities in good working order and in compliance with applicable legislation and regulations. The Program is comprised of the following four segments:

- **Facilities Maintenance Services**: Work directed at maintaining the utility's facilities in good working order and in compliance with applicable legislation and regulations;
- **Rentals & Leases**: The costs associated with Toronto Hydro's leasehold agreements, including short-term equipment needs;

- **Utilities & Communications**: Enabling technologies that allow Toronto Hydro to run and operate its facilities; and
- **Property Taxes**: Municipal taxes on the value of property held by Toronto Hydro.

The Program and its constituent segments are a continuation of the activities described in the Facilities Management program in Toronto Hydro's 2020-2024 Rate Application.[1]

2. OUTCOMES AND MEASURES

Table 2: Facilities Management Program Outcomes and Measures Summary

Operational Effectiveness – Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: o Complying with the applicable legislative and regulatory requirements for key assets in work centres and distribution system facilities (e.g. lifting devices, overhead doors, dock levellers, etc.); and o Maintaining building systems and elements that secure and mitigate the risk of damage to critical infrastructure (e.g. sump pumps, building envelopes).
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by ensuring compliance with applicable regulatory and legislative requirements such as the Ontario Energy Board's Cyber Security Framework[2] by: o Leading the implementation, maintenance and continuous lifecycle management of modern commercial security systems and technology in partnership with security subject matter experts and in alignment with enterprise risk assessments; o Applying security management policies and procedures across all Toronto Hydro sites; and o Maintaining the physical security measures that help safeguard sensitive or confidential personal or system

[1] EB-2018-0165, Exhibit 4, Tab 2, Schedule 11.
[2] EB-2016-0032, *Cyber Security Framework to Protect Access to Electronic Operating Devices and Business Information Systems within Ontario's Non-Bulk Power Assets*.

	information through measures that prevent unauthorized physical access to work centres, stations, and job sites.
Environment	• Contributes to Toronto Hydro's environmental objectives by: o Supporting the achievement of goals outlined in Toronto Hydro's Net Zero 2040 Strategy in Exhibit 2B, Section D6 by reducing greenhouse gas emissions. (E.g. through the use of more energy efficient HVAC and lighting fixtures); and o Conducting annual waste audits and monthly diversion reports which help Toronto Hydro comply with requirements of the *Waste Reduction and Waste Audit Work Plans* (O. Reg. 102/94),[3] and maintain the *ISO 14001* certification for environmental management.
Operational Effectiveness – Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by: o Ensuring compliance with the Ontario Building Code[4] and the Ontario Fire Code[5]; o Repairing deficiencies which may cause safety (e.g. trip and fall) hazards; o Addressing legacy structural deficiencies such as the absence of secondary exits, non-compliant stairs, and inaccessible doors along pathways; o Improving internal lighting conditions and repairing external damaged lighting in work areas; o Implementing measures to minimize the risk of unauthorized access into Toronto Hydro's work centres and stations; o Maintaining *ISO 45001* certification for Occupational Health and Safety Management using the Program's maintenance management system; and o Conducting Designated Substance Surveys, required under the *Occupational Health and Safety Act, 1990,*[6] which help identify and dispose of designated substances (e.g. asbestos, lead, etc.).

[3] *Waste Reduction and Waste Audit Work Plans,* Ontario Regulation 102/94.
[4] Ontario Building Code, Ontario Regulation 332/12.
[5] Ontario Fire Code, Ontario Regulation 213/07.
[6] R.S.O 1990, c. O.1. ["*Occupational Health and Safety Act*"].

Financial Performance	• Contributes to Toronto Hydro's financial performance objectives through the utility's total cost and efficiency measures by: o Utilizing detailed asset condition assessments in order to efficiently manage assets in accordance with the utility's Facilities Asset Management Strategy[7] and replace assets that are at their end of life or in poor condition; o Undertaking security enhancements at work centres and stations facing the highest level of need and risk; o Prioritizing preventative maintenance actions for end of life assets in poor condition to mitigate against costly reactive repairs; o Deterring theft and vandalism through the installation and usage of enhanced security systems; o Utilizing benchmarking data (e.g. by the Building Owners and Managers Association ("BOMA")) to optimize the space utilization of existing buildings and facilities and control maintenance and utility costs; and o Reducing utility costs at Toronto Hydro's work centres through energy efficient HVAC and lighting systems.

3. PROGRAM DESCRIPTION

As of 2023, Toronto Hydro owns or operates 205 sites. The condition of these buildings and stations varies widely and their age ranges from historic sites covered by heritage property requirements to new buildings. Each Toronto Hydro property has unique features and considerations that drive its maintenance and service requirements. These include applicable legislative and regulatory requirements on safety, accessibility, emergency preparedness, and environmental protection, Toronto Hydro's own environmental, health, and safety policies, and the needs of the distribution system. The Program's activities are categorized into the following four segments: (i) Facilities Maintenance Services; (ii) Rentals & Leases; (iii) Utilities & Communication; and (iv) Property Taxes.

[7] Exhibit 2B, Section D5.

4. PROGRAM COSTS

In 2025 Toronto Hydro requires $27.9 million in rate funding for the Facilities Management program, which represents an increase of $3.6 million over the last Custom Incentive Risk Application in 2020. When normalized for shared services recoveries outlined in Exhibit 4, Tab 5, Schedule 1, the expected increase in this program is $3.8 million.

Over the 2025-2029 rate period, the utility expects the cost of this program to increase by annual growth rate of 2.0 percent which is necessary to address the program needs and deliver the customers outcomes enabled by this program

The Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for each of the Program's segments are summarized in Table 3 below.

Table 3: Facilities Management Program Expenditures by Segment ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Facilities Maintenance Services	16.6	18.4	17.4	18.0	19.6	19.4	19.8	20.1	20.6	21.0
Rentals & Leases	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6
Utilities & Communications	2.3	2.2	2.1	2.3	2.4	2.5	2.5	2.6	2.6	2.7
Property Taxes	5.0	4.9	5.0	5.2	5.4	5.5	5.6	5.7	5.8	6.0
Total	**24.3**	**26.0**	**25.0**	**26.0**	**27.9**	**27.9**	**28.4**	**28.9**	**29.6**	**30.3**

4.1 Cost Control and Productivity Measures

Toronto Hydro uses the following tools and initiatives to control overall Program costs:

- **Real Estate Management**: Toronto Hydro employs a data-driven framework for making real property investments and managing owned properties in a manner

that is responsive to the utility's forecasted distribution and load-demand needs in relation to its current capacity. The utility strategically makes investments to support the utility's critical functions and goals of grid reliability and resiliency and divests properties that are deemed to be no longer used or useful for distribution purposes. Refer to Exhibit 2B, Section D6 for a discussion of these approaches under the umbrella of Toronto Hydro's Facilities Asset Management Strategy.

- **Hybrid Maintenance Approach:** Toronto Hydro uses a combination of internal resources and a third-party service provider to execute a cost-effective facilities maintenance approach. This approach balances preventative maintenance and run-to-fail strategies. Preventative maintenance is scaled up or down to optimize the lifecycle of an asset depending on its cost and ease of replacement. This is done through a hybrid approach by augmenting the internal team with third-party service providers acting as a single source of support. The utility modifies service modes, services, and maintenance routines as required through change order management. This allows the internal team to focus on stakeholder management, strategy, and the alignment of the Program to core business activities.

- **Performance Benchmarking:** Toronto Hydro leverages parametric data it obtains from various industry resources such as the Building Owners and Managers Association ("BOMA") and International Facilities Management Association ("IFMA") to improve the utility's operating efficiency. Toronto Hydro studies data from the regional industry reports to measure the cost per square-foot of key facilities management functions and benchmarking data retrieved from the Energy Star Portfolio Manager. The utility uses this information to measure and track its energy and water consumption against other commercial and

institutional buildings, analyze its performance and make recommendations for improvements to areas such as energy and utilities conservation. Toronto Hydro also utilizes the five-level BOMA BEST certification program and assessment framework to improve environmental performance. To date, three sites have been enrolled in the program, and their certifications are shown below.

Table 4: Toronto Hydro Sites – BOMA Certification

Toronto Hydro Site	Certification Level	Score
71 Rexdale	Gold	80-90 percent
715 Milner	Gold	80-90 percent
500 Commissioners	Silver	50-79 percent

- **Data Driven Decision Making:** Toronto Hydro uses a computerized maintenance management system ("CMMS") that manages, tracks and schedules maintenance work. The CMMS, in conjunction with departmental performance measures such as the On-Time in Full ("OTIF") metric that steers the completion criteria for tenant requests, enables Toronto Hydro to maximize the effectiveness of its maintenance resource dispatching strategy. The CMMS provides users with a range of functions that display new, existing, and historical work orders for repair, maintenance, cleaning, and external grounds segments and for each work centre, and track the resources allocated to a given activity or segment.

- **Competitive Procurement:** Given its hybrid maintenance approach, Toronto Hydro routinely solicits bids to maintain the currency of its key service contracts. This process introduces competition and offers the utility a venue for negotiation, which facilitates cost control.

5. FACILITIES MAINTENANCE SERVICES SEGMENT

5.1 Segment Description

The purposes of the Facilities Maintenance Segment are a) to provide Toronto Hydro's employees with a safe work environment that encourages the effective and efficient execution of their duties, and b) to ensure that the utility's properties, buildings, and stations are structurally sound and safe for employees and the public. The Facilities Maintenance Segment is driven by legislative and regulatory requirements, internal environment, health and safety policies, building and asset condition reports, and industry best practices. This segment governs a broad range of daily, monthly, and annual maintenance activities including all the necessary tasks and services to maintain the offices, work centres and buildings housing the utility's transformer and municipal stations ("TS" and "MS", respectively). Toronto Hydro's attention to regular preventative maintenance of its office buildings, work centres, and stations contributes to the utility's safety record.

If the utility were to fail to comply with applicable legislative and regulatory requirements, temporary equipment lock-outs and fines could be imposed, leading to costly interruptions in the utility's business activities that impact distribution customers.

As described in section 3.2.2, Toronto Hydro relies on a combination of internal resources and a third-party service provider to execute the Program functions. This arrangement allows Toronto Hydro to react to issues rapidly and scale its service model to changing needs or strategies.

Toronto Hydro's maintenance strategy applies a balance of preventative maintenance and run-to-fail strategies. Run-to-fail strategies are used to manage low impact and low-

cost equipment that have readily available parts or replacements, and where preventative work would not be cost-effective. The level of preventative maintenance is predicated by asset criticality, cost and system complexity (i.e. special orders, long lead times, etc.), which justify the recurring lifecycle costs. Balancing the two methods keeps vital building systems operating while enabling technicians' capacity for proactive and reactive work. Even the most robust preventative maintenance routine will require reactive work as a by-product. Toronto Hydro's approach balances the upfront cost and monitors the degree of reactive work to ensure critical tasks are manageable for its complement of internal and external trades. Through the CMMS, the utility applies this maintenance approach by tracking and scheduling the following maintenance activities:

Preventative Maintenance: Routine inspections and tasks to ensure that equipment, systems, and their respective components are fully operational. This includes activities such as the periodic inspections of facilities assets (e.g. magnetic locks on emergency exits to prevent unauthorized entry and release when a fire alarm is activated). If the frequency of Toronto Hydro's maintenance activities were to fail to meet manufacturer recommended schedules and regulated maintenance standards, the utility could experience premature failures, locked-out equipment, potential fines (e.g. by the Technical Standards and Safety Authority), and unsafe work conditions.

Corrective Maintenance: Through routine preventative inspections, Toronto Hydro identifies the systems and equipment requiring corrective work, ensuring that any malfunctions are proactively rectified. For example, a blower motor bearing noise may be heard during HVAC maintenance and would indicate a pending failure. Logging a corrective work order when this noise is heard permits timely replacement before the unit fails and contributes to the air quality in work centres and other facilities.

Reactive Maintenance: Toronto Hydro employs reactive maintenance strategies to address specific issues that are observed from time to time through various reports and requests. Program employees, other employees, and contractors all contribute to the effort of flagging failures, near misses, and related observations in the field. Despite the utility's effective preventative maintenance program, reactive work is a recurring element of the Program driven by run-to-fail assets, external factors (e.g. extreme weather, property damage), and a deferred maintenance backlog (e.g. work deferred due to budget constraints). The deferred maintenance backlog represents real-time deficiencies in the field that at the time of diagnosis were deemed less critical (i.e. postponed repairs), but could deteriorate to the point of unplanned asset failure or impacted building functionality. The decision to defer work is the result of budget constraints, which means deficiencies are evaluated based on system criticality, building functionality, safety, tenant comfort, etc. This is a repetitive process that compares incoming work orders to the deferred maintenance backlog to manage the budget. Furthermore, the utility uses an industry metric called the Facilities Condition Index (FCI) to evaluate, monitor, and project the level of in-field deficiencies. The FCI represents the ratio of the estimated value of deferred maintenance to the replacement value of the respective assets. Therefore, it relates the predicted impact of planned capital to the allocated operational expenditures. Figure 1 shows the mix of FCI scores by building age. The colour represents the classification of the condition.

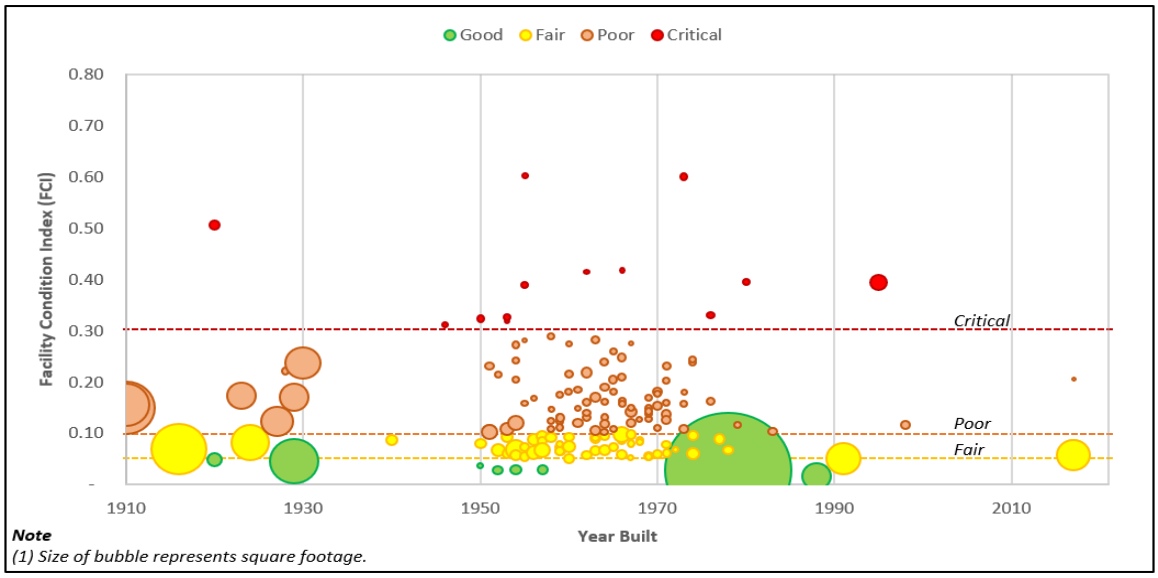

Figure 1: Current State of the Facilities Condition Index ("FCI")

Using the FCI allows for the monitoring and projection of the index score by accounting for the utility's planned operational and capital investments. Therefore, Toronto Hydro is able to predict and control the level of deficiency that it experiences period over period as seen in Figure 2.

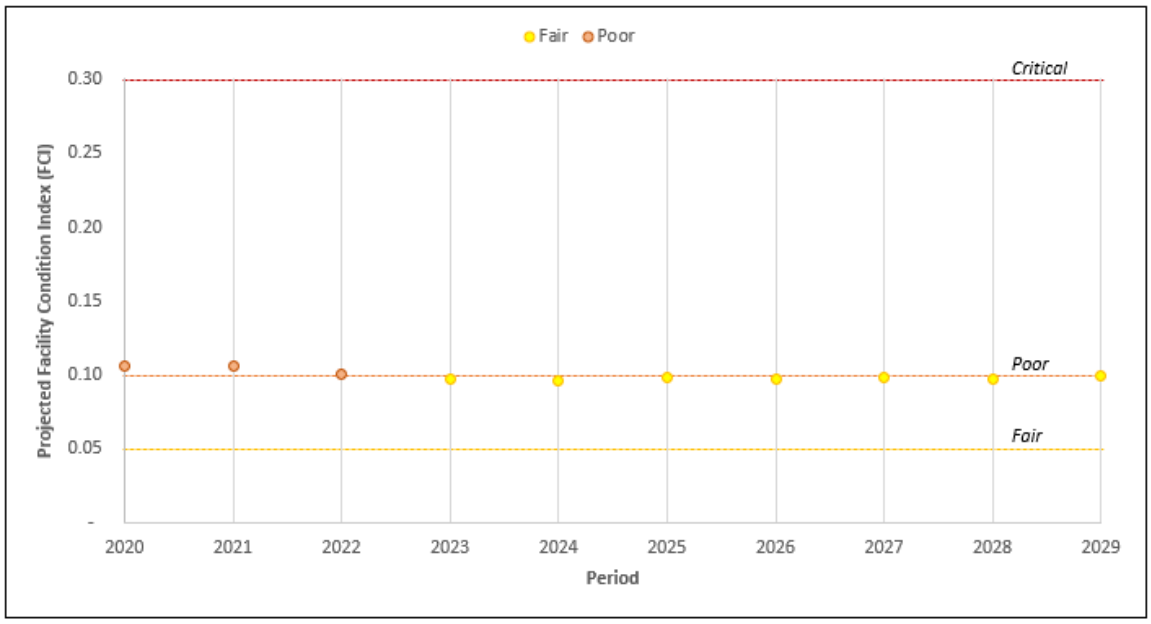

Figure 2: Current and Projected State of the Consolidated Facilities Condition Index ("FCI")

The utility anticipates that it will sustain the current consolidated FCI level around the 'Fair-Poor' threshold for the duration of the 2025-2029 rate period through a combination of the operational expenditures for the Facilities Maintenance Services Segment discussed in Section 4.2 below and the planned capital investments discussed in Exhibit 2B, Section E8.2.

5.2 Facilities Maintenance Services Segment Costs

Table 5 below provides the Historical (2020-2022), Bridge (2023-2024) and Forecast Years (2025-2029) expenditures for the Facilities Maintenance Services Segment. These costs include both internal and external work, vehicle costs for travel between sites, and other related expenses, driven by the factors discussed above under subsection 3.1.1.

5.2.1 Facilities Maintenance Services Segment Cost Control Measures

Through competitive procurement, the Program reduced the base cost of its hybrid maintenance approach described in section 3.2.2 by applying lessons learned from previous vendor contracts and better customizing scopes of work for the third-party service providers in accordance with the utility's property and business needs. The reduction of base contract costs enabled the allocation of more funds to reactive and deferred maintenance while controlling the growth of the overall Program. This is further outlined in the 2021-2022 variance description of the segment found at section 4.3.

Table 5: Facilities Maintenance Services Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Facilities Maintenance Services	16.6	18.4	17.4	18.0	19.6	19.4	19.8	20.1	20.6	21.0

5.3 Facilities Maintenance Services Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

The $1.8 million increase from 2020 to 2021 is attributable to:

- A $1.5 million increase resulting from a combination of corrective and reactive maintenance activities. This increase in maintenance activities was driven by the need to address the increasing age of assets and the backlog of deferred maintenance which grew due to the slowdown of work during the COVID-19 pandemic; and
- A $0.3 million increase resulting from inflationary pressures on contractual agreements, reactive maintenance (i.e. material and service pricing), and compensation increases.

2021 – 2022 Variance Explanation

The $1 million decrease from 2021 to 2022 is attributable to:

- Contract management related to a new RFP; and
- Offsetting inflationary pressures.

2022 – 2025 Variance Explanation

The $2 million increase from 2022 to 2025 is attributable to:

- A $0.2 million decrease in operational cost drivers, corresponding to capital investment in the 2023 period;
- A 0.3 million decrease to adjust investments to sustain facilities assets in alignment with the Fair-Poor threshold of the consolidated FCI and management of the deferred maintenance backlog;
- An increase of $1.7 million to address an increased emphasis on security equipment maintenance and strategy due to increased criminal activity (e.g. cable thefts, trespassing, vandalism, etc.); and access control availability for system reliability and response;
- An increase of $0.8 million dollars in headcount and compensation to support increased capabilities to perform a higher complexity of work;
- The go-live of functional operations at Toronto Hydro's second control room;[8] and
- Inflationary pressures.

[8] From the completion of the Control Operations Reinforcement program in Exhibit 2B, Section E8.1 of Toronto Hydro's 2020-2024 Custom Incentive Rate Application (EB-2018-0165). See also Exhibit 2B, Section E4 of this application.

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $1.6 million, or an average of $0.4 million per year. Without the requested funding over the upcoming rate period, Toronto Hydro faces the following risks:

- Costly business interruptions caused by fines, penalties, and equipment lockouts for non-compliance with applicable legislative and regulatory requirements;
- Deferred maintenance that compromises building envelope integrity and puts at risk the functioning of critical distribution assets, jeopardizing the reliability of the utility's key systems;
- Physical security threats and vulnerabilities (e.g. theft, trespassing, vandalism) due to the inability to maintain security equipment such as the video management and access control systems;
- Diminished productivity resulting from malfunctioning or unavailable assets and other pending repairs that put the utility's office safety, office ergonomics, and air quality initiatives at risk; and
- Employee and public safety risks resulting from deteriorating assets, inadequate response times, and deferred maintenance that fails to identify and rectify in a timely manner safety issues or equipment malfunctions.

6. Rentals & Leases Segment

6.1 Segment Description

The utility's rentals and leases expenditures are driven by electrical distribution assets located within transmission corridors and on private lands. Furthermore, many of the joint tenancy agreements are with other utilities, which maximises the utility of the properties.

6.2 Rentals & Leases Segment Costs

Table 7 below provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Year (2025-2029) expenditures for the Rentals and Leases segment.

6.2.1 Rentals and Leases Segment Cost Control Measures

Toronto Hydro minimizes costs within this segment by routinely reassessing agreements for distribution related leases. This strategy focuses on delineating space usage and holding partners to fair market value ("FMV") when Toronto Hydro is the lessor.

Table 7: Rentals & Leases Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Rentals & Leases	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6

6.3 Rentals & Leases Segment Year-over-Year Variance Analysis

Variance Year-Over-Year Explanation

The primary driver of variances is the amendment of long-standing agreements with different utilities and agencies (e.g. Hydro One, City of Toronto, Toronto Community Housing Corporation) that expire and require renewal. As some of these agreements date back more than 20 years, at time of renewal, renegotiation with the landlords typically results in the utility's costs increasing to FMV.

2025-2029 Variance Explanation:

Between 2025 and 2029 costs in this segment are expected to increase by $0.1 million. Without the requested funding over the upcoming rate period, Toronto Hydro would face the following risk:

- An inability to pay for rentals and leases, diminishing the utility's ability to obtain access to real property and equipment and impeding operational effectiveness.

7. Utilities & Communications Segment

7.1 Segment Description

The Utilities & Communications segment includes the costs of providing water, electricity, natural gas, and related services to Toronto Hydro's office buildings, work centres, and stations. The utility's costs for this segment are primarily driven by the prescribed costs charged by various service providers. Additional drivers of year-over-year cost variances are weather fluctuations, such as extremely hot summers that increase electricity consumption or cooler-than-normal winters that result in higher heating expenditures.

Toronto Hydro works to manage its costs by promoting conservation and improving the energy efficiency of its facilities. To facilitate consistent implementation of energy efficiency standards, Toronto Hydro developed standards that outline the relevant energy, water, and gas efficiency criteria for the utility's new and renovated work spaces. The utility routinely reviews and amends these standards are to align with emerging conditions and corporate objectives such as the utility's Net Zero 2040 Strategy.[9] Examples of decarbonization actions by Toronto Hydro include the conversion to energy efficiency lighting, the implementation of building automation system ("BAS") controls for new space build-out, and retrofitting activities for corrective maintenance when feasible.

To support the utility's goal to reach Net Zero by 2040 by reducing scope 1 greenhouse gas ("GHG") emissions, Toronto Hydro also continues to integrate and revise the

[9] Exhibit 2B, Section D6.

programming for its legacy HVAC units to reduce energy consumption of its existing equipment. For more information on the capital investments in fuel switching Toronto Hydro is making to support this goal, please refer to the Facilities Management & Security capital program in Exhibit 2B, Section E8.2.

7.2 Utilities and Communications Segment Costs

Table 9 below provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Year (2025-2029) expenditures relating to Utilities and Communications.

7.2.1 Utilities and Telecommunication Segment Cost Control Measures

To mitigate energy costs, Toronto Hydro is using BAS integration and programming to improve the electricity, natural gas, and water consumption efficiency of the utility's legacy equipment. These efficiency gains directly support the utility's Net Zero by 2040 goal by reducing the utility's associated scope 1 GHG emissions.

Table 9: Utilities and Communications Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Utilities & Communications	2.3	2.2	2.1	2.3	2.4	2.5	2.5	2.6	2.6	2.7

7.3 Utilities and Communications Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

The $0.1 million decrease from 2020 to 2021 was attributable to:

- Low building occupancy during the COVID-19 pandemic reducing overall HVAC load.

2021 – 2022 Variance Explanation

The $0.1 million decrease from 2021 to 2022 was attributable to:

- Continuing to integrate legacy HVAC equipment into the BAS to improve efficiency as part of Toronto Hydro's Net Zero 2040 Strategy.

2022 – 2025 Variance Explanation

Between 2022 and 2025, costs in this segment are expected to increase by $0.4 million or an average of $0.1 million per year. This increase is attributable to:

- Increases in costs attributable to building occupancy due to the adoption of hybrid work at Toronto Hydro's work centres as of July 2022 and inflationary pressures;
- Continued enhancement of the BAS controls and optimization of the BAS programming to hybrid work trends;
- Continued enhancement of the BAS controls; and
- Impacts from fuel switching, and offsetting efficiency gains from asset replacements related to Toronto Hydro's Net Zero by 2040 Strategy.

2025-2029 Variance Explanation:

Between 2025 and 2029 costs in this segment are expected to increase by $0.2 million, or an average of $0.1 million per year. Without the requested funding over the upcoming rate period, Toronto Hydro faces:

- An inability to pay for utility and communications services, resulting in productivity losses.

8. Property Taxes Segment

8.1 Segment Description

Property taxes are calculated based on the amount of the property owned by Toronto Hydro, in accordance with municipal tax rates and any applicable credits. With more than 5,000,000 square feet of property in the City of Toronto, property taxes are a significant expense for the utility. Historically, Toronto Hydro's property taxes have increased at the rate of inflation and a similar trend is expected to continue through the 2025-2029 rate period, which is reflected in the utility's forecasts.

8.2 Property Taxes Segment Costs

Table 11 below provides the Historical (2020-2022), Bridge (2023-2024) and Forecast Years (2025-2029) expenditures relating to Property Taxes.

Table 11: Property Taxes Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Property Taxes	5.0	4.9	5.0	5.2	5.4	5.5	5.6	5.7	5.8	6.0

8.3 Property Taxes Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

The $0.1 million decrease from 2020 to 2021 was attributable to:

- The sale of one property; and
- Tax cap adjustments for two work centres.

2021-2022 Variance Explanation

The $0.1 million increase from 2021-2022 was attributable to municipal property assessments and inflationary escalation.

2022-2025 Variance Explanation

Between 2022 and 2025, costs in this segment are expected to increase by $0.5 million, or an average of $0.2 million pear year due to municipal property assessments and inflationary escalation

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $0.5 million, or an average of $0.1 million per year. Without this level of funding for this segment over the upcoming rate period, Toronto Hydro faces:

- An inability to pay property taxes in full and on time, leading to higher costs due to interest payments on deferred amounts and a deterioration of the utility's relationship with the City of Toronto, affecting the overall viability of distribution operations.

SUPPLY CHAIN SERVICES

1. OVERVIEW

Table 1: Supply Chain Services Program Summary

Supply Chain Program Summary									
Outcomes: Operational Effectiveness - Reliability, Environmental, Financial Performance									
Segments: • Supply Chain Services									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
15.8	12.9	13.8	16.7	18.8	21.5	23.5	24.9	25.5	27.1

The Supply Chain Services program (the "Program") provides procurement and warehousing activities that support the execution of Toronto Hydro's capital and operating programs. The objectives of the Program are to facilitate timely and cost-effective acquisition of services, materials and equipment, maintain sufficient inventory to support uninterrupted work execution, and manage material handling costs. This Program is anticipated to grow significantly over the upcoming 2025-2029 rate period in order to facilitate the utility's growth, modernization and sustainment investments, and fulfil its capital plan.

The Program consists of two interrelated functions: (i) Demand and Acquisition Services; and (ii) Warehouse and Logistics. The Demand and Acquisition Services function secures the requisite equipment, materials and services for Toronto Hydro within specified timelines and at an optimal cost. It also monitors vendor performance to ensure that the goods and services acquired are being delivered to Toronto Hydro in an efficient and effective manner. The Warehouse and Logistics function facilitates coordinated, cost-effective and timely receiving, stocking and distribution of materials and equipment

required to execute Toronto Hydro's capital and maintenance work programs. The Program and its activities are a continuation of the Supply Chain Services program described in Toronto Hydro's 2020-2024 rate application.[1]

2. OUTCOMES AND MEASURES

Table 2: Supply Chain Services Program Outcomes and Measures Summary

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: o Supporting the effective execution of capital and maintenance programs by fulfilling warehouse orders and fulfilling supplier deliveries; and o Supporting Toronto Hydro's ability to respond to outages promptly and restore power through effective management of inventory.
Environment	• Contributes to Toronto Hydro's environmental objectives by ensuring Toronto Hydro meets all Municipal, Provincial and Federal regulations related to managing hazardous materials by safely collecting, storing, and removing hazardous waste from work sites. • Supports Toronto Hydro's decarbonization efforts by procuring materials and equipment (e.g. electric vehicles) with a view to reducing greenhouse gas emissions where possible and cost-effective
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives as measured by the total cost and efficiency measures by: o Implementing processes such as automating the disbursement of certain inventory stock and purchasing certain equipment directly from the manufacturer; and o Maintaining an optimal level of inventory of materials and equipment to support uninterrupted work execution with minimal carrying cost.

[1] EB-2018-0165, Exhibit 4A, Tab 2, Schedule 13.

3. PROGRAM DESCRIPTION

The Program is comprised of two interrelated functions: Demand and Acquisition Services and Warehouse and Logistics, each of which are described in the sections below.

3.1 Demand and Acquisition Services

The Demand and Acquisition Services function supports Toronto Hydro's capital and maintenance work programs, and enables the utility's day-to-day operations, by providing the goods and services required to perform the work. The employees who deliver this function require an extensive set of supply chain and electricity industry-specific skills, including understanding of the competitive bid process, in-depth knowledge of quantitative analysis and inventory management tools, familiarity with changing electricity system equipment standards, and advanced negotiation and communication skills.

3.1.1 Procurement and Contract Management

Demand and Acquisition Services' activities involve sourcing of reputable and reliable suppliers, monitoring their performance to ensure that they meet their contractual obligations, and generating the purchase orders that underlie each agreement. Working with the various parts of the utility's operations, Demand and Acquisition Services leads the competitive bid generation and evaluation processes, and conducts market trend analysis to identify emerging industry trends and locate suitable suppliers.

Toronto Hydro's competitive bid selection process is based on pre-established selection criteria that balance the quantitative and qualitative aspects of each desired proposal. The proposals and the criteria are developed in collaboration with the internal business units that require the goods or services in question.

After the supplier is chosen, Toronto Hydro negotiates the contract terms and conditions relevant to the goods or services provided. Demand and Acquisition Services monitors supplier performance through collaboration with other departments and regular meetings with the supplier.

In 2021, Demand and Acquisition Services implemented an enhanced Contract Management Framework (CMF). CMF is a set of guiding principles, documents, procedures, and Management Control and Reporting System (MCRS) designed to govern the end-to-end sourcing process. The framework is a part of the Contract Management section of Demand and Acquisition Services' overall Supplier Relationship Management Framework (SRM), as shown in Figure 1, below. The full SRM is in the process of development and is expected to be fully executed by 2027.



Figure 1: Supplier Relationship Management Framework (SRM)

CMF allows proactive governance of active contracts while ensuring full compliance with internal policies and contractual obligations. The implementation of CMF has enhanced the Demand and Acquisition Services team's ability to:

- Engage business units more frequently to keep them up to date on contract spend, which enables a proactive management approach;
- Immediately highlight violations to contract spend and contract data integrity through implementation of KPIs, reporting, and short interval control;
- Better forecast and balance annual workload, which helps manage resource constraints and reduce bottlenecks;
- Standardize training and data management approach to ensure process consistency and data integrity; and
- Enhance visibility and increase alignment of aggregate data from SAP and Ariba.

The enhanced CMF has resulted in the following impacts from 2022 to 2023:

- Greater compliance with internal policies related to authorized spend amounts, resulting in a 76% decrease in over-committed contracts;
- Improved proactive management of contracts to reduce compliance, legal, and operational risks, resulting in an 84percent decrease in expired contracts;
- Improved purchase order management and reduced open liability, resulting in a 54 percent decrease in aging purchase order balances; and
- Increased alignment of aggregate data from SAP and Ariba, resulting in a 25 percent increase in data accuracy and integrity.

The outcome of the enhanced CMF contributes to improved contract management practices, productivity and data integrity, and ensuring efficient procurements at the most favourable acquisition cost.

3.1.2 Material Requirements Planning

The Demand and Acquisition Services function manages inventory levels in Toronto Hydro's warehouses in support of the utility's capital and maintenance programs. This involves reviewing historic use trends and known work projects to develop planned work requirement forecasts and supplier orders.

In addition, Demand and Acquisition Services oversees materials and equipment inventory for reactive work driven by adverse weather, system contingencies and other unforeseen events. To facilitate efficient and expedient execution of reactive work, Toronto Hydro establishes minimum and maximum inventory settings for each warehouse location, and determines appropriate material re-order points and quantities that trigger purchase order generation as inventories are gradually depleted. Toronto Hydro maintains inventory levels by setting and regularly reviewing reorder points, which consider historic demand, material lead time, service requirements, and critical spare requirements. Late shipments that can affect available inventory for either planned or reactive work are expedited with suppliers, and optimal delivery dates are ascertained and communicated to warehouses and requesting areas of the utility.

Demand and Acquisition Services also works with other operational groups at Toronto Hydro to identify certain materials and equipment that are critical to the ongoing operation of the distribution network (e.g. various models and vintages of pad mounted switchgear and transformers) and to introduce new technology and models of equipment. Once critical materials are identified, these inventory items are flagged as critical spares and segregated from general stock for specific use in reactive situations, which ensures investment levels are sufficient to support system reliability. New technology is researched thoroughly by subject matter experts to ensure compatibility

with the distribution network. Demand and Acquisition Services supports the rollout of new technology and models of equipment by setting up stock codes and negotiating contracts with suppliers to ensure favourable lead times and pricing are in place.

3.1.3 Third-Party Procurement Provider

Since 2015, Toronto Hydro has been using a Third-Party Procurement ("3PP") provider to complement internal resources and improve productivity. This approach:

- Reduces the overhead cost per purchase order;
- Provides better operational cost certainty; and
- Provides more operational flexibility to meet Toronto Hydro's varying operational requirements consisting of managing over 10,000 active inventory codes linked to individual assets, issuing 32,000 purchase order lines, and executing 76 solicitations, averaged over 2020-2022.

The 3PP provider's employees are now fully integrated and act as an extension of the core Demand and Acquisition Services team by performing the full range of procurement and vendor performance and inventory management activities. In 2022, the 3PP provider was responsible for managing 96 percent of 10245 active inventory codes, issuing 97 percent of 34656 purchase orders, and executing 97 percent of 79 solicitations annually. From 2020 to 2022, this represents an increase of 3 percent of active inventory codes, 32 percent of purchase orders, and 2 percent of solicitations managed by the 3PP provider.

The 3PP provider has demonstrated its ability to effectively adapt to Toronto Hydro's business processes and systems and work alongside other operational groups at Toronto Hydro. The Demand and Acquisition Services team leveraged the competencies of the 3PP provider's employees to expand their responsibilities to:

- Coordinate equipment repairs with repair and recertification suppliers and liaise between suppliers and Toronto Hydro quality assurance engineers;
- Attend capital project planning meetings with other operational groups to provide inputs related to material forecasts; and
- Support the product change committee with the introduction or change of stock coded items used in Toronto Hydro's distribution system.

By complementing the core Demand and Acquisition Services team, the engagement of the 3PP provider has resulted in the following productivity impacts from 2022 to 2023:

- Improved competitive sourcing turnaround times, resulting in a 64 percent reduction in median business days between contract award to fully published state; and
- Increased agility to process purchase orders, resulting in a 46 percent reduction in purchase requisition to purchase order conversion days.

The integration and expansion of responsibilities of the 3PP provider has allowed the core Demand and Acquisition Services team to focus on strategic endeavours to secure a reliable supply of materials and equipment and mitigate supply chain challenges, including:

- Implementing system enhancements and upgrades to enable better decision making for forward buys and material demand planning;
- Optimizing inventory schedules with suppliers and improving and embedding material demand planning across the organization;
- Conducting frequent short interval control meetings with operational leaders to maintain visibility, provide status updates of expected deliveries, and prioritize material allocations; and

- Creating critical asset forecasting models to anticipate, predict, and accommodate market changes in real-time by implementing predictive forecasting.

3.1.4 Response to Global Supply Chain Disruption

Major world events in the 2020-2024 rate period, such as the COVID-19 pandemic, changes to work patterns, geopolitical conflict, and high inflation, significantly disrupted the global supply chain by adversely affecting manufacturing capacity and transportation networks. These disruptions have caused a number of risks to materialize with respect to the timely and cost-effective procurement of materials and equipment. As examples, the lead times for acquiring certain items have significantly increased, requiring capital projects to be planned further ahead of time. Higher raw material and labour costs have put upward pressure on the price of materials. The timely delivery of orders has become less reliable, requiring greater stock to ensure the availability of critical spares. Collectively, all of these effects have increased the risk of materials shortages, with the potential to adversely affect project schedules.

To mitigate these issues and ensure reliability of supply, Demand and Acquisition Services updated its procurement strategy to incorporate a comprehensive assessment of supply chain risks and address challenges with a combination of proactive, long-term measures and reactive, short-term actions. The revised strategy adopts a 360-degree view of Toronto Hydro's supply needs in the present and into the short- and medium-term, as informed by engagements with business units, while simultaneously keeping track of market conditions through touchpoints with vendors and manufacturers. In light of these inputs, Demand and Acquisition Services has adopted an approach that focuses on 5 critical factors:

- **Product**: In order to increase resiliency against material constraints, Demand and Acquisition Services conducts diligent reviews of alternative sources of supply and alternative products for equipment, and negotiates forward buys with suppliers for major components and materials in order to secure manufacturing slots with factories ahead of time. Sharing known work projects and planned work requirement forecasts with supplier partners more frequently and at longer time horizons affirm supply plans and provisions. Demand and Acquisition services prudently negotiate proposed price increases and structure supply and service contracts to maintain a favourable position for Toronto Hydro.
- **Parameter**: Inventory parameters, including re-order points, lead times, and critical spares, are strategically reviewed and adjusted to proactively respond to changes in the demand forecast.
- **People**: Internal and outsourced resourcing are ramped up to increase flexibility of the workforce and manage ongoing disruptions and challenges.
- **Program**: Internal business units are continuously engaged to provide status updates on expected deliveries, prioritize material allocation for major assets, and conduct material demand planning workshops for planned projects.
- **Process**: With respect to the governance of materially impactful price increases and streamlining processes, additional due diligence procedures are implemented and used to evaluate change requests and other procurement decisions.

Examples of achievements resulting from this strategy between 2020 to 2022 include:

- **Product:** In 2020, the Utility's primary transformer supplier advised that they were not able to keep up with the demand due to global supply chain challenges. In order to maintain a steady supply of critical assets to sustain the capital program, Demand and Acquisition Services, along with Standards and Quality, diligently

sourced and approved two new suppliers to supply the equipment, with pricing in line with market rates, and lead times 12 weeks shorter than the industry average of 60 weeks. Detailed tests were conducted to ensure specifications meet approved standards and that the transformers are compatible with existing infrastructure. Furthermore, with respect to cable, the Utility's primary cable supplier was faced with labour disruptions between 2021-2022 and the unexpected loss of one of their copper suppliers in 2022 due to an incident at the plant, which constrained their ability to supply and extended lead times. Demand and Acquisitions Services worked closely with the supplier to ensure production slots are allocated to the utility, increase communication in regards to production and shipping statuses of existing commitments, and negotiate forward buys to secure production slots for future demand ahead of lead time. In tandem, a secondary cable supplier was sourced to minimize material disruptions and establish forward buy agreements. This outcome successfully reduced the risk of material shortage for planned capital and reactive work, and ensured critical materials were on hand for emergency situations.

- **Parameter:** In 2022, Demand and Acquisition Services updated contract lead times for major assets in SAP to reflect current vendor lead times for material requirements planning. With global disruptions significantly effecting lead times, it was necessary to adjust the lead times in the system to align with the current macroeconomic environment. This outcome enables more accurate forecasting, project planning, and re-order point calculation, and thus contribute to strengthening the ability to manage and minimize the risk of material disruptions.

- **People**: In 2022, Demand and Acquisition Services put together a dedicated demand planning team to work with execution business units on the alignment of strategic project planning, forecasting and budgeting, and materials management to enable balanced, dynamic, and choreographed execution and decision making. This outcome enhances information sharing, establish greater control and monitoring, and drives discussions for future state improvement opportunities to further increase resiliency in Toronto Hydro's supply chain.

- **Program**: In 2020, Demand and Acquisition Services sourced a supplementary transformer supplier to ensure a steady supply of padmount and vault transformers, which are major assets commonly used in the distribution system. Internal business units were continuously engaged to provide status updates on expected deliveries, and to shift projects into future periods when material will be available. This outcome contributes to the sustainment of Toronto Hydro's capital program by providing an alternative source of supply of such equipment, and ensuring project are planned with realistic and tangible inputs.

- **Process**: For critical network protectors and network protection accessories, Demand and Acquisition Services negotiated a proposed price increase, driven by material increases in raw material costs, that was approximately 43 percent lower than the supplier's originally requested increase. This outcome successfully reduced the risk of equipment shortage for planned capital and reactive work while limiting cost increases to a reasonable degree, and thus contributed to Toronto Hydro's system reliability outcomes.

3.1.5 Procurement Consulting Services

In 2023, Demand and Acquisition Service engaged a procurement consulting service provider to conduct an analysis of Toronto Hydro's Procurement Policy and to establish an ongoing supply chain market intelligence and analytical reports for the continuous improvement of the utility's procurement practices. The consultant will be responsible to:

- Assess policy performance in relation to industry peers (including public utilities) and in relation to the latest best practices within the North American utility industry;
- Develop gap analysis and provide specific recommendations on how to improve the Procurement Policy to meet or exceed industry best practices;
- Review current supply chain environment within Toronto Hydro;
- Provide recommendations on the most appropriate areas for monitoring; and
- Develop and provide on an ongoing basis a standardized report with respect to the above elements.

The resulting policy analysis and market intelligence reports will provide insights to emerging opportunities and potential threats to the business to allow for better strategic decision making and improved sourcing strategies, in conjunction with the approaches outlined in Section 3.1.4, Response to Global Supply Chain Disruptions. These macro level insights will enable Toronto Hydro to reduce and mitigate risks related to macroeconomic factors such as inflation and price indices, supply chain constraints, and global trade policies such as tariffs, duties, and sanctions. In turn, the utility's risk mitigation measures will allow it to better manage supply risks of critical materials and equipment and work more efficiently with suppliers to identify and adopt innovative delivery practices.

3.2 Warehouse and Logistics

3.2.1 Inventory Management

The Warehousing and Logistics function receives, stocks, and supplies all inventory materials in accordance with Toronto Hydro's capital and operational program requirements. Field crews receive the requisite equipment and materials from any of the five warehouses which are strategically situated across the City.

The typical activities of the Warehousing and Logistics function includes:

- Unloading, visually inspecting, receiving, and storing materials and supplies from vendor vehicles to issue to crews;
- Selecting, staging, and loading distribution equipment and materials onto fleet vehicles to facilitate a quick exit from work centres at the beginning of each workday;
- Delivering and distributing requisite materials to and from job sites and between warehouses to facilitate faster and more efficient materials distribution;
- Issuing miscellaneous (over-the-counter) items such as tools, clothing and safety equipment to ensure that field crews have the mandatory safety equipment and necessary tools to perform work;
- Handling excess materials returned from the field upon work completion, such as partial cable reels which can be re-entered into inventory and issued to other jobs;
- Arranging for field equipment set aside for repairs or replacement to be returned to vendors and suppliers;
- Establishing and maintaining appropriate minimum and maximum inventory levels at each warehouse to ensure that the appropriate product mix is available to support the work performed by the crews of each work centre; and

- Performing daily inventory cycle count activities to ensure the accuracy of Toronto Hydro's financial reporting and recordkeeping, and reconcile physical inventory on the shelf with records.

3.2.2 Third-Party Logistics Provider

Since 2013, Toronto Hydro has been using a Third-Party Logistics ("3PL") warehousing services provider to support the scale of its capital program in a flexible and sustainable manner. The 3PL provider uses Toronto Hydro's Warehouse Management System ("WMS") software and provides services at competitive market rates. This service is competitively sourced. Utilizing a 3PL provider gives the utility the flexibility (across and within rate periods) to quickly adjust to fluctuating inventory demands; such as those that were experienced throughout the pandemic. In 3PL's absence, Toronto Hydro would have the responsibility and would need to assume the risk of investing in additional warehouse space, equipment and resources to support a growing capital program.

The 3PL provider owns and operates two warehouses located just north of Toronto as an addition to the three existing Toronto Hydro warehouses. While the 3PL provider has assumed a significant portion of Toronto Hydro's warehousing duties, the internal work centres continue to play a key operational role by facilitating prompt materials issuance to the crews departing from the three work centres, and facilitating timely response to emergency response needs. Toronto Hydro crews are able to reach job sites faster by being able to pick up materials from the warehouses across the City. This creates greater efficiency and execution of planned work and faster power restoration during reactive assignments.

3.3 On-Cost

The cost of Warehouse and Logistics function and a portion of the Demand and Acquisition Services function are recovered internally through the materials on-cost rate, which is applied to the value of the goods issued to crews for specific projects, and ultimately reflected in the projects' overall capital costs.[2]

On-cost rates shown in Table 3 below reflect the historical rates over the previous 3-year actual period (2020-2022), bridge period (2023-2024) and forecast period (2025-2029). The increase in the on-cost rate is driven by increased throughput to support the growth in the capital project program in the forecast period, and the need for additional staff to support the material issuances.

Table 3: On-cost rates for 2023-2029

Year	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
On-Cost Rate	12.0 %	10.5 %	10.0 %	13.1 %	13.3 %	13.2 %	13.6 %	13.8 %	14.5 %	14.9 %

4. PROGRAM COSTS

Toronto Hydro is requesting an average of $24.5 million per year over the 2025-2029 rate period to efficiently execute the Program functions described above.

Table 4, below, provides the Actual (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for the Program.

[2] Toronto Hydro calculates the annual rate by dividing the applicable Program costs over the anticipated cost of materials supplying that year's capital and maintenance work program. The resulting rate (%) is then added to the materials charged to the capital and maintenance projects.

Table 4: Supply Chain Services Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Supply Chain Services	15.8	12.9	13.8	16.7	18.8	21.5	23.5	24.9	25.5	27.1
Total	**15.8**	**12.9**	**13.8**	**16.7**	**18.8**	**21.5**	**23.5**	**24.9**	**25.5**	**27.1**

4.1 Cost Drivers

The cost increases in this program are primarily a result of:

- **Increase in requests for materials:** To meet the volume of materials and equipment required to fulfill Toronto Hydro's capital program for the 2025-2029 rate period, the Program anticipates a commensurate rise in costs. Program costs have a direct relationship with the amount of material movements required by the utility, which are tied to its capital investments. The Program will additionally require an increase in headcount in order to process material movements, and competitively bid for strategic projects.
- **Challenging procurement environment:** With increased volume in capital projects and a disrupted procurement environment requiring a greater degree of advanced planning, more resources are needed to process purchase orders, conduct efficient competitive sourcing at the most favourable acquisition cost, collaborate with business units, and mitigate material supply risks to support grid modernization and electrification initiatives.
- **Increase in payroll and labour costs**: Internal labour, responsible for monitoring, controlling, governance, and continuous improvement initiatives, will supplement the operational work executed by external labour. Warehouse and Logistics will increase its hiring in 2024 to support the growth in the capital program.
- **Engagement of procurement consulting services:** Toronto Hydro engaged a procurement consulting service provider to provide consulting services and

conduct a thorough review of Toronto Hydro's Procurement Policy and establish the delivery of ongoing supply chain market intelligence reports. The costs of the service in 2023 include the initial analysis and development of the market intelligence models, which will form the gap analysis and recommendation development framework. Subsequent market intelligence reports in 2024-2026 will provide Toronto Hydro with recommendations on risk management strategies to reduce risks related to macroeconomic factors, supply chain constraints, and global policies. In the future, as Demand and Acquisition Services implements risk and mitigation measures from the market intelligence reports, Toronto Hydro expects cost savings through improved sourcing strategies.

4.2 Cost Control and Productivity Measures

In 2018, Toronto Hydro implemented SAP Ariba, a cloud-based procurement software, which connects prospective suppliers with buyers on a single platform. SAP Ariba, which is part of the SAP suite of applications, synchronizes seamlessly with Toronto Hydro's Enterprise Resource Planning ("ERP") software.

In 2022, all of Demand and Acquisition Services' sourcing activities are conducted through SAP Ariba and have provided the following benefits to Toronto Hydro:

- **Collaboration and digital transformation**: SAP Ariba enhances Toronto Hydro's competitive bid process by bringing together prospective suppliers, buyers, and internal business unit collaborators on a single platform. With a cloud-based solution, SAP Ariba can be accessed from different locations. Toronto Hydro leverages Ariba's ability to share documents digitally and securely in the cloud, which mitigates the need for physical movement and storage of documentation, and allows for more efficient record keeping. Toronto Hydro's investment in the

Ariba software has helped the company reduce the environmental impact of its internal operations and create a collaborative digital environment for productivity and growth.

- **Operational efficiency and compliance:** SAP Ariba compliments and enhances Toronto Hydro's Contract Management Framework, which is a set of guiding principles, documents, and procedures designed to govern the end-to-end sourcing process. SAP Ariba improves Toronto Hydro's operational efficiency and compliance through consolidation of data and documents, and increases visibility on current engagements. SAP Ariba provides notifications to Demand and Acquisition Services when contracts are within the defined notification period to exercise option to renew. As a result, Toronto Hydro's risk of engaging with a supplier with an expired contract is greatly reduced.

Where materials and equipment at the end of their useful lives are replaced with alternatives built to newer technical standards, Toronto Hydro ensures that the existing stock of the obsolete parts are used up first to minimize any residual inventory. In certain cases, Toronto Hydro may also return remaining quantities of the obsolete equipment to the supplier, or sell them for parts. This approach ensures that warehouse storage space is used efficiently and without impeding the adoption of new technologies or types of equipment.

In order to further reduce Toronto Hydro's carbon footprint and overall costs, major assets such as transformers that were used for temporary connections or capital upgrades go through Toronto Hydro's Major Asset Equipment Reuse Program when they are returned from the field. Engineers from the Quality and Compliance team inspect each unit carefully, and if the unit is deemed fit for reuse, it is returned to stock and issued out

to the next capital project. If the unit can be repaired, it is sent back to the manufacturer if it is under warranty, or sent to a third-party repair and recertification supplier for a small fee. By reusing and recertifying the major assets, Toronto Hydro is able to reduce the amount of waste generated and reduce the lead time and costs associated with purchasing a new unit. To ensure sufficient capacity to inspect and certify transformers for reuse, Toronto Hydro engaged an additional contractor in 2022 to execute this work and proactively manage the eligibility criteria for assets' inclusion in this program. This approach further mitigates supply risks.

Toronto Hydro will continue to manage costs in this Program by leveraging the 3PP provider to:

- Diversify and balance workload between internal and outsourced resources to increase flexibility and resiliency in the workforce; and
- Streamline operations through the 3PP provider, and reduce costs through the vendor managed inventory initiative. Under this initiative, suppliers are responsible for maintaining an appropriate level of inventory to ensure material is always ready for pick up. Once an order is placed, inventory is transferred from the vendor managed portion of the warehouse into the main warehouse. This reduces lead time and provides cost savings by engaging suppliers directly instead of distributors.

Toronto Hydro will continue to manage costs in this Program by leveraging the procurement consulting services provider for assessing its policies, identifying best practices and developing market intelligence monitoring, including macroeconomic trends and category-specific trend analysis. The trend analysis will specifically:

- Compare Toronto Hydro's Procurement Policy with similar organizations in the utilities sector, and identify leading practices and areas of improvement;
- Identify components and subcomponents for key spending categories and risks that can affect supply; and
- Create a template for market intelligence monitoring containing macroeconomic trends and category-specific trend analysis.

Toronto Hydro will also continue to manage costs in this Program by leveraging the 3PL provider to:

- The WMS software and hardware solutions utilize barcode technology and provide real-time visibility into inventory, increasing the efficiency of the receiving and picking functions. Warehouse transactions are centrally prioritized and assigned to warehouse employees by queuing tasks to the employees' hand-held barcode guns. Tasks such as receiving, picking, and cycle counting are carried out by scanning the product bar code affixed to all incoming materials. This technology significantly speeds up the previously manual tasks of keying in the entries for every incoming packing slip, outgoing picking slip, or cycle count entry. The use of this technology allows the warehouse to provide efficient service to Toronto Hydro crews.
- In 2023, the Warehouse and Logistics function is going to upgrade its WMS to the SAP Warehouse Management Module, which allows full integration with the Toronto Hydro's ERP system by SAP. This outcome will reduce the likelihood of data errors and inefficiencies that may result from the use of separate WMS and ERP systems, facilitate reporting and recordkeeping, and consequently reduce operational costs.

As shown in Figure 2 below, despite challenges presenting themselves in the last three years, the Warehouse and Logistics function successfully fulfilled material requirements On Time and in Full ("OTIF") at an average rate of 95 percent since Jan 2020. This is consistent with our fulfilment performance in the previous rate period.

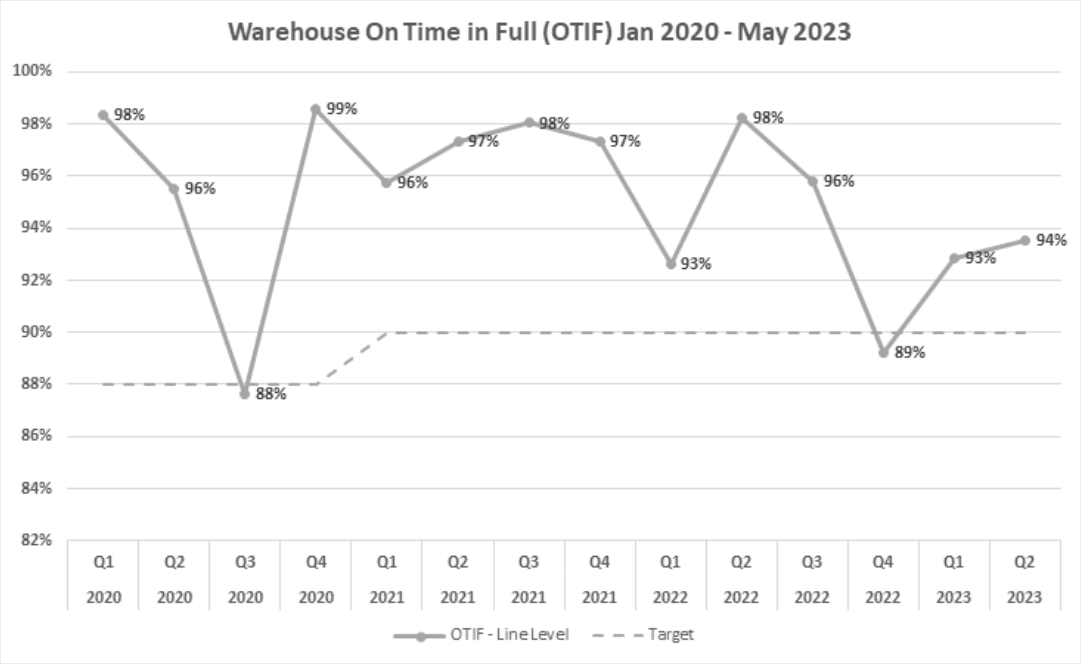

Figure 2: Warehouse OTIF Rate

4.3 Supply Chain Services Program Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

The Program experienced a $2.8 million decrease from 2020 to 2021. This decline was due to the following factors:

- a $1.9 million decrease in labour related expenses due to retirement in the workforce;
- a $2.0 million decrease in inventory and direct purchases due to a variance of $1.4 million in inventory written off in 2021 versus 2020 resulting from revised

standards and obsolete materials, and $0.6 million in on-cost true-down caused by a lower on-cost recovery rate in 2021;

- a $0.1 million reduction of office supply purchases due to a remote environment driven by COVID;
- a $0.8 million increase driven by 3PL and 3PP costs as a result of increased material throughput; and
- a $0.4 million increase in other support costs driven real inventory write offs in 2021 resulting from obsolete materials.

2021 – 2022 Variance Explanation

The Program experienced a $0.9 million increase from 2021 to 2022. This increase was due to the following factors:

- a $1.9 million increase driven by 3PL and 3PP costs as a result of increased material throughput;
- a $1.6 million decrease in inventory and direct purchases
- a $0.4 million in inventory written off in 2022 versus 2021 resulting from revised standards and obsolete materials, and $1.1 million on-cost variance true up caused by a higher on-cost recovery rate in 2022 versus 2021
- a $0.4 million increase in labour related expenses due to compensation and salary inflationary increases;
- a $0.1 million increase of purchases related to office supplies due a hybrid return-to-office environment; and
- a $0.1 million credit related to volume purchasing rebates in 2022 for pole line hardware.

2022 – 2025 Variance Explanation

The Program is expected to experience a $7.7 million increase from 2022 to 2025. This increase is due to the following factors:

- a $2.7 million increase in labour related expenses due to additional resources required to support material demand planning and strategic sourcing initiatives, and compensation and salary inflationary increases;
- a $0.6 million increase in inventory direct purchases due to materials written off resulting from revised standards and obsolete materials;
- a $4.6 million increase driven external contract costs of due to a $3.8 million increase in 3PL and 3PP costs as a result of an increase in projected material throughput and expected costs from new contract setting process, and a $0.8 million increase driven by procurement consulting services to conduct a review of Toronto Hydro's Procurement Policy and establish the delivery of ongoing supply chain market intelligence reports;
- a $0.1 million increase of purchases related to office supplies due a hybrid return-to-office environment; and
- a $0.2 million decrease in other support costs due to a variance caused by material volume rebates not yet materializing in the latter periods.

2025 – 2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $5.6 million, or an average of $1.4 million per year Without the requested level of funding over the upcoming rate period, Toronto Hydro could be exposed to a number of risks, including:

- Delayed or inefficient procurement of goods, which could affect the timely completion of planned and reactive capital work as well as operations, leading to

worse reliability outcomes for customers and delays in the achievement of other outcomes;

- Delayed or inefficient procurement of services, which could affect the cost of third-party resources and increase overall operating costs; and
- Errors in inventory management, such as equipment and materials being misplaced, issued incorrectly, or damaged, increasing overall operating costs and delaying the execution of capital programs and customer connections.

CUSTOMER CARE

1. OVERVIEW

Table 1: Customer Care Program Summary

Customer Care Program									
Outcomes: Customer Focus, Public Policy Responsiveness, and Financial Performance									
Segments: • Billing, Remittance, and Meter Data Management • Collections • Customer Relationship Management									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
55.7	39.3	39.3	44.9	48.4	48.6	51.6	52.5	54.4	56.1

The Customer Care program (the "Program") addresses the direct interactions between Toronto Hydro and its approximately 791,000 customers, through customer relationship management, billing, metering, and collections functions. Providing high-quality customer service is a core priority for Toronto Hydro, and the utility is constantly seeking new ways to foster meaningful two-way communication, expand the range of service offerings to meet customers' evolving needs, improve service convenience and experience, and integrate new technological advancements to drive improvement and productivity.

The Program is comprised of the following three segments: (i) Billing, Remittance, and Meter Data Management, which handles the reading of customer meters, upkeep associated with infrastructure and metering data management, preparation of customer bills, and payment processing; (ii) Collections, which handles all activities associated with

unpaid accounts; and (iii) Customer Relationship Management, which involves activities related to customer interactions.

The Program and its constituent segments are a continuation of the activities described in the Customer Care program in Toronto Hydro's 2020-2024 Rate Application.[1] Adequate funding for the Program is essential to the utility's ability to provide timely, effective, and efficient customer services, remain financially viable, and contribute to the billing and settlement of pass-through rates and charges that relate to other stakeholders in the electricity industry. Over the 2025-2029 rate period, Toronto Hydro also expects that it will need to continuously evolve its business practices and service offerings to adapt to broad societal developments and industry trends affecting its business and customers' needs and preferences, such as new public policies, electrification, and increased adoption of electric vehicles ("EVs") and distributed energy resources ("DERs"). These transformations will likely lead to numerous changes in customer expectations, including, demands for greater information on and control over electricity usage and expenditures, greater choice to purchase renewable power or self-generate for sale back to the grid, and the incorporation of environmental, social, and governance ("ESG") goals in energy use.

Although it remains to be seen how and to what extent these industry trends, public policy changes, and changes in customers' preferences and behaviours will impact the Program's operational areas and key performance metrics such as call volumes, average service times, metering, billing, and remittance, Toronto Hydro needs to be well-poised to adapt to these uncertain circumstances. The 2025-2029 rate period will be crucial for the utility to lay the foundation for such adaptation by continuously monitoring trends,

[1] EB-2018-0165, Exhibit 4A, Tab 2, Schedule 14.

modifying its business processes, achieving productivity gains through initiatives such as automation, upskilling its workforce, and acquiring additional specialized resources. Investing in these measures will allow the Program to remain agile and effectively meet customers' needs under any scenario that may occur.

Toronto Hydro's proposed investments in the Program over the 2025-2029 rate period include the following to enable the utility's effective response to the related new demands and challenges:

- Contact Centre services designed to respond to new types and complexities of technical, metering, and billing enquiries associated with EVs and EV charging systems, DERs, and government programs and incentives;
- Enhancements to improve the customer experience and two-way communication through more flexible channels such as online chat, mobile application and digital self-service platforms;[2]
- Metering solutions associated with net metering and remote metering;
- Billing options including provincial pricing plans or utility-specific options;
- Remittance processing including support for new and emerging payment methods, and for public and private EV charging systems;
- Data analytics resources including staff, business processes, and technology to help capture a holistic view of customers' individual needs, preferences, and past interactions to offer personalized service and allow proactive engagements;
- Information and support resources to facilitate eligible customers' access to financial assistance programs, including the improvements discussed under the Charitable Donations and Low-Income Energy Assistance Program; [3]

[2] Exhibit 2B, Section E8.4; and Exhibit 4, Tab 2, Schedule 17.
[3] Exhibit 4, Tab 2, Schedule 19.

- Enhanced collections services and capabilities including increased self-service functionality, multi-channel communications and proactive notifications to support customers with on-time payments; and
- Efficiency improvements through chatbots, virtual assistants, and other automation tools to handle routine inquiries and exception handling, based upon aritfical intelligence-powered tools to analyze customer interactions and identify areas for improvement.[4]

2. OUTCOMES AND MEASURES

Table 2: Customer Care Program Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus outcomes over the 2025-2029 rate period by: ○ Answering telephone calls within 30 seconds at least 65 percent of the time on average, as measured by the OEB's Telephone Accessibility metric; ○ Providing written responses to qualified enquiries within ten business days at least 80 percent of the time on average, as measured by the OEB's Written Response to Enquiries metric; ○ Addressing customers' needs in the first instance they contact Toronto Hydro, as measured by the OEB's First Contact Resolution measure; ○ Achieving a billing accuracy rate of at least 98 percent, as measured by the OEB's Billing Accuracy metric; ○ Increasing the adoption of electronic billing to a total of approximately 488,000 customers, representing cumulative savings of approximately $2.0 million by the end of the 2025-2029 rate period; ○ Meeting or exceeding the OEB's Reconnection Standards of 85 percent; and ○ Ensuring no more than ten percent of calls are abandoned, as measured by the OEB's Telephone Call Abandon Rate.

[4] Exhibit 2B, Section E8.4. and Exhibit 4, Tab 2, Schedule 19.

Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness outcomes by implementing legislative and regulatory requirements within mandated timelines over the 2025-2029 rate period.
Financial Performance	• Contributes to Toronto Hydro's financial performance outcomes as measured by the total cost and efficiency metrics by: o Ensuring financial stability and revenue generation capabilities via timely issuance of customers' bills and the collection and processing of customers' payments; and o Investing in process improvements that eliminate manual efforts and promote customer self-service.

3. PROGRAM DESCRIPTION

The Program is composed of three segments covering most of the direct interactions between Toronto Hydro and its customers, and the work required to support these interactions:

- **Billing, Remittance, and Meter Data Management:** Involves the reading of customer meters, upkeep of the associated metering infrastructure, management of meter data, preparation of customers' bills, and the processing of customer payments;
- **Collections**: Involves activities to collect money associated with unpaid customer accounts; and
- **Customer Relationship Management:** Involves activities related to Toronto Hydro's interactions with its customers.[5]

4. PROGRAM COSTS

In 2025 Toronto Hydro requires $48.6 million in rate funding for the Customer Care program, which represents an increase of $7.1 million over the last rebasing in 2020.

[5] This segment excludes interactions with the utility's large customers and key accounts, which are captured under the Key Accounts segment of the Customer Operations program in Exhibit 4, Tab 2, Schedule 8.

When normalized for shared services recoveries outlined in Exhibit 4, Tab 5, Schedule 1, the expected increase in this program is $7.4 million.

Over the 2025-2029 rate period, the utility expects the cost of this program to increase by an annual growth rate of 3.7 percent which is necessary to address the program needs and deliver the customers outcomes enabled by this program.

The proposed level of Program funding is expected to maintain and improve Toronto Hydro's level of customer service, support the implementation of public policy initiatives, be responsive to customers' emerging needs and preferences, and support continuous improvement efforts to help the utility achieve its strategic objectives and outcomes, including the modernization of business processes in response to industry trends such as electrification and for the enhancement of customer experience.

The Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for each segment are summarized in Table 3 below.

Table 3: Customer Care Program Expenditures by Segment ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Billing, Remittance and Meter Data Management	19.4	18.9	19.4	20.9	23.1	23.7	25.0	25.4	26.2	27.0
Collections	24.9	9.0	7.8	9.6	10.2	10.2	10.9	11.0	11.3	11.6
Customer Relationship Management	11.4	11.4	12.1	14.4	15.1	14.7	15.7	16.1	16.9	17.5
Total	**55.7**	**39.3**	**39.3**	**44.9**	**48.4**	**48.6**	**51.6**	**52.5**	**54.4**	**56.1**

4.1 Cost Drivers

The Program's cost increases are primarily a result of:

- Replacing retired and vacant positions to attain operationally effective staffing levels;
- Building temporary backfill teams to support large-scale foundational projects such as Advanced Metering Infrastructure ("AMI") 2.0 and Customer Information System ("CIS") Project, and staff transitioning between these projects and day-to-day operational functions;
- Increasing external vendor costs due to increases in payroll costs and other inflationary pressures;
- Increased costs relating to post-COVID-19 collections activities at higher than pre-COVID-19 volumes and arrears balances until electricity payment arrears are normalized;[6]
- Increasing staff levels to develop and deploy new programs to enhance customer service; and
- Implementing and operationalizing new public policy initiatives that may require additional customer service, collections, and field resources.

As the electricity industry evolves, Toronto Hydro's customer service functions must keep up with broad changes in customer needs and preferences driven by the energy transition and adapt to handle evolving customer behaviour and more complex information. The utility is already observing these trends even with respect to traditional customer interactions. For example, a high bill inquiry now often requires a frontline representative to consider more factors than before, such as the customer's

[6]Since the resumption of disconnections in June 2022, although Toronto Hydro has seen an improvement in the arrears balances of 57 percent (due to reverting to pre-COVID-19 guidelines and severance thresholds during the 2023 disconnection cycle), continued effort is required to return to pre-COVID-19 levels.

choice of available pricing plans (tiered, Time of Use, Ultra-Low Overnight Time of Use) or the customer's usage of electricity-intensive devices such as electric vehicle chargers or heat pumps. These trends are even more pronounced with respect to services that have been historically niche areas, but are gradually becoming more commonplace, such as DERs. For example, the billing of net metered accounts is an order of magnitude more complex than regular load accounts, due to the calculation of generation credits and the treatment of Harmonized Sales Tax.

In this environment, customers' expectations are also continually reshaped by all service providers they interact with, not just utilities. As online services and electronic transactions are gradually becoming the norm for the majority of small and large businesses, customers are coming to expect the same standard of service from their electricity distributor as table stakes.

The Program has been adapting to these trends by increasing the variety of communication channels available to customers, with a focus on self-service. In 2022, the number of such channels increased from seven to nine, with the addition of live chat and Toronto Hydro's mobile application.[7] As a result, customers are currently able to perform a broad variety of online transactions, such as registering for eBills, requesting move-ins or move-outs, downloading consumption information for their rental property to comply with the utility's obligations under the Ontario Regulation 389/10,[8] registering for pre-authorized debit payments, or reporting streetlight outages. While each channel adds to customer convenience, managing interactions through different

[7] Prior to 2022, communication channels included telephone, email, fax, mail, Toronto Hydro's website, interactive voice response ("IVR") through the Contact Centre function, and the online Customer Self-Serve ("CSS") portal.
[8] Ontario Regulation 389/10, under the *Energy Consumer Protection Act, 2010*, SO 2010, c 8.

channels requires different staff skills to operate systems and perform analytics for gaining insights on customer behaviour and each channel's effectiveness and efficiency.

Against these trends, Toronto Hydro plans to transfer a portion of certain Program functions from its external contact centre vendor to internal staff, in order to better build, preserve, and diversify in-house knowledge and expertise of core functions and leverage the same for modernization initiatives and projects or business processes borne out of regulatory compliance requirements. This approach will increase operational and financial flexibility for the Program by reducing dependency on external vendors and mitigating the effects of associated cost increases.

Parallel to the insourcing effort, the Program will hire new staff to replace retiring staff and/or fill vacant positions. The addition of new and the proportion of relatively inexperienced staff will drive the need for more training time and quality assurance ("QA") work, which further contributes to the Program's staffing needs. In order to increase the effectiveness of QA processes, Toronto Hydro plans to increase its reliance on data analytics. For example, the deployment of a speech analytics tool will automatically transcribe and analyze customer interactions to provide objective indicators of customer sentiment and intent, and identify call drivers. The application of this data to automated quality management, powered by artificial intelligence and machine learning technologies, will enable the Program to evaluate customer relations representatives' performance on telephone calls based on robust empirical data and provide much more precise and effective feedback. In order to fully leverage these capabilities, the Program will also hire staff with the necessary data analytics skillsets.

Another area driving resourcing needs will be knowledge management. As the complexity of service offerings and customer interactions grows, either through new legislative and regulatory requirements or evolving customer needs and technologies, it will become more important to keep knowledge management databases current. To address this need, the Program will hire dedicated staff for maintaining consistent and current information and making it accessible to customers and staff across all engagement channels.

In addition to the cost drivers listed above, Toronto Hydro expects that broader industry trends will drive costs under the Program over the 2025-2029 rate in response to the following customer service expectations:

- **Support for EV Users**: As EV ownership and usage increases, the utility anticipates an increase in customer inquiries related to EV's and EV charging on topics such as service upgrades, infrastructure (e.g. questions about installing/troubleshooting charging stations), available pricing plans, and on-street charging and billing. To provide an effective response to these types of inquiries, Toronto Hydro will require additional specialized resources possessing the relevant knowledge for its Contact Centre, under the Customer Relationship Management segment. In addition, the utility will need to develop new business processes or modify existing ones to ensure the seamless management of EV-related inquiries and improve related internal support systems.
- **Support for DER Owners and Operators**: As more customers adopt distributed generation (e.g. solar panels) and energy storage systems, Toronto Hydro anticipates an increase in customer inquiries related to these technologies, such as connections to the distribution system, net metering and associated billing, guidance on optimizing energy use, participation in current and future demand

management programs, or to report issues with DER equipment. In addition, these customers will be looking for additional support in understanding and managing their energy consumption patterns. To support these customers, the utility will need to upskill and allocate additional resources to provide customers with timely and effective service.

4.2 Cost Control and Productivity Measures

Toronto Hydro recognizes that it must remain responsive to all customers' needs and preferences and the utility continues to actively seek out efficiencies and productivity improvements throughout Program operations.

During the 2020-2024 rate period, Toronto Hydro successfully implemented numerous public policy initiatives by achieving a plethora of process and technological improvements, limiting the number of additional staff resources that would have been required in absence of such improvements. For example, the implementation of the Ultra-Low Overnight Time of Use ("ULO") Price Plan in 2023 required additional customer service, meter data and billing resources to ensure appropriate processing of customer-requested price plan changes and exception handling. However, Toronto Hydro was able to implement the ULO Price Plan and other initiative without hiring additional resources by reallocating existing resources efficiently and managing costs through the following strategies:

- Enhancements to the Customer Self-Serve (CSS) portal made it easier for residential customers to register for pre-authorized debit (PAD) online, and added functionality to extend these online services to commercial customers. This resulted in increased PAD adoption by 15 percent between 2020 and 2022 period;

- Development of a customer escalation team to respond effectively to increasingly complex nature of customer complaints and escalations;
- Ongoing oversight, management, and improvements of the metering infrastructure enabled Toronto Hydro to reduce estimated billing and consistently exceed the OEB-prescribed Billing Accuracy target of 98 percent over 2020-2022;
- Automation of the meter exchange program to eliminate manual inputs of meter data into the CIS, saving approximately 5 minutes per meter change or 4,000 person-hours of manual work on average;
- Reduction in paper, printing, and postage costs by converting a total of approximately 381,000 customers to electronic billing since 2013, yielding cumulative savings of $4.4 million as of the end of 2022;
- Redesign of the CSS portal with additional functionalities to reduce the need for customer contact, increasing the proportion of automated moves from 12 percent in 2020 to 22 percent in 2022, the equivalent of 20,000 moves;
- Redesign and promotion of the customer self-service features on Toronto Hydro's website, providing easier 24/7 access to customer information, reducing the need for customer contact;
- Launch of new communication channels to target a broad range of customer interaction preferences, including live chat and a mobile application;
- As a result of the improvements to the accessibility and promotion of self-service features, over the 2020-2022 period, the number of customer self-service transactions have increased more than ten-fold from about 200,000 to almost 3.6 million and resulted:
    - a 16 percent reduction (approx. 67,000) in call volumes; and
    - a 24 percent reduction (approx. 23,000) in email volumes.

- Better workflow management to streamline and automate telephone and email response processes and improve customer response times, which enabled the utility to consistently exceed the OEB-mandated Telephone Accessibility Written Response to Enquiries targets over 2020-2022;
- Introduction of pre-defined tasks to respond to common customer requests and automation of process controls including bots and additional reporting, for areas such as the automation of back-end meter exchanges in the CIS (e.g. filling in new/old badge numbers, meter reads collected from the field, completing the field activity) and the addition of meter inventory to the CIS (serial numbers, nameplate information, etc.);
- Elimination of the manual work required to process and record field activities and updating the CIS by automating the processing of field activities and subsequent updates to the CIS through the implementation of a mobile workforce management system. This system allows field staff to record and update systems through hand-held devices, reducing the risk of billing errors, and enabling the submission of meter reads directly from the field, contributing to timely and accurate billing;
- Streamlining operations to improve access to meters, which reduced the annual number of manually read meters from 885 to 162 over the 2020-2022 period;
- Developing and implementing a standard operating procedure for the cancellation of bills, enabling the Billing, Remittance, and Meter Data Management segment to handle billing errors in a more streamlined manner and contributing to the accurate reporting of Toronto Hydro's billing accuracy performance;
- Optimizing the process for identifying customers in premises where the service is energized and no account has been opened to more effectively mitigate future risks associated with unbilled electricity and the accumulation of bad debt; and

- Streamlining the customer communications process for rate reclassifications to better aid customer understanding and reduce the volume of administrative tasks and printing costs.

5. BILLING, REMITTANCE, AND METER DATA MANAGEMENT SEGMENT

5.1 Segment Description

The Billing, Remittance, and Meter Data Management segment includes reading electricity meters, the validation and management of meter data, the preparation of customer bills, and the processing of payments and refunds.

The Billing, Remittance, and Meter Data Management segment is at the core of Toronto Hydro's meter-to-cash process that transforms customers' electricity consumption, demand, and other billable activities into bills in accordance with the utility's tariff of rates and charges, OEB rate orders, and other applicable legislative and regulatory requirements, and processes customers' payments and refunds. In performing this work, the utility provides its customers with a variety of billing and payment options in accordance with their needs and preferences. Many of these options involve high levels of automation, enabling faster receipt of payments, more effective customer communications, lower costs, optimal cash flow, and higher customer satisfaction. In addition, the automated nature of the majority of data collection and verification processes facilitate timely and accurate billing practices. Over the 2020-2022 period, Toronto Hydro enhanced its automated meter data collection and verification capabilities, maintained annual billing accuracy results over 99 percent, expanded its offerings of online and self-service tools, and implemented numerous public policy initiatives.

5.1.1 Billing

The Billing function is responsible for the creation and issuance of bills for electricity distribution and other services. Toronto Hydro prepares and issues over nine million bills annually and offers its customers multiple delivery options, including standard paper-based bills and electronic bills ("eBills"). For customers with specific accessibility needs, Toronto Hydro provides additional accommodation options, including bills with increased text size and audio playback.

In addition to issuing electricity bills, Toronto Hydro prepares and issues over 12,300 bills annually for other services, such as customer connections and expansions, including DER connections, service upgrades, customer-requested disconnections and reconnections, and distribution asset relocations.

Annually, the utility conducts a rate classification review for all non-residential customers, per the Distribution System Code ("DSC"), to validate the rate class for these customers. Where changes to a customer's annual consumption or monthly average peak demand justify a reclassification, the utility reassigns the customer to the appropriate rate class. As part of the rate classification review, Toronto Hydro also reviews any pricing plan elections (such as tiered, time of use, or ULO) and self-declarations to verify that the customer's account is billed on the appropriate pricing plan and enrolled in programs/rebates for which the customer is eligible, such as the Ontario Electricity Rebate. This process ensures the timely and accurate reclassification and billing of non-residential customers, and the accurate calculation of revenue.

The utility also administers and executes the Industrial Conservation Initiative ("ICI") program whereby eligible Class A customers pay global adjustment ("GA") charges based

on their contribution to Ontario's top five peak hours over the applicable base period. Managing this process requires Billing staff to verify customer demand and eligibility, obtain confirmation of the customer's choice to opt in or out of ICI (where applicable), work with other Toronto Hydro personnel to obtain key information from and submit reporting data to the IESO, and accurately reflect all applicable inputs on customers' bills for the applicable adjustment period.

The utility frequently receives requests from customers for electricity consumption or demand data. Two of the most common types of requests come from 1) owners of commercial, industrial, and multi-unit residential buildings with a gross floor area of 50,000 square feet in order to comply with the requirements of the Large Buildings Energy and Water Consumption Reporting and Benchmarking ("EWRB") program,[9] and 2) residential landlords of suite metered units in residential complexes.[10] To respond to these requests, Billing staff extract data from the CIS and provide the requested information through the customer's preferred channel.

The utility also provides tailored services to its net metered customers, including establishing and renewing net metering agreements, responding to inquiries related to the net metering service, generating bills and issuing credits in accordance with Ontario Regulation 541/05 ("Net Metering Regulation"),[11] including applicable taxation rules for Harmonized Sales Tax ("HST") registrants.[12]

[9] Ontario Regulation 506/18, under the *Electricity Act, 1998*, SO 1998, c. 15, Schedule. A.
[10] *Supra* note 8.
[11] Ontario Regulation 541/05, under the *Ontario Energy Board Act, 1998*, SO 1998, c. 15, Sched. B and Section 6.7 of the Ontario Energy Baord's *Distribution System Code*.
[12] *Excise Tax Act*, RSC 1985, c. E-15.

To ensure ongoing functionality and compliance with relevant legislative and regulatory requirements of the meter-to-cash process, Toronto Hydro maintains a system of internal controls for all systems and processes, and reviews these on an annual basis. These controls enable the utility to discover any billing errors in a timely manner and promptly take the necessary actions to correct them.

As the industry shifts towards electrification, the utility's billing practices must also evolve to account for the evolution of customers' needs and preferences as the use of EVs and EV charging stations, and DERs become commonplace.

5.1.2 Remittance (Payment) Services

The Remittance function is responsible for the management of customer payments, transfers, refunds and related processes, and the processing of retailer service transaction requests ("STRs").

Toronto Hydro accepts a variety of payment methods including cheques, transfers through a variety of financial institutions, and electronic funds transfers ("EFT"). The utility also accepts credit card payments in limited circumstances where a customer is in the process of disconnection for non-payment.

Remittance staff is also responsible for setting up pre-authorized debit ("PAD") arrangements upon customers' request. The utility promotes PAD to its customers to optimize cash flow and minimize the risk of bad debt due to non-payment. Since October 2021, enhancements to the CSS portal have simplified the registration process for residential customers and enabled commercial customers to register for PAD electronically, which has increased PAD adoption by 15 percent between the 2020 and 2022 period.

In accordance with the OEB's Standard Supply Service Code, Toronto Hydro also offers residential and general service under 50 kW customers on standard supply the option to smooth out their payments through an equal monthly payment plan ("EPP").
Remittance staff work closely with Toronto Hydro's financial institution to process any payment issues and errors such as non-sufficient funds ("NSF"), returned payments, or misapplied payments.

The utility processes approximately 2,800 refunds and credits per month for customers, which include: IESO payments to generation customers (e.g. participants in the Feed-in Tariff program), refunds or security deposits, application of Ontario Electricity Support Program ("OESP") credits, and retailer-initiated adjustments.

Remittance staff also perform other tasks such as payment tracing, transfers of balances, and exception handling in the CIS as needed with respect PAD, EPP, OESP credits, refunds, address errors, payment reversals, etc. These supporting tasks may also include targeted customer communications relating to OESP registration renewals and a variety of other scenarios, which typically generate approximately 1,600 customer letters per month.

As of 2022, 21 retailers were registered and set up on the provincial Electronic Business Transaction ("EBT") System for operation within Toronto Hydro's service territory on distributor-consolidated billing. Remittance staff are responsible for retailer management functions such as settlements with retailers, the issuance of supply change notification letters to low volume customers, the processing of STRs and historical information requests, and responses to relevant retailer and customer inquiries. Remittance staff ensure accurate data flows through the EBT System and timely and accurate settlements with retailers.

Finally, Remittance staff annually issue T5 tax forms to customers accruing interests on their security deposits in accordance with applicable tax legislation and regulations.

In support of the processes described above, Remittance staff maintains several controls to ensure the accuracy of internal and external reporting and record keeping, such as a daily bank reconciliation to match incoming payments through various channels to what is recorded in the bank general ledger, daily refund reconciliations between the CIS and the financial system, and the daily review of aged credit reports to ensure credits are promptly returned to customers.

5.1.3 Meter Data Management

The Meter Data Management ("MDM") function is responsible for the collection and processing of meter data for billing and settlement purposes. As of January 1, 2023, Toronto Hydro had over 803,000 installed meters, of which over 99.9 percent are read remotely on a daily basis. The automated meter data is retrieved by one of Toronto Hydro's three data collection systems. Each data collection system serves different meter types and customer classes, and requires specialized skills to maintain acceptable data quality standards. These data collection systems further pass the data to two separate meter data management systems. The two meter data management systems validate the data for consistency, accuracy, and readiness for billing. If the meter data is not successfully validated, the systems will automatically attempt to estimate the correct reading. If the systems cannot develop an estimate for the missing data the entry is directed to MDM staff to manually assess for billing, for which average volumes of approximately 664 accounts are assessed on a monthly basis.

As of 2022, Toronto Hydro had approximately 160 manually read meters in locations where remote data collection is not possible, such as parking garages with limited cellular

signals. The utility is prioritizing the installation of antenna extensions for wireless capable meters experiencing such communication problems, to facilitate remote communication with meters and reduce manual reads. The utility's continuous improvement efforts to expand automated meter data collection have contributed to the utility achieving strong Billing Accuracy results of over 99 percent in 2022, exceeding the OEB-prescribed billing accuracy performance metric.

In addition, Toronto Hydro is working on further improving the efficiency of data collection by modernizing its systems, enhancing communication networks, and improving system processing capabilities to increase the amount of meter data that is retrieved automatically. For example, through the AMI 2.0 initiative, the utility is going to replace the entire population of residential and small commercial smart meters with next generation smart meters and upgrades to supporting metering infrastructure to deliver certain out-of-the-box capabilities beyond AMI 1.0, which was predominantly focused on meter-to-cash efficiencies. These new benefits include improved billing accuracy, faster outage response, improved network range, enhanced security against cyber-threats, increased grid transparency (i.e. system observability), improved data granularity and analytical capabilities, and improved customer experience thanks to greater meter reliability and robust integration with metering data collection and reporting processes.[13] Over the 2025-2029 period, Toronto Hydro is deploying additional gate keepers and antenna extensions for interval meters to improve automatic data collection.

In addition to metered customers, Toronto Hydro serves approximately 17,800 Unmetered Scattered Load ("USL") connections as of 2022, which include service to bus

[13] Exhibit 2B, Section E 5.4.

shelters, cable television boosters, telephone booths, traffic and park lighting, and signs. These unmetered devices typically consume the same amount of electricity each month and therefore, billing determinants are based on the technical consumption parameters of the device. The Billing, Remittance, and Meter Data Management segment is responsible for maintaining an up-to-date list of all service locations and updating usage calculations when customers make changes. To ensure accuracy in billing USL services, the utility annually conducts an average of 500 random field audits and reconciliation exercises with its customers.

5.2 Billing, Remittance, and Meter Data Management Segment Costs

Table 4 below provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Year (2025-2029) expenditures for the Billing, Remittance, and Meter Data Management segment.

Table 4: Billing, Remittance, and Meter Data Management Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Billing, Remittance and Meter Data Management	19.4	18.9	19.4	20.9	23.1	23.7	25.0	25.4	26.2	27.0

The primary drivers of costs in this segment were, or are expected to be, the following:

- Backfilling of vacancies (2021-2023): Backfilling of vacancies due to filling current vacancies primarily attributable to retirements, resignations, promotions and CIS project requirements;
- Support the development and implementation of the CIS upgrade (2021-2022): For the period of 2021 -2022, increase in costs associated with additional temp

staff hired to replace the permanent staff that were moved from the CIS project to support Operations, contributing to increased costs;

- Implementation of public policy initiatives (2020-2023): This cost is attributed to ongoing mandatory legal and regulatory obligations such as changes to OEB and IESO related programs, for example changes to Class A, OER, an introduction of the ULO Price Plan as of May 1, 2023 and the Green Button Initiative by November 1, 2023 which require ongoing administrative costs to implement these initiatives;
- Annual compensation increases; and
- Increases to external vendor costs: As a result of inflationary pressures, increases in vendor payroll due to increases in minimum wage, consumable cost etc.

The proposed level of funding is necessary to mitigate several segment-level risks, including**:**

- Decline in timely and accurate meter reading and the resolution of meter-related issues, as well as delays in the future implementation of initiatives associated with the rollout of AMI 2.0;
- Decrease in timely and accurate billing, resulting in billing errors, lower customer satisfaction, and risks to Toronto Hydro's financial viability;
- Reduced ability to promptly and accurately reclassify non-residential customers, resulting in decreased billing accuracy;
- Inability to process payments, credits, and refunds in a timely and accurate manner, jeopardizing the utility's cash flow and increasing the costs of working capital;
- Failure to attain full revenue collection, resulting in higher levels of bad debt and affecting the financial stability of the Toronto Hydro;

- Changes in existing or new public policy and regulatory changes may not be implemented in accordance with required timelines or in the most cost-effective manner;
- Reduced ability to respond appropriately to future changes in customers' needs and preferences; and
- Reduced ability to automate and continuously improve the efficiency of business processes.

5.3 Billing, Remittance, and Meter Data Management Segment Year-over-Year Variance Analysis

2020 - 2021 Variance Explanation

Costs decreased by $0.5 million primarily due to the following reasons:

- $1.0 million decrease in payroll costs due to filling vacancies and transfer of staff to the CIS program;
- $0.3 million decrease in labour costs due to capitalization of business labour to projects;
- $0.1 million increase in temporary and contracted labour to backfill for vacancies;
- $0.4 million decrease in postage from conversion of customers from paper bills to eBills;
- $0.2 million increase in business processing services due to inflation;
- $0.4 million increase to adjust a bad debt accounting provision (ECL) for non-electricity accounts receivables;
- $0.4 million increase in contracted field services to support reactive metering work, and
- $0.1 million increase in printing costs due to inflation.

2021 - 2022 Variance Explanation

Costs increased $0.5 million primarily due to the following reasons:

- $0.3 million increase in payroll costs due to the filling of vacancies and compensation increases;
- $1.5 million decrease in labour costs due to capitalization of business labour to capital projects (e.g. CIS);
- $1.0 million increase in contracted services for temporary staff to backfill vacancies and staff transferred to capital projects (e.g. CIS);
- $0.4 million increase in contracted business processing services due to backfilling for staff on capital projects (e.g. CIS) and inflationary pressures;
- $0.1 million increase in other support costs, and
- $0.2 million increase in postage costs due to inflation, offset by savings in converting customers to eBills.

2022 – 2025 Variance Explanation

Between 2022 and 2025, costs in this segment are expected to increase by $4.3 million. This is primarily due to the following reasons:

- Increase in labour costs due to compensation increases, filling of vacancies and planned upskilling, fewer business resources capitalized to projects, primarily meter technology projects and the CIS project, higher contract costs for external vendors supplying business processing services and field support to maintain resourcing capacity and increased complexity, and increases in postage and payment processing fees; and
- This was partially offset by a decrease in contracted services for temporary staff replaced by internal staff returning from the CIS project and other technology projects, a reduction in the accounting provision for bad debt for non-electricity

accounts, and actual and forecasted ebill adoption helping to contain postage and printing cost increase impacts.

2025 – 2029 Variance Explanation

Between 2025 and 2029, costs in this segment are expected to increase by $3.3 million, to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work discussed above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various legal and regulatory compliance risks and drawbacks, in addition to the following:

- A decrease in timely and accurate billing, resulting in billing and settlement errors, lower customer satisfaction, increased customer contacts, and risks to Toronto Hydro's financial viability;
- A decline in timely and accurate meter reading and resolution of meter-related issues, which may result in greater reliance on estimated bills and lower billing accuracy;
- Inability to process payments, credits, and refunds in a timely and accurate manner, jeopardizing the utility's cash flow and increasing the costs of working capital; and
- Reduced ability to prioritize and schedule the AMI 2.0 implementation and attain the associated benefits such as remote disconnection and improved meter communication capabilities. [14]

[14] *Ibid.*

6. COLLECTIONS SEGMENT

6.1 Segment Description

The Collections segment involves work related to tracking and collecting amounts owing on customer accounts and administering financial assistance programs such as the Low-Income Energy Assistance Program ("LEAP"),[15] and the Ontario Electricity Support Program ("OESP"). Toronto Hydro's collections procedures work to minimize the bad debt expenses incurred by the utility, while providing customers flexible options and assistance to pay outstanding accounts. The segment plays a key role to Toronto Hydro's financial viability and settlement process through the collection of distribution revenue and other rates and charges while minimizing bad debt expenditures. In the absence of a robust collections process, the utility's bad debt expenditures would increase and settlement variances would grow, to the detriment of all ratepayers and other sector participants.

To assist with collections-related customer inquiries, dedicated customer relations representatives are available on business days from 8:00 a.m. to 10:00 p.m. from May to November, and from 8:00 a.m. to 8:00 p.m. from December to April. Customers also have 24/7 access to collections information through an interactive voice response ("IVR") system, Toronto Hydro's mobile application and the CSS portal. These options assist customers by providing access to key information such as current and historical account balances, consumption and demand information, payment options, and bill amount predictions.

To facilitate stable and predictable cash flows and manage emerging arrears, Toronto Hydro proactively issues approximately 592,000 account overdue notices and places 842,000 account overdue reminder phone calls to its customers each year. To manage

[15] *Supra* note 3.

the costs of these high-volume activities while maintaining the efficiency and timeliness of reminders, the utility deploys automated systems for both types of notifications.

As of the end of 2022, Toronto Hydro had over 97,000 smart meters capable of remote disconnection, reconnection, and intermittent disconnection. By enabling remote disconnection, this technology reduces on the need for conducting costly field visits and lowers the risk of accumulating bad debt. These meters also allow for remote reconnections, which helps the utility meet the OEB-prescribed reconnection performance standard of reconnecting customers within 2 business days of receiving payment, allowing Collections staff to restore power almost immediately upon receipt of payment without the need to schedule a site visit for reconnection, also positively impacting the customer experience. As Toronto Hydro upgrades more of its smart meters to remotely controlled models, remote disconnections and reconnections will become more frequent.

To give effect to the OEB's winter disconnection moratorium in accordance with the Distribution System Code, Collections staff have processes in place to rapidly identify and contact residential customers previously disconnected for non-payment, process reconnections, and provide information on financial assistance programs.

To encourage timely payments, proactively identify at-risk accounts, and otherwise facilitate the collection of arrears, Collections staff also undertake the following activities:

- Managing and monitoring approximately 12,000 commercial accounts with security deposits and overseeing the annual process of security deposit reassessments;

- Preparing and sending approximately 14,000 accounts per year to external collection agencies for collection;
- Establishing arrears payment agreements ("APAs"), equal payment plans, and other custom payment plans to assist customers with paying off their arrears; and
- Educating customers on and overseeing the administration of financial assistance programs such as LEAP and OESP.

On March 17, 2020, the Government of Ontario declared a state of emergency pursuant to the *Emergency Management and Civil Protection Act* in response to the World Health Organization declaring the COVID-19 outbreak as a global pandemic. [16] This resulted in immediate and material disruptions to businesses and the economy, as the Government of Ontario and City of Toronto imposed various restrictions and closures on public health grounds that lasted at varying degrees until the last restrictions were lifted in 2022.

More specifically in the utilities sector, on March 19, 2020, the OEB extended the winter disconnection moratorium for all low-volume customers until July 31, 2020.[17] As a result, electricity distributors were prohibited from issuing disconnection notices for non-payment to these customers until August 1, 2020. During this time, in addition to complying with the requirements mandated by the OEB and different levels of government, Toronto Hydro implemented several temporary changes to its customer service rules and procedures to provide greater relief to its customers, consistent with the approach taken by other utilities. Toronto Hydro:

- reduced its late payment charge by 75 percent;

[16] RSO 1990, c. E.9. [*"Emergency Management and Civil Protection Act*"].
[17] The OEB provided further relief through successive licence amendments in 2021 by prohibiting electricity distributors from issuing disconnection notices to residential customers from April 13, 2021 until June 2, 2021. For more information, refer to OEB decisions and orders in EB-2020-0109 and EB-2021-0137.

- waived the Returned Cheque charge, normally collected for payments returned as NSF by banks due to customer account having insufficient funds to cover the payment;
- sent targeted arrears communications to provide its customers with greater flexibility in payment terms, offer APAs, and promote financial assistance programs such as LEAP, OESP, the COVID-19 Energy Assistance Program ("CEAP") and COVID-19 Energy Assistance Program for Small Business ("CEAP-SB"), and the Canada Emergency Response Benefit ("CERB"); and
- voluntarily extended its moratorium on disconnecting residential and low volume customers.

Collectively, these measures remained in effect from March 2020 until July 2022, with the exception of Toronto Hydro's extended disconnection moratorium which ended in June 2022.

In 2020, Toronto Hydro recorded an incremental $17.2 million in bad debt expenses as a result of the COVID-19 emergency and related financial pressures. Consequently, the utility adjusted its expected credit loss ("ECL") provision based on trends for customer collections, and current and forecasted economic conditions at the time to account for higher levels of expected customer defaults than pre-pandemic levels. Between 2020 and 2022, Toronto Hydro continued to actively monitor its exposure to credit risk, including the potential impacts of the pandemic, and made subsequent adjustments to the ECL provision as needed.[18]

[18] There is some uncertainty of the pandemic's impacts, the utility could not provision for all possible outcomes.

As of the summer of 2022, Toronto Hydro resumed its disconnection activities for non-payment by applying a segmented approach, focusing first on customers with larger balances or higher collections risk, particularly those with pre-pandemic arrears. The utility also continued providing greater flexibility in payment terms, such as longer payment periods and reduced down payment options. Overall, Toronto Hydro expects that the measures it took in response to the COVID-19 pandemic has saved its customers from undue hardship and has better positioned the utility to deal with the bad debt impacts going forward.

6.2 Collections Segment Costs

Table 5 below provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Year (2025-2029) expenditures relating to the Collections segment:

Table 5: Collections Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Collections	24.9	9.0	7.8	9.6	10.2	10.2	10.9	11.0	11.3	11.6

The costs for 2020 are a significant outlier due to the accumulated bad debt expense recorded in that year due to the COVID-19 pandemic.

The utility's costs in this segment are expected to increase over the 2025-2029 period primarily due to payroll compensation increases during the term and inflationary pressures impacting vendor costs to support collections activities.

Generally, the volume of collections-related work and the success of collecting accounts in arrears is heavily influenced by the number of customer interactions, the number of

low income customers and the available assistance programs, the availability of collection tools to encourage payment (such as the ability to disconnect for non-payment), the number of customers who move out and receive a final bill in any given year, macroeconomic conditions, industry disruptions causing bankruptcies, and regulatory changes impacting customer behaviour and collections tools. Toronto Hydro monitors trends and implements strategies to minimize the cost of bad debt to ratepayers. During the 2020-2024 rate period, the implementation of OEB mandated customer service rule changes (such as extension of the minimum payment period from 16 to 20 calendar days), the effects of the winter disconnection moratorium, and Toronto Hydro's voluntary extension of the disconnection moratorium for the duration of the COVID-19 pandemic contributed to the utility attaining higher unpaid balances over longer collection cycles.

The proposed level of segment funding is expected to support efforts to manage the accounts receivable balances, maximize the collection of distribution revenue and other rates and charges while minimizing bad debt, and continue to offer flexible and meaningful payment options. On a broader scale, the requested funding will support the implementation of public policy initiatives, the utility's responsiveness to customers' emerging needs and preferences, and continuous improvement through business process enhancements and technological solutions. The proposed level of funding is necessary to mitigate several segment-level risks, including**:**

- Increased volumes and amounts of arrears associated with unpaid accounts, causing upward pressure on rates for all customers;
- Limited capacity to offer customers flexible and personalized arrears payment options;
- Reduced ability to innovate service offerings, such as self-service payment arrangements;

- Reduced ability to effectively develop, deliver, and communicate financial assistance programs, leading to increased financial difficulties for customers and greater likelihood of disconnections for non-payment, resulting in lower customer satisfaction;
- Limited ability to modify collection tools or practices in response to changes in customers' evolving needs and preferences; and
- Reduced cash flow for the utility, increasing the cost of working capital to the detriment of ratepayers.

6.3 Collections Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

Between 2020 and 2021, costs in this segment decreased by $15.9 million due to the following:

- $0.2 million increase due to compensation increases,
- $0.2 million decrease in contracted field services as a result of continuing the utility's customer support strategy during COVID-19; and
- $15.9 million decrease in bad debt as a result of the significant increase in 2020 for the accounting provision for bad debt (i.e. ECL) due to the COVID-19 pandemic.

2021 – 2022 Variance Explanation

Between 2021 and 2022, costs in this segment decreased by $1.2 million due to the following:

- $0.1 million increase in collection agency fees reflecting higher average arrears balances due to COVID-19;

- $0.3 million decrease in labour costs due to capitalization of business labour to projects, partially offset by increase in payroll costs due to compensation increases;
- $0.2 million increase in contracted clerical labour to backfill for staff working on capital projects (e.g. CIS);
- $0.4 million increase in contracted field resources reflecting the additional collection activity volumes post COVID-19, and
- $1.6 million decrease in bad debt that reflects a downward risk adjustment in the accounting provision for bad debt (i.e.ECL) as COVID-19 related customer arrears balances decline.

2022 – 2025 Variance Explanation

Between 2022 and 2025, costs in this segment are expected to increase by $2.4 million due to the following:

- Increases in labour cost as staff return from capital projects (e.g. CIS), partially offset by a reduction in temporary labour no longer needed to backfill for staff on the CIS Project;
- Increases in collection agency fees reflecting the higher volume of accounts, post COVID-19, being assigned to third party collection agencies;
- Increases in contracted field collection activities to reflect higher than historical customer payment arrears volumes and balances, post-COVID-19;
- Increases in payroll costs due to filling vacancies and compensation increases; and
- Increases in the accounting provision for bad debt (i.e. ECL) to account for the inflationary pressure on rates and subsequently on the receivables balance.

2025 – 2029 Variance Explanation

Between 2025 and 2029, costs in this segment are expected to increase by $1.4 million, to manage increases in payroll costs due to compensation increases, inflationary pressure on the accounting provision for bad debt (i.e. ECL), and inflationary pressure on several contracted business process, field service providers, and other collections related vendors, as discussed above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various regulatory and legal compliance risks and drawbacks, including:

- Failure to attain full revenue collection, resulting in higher levels of bad debt and affecting Toronto Hydro's financial viability; and
- Limited ability to modify collection tools or practices in response to changes in customers' evolving needs and preferences.

7. CUSTOMER RELATIONSHIP MANAGEMENT SEGMENT

7.1 Segment Description

The Customer Relationship Management ("CRM") segment involves Toronto Hydro's communications with its customers[19] to provide information relating to customer service and the utility's operations, build trust, and maintain transparency. Toronto Hydro aims to build trusted relationships by engaging customers at the right time, with the right information, and through the right channel to meet their preferences. This approach delivers customer value by providing efficient and timely responses to all enquiries, building awareness of available service choices (such as billing format or pricing plan options) and financial assistance programs, and educating customers on how to better manage their electricity usage.

[19] *Supra* note 5.

The segment includes the following functional areas: the Contact Centre, Escalations and Special Investigations, Customer Experience, and Quality Assurance. These functions are designed to provide high-quality customer service and improve operational efficiencies identified through the tracking and analysis of inbound customer inquiries, transactional surveys, and other means of soliciting customer feedback.

In addition to the functional areas noted above, the CRM segment is also responsible for designing and overseeing technology projects for continuous monitoring, business process analysis, and performance measurement activities, which drive customer experience and efficiency improvements. To provide an optimal customer experience, Toronto Hydro will need to adapt its services to each customer's unique needs and preferences, especially as these needs and preferences evolve in conjunction with broader trends. The utility expects that the CRM segment's workforce, business processes, and tools will benefit from enhancements on multiple fronts to provide this level of personalized service.

The CRM segment remains responsive to customer, public policy, and industry demands by monitoring trends and adapting business processes, employing technology and process improvements to help contain costs, developing more effective ways to address customer enquiries at first contact, and supporting staff with training and upskilling.

7.1.1 Contact Centre

Toronto Hydro's Contact Centre is the primary functional area of the CRM segment. In 2022, the Contact Centre received and addressed approximately 70,000 written (paper mail, fax, and email) enquiries and over 343,000 telephone calls. Customers engage with the Contact Centre to inquire about the utility's business practices, available programs

and service choices (such as pricing plan options), government incentives and rebates, payment options, electricity consumption and demand, moves, collections, financial assistance programs, and a variety of other topics. During significant outage events, the Contact Centre also provides 24/7 support to the Emergency Response program,[20] and customers who want to report an outage or obtain current outage information.

As part of this function, Toronto Hydro tracks and processes customer move-ins and move-outs to obtain correct meter data, identify account holders, and correctly address and promptly issue first and final bills. In 2022, the utility processed over 183,000 customer moves, of which 24 percent were partially automated moves and 22 percent were fully automated self-service moves. Over 2020-2022, customers' use of the CSS portal for moves has increased by 92 percent.

The Contact Centre will need to adapt its business processes over the 2025-2029 rate period to respond to the evolution of customers' needs and preferences. As broader societal and industry trends point towards decarbonization and greater electrification (e.g. the adoption of EVs and DERs by residents and businesses in greater numbers), the potential for increased electricity prices, and new pricing and service options, customers' needs, the information they require, and their expectations of service from Toronto Hydro are all dramatically changing. Meanwhile, emerging technologies such as artificial intelligence, machine learning, and process automation are enabling new channels and opportunities for customer-utility interactions, while ensuring appropriate handling of customers' personal information through policies and processes. In the context of these developments, the Contact Centre will need to upskill its workforce and enhance its

[20] Exhibit 4, Tab 2, Schedule 5.

business processes and tools in response to customers' changing expectations and the concomitantly increasing complexity and variety of enquiries.

The Contact Centre closely monitors the quality and efficiency of its customer contact activities using a combination of OEB-mandated, common industry and internally developed measures. Toronto Hydro performs well against the OEB's performance targets in the areas of telephone accessibility, telephone call abandon rate, and written response, consistently exceeding the mandatory service standards, whilst balancing costs and meeting customer expectations. In 2022, the Contact Centre answered 79 percent of calls within 30 seconds, and responded to over 99 percent of written enquiries within ten days. To support Toronto Hydro's customer service objectives, the Contact Centre operates from 8:00 a.m. to 8:00 p.m.

Customers increasingly use email to interact with Toronto Hydro and expect shorter response times due to the electronic medium; therefore, the utility has put significant effort into improving its performance in responding to written inquiries. In 2022, Toronto Hydro responded to over 90 percent of emails within one business day. The utility achieved this result by implementing a number of training and process improvements, including enhancements to internal email routing algorithms, to quickly identify and contact the most appropriate resource that can assess the customer inquiry and respond to the email. Toronto Hydro has found that responding more quickly to customers has reduced the total volume of emails annually by 25 percent (approximately 23,000 emails) from 2020 to 2022, and resulted in a 15 percent increase in customer satisfaction in this area. The utility also continues to change and evolve its business processes to redirect customers with more complex questions, such as service upgrades for EV charging, to the most appropriate communication channel or subject matter experts.

Through the introduction of various self-service tools such as the CSS portal and mobile application, targeted process improvements, and upskilling, Toronto Hydro's customer response model is becoming more efficient at understanding and adapting to customer inquiries faster and improving the overall customer service experience.

7.1.2 Escalations and Special Investigations

The Escalations and Special Investigations function resolves specific customer concerns that require complex or detailed analysis. The most frequently occurring issues relate to energy and bill management, including high bill issues, energy management, payment challenges, and power quality requests pertaining to power interruptions and other technical issues. With customers increasingly working from home since 2020, any interruption in power, including momentary and short duration outages, has become more impactful to customers. The Escalations and Special Investigations function intakes escalated matters through a variety of channels. For example, in 2022, this function processed approximately 1,900 escalations received through the Contact Centre, 112 through the Office of the President function under the Public, Legal and Regulatory Affairs program,[21] and 38 from the OEB. The Escalations and Special Investigations function is also responsible for Toronto Hydro's consumer complaint response process and the resolution of customer escalations forwarded through the OEB's E-Portal. The function deploys field resources as necessary to investigate power quality, billing, or other issues. In 2022, Escalations and Special Investigations resolved 99 percent of escalated customer inquiries within ten business days or less.

In recent years, the issues handled by the Escalations and Special Investigations function have become progressively more complex. The investigation and resolution of these

[21] Exhibit 4, Tab 2, Schedule 18.

issues typically involve greater collaboration with internal stakeholders from multiple capital and OM&A programs, such as Customer Operations,[22] Work Program Execution,[23] or Public, Legal and Regulatory Affairs, and sometimes external stakeholders such as provincial and municipal transit operators, various departments of the City of Toronto, or social assistance agencies. Toronto Hydro expects the complexity of issues addressed by this function to increase as more customers adopt DERs and EVs and as those resources are integrated into distribution operations.

7.1.3 Customer Experience

The Customer Experience function works to achieve consistency across all customer interactions through the expanded use of technology. Technological solutions allow for the more efficient capture of customer interactions, more effective routing and streamlined processing of work, the provision of structured options, and consistent customer engagement. These enhancements in turn support the provision of high-quality services and communications that align with customer needs and expectations, while identifying ongoing trends and opportunities for the improvement of current programs and the development of new programs.

The growth and evolution of the Customer Experience function over the 2025-2029 rate period will lay the foundation for future customer interactions, which Toronto Hydro expects to be highly influenced by the shift towards electrification. Federal, provincial, and municipal energy policies are establishing plans, guidelines, and requirements that support customers' need and ability to make informed decisions about their energy usage and influence their bills through consumption behaviours and technology investments. Customers will look to Toronto Hydro to provide the tools and information

[22] *Supra* note 5.
[23] Exhibit 4, Tab 2, Schedule 12.

to enable them to make informed choices that best suit their lifestyles and budgets, including public policy initiatives such as Green Button to comply with Ontario Regulation 633/21.[24] This requires the utility to modernize its business processes, invest in the appropriate tools that allow customers to effectively manage their energy usage in emerging contexts (e.g. with respect to EV charging or load displacement via DERs) and upskill resources to respond to the changes in customers' needs and expectations. Much of the relevant investments in technology, additional resourcing, and process modifications need to occur in advance of these industry shifts to ensure that Toronto Hydro is prepared to respond to customers' needs in time for the energy transition.

Customer engagement plays a significant role in Toronto Hydro's decision making and helps inform and guide overall business planning processes. Beyond survey-based research, Toronto Hydro considers direct customer feedback and the advice of a Customer Advisory Panel ("CAP"), discussed in greater detail in the Public, Legal and Regulatory Affairs segment.[25]

One increasingly popular method of engagement continues to be Toronto Hydro's redesigned CSS portal, which is available to both residential and commercial customers. The portal offers live chat with a Toronto Hydro representative, automated move-in and move-out capability, eBill and pre-authorized debit registration, and the ability to view bill and payment histories. Eligible customers can also opt into outage notifications via email and text message. In addition, the utility redesigned its website to increase traffic and increase customers' ease of access to commonly requested information when they visit the site. This redesign consisted of expanding the "My Usage" page on the CSS portal to provide customers the ability to track and compare their electricity usage and costs on

[24] Ontario Regulation 633/21 under the *Electricity Act, 1998*, SO 1998, c. 15, Sched. A.
[25] *Supra* note 21.

an hourly, daily, monthly, and yearly basis. Furthermore, customers are able to access a price comparison tool to help make an informed decision when selecting between tiered, standard time of use, and the new ULO time of use electricity pricing plans.

In 2022, Toronto Hydro launched a mobile application to offer another channel for customers to receive customized service based on their preferences. The mobile application supports core customer inquiries such as viewing their bills and payment history, addition to supporting transactions such as moves, eBill registration, and changes in pricing plans. The utility promotes the adoption of this channel through marketing campaigns and the Contact Centre as a means to increase customer convenience and operational efficiency. Enabling customers to self-serve reduces the volume of interactions with live agents and manually initiated processes, which increases operational efficiency.

The Customer Experience function's increased focus on improving customer service and meeting customers' expectations through the adoption of modern technology will support the identification and implementation of additional services that align with the changes in customers' needs and expectations. For example, current items under consideration include offering enhanced bill prediction tools and alerts, online payment options, proactive notifications, and expanding existing capabilities to support customers in making an informed decision when choosing between different pricing options.

7.1.4 Quality Assurance

The Quality Assurance function manages knowledge and service quality, the analysis and evaluation of staff performance, and the analysis of escalation trends and post-call customer survey results. The function develops and distributes training materials for

internal and external resources, and focuses on exceeding the OEB-mandated service quality requirements by identifying training gaps, and process and technology improvement opportunities. The function is also responsible for maintaining knowledge base tools to support staff with information on current policies, procedures, and changes to legislative and regulatory requirements. This helps staff to better serve customers and develop effective change management strategies to support the launch of new initiatives and technologies.

The criticality of this team will grow throughout the 2025-2029 rate period, as its role expands in two areas: 1) the upskilling of staff to support the enhancement of business processes in response to the evolution of customer needs and preferences and industry trends, and 2) the expansion of quality assurance beyond staff and into the fine-tuning of systems and technology.

As mentioned earlier, customers engage in a broad variety of decarbonization and electrification activities such as the adoption of EVs, elimination of natural gas and other fossil fuels for heating and other needs, the installation of distributed generation and energy storage equipment, the demands on Toronto Hydro staff will greatly increase and the engagements with customers will become materially more complex and diverse. The Quality Assurance function will need to design, build, and maintain knowledge programs to prepare staff on how to respond effectively to these types of inquiries.

Second, Toronto Hydro expects the role of the Quality Assurance function to evolve as new technologies and tools such as artificial intelligence, machine learning, and process automation are introduced to the organization. In addition to coaching staff to provide high-quality responses to emerging needs and demands of customers, the team will also

need to "train" systems to perform in a similar fashion by completing necessary upgrades or adopting new technology.

Customer Relationship Management Segment Costs

Table 6 below presents Toronto Hydro's Historical (2020-2022), Bridge (2023, 2024), and Forecast Year (2025-2029) costs relating to the Customer Relationship Management Segment:

Table 6: Customer Relationship Management Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Customer Relationship Management	11.4	11.4	12.1	14.4	15.1	14.7	15.7	16.1	16.9	17.5

The proposed level of segment funding is required to support the development of human resources, implement process enhancements, and utilize technologies to meet increasingly more complex customer needs in an evolving electricity sector. Building knowledge systems to support frontline customer service representatives and streamlining internal knowledge networks will be essential to responding effectively to enquiries related to emerging topics such as EVs, DERs, and associated public policy initiatives. Automating customer contact points to provide efficient and consistent customer support will require support from self-service portals, artificial intelligence, and machine learning systems as they are integrated into the customer experience. The proposed level of funding is necessary to mitigate several segment-level risks, including the potential for**:**

- Backlogs of customer account updates resulting in delays in issuing bills and additional work to correct billing errors, increasing risk of non-compliance with the OEB -prescribed billing accuracy metric;

- Extended wait times to resolve calls and written inquiries, potentially leading to the erosion of service level standards and lower customer satisfaction as well as increasing risk of non-compliance with OEB-prescribed call response and written response metrics;
- Compromised ability to enroll customers in, and educate them on, existing and new energy and public policy programs, leading to lower engagement and program success;
- Reduced ability to invest in modern technologies, staff capacity, and time to provide customers with meaningful insights, tools, and services in an environment of evolving customer expectations; and
- Limited support as customers navigate an increasingly complex energy environment, leading to less customer control over their energy usage than would otherwise be achieved.

7.3 Customer Relationship Management Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

Costs remained flat with increases in contracted services for business process services, IT consulting for CIS project support, and temporary staff, offset by decreases in payroll and labour costs due to vacancies.

2021 – 2022 Variance Explanation

Costs increased by $0.7 million due to the following reasons:

- $0.4 million increase in payroll to fill vacant positions and annual increases in compensation ;
- $0.8 million decrease in labour costs associated with the transfer of staff to the CIS upgrade project;

- $0.3 million increase in contracted services costs for temporary staff to backfill staff on the CIS upgrade project;
- $0.2 million increase in consulting costs to support the CIS upgrade project, and
- $0.6 million increase in cost for contracted business process services, including the impacts of the minimum wage increase.

2022 – 2025 Variance Explanation

Between 2022 and 2025, costs in this segment are expected to increase by $2.6 million due to the following reasons:

- increase in payroll costs to fill vacant positions and compensation increases,
- increase in labour costs as staff return from the CIS upgrade project to support operations, and
- decrease in contracted services costs and software and consulting fees due to the efficiency gains expected from the CIS upgrade project.

2025 – 2029 Variance Explanation

Between 2025 and 2029, costs in this segment are expected to increase by $2.8 million, to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work discussed above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various legal compliance risks and drawbacks, including:

- Insufficient or inadequate level of resources to provide timely and effective responses to customer inquiries;
- Reduced ability to implement public policy initiatives and legislative and regulatory requirements in accordance with mandated timelines or in a cost-effective manner;

- Inadequate ability to research, analyze, and respond to future changes in customers' preferences; and
- Inability to support customers' preferences and provide personalized service through large scale technology projects such as omnichannel communication, AMI 2.0, and customer relationship management.

HUMAN RESOURCES, ENVIRONMENT AND SAFETY

1. OVERVIEW

Table 1: Human Resources, Environment and Safety Program Summary

Fleet and Equipment Program Summary									
Outcomes: Public Policy Responsiveness, Environment, Operational Effectiveness - Safety, Financial Performance									
Segments: • Environment, Health & Safety • Human Resources Services & Systems, Organizational Effectiveness & Employee Labour Relations • Talent Management, Change Leadership & Sustainability									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
15.5	17.6	16.7	18.9	21.3	22.6	23.2	24.2	25.3	26.3

The Human Resources ("HR"), Environment and Safety program (the "Program") provides broad human resource management services to Toronto Hydro. The Program's activities manage the employee lifecycle through the processes of employee recruitment, compensation and benefits, onboarding, performance management, training and leadership development, labour relations, employee communications and engagement, and human resources technology management. All of these activities are carried out within a culture of ensuring employees' health and safety and environmental sustainability. The delivery of these activities is tailored to the utility's complex capital program and operating environment, labour dynamics and workforce demographics.

To achieve these outcomes, adequate funding and staffing for the Program will be crucial to the utility's success.

2. OUTCOMES AND MEASURES

Table 2: Human Resources, Environment and Safety Program Outcomes and Measures

Summary

Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by ensuring regulatory and legislative requirements are met in relation to employee training, collective bargaining and the development of utility-wide policies.
Environment	• Contributes to Toronto Hydro's environmental objectives and Net Zero 2040 commitment by: o Integrating environmental, social and economic issues into planning; o Measuring greenhouse gas ("GHG") emissions, waste reduction, and promoting recycling and a culture of conservation; o Ensuring compliance with legislative and regulatory requirements such as the *Environmental Protection Act, 1990*[1].
Operational Effectiveness – Safety	• Contributes to Toronto Hydro's health and safety objectives, measured through metrics like Total Recordable Injury Frequency ("TRIF") by: o Implementing controls to reduce the risks associated with exposure to hazards and ensure employees are working safely; o Providing training on workplace safety to employees; o Closing gaps associated with audit and inspection findings; and • Ensuring compliance with legislative requirements.

[1] RSO 1990, c E.19. ["*Environmental Protection Act*"].

Financial Performance	• Contributes to Toronto Hydro's total cost and efficiency measures through the development and delivery of virtual training and internal training facilitation to reduce reliance on external services. • Focuses Toronto Hydro's workforce on work aligned with organizational objectives by utilizing a rigorous performance management system, thereby decreasing costly wasted productive time. • Promotes processes that decrease Workplace Safety & Insurance Board premiums and other costs.

3. PROGRAM DESCRIPTION

The Program provides broad human resource management services to Toronto Hydro. The Program's activities enable the utility to maintain a robust and effective work environment, the health and wellness of its employees, and its safety management system. The Program also supports the utility's sustainability activities and the promotion of good working conditions to increase employees' job satisfaction, facilitate productivity and promote innovation.

The Program's activities support key operational goals by deploying technology solutions, applying risk-based management system standards, and supporting effective training, diligent inspections, and appropriate investigations into incidents and near misses. Toronto Hydro's business operations and dense urban environment create a number of distinct challenges for the Program, including:

- A complex and rapidly evolving distribution system that includes an asset-intensive downtown distribution network;
- Mature and diverse grid infrastructure featuring legacy assets that require specialized asset management skills (e.g. box construction and paper insulated lead covered cable);

- An increasingly complex mix of load consumers and distributed energy resources of varying sizes, driving the need for a broad range of advanced customer service, data analysis, strategic planning, and technological know-how skills; and
- Unique safety challenges for executing work.

These challenges drive Toronto Hydro to maintain a high standard of health and safety requirements and provide comprehensive training and apprenticeship programs for employees. These challenges also make it important for Toronto Hydro to prepare talent to fill future key roles so that leaders can continue to be responsive to the utility's operating conditions.

The Program includes three segments, each described in detail below:

- Environment, Health & Safety;
- Human Resource Services & Systems, Organizational Effectiveness & Employee Labour Relations; and
- Talent Management, Change Leadership & Sustainability.

The objective of the Environment, Health & Safety ("EHS") segment is to ensure that Toronto Hydro operates in a safe, environmentally responsible, and sustainable manner. Toronto Hydro achieves these operational objectives by implementing programs, procedures, safe work practices, and engineering and administrative controls as required. This segment also ensures that Toronto Hydro complies with applicable legislative requirements pertaining to health and safety, environmental protection and sustainability.

The objective of the Human Resource Services & Systems, Organizational Effectiveness & Employee Labour Relations segment is to effectively manage labour relations with the utility's employees, compensate employees appropriately and provide benefits to support employee health and well-being. Activities within this segment include interpreting, administering and negotiating collective agreement provisions, case management, performance management, productivity measurement, designing and administering the utility's compensation and benefits program, and administering technology systems to support human resources, environment and safety data.

This segment also includes a program to foster innovation and another program to track the benefits of initiatives undertaken by the utility. In addition, this segment supports the organization to ensure workplace issues are addressed promptly and in compliance with applicable legislation, policies, and collective agreements. This segment oversees all employee engagement events, including Toronto Hydro's annual United Way campaign. It also manages all internal communications to employees, including the semi-annual publication of the utility's company magazine, Spectrum.

The objective of the Talent Management, Change Leadership & Sustainability segment is to develop and execute the utility's workforce staffing and development plans and conduct organization design and job design activities, to support the organization's talent development and succession planning processes and programs. Teams in this segment are responsible for internal and external staffing selection. They also create and implement a variety of training, development, and change management initiatives to ensure Toronto Hydro employees are qualified and have the necessary skills, resources, and tools to successfully execute their role.

4. PROGRAM COSTS

In 2025 Toronto Hydro requires $22.6 million in rate funding for Human Resources and Safety program, which represents an increase of $7.1 million over the last Custom Incentive Risk application in 2020. When normalized for shared services recoveries outlined in Exhibit 4, Tab 5, Schedule 1, the expected increase in this program is $6.1 million.

Over the 2025-2029 rate period, the utility expects the cost of this program to increase by annual growth rate of 3.9 percent which is necessary to address the program needs and deliver the customers outcomes enabled by this program. The Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for each segment are summarized in Table 3 below.

Table 3: Human Resource and Safety Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Environment, Health & Safety	2.4	2.3	2.4	3.0	3.1	3.3	3.4	3.6	3.8	3.9
Human Resource Services & Systems, Organizational Effectiveness & Employee Labour Relations	5.9	6.3	5.9	8.0	9.4	10.0	10.4	10.8	11.3	11.8
Talent Management, Change Leadership & Sustainability	7.2	9.0	8.4	7.9	8.8	9.3	9.4	9.8	10.2	10.6
Total	**15.5**	**17.6**	**16.7**	**18.9**	**21.3**	**22.6**	**23.2**	**24.2**	**25.3**	**26.3**

4.1 Cost Drivers

The cost increases are primarily a result of:

- **Increasing Capacity to Support Investment Plan*:*** Staffing changes to support projects and to fill vacancies have created yearly variances in actual and budgeted segment costs. These are outlined in the sections below. Payroll costs are

expected to increase by approximately $2.1 million in 2024 and $1.3 million in 2025. These variances are driven by headcount increases to attract, recruit and train talent, to support grid and technology modernization efforts, capital and operating programs and environment, social and governance and compliance activities; and

- **Legal and arbitration related expenses:** Legal expenses associated with grievance arbitrations, and other employment related legal matters have trended upwards in the Program. These expenses vary based on the matter's complexity, the number of internal and external witnesses, and the degree of preparation and legal research required. An increase in headcount in bargaining unit positions is expected to increase the volume of arbitration and grievance matters. Both PWU and Society IT collective agreements will be renegotiated during the next rate application which will drive additional legal costs.

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

Toronto Hydro has implemented or is in the process of executing the following initiatives to realize cost savings:

- Using services, including specialized software, to collect and report data on incidents, inspections, audits, and facilitate contractor prequalification screening;
- Optimizing training by leveraging digital tools to facilitate sessions, clustering training in concentrated blocks of one to two weeks to minimize operational disruption; engaging internal resources, familiar with Toronto Hydro systems, processes and equipment, to complete program development, testing, audits and completion of applications;

- Toronto Hydro has completed a proof of concept for virtual reality training. This training would offer employees a safe environment to learn and develop skills prior to executing them in a physical environment. A request for proposal is currently underway to select a vendor for this solution. This technology will decrease the time required for employees to travel to training, and the time required to deliver training; and
- Using existing internal resources instead of hiring specialized external service providers to develop and distribute EHS related communications materials including posters, Toronto Hydro TV and safety meeting materials; This results in a cost savings associated with not having to hire external service providers to complete this work.

The utility has negotiated a five-year collective agreement with the Power Workers' Union ("PWU") (2022-2027) and a four-year agreement with the Society of United Professionals ("Society") (IT) (2021-2025). These agreements will provide labour stability and predictability around compensation and benefits costs.

4.2.2 Productivity

The Program has enabled the utility to achieve significant and sustained productivity outcomes. For example, from 2018 to 2022, the utility achieved improvements relating to:

- Occupational safety, including a 43 percent improvement in total recordable injury frequency;
- A 94 percent improvement in lost time severity; and
- The corporate attendance number remained stable, with an improvement of 1.9 percent.

The above was achieved despite the effects of the COVID-19 pandemic. Toronto Hydro's absenteeism rate remains much lower than historic rates, both within the organization and broader industry. Toronto Hydro has been able to effectively manage employee absenteeism and ensure the workforce is productive and engaged.

Toronto Hydro's implementation of the cloud-based Success Factors program has supported the business processes and innovation. The foundational design integrates between modules and facilitates automation of workflows. The integrated solution supports the employee life cycle starting with the foundation of 'Employee Central', which houses core employee information from job to organizational data. The core employee data is integrated with other modules within Success Factors such as recruitment, on-boarding, performance management, learning, benefits and compensation. The integration has expanded the capture of master data, increased data accurancy and operational efficiences. The system has enabled employees to self-serve, allowing employees access to manage their own personal data such as home address, phone number and emergency contact, increasing overall data accurancy. The technology also supports other systems in the organization through integration, feeding real-time employee master information such as job and organizational data. The cloud solution has annual releases of new features to expand system functionalities and optimize business processes.

- Toronto Hydro has upgraded the video and audio-conferencing applications of its work centres, making remote and hybrid work more effective and reducing the facilitation costs of virtual learning and training programs.
- Electronic tailboards are used by crews to complete a risk assessment digitally prior to their work as part of developing a safe job plan have increased productivity. This electronic tool allows leaders to access job planning details

without having to be on site. Moving from what was previously a paper process to an electronic process has resulted in improved data analytics and auditing capabilities and increased job planning quality, which has contributed to a decrease in injuries. Recordable injury performance has improved by 16 percent in the year following the introduction of the electronic tailboard and the utility has not had any critical or fatal injury since the electronic tailboard was launched.

- A new Employee and Labour Relations solution was implemented in 2022 to streamline the administration and tracking of grievances, arbitrations and to facilitate contract negotiations through system integration and automation. Leveraging the SuccessFactors foundation, an integration was built to pull real-time employee data such as job and organizational data to effectively manage a centralized employee labour relations system. Some of the features included automation of the Collective Agreement, ease of updating clauses and consistent policy interpretation.

5. ENVIRONMENT, HEALTH & SAFETY SEGMENT

5.1 Segment Description

The Environment, Health & Safety ("EHS") segment ensures that Toronto Hydro operates in an environmentally conscious manner and implements programs, procedures, safe work practices, and engineering and administrative controls to provide a healthy and safe working environment for employees.

The activities performed as part of this segment are instrumental to ensuring that the utility complies with legislative and regulatory requirements. The EHS segment executes operational activities, prepares the planning and delivery of targeted initiatives and executes applicable internal and external reporting requirements. The work performed

within this segment is carried out 24 hours a day, 7 days a week in line with Toronto Hydro's service obligations. Functions within this segment include Health Services and Environment, Health and Safety.

5.1.1 Health Services

Toronto Hydro's health services function effectively processes and monitors occupational and non-occupational health and injury claims. Health services supports injured employees receiving appropriate treatment and recovery measures, and encourages their participation in the workplace within their prescribed restrictions until they can safely return to their pre-injury role. Health services also manages short and long-term disability cases. As a result of these efforts, Toronto Hydro achieved a 94 percent improvement in its lost time severity from 2018 to 2022.

During the pandemic Health Services played a significant role in supporting the utility's successful response to COVID-19 through the implementation of the infectious disease plan. This included the development and implementation of protocols for reporting illness, returning to work, contact tracing, health screening as well as organizing vaccination clinics for employees. This contributed to the company maintaining a healthy and safe environment for employees, including no substantiated cases of workplace transmission since the onset of the pandemic.

5.1.2 Environment, Health and Safety

Environment, Health and Safety ("EHS") activities include the following:

- **Environment, Health & Safety Management Systems ("EHSMS"):** The EHSMS improves the efficiency of activities within this segment. The EHSMS system also facilitates Toronto Hydro's compliance with applicable legislative and regulatory

requirements such as the *Utility Work Protection Code*[2], *Electrical Utility Safety Rules*[3], *and Occupational Health & Safety Act, 1990* and Regulations.[4] In addition, the EHSMS provides a mechanism for mitigating risk and achieving corporate objectives relating to health, safety, and environmental performance. The EHSMS established the frameworks (such as contact tracing) to successfully manage the COVID-19 Pandemic;

- **EHS Framework:** Toronto Hydro coordinates all EHS activities in accordance with internationally recognized ISO standards. Toronto Hydro is certified in conformance with ISO 14001:2015 and ISO 45001:2018, both of which are internationally recognized EHS standards requiring third-party audits. In line with these certifications, Toronto Hydro has implemented a framework that incorporates effective risk management and continual improvement to support occupational health and safety performance and prevent employee illness and injuries;
- **Occupational Health and Safety Activities:** Toronto Hydro implements robust occupational health and safety training programs. These programs maintain the long-term health, safety and wellness of the utility's workforce. The utility continually improves these programs by developing action plans to address identified gaps from investigation and audit activities. Our recordable injury performance has improved by 19% since 2020 and we have not had any critical or fatal incidents since that time; and /C
- **Environmental, Social and Governance ("ESG"):** The internationally recognized guidance document ISO 26000:2010 informs Toronto Hydro's approach to social responsibility. In line with this document, Toronto Hydro has integrated the

[2] Ontario Infrastructure Health and Safety Association, Utility Work Protection Code.
[3] Ontario Infrastructure Health and Safety Association, Electrical Utility Safety Rules.
[4] R.S.O. 1990, c. O.1. [*"Occupational Health and Safety Act"]*

promotion of social responsibility into its core values, processes, and operations.[5] Toronto Hydro has leveraged this guidance document together with elements of the EHS management system to develop and implement a consolidated ESG strategy. The utility's ESG activities and performance have been recognized with 10 ESG-related awards since 2018.[6]

EHS complies with applicable environmental legislation and regulations such as the *Environmental Protection Act, 1990*[7] and the utility's environmental policy by delivering a number of environmental protection and compliance programs, such as:

- Environmental spill response, cleanup, investigation and reporting;
- Delivery of prescribed environmental training (e.g. Transportation of Dangerous Goods);
- Maintenance of environmental permits for equipment that discharges contaminants into the atmosphere;
- Registering Hazardous waste streams and reporting waste management activities with the Ontario Ministry of the Environment, Conservation and Parks; and
- Internal and External Reporting, including internal and external reporting on EHS performance; external reporting including mandatory reports and notifications to the City of Toronto, the Ministry of Labour, Immigration, Training and Skills Development, the Work Safety and Insurance Board, the Ontario Ministry of the Environment, Conservation and Parks, and Environment and Climate Change Canada and Electricity Canada.

[5] Adherence to this ISO 26000 standard is required for the utility's continued maintenance of its Sustainable Electricity Company designation from Electricity Canada.
[6] Toronto Hydro has been recognized by Corporate Knights, Electricity Canada, Centre of Excellence and Canadian Occupational Safety Magazine.
[7] *Supra* note 2.

5.2 Environment, Health & Safety Segment Costs

Table 4, below, provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for the EHS segment.

Table 4: Environment, Health & Safety Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Environment, Health & Safety	2.4	2.3	2.4	3.0	3.1	3.3	3.4	3.6	3.8	3.9

The cost increases are primarily attributable to filling employee positions in order to support the safe execution of the utility's capital work program and inflationary pressures.

5.3 Environment, Health & Safety Segment Year-over-Year Variance Analysis

2020-2021 Variance Explanation

From 2020 to 2021, costs decreased by $0.1 million due to delays in hiring as a result the COVID-19 pandemic.

2021-2022 Variance Explanation

From 2021 to 2022, costs increased by $0.1 million, due to an increase in hiring that had been previously postponed due to the COVID-19 pandemic.

2022-2025 Variance Explanation

From the 2022 actual to 2025, costs are expected to increase by $0.9 million. This increase is required to increase capacity and capabilities to perform the hiring necessary to facilitate the safe execution of the utility's 2025-2029 investment plan.

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $0.6 million, or an average of $0.2 million per year. If the utility does not receive the funding it requires to execute this segment as described, Toronto Hydro could be exposed to a number of risks, including:

- Injuries, illnesses or fatalities to employees due to occupational health and safety hazards;
- Stop work orders, which would halt the execution of the utility's capital work program.
- An increased likelihood of safety-related incidents, including critical injuries or fatalities to Toronto Hydro employees;
- An increased likelihood of incidents with a negative environmental impact or worsening environmental performance;
- Legislative or regulatory non-compliance because of inadequate training and resources to provide advice, consultation, and research on matters relating to employment and labour relations, safety, and the environment.

6. HUMAN RESOURCES SERVICES & SYSTEMS, ORGANIZATIONAL EFFECTIVENESS & EMPLOYEE LABOUR RELATIONS SEGMENT

6.1 Segment Description

This segment delivers Human Resources services and leverages technology solutions to support the utility's employment life cycle. Its activities also drive effective performance management through ensuring market competitive compensation and benefits and overseeing employee and union relations.

Functions within this segment include:

- Employee and Labour Relations;

- Employee Engagement and Communications;
- Compensation and Benefits;
- Performance Management and Productivity;
- Innovation, and
- HR Systems and Data Governance.

6.1.1 Employee and Labour Relations

The Employee Labour Relations ("ELR") function manages issues relating to employee and labour relations and employee compliance with legislative and regulatory requirements, corporate policies and collective agreement provisions. ELR also supports Toronto Hydro's unionized and non-unionized work groups by ensuring that the utility follows all applicable labour and employment related legislation, policies, and collective agreement requirements.

This work requires labour relations and legal professionals to provide advice, guidance, and support on how to address challenges, and where necessary, assist in preparing for dispute resolution. This dispute resolution can include grievance arbitration, civil employment claims, Ontario Labour Relations Board matters, and human rights claims.
Toronto Hydro has a diverse workforce that includes both unionized and non-unionized employees. Over half of Toronto Hydro's employees belong to a union. There are two unions at Toronto Hydro – the Power Workers' Union (PWU) and the Society of United Professionals. Unionized employees are organized into four bargaining units. Inside workers and outside workers are represented by the PWU, and information and technology employees and professional engineers are represented by the Society of United Professionals.

6.1.2 Employee Engagement and Communications

The Employee Engagement and Communications function provides employees with awareness of important and key messages through multiple channels such as, company intranet, mass communications, pulse surveys, posters, employee magazine, and in-person gatherings. This function also oversees all employee events including the annual United Way campaign.

6.1.3 Compensation and Benefits

This function oversees and administers Toronto Hydro's workforce compensation strategy and practices. This function is critical to maintaining a workforce that is skilled, adaptable, committed, and performance-driven within a tight labour market. Toronto Hydro strives to achieve these key outcomes in a financially responsible manner by providing employees with a competitive total reward offering. This function compensates employees for contribution to individual, divisional, and corporate performance goals. For more information on Toronto Hydro's compensation and benefits program.[8]

6.1.4 Performance Management and Productivity

Toronto Hydro utilizes a Management Control and Reporting System ("MCRS") which sets forth a disciplined methodology to forecast, plan, control and report on its processes in order to keep focused on organizational objectives and continually improve.

Every year, Toronto Hydro reviews its corporate objectives in light of organizational priorities and updates its balanced scorecard to ensure appropriate targets are set. The same is done at the divisional and department level to result on a fresh slate of objectives at the beginning of each year, where progress is then reported out on a monthly basis.

[8] Exhibit 4, Tab 4, Schedule 4.

The performance management process also provides employees and managers with multiple opportunities to set individual goals throughout the year that are aligned with corporate objectives and outcomes. This ensures that employees understand their job expectations and how their roles support the utility's strategic objectives.[9] There is ongoing feedback to ensure project deadlines and goals are achieved. All employees are coached on aligning individual and organizational outcomes.

This rigourous performance system has become instrumental to Toronto Hydro's success in the face of challenges to the utility such as COVID-19 and extreme weather. Looking forward, this performance system will help the organization adopt new technologies and support new ways of operating (e.g. distributed energy resources) through setting evidence based goals, tracking progress and having past results inform future goals.
This function also includes various productivity initiatives such as LEAN and 5S (a subset of LEAN pertaining to workspace organization) which have allowed for the elimination of waste from printing rooms to warehouse environments.

6.1.5 Innovation

Further to the performance systems, Toronto Hydro also has an "Innovation @ Toronto Hydro" program which sets aside an annual budget to incubate and bring employee innovation to life. Projects with a completed proof of concept to-date include virtual reality training and implementation of project management software.

6.1.6 HR Systems and Data Governance

The HR Systems and Data Governance function supports the organization's technology needs with respect to employee data. The team oversees all HR related technology

[9] Exhibit 1B, Tab 2, Schedule 1.

solutions and develops the utility's long term system plan. This function conducts a regular review of systems to identify opportunities to optimize functionality and maximize benefits. SuccessFactors has enabled the utility to integrate and automate management of the employee life cycle from hire to retire.

6.2 Human Resources Services & Systems, Organizational Effectiveness & Employee Labour Relations Segment Costs

Table 5, below, provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Year (2025-2029) expenditures for the Human Resource Services and Employee Relations segment.

Table 5: Human Resources Services & Systems, Organizational Effectiveness & Employee Labour Relations Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Human Resource Services & Systems, Organizational Effectiveness & Employee Labour Relations	5.9	6.3	5.9	8.0	9.4	10.0	10.4	10.8	11.3	11.8

6.3 Human Resources Services & Systems, Organizational Effectiveness & Employee Labour Relations Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

Costs increased by $0.4 million from 2020 to 2021 due to inflationary pressures.

2021 – 2022 Variance Explanation

Costs decreased by $0.4 million from 2021 to 2022 due to hiring plan adjustments.

2022 – 2025 Variance Explanation

From 2022 to 2025, costs are expected to increase by approximately $4.1 million due to reorganization within the HR, Environmental & Safety division to align leadership and support delivery on current and upcoming organizational operational strategies and strategic projects. This reorganization will support the following outcomes:

- Support for the SAP S4 HANA upgrade as outlined in Exhibit 2B, section E8.4, specifically for the component associated with human resources data, including timekeeping and employee master data systems;
- Increased headcount due to the delay in hiring from the pandemic;
- Support succession planning and development within the division; and
- Support the Human Resources, Environment and Safety division in the rate application.

2025 – 2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $1.8 million, or an average of $0.5 million per year. If the utility does not receive the funding it requires to execute this segment as described, Toronto Hydro could be exposed to a number of risks, including:

- Insufficient resources to monitor, advise, and enforce compliance with the utility's legislative and regulatory obligations;
- Insufficient resources to investigate and remedy employment issues such as attendance management, lowering workforce productivity;
- A lack of competitive and informed total rewards compensation offerings contributing to an inability to attract talent in a tight labour market in a large urban city, as well as losing talent to other utilities, resulting in an insufficient

workforce to execute the utility's capital program and growth and modernization programs;

- An inability for the utility to defend itself against civil employment claims, Ontario Labour Relations Board matters, and human rights claims;
- A lack of resources to improve the utility's innovation capabilities and a lack of productivity support to run lean programs that decrease organizational waste (e.g. time, materials, etc); and
- A lack of modern technology solutions requiring employees to focus more on manual and tedious data work rather than focusing on higher-level value-added work;

7. TALENT MANAGEMENT, CHANGE LEADERSHIP & SUSTAINABILITY SEGMENT

7.1 Segment Description

The Talent Management, Change Leadership & Sustainability segment governs the development and execution of the utility's workforce staffing plan, career succession, and employee development strategies and programs. The primary objective of this segment is to align workforce and culture change strategies to organizational strategies and key competencies for current and future workforce requirements. This enables the advancement of the organization as an employer of choice, builds workforce competence to drive technology, process change and innovation, and enhances leadership skills and competence. Functions within this segment include:

- Short and long-term workforce staffing and planning;
- Talent attraction and retention;
- Succession planning and career development;
- Organization and job and design;
- Diversity, equity and inclusion; and

- Change management systems; training and development.

7.1.1 Talent Management

The Talent Management function plans and executes the utility's short and long-term workforce strategy,[10] which includes: (i) mapping the resources that the utility needs to execute its capital plans and operational programs; (ii) analyzing the availability of talent within the utility and in the external labour market; and (iii) understanding the utility's actual and projected turnover rates. This information forms the basis of the utility's workforce strategy. This segment is also responsible for administering collaborations with colleges and universities and its talent attraction strategies.

The utility has evolved its talent management processes to build a more diverse workforce. Specific plans to support these objectives include creating engagement, communication and educational opportunities to build employees' understanding of unconscious bias and the importance of inclusive leadership. For example, as of June 1, 2023, 241 leaders (91 percent) have completed unconscious bias training.

The utility's Talent Management processes supports a bias and barrier-free recruiting experience. Toronto Hydro is committed to attracting, retaining and promoting qualified individuals to meet its resourcing requirements. Toronto Hydro uses a competency-based selection approach to align candidates to behavioural corporate competencies and technical job specific requirements. This process mitigates operational and safety risks for the organization due to poor hiring decisions.

[10] Exhibit 4, Tab 4, Schedule 3.

Toronto Hydro collaborated with George Brown College to develop curriculum for the Electromechanical Engineering Technology – Power and Control Program. Graduates of this program will meet minimum entry qualifications to Power Line Technician, Engineering Technologist, Distribution System Technology, Power System Controller and Certified Meter Mechanic Tester roles. All of these are key certified and skilled trades and designated technical professional roles that support the safe, productive, design and operation of the distribution system. This program was launched in 2021 and demonstrates the utility's commitment to investing in future talent by giving back to the diverse community it serves. The first graduates of this program will reach the labour market in the spring of 2024.

Team members from this segment work directly with educational institutions, including George Brown College, to lead the establishment of collaboration outcomes. These include annual goal setting in the areas of curriculum development, training support, recruitment and marketing for current and prospective students, scholarships and awards and work integrated learning program support, and lab equipment upgrades. Expected outcomes for the utility include a ready talent pool versed in relevant knowledge to fill short and long-term workforce needs over the 2025-2029 period.

7.1.2 Organization Design

Toronto Hydro's organization design function collects information on business departments' functional responsibilities and processes for the purpose of optimizing business functionalities, identifying strategies that enhance existing processes, seeking options to increase workforce flexibility, achieving operational efficiencies and cost savings, and improving overall organizational performance. This function ensures that job roles are clearly defined. This function also assesses the utility's management systems

and operational processes to identify short and long-term talent needs and opportunities and support succession plans at all levels. This organizational design process flows into creating tailored short-term and long-term workforce and leadership requirements to meet the utility's objectives.

7.1.3 Change Leadership

The change leadership function enables Toronto Hydro's journey to transform the workforce through key business processes alignment, continual improvement and innovation. In addition, this team supports the people side of change with upskilling, development and engagement and communication as applicable.

This function also supports the utility's culture change goals with its hybrid work arrangement and its focus on ESG and diversity, equity and inclusion goals. This function further executes strategies to maintain employee engagement and productivity throughout the planning, delivery and sustainment of these projects.

One example of organizational change at Toronto Hydro has been the development of the "Enterpriser" community across the organization. Enterprisers are a network of approximately 80 employees who are involved as change agents in the business. This cross divisional network has been maintained for five years following the implementation of SAP, and has supported system enhancements, adherence to standards and processes and the learning of employees who are onboarded or transition to new roles.

7.1.4 Training and Development

Toronto Hydro provides training and development programs to sustain a qualified and competent workforce. These include an onboarding program to support employees'

transitions to new roles, apprenticeship training, leadership, technical, legislative, and Toronto Hydro-specific compliance programs. For example, in 2022, the Sustainability and Training team organized and delivered 655 scheduled classes across 86 distinct training programs. Toronto Hydro primarily develops these programs in-house. This in-house development has accelerated training program development time, increased the quality of training materials, and improved training material maintenance for a lower overall cost. External designers are only used for complex legislative compliance matters or complex technologies such as virtual reality.

Effective leadership and succession planning are essential to the utility's success. They provide value to Toronto Hydro's customers by driving productivity and efficiency and by protecting the continuity of the utility's operations. Leadership responsibilities include: championing environmental, social and governance programs, training, performance management, employee engagement, coaching and mentoring, and employee development.

The Sustainability and Training team facilitates these objectives, in conjunction with the performance management program, which allows employees to identify career development goals, specific interests, and any skill or knowledge gaps that they would like to fill. This information is critical to recognizing and developing potential leaders and successors from within the utility and to delivering Toronto Hydro's staffing strategy.[11] Through well-developed processes for identifying and developing leadership potential, Toronto Hydro has successfully improved leadership bench strength, creating a pool to fill this critical function. Leadership training is provided to employees at all levels of the organization.

[11] *Ibid.*

Toronto Hydro's technical training and development programs are an essential resource for meeting all legislative, compliance and utility specific training requirements. Comprehensive training is not only a legislative requirement under the *Occupational Health Safety Act, 1990*[12] and other key statutes and codes that govern Toronto Hydro, but it also contributes to higher employee productivity, efficiency and safer operations.

Toronto Hydro administers four certified apprenticeship training programs :

- Power Line Technician ("PLT");
- Distribution System Technologists ("DST");
- Power System Controllers ("PSC"); and
- Certified Meter Mechanics ("CMM").

Toronto Hydro also administers two technical training programs: (i) Engineering Technologists; and (ii) Engineers.

Together, these programs play a key role in facilitating the development and transfer of core knowledge about the complexities of Toronto Hydro's distribution system and in maintaining the specialized work skills which are critical to the utility's capital program and operations (e.g. network switching, positive identification of underground cable and lead cable splicing in the underground system). Informal mentorship also occurs, providing experienced employees with an opportunity to share best practices along with greater understanding of the complexities of the utility's assets.

Toronto Hydro was granted Training Delivery Agent status by the Provincial training authority to provide training to the utility's Powerline Technicians. Its other three

[12] *Supra* note 4.

apprenticeship programs are structured and designed in a similar fashion with the objective of developing and maintaining the specialized skills and knowledge that certified and skilled trades and designated and technical professionals require to work on Toronto Hydro's distribution system safely and efficiently.

7.2 Talent Management, Change Leadership & Sustainability Segment Costs

Table 6, below, provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Years (2025-2029) expenditures associated with the Talent Management, Change Leadership & Sustainability segment.

Table 6: Talent Management, Change Leadership & Sustainability Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Talent Management, Change Leadership & Sustainability	7.2	9.0	8.4	7.9	8.8	9.3	9.4	9.8	10.2	10.6

7.3 Talent Management, Change Leadership & Sustainability Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

From 2020 to 2021, costs increased by $1.8 million due to:

- The introduction of additional headcount as additional trainers for the apprenticeship program in Sustainability & Training;
- The re-initiation of training programs that were paused in 2020 due to the COVID-19 pandemic; and
- Headcount to support programs such as leadership development and corporate engagement and communication.

2021 – 2022 Variance Explanation

From 2021 to 2022, costs decreased by $0.6 million due to hiring plan adjustments.

2022-2025 Variance Explanation

From 2022-2025, costs are expected to increase by $0.9 million due to:

- Investments in headcount to support leadership development, diversity equity and inclusion programs and resources to attract and train the talent required to support capital and operational work programs

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $1.3 million, or an average of $0.3 million per year. If Toronto Hydro does not receive the requested level of funding to perform the functions and satisfy the responsibilities identified in this segment, the utility could be exposed to a number of risks, including, a reduced ability to successfully recruit, advance the inclusive culture and develop the skilled and specialized resources that Toronto Hydro requires in the next five years.

FINANCE

1. OVERVIEW

Table 1: Finance Program Summary

Finance Program									
Outcomes: Public Policy Responsiveness, Financial Performance									
Segments: • Controllership • Financial Services • External Reporting									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
16.4	17.9	18.4	20.9	22.9	24.4	26.2	27.6	29.4	31.1

The Finance Program (the "Program") supports Toronto Hydro's operations through financial planning, management reporting, capital planning and reporting, payroll and disbursements, corporate tax, treasury, insurance and internal audit as well as external reporting and financial regulatory and revenue management.

The Program provides value to customers through the oversight of financial planning activities that support the utility's ability to execute long-term and short-term strategic plans, the appropriate governance of key performance measures such as operating expenses, regulated capital, in-service assets, net income, investor and stakeholder engagements, and compliance with applicable statutory and regulatory financial requirements.

The Program includes the following three segments:

- **Controllership**: Encompasses oversight and governance of Toronto Hydro's financial activities. This includes financial planning, management reporting, capital planning and reporting, and payroll and disbursements.
- **Financial Services:** Governs the activities permitting Toronto Hydro to meet its financial obligations. This includes treasury, insurance, corporate tax, and internal audit. These functions are integral to contributing to financial compliance and solvency.
- **External Reporting:** Oversees preparation and compilation of financial reporting materials for external parties, including, but not limited to, the Ontario Energy Board ("OEB"), and the Ontario Securities Commission ("OSC").

The Program and its constituent segments are a continuation of the activities described in the Finance program in Toronto Hydro's 2020-2024 Rate Application.[1]

Functionally, these segments work to support Toronto Hydro's operations through diligent financial planning, management reporting, capital activities, payroll and disbursements, corporate tax, treasury, insurance, and compliance with internal and external auditing standards.

[1] EB-2018-0165, Exhibit 4A, Tab 2, Schedule 16.

2. OUTCOMES AND MEASURES

Table 2: Finance Program Outcomes and Measures Summary

Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by: o Providing accurate and timely reporting pursuant to the OEB's Electricity Record Keeping Requirements (the "RRR") and compliance with the Accounting Procedures Handbook ("APH") by maintaining the necessary processes and controls; and o Preparing and issuing quarterly and audited annual financial statements, including the Management Discussion & Analysis ("MD&A") and Annual Information Form ("AIF") as required by the OSC and the Canada Revenue Agency ("CRA").
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by: o Leading the governance of the DSP Implementation Progress Metric and Financial Ratios as annually reported via the OEB Distributor Scorecard; o Meeting the financial obligations and maintenance of compliance requirements imposed by the relevant regulatory bodies and debt holders; o Raising capital and providing financial services that enable the uninterrupted continuation of the utility's capital investments and distribution activities.

3. PROGRAM DESCRIPTION

The Program provides financial support to every aspect of Toronto Hydro's operation through business planning activities, management reporting, capital planning, payroll services, accounts payable, internal audits, and other issue-specific functions. It also enables compliance with statutory and regulatory requirements and reporting obligations. These requirements primarily relate to the preparation and issuance of securities-related continuous disclosure information that is completed on a consolidated basis. Regulatory financial reporting required by the OEB includes quarterly and annual reporting under the RRR and compliance with the APH.

The Program also delivers traditional finance functions such as payroll and disbursement services, treasury, corporate tax, and internal audit that allow Toronto Hydro to meet its short and long-term financial, legal, and legislative obligations to its employees, external suppliers, service providers, debt holders, government agencies, board of directors, and its external auditors**.** In addition, the Program oversees a number of operational processes (i.e. management reporting and analysis and capital planning and reporting) that monitor the utility's financial performance and support management**'**s ability to make informed, strategic decisions.

The Program also provides oversight and governance of the utility's business planning activities through the financial planning function. This function is responsible for the assessment and recommendation of short and long-term strategic plans and integration of operational, financial and regulatory plans. The Program also manages the co-ordination and consolidation of the annual budget.

The activities described above are accomplished via the following three segments:

- **Controllership**: includes functions such as financial planning, management reporting and analysis, capital planning and reporting, and payroll and disbursements;
- **Financial Services**: includes functions such as corporate tax, treasury, insurance, and internal audit; and
- **External Reporting**: includes statutory and regulatory reporting functions such as external reporting and regulatory financial reporting and revenue management.

4. PROGRAM COSTS

In 2025 Toronto Hydro requires $24.4 million in rate funding for the Finance program, which represents an increase of $8 million over the last Custom Incentive Rate Application in 2020. When normalized for shared services recoveries outlined in Exhibit 4, Tab 5, Schedule 1, the expected increase in this program is $7.5 million.

Over the 2025-2029 rate period, the utility expects the cost of this program to increase by an annual growth rate of 6.1 percent which is necessary to address the program needs and deliver the customers outcomes enabled by this program

Table 3, below, provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for each of the Program's segments:

Table 3: Finance Program Expenditures by Segment ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Controllership	6.5	6.9	6.9	7.7	8.8	9.4	10.1	10.5	11.0	11.4
Financial Services	6.7	7.7	8.4	9.3	9.7	10.5	11.4	12.2	13.3	14.4
External Reporting	3.2	3.3	3.1	3.9	4.4	4.5	4.7	4.9	5.1	5.3
Total	**16.4**	**17.9**	**18.4**	**20.9**	**22.9**	**24.4**	**26.2**	**27.6**	**29.4**	**31.1**

4.1 Cost Drivers

The primary driver of cost increases in the program is compensation cost increases due to an increase in staffing levels and general compensation increases of existing employees. As the volume and complexity of Toronto Hydro's capital investments and operations increase in the 2025-2029 period, the Program will require a highly skilled and dedicated workforce to perform all of the Program functions in a timely and effective manner.

Secondly, the Program costs are expected to increase due to higher insurance premiums, reflecting expected cost increases for general and cyber security insurance. The upward trend in insurance costs is attributable to higher premiums on the existing insurance programs of property, liability and cyber insurance policies. In particular, cyber security insurance premiums are increasing in correlation with growing and more acute cyber security threats that affect large organizations such as Toronto Hydro each year.[2] Additionally, Toronto Hydro's rate base is expected to increase from $5.2 billion in 2022 to $7.6 billion in 2029 which has a direct impact on the future property and liability insurance premiums.

4.2 Cost Control and Productivity Measures

The Program has undertaken cost control measures over the 2020-2024 plan period to control costs and offset cost increases identified above in Section 4.1. Some of these measures are expected to result in cost savings through the 2025-2029 forecast period. The Program continuously engages in the assessment and review of its processes to explore opportunities to streamline functions and make process improvements.

Within the controllership segment, some of the examples of these departmental efficiencies include:

- Process improvement and automation of the payroll processing and disbursement functions resulting in sustained annual savings of $0.2 million starting in 2021; and
- Annual cost avoidance of $0.4 million through the elimination of manual processes and use of technology to automate repetitive tasks starting in 2022.

[2] Exhibit 4, Tab 2, Schedule 17.

These savings of $0.6 million are forecasted to be sustained for through the bridge years (2023-2024) and forecast years (2025-2029). These forecasted efficiencies enable the segment to maintain the same staffing levels as 2025 through the 2026-2029 forecast years despite the increase in the volume and complexity of the capital and operating work programs.

5. CONTROLLERSHIP SEGMENT

5.1 Segment Description

The controllership segment provides oversight and governance of Toronto Hydro's financial planning activities, timely and accurate financial information and support to Toronto Hydro's senior management and operational business units. This segment also allows the utility's financial reports to meet both statutory and regulatory financial reporting requirements. The controllership segment leverages knowledge of operational processes to produce accurate and relevant financial information, and provides appropriate financial context for decision making by the operational business units and senior management. This segment is crucial to enabling senior management to make informed decisions, and for monitoring and analyzing the utility's financial performance against short-term goals, long-term plans and regulatory filings. The activities comprising this segment encompass the following functions: (i) financial planning; (ii) management reporting and analysis; (iii) capital planning and reporting; and (iv) payroll and disbursements. Further details about these activities are below.

5.1.1 Financial Planning

The financial planning function provides centralized oversight and governance of the utility's financial planning activities including the assessment and recommendation of long-term strategic plans and the integration of operational, financial, and regulatory

plans. This function coordinates the development and execution of the utility's annual budget, long-term financial projections, and support for electricity distribution rate applications. The group leverages the analysis provided through the management reporting and analysis function described below to identify issues that may impact Toronto Hydro's ability to achieve its financial objectives. Financial planning allows the utility to make effective decisions that enable the achievement of the company's strategic goals and objectives and outcomes to the benefit of ratepayers while ensuring governance and oversight of all financial planning activities. Without this function, Toronto Hydro's business planning and budgeting processes would be decentralized, which would introduce a variety of governance risks to the utility.

5.1.2 Management Reporting and Analysis

The management reporting function oversees internal management reporting and supports operational groups through month-end activities and financial analysis for decision making and achievement of strategic objectives. Responsibilities of this function include: managing financial systems and processes to effectively deliver timely reports and outlooks; reviewing, consolidating and preparing analyses for management reports to enable timely decision making; providing support for external reporting and disclosure; performing core month-end accounting functions such as month-end close entries, account reconciliation, and analysis to ensure compliance with OSC, OEB and audit requirements; and reviewing and consolidating monthly financial outlooks. By providing regular reports and analysis of the utility's operational expenditures, this function enables Toronto Hydro to track and monitor its performance relating to execution of the operational work plan. In addition, the team collaborates with operational groups to develop, implement and optimize internal controls and processes to maintain the integrity of financial data and improve efficiency. These services are essential to Toronto

Hydro's ability to comply with regulatory and statutory accounting standards, to produce accurate financial statements, and to successfully deliver the utility's operating work plans.

5.1.3 Capital Planning and Reporting

The capital planning function oversees the development of the utility's annual capital expenditure budget and long-term capital expenditure projections. The Capital Reporting function records capital projects in the fixed asset register, and maintains tangible, intangible, regulatory and statutory assets, and financial data under both Modified IFRS and IFRS. The team provides fixed assets, capital expenditure ("Capex"), depreciation expense, construction work in process ("CWIP") and ISA continuities, reconciliations, reports and analysis to ensure compliance with OSC, OEB and audit requirements. By providing regular reports and analysis of the capital work plan, this function enables Toronto Hydro to track and monitor its performance relating to execution of the plan. In addition, the team collaborates with operational groups to develop, implement and optimize internal controls and processes to maintain the integrity of financial data and improve efficiency. These services are essential to Toronto Hydro's ability to comply with regulatory standards, to produce accurate financial statements, and to successfully deliver the utility's capital work plans.

5.1.4 Payroll and Disbursements

The payroll function ensures that Toronto Hydro employees are compensated for their services in a timely and accurate manner, consistent with relevant time-keeping and other records. The function also ensures that all relevant legislative requirements and statutory deductions are appropriately applied to employee payments and that payroll

withholdings amounts are remitted on a timely basis. In addition, the function maintains accurate OMERS pension fund records for participating employees.

The disbursements function facilitates timely and accurate payment of valid vendor invoices. It also processes payments for eligible customer refunds initiated by Toronto Hydro's Customer Care Program. In performing these tasks, the disbursements function utilizes financial software to validate and, if necessary, correct the amounts and timing of payment of supplier invoices. In addition, it reviews software generated payment files and approves the resulting bank transfer files or cheque runs.

5.2 Controllership Segment Costs

Table 4, below, provides the Historical (2020-2022), Bridge (2023-2024), and Test Year (2025-2029) expenditures for the controllership segment.

Table 4: Controllership Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Controllership	6.5	6.9	6.9	7.7	8.8	9.4	10.1	10.5	11.0	11.4

5.3 Controllership Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

An increase of $0.4 million was primarily due to:

- Sustained increase in headcount in 2021 to support the increased size and complexity of the 2020-2024 capital program approved in the last OEB decision and general compensation increases of existing employees. These increases were net of sustained cost savings of $0.2 million annually from 2021 and beyond as a result of the payroll and disbursement process automation.

2021 – 2022 Variance Explanation

There was no sustained variance. General compensation increases in 2022 of existing employees were offset by lower headcount in 2022. The 2022 headcount was lower than expected due to unplanned employee turnover; these roles are expected to be filled in 2023. Additionally, through continued adoption of technology and automation of business processes, costs reduction and avoidance of $0.4 million was achieved annually from 2022 and beyond.

2022 – 2025 Variance Explanation

A forecasted increase of $2.5 million due to:

- Increase in payroll costs as a result of backfilling of open positions that were left vacant in 2022, general compensation increases of existing employees, and recruitment of additional resources to support the increased size and complexity of the capital program and to support the 2025-2029 rate application.

2025 – 2029 Variance Explanation

Between 2025 and 2029, costs in this segment are expected to increase by $2.0 million, or an average of $0.5 million per year. Without the requested funding, Toronto Hydro faces the following risks:

- Reduced governance and oversight of financial planning activities that can limit the organization's ability to execute its long-term and short-term strategic vision and plans and deliver outcomes to the benefit of ratepayers;
- Reduced governance of key performance measures such as operating expenses, regulated capital investments, in-service assets, and net income;
- Increased risk of de-centralization of financial planning activities resulting in lack of integration of operational, financial, and regulatory plans;

- Compromised month-end and financial analyses for management reports to enable timely decision making related to operational expenditures and capital investment;
- Reduced management of fixed assets and oversight of capital program spending and ISAs that can impact approved commitments in prior OEB decisions and compromise the achievement of strategic and financial objectives;
- Increased risk of delays and compromised accuracy of payroll remittances to employees for their services, remittances of payroll withholding amounts and payments of valid vendor invoices, which could result in non-compliance with employment standards and an increase in litigation involving employees and vendors; and
- Compromise on the quality of record keeping of OMERS pension fund for participating employees.

6. FINANCIAL SERVICES SEGMENT

6.1 Segment Description

The financial services segment encompasses the functions that enable Toronto Hydro to meet its regular and long-term financial obligations to its external suppliers, service providers, and debt holders, and the government. It also allows the utility to plan for, secure, and provide timely payments for market-competitive debt instruments that it needs to finance its capital work program.

The financial services segment provides Toronto Hydro with a means to objectively evaluate its core functions in order to ensure compliance to internal and external policies and facilitate transparency in all corporate activities. The scope of activities comprising

this segment includes the following functions: (i) Corporate Tax; (ii) Treasury; (iii) Insurance; and (iv) Internal Audit.

6.1.1 Corporate Tax

The corporate tax function facilitates the utility's compliance with all relevant tax laws and regulations. In addition, it ensures that taxes are appropriately recorded and reflected in accounting records and external financial statements. This function is responsible for preparing and submitting timely tax filings and applicable payments that include corporate income taxes, the harmonized sales tax, and the non-resident withholding tax. The group executes tax-related financial planning activities, performs tax-related monitoring and reporting work, and supports both internal and external tax compliance audit activities as required by applicable legislation and internal policies. Corporate tax is also responsible for regulatory tax reporting and compliance, such as the Payment in Lieu of Taxes ("PILs") calculations for the purposes of rate filings.[3]

6.1.2 Treasury

The treasury function oversees Toronto Hydro's cash management, debt management, and investor relations activities. Cash management activities include: (i) borrowing to provide the utility with adequate funds to meet its financial obligations, or investing any excess funds on hand; (ii) managing and implementing risk controls, including segregation of duties and independent verification and approval of borrowing activities; and (iii) daily reporting and reconciliation of Toronto Hydro's cash position and general ledger and sub-ledger accounts. Debt management activities include the issuance of both long-term and short-term debt instruments to fund the capital programs and for general corporate purposes. Investor relations activities include developing and managing relationships

[3] Exhibit 6, Tab 2.

with bank lenders, bond investors, independent financial and credit analysts, and the credit rating agencies in order to optimize the cost of funding. The activities performed by this function help facilitate access to the debt capital markets from which Toronto Hydro accesses funds to carry out its operations and fund its long-term capital program.

6.1.3 Insurance

The insurance function oversees the utility's comprehensive insurance requirements, the purpose of which are to provide Toronto Hydro protection for asset exposure, corporate liability and other activities which may expose the utility to a financial loss. Current insurance policies administered by this group provide coverage for a variety of losses and expenses, including comprehensive general liability, all risk property and boiler and machinery insurance, liabilities of directors and officers, automobile liability, professional liability, and crime and cyber security insurance.

6.1.4 Internal Audit

Internal audit provides independent and objective reporting to Toronto Hydro Corporation's Audit Committee and management through operational, compliance, and performance audits. Internal audit focuses on assessing the adequacy and effectiveness of the utility's risk management, governance, and system of internal controls, and provides consultation and advisory services on the design, implementation, and maintenance of internal controls and reporting systems, governance activities, fraud detection procedures, and other matters requested by senior management or the Audit Committee.

6.2 Financial Services Segment Costs

Table 5, below, provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for the financial services segment:

Table 5: Financial Services Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Financial Services	6.7	7.7	8.4	9.3	9.7	10.5	11.4	12.2	13.3	14.4

The expected increase in costs are primarily due to higher premiums on the existing insurance programs for property, liability and cyber insurance policies. These programs are in place to cover all material risks to Toronto Hydro. Toronto Hydro's rate base is expected to increase from $5.2 billion in 2022 to $7.6 billion in 2029 which has a direct impact on the future property and liability insurance premiums. The cyber insurance premium increase is being driven by global geopolitical tensions, privacy regulations, ransomware evolution and the capacity constraints of insurers. For the 2023 to 2024 bridge years and 2025 to 2029 forecast years all policy and self-insured deductible limits are expected to be at 2023 levels.

6.3 Financial Services Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

An increase of $1.0 million was primarily due to:

- The utility having sustained increased property and cyber security insurance costs of $0.8 million, and
- General compensation increases for existing employees of $0.2 million.

2021 – 2022 Variance Explanation

An increase of $0.7 million was primarily due to:

- The utility having sustained increased property, general and cyber security insurance costs of $0.5 million, and
- General compensation increases for existing employees of $0.2 million.

2022 – 2025 Variance Explanation

A forecasted increase of $2.1 million is primarily due to:

- An increase in costs for general and cyber security insurance of $1.2 million
- General compensation increases for existing employees of $0.7 million, and
- Increased support costs for tax audits of $0.2 million.

2025 – 2029 Variance Explanation

Between 2025 and 2029, costs in this segment are expected to increase by $3.9 million, or an average of $1.0 million per year. Without the requested funding, Toronto Hydro faces the following risks:

- Compromised ability to secure funding to finance the capital programs and risk of violation of the covenants contained in existing debt issuances;
- Increased difficulty maintaining compliance with relevant tax laws, rules, regulations and appropriate tax reporting and disclosure requirements, which could cause an increase in tax risks and related costs;
- Reduced ability to ensure operational compliance and performance due to lack of design, implementation, and maintenance of internal controls and reporting systems, governance activities, and fraud detection procedures; and
- Inability to effectively protect the utility against a variety of potential insurance risks and losses outside of normal business operations.

7. EXTERNAL REPORTING SEGMENT

7.1 Segment Description

The external reporting segment oversees the preparation and compilation of external financial reporting materials, such as those required by the OSC and the OEB. Among other things, this function requires the preparation of publicly filed annual and interim financial statements and disclosures and reporting to the Board Audit Committee. The segment is also responsible for assessing, reviewing, documenting and communicating all changes in accounting standards to relevant stakeholders, and assessing the accounting treatment for new or complex transactions.

The specific activities and internal controls underlying Toronto Hydro's external reporting processes are subject to regular reviews by independent internal and external auditors.

To enable timely and accurate execution of its core functions, the segment undertakes two sets of primary activities. First, the segment performs central accounting functions such as consolidation entries, intercompany settlements and eliminations, accounting for post-employment benefits, and other account reconciliation and management activities. Second, it uses information in the company's accounting systems to prepare all required financial filings. These filings include the audited annual financial statements and notes (consolidated and for each legal entity separately), the MD&A, the AIF and other reporting requirements from time to time. With the exception of the AIF, the above documents are filed quarterly.

In addition, the external reporting segment is responsible for the regulatory reporting and revenue management function which oversees financial activities associated with the OEB and is responsible for the accounting in relation to Toronto Hydro's transactions with

the IESO and other suppliers for cost of power expenses and other related regulatory settlements. Other responsibilities include budgeting, forecasting, financial analysis and related preparation of information for reporting under the RRR and for the purpose of rate applications. This function also supports OEB audits, enables compliance with the OEB-mandated financial and regulatory accounting requirements outlined in the APH, and supports the external reporting, management reporting, analysis, and financial planning in relation to regulatory assets and liabilities.

7.2 External Reporting Segment Costs

Toronto Hydro requires approximately $4.9 million per year over the 2025-2029 plan period to execute the functions in the external reporting segment, as described above.

Table 6, below, provides the Historical (2020-22), Bridge (2023-2024), and Forecast (2025-2029) expenditures for the external reporting segment:

Table 6: External Reporting Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
External Reporting	3.2	3.3	3.1	3.9	4.4	4.5	4.7	4.9	5.1	5.3

7.3 External Reporting Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

An increase of $0.1 million was due to:

- Inflationary impacts on non-payroll costs.

2021 – 2022 Variance Explanation

A decrease of $0.2 million was due to:

- Lower payroll costs as a result of lower headcount in 2022. The 2022 headcount was lower than expected due to unplanned employee turnover; these roles are expected to be filled in 2023; and
- The lower payroll costs were partially offset by general compensation increases of existing employees and inflationary impacts on non-payroll costs.

2022 – 2025 Variance Explanation

A forecasted increase of $1.4 million is due to:

- Increases in payroll costs due to hiring of open positions that were left vacant in 2022,
- General compensation increases of existing employees,
- The recruitment of additional resources to support the rate application, partially offset by staff reduction upon winding down of rate application support, and
- Inflationary increases on non-payroll costs.

2025 – 2029 Variance Explanation

Between 2025 and 2029, costs in this segment are expected to increase by $0.8 million, or an average of $0.2 million per year. Without the requested funding, Toronto Hydro faces the following risks:

- Increased risk of reporting errors and material misstatements for financial disclosures;
- Compromised ability to accurately prepare and compile external financial reporting materials, such as those required by the OSC;
- Compromised quality of financial activities associated with the OEB, accounting in relation to Toronto Hydro's settlements and transactions with the IESO, and other related regulatory settlements;

- Lack of appropriate governance to support the Board of Directors' responsibilities with respect to financial and audit matters; and
- Lack of regulatory and revenue management leading to increased risk of material misstatements and inability to comply with the OEB's financial and regulatory accounting requirements.

INFORMATION TECHNOLOGY

1. OVERVIEW

Table 1: Program Summary

Information Technology Program									
Outcomes: Customer Focus, Operational Effectiveness - Reliability, Public Policy Responsiveness, Operational Effectiveness - Safety, and Financial Performance									
Segments: • Security & Enterprise Architecture • IT Operations • Project Execution • IT Governance									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
48.0	50.6	53.5	57.5	61.1	63.3	65.8	68.7	71.7	75.1

The Information Technology ("IT") program (the "Program") supports all aspects of Toronto Hydro's business. The IT infrastructure, cybersecurity controls, business applications and services supported and delivered by this Program enable efficient operations of the utility and play a critical role in achieving Toronto Hydro's objective to provide safe, secure and reliable electricity.

The Program deploys, operates and supports all information systems and controls, including:

- **IT Hardware Support**: includes the core back-end infrastructure assets (e.g. servers, storage, backup, networks and data centres), cybersecurity components and endpoint assets (e.g. desktop computers, laptops, printers, smart phones, and tablets) that support Toronto Hydro's day-to-day operations and core systems;

- **IT Software Support:** includes software applications such as cybersecurity, databases, middleware and business-facing applications; and
- **Communication Support:** includes assets that enable the monitoring and control of distribution communication infrastructure, including fibre-optic assets and wireless Supervisory Control and Data Acquisition ("SCADA") infrastructure, as well as communication cost provided by third-party vendors.

Toronto Hydro performs this work under clearly defined IT architectural standards and governance frameworks, defined in the IT Investment Strategy ("the Strategy").[1]

The Program consists of the following four segments:

- **Security and Enterprise Architecture**: Defines and implements a utility-wide IT strategy, develops and oversees corporate IT policies and standards, assesses and evaluates the suitability of new technologies to support the growth and modernization of IT business processes and systems. This segment also performs security operations, and manages enterprise IT risks including cybersecurity, restore & recover, and disaster recovery**.**
- **IT Operations**: Supports and maintains the day-to-day operation of Toronto Hydro's IT assets, including core back-end infrastructure (e.g. servers, local area networks and data storage/centres), security appliances and endpoint assets (e.g. desktop computers, laptops, printers, smart phones, and tablets and end-user applications).
- **Project Execution:** This segment is responsible for the implementation of new IT solutions (programs, projects, and applications), that are required to achieve Toronto Hydro's strategic objectives in accordance with the IT expenditure plan. This segment also includes the implementation costs for cloud solutions.

[1] Exhibit 2B, Section D8.

- **IT Governance:** Provides support to the IT investment planning process by ensuring documentation and justification are developed to align with the Strategy. This includes developing program and project level artifacts, and establishing program goals and benefits. This segment provides financial and data governance in accordance with the Strategy and the Enterprise Technology Portfolio ("ETP") Framework.[1] This segment also oversees IT administrative and procurement activities and processes, as well as records management, reporting on IT Key Performance Indicators ("KPIs") and program planning.

The Program and its constituent segments are a continuation of the activities described in the Information Technology program (OM&A) in Toronto Hydro's 2020-2024 Rate Application.[2]

2. OUTCOMES AND MEASURES

Table 2: Information Technology Program Outcomes and Measures Summary

Customer Focus	• Contributes to Toronto Hydro's customer focus objectives by: o Ensuring that IT assets which support Toronto Hydro's customer-service and communication tools and systems (e.g. email and telephony systems and the Customer Information System) are available and in reliable working condition. o Maintaining the integrity and availability of key external customer facing applications such as the Customer Self-Serve Web Portal, Toronto Hydro website and the interactive Outage Map (i.e. a map of Toronto Hydro's service area displaying outage zones and estimated restoration times).

[2] EB-2018-0165, Exhibit 4A, Tab 2, Schedule 1.

Operational Effectiveness - Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: o Supporting and maintaining the availability of modern, reliable and secure enterprise-wide IT/OT systems that monitor and control the performance of distribution. assets (e.g. SCADA), and by providing system operators timely and accurate information about these assets. o Supporting the outage restoration efforts by ensuring that system operators have the necessary IT/OT System tools to promptly identify incidents, develop effective resolution plans and communicate them to operational teams. o Supporting the creation and maintenance of cybersecurity controls to mitigate against potential vulnerabilities and threats that may jeopardize the safe and proper functioning of IT/OT assets. o Investing in innovative solutions including cloud solutions to ensure alignment of IT/OT systems with industry best practices and trends and support the growth and modernization of business operations.
Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by: o Enabling the efficient implementation of new policy initiatives and compliance with regulatory requirements. o Providing the technological infrastructure required by the utility to continuously improve and adapt its IT business processes to changing customers' needs and preferences as a result of future industry challenges such as electrification.

Operational Effectiveness - Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics like the Total Recordable Injury Frequency ("TRIF") by: o Enabling more substation and field assets to be constantly monitored. o Ensuring underlying IT/OT Systems such as SCADA are functioning properly and are consistently available; and o Driving safety performance using: ▪ On-premises software systems such as SCADA, Network Management System (NMS) including Utility Work Protection Code (UWPC), and Radio Panic Button. ▪ Cloud Solutions systems such as: Automated Vehicle Location (AVL) for House of Services Regulation O.Reg.555/06, Electronic Tailboard (eTailboard), Intelex, Learning Management System (LMS).
Financial Performance	• Contributes to Toronto Hydro's financial performance objectives by ensuring that core systems are operational with high reliability and availability supporting all areas of Toronto Hydro's business, including operations, customer service, and regulatory, management, and internal and external financial reporting.

3. PROGRAM DESCRIPTION

The Program provides reliable technology solutions to Toronto Hydro and its customers in a secure, timely, and cost-effective manner by implementing products that meet the utility's evolving operational needs. Timely technical maintenance and support under this Program ensures the ongoing reliability, availability, security and operability of key business applications and underlying IT infrastructure. The Program also continues to ensure preventative and detective system controls are aligned with industry best practices including the Ontario Energy Board's ("OEB") Cybersecurity Framework.[3] Ultimately, Toronto Hydro relies on the Program to satisfy its obligations to customers, maintain system reliability, availability and safety, and to comply with existing and

[3] Ontario Energy Board, *Ontario Cybersecurity Framework* (December 6, 2017).

emerging requirements of the various regulatory bodies that govern the utility's operations.

IT infrastructure, cybersecurity controls, and software applications must be periodically refreshed and enhanced to maintain the reliability and availability of systems to support core operations, mitigate against potential cybersecurity vulnerabilities and threats, and minimize the risks of system failure. Accompanying this infrastructure, software applications, and communications capital expenditures is the associated support in the form of asset maintenance, licensing, and subscriptions, as well as the internal resources required to support and maintain these assets. IT infrastructure, cybersecurity controls and software applications must be kept current to mitigate the risks of cyber-attacks that can disrupt day-to-day operations, compromise or exfiltrate sensitive data as well as to prevent obsolescence and reduce interruptions to the distribution system.

The Program supports the automation of core processes and functions, such as customer billing and outage management. It also enables the utility to evolve its existing business processes to meet new business objectives and requirements in response to changes in customers' needs and preferences due to industry changes. For example, the shift towards electrification will require the need for additional energy data storage and processing capabilities, and these IT systems will enable the connection of Distributed Energy Resources ("DER") by streamlining the evaluation and technical assessment of the connection. The IT systems will also provide the capability to remotely monitor and control assets (e.g. DERs, switches, breakers, etc.).

All of these activities are provided through IT's program four segments: (i) Security and Enterprise Architecture; (ii) IT Operations; (iii) Project Execution; and (iv) IT Governance.

4. PROGRAM COSTS

In 2025, Toronto Hydro requires $63.3 million in rate funding for the Information Technology (IT) Program, which represents an increase of $15.3 million over the last rebasing in 2020. When normalized for shared services recoveries outlined in Exhibit 4, Tab 5, Schedule 1, the expected increase in this Program is $14.9 million.

Over the 2025-2029 period, the utility expects the cost of this Program to increase by a compounded annual growth rate of 4.4 percent which is necessary to ensure the efficient execution of the functions in this Program.

The Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for each segment are summarized in Table 3 below.

Table 3: Information Technology Program Expenditures by Segment ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Security & Enterprise Architecture	3.7	4.5	6.1	6.6	7.3	7.6	7.9	8.4	8.8	9.3
IT Operations	36.9	38.4	39.9	43.0	44.8	46.0	47.5	49.1	50.8	52.2
Project Execution	4.7	4.9	5.0	5.6	6.7	7.4	8.0	8.8	9.7	11.1
IT Governance	2.7	2.8	2.5	2.3	2.3	2.3	2.4	2.4	2.4	2.5
Total	**48.0**	**50.6**	**53.5**	**57.5**	**61.1**	**63.3**	**65.8**	**68.7**	**71.7**	**75.1**

4.1 Cost Drivers

Maintenance and subscription costs account for 47 percent of the increase from 2020 to 2024 and 52 percent of the increase from 2025 to 2029. Software applications and hardware systems require ongoing maintenance and subscription contracts ranging from regular upgrades, to simple patches and updates, to targeted problem resolution (e.g. defect fixes). The maintenance and subscription fees associated with software and

hardware are required to ensure systems receive support from vendors, align with industry best practices, remain integrated with other relevant software systems, and are protected against future cybersecurity threats. These contracts allow Toronto Hydro to maintain the integrity, reliability, availability, and security of its IT systems.

Factors driving the expected increase in maintenance and subscription costs include:

- Implementation of new applications such as Oracle Field Services Cloud ("OFSC"), an upgrade to the mobile workforce management system for Grid Emergency Management which replaced the legacy on-premises in-house developed solution. OFSC is a tool that allows Dispatchers and Grid Response crews to collaboratively manage outage events that include: assembling crews, managing priorities, and communicating across different groups to respond to an unplanned outage event in a timely and effective manner.
- Modernization to the external Customer Self-Serve ("CSS") Web portal and mobile application to provide additional channels and functionalities to customers. Functionalities include proactive outage notifications, automated move-in and move-out processes, and the ability to view consumption in real time.
- E-Tailboard application allows field staff to conduct electronic worksite risk assessments. This solution provides an efficient, comprehensive and transparent digital platform which highlights the safety aspects, precautions, and risk levels while ensuring all safety procedures & protocols are in place at the job sites before crews carry out their duties.
- Increases in cybersecurity maintenance and subscription fees as a result of new continued investments into cloud based, AI-enabled prevention, detection, and response solutions in addition to cybersecurity hardware and software to adequately protect current systems, applications, and endpoints against the

evolving cybersecurity threat landscape and to fulfill regulatory compliance obligations. This ensures that cybersecurity processes and controls are capable of adequately responding to the evolving threat. Cybersecurity requirements need to adapt to changes in the environment, such as hybrid work model, evolving cybersecurity landscape, geo-politically driven Advanced Persistent Threats (ATP), supply chain attacks and zero-day vulnerabilities. Toronto Hydro plans to meets its security requirements arising from such scenarios by continuing to invest in its robust infrastructure using layered Defence-in-Depth model to ensure the protection of both IT and OT assets, in response to future industry challenges such as electrification. Additional investments will be required to take a more proactive approach to cybersecurity, including threat hunting, Extended Detection & Response (XDR), attack surface management and Red/Purple Team simulations. Additionally, a growing number of cybersecurity solutions are moving to subscription licensing models, driving further increases in maintenance costs.

- Increases in subscription fees due to greater investments in cloud solutions, as deemed appropriate in alignment with the Strategy. This shift to subscription from the traditional perpetual licensing model is expected to grow as more IT vendors move towards a subscription model for both cloud-based and on-premises systems. Many vendors are adopting "cloud only" solutions that rely solely on cloud technologies instead of providing an option to host a solution on-premises.
- On aggregate, all maintenance costs have been increasing as a result of inflationary contract escalation increases and the relative depreciation of the Canadian dollar against the U.S. dollar.

Other labour, including internal and external resources, account for 51 percent of cost increases from 2020 to 2024 and 48 percent of the cost increases from 2025 to 2029.

Adequate resourcing for this program will be critical to supporting all of Toronto Hydro's business units and enabling the execution of the business plan over the 2025-2029 rate period. As examples, Toronto Hydro has observed the following workload trends driving the program's resourcing needs:

- From 2020-2024 to 2025-2029, an increase of 18% in the number of complex systems operated and maintained by the program;
- From 2020 to 2023, an increase of 22% in IT service requests handled by the program;
- From 2020-2024 to 2025-2029, an increase of 9% in cyber security systems and controls overseen by the program; and
- From 2020-2024 to 2025-2029, an increase of 6% in the number of endpoint devices supported by the program.

The external labour includes consulting costs primarily related to cloud implementation, temporary staff that were engaged in cloud project work or backfill for permanent staff, and managed services for security services and for Toronto Hydro's Enterprise Resource Planning ("ERP") system. Filling vacancies due to retirements and resignations and the need for additional headcount are the contributing factors for internal and external labour rate increases. Additional headcounts with specialized skillsets are also forecasted to support the increased investments in IT systems both on-premises and cloud (such as Asset Investment Planning ("AIP"), OFSC, CSS portal etc.), and the ongoing sustainment and support of new and existing IT systems. The expected increase in headcount will ensure Toronto Hydro has the appropriate level of resources to achieve the objectives of the Program.

4.2 Cost Control and Productivity Measures

Toronto Hydro's IT and Operational Technology Systems Program aims to modernize business processes sustainably to support customer and business-facing services in response to future industry shifts towards electrification.[4] The IT team continuously explores and implements opportunities to improve productivity by supporting the modernization and automation of IT business processes, while meeting the program objectives. Some examples of productivity improvements are outlined below.

For example, IT Service Management ("ITSM") automated processes in the areas of Service Request Management, Help Desk Support, and the Application Deployment Management. High-volume service requests such as system and folder access, onboarding, offboarding and unlocking user accounts are now fully automated. Reducing time spent on repetitive calls frees helpdesk teams to focus on more complex issues. Although IT Service requests increased by 79 percent between 2020 – 2022, all service level targets were achieved without requiring additional headcount. In addition, automation in the ITSM processes resulted in a cost savings of $0.5 million over the two years.

In managing software subscription and maintenance costs, Toronto Hydro developed an IT maintenance and subscription dashboard to support its application rationalization process. The dashboard allows teams to identify opportunities to keep, replace, retire, or consolidate business applications. Toronto Hydro examines various factors prior to renewing a maintenance and subscription contract to determine if there are any efficiencies or cost-savings to be leveraged before renewal. This allows IT to consolidate and rationalize applications, optimize license usage, resulting in anticipated operational

[4] Exhibit 2B, Section 8.4.

savings of approximately $1 million between 2022-2025. Toronto Hydro was able to effectively negotiate multi-year contracts to mitigate inflationary risk and take advantage of volume discounts, where appropriate.

The IT team evaluates global technology trends to identify improvement opportunities for Toronto Hydro's IT hardware environment. This includes identifying more efficient hardware options and life-cycle hardware for different environments, thus optimizing investments and limiting costs. This strategy allows Toronto Hydro to align its IT system investments with the industry best practices and be equipped to meet customers' needs and preferences in the face of future industry challenges such as electrification.

The Project Execution team continues to refine and enhance the project management framework by studying and implementing the lessons learned from prior projects and adopting industry best practices and standards. This approach reduces the risk of cost overrun and helps to avoid redundant IT investments that do not align with Toronto Hydro's Information Technology Asset Management Strategy and Investment Planning procedures or the organization's modernization strategic objective.[5] This team delivers value to the business quickly while maintaining the timely completion of high-quality deliverables. In the period from 2020 to 2022, this team generated cost savings of $0.8 million.

[5] *Supra* note 5.

5. SECURITY AND ENTERPRISE ARCHITECTURE SEGMENT

5.1 Segment Description

The Security and Enterprise Architecture segment manages Toronto Hydro's cybersecurity function, oversees the corporate Information Technology portfolio, implements utility-wide IT strategy, and develops and oversees corporate IT polices.

This segment addresses cybersecurity at Toronto Hydro by implementing preventative and detective controls aligned with industry best practices, including the OEB's Cybersecurity Framework.[6] IT is becoming increasingly important as a key business enabler, which also carries the increased risk of cybersecurity exposure. The global cybersecurity threat landscape is constantly evolving, with attacks ranging from social engineering to destructive ransomware attacks to nation-state backed Advanced Persistent Threats (APT). A recent Statistics Canada survey of more than 12,000 companies revealed that the number of cybersecurity incidents and the costs associated to detect and prevent these incidents increased in 2021 from 2019.[7] Recent ransomware attacks include a 2020 attack on Colonial pipeline (a major fuel pipeline in United States that carries gasoline, diesel and jet fuel from refiners), [8] a 2021 attack on the Toronto Transit Commission (TTC),[9] a 2022 attack on Toronto's Hospital for Sick Children on December 18, 2022,[10] and a January 2023 cybersecurity incident at the Liquor Control Board of Ontario highlight the ongoing need to prevent security breaches before they

[6] *Supra* note 3.
[7] Statistics Canada, *Impact of cybercrime on Canadian businesses*, 2021, (October 18, 2022) online: < https://www150.statcan.gc.ca/n1/daily-quotidien/221018/dq221018b-eng.htm>.
[8] Colonial Pipeline, *Media Statement Update: Colonia Pipeline System Disruption* (May 17, 2021);
[9] Toronto Transit Commission, *TTC provides update on cyber security incident*, (November 8, 2021) online: <https://www.ttc.ca/news/2021/November/TTC-provides-update-on-cyber-security-incident#:~:text=Today%2C%20the%20TTC%20is%20providing,TTC%20promptly%20began%20an%20investigation.>.
[10] Sick Kids, *SickKids Lifts Code Grey with 80 percent of priority systems restored* (January 5, 2023) online:< https://www.sickkids.ca/en/news/archive/2023/sickkids-lifts-code-grey-with-80-per-cent-of-priority-systems-restored/#:~:text=Summary%3A,a%20ransomware%20attack%20on%20Dec.>.

happen in order to protect the privacy of Toronto Hydro's customers and employees and maintain the integrity of the grid.[11]

The OEB's Cybersecurity Framework acknowledges the criticality of these emerging threats to utility operations, and prescribes regulatory requirements to address the associated risks.[12] The Security function's efforts work towards ensuring the confidentiality, integrity, and availability of the utility's information assets, including the protection of customer information. This segment also deals with an increasing volume of threats to the energy sector including but not limited to sophisticated phishing, impersonation and social engineering campaigns, ransomware that includes data exfiltration functions, targeted industrial control systems attacks, and the malicious use of Artificial Intelligence ("AI") to automate malware creation and distribution. The evolving cybersecurity threat landscape drives the need to continuously improve cybersecurity posture and associated preventative and reactive controls.

The Enterprise Architecture function develops architecture practices and standards, and identifies and manages key enterprise IT risks, such as cybersecurity, disaster recoverability and IT restore & recover.

The IT Disaster Recovery ("DR") program enables Toronto Hydro to maintain the delivery of its technical services when operationally impacted by major events such as a data center failure. These could be the result of weather-related incidents, widespread power outages, large scale application/system failures, or cybersecurity events. An IT DR

[11] Liquor Control Board of Ontario, *LCBO Statement Regarding Cybersecurity Incident and Response*, (January 12, 2023) online: < https://www.lcbo.com/content/lcbo/en/corporate-pages/about/media-centre/news/2023-01-12.html>.
[12] *Supra* note 5.

program that is continuously maintained, validated and improved upon helps Toronto Hydro mitigate technical, operational, and financial risks to ensure business continuity.

The IT Restore & Recover ("R&R") program enables Toronto Hydro to safely practice the recovery of its critical applications from backup, validating the recovery plans for each application using both on-line and offline/offsite backups. This enables IT teams to rehearse data recovery in a segregated environment without impacts to production systems, confirming data recoverability in the event of a ransomware attack or a major system failure. The R&R program focuses on different applications each year in order to cover all critical applications. This program allows Toronto Hydro to mitigate technical, operation and financial risks by ensuring adequate tools and processes are in place and practiced ahead of the actual need.

The function fulfills several key responsibilities:

- Establishes and maintains corporate IT standards, policies, and enterprise architecture principles and standards based on best practices;
- Establishes and maintains IT disaster recovery program/framework and ensure readiness to respond to an event;
- Ensures Toronto Hydro's readiness to recover and restore data from back up environments;
- Evaluates new technologies through Proof of Concepts ("PoC") to identify opportunities to modernize existing IT processes and systems. This includes trialing an IT solution for a period to learn and understand its capabilities, benefits, and assess alignment with the organization's technical landscape and business needs. PoC also enables the Enterprise Architecture team to update the IT standards, policies, and frameworks, accordingly;

- Manages compliance and ensures programs adheres to the above policies, architecture principles and standards;
- Manages the enterprise information security posture and risk profile; and
- Drives operational cost efficiencies and business process streamlining.

5.2 Security and Enterprise Architecture Segment Costs

Table 4, below, provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Year (2025-2029) expenditures for the Security and Enterprise Architecture segment.

Table 4: Security and Enterprise Architecture Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Security & Enterprise Architecture	3.7	4.5	6.1	6.6	7.3	7.6	7.9	8.4	8.8	9.3

Without this level of funding for this segment, Toronto Hydro could be exposed to a number of risks, including:

- Increased risk of a successful cyber attack that could disrupt grid operations, impact system safety, compromise the confidentiality and availability of customer, employee, and corporate data, and ultimately, undermine the integrity of the entire distribution system;
- Cybersecurity asset and control obsolescence resulting in cybersecurity posture and lack of vendor support, may lead to frequent system outages and increased vulnerability of critical systems to cyber security threats;
- Shortages in technical subject matter experts and Managed Services resources leading to the inability to adequately maintain and support the cybersecurity ecosystem, further eroding the cybersecurity defenses, leaving critical systems vulnerable to attacks;

- Undue pressure on infrastructure reliability and capacity as requirements may not align with the long-term IT growth plan;
- Inability to evaluate new and emerging technologies (e.g. PoCs) to ensure alignment with industry best practices and support organization's modernization objectives, in response to future industry challenges such as electrification;
- Reduced or lack of technical capacity to lead IT and business teams in accordance with IT standards;
- Increased risk of greater service outages due to a lack of IT architecture and governance oversight;
- Inefficient design or configuration of ongoing and planned IT capital programs due to a lack of IT architecture and security oversight;
- Lack of corporate IT standards/policies and enterprise architecture principles increases tech sprawl which will result in increased operational costs due to higher licensing, maintenance and support costs;
- Inability to support the successful implementation of IT programs and projects in accordance with corporate IT standards and policies; and
- Lower customer experience due to inadequate or lack of integration in IT system as a result of using various technologies that are incompatible or obsolete or due to greater service disruptions as a result of weaker cybersecurity posture.

5.3 Security and Enterprise Architecture Segment Year-over-Year Variance Analysis

2020-2021 Variance Explanation

Between 2020 and 2021 costs in this segment increased by $0.8 million due to:

- An increase of $0.6 million in maintenance and subscription costs consisting of:
  - $0.1 million increase was due to inflationary pressures on existing contracts; and

- $0.5 million for net new contracts and full year subscription costs (e.g. detection and prevention of cybersecurity attacks);
- An increase of $0.2 million in consulting services to keep up with the evolving cybersecurity threat landscape.

2021-2022 Variance Explanation

Between 2021 and 2022, costs in this segment increased by $1.6 million due to:

- An Increase of $0.8 million due to consultant services to keep up with the evolving cybersecurity threat landscape. The Security Information and Event Management system was reviewed to determine if the service met its business needs without having to incur large up-front investment associated with implementing the system. In addition, the failover capabilities and disaster recovery preparedness for Toronto Hydro's data centre network infrastructure between its two main data centre locations was reviewed and updated. This work contributed to the zero-downtime goal of critical IT infrastructure services;
- An increase of $0.4 million for labour costs for filling of vacancies due to resignations; and
- An increase of $0.5 million in maintenance and subscription fees consisting of $0.3 million for net new contracts (e.g. detection and prevention of cybersecurity attacks) and $0.2 million due to inflationary pressures on existing contracts.

2022-2025 Variance Explanation

Between 2022 to 2025, costs in this segment are expected to increase by $1.5 million, due to:

- Compensation increases;

- Net new additions to the cybersecurity software and hardware capital program to respond to evolving cybersecurity threat landscape consisting of higher volumes and greater complexity of cybersecurity attacks;
- An increase in consulting costs for a cybersecurity audit to be completed in 2024 and other consulting such as POCs; and
- An increase in maintenance and subscription costs due to inflationary pressures on existing contract and net new contracts (e.g. detection and prevention of cybersecurity attacks).

These increases were partially offset by decreases in temporary staff costs due to reduced need for temporary staff to back fill for vacancies due to all full-time vacancies filled by the end of 2022 and decrease in temporary staff required for security services as more services are moving to the cloud.

2025-2029 Variance Explanation

Between 2025 to 2029, costs are expected to increase by $1.7 million, or an average of $0.4 million per year, to support the new additions to the cybersecurity software and hardware capital program to protect against increased volume and complexity of emerging cybersecurity threats, as described above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face legal compliance risks and drawbacks including:

- Failure to maintain compliance with all applicable laws;
- An inability to effectively administer controls for the protection of customer privacy;
- An inability to effectively administer legal and transactional controls for the protection of utility information data in the cybersecurity landscape;

- Increased exposure to cybersecurity risk which could compromise customers' and employees' personal information and operational data and jeopardize the safe and proper functioning of IT/OT assets;
- Inability to ensure IT systems can meet changing customers' expectations in response to future industry changes such as electrification and alignment with the Strategy.

6. IT OPERATIONS SEGMENT

6.1 Segment Description

The IT Operations segment is responsible for day-to-day operation and support of all IT systems at Toronto Hydro and also includes ITSM, IT Deskside and Helpdesk support. This includes maintaining the integrity and availability of all corporate data, ensuring adequate end user devices and backend infrastructure are available to support real-time data processing of applications and databases, proactive capacity and performance planning, routine systems maintenance, and continuous monitoring of all critical business systems including radio and telephony.

The IT Operations segment consists of three core functions: (I) Hardware; (ii) Software; and (iii) ITSM.

The Hardware function is responsible for the deployment and management of the following asset components and services:

- Data and voice networks, fibre optic and radio infrastructure, telephony and communication infrastructure;
- Advanced Metering Infrastructure and grid management networks;
- Servers, virtualization and operating system infrastructure;

- Data storage and backup environments; and
- Physical data centre infrastructure (cabling and racking).

The Software support function is responsible for the introduction and continuous operation of the following asset components and services:

- Customer-facing software assets;
- Integrations between IT systems and applications;
- Database and middleware software assets such as Messaging Systems, Integration Platforms, Application Servers, Web Servers, Oracle and Microsoft SQL Databases;
- End user devices, including desktops, laptops, phones, printers, as well as services such as the deployment of operating system and software applications; and
- End user application development and reporting software assets and services.

The ITSM function is responsible for maintaining the reliability, availability and security of all hardware, software and communication assets. To facilitate the continued operation of these and other systems, Toronto Hydro follows the Information Technology Infrastructure Library (ITIL) framework for effectively managing IT services throughout the entire service lifecycle. This includes a 24/7 IT Helpdesk response structure that is vital to ensuring timely resolution of incidents and problems to quickly respond to major system outages. The Toronto Hydro ITSM has a three-level support path to effectively manage and resolve issues and incidents. The path uses hierarchical structure to triage, i.e. assign issues to the relevant technical specialists, thus facilitating effective troubleshooting and resolution. This segment is responsible for incident, problem and change management functions to ensure business continuity by restoring critical operations in a timely and efficient manner during unplanned outages or a change (modification, addition or

removal) of an IT service or system. The problem management process investigates the root causes of an incident and develops a corrective action plan to prevent its recurrence.

The IT Operations segment includes maintenance and subscription contracts, which provide vendor support for technology, performance and security fixes (e.g. patches), and new features and functionality. The IT operations segment also installs patches to the utility's technology assets, when they are released by vendors, thereby mitigating cybersecurity and system performance risks. Prior to installing a patch, this segment is responsible for conducting extensive testing to ensure the patch does not impede existing functionality, and does not introduce reliability risk across different testing environments.

6.2 IT Operations Segment Costs

Table 5, below, provides the Historical (2020-2022), Bridge (2023-2024), and Test Year (2025) expenditures for the IT Operations Segment.

Table 5: IT Operations Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
IT Operations	36.9	38.4	39.9	43.0	44.8	46.0	47.5	49.1	50.8	52.2

Without this level of funding for this segment, Toronto Hydro could be exposed to a number of risks, including:

- Increase in frequency and duration of IT service outages and reduced availability of critical IT systems;
- Inability to adequately maintain and support critical systems, processes and functions such as security systems, metering, stations and SCADA

communications, radio, telephony and business and customer applications services;

- Inability to install patches for utility's technology assets, resulting in inadequate protection of critical business operations against expected increases in security threats as a result of industry shift towards electrification;
- Inefficient or delayed execution of ongoing and planned IT capital programs and risk of applications running out of vendor support, including initiatives related to safety, reliability, regulatory compliance and customer service;
- Increase in resolution time of incidents and problems to prevent outages to critical systems; and
- Inability to support end-users with day-to-day technical issues and remotely deploy applications and install patch updates to hundreds of devices.

6.3 IT Operations Segment Year-over-Year Variance Analysis

2020-2021 Variance Explanation

Between 2020 and 2021, costs in this segment increased by $1.5 million due to the following:

- An increase of $1.7 million in maintenance contracts and subscription fees consisting of $0.5 million due to inflationary pressures of existing contracts and $1.2 million for net new contracts,
- Increases of $0.9 million in consultant services such as vendor support during warranty periods of deployed software solutions and PoC;
- A decrease of $0.9 million for retirements at the end of 2020 which were not filled until 2021; and

- A decrease of $0.2 million in labour costs due to the implementation of productivity improvements through the automation of IT Service Management ("ITSM") processes.

2021-2022 Variance Explanation

Between 2021 and 2022, costs in this segment increased by $1.5 million due to the following:

- Increases of $1.0 million due to inflationary pressures on maintenance and subscription costs; a $0.6 million increase for existing contracts and the remaining $0.4 million for net new contracts;
- Increases of $0.4 million in payroll costs due to compensation increases and the transferred headcount from the Governance segment to the Service Management segment;
- An increase of $0.2 million in payroll costs due to compensation increases;
- An increase of $0.2 million due to inflationary pressures on telecom costs; and
- A decrease of $0.3 million in labour costs due to implementation of productivity improvements through the automation of IT processes.

2022-2025 Variance Explanation

Between 2022 and 2025, costs in this segment are expected to increase by $6.1 million, due to:

- Increases in maintenance and subscription costs for existing, some of which were subject to US Dollar exchange rate fluctuations and inflationary pressures and net new contracts. This increase was mitigated by implementing application consolidation and rationalization initiatives;

- Compensation increases and increases in labour costs to fill vacancies between 2022-2023 in order to support new systems (e.g. patching) and ensure availability of these systems;
- Increases in consultant services for post project go-live vendor support for the CIS Project;
- Increases in employee related expenses incurred to support a hybrid work environment such as computer peripherals; and
- Increases in telecom costs due to inflationary pressures.

2025-2029 Variance Explanation

Between 2025 and 2029, costs in this segment are expected to increase by $6.2 million, or an average of $1.6 million per year to support the continued growth of the capital program, including increases in maintenance and subscription costs for existing and net new contracts and increases in consulting costs, as described above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various legal compliance risks and drawbacks, including:

- Limited ability to monitor and control assets if critical systems (e.g., SCADA, NMS, Energy Centre) are not adequately maintained;
- Inability to remotely monitor and control assets that include DERs, switches, breakers, etc. due to system unavailability;
- Risk of increased outage durations if critical systems (e.g. SCADA, NMS, OFSC, tailboard, Radio Communication, Telephony, Metering, and Customer Care applications) are not adequately maintained;
- An increase in field crew idle time as the critical safety systems are not available for crews to carry out their duties such as responding to outages (e.g. SCADA,

NMS, OFSC, eTailboard, Radio Communication, Telephony, Metering, and Customer Care applications);

- Unavailability of the Customer-Self-Serve Web Portal, Toronto Hydro website, and Outage Map resulting in customers' inability to monitor their energy consumption usage, view or receive outage notifications and restoration timelines, leading to an increase in customer call volumes and lower satisfaction; and
- Delay or failure to provide the required support and maintenance for IT capital programs including initiatives related to safety, regulatory compliance, reliability and customer service.[13]

7. PROJECT EXECUTION SEGMENT

7.1 Segment Description

The Project Execution segment is responsible for the execution of Toronto Hydro's IT software programs both on-premises and in the cloud. This segment is also responsible for the implementation of new IT cloud solutions (e.g. projects, programs and applications).

Toronto Hydro's IT project execution practices are consistent with industry best practices for project management frameworks. Toronto Hydro governs each project using a hybrid project management framework that combines waterfall and agile methodologies. The implementation approach for each project is based on the project complexity, use cases, and timeline. For example, Toronto Hydro used Agile methodology to deliver Web-based projects that require more frequent releases, whereas Waterfall methodology is best suited for large, multi-year, Tier 1 system upgrade complex, high-risk projects. Toronto

[13] *Supra* note 4.

Hydro's hybrid project execution approach strives to modernize the organization's project management and execution processes and supports the growth in investment plans. The combination of these two different methodologies enables the Project Management Office to become adaptive, flexible, innovative, and efficient in delivering different types of projects. Toronto Hydro governs each project using the Modern Project Management methods, and produces a mature scorecard which demonstrates the overall health of the project.

In addition, the segment is responsible for continuous improvement of various project processes and procedure and ensures projects are implemented on-time, on-budget and meets project/program objectives. This segment monitors project performance through short-interval control by ensuring the Project Status Reports (PSRs) are completed on a monthly basis and associated project risks are identified and addressed through Management Control & Reporting System ("MCRS") process on an ongoing basis.

Greater investment in cloud solutions was required in the 2020-2022 period and is expected to grow in the 2024-2025 period and 2025-2029 period to keep up with industry trends. Where deemed appropriate and feasible as per the Strategy, cloud solutions will equip the utility with the tools needed to support the modernization of business processes. As the industry trend moves towards offering more cloud-based solutions, these costs are expected to grow. Costs to implement the cloud-based solutions include project initiation, planning, execution (e.g. configuration, development, testing, customization, etc.), monitoring & control and deployment. Existing accounting rules under International Financial Reporting Standards ("IFRS") require these costs to be expensed.

The successful execution of ongoing and planned IT software programs allows IT to support the organization's modernization strategic objective.

7.2 Project Execution Segment Costs

Table 6, below, provides the Historical (2020-2022), Bridge (2023-2024) and Forecast Years (2025-2029) expenditures for this segment.

Table 6: Project Execution Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Project Execution	4.7	4.9	5.0	5.6	6.7	7.4	8.0	8.8	9.7	11.1

7.3 Project Execution Segment Year-over-Year Variance Analysis

The IT industry is currently trending towards more cloud offerings, and with this shift to the cloud, the forecast anticipates cloud implementations and subscriptions will be required to replace or enhance the current on-premises solutions.

2020-2021 Variance Explanation

Between 2020 and 2021, costs in this segment increased by $0.2 million due to the following:

- An increase of $0.8 million in external costs (e.g. consultant services) for the implementation of a full year of cloud-based solution such as Non-conformance Management System, Crew Management Systems and Electronic Tailboard solutions; and
- A decrease of $0.6 million in labour costs due to the introduction of a modernized project management framework to streamline processes.

2021-2022 Variance Explanation

Between 2021 and 2022 costs in this segment increased by $0.1 million due to the following:

- Increases of $0.5 million in external costs, including consulting costs and additional headcount to implement cloud computing solutions with the implementation of new cloud projects such as Customer Connection Portal, and OFSC; and
- A decrease of $0.4 million in labour costs due to redeployment of internal staff to focus on capital work.

2022-2025 Variance Explanation

Between 2022 and 2025 costs in this segment increased by $2.4 million, due to:

- An increase in external costs consisting of consulting services and additional headcount to implement cloud-based solutions such as Customer Connection Portal and OFSC;
- Compensation increases; and
- Headcount increases between 2023-2024 to support CIS cloud-based solutions.

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $3.7 million, or an average of $0.9 million per year, to support the implementation of cloud-based solutions including increases in external costs, as discussed above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility's capital investments could be at risk of falling behind industry best practices which can result in financial risk to the organization, including:

- Limiting the utility's flexibility to adopt cloud solutions, where necessary, in alignment with industry best practices to continue to modernize and innovate;
- The inability to identify and execute IT projects that best support the utility's operations. Reductions in this area could place implementation of the planned IT capital programs at risk, including initiatives related to safety, regulatory compliance and customer service;
- The inability to execute IT projects to support the modernization of business processes in response to industry shift towards electrification; and
- A reduced or limited ability to implement cloud solutions, which may be better positioned to efficiently handle the growing technology requirements in storage and computing and often required by investments technologies such as smart grid and DER integrations.

8. IT GOVERNANCE SEGMENT

8.1 Segment Description

The IT Governance segment supports the IT investment planning process by ensuring appropriate documentation (e.g. scope of work, change requests, purchase requisitions) and justification are in place to support the IT programs. This includes developing program and project-level artifacts and establishing program goals. This segment is further responsible for providing budget control and oversight to track and report on IT program expenditures and their alignment with the overall budget. This enables Toronto Hydro to record IT expenditures correctly in accordance with OEB's and IFRS reporting requirements. The IT financial governance process includes conducting cost variance analysis and determining program forecasts, as per the Enterprise Technology Portfolio or in accordance with Toronto Hydro's Information Technology Asset Management

Strategy and Investment Planning procedures.[14] Administratively, it oversees the administration of external IT vendors maintenance and subscription contracts and third party contractors.

This segment supports the enterprise-wide tracking and reporting requirements needed to comply with Toronto Hydro's Records Management Policy and Record Management Framework, as well as applicable regulatory requirements, such as the OEB's Electricity Reporting and Recordkeeping Requirements.[15]

8.2 IT Governance Segment Costs

Table 7, below, provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Years (2025-2029) expenditures for the IT Governance segment.

Table 7: IT Governance Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
IT Governance	2.7	2.8	2.5	2.3	2.3	2.3	2.4	2.4	2.4	2.5

Without this level of funding for this segment, Toronto Hydro could be exposed to a number of risks, including:

- Financial risk due to lack of oversight on capital planning, operational budgets, contract and vendor management and compliance tracking of IT projects/programs;
- Inability to continuously monitor changes in industry best practices and customer needs to prioritize new IT capital investments accordingly, leading to delayed

[14] *Supra* note 5.
[15] Ontario Energy Board, Electricity Reporting & Record Keeping Requirements (March 8, 2023).

execution of ongoing and planned IT capital programs including initiatives related to safety, reliability, regulatory compliance, or customer service;

- Failure to meet regulatory and legal obligations with respect to records management and data governance; and
- Failure to comply with privacy legislation and regulations governing the retention of personal information.

8.3 IT Governance Segment Year-over-Year Variance Analysis

2020–2021 Variance Explanation

Between 2020 and 2021 the costs in this segment increased by $0.1 million due to compensation increases.

2021-2022 Variance Explanation

Between 2021 and 2022 the costs in this segment decreased by $0.3 million due to labour costs decreased as the function of Service Management is redeployed to Operations Segment.

2022-2025 Variance Explanation

Between 2022 and 2025 the costs in this segment decreased by $0.2 million, due to:

- Mitigating compensation increases by assigning staff to capital planning work and streamlining governance activities to redeploy staff to other functions; and
- Decrease in consulting costs for a one-time a Disaster Recovery assessment incurred in 2022.

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $0.2 million, or an average of $0.1 million per year, to maintain the resourcing capacity and capabilities required to support the anticipated increases in volume and complexity of work for a growing capital program. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various legal compliance risks and drawbacks, including:

- Increased financial risk due to inadequate IT governance procedures and oversight of capital planning, operational budgets, and contract and vendor management and compliance tracking of IT projects/programs; and
- Reduced ability to meet the utility's regulatory and legal obligations, including0020records management and data governance.

PUBLIC, LEGAL AND REGULATORY AFFAIRS

1. OVERVIEW

Table 1: Public, Legal and Regulatory Affairs Program Summary

Public, Legal & Regulatory Program									
Outcomes: Customer Focus, Public Policy Responsiveness, and Financial Performance									
Segments: • Legal Services • Regulatory Affairs • Communications and Public Affairs									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
18.5	19.0	19.2	24.7	28.0	29.9	30.9	32.0	33.2	34.2

As the electricity distributor providing an essential service to the residents and businesses of City of Toronto, the utility is responsible for cultivating and maintaining open channels of communications with its diverse stakeholders, including customers, media, the general public, the Ontario Energy Board ("OEB"), the Independent Electricity System Operator ("IESO"), industry associations, municipal councillors and provincial and federal government officials. Through effective and timely communication and engagement, Toronto Hydro aims to build trust and maintain its strong brand and reputation. These duties are fulfilled by the highly-trained professional teams operating in this Program.

The Public, Legal and Regulatory Affairs program ("Program") provides specialized legal, regulatory and public relations professional services to the utility and its affiliates. The Program addresses Toronto Hydro's extensive legal, regulatory and communication needs; being one of the largest electricity distributors in the province of Ontario and serving Canada's largest city. The objective of this Program is to sustain and improve

utility performance and compliance with external requirements through expert management of the ongoing and evolving external demands and expectations of the legal, regulatory, and public policy environment within which Toronto Hydro operates each day.

Under the umbrella of this Program, Toronto Hydro manages its corporate governance, securities and disclosure, commercial law matters, construction, real property, litigation, claims, privacy, regulatory reporting and compliance, energy policy and stakeholder relations, rate application, regulatory law and compliance matters, load forecasting, wholesale settlement, and rate-making processes. It also manages communication channels with the public, outage notifications, strategic communications, ongoing customer engagement, digital communications, media relations, issues management, municipal stakeholder engagement, customer escalations and community relations.

Reflecting both the breadth and depth of the issues and matters that must be addressed in the electricity sector, resources responsible for executing this Program have academic backgrounds, experience and professional designations and skills in areas as such as law, public policy, engineering, economics, communications, business management and accounting. The resources conduct a large workload year-round, consisting of a variety of high-volume processes and activities, such as preparing customer connection agreements (including offers to connect and customer contribution agreements), negotiating complex relocation agreements to facilitate large transit projects, drafting and reviewing legal agreements with service providers and suppliers, processing legal claims, performing IESO wholesale market settlements, assisting with escalated customer inquires, filing annual and major rate applications, and complying with regulatory obligations. Personnel in this program also provide strategic advisory services, such as working with utility operations to support business and investment planning, manage

organizational risks and enable decision-making in accordance with legal and regulatory requirements and expectations.

The Program costs include the fees remitted to the OEB, the amortized costs of major rate applications, as well as the cost of shared services to affiliates and supporting non-rate regulated business activities, which are recovered through allocations and recoveries detailed in Exhibit 4, Tab 2, Schedule 21 and Exhibit 4, Tab 5, Schedule 2.

2. OUTCOMES AND MEASURES

Table 2: Public, Legal and Regulatory Affairs Program Outcomes

Public Policy Responsiveness	• Analyze and respond to OEB policy proceedings on behalf of Toronto Hydro, either individually or through an industry organization; • Facilitate Toronto Hydro's participation in OEB policy working groups; • Respond in a timely manner to Electricity Reporting & Recordkeeping Requirements ("RRR") and other required regulatory submissions in accordance with OEB requirements; • Advise on legal and regulatory compliance requirements, including service quality, consumer protection, and customer privacy requirements; and • Respond to freedom of information requests in accordance with the *Municipal Freedom of Information and Protection of Privacy Act*.[1]
Operational Effectiveness - Reliability	• Drafting and reviewing various documents (e.g. procurement documents, purchase agreements, master contractual arrangements) that support the execution of Toronto Hydro's capital programs; • Preparing various construction contracts, relocation agreements, and other bespoke contracts that protects the property, assets, design and construction of Toronto Hydro infrastructure. • Prepare and defend distribution rate applications to secure funding for Toronto Hydro's capital and operations work programs.

[1] R.S.O. 1990, c. M.56, ["*Municipal Freedom of Information and Protection of Privacy Act*"].

Operational Effectiveness - Safety	• Contributes to Toronto Hydro's public and employee safety objectives (as measured via metrics like Total Recordable Injury Frequency) by communicating timely information to customers and the public concerning capital work and outages (planned and unplanned).
Financial Performance	• Prepare distribution rate applications in accordance with OEB requirements; • Support business and investment planning processes in conjunction with major rate applications; • Minimize legal liability, recouping damages, and providing strong defenses against claims; and, • Ensure consistent and complete IESO wholesale market settlements
Customer Focus	• Support the execution of customer connections offer to connect processes; • Address easement inquiries and other real property matters; • Resolve claims and legal disputes; • Manage customer and stakeholder-facing issues governed by various legislation, regulations and codes.

3. PROGRAM DESCRIPTION

The Public, Legal and Regulatory Affairs program consists of three segments:

1) Legal Services,
2) Regulatory Affairs, and
3) Communications and Public Affairs.

Legal Services provides timely, accessible, and specialized legal advice and support to all divisions within Toronto Hydro. In alignment with the utility's corporate and operational strategy, Legal Services ensures Toronto Hydro is able to meet legal requirements and operate in an efficient and compliant manner. Legal Services provides dispute resolution services and general guidance and compliance advice with respect to legal interests, rights, and responsibilities of the utility, including, but not limited to, any requests or

compliance metrics relating to customer privacy. Legal Services facilitates the drafting, negotiation, and execution of a variety of contractual instruments (including commercial documents, construction documents, procurement documents, and customer offers to connect) as well as real property transactions with necessary protections and legal due diligence, and structures corporate governance processes to meet legal standards and best practices.

Regulatory Affairs enables the utility to meet its obligations to the Government of Ontario, OEB, IESO, and other regulatory and public policy stakeholders. The main services provided by the segment include the development and execution of rate applications and other matters before the OEB, regulatory legal and advisory services, energy policy stakeholder relations, advocacy and implementation, regulatory compliance monitoring, regulatory reporting, load forecasting, wholesale market settlement, and rate design. Quarterly fees remitted to the OEB are included in this segment. Costs pertaining to this rate rebasing application are also included, but presented separately, with the full amount of these costs proposed to be recovered on an amortized basis from 2025-2029.

Communications and Public Affairs maintains open channels of communications between Toronto Hydro and its various stakeholders. The main services provided by this segment include managing a number of different channels including owned media channels (such as Toronto Hydro's website and social media) and conducting customer engagement surveys. This segment also manages communication with the media and the public on a variety of matters including planned and unplanned outages, engagement with municipal stakeholders, customer escalations and community engagement and relationship management concerning planned capital work.

4. PROGRAM COSTS

In 2025 Toronto Hydro requires $29.9 million in rate funding for Public, Legal and Regulatory Affairs program, which represents an increase of $11.4 million over the last rebasing in 2020. When normalized for shared services recoveries outlined in Exhibit 4, Tab 5, Schedule 1, the expected increase in this program is $10.4 million.

Over the 2025-2029 rate period, the utility expects the cost of this program to increase by annual growth rate of 3.4%. This increase is necessary in order to maintain the resourcing capacity to address the extensive legal, regulatory and public communication needs enabled by this program.

Table 3 provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for each of the Program's segments.

Table 3: Legal Services and Regulatory Affairs Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Legal Services	6.1	5.7	5.8	7.9	9.2	9.8	10.3	10.7	11.2	11.6
Regulatory Affairs	3.8	4.4	4.1	5.6	6.4	7.0	7.1	7.5	7.9	8.1
OEB Fees	3.4	3.2	3.6	4.0	4.4	4.5	4.6	4.6	4.7	4.8
Regulatory Applications (Custom IR)	1.6	1.6	1.6	1.6	1.6	2.0	2.0	2.0	2.0	2.0
Communications & Public Affairs	3.6	4.1	4.1	5.5	6.4	6.6	6.9	7.1	7.3	7.6
Total	**18.5**	**19.0**	**19.2**	**24.7**	**28.0**	**29.9**	**30.9**	**32.0**	**33.2**	**34.2**

4.1 Cost Drivers

There are a number of distinct and interrelated cost drivers in this Program.

4.1.1 Volume and Complexity of the Capital Program

Toronto continues to be one of the fastest growing cities in North America. As outlined in Exhibit 2B, Section E5.1 (Customer and Generation Connections), serving this growing city, Toronto Hydro receives a high volume of requests for connections and service upgrades for residential and commercial development each year. From 2017 to 2022, the City's development pipeline included 2,413 projects in various stages of approval and completion,[2] setting a record of 717,327 residential units and 14,484,961 square metres of non-residential gross floor area. This was the highest development volumes for any five-year period the City has reported on to date. This rate of development drives a high volume of work requiring legal and regulatory support, including offers to connect, arrangements with developers, suite metering agreements, easements, operating agreements, and third-party damage incidents.

In addition, the complexity of the utility's work program, particularly in areas of System Access, System Service and Information Technology (IT) investments, is increasing as Toronto Hydro makes investments to lay the foundation for the energy transition by expanding and modernizing the grid to enable customer choice to connect new technologies such as solar panels, heat pumps and electric vehicles.[3] To support Toronto Hydro and its customers in this electrification journey, the Program must keep up with public, legal and regulatory advisory work that is increasing in both volume and complexity. These needs are most cost-effectively addressed by internal resources with the necessary skills and experience to provide the required services. Toronto Hydro must have sufficient funding in this Program to attract and retain such talent in a competitive

[2] Including projects that are pending approval, approved, awaiting or holding building permits, or under construction - The 2413 pipeline projects breakdown is 622 built, 879 active and 912 under review. Toronto City Planning, Profile TO *Development Pipeline 2022 Q2*, (February 2023), online: <https://www.toronto.ca/wp-content/uploads/2023/02/92b5-CityPlanning-Development-Pipeline-2022-Q2.pdf>.
[3] Exhibit 2B Section E5.1

labour market. That is a tall order particularly for legal and regulatory professionals with transferrable skills who can often obtain higher paying jobs at other firms and organizations. For example, over the 2020 to end of 2022, the Legal Services segment of this Program experience a turnover rate of 156%.

4.1.2 Supporting Major Infrastructure Projects

As the city continues to grow, so does its need for expanded services and infrastructure such as transit, public works, roads and highways. This need requires additional work to be done by Toronto Hydro to rebuild and relocate infrastructure to support the expansion and modernization of other services such as City water work, major transit expansion projects by Metrolinx or the Toronto Transit Commission ("TTC"), developments, and third-party communication upgrades.[4]

In addition, a number of large transit projects are currently planned or under construction, including the Metrolinx Eglinton Crosstown, Metrolinx Finch West LRT, Ontario Line Subway, Scarborough Subway Extension, and Yonge North Subway extension. Third party-initiated projects require large scale relocation of Toronto Hydro's existing distribution assets and the energization of new assets. Timely and effective planning and execution of these multi-year projects necessitates negotiation of complex relocation agreements, the preparation of offers to connect and customer contribution agreements, and thorough regulatory analysis to ensure alignment with the Distribution System Code and applicable cost recovery rules. Expanded development also entails a greater risk of third-party damage incidents, requiring appropriate construction and litigation support. The need to maximize efficiency of transit development, as envisioned by the *Building Transit Faster Act, 2020* ("BTFA") which requires utilities to act swiftly to

[4] Exhibit 2B, Section E5.2.

remove and relocate distribution infrastructure which in turn depends on having expert legal advisors and consultants to support the negotiation of relocation and real property related agreements.[5]

4.1.3 Evolving Legal, Regulatory and Policy Requirements

There is a major transformation taking place in the energy sector as municipal, provincial and federal governments take steps to decarbonize key sectors of the economy. Various government and OEB policy documents make it clear that local distribution companies like Toronto Hydro play a crucial role in enabling this transformation. For example:

- The Ministry of Energy's *Powering Ontario's Growth* report recognizes that Distributed Energy Resources ("DERs") are transforming the way residents and businesses meet their energy needs and that much of this innovation is happening at the distribution level.[6] In addition to recent legislative changes, the government is considering additional changes to encourage innovation;
- The Minister's 2022 *Letter of Direction* to the OEB notes the critical role of the distribution sector as the pace of electrification increases and extreme weather impacts communities – and the pressure on local distribution companies ("LDCs") to continue providing high levels of reliability and resiliency to their customers while also being responsive to changing customer expectations and new government mandates;[7] and,
- The OEB's 2023-2026 Business Plan emphasizes the scale and magnitude of the energy sector transformation, the necessary reforms to energy regulation to

[5] SO 2020, c 12. ["*Building Transit Faster Act"].*
[6] Ministry of Energy, *Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future* (July 10, 2023), online: <https://www.ontario.ca/page/powering-ontarios-growth>.
[7] Ministry of Energy*, Letter of Direction from the Minister of Energy to the Chair* (October 21, 2022), online: <https://www.oeb.ca/about-oeb/corporate-governance-and-reports/letters-direction-formerly-mandate-letters>.

enable electrification as well as the necessary collaboration from industry stakeholders.[8]

Changes in the energy sector driven by public policy, technological advancement and customer-driven evolutions require both expanded levels and novel types of support services from the Public, Legal and Regulatory Affairs program. Toronto Hydro must adapt its legal and regulatory posture in an agile manner to meet the expectations of customer and stakeholders and give effect to policy objectives while keeping the risk to the utility, its ratepayers, and the public to a minimum. This places higher demands on the full range of functions executed within this Program, including energy policy advocacy and implementation, commercial law advice and transaction support, legal and regulatory advice, reporting and compliance. For example, in 2018 Toronto Hydro made 17 policy submissions to the OEB, MOE, IESO and NRCan, rising to 29 submissions in 2022. In addition, Toronto Hydro participated in 85 external engagements in 2022.[9] Toronto Hydro also implemented 15 new or modified regulatory requirements. This volume of work is expected to continue and further increase as the pace of the energy transition intensifies.

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

Toronto Hydro's past and ongoing efforts to minimize the cost of this Program and offset, in part, the external factors driving increases in this program yield significant benefits for customers. Cost management efforts in this Program focus on building a strong model of internal resources with the necessary expertise, reducing reliance on external resources (which are generally more expensive than internal resources on a per hour basis), or

[8] Ontario Energy Board, *OEB Business Plan 2023- 2026*
[9] These include working groups, committee meetings, webinar participation, direct meetings – and are inclusive of Coalition of Large Distributors and Ontario Energy Association submissions.

finding alternative, lower-cost means of accomplishing the work such as alternative-fee arrangements and secondments from third party-service providers. Specific cost control measures employed include:

- Reducing and freezing external law firm hourly rates through a request for proposal ("RFP") process. The RFP also resulted in additional benefits at no incremental cost, such as access to legal research database and resources, temporary staff lawyer backfilling and articling student secondments, which further reduce the need to rely on external legal services;
- Negotiating alternative fee arrangement to cap costs on certain types of files;
- Negotiating additional contractual indemnities and insurance to reduce legal costs and payable claims in order to protect the utility and its ratepayers;
- Working within industry consortiums and associations to collaborate on common interest files, allowing Toronto Hydro to dedicate fewer resources to those files while maintaining high quality engagements in energy policy development; and
- Proactively working with stakeholders on energy policy design and implementation, reporting and compliance activities to build awareness of more efficient and effective solutions and mitigate risks and future costs, including those associated with potential non-compliance.

4.2.2 Productivity

Productivity enhancements enabled by this program include:

- Developing and delivering internal training and education sessions that improve adherence to legal and regulatory requirements, thus reducing the costs of substandard performance and non-compliance;

- Developing legal and regulatory knowledge management databases, including document precedents, samples, clauses, research, and training materials, to prevent duplication of effort and improve work efficiency;
- Attending continuing professional development sessions offered by external law firms, educational institutions, consultant firms, and legal organizations, to expand the scope of internal legal and regulatory expertise relating to issues that can be addressed without engaging external resources;
- Development of teams with specialized legal expertise. The recent introduction of new leadership positions in the Legal Services Segment has allowed for more focused training of junior lawyers allowing for more efficient transfer of knowledge;
- Standardizing processes to minimize the personnel time required to process third party requests such as claims and freedom of information requests;
- In-housing legal work for customer connections, claims and major rate applications and making process improvements to allow the utility to meet necessary timelines and reduce overall external legal costs; and
- Subscribing to technology solutions for regulatory research services enhancing internal regulatory acumen and expertise, and avoiding costs associated with staff gathering and analyzing this information through manual efforts.

5. LEGAL SERVICES SEGMENT

5.1 Segment Description

The Legal Services segment covers a wide-range of activities including: day-to-day legal advice to internal clients; the review, negotiation, and drafting of commercial agreements; and completion of corporate, financial, and commercial transactions. This segment also includes the corporate governance functions which supports corporate

filings and external reporting and disclosure activities, and the corporate secretariat function, which supports governance matters, compliance with corporate statutes and related rules and best practice guidelines. A key objective of these services is to ensure the utility functions within the existing legislative and regulatory landscape and to work with the other teams within the organization to ensure new policy and legal requirements are properly implemented.

Legal advice on commercial matters includes execution of a variety of commercial instruments, including the review and evaluation of procurement documents for the purchase of goods and services by external vendors. Legal Services assists with review, negotiation, and drafting of commercial contracts, including purchase agreements, agreements for professional services, master contractual arrangements for long-term vendors, and other bespoke agreements as may be required to give effect to the utility's intentions in the applicable commercial transaction. Legal Services further supports the administration of each commercial contract through any disputes with the applicable vendors, as well as variance of those contracts to ensure the utility's interests are protected, that the utility gleans the benefit intended from the contract, and that such benefits are ultimately leveraged for the benefit of the utility's ratepayers.

Legal advice on construction matters includes reviewing, negotiating and drafting various forms of construction contracts, relocation agreements, and other bespoke contracts that facilitate third-party initiated projects (such as large-scale transit projects) while protecting the property, assets, and design and construction of Toronto Hydro infrastructure. The legal staff supporting construction ensure that Toronto Hydro's capital projects, operations, and collaboration projects with third party entities run smoothly, at an acceptable cost and without delay. In addition, the construction legal staff also ensure

that disputes regarding scheduling, defects, and/or other contractual terms are appropriately and timely resolved to protect Toronto Hydro's interests in construction projects. This work ensures that planned construction projects, or such other projects where Toronto Hydro has an interest at stake, are completed in an efficient and timely manner, and without protracted disputes impacting the projects and parties involved.

Legal advice on real estate matters includes reviewing, negotiating and drafting legal documents relating to real property, such as customer connection agreements, easements, as well as real property dispositions and acquisitions and leasing and licensing arrangements. The legal staff supporting the real property function work closely with the construction, asset management, stations and facilities operational units in their activities to help ensure compliance with the requirements of the utility and its counterparties related to property access, occupancy and equipment maintenance and repair. New access and occupancy rights are obtained where necessary, in particular for new infrastructure builds or connections. This allows capital projects and relocation projects to move forward efficiently, and enables Toronto Hydro to avoid penalties and damages relating to non-compliance with legislative restrictions or contractual obligations. For instance, the BTFA grants Metrolinx the authority to prescribe specific timelines for the completion of utility relocation work in relation to priority transit projects. Where a utility is unable to comply with a prescribed timeline, Metrolinx is entitled to seek compensation for losses or expense incurred because of the utility's non-compliance. The utility's risk and liability exposure under the BTFA is unlimited.

As growth in the city drives increased volumes of capital work, there is a corresponding increase in the volume of work on commercial, construction and real property matters.

Figure 1 below demonstrates that over the 2018-2022 period, Toronto Hydro has experienced a steady increase in the number of contracts negotiated with suppliers.

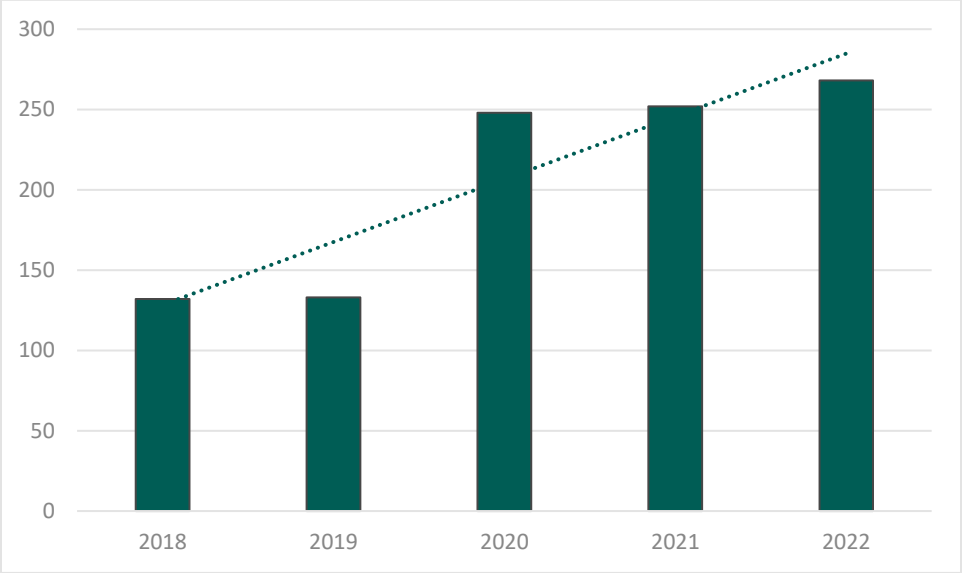

Figure 1: Contract Negotiated (initiated by Supply Chain)

Similarly, Figure 2 shows that over the past five years the number of Offers to Connect requiring expansion has increased driving both volume and complexity in this aspect of the Legal Services segments.[10]

[10] *Supra* note 3

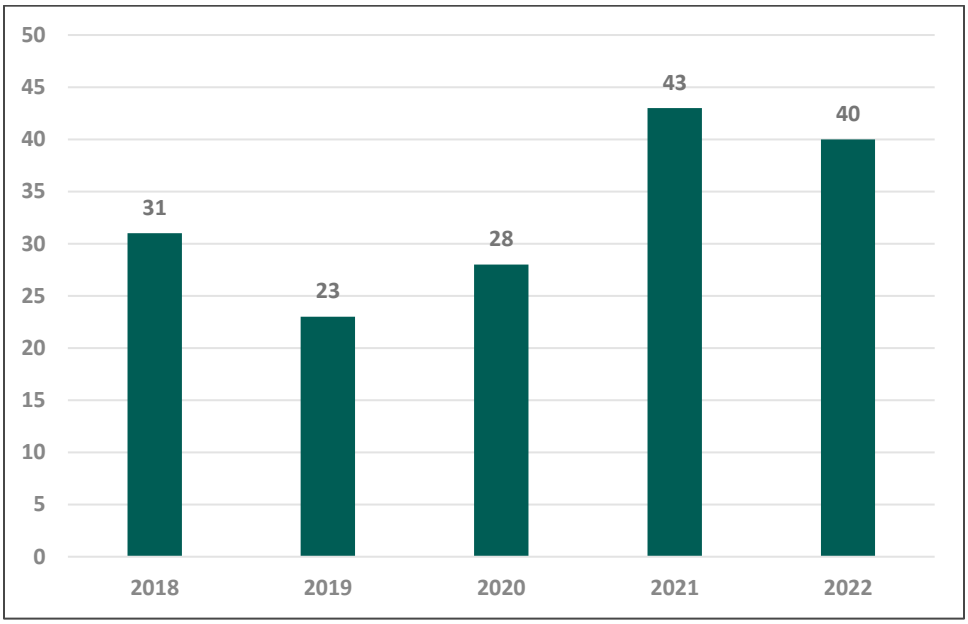

Figure 2: Offers to Connect Requiring Expansion

Toronto Hydro expects that the volume of commercial, construction and real property work will continue to grow as Toronto Hydro's capital program increases by approximately 42% over the 2025-2029 period.

In addition, Toronto Hydro's information technology groups are continuing to modernise functions across the distribution entity as a whole, including the purchase and implementation of a variety of cloud computing software and services to automate or streamline existing functions. The complexity and volume of such commercial deals, often comprised of multiple contracts for one purchase, will require an increase in commercial efforts.

Claims professionals provide pre-litigation defense and response to claims made against Toronto Hydro through the investigation of incidents, engagement with customers and insurers, and supervision of external adjustment service providers. This part of the

segment's function manages and settles matters prior to them proceeding to litigation. In addition to resolving claims brought against the utility, claims professionals also support the recovery of invoiced claims when the utility's plant is damaged (e.g. poles hit by cars). By pursuing demands and legal actions, Legal Services recovers damages suffered by Toronto Hydro which otherwise would be unrecovered losses. Responding to claims and inquiries by customers, while still advocating the legal rights of the utility, is essential to positive customer service.

Litigation staff in Legal Services both respond to legal proceedings brought against Toronto Hydro and advance legal proceedings to assert the utility's legal rights. This involves the preparation and filing of statements of claim, statements of defence and related documentation. It also involves undertaking or working with external counsel on the defence and prosecution of personal injury and property damage matters and commercial disputes as they proceed to formal litigation. For some matters covered by the organization's insurance policies, Legal Services oversees external counsel approved by Toronto Hydro's insurers.

Legal Services also manages issues relating to privacy compliance and protection of personal information. This includes legal support in response to access to information requests, customer privacy complaints, or internal privacy inquiries. Toronto Hydro takes a pro-active approach to compliance with privacy best practices and emphasizes providing optimal, proactive customer service. For example, the Legal Service team routinely provides training workshops and proactive resources to its counterparts in operations to ensure that privacy expectations are well understood and that privacy risks are appropriately identified and managed.

5.2 Legal Services Segment Costs

Table 4 provides the Actual (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for the Legal Services segment.

Table 4: Legal Services Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Legal Services	6.1	5.7	5.8	7.9	9.2	9.8	10.3	10.7	11.2	11.6

Legal Services Segment Year-over-Year Variance Analysis

2020-2021 Variance Explanation

Between 2020 and 2021 costs in this segment decreased by $0.4 million. This is attributed to lower than expected claim payouts.

2021-2022 Variance Explanation

Between 2021 and 2022 costs in this segment increased by $0.1 million attributed to normal course compensation increases

2022-2025 Variance Explanation

Between 2022 and 2025, costs in this segment are expected to increase by $4 million, or an average of $1.3 million per year due to:

- inflationary cost pressures, including compensation increases consistent with the evidence outlined in Exhibit 4, Tab 4, Schedule 4; and
- incremental resourcing requirements to address: (i) increased volumes of customer connections activity to support growth and electrification in the City of Toronto, (ii) higher procurement activity to support the execution of the 2025-2029 Distribution System Plan, including a ramp up in IT Software

investments (including cloud computing), and (iii) enhanced scope and complexity in planning and coordination with third parties due to Priority Transit, Building Broadband and City Development.

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $1.8 million, or an average of $0.5 million per year to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work discussed above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various legal compliance risks and drawbacks, including:

- Failure to maintain compliance with all applicable laws;
- Vendor non-compliance with Toronto Hydro policies and procedures, undermining financial and operational controls;
- An inability to effectively administer controls for the protection of customer privacy;
- An inability to effectively administer legal and transactional controls for the protection of utility information data in the cybersecurity landscape;
- Ineffective or unfavourable negotiation of contract terms, resulting in substandard performance by contracted parties or foregone recourse to appropriate remedies, reducing the value to ratepayers;
- An inability to effectively recover amounts owing to the company from damages caused by third parties, or defend against third party claims or litigation;
- Dissatisfied customers and other stakeholders, due to delays in completing planned and externally-driven capital work (e.g. not achieving customer connection timelines);

- Reduced risk-management which would lead to greater exposure to litigation claims;
- Delays to externally-initiated relocation projects resulting in delays to development and transit projects;
- Failure to obtain or protect adequate real property access rights for infrastructure, leading to additional costs and project delays for planned and externally-driven capital work; and
- An erosion in the utility's corporate governance performance and adherence to securities law and principles, reducing the utility's access to capital markets and raising the cost of capital.

6. REGULATORY AFFAIRS SEGMENT

6.1 Segment Description

Regulatory Affairs works with external stakeholders and internal subject matter experts to support the advancement of public policy objectives and priorities outlined by the Government, the OEB, and IESO in key documents such as the Minister's *Letter of Direction* to OEB,[11] the OEB's Business Plan,[12] the IESO's *Pathways to Decarbonization* report,[13] and the Ministry of Energy's *Powering Ontario's Growth* report.[14] All of these documents underscore the central role that energy policy plays in supporting economic growth, decarbonization and the ongoing transformation of Ontario's electricity system.

As Toronto Hydro prepares for electrification and the energy transition, there will be increasing demands on the Regulatory Affairs team to ensure it can continue providing

[11] *Supra* note 7.
[12] *Supra* note 8.
[13] Independent Electricity System Operator, *Pathways to Decarbonization Report* (December 15, 2022) online:<https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization>.
[14] *Supra* note 6.

thoughtful engagement with external and internal stakeholders. Externally, the objective is to fully inform policy-makers with respect to the effects of prospective legislation, regulations, codes, and other rules and guidelines. Thoughtful engagement also includes providing the distribution company perspective to big policy questions brought on by the energy transition. Toronto Hydro provides written submissions and formally participates in working groups at the provincial level. Internally, the objective is to ready the utility for potential energy policy changes and work with the affected parts of the utility to ensure new requirements are well-understood and properly implemented. Continually evolving regulatory requirements (e.g. Ultra-Low Overnight and Dynamic Class B Pilot price plans, Green Button initiative, updated OEB codes) require significant effort across the utility. Regulatory Affairs professionals coordinate these efforts, providing guidance and advice to facilitate timely, efficient and sound implementation.

Regulatory Affairs and Government Relations staff work to build relationships with stakeholders, like Metrolinx, to ensure that major projects (including priority transit projects) can proceed without obstructions and that Toronto Hydro's relationships and reputational interests are protected. As part of a mutually agreed upon issues management and project update process, regular meetings are held with priority transit partners to have a forum for open communication and issue resolution.

The Regulatory Affairs segments addresses the utility's financial requirements through multi-year and annual rate-setting processes, as well as monthly wholesale settlement, retail settlement and related transactions and reporting requirements to the government, IESO, and OEB. The nature of these activities and associated governing rules continue to evolve as a result of significant changes in government policy (e.g. feed-in-tariffs, net metering, bill rebate/reduction programs). As these activities affect the accuracy of not

only Toronto Hydro's financials, but also the financials of the IESO and customers, Toronto Hydro must be able to continue to attract and retain skilled and experienced staff who can perform these highly-specialized rate-making and settlement tasks.

Regulatory Affairs prepares Toronto Hydro's applications to the OEB for rates and other regulatory approvals. The most significant of these are rebasing applications, which have most recently been large, complex custom applications. Over the span of a 5-year rate cycle, regulatory professionals in this segment help the utility prepare and prosecute thousand of pages of evidence and canvass hundreds of issues and claims raised by parties who intervene in major rate applications. The cost of preparing and prosecuting distribution rate rebasing applications is driven by the volume and complexity of the application evidence, the utility's business plans, evolving business circumstances, and responsiveness to regulatory and policy requirements and expectations.

The team responsible for major rate applications also plays a central role in the implementation of the OEB Decisions and Rate Orders. This includes responding to directives and undertakings, such as the Depreciation Study filed at Exhibit 2A, Tab 2, Schedule 1, Appendix D and aligning utility planning with the parameters and guidance of the OEB Decision. This end-to-end regulatory oversight approach for five-year custom incentive rate periods is necessary in order to ensure that the utility has adequate time to incorporate lessons from the OEB's prior rebasing decision, adapt to emerging evolutions in the regulatory policy framework and evolving business circumstances, and obtain and incorporate customer feedback in business planning.

In addition to the preparation, defence and implementation of rate applications, Regulatory Affairs performs other rates-related functions, including: developing annual

forecasts of the utility's load and customers, processing annual distribution rate changes, semi-annual commodity rate changes and other regulated rate updates (e.g. Rural or Remote Electricity Rate Protection (RRRP), Wholesale Market Service Charge (WMSC), and Retail Transmission Service Rates (RTSRs)), and updating and testing in Toronto Hydro's billing system to ensure that the correct tariff rates are charged. Regulatory professionals in this segment also gather and report information to the OEB through annual RRR and other filings (e.g. winter disconnections, major outage events, cyber security).

This segment also monitors other utility applications, conducts jurisdictional research, prepares internal educational materials to advance regulatory acumen throughout the organization, and advises internal stakeholders on a wide-range of regulatory law and compliance matters including the implementation of new or modified regulatory requirements such as Distribution System Code amendments. All of these proactive activities enable Toronto Hydro to operate in accordance with its regulatory obligations, bring forward thoughtful submissions and proposals to the OEB and other energy sector stakeholders, and contribute to the advancement of public policy objectives.

6.1.1 Distribution Rate Rebasing Applications

As discussed above, Regulatory Affairs is responsible for preparing and prosecuting Toronto Hydro's distribution rate applications, which include large and complex issues that must be put forward in a very thorough way:

> *Toronto Hydro is larger and has more complex issues than most if not all distributors in Ontario, and the Application involves billions of dollars of*

> *spending. The RRFE requires distributors to prepare and support their applications, particularly Custom IRs, in a very thorough way.*[15]

In preparing this rebasing application, Toronto Hydro conducted extensive research and background work to develop key elements of the performance-based rate framework outlined in Exhibit 1B, Tab 3, Schedule 3. Carrying out this work Toronto Hydro was mindful that this being among the first custom rate application to address imperatives of the energy transition, the utility has an added responsibility to bring forward a thoughtful and thorough proposal. Since 2021, the regulatory professionals in this segment worked diligently to ensure that the record in this application is clear, cogent and responsive to customers needs and stakeholder expectations as the utility takes active steps towards preparing the grid and its operations for an unprecedented energy transition. Once the application is filed, these staff will assist with the intensive requirements of prosecuting the application and thereafter with the implementation of the Decision and Rate Order and the execution of the 2025-2029 plan.

The costs of the major rate applications are included in this segment on an amortized basis consistent with the Chapter 2 Filing Requirements and past OEB decisions. As with the 2020-2024 Custom IR application, the costs of the 2025-2029 Custom IR filing are expected to be approximately 0.2 percent of the total applied for revenue requirement found at Exhibit 6, Tab 1.

OEB Exhibit 4, Tab 2, Section 18, Appendix 2-M provides a detailed breakdown of the budget for this rate application.

[15] EB-2014-0116 Decision and Order (December 29, 2015), pp. 12-13.

6.1.2 OEB Fees

OEB costs invoiced to Toronto Hydro are a condition of its distribution licence. Pursuant to the OEB Business Plan for 2023-2026,[16] and the OEB's Annual Reports for prior years, the OEB's General Cost Recovery compound annual growth rate is forecast to be 7.07% percent between 2022 actuals and 2026 budget. For the same period, Toronto Hydro's projected Fees to the OEB have a compound annual growth rate that is slightly lower at 6.7%.

Over the 2020-2024 period, Toronto Hydro projects that it will pay a total of $18 million to the OEB or approximately $3.6 million per year. Over the 2025-2029 period, Toronto Hydro projects it will pay a total of $22.4 million or $4.5 million per year. Toronto Hydro's projected OEB Fees are approximately 8% of the OEB's s. 26 Financial Plan, which is consistent with Toronto Hydro's historical percentage share.

6.2 Regulatory Affairs Segment Costs

Table 5 provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Years (2025-2029) expenditures for this segment.

Table 5: Regulatory Affairs Segment and CIR Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Regulatory Affairs	3.8	4.4	4.1	5.6	6.4	7.0	7.1	7.5	7.9	8.1
OEB Fees	3.4	3.2	3.6	4.0	4.4	4.5	4.6	4.6	4.7	4.8
Regulatory Applications (Custom IR)	1.6	1.6	1.6	1.6	1.6	2.0	2.0	2.0	2.0	2.0

[16] *Supra* note 8.

2020-2021 Variance Explanation

Between 2020 and 2021 the costs in this segment increased by $0.4 million. A slight increase in payroll was offset by a decrease in administrative costs and OEB fees.

2021-2022 Variance Explanation

Between 2021 and 2022 the costs in this segment decreased by $0.1 million. An increase in OEB fees and payroll costs was offset by a reduction in external services costs reflecting the decision to in-source more regulatory work. The payroll increase was also offset by labour recoveries for resources being allocated to support the blueprinting phase of the Customer Information System project.[17]

2022-2025 Variance Explanation

Between 2022 and 2025 the costs in this segment are expected to increase by $4.2 million, or an average of $1.4 million per year. Of this increase, $0.9 million is attributable to OEB Fees, and $0.4 million is related to the costs of this application which are being amortized starting in 2025. The remaining $2.9 million increase over this three-year period represents an average of $1 million per year, and is due to:

- incremental internal and resources to support: (i) higher volumes of work and complexity related to the preparation, prosecution and implementation of the 2025-2029 rate application and Decision and Order, and (ii) increased volume and complexity of activity already occurring and further expected in respect of regulatory policy, law and compliance matters consistent with the priorities highlighted in the 2023-2026 OEB Business Plan and the Ministry of Energy's *Powering Ontario's Growth* report which outlines actions to support economic

[17]Customer Information System is a Tier 1 application described in Exhibit 2B, Section E8.4.

growth, decarbonization and the ongoing transformation of Ontario's electricity system.

- inflationary cost pressures, including compensation increases consistent with the evidence outlined in Exhibit 4, Tab 4, Schedule 4.

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this program are expected to increase by $1.5 million, or an average of $0.4 million per year, to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work in this segment discussed above. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various regulatory compliance risks and drawbacks, including:

- Incorrect wholesale settlement filings, which would adversely affect the cash flow of the utility or the IESO and disrupt the settlement and reimbursement of a broad range of charges;
- Errors in the Tariff of Rates and Charges that would result in billing inaccuracies, increased volumes of customer complaints and customer dissatisfaction;
- Non-compliance or incorrect implementation of new requirements, policies or programs resulting in increased customer complaints, and potentially compromising the advancement of public policy objectives;
- Costlier and less effective energy policies due to Toronto Hydro not being sufficiently engaged in public policy development processes;
- Unmet OEB evidentiary requirements or expectations as part of the rate-setting processes and other regulatory applications;

- Inadequate strategic business support on regulation or policy driven matters, hampering the utility's ability to effectively respond to emerging needs and evolving industry circumstances; and
- Failure to meet important regulatory reporting requirements on time, such as the OEB Scorecard or RRR filings.

7. COMMUNICATIONS AND PUBLIC AFFAIRS SEGMENT

7.1 Segment Description

The Communications and Public Affairs segment maintains open channels of communications between Toronto Hydro and its customers, stakeholders, media, general public and other interested parties. Through effective and timely communication and engagement, the utility aims to build trust and customer satisfaction to maintain Toronto Hydro's strong brand and reputation.

Toronto Hydro engages in these activities through the following functional areas: Media and Public Relations, Municipal Relations/Office of the President and Community Relations. Working together, these three groups deliver high-quality, practical and timely proactive and reactive information about Toronto Hydro's operations and programs.

To perform the activities in this segment, Toronto Hydro uses a number of different channels,[18] including:

- Owned media channels (content that is published on channels that Toronto Hydro creates or controls). e.g. website, social media, print newsletters, email newsletters/blasts, bill inserts, customer bill, mobile app, media events, community events, Interactive Voice Response);

[18] These channels are regularly reviewed and updated to reflect customer feedback and preferences.

- Paid media channels (third-party channels that require payment from Toronto Hydro). e.g. newspaper advertising, radio advertising, direct mail;
- Earned media channels (content about Toronto Hydro that comes voluntarily from others) such as media outlets;
- Customer engagement surveys about general customer satisfaction and brand trust and focus groups on individual topics and business decisions;
- Contact with local business improvement organizations, community groups and ratepayer associations;
- Proactive outreach to City Councillors, the Mayor's office and City staff;
- Community events; and
- Capital program and planned outage communications through the Community Relations Office.

Effective and timely communication within each work function is critical for customers and other stakeholders as it increases awareness about matters of interest such as planned and unplanned power outages, information about where capital projects are being conducted, and services and programs offered by Toronto Hydro.

Increasingly, Toronto Hydro is seeing more diverse and higher volumes of communications. There are several factors driving this increase, including changes in how customers communicate and increasing focus on the energy transition. Since 2020, there have been more than 45,000 online mentions of Toronto Hydro, and the utility has resolved 5,226 customer issues via social media.

As technology changes, customers increasingly expect Toronto Hydro to provide frequent and near real-time updates about outages via numerous digital channels. According to

industry research, effective communications during outages is a key driver of customer satisfaction.[19] During major events, it is not uncommon for Toronto Hydro to receive hundreds of social media mentions in a short period of time, as well as dozens of inquiries from media and through the Office of the President. This growing volume of requests increases the need for more frequent communications, and additional resources to help manage this need. By communicating key information proactively, stakeholders and customers may also have fewer reasons to contact Toronto Hydro reactively.

In addition, as the city of Toronto shifts towards electrification, the Communications and Public Affairs teams are dealing with a more diverse customer base and more complexity in terms of the number of topics and issues that this team needs to be prepared to address. For example, increased volume and complexity in how customers connect to the grid can result in more varied communication as customers have varying needs and relationships with Toronto Hydro.

Collectively, all of these trends contribute to the segment's resourcing needs, as the increased complexity and evolving nature of customer needs and communications require Communications and Public Affairs staff to possess a diverse array of media-aware and technology-oriented skillsets.

7.1.1 Media and Public Relations

As the customer landscape changes, Media and Public Relations is faced with managing an increasing number of communications channels, a broader range of customers and has a wider range of topics to communicate about. In addition, increased customer engagement is required to understand these evolving needs to help ensure that

[19] Chartwell Inc., *2022 Residential Consumer Survey,* online: <https://chartwellinc.com/>.

communications are being executed effectively, and in-line with customer expectations. In order to effectively manage this expanding work, the function is continuing to increase and expand its skillset through training and additional resources to effectively meet the changes in customers' needs and expectations.

The Media and Public Relations function is responsible for external communications at Toronto Hydro, which includes several core functions:

- Strategic customer and stakeholder communications (development of communications strategies and materials);
- Customer engagement (facilitation of primary and secondary research studies that enable Toronto Hydro to gather critical information to help inform business decisions);
- Digital communications (management of digital communications channels, such as website and social media, as well as supporting the development of digital tools, like Toronto Hydro's mobile app);
- Media relations, and
- Issues management to help the organization detect and respond appropriately to emerging issues and trends, as well as changes in its operating environment.

Toronto Hydro also considers direct customer feedback and the advice of a Customer Advisory Panel ("CAP"). The CAP includes six sub-panels selected through a multi-step process to ensure representation from a diverse cross-section of customers. The utility engages the CAP to obtain ongoing feedback on a variety of topics through a mix of focus groups, surveys, and workshop sessions for both residential and business customers.

Toronto Hydro's customer base is becoming larger, more diverse, and more sophisticated. As the city of Toronto continues to grow, more customers are turning to electricity to power their homes, businesses, and transportation, and some are also installing distributed energy resources such as battery storage and solar panels.

Toronto Hydro will need to ensure it has updated information to assist customers in connecting these new technologies to Toronto Hydro's distribution system and the appropriate channels to effectively communicate such information. This communications effort will require the Media and Public Relations team to understand the increasingly diverse needs of customers – including through customer engagement – to ensure communications are tailored appropriately as the energy transition takes hold.

To prepare the grid for the energy transition, there will also be an increasing amount of work taking place in various neighbourhoods across the city. This, in turn, increases the demand on the Media and Public Relations team to educate and inform customers about the purpose of the work being completed. The Media and Public Relations team will have a significant role to play in educating the public about the investments Toronto Hydro is making to adapt and prepare for the energy transition and the changes in the way customers use electricity.

Along with the development of strategic communications and facilitation of collecting customer feedback, media relations, digital communications and issues management are also of critical importance when it comes to managing Toronto Hydro's brand and reputation.

The media serves as an important conduit between Toronto Hydro and its customers and other stakeholders. The segment's media relations function proactively and reactively communicates accurate and timely information about Toronto Hydro's programs, services and operations, including power outages, electrical safety, rates, and investments in the distribution system.

Media relations and the digital team have a significant role to play during emergency outage situations. Throughout the duration of these outages, communications staff often remain in contact with media outlets until services are restored. Media representatives receive up-to-date information on suspected outage causes, likely duration, and if necessary, appropriate measures to be taken for the protection of the public and Toronto Hydro's and customer-owned equipment. These efforts help disseminate key information to customers at a time when they are most likely to be looking for it.

Dedicated media relations personnel engage reporters directly on all matters, which allows the dispatched crews and other employees to proceed with their work safely and without interruption.

Increasingly, digital channels, including social media and online tools, such as Toronto Hydro's mobile application, SMS notifications, and live online chat, are becoming the preferred source of information for customers experiencing an outage. The digital team focuses on engaging the public through these channels and actively messages those who engage Toronto Hydro via X (formerly known as Twitter) during outages. As of July 2023, Toronto Hydro has over 121,400 followers on X (formerly known as Twitter), approximately 40%-60% more followers than the other three large distributors in the

province. Media also rely on digital channels to collect information, increasing its importance and creating an opportunity for Toronto Hydro to use this channel as an additional communications tool with media.

In terms of public safety, as part of its daily operations, the team also responds to safety questions reported through social media and shares these reports with the appropriate operational teams, seven days a week.

For both media relations and social media, Toronto Hydro has after-hours standby for evenings and weekends, and 24/7 support during significant outages.

The Media and Public Relations function also leads an internal issues management process to help the organization proactively detect and respond to emerging issues and trends, such as customer escalations and developing media stories, as well as changes in the external environment such as changing attitudes towards government, and the cost-of-living crisis. Issues management is a cross-functional process that allows many functions within the organization to work together to help address customer and stakeholder requirements in a timely and effective manner, and help manage Toronto Hydro's reputation in the industry and the community.

7.1.2 Municipal Government Relations/Office of the President

Managing relationships with key City stakeholders contributes to improved utility performance and customer outcomes. These relationships allow Toronto Hydro to monitor for emerging risks to utility work, resolve points of conflict, and provide timely information to the City, particularly during extended or highly impactful outages. Like other organizations that construct and maintain infrastructure in Toronto, establishing

and enhancing relationships with municipal stakeholders is critical to Toronto Hydro's ability to serve its customers and stakeholders efficiently. City policy and infrastructure is increasing in its volume and complexity and is expected to continue. The elevated levels of work expected to be undertaken by the City of Toronto in the coming years is clear from the City's 2023 10-year capital plan which has increased to $49.3 billion, up from $26 billion five years ago.[20] City climate policy – specifically TransformTO and its Net Zero Strategy – is animating climate action across the City and at City-owned buildings, requiring greater and improved coordination with Toronto Hydro.

Toronto Hydro routinely meets with City staff on a range of ongoing and emerging issues, oversees a robust councillor engagement process, and actively participates in City-led committees and working groups to advance the utility's interests. Municipal Government Relations also maintains a process to monitor City Council items for potential consequences for Toronto Hydro and its ratepayers and provide the company with strategic advice on any relevant bylaw changes. For example, in 2020 at the outset of COVID, the City developed the CafeTO program to allow bars and restaurants to construct temporary patios in curb lane of certain streets. Action by Toronto Hydro resulted in electrical safety and reliability considerations being incorporated into the original program guidelines and subsequent revisions, allowing capital work and outage restoration activities to proceed more efficiently and proactively maintaining safe distances from electrical equipment.

Customer escalations for complex cases are managed through a multi-stage dispute resolution process. The Office of the President handles approximately 1,000 issues per

[20] City of Toronto. *2023 City of Toronto Budget Summary*, online: <https://www.toronto.ca/wp-content/uploads/2023/05/95f8-2023-City-of-Toronto-Budget-Summary.pdf>

year, with approximately two-thirds directed to it from councillors and other elected and public officials. The remaining third is comprised of the second level in the customer dispute resolution process if customers are not satisfied with the outcome of their initial contact with frontline customer facing teams. The Customer Advocate is the final step within Toronto Hydro's complaint process and reviews cases for customers unsatisfied with responses provided by Toronto Hydro. The Customer Advocate reviews assess whether:

- Toronto Hydro's internal processes and policies were applied fairly;
- All facts and evidence were incorporated in reaching a decision;
- Complaints were addressed promptly; and
- Comprehensive reasons were provided to support Toronto Hydro's decision.

Of the approximately 1,000 issues managed through the Office of the President in 2022, over 98% were successfully resolved without a formal Customer Advocate review.

7.1.3 Community Relations

As the industry evolves, so does Toronto Hydro's commitment to customer service and the community. Toronto Hydro has comprehensive processes and protocols for communicating information to customers concerning planned capital work and planned outages, in order to provide a better understanding of the capital program and to help prepare customers for work at or near their property.

Toronto Hydro issues proactive communications to notify customers of planned work, and also has a customer inquiry line and escalation process for customers. Community Relations staff are dispatched on-site, when needed, to liaise with customers. This process is critical for building brand trust and reputation management.

Toronto Hydro maintains productive relationships with public interest groups and agencies involved in commerce, environmental protection, and education. Stakeholder outreach commonly takes the form of one-on-one contact with customers, community town hall meetings, special information sessions, and a variety of online content. Using a variety of communication channels allows Toronto Hydro to engage customers with varying needs, concerns, and preferences, with the goal of giving appropriate attention to all customer segments.

Toronto Hydro continues to make investments in sustaining the grid, but is also planning for new investments and projects to build capacity and enable growth and electrification. As the city continues to grow, so does its infrastructure. These changes require additional work to be done by Toronto Hydro to support the expansion and modernization of other services. This means Toronto Hydro is rebuilding or relocating infrastructure to support City water work, Metrolinx, TTC expansion, development and third-party communication upgrades.[21] Over the course of the 2025-2029 period, the capital program associated with system access, renewal and service is increasing by 47 percent relative to the 2020-2024 period. All of this work means that communications supporting capital projects will continue to grow in importance and frequency.

In preparation for this increasing volume and complexity of projects, Community Relations is reviewing its existing processes to help identify opportunities for modernizing that will allow Toronto Hydro to better communicate with customers and stakeholders.

In particular, planned improvements to Toronto Hydro's website will allow for an enhanced construction and outage map to more accurately identify project areas. The

[21] *Supra* note 4.

content on the website will also be expanded to include more detailed information about the utility's work, including photos, equipment and construction descriptions and project status updates and general information.

In addition, potential expansion of the channels through which planned outages are communicated will also be critical for maintaining Toronto Hydro's commitment to Customers and the community. Social media, text message/SMS and email communications are all being considered as additional communications channels.

To maintain expected service levels, the need for additional software, technology and resources to support this increasing volume and complexity of projects will need to be evaluated. Resources to provide dedicated support to these large-scale projects for enhanced community engagement may also need to be considered.

7.2 Communications and Public Affairs Segment Costs

Table 7 presents Toronto Hydro's Historical (2020-2022), Bridge (2023-2024), and Forecast Years (2025-2029) costs relating to the Communications and Public Affairs segment.

Table 7: Communications and Public Affairs Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Communications & Public Affairs	3.6	4.1	4.1	5.5	6.4	6.6	6.9	7.1	7.3	7.6

2020 – 2021 Variance Explanation

Between 2020 and 2021 costs in this segment increased by $0.5 million. This is primarily attributed to:

- increases in payroll costs due to inflationary increases, and
- increase in marketing costs associated with a gradual return to pre-pandemic levels of communication following COVID-19.

2021 – 2022 Variance Explanation

There is no variance in this segment between 2021 and 2022.

2022 – 2025 Variance Explanation

Between 2022 and 2025 costs in this segment are expected to increase $2.5 million or an average of $0.8 million per year primarily due to the following:

- increase due to inflationary cost pressures, including compensation increases consistent with the evidence outlined in Exhibit 4, Tab 4, Schedule 4;
- incremental resources to support an additional focus on digital communications channels and increasing customer expectations, and
- increase in advertising, event, and market research costs associated with meeting increasing customer expectations, including an increasing number of communications channels and the need for more timely and frequent communications.

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $1 million, or an average of $0.3 million per year to maintain the resourcing capacity and capabilities that are required to support the increased volume and complexity of work in this segment. If Toronto Hydro were forced to deliver this segment with a reduced level of funding over the 2025-2029 rate period, the utility could face various customer-related and stakeholder-facing risks, including:

- Increased frequency of inaccurate or delayed information resulting in customer confusion and dissatisfaction;
- Inability to meet Toronto Hydro's strategic priorities such as modernizing business processes and adopting new tools to meet the changes in customer's needs and expectations in response to electrification;
- Reduced ability to announce the timing, scope and customer impact of Toronto Hydro's capital projects, resulting in resident confusion and dissatisfaction;
- Increased number of issue escalations, with overall diminished customer and stakeholder satisfaction;
- Weakened relationship with members of the media due to lack of communication, resulting in increased potential for the dissemination of misinformation or negative information;
- Decreased understanding of customer perceptions and preferences, resulting in misalignment with customer expectations;
- Reduced uptake in key corporate programs and services such as the Low-Income Energy Assistance Program ("LEAP") due to lack of awareness/marketing, [22] and
- An increased potential for brand and reputation decline, resulting in loss of customer trust and faith in Toronto Hydro and diminished customer satisfaction.

[22] Exhibit 4, Tab 2, Schedule 19.

CHARITABLE DONATIONS AND LOW-INCOME ENERGY ASSISTANCE PROGRAM ("LEAP")

1. CHARITABLE DONATIONS

Toronto Hydro is an important corporate contributor in the city of Toronto and supports outreach events that engage the community, advance energy related issues of public importance (such as safety and sustainable energy), and promote programs and services that help customers, particularly those that are most vulnerable.

Table 1, below, provides Toronto Hydro's Historical (2020-2022), Bridge (2023-2024), and Forecast Year (2025-2029) charitable contributions.

Table 1: Charitable Contributions Summary ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Rate Recoverable	1.0	1.0	1.0	1.3	1.4	1.5	1.6	1.7	1.8	1.9
Non-Rate Recoverable	0.1	0.1	0.1	-	-	-	-	-	-	-

Toronto Hydro's sole rate recoverable charitable contributions for the 2025-2029 rate period are its payments towards the OEB's Low-Income Energy Assistance Program ("LEAP"). As discussed in greater detail in section 3 below, the utility is requesting the OEB's permission to increase its LEAP funding allocation for the 2025-2029 rate period and targeted exemptions from the Ontario Electricity Support Program ("OESP") & LEAP Program Manual (the "Manual") to more effectively promote and operate LEAP for the benefit of its low-income customers. [1]

[1] *OESP and LEAP Program Manual* (October 2015).

Toronto Hydro's non-rate recoverable charitable contributions are comprised of multiple minor sponsorships of community not-for-profits, industry associations, City of Toronto entities, and events of strategic alignment. The following are examples of causes the utility has made contributions to:

- Not-for-profit entities (e.g. Tree Canada, which supports planting and nurturing trees in rural and urban environments and Pembina Institute, which performs research on energy policy matters);
- Industry associations (e.g. Ontario Energy Association and Ontario Energy Network, which provide a voice to the energy industry, an opportunity to network and share best practices, and the furthering of industry issues publicly and at various levels of government); and
- City entities or events of strategic alignment (e.g. Toronto Region Board of Trade, Cycle Toronto, and Cavalcade of Lights, which provide opportunities to engage with communities regarding issues that align with Toronto Hydro's Corporate Social Responsibility Strategy and promote programs and services).

Sponsorships can be used to align with business development strategies to further Toronto Hydro's network and presence in areas of interest to the public (e.g. electric vehicles). Each sponsorship is reviewed according to an established process and matrix to gauge appropriateness and optimal level of support.

2. POLITICAL CONTRIBUTIONS

Toronto Hydro does not make political contributions of any kind.

3. LOW-INCOME ENERGY ASSISTANCE PROGRAM ("LEAP")

Toronto Hydro proposes to increase its LEAP funding allocation for the 2025-2029 rate period from the default 0.12 percent of its total (service) distribution revenue requirement to 0.15 percent, which would amount to approximately $8.5 million. Furthermore, the utility plans to top up rates funding with its surplus LEAP funds and requests targeted exemptions from the Manual for itself and its lead and intake agencies to implement several operational changes to enhance the administration of LEAP in Toronto Hydro's service territory, as discussed below.

Table 2: Toronto Hydro's 2025-2029 LEAP Funding Plan ($ Millions)[2]

	Rates Funding – 0.15% of Revenue Requirement (A) ($ M)	LEAP Funds Carried Over from Previous Years (B) ($ M)	Total Annual Funding (A + B) ($ M)	15% Agency Admin Fees ($ M)	Total Funds Available for LEAP Disbursements ($ M)	Estimated Customers Assisted / Year (approx.)
2025	$1.5	$0.5	$2.1	$0.3	$1.8	1,800
2026	$1.6	$0.5	$2.1	$0.3	$1.8	1,800
2027	$1.7	$0.5	$2.2	$0.3	$1.9	1,900
2028	$1.8	$0.5	$2.3	$0.4	$2.0	2,000
2029	$1.9	$0.5	$2.4	$0.4	$2.1	2,000
TOTAL	$8.5	$2.6	$11.2	$1.7	$9.5	9,500

3.1 Proposed Enhancements to LEAP

As part of its business planning for the 2025-2029 rate period, through a variety of channels Toronto Hydro obtained customers' feedback on their experience with accessing financial assistance under LEAP. In general, customers expressed that 1) the application

[2] Variances due to rounding may exist. Column "B" shows the cumulative LEAP funds carried over from the 2020-2024 rate period spread out over the 5 years of the 2025-2029 rate period.

process for LEAP is difficult and should be simplified to facilitate access to grants, and 2) the utility can do more to promote LEAP to eligible customers.

Meanwhile, several macroeconomic factors that materialized during the 2020-2024 period, such as the effects of the COVID-19 pandemic, higher than average inflation and interest rates, and rising costs of living, have significantly affected vulnerable customers' ability to pay their electricity bills. As an illustration, the number of Toronto Hydro's eligible low-income customers ("ELIC") in arrears increased by approximately 14% from 2020 to 2021 and by approximately 34% from 2021 to 2022. Similarly, the total dollar amount of arrears on ELIC accounts increased by approximately 19% from 2020 to 2021 and by approximately 40% from 2021 to 2022. From 2022 to 2023, Toronto Hydro estimates that the number of ELIC in arrears will continue to increase by 16%, while the total dollar amount of arrears on ELIC accounts will decrease by approximately 20%. Therefore, the total number of ELIC in arrears and the total dollar amount of arrears on ELIC accounts are still 20% and 129% greater than pre-pandemic levels in 2019, respectively.

In recent years, 1,000 Toronto Hydro customers on average received LEAP assistance per year (See Figure 1). In the utility's assessment, the 2020 and 2021 years are not representative of typical volumes of assistance due to the distortionary effects of the COVID-19 pandemic, the extended disconnection moratoriums and Toronto Hydro's customer-forward collections policies (as discussed in the Customer Care program),[3] and other financial assistance programs "competing" with LEAP.

[3] Exhibit 4, Tab 2, Schedule 14.

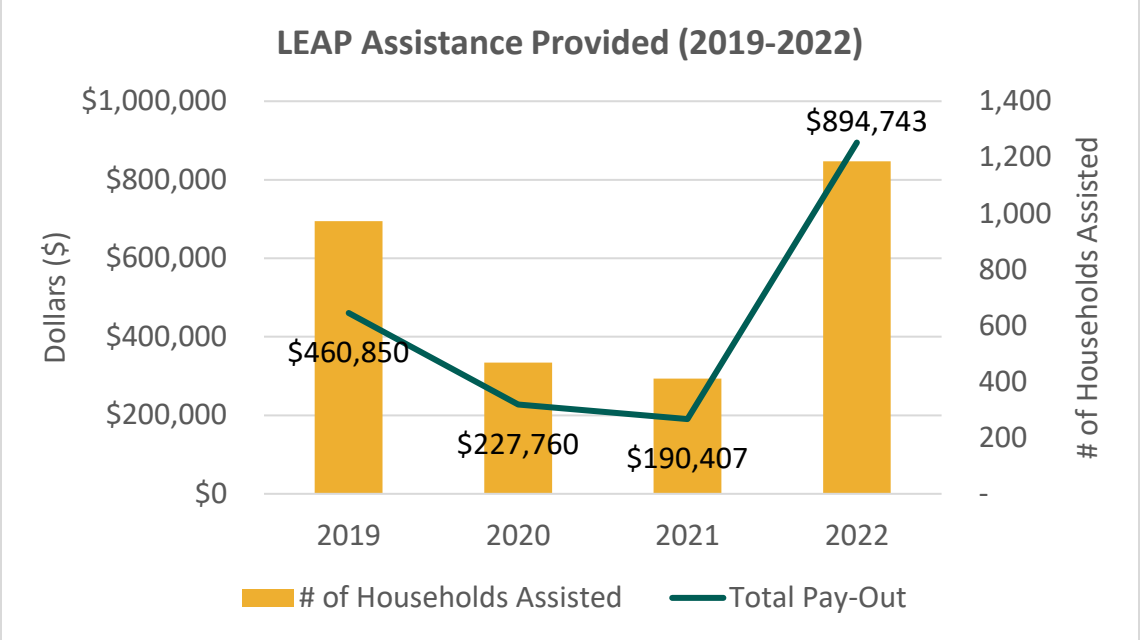

Figure 1: LEAP Assistance Provided (2019-2022)

Based on the trending shown above, in Figure 1, Toronto Hydro expects that many of its customers will likely continue to face financial difficulties well into the 2025-2029 rate period. In addition to the bill impacts from the rates Toronto Hydro is requesting through this application, other charges on electricity bills may also continue increasing throughout 2025-2029, as other stakeholders in the industry adjust their rates and levies, and energy transition policies take effect.

The demographics of Toronto Hydro's service territory also shed light on the need to provide vulnerable customers robust assistance through the energy transition. For example, the City of Toronto's analysis of the 2021 Census shows that the proportion of low-income households in Toronto is higher compared to all other regions in the Greater Toronto and Hamilton Area and both Ontario and national averages (See Figure 2 below).

As of 2021, there were 363,955 persons, or 13.2% of the population in Toronto, with an income below Statistics Canada's Low-Income Measure After Tax ("LIM-AT").[4]

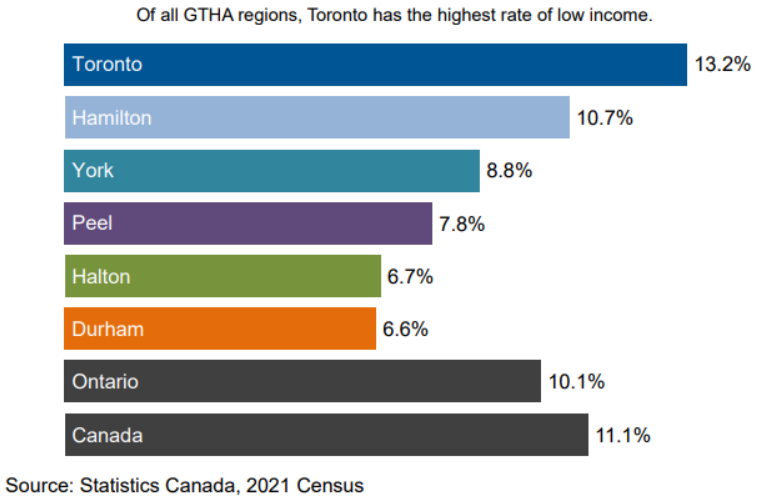

Figure 2: Prevalence of Low-Income After-Tax Households ("LIM-AT") for the Greater Toronto and Hamilton Area, Ontario and Canada, 2021[5]

Against this backdrop, Toronto Hydro recognizes that it has a role to play in providing effective support to its low-income customers throughout the 2025-2029 rate period and proposes to implement various enhancements to its administration of LEAP to increase the annual average number of customers assisted to approximately 1,900 per year or over 9,000 over the five-year period.

To enable this outcome, Toronto Hydro is requesting the OEB's permission on the following matters for the duration of the 2025-2029 rate period.

[4] City of Toronto Backgrounder, *2021 Census: Families, households, Marital Status and Income* (July 19, 2022), online: <https://www.toronto.ca/wp-content/uploads/2022/07/9877-City-Planning-2021-Census-Backgrounder-Families-Hhlds-Marital-Status-Income.pdf>.
[5] *Ibid.*

1. *Continue the flexibility for LEAP eligibility criteria permitted by the OEB in its letter dated February 27, 2023.*

On February 27, 2023, the OEB issued a letter to licensed electricity distributors, LEAP lead agencies, and other industry participants to extend the flexibility of two specific program requirements through 2023.[6] These requirements are:

- To be eligible for LEAP emergency financial assistance, an applicant needs to be in arrears but does not need to be in threat of disconnection or have been disconnected; and
- Applicants can receive LEAP emergency financial assistance more than once per year subject to the maximum annual household grant amount.[7]

Toronto Hydro submits that the continuation of these measures into the 2025-2029 rate period is warranted, as it expects the conditions that informed the OEB's decision to increase flexibility for emergency financial assistance recipients under LEAP and the economic circumstances discussed above to persist in Toronto Hydro's service area.

2. *Increase the maximum grant amounts per household per year from $500 to $1,000 (from $600 to $1,200 for electrically heated households).*

Similar to the previous request, Toronto Hydro submits that increasing the maximum grant amounts for the 2025-2029 rate period is warranted as it expects the circumstances that informed the OEB's decision to double grant amounts in 2022 and the economic circumstances discussed above to persist in Toronto Hydro's service area.[8] The OEB's rationale at that time was to increase the flexibility and effectiveness of LEAP emergency

[6] OEB Letter, *Providing Flexibility to Consumers through the Low-income Energy Assistance Program – Emergency Financial Assistance*, (February 27, 2023).
[7] Currently, the maximum allowable grant is set at $500 ($600 for electrically heated households). *Supra* note 6.
[8] OEB Letter, *Providing Flexibility to Assist Consumers through the Low-income Energy Assistance Program – Emergency Financial Assistance* (January 10, 2022).

financial assistance when customers were facing higher than normal arrears and many utilities had large balances of unused funding carried over from previous years. As previously discussed, Toronto Hydro's empirical data suggests that higher than normal arrears for the utility's customers may very likely persist into the 2025-2029 rate period.

Increasing the maximum grant amounts per household as requested, in combination with the LEAP funds expected to carry over from the 2020-2024 rate period, would increase the effectiveness and expand the reach of the program in the 2025-2029 rate period.

3. *Increase the annual rate funding allocation for LEAP from 0.12% to 0.15% of Toronto Hydro's revenue requirement.*

Toronto Hydro submits that a modest increase in its LEAP funding allocation would support the utility's ability to provide assistance to more customers over the 2025-2029 rate period, without any material impacts to any other funding requirements. This increase, in combination with the other measures proposed herein, would enable an increase of approximately 50% in the number of LEAP recipients, as discussed below.

Table 3: Rates-Funded LEAP Allocation of 0.15% of the Revenue Requirement
($ Millions)

	2025	2026	2027	2028	2029	Total
0.15% Allocation	1.5	1.6	1.7	1.8	1.9	**8.5**

4. *Exempt Toronto Hydro and its lead and intake agencies from steps 1 through 7 of section 3.3 of the OESP & LEAP Manual to increase the flexibility of the customer application process.*

As previously discussed, the feedback that Toronto Hydro collected from its customers indicates that applicants find the LEAP application process to be time-consuming and difficult to navigate. Certain procedural requirements embedded in the Manual and currently used by lead and intake agencies, such as pre-screening by phone, in-person interviews, lead agency reviews (if applicable), or the separate verification and communication with the utility, add to the average time for processing applications and sometimes discourage customers from carrying through their application to completion, or from re-applying in the future. To address these challenges, Toronto Hydro proposes to work with its lead and intake agencies to make small, incremental changes to existing procedures and modernize the process in favour of customers, while still retaining robust controls for the application of eligibility requirements, the protection of customer privacy, and good governance of assistance funds.

Examples of procedural improvements that the utility may explore with its lead and intake agencies include:

- Having agencies conduct interviews virtually over Zoom or similar technologies;
- Allowing the submission of applicant documents and other communications via email and/or other electronic means;
- Having agencies refer to previously obtained and current applicant information for re-applications within the same calendar year; and
- Providing easily accessible information resources for applicants.

In order to implement measures such as the above, Toronto Hydro requests the OEB to exempt the utility and its lead and intake agencies from steps 1 through 7 of the Manual.

Toronto Hydro submits that the four proposals discussed above would enable the utility and its agencies to deliver financial assistance in the most effective and targeted manner to the customers that need it the most. The utility further submits that the experience it will gain in modernizing its administration of LEAP as proposed may yield valuable insights, which Toronto Hydro is willing to share with the OEB and the industry through the Financial Assistance Working Group or by other means as the OEB may direct.

3.2 LEAP Expenditure Summary

To determine the optimal level of funding for the 2025-2029 rate period, Toronto Hydro completed a detailed analysis of historical LEAP data pertaining to the number of grants and disbursement amounts.

Although the number of households receiving LEAP has remained relatively flat since 2019 (except for 2020 and 2021, which the utility deems to be outlier years due to the effects of the COVID-19 pandemic), the amount of unused LEAP funds carrying over from previous years has been growing during the current rate period, as shown in Table 4 below.

Table 4: LEAP Contributions and Disbursements for the 2020-2024 rate period ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge
Annual Contribution	958	958	958	958	958
Carryover from Prior Years	737	1,468	2,349	TBD	TBD
One-Time Contribution	-	113[9]	-	-	-
Total Available[10]	**1,694**	**2,539**	3,307	TBD	TBD
Total Disbursed (including agency administration fees)[11]	227	190	893	TBD	TBD
Total Unused	1,468	2,349	2,414	TBD	TBD

Toronto Hydro's plan to increase the accessibility and reach of LEAP and the permissions it requests from the OEB for the 2025-2029 rate period is outlined in section 3.1 above. In implementing this plan, the utility is going to deploy:

1) $8.5 million in rates funding allocation for LEAP, equivalent to 0.15% of the revenue requirement, and
2) the estimated $2.6 million in surplus LEAP funds carried over from the 2020-2024 rate period.

This amounts to a total allocation of approximately $11.2 million for 2025-2029. Net of the 15% annual agency administration and program delivery fees, the utility will have approximately $9.5 million available for LEAP disbursements. Table 5 below shows the estimated number of assisted households/customers, if Toronto Hydro's four proposals discussed in section 3.1 are granted.

[9] Represents a one-time contribution in 2021 is attributable to the credit amount that the OEB applied to Toronto Hydro's 2021-2022 costs assessment invoice from the OEB's administrative monetary penalty funds to supplement utilities' LEAP budgets for 2021. OEB Letter, *July 2021 Cost Assessment Invoice and Temporary Changes to the Screening Guidelines for the Low-income Energy Assistance Program – Emergency Financial Assistance*, (July 14, 2021).
[10] The indicated amounts exclude funding and grants from the Pichette settlement funds, which are administered by United Way of Greater Toronto (see section 3.3 below).
[11] *Ibid.*

1 **Table 5: Toronto Hydro's 2025-2029 LEAP Funding Plan ($ Millions)[12]**

	Rates Funding – 0.15% of Revenue Requirement (A)	LEAP Funds Carried Over from Previous Years (B)	Total Annual Funding (A + B)	15% Agency Admin Fees	Total Funds Available for LEAP Disburse-ments	Estimated Customers Assisted Per Year
2025	$1.5	$0.5	$2.1	$0.3	$1.8	1,800
2026	$1.6	$0.5	$2.1	$0.3	$1.8	1,800
2027	$1.7	$0.5	$2.2	$0.3	$1.9	1,900
2028	$1.8	$0.5	$2.3	$0.4	$2.0	2,000
2029	$1.9	$0.5	$2.4	$0.4	$2.1	2,000
TOTAL	**$8.5**	**$2.6**	**$11.2**	**$1.7**	**$9.5**	**9,500**

[12] Variances due to rounding may exist. Column "B" shows the cumulative LEAP funds carried over from the 2020-2024 rate period spread out over the 5 years of the 2025-2029 rate period.

COMMON COSTS AND ADJUSTMENTS

1. OVERVIEW

This schedule describes Toronto Hydro's costs that are not attributable to a specific program or would be administratively difficult or immaterial to allocate. The total expenditures associated with this schedule are comprised of ongoing or recurring costs and adjustments.

Table 1: Common Costs and Adjustments ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Ongoing or Recurring	(0.2)	(0.3)	(1.0)	(1.1)	(0.9)	(0.9)	(0.9)	(0.8)	(0.8)	(0.8)
Total	**(0.2)**	**(0.3)**	**(1.0)**	**(1.1)**	**(0.9)**	**(0.9)**	**(0.9)**	**(0.8)**	**(0.8)**	**(0.8)**

2. ONGOING OR RECURRING COSTS AND ADJUSTMENTS[1]

Ongoing or recurring costs and adjustments are comprised of the following expenditures described in further detail in the sections below.

2.1 Difference in Forecast and Actual Employee Benefits Costs

Toronto Hydro provides current employees with benefits that include medical, dental, and life insurance benefits, and includes a provision for employees' future benefits. Benefit costs are allocated through the payroll process using budgeted rates. The actual costs for benefits are based on employee consumption. The difference between budgeted and the actual benefit costs incurred by the utility are reflected in this Schedule.

[1] The utility has not included any one-time costs for recovery.

2.2 Investment Tax Credits ("ITC")

The Historical (2020-2022), Bridge (2023-2024), and Forecast Year (2025-2029) costs reflect both refundable and non-refundable ITCs in compliance with International Financial Reporting Standards ("IFRS").[2]

2.3 Financing Costs

Financing costs are made up of standby fees, the amortization of the upfront and arrangement fees for Toronto Hydro's revolving credit facility, and letters of credit fees.

2.4 Common Costs and Adjustments Year-over-Year Variance Analysis

2020-2021 Variance Explanation

The decrease of $0.1 million is primarily due to difference in forecasted and actual employee benefits costs in 2021.

2021-2022 Variance Explanation

The decrease of $0.7 million is primarily due to higher ITC credit received in 2022 and difference in forecasted and actual employee benefits costs in 2022.

2022-2025 Variance Explanation

Between 2022 and 2025, Toronto Hyro forecasts immaterial increase of $0.1 million due to higher financing costs.

[2] Exhibit 6, Tab 2.

2025-2029 Variance Explanation

Toronto Hydro forecasts immaterial variances in common costs and adjustments over the 2025-2029 rate period, except for a forecasted increase of $0.1 million from 2026 to 2027 due to higher financing costs.

ALLOCATIONS AND RECOVERIES

1. OVERVIEW

This schedule discusses the allocations and recoveries of Toronto Hydro's total Operations, Maintenance, and Administration ("OM&A") costs to reflect the recovery of certain expenditures such as warehousing, facilities, fleet and equipment, and Information Technology ("IT") services obtained by internal user departments through other OM&A and/or capital programs and shared services.

2. DESCRIPTION

Table 1 below provides a breakdown of the historical (2020-2022), bridge (2023-2024), and forecast year (2025-2029) allocations to and recoveries from Toronto Hydro's OM&A expenditures. The manner of allocation for each individual component is discussed in detail below.

Table 1: Allocations and Recoveries Adjustments to OM&A ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
On-cost recovery	(13.2)	(12.9)	(14.2)	(16.9)	(19.1)	(21.7)	(23.7)	(25.1)	(25.7)	(27.3)
Fleet Recovery Offset	(9.6)	(9.8)	(9.4)	(10.3)	(10.7)	(11.0)	(11.3)	(11.5)	(11.8)	(12.2)
IT and Occupancy Charges	(0.8)	(0.8)	(0.6)	(0.8)	(0.8)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)
Shared Services	(1.0)	(2.3)	(1.5)	(3.0)	(2.9)	(3.4)	(3.0)	(3.2)	(3.4)	(3.8)
Other Allocated Costs	(0.9)	(0.8)	(0.8)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.5)	(0.6)
Total	**(25.5)**	**(26.6)**	**(26.5)**	**(31.4)**	**(33.9)**	**(37.5)**	**(39.4)**	**(41.2)**	**(42.3)**	**(44.8)**

3. ON-COST RECOVERY

On-cost recovery is a material handling surcharge applied to all inventory issuances from the warehouse by the Supply Chain OM&A program to both capital and operational

projects.[1] If the items issued from the warehouse are associated with capital projects, the on-cost charge is capitalized, whereas if the items issued are associated with operational projects, the on-cost charge is expensed in the period in which it is incurred.

The costs included in the on-cost recovery are mainly comprised of:

- Supply Chain OM&A program compensation costs;
- Directly attributable support costs; and
- Other warehouse costs (e.g. warehouse maintenance costs).

4. FLEET RECOVERY

The allocation of fleet costs is based on the number and type of vehicles used in projects and contributes to Toronto Hydro's efficient utilization of vehicles in the Fleet and Equipment Services program.[2] In the case of maintenance projects, the allocation provides for a transfer of operating costs from the Fleet and Equipment Services program to other programs using vehicles and equipment. In the case of capital projects, the allocation provides for a transfer of operating costs to capital projects. The allocation to capital is based on the nature of the work performed and follows Toronto Hydro's labour costing methodology.

The costs included in the fleet allocation are mainly comprised of:

- Fleet and Equipment OM&A program compensation costs;
- Parts and materials;
- Vehicle insurance, licensing, and registration; and
- Other fleet costs.

[1] Exhibit 4, Tab 2, Schedule 13.
[2] Exhibit 4, Tab 2, Schedule 11.

The Fleet and Equipment Services program employs a vehicle "lease-rate" cost recovery model, whereby vehicle expenses are recovered using a monthly user charge at the vehicle class level (e.g. "Compact Car", "Passenger Minivan up to 2,500 kilograms"). The lease-rate is calculated on an annual basis to ensure that operating cost changes at the vehicle class level are accurately reflected in user lease rates of the following year.

5. IT AND OCCUPANCY CHARGES

The allocation of IT charges to Toronto Hydro's affiliates and non-rate regulated business is based on support by the IT OM&A program to end users of IT assets and systems, including directly attributable labour and support costs, and contributes to Toronto Hydro's efficient use of technology assets.[3]

The costs included in the IT allocation are comprised mainly of:

- IT OM&A program compensation costs; and
- Directly attributable support costs.

The allocation of occupancy charges and Facilities Management OM&A program costs is based on square-footage and type of space used and contributes to the efficient use of space within Toronto Hydro's facilities.[4]

The costs included in the occupancy and facilities allocation primarily consist of:

- Facilities Management OM&A program compensation costs;
- Maintenance costs;
- Facilities costs;

[3] Exhibit 4, Tab 2, Schedule 17.
[4] Exhibit 4, Tab 2, Schedule 12.

- Utilities costs;
- Property taxes; and
- Property leases.

6. SHARED SERVICES

Toronto Hydro allocates shared services costs included in OM&A programs to its affiliate corporations and the non-rate regulated business of the utility. For more information about Toronto Hydro's shared services model and a description of Toronto Hydro's corporate structure and governance, please respectively refer to Exhibit 4, Tab 5 and Exhibit 1C, Tab 2, Schedule 1.

7. OTHER ALLOCATED COSTS

Other allocated costs represent costs which are not specifically attributed to an OM&A program.

PURCHASES OF NON-AFFILIATE SERVICES

Toronto Hydro's Procurement Policy (the "Policy") establishes processes and protocols for obtaining services, equipment, and materials that satisfy the operational needs of the utility in a manner that appropriately balances cost and value. Toronto Hydro relies on a comprehensive governance framework for its procurement activities. The Policy is set out at Appendix A to this Schedule.

Procurement exceeding $25,000 in value is sourced in accordance with Toronto Hydro's competitive procurement procedure, which outlines the general competitive bid process and sets out various rules with respect to communications, negotiations, bid reviews, and conflicts of interest. This formalized competitive bidding process helps ensure that the procurement process remains fair, transparent, efficient, and consistent.

1. SOLE SOURCING

Where procurement is related to, amongst other things, unforeseeable circumstances or where there is only one vendor uniquely qualified to deliver goods or services, Toronto Hydro may use sole source procedures as described in the Policy.[1] When exercising the option to perform sole source procurement, Toronto Hydro is often able to reduce the cost of goods or services or improve the value proposition in other ways.

Before executing sole source procurements, Toronto Hydro conducts due diligence reviews of the sole source purchase request. The reviews determine if the sole source purchase is warranted, and include a review of the proposed contract's specifications, scope, definition, commercial terms, liabilities, and insurance requirements.

[1] See Appendix A to the Procurement Policy (Exception 4).

Proposed sole source procurements that pass the review process are finalized through contract negotiations with the vendor. At that point, a purchase order is issued.

2. PRE-QUALIFICATIONS FOR CONSTRUCTION CONTRACTS

When Toronto Hydro contemplates a civil or electrical construction project, potential contractors are pre-qualified in accordance with Toronto Hydro's pre-qualification procedure. A contractor's pre-qualification signifies that the contractor has met the minimum requirements established by Toronto Hydro for the purposes of a project. The factors used for evaluating contractors at this stage include, but are not limited to, technical skill and competence, experience, financial viability, health and safety record, reputation, work load, and any previous relationship with Toronto Hydro.

All contracts are authorized and executed in accordance with Toronto Hydro's Signing Policy. Toronto Hydro's signing authorization levels are approved by the Board of Directors and delegated to individual members of the executive and senior management of the utility to facilitate the day-to-day running of the business. Contracts must be signed by an authorized person who is directly responsible for the budget related to the subject area of the contract. Toronto Hydro's signing authorization levels for procurement contracts are shown in Table 1, below.

Table 1: Toronto Hydro's Signing Authorization Levels for Procurement Contracts

Category	President and CEO	CFO	Responsible Officer	Controller	General Manager	Director	Manager that is a direct report of an Officer
Procurement Signing Limit	Up to $30M	Up to $5M	Up to $5M	Up to $1M	Up to $500,000	Up to $250,000	Up to $150,000

3. COMPLIANCE CONFIRMATION

Toronto Hydro confirms that its non-affiliate purchases are in compliance with the utility's Policy. Appendix B identifies non-affiliate services that were procured in 2020, 2021, 2022, and 2023 under the exceptions to the general procurement rules contemplated within the Policy. These engagements did not originate from a competitive procurement process and surpass the utility's materiality threshold of $1 million.

POLICY

PROCUREMENT	**Policy Owner:** **Executive Vice-President Planning & Chief Engineering & Modernization Officer (THESL)**
	Policy Approver: **Policy Administration Steering Committee**
	Version Approval Date: **V8.0 2022-04-12**
	Last Reviewed by PASC: **V8.0 2022-04-12**
The most recent version of this policy can be obtained from the Toronto Hydro intranet Plugged In at: http://pluggedin.torontohydro.com/policy/Pages/DistributionGridManagementPolicies.aspx	
The distribution of this policy is not restricted.	

Anthony Haines
President and CEO, Toronto Hydro Corporation

May 6, 2022

Date

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1 DOCUMENT REVIEW & REVISION HISTORY

This policy is reviewed annually.

Version Number	Date of Review	Reviewed By	Brief Description of Change
V1.0	2007-07-01	PASC	V1.0 approved by PASC.
V2.0	2009-10-23	PASC	V2.0 Approved outside of regular scheduled PASC meeting
V3.0	2013-04-25	PASC	V3.0 approved by PASC members
V.3.1	2013-12-09	PASC	V3.1 approved by PASC
V4.0	2015-06-09	PASC	Administrative Changes V4.0 approved by PASC
V5.0	2017-10-16	PASC	Administrative Changes. Additional changes to align with new THESL Signing Policy. Added standards section regarding conflicts with other corporate policies and tracking policy compliance.
V6.0	2018-10-22	PASC	Administrative Changes. Added clause to address procurement affecting real property. Additional changes to align with the THESL Signing Policy
V7.0	2020-05-26	PASC	Added new clause for Supplier References, added new exception for Contract term as it relates to real property, added new exception for Crisis and Emergency management. General clarifications.
V8.0	2022-04-12	PASC	-Added new clause for Procurement between THESL and Affiliates -Modified clause 7.4, Administrative Changes.

2 DISTRIBUTION HISTORY

Version Number	Date of Issue	Recipients
V1.0	2007-07-01	Toronto Hydro @ Home Employee Extranet
V2.0	2009-10-26	Toronto Hydro @ Home Employee Extranet
V3.0	2013-05-10	Toronto Hydro Intranet Plugged In at: http://pluggedin.torontohydro.com/policy/Pages/
V3.1	2013-12-09	Toronto Hydro Intranet Plugged In at: http://pluggedin.torontohydro.com/policy/Pages/
V4.0	2015-06-09	Toronto Hydro Intranet Plugged In at: http://pluggedin.torontohydro.com/policy/Pages/
V5.0	2017-10-16	Toronto Hydro Intranet Plugged In at: http://pluggedin.torontohydro.com/policy/Pages/
V6.0	2018-10-22	Toronto Hydro Intranet Plugged In at: http://pluggedin.torontohydro.com/policy/Pages/
V7.0	2020-05-26	Toronto Hydro Intranet Plugged In at: https://pluggedin.torontohydro.com/policy/Pages/allpolicies.aspx
V8.0	2022-04-12	Toronto Hydro Intranet Plugged In at: https://pluggedin.torontohydro.com/policy/Pages/allpolicies.aspx

3 POLICY OVERVIEW

This policy outlines the process that is to be followed for the procurement of any good or service by any of Toronto Hydro's corporate entities. The goals of this policy are to ensure Toronto Hydro business objectives are achieved and to facilitate compliance with applicable internal standards and requirements as well as regulatory, statutory and other legal requirements.

4 DEFINITIONS AND ABBREVIATIONS

TERM or ACRONYM	DESCRIPTION
Affiliate	An affiliate has the same meaning as in the Business Corporations Act (Ontario). THESL's affiliates are Toronto Hydro Corporation (THC), Toronto Hydro Energy Services Inc. (THESI), any other Subsidiary, the City of Toronto, and other City-owned entities (agencies, boards, commissions and corporations).
Authorization Level Document	The most recent version of the Authorization Level Document setting out expenditure levels for authorized persons.
Board	The Board of Directors of Toronto Hydro Corporation or of any Subsidiary as may be applicable.
Business Unit	The Toronto Hydro Corporation or Subsidiary department requesting a Procurement.
CEO	President and Chief Executive Officer of Toronto Hydro.
CIO	Customer Care & Chief Information Officer of THESL.

TERM or ACRONYM	**DESCRIPTION**
Contract	Contract means: (i) an agreement for the payment of monies, delivery of goods/services, or transfer, sale or lease of property, material or equipment; (ii) an agreement that relates to financing activities, capital management initiatives, the granting of liens or other secured arrangements; (iii) an easement or right-of-way; (iv) a release or settlement of claim; or (v) any other agreement or document that imposes binding obligations on the Corporation.
Confidential Information	All information and data of any nature relating to the business and operations of Toronto Hydro or any of its affiliates (as that term is defined in the Business Corporations Act (Ontario)), including without limitation, information or data that relates to prices, or forms of contracts, or is financial, technical, business, operational or marketing in nature, or relates to research, development, marketing plans, generating facilities, machinery, equipment configurations, generation, costs, customers, suppliers, formulae or terms of sale, whether factual or interpretive, in all cases whether in written, oral, visual, photographic, electronic, magnetic or other form, and whether or not identified verbally, visually or in writing as confidential.
Contract Amount	The total amount of expenditures required under any Contract, excluding HST and any other value added tax, and shall be determined by calculating the total amount of all possible expenditures over the term of the Contract, including all years of a multi-year term and all years of all possible Contract renewals, and shall include the potential maximum amount of all conditional, contingent and variable payments. Procurements shall not be artificially divided so as to constitute a Contract Amount below applicable threshold values. For Contracts to be signed by the CEO, the Contract Amount shall exclude the value of any optional Contract renewal years where this option is exercised at the Corporation's discretion.
Enterprise Connect	Toronto Hydro enterprise resourcing planning system.
Executives	The Executive Vice Presidents of Toronto Hydro or of any Subsidiary as may be applicable.

TERM or ACRONYM	DESCRIPTION
Personal Information	Information about an identifiable individual that is in the possession of or under the control of Toronto Hydro, including: (a) information relating to race, national or ethnic origin, colour, religion, age, sex, sexual orientation, marital status, education, medical and employment history; (b) any identifying number, symbol, or other particular assigned to him or her; (c) his or her address or telephone number; (d) his or her name if it appears with other information about the individual or would reveal his or her Personal Information; and (e) his or her personal opinions or views except if they relate to another individual. Personal Information does not include an individual's business contact information or work product, nor does it include information that has been aggregated or de-identified, such that an individual's information cannot be identified. Personal Information does not include information that is maintained for the purpose of creating a record that is available to the general public.
Procurement	A purchase, agreement to purchase, licence, lease or rental of any good or service, including an agreement to purchase construction services. Includes any extension or renewal of any procurement or construction Contract made prior to the date of this policy.
Procurement Policy	This Procurement Policy together with all forms and procedures referenced herein.
Senior Management	The Manager, Director, or General Manager of any Business Unit with responsibility for an approved budget for the Procurement in question.
Senior Management, IT	The Senior Management that is responsible for the operation of the Information Technology department.
Senior Management, Supply Chain Services	The Senior Management that is responsible for the operation of the Supply Chain Services.
Signing Policies	The most recent versions of the signing policies of Toronto Hydro as approved by the relevant Board of Directors.
Subsidiary	Toronto Hydro-Electric System Limited, Toronto Hydro Energy Services Inc. and any other direct or indirect subsidiary of Toronto Hydro Corporation, from time to time.
Supply Chain Services	The department responsible for all the Procurements within Toronto Hydro.
THESL	Toronto Hydro-Electric System Limited.
Toronto Hydro	Toronto Hydro Corporation and its Subsidiaries.

5 SCOPE

This policy applies to all Procurements made by Toronto Hydro except as otherwise authorized in writing by the Board or the CEO.

5.1 This policy is designed to augment other corporate policies and is not intended to replace or preclude them. Should an overlap arise between the application of this policy and any other policy, the policy most specific to the situation will apply.

6 OBJECTIVES

6.1 This policy is intended to assist in achieving Toronto Hydro's business objectives such as:

- Ensuring efficient Procurement at most favourable acquisition cost
- Promoting the use of competition in selecting suppliers and contractors
- Providing for the fair and equitable treatment of all suppliers and contractors
- Providing safeguards for maintaining a Procurement system of quality and integrity
- Ensuring suppliers meet or exceed Toronto Hydro's quality, safety and environmental requirements
- Ensuring that all Procurement is made in compliance with all regulatory requirements and applicable laws

7 GENERAL PROCUREMENT RULES APPLICABLE TO ALL BUSINESS UNITS

Unless otherwise authorized in writing by the Board or the CEO:

7.1 All Procurement shall be administered by the Supply Chain Services. All Procurement shall be reviewed and approved by Senior Management, Supply Chain Services unless it meets conditions outlined in section 2 of the *Appendix A - Exceptions to General Procurement Rules.*

7.2 Other than the exceptions in *Appendix A - Exceptions to General Procurement Rules*, all Procurements shall be sourced via the *Procedure for Competitive Procurement*.

7.3 All approved Procurement shall be processed and documented in accordance with the *Procedure to Document Approved Procurement*.

7.4 All Procurement of information technology related goods or services (including computer equipment, software or related services) with a Contract Amount greater than $25,000 USD or CAD must also be approved by the CIO or Senior Management, IT in writing**.** For all other Procurement of information technology related goods or services (including computer equipment, software or related services) Business Unit must consult with IT before Procurement.

7.5 The initial term for any Contract shall not exceed five (5) years, and any renewal term(s) shall not exceed a total of five (5) years unless it meets conditions outlined in section 8 of the *Appendix A - Exceptions to General Procurement Rules.*

7.6 The Senior Management, Supply Chain Services may at any time request that a particular Procurement be made through the *Procedure for Competitive Procurement*.

7.7 No current employee of Toronto Hydro shall communicate with a third party about a former or current supplier for purposes of providing reference/recommendation where such reference recommendation could be in any way construed as a reference/recommendation made on behalf of Toronto Hydro or that directly relates to work performed by the supplier unless authorized in writing by Senior Management, Supply Chain Services.

8 PROCUREMENT BETWEEN THESL AND AFFILIATES

8.1 Any and all Procurement involving the provision or receipt of services, resources, products, or use of an asset between THESL and one or more Affiliates must comply with the Ontario Energy Board's Affiliate Relationships Code for Electricity Distributors and Transmitters. For greater clarity, this includes transactions subject to Appendix A - Exceptions to General Procurement Rules.

8.2 Supply Chain Services and/or Business Units shall be responsible for obtaining the appropriate regulatory and legal advice from the Director, Regulatory Applications & Business Support and Director, Business Law Services or their respective delegates.

9 OWNERSHIP, APPROVAL AND RESPONSIBILITIES

Policy Owner

9.1 This policy is owned by the Executive Vice-President Planning & Chief Engineering & Modernization Officer (THESL).

9.2 The Executive Vice-President Planning & Chief Engineering & Modernization Officer is responsible for*:*

- Ensuring that this policy is comprehensive, clear and current
- Ensuring that this policy is implemented and communicated to the departments and staff that are impacted
- Ensuring ongoing compliance with this policy
- Reviewing this Policy annually and recommending any amendments for approval by the Administration Steering Committee

Policy Approver

9.3 This policy is approved by the Policy Administration Steering Committee*.*

9.4 The Policy Administration Steering Committee is responsible for:

- Considering the impact of the proposed policy to the identified risk
- Reviewing and approving any proposed amendments or content extensions to this policy
- Reviewing and approving this policy annually

Designated Responsible Person (DRP)

9.5 This policy is managed by the Senior Management, Supply Chain Services.

9.6 The Senior Management, Supply Chain Services is responsible for:

- Immediately communicating any exceptions or violations of this policy to the Executive Vice-President Planning & Chief Engineering & Modernization Officer.
- Reviewing this policy annually and communicating any proposed amendments to the Executive Vice-President Planning & Chief Engineering & Modernization Officer.
- Conducting quarterly reviews to ensure compliance with this policy

Staff

9.7 All Toronto Hydro employees, officers and directors are required to comply with this policy.

10 POLICY COMMUNICATION

10.1 Table below outlines how this policy changes will be communicated to Toronto Hydro

TYPE OF COMMUNICATION	COMMUNICATION TRIGGER	PARTY RESPONSIBLE FOR POLICY COMMUNICATION	AUDIENCE	ACKNOWLEDGEMENT?
E-mail	Minor policy Revision as per discretion of Executive Vice-President Planning & Chief Engineering & Modernization Officer.	Senior Management, Supply Chain Services	All Business Unit employees involved in any Procurement	No
Plugged In	Minor policy Revision as per discretion of Executive Vice-President Planning & Chief Engineering & Modernization Officer	Senior Management, Supply Chain Services	All Business Unit employees involved in any Procurement	No
Presentation	Significant policy Revision as per discretion of Executive Vice-President Planning & Chief Engineering & Modernization Officer	Senior Management, Supply Chain Services	All Business Unit employees involved in any Procurement	Quiz and Attestation

11 POLICY COMPLIANCE AND VIOLATIONS

11.1 Any employee who fails to comply with this policy is subject to disciplinary action up to and including dismissal.

11.2 Failure to comply with this policy will pose significant financial, operational, legal and regulatory risks to Toronto Hydro.

Compliance Monitoring

11.3 Senior Management, Supply Chain Services is responsible for tracking and collecting applicable data, measuring compliance and reporting in such format as may be required.

12 RELATED LAWS, REGULATIONS AND DOCUMENTATION

This policy shall be read and applied in conjunction with the Signing Policies, the Authorization Level Document, as well as the following documents and regulatory authorities:

- *Appendix A - Exceptions to General Procurement Rules*
- *Procedure for Competitive Procurement*
- *Competitive Procurement Request Form*
- *Competitive Procurement Evaluation Recommendation Form*
- *Sole Source Justification Form*
- *Extending Existing Contract Justification Form*
- *Procedure to Document Approved Procurement*
- *Non-Discretionary Providers List*
- *Contractor Pre-Qualification Application*
- *Ontario Energy Board Affiliate Relationships Code for Electricity Distributors and Transmitters*

1	**Petty Cash or Procurement Credit Card Purchases**	Procurement Policy does not apply to the following items:	
		1.1	Procurement that is processed in accordance with the most recent version of the Petty Cash Policy.
		1.2	Procurement that is processed in accordance with the most recent version of the Procurement Card Policy.
2	**Purchases Below $25,000**	Procurement that meets all of the following conditions may be sourced using procedures outlined in this section instead of the competitive procedures described in section 7.2 of the Procurement Policy or the sole source procedures described in section 4 of this document.	
		Conditions	
		2.1	Annual cumulative Contract Amount of the Procurement from a particular vendor is below $25,000.00 USD or CAD.
		2.2	Procurement is not artificially divided so as to constitute a Contract Amount below $25,000.00 USD or CAD.
		Procedures	
		2.3	If all of the above conditions have been met, an authorized person under the Authorization Level Document may approve such Procurement.
		2.4	It is strongly recommended to solicit at least 3 quotes from different suppliers to ensure competitive pricing.
		2.5	The Business Unit shall retain all documentation, including award justification, related to such Procurement for a review by the Supply Chain Services or Toronto Hydro's Internal Audit department or as otherwise directed by the Supply Chain Services on annual or as needed basis.
		2.6	Documentation shall be retained for no less than six years from the time of the Procurement and in accordance with Toronto Hydro's Records Management Policy.
3	**Contract Value Adjustments**	Procurement that meets all of the following conditions may be sourced using procedures outlined in this section instead of the competitive procedures described in section 7.2 of the Procurement Policy or the sole source procedures described in Section 4 of this document.	
		Conditions	
		3.1	Procurement represents an amendment to the original Contract Amount of an active, unexpired Contract.
		3.2	Cumulative value of all amendments is less than or equal to 10% of the original Contract Amount or is less than or equal to $250,000.00, whichever is smaller.
		Procedures	
		3.3	If all of the above conditions have been met, Senior Management may in writing, at his/her discretion and in accordance with the Signing Policy, authorize such Procurement.
		3.4	The Business Unit shall retain all documentation related to such Procurement for a review by the Supply Chain Services

			Department or the Internal Audit Department or the Legal Services department or as otherwise directed by the Supply Chain Services Department on as needed basis.
		3.5	Documentation shall be retained for no less than six years from the time of the Procurement and in accordance with Toronto Hydro's Document Retention Policy.
4	**Sole Source Procurement**	Procurement that meets any of the following conditions may be sourced using procedures outlined in this section instead of the competitive procedures described in section 7.2 of the Procurement Policy.	
		Conditions	
		4.1	Procurement cannot be processed in accordance with section 7.2 of the Procurement Policy due to time contraints imposed by an unforseeable situation or an emergency.
		4.2	Only one vendor is uniquely capable of providing goods or services.
		4.3	Procurement represents an amendment to the original Contract Amount above the threshold outlined in section 3.2 (of this document) or original term of an active, unexpired Contract.
		4.4	Procurement is related to a government or municipal agency that is not included in the *Non-Discretionary Providers List.*
		4.5	Competitive sourcing is currently in progress and goods or services are required for business continuation.
		4.6	Procurement is related to membership or donations.
		4.7	Goods or services required to support existing infrastructure, equipment, or system/applications and are either proprietary or are unavailable from any source except original supplier.
		4.8	Toronto Hydro is performing work on a property that can only be done by the lessor, owner, or their approved suppliers.
		4.9	Lease agreements.
		4.10	Procurement of goods or services for which Toronto Hydro will be fully reimbursed.
		Procedures	
		4.11	Business Unit shall submit a sole source purchase requisition in the Enterprise Connect (SAP) for the entire Contract Amount.
		4.12	Business Unit Executive shall review and authorize all sole source requisitions.
		4.13	Business Unit must complete and submit a *Sole Source Justification Form* to the Supply Chain Services.
		4.14	Upon receiving a completed *Sole Source Justification Form*, the Supply Chain Services will conduct a due diligence review in connection with the sole source purchase request. The review will also determine if the sole source purchase is in the best interests of Toronto Hydro, and include a review of the proposed contract's specifications, scope, definition, commercial terms, liabilities, and insurance requirements.
		4.15	Senior Management, Supply Chain Services shall review and authorize all sole source requisitions.

5	**Procurements From Non-Discretionary Providers**	Procurement that meets all of the following conditions may be sourced using procedures outlined in this section instead of the competitive procedures described in section 7.2 of the Procurement Policy or the sole source procedures described in Section 4 of this document.	
		Conditions	
		5.1	Supplier is listed on the *Non-Discretionary Providers List.*
		Procedures	
		5.2	An authorized person under the Authorization Level Document may approve such Procurement.
		5.3	This procurement may be paid via the non-order invoice.
6	**Extension of Existing Contracts**	Procurement that meets any of the following conditions may be sourced using procedures outlined in this section instead of the competitive procedures described in section 7.2 of the Procurement Policy.	
		Conditions	
		6.1	Business Unit wishes to exercise its contractual right to extend an existing Procurement as set out in an existing contract.
		6.2	Contract has provisions for extensions.
		6.3	Contract Amount is not depleted.
		Procedures	
		6.4	Business Unit shall complete *Extending Existing Contract Justification Form* and submit it to Supply Chain Services.
		6.5	Upon receiving a completed *Extending Existing Contract Justification Form*, the Supply Chain Services in consultation with Legal Services department will conduct a due diligence review of the extension request to determine if the current contract permits such an extension and whether such extension is in the best interests of Toronto Hydro, including a review of the proposed contract's specifications, scope, commercial terms, liabilities, and insurance requirements. Supply Chain Services will then process the request.
7	**Crisis / Emergency Management**	Procurement that meets all of the following conditions may be sourced using procedures outlined in this section instead of the competitive procedures described in section 7.2 of the Procurement Policy or the sole source procedures described in Section 4 of this document.	
		Conditions	
		7.1	Declaration of crisis / emergency by the Grid Emergency Management, Executives, or CEO.
		Procedures	
		7.2	If all of the above conditions have been met, Senior Management, Supply Chain Services may in writing, at his/her discretion and in accordance with the Authorization Level Document, authorize such Procurement.

		7.3	Supply Chain Services shall retain all documentation, including award justification, related to such Procurement for a review by the Toronto Hydro's Internal Audit department on annual or as needed basis.
		7.4	Documentation shall be retained for no less than six years from the time of the Procurement and in accordance with Toronto Hydro's Records Management Policy.
8	**Contract Term exemption**	Procurement that meets all of the following conditions may have a longer Contract term than described in section 7.5 of the Procurement Policy.	
		Conditions	
		8.1	Procurement is related to Real Estate leasing agreement.
		Procedures	
		8.2	If all of the above conditions have been met, The Executive Vice President, Chief Customer Care, Electric Operations & Procurement Officer may in writing, at his/her discretion authorize such procurement.

Appendix B
Engagements Not Originating from a Competitive Procurement Process

Year	Supplier Name	Cost ($M)	Summary of Nature of Transaction	Methodology used for Selection
2020	Anixter Power Solutions Canada	$4,500,000	Purchase of submersible and vault transformers for business continuity and contingency management.	Sole Source
2020	Oracle Canada ULC	$2,000,000	Purchase of proprietary license subscriptions and maintenance.	Sole Source
2020	SAP Canada Inc.	$1,600,000	Purchase of SAP licence products for system capability expansion.	Sole Source
2020	Bentley Canada Inc.	$1,300,000	Purchase of support and maintenance services for Bentley MicroStation application.	Sole Source
2020	Dynatrace Corporation of Canada	$1,245,000	Purchase of support services for suite of Dynatrace application monitoring products.	Sole Source
2021	Motorola Solutions Canada Inc.	$1,802,000	Purchase of radio-based communication equipment upgrades.	Sole Source
2021	IBM Canada Ltd.	$1,800,000	Purchase of support services for IBM software and maintenance products.	Sole Source
2022	SAP Canada Inc.	$3,851,088	Purchase of maintenance and support for SAP software applications.	Sole Source
2022	Nokia Canada Inc.	$1,200,000	Purchase of proprietary software used for capacity augmentation and maintenance.	Sole Source
2023	Trans Canada Forest Products	$2,000,000	Purchase of treated wood poles for business continuity and contingency management.	Sole Source
2023	Dell Canada Inc.	$4,600,000	Purchase of licences for a suite of Dell application storage products.	Sole Source

WORKFORCE STAFFING AND COMPENSATION OVERVIEW

Investments in human capital are a key component of the 2025-2029 investment plan, as Toronto Hydro relies on having a highly-skilled and dedicated workforce to deliver the 38 capital and operations work programs in Exhibit 2B and Exhibit 4, Tab 2, respectively. Without a sufficiently skilled and capable workforce, Toronto Hydro would face significant risks in executing its plan and achieving performance outcomes that customers need and value.[1] To prevent these consequences, the utility needs to increase its workforce capacity by approximately 214 resources starting in 2024 through 2029.[2] On a Full Time Employee ("FTE") basis as outlined in Appendix 2-K, this increase amounts to roughly 25 percent of the overall FTE complement.

In addition to the accelerated pace of investment that is required to sustain, modernize and expand the grid for an electrified future, changes in technology, policy and customer expectations are putting pressure on the workforce to be future-ready and capable with enhanced skills to perform work in an increasingly fast-paced, complex and data-intensive operating environment. Toronto Hydro's workforce plan includes critical investments in building advanced skills and capabilities needed to rise up to the challenge.

The evidence in this Exhibit 4, Tab 4 presents Toronto Hydro's workforce needs, plans and its compensation strategies and costs for the 2025-2029 rate period as follows:

- Schedule 1 – Overview
- Schedule 2 – OEB Appendix 2-K (Employee Cost)
- Schedule 3 – Staffing Strategy

[1] Please see Exhibit 1B, Tab 3, Schedule 2 for an overview of Toronto Hydro's historical performance.
[2] The staffing plan is based on headcount needs and requirements over the filed period. Appendix 2-K presents the translation of the staffing plan to budgeted full time equivalents (FTEs).

- Schedule 4 – Compensation
- Schedule 5 – Mercer Benchmarking Report

1. STAFFING PLAN AND CHALLENGES

Toronto Hydro has a robust and engaged workforce that delivers valuable outcomes to the company and its customers. The key tenets of Toronto Hydro's workforce philosophy are:

a) **Talent Acquisition & Development**: Attract and recruit talent for the organization to fill critical roles and achieve business objectives. Provide training and development opportunities to help employees grow and acquire new skills, create career paths and implement succession plans.

b) **Workforce Culture, Diversity and Inclusion**: Create a diverse and inclusive workplace where everyone feels valued, supported and respected. Foster a growth mindset and positive culture that promotes employee engagement, wellness and work-life balance to maintain an engaged, innovative and high-performing workforce.

c) **Performance and Productivity**: Achieve objectives by setting clear expectations, providing regular feedback, and recognizing and rewarding employees who meet or exceed expectations. Embrace new technology and invest in tools and systems that can improve efficiency, automate repetitive tasks, enhance the quality of work, and promote collaboration across teams.

d) **Agility & Innovation**: Adapt to evolving business needs, emerging technologies, and changing market conditions by leveraging data and analytics to monitor market trends, measure performance, and make data-driven decisions.

1.1 Needs and Challenges

Over the last decade and throughout the current rate period, Toronto Hydro focused on rebuilding and replenishing its workforce in the face of both familiar challenges (i.e.

retirements and attracting and retaining talent) and emerging challenges brought on COVID-19 and other external factors affecting Toronto Hydro's business. During the pandemic, Toronto Hydro's workforce numbers reached a historic low in 2021. Retirements that were expected to be paced fairly evenly over the 2020-2025 rate period were instead concentrated in years 2020 and 2021. At the same time, the pandemic temporarily suspended talent acquisition, training, and development for critical areas and skill sets established during the previous rate period. As a result, Toronto Hydro's plans to increase its staffing levels over the 2020-2024 period were delayed.

Toronto Hydro proved its aptitude in addressing these challenges, with notable achievements including:

- Over 100 trades and technical positions filled as of 2022;
- Average age of employees in 2022 was 40 – a 14% decrease over the last decade;
- 76% talent retention rate;
- 25% of roles filled by new graduates from colleges and universities;
- Continued focus on job harmonization with the Power Line Technician trade, augmenting total harmonization from 51 non-management unionized jobs to 12; and
- 40% of roles filled from within to support career development, talent retention and succession planning.
- Total recordable injury frequency improved by 43% from 2018 to 2022 leading to a safer and more productive workforce;
- Consistently ranked as one of the Best Corporate Citizens in Canada by Corporate Knights since 2018 (in 2022 placing 2nd overall and 1st in the category of Electricity Transmission and Distribution) in recognition of responsible investments to achieve social and environmental benefits for the customers of Toronto Hydro; and

- Received multiple awards, including: (i) recognition by Electricity Canada for Leadership in External Collaboration and Partnerships, and the President's Award of Excellence for Employee Safety – Distribution, (ii) sustainability leader by Canada's 2024 Clean50, in addition to earning a spot on Canada's Clean16 list as a top contributor in the category of Traditional Energy and (iii) Most Effective Recovery Award from the Business Continuity Institute Americas recognizing Toronto Hydro's response to COVID-19 and its efforts to mobilize immediately to protect its workforce and the public, while continuing to provide safe and reliable delivery of electricity throughout the city of Toronto.

In addition to these achievements, the utility also expects to successfully implement its resource plan over the current rate period by catching-up to the overall levels that were forecasted in the 2020-2024 rate application.[3] Yet fundamental shifts have taken place since the last application that have material implications, and require responsive action over the 2025-2029 rate period. Customers, governments, and markets have started coalescing around a need to accelerate the energy transition to mitigate the existential and economic impacts of climate change. As customers electrify previously non-electric energy uses (e.g. transportation and heating) and increase participation in clean energy production and management, these actions will have fundamental long-term implications for Toronto Hydro and its system. Because the external environment has changed, Toronto Hydro's resource catch-up efforts are also a foundational step towards a future-ready plan that includes investments in resourcing capacity (headcount) and capabilities (enhanced skills) that are necessary to meet the challenge ahead.

[3] EB-2018-0165.

Toronto Hydro needs to expand its workforce by approximately 214 resources starting in 2024 through 2029 to meet the imperatives and objectives of its 2025-2029 investment plan. These investments are necessary to both ensure adequate resourcing to support the safe and efficient execution of planned work programs, and develop advanced capabilities to advance outcomes that matter to customers and stakeholders, including a building a more resilient and efficient grid for the future and enabling the city's economic growth and electrification.[4] Technological advancements and evolving customer expectations require Toronto Hydro to accelerate digital transformation to keep up with the pace of change. Attracting and developing employees with the skills and competencies to meet the technical challenges and achieve the objectives of modernizing and expanding the grid is a critical component of the utility's workforce strategy.

1.2 Talent Development Strategy

A strong talent attraction and engagement strategy is critical to: (i) continue to position Toronto Hydro as an employer of choice; (ii) build staff competence to address requirements, deliver plans, and integrate more technology and innovation into their work; and (iii) advance leadership skills and competence to support diversity, equity and inclusion, lead in a hybrid work environment and role model culture change.

Toronto Hydro takes a comprehensive, forward-looking approach to maximizing the value of its existing employee resources by providing timely upskilling and training opportunities, applying productivity strategies, supporting innovation, promoting from within the organization, and using management tools to maximize employee performance. Toronto Hydro relies on a combination of all these approaches to achieve organizational success and meet its human resource requirements.

[4] See Exhibits 2B, Section E and Exhibit 4, Tab 2.

While Toronto Hydro maximizes the value of its existing workforce, the utility is unable to meet the needs and drivers of its staffing plan exclusively from hiring internally. To meet its staffing needs through external recruits, Toronto Hydro employs a combination approach that includes acquiring additional talent from the market, hiring new graduates, leveraging its relationships with colleges and universities, and outsourcing work to third-party service providers where appropriate.

2. COMPENSATION STRATEGY

Toronto Hydro's workforce is the means by which the utility delivers service and value to its customers, carries out its objectives, and complies with its mandatory obligations. The utility strives to secure and maintain a workforce that is highly skilled, agile, innovative, productive and engaged. To achieve these key outcomes in a cost-effective manner, Toronto Hydro's compensation strategy is to: (i) provide wages and benefits that are competitive in the markets where Toronto Hydro competes for talent, and (ii) use a pay-for-performance model to align the workforce with the utility's core objectives, set and manage high performance expectations, foster productivity, and reward employees for their contributions to the utility's performance. The effect of external pressures and shifting preferences of candidates in a large and diverse urban city requires a strong market-competitive compensation program to attract, retain and engage employees.

According to Mercer's Compensation Benchmarking study (the "Mercer Study") which can be found at Exhibit 4, Tab 4, Schedule 5, Toronto Hydro's total compensation is positioned within a market competitive range relative to the 50th percentile of the energy market. With respect to the general industry peer group, total compensation is slightly above market due to pensions and benefits, while the total cash component of compensation is within market

range. The Mercer Study affirms that Toronto Hydro's compensation strategy continues to yield good value for the utility and its customers.

The forecasted total compensation cost for 2029 is $375.5 million, which represents a compound annual growth rate of 6.6 percent over the total compensation costs of $211.1 million in 2020. For total cash compensation costs (i.e. base salary wages, overtime and incentive payments) the average cost per full-time employee ("FTE") is increasing by a compound annual growth rate of 3.7 percent from 2020 to 2029.[5] In preparing 2024 to 2029 total cash compensation forecasts and the various components of them, Toronto Hydro considered, and the forecasts reflect, the following inputs: (i) Toronto Hydro's obligations under collective agreements, (ii) relevant labour market data (where available),[6] and (iii) the utility's projections of outcomes of future rounds of collective bargaining that will take place throughout the forecast period. More specifically, in the absence of objective market indicators to forecast compensation increases over the 2025-2029 forecast period, the utility (in consultation with its compensation expert Mercer Canada and based on experience) relied on a using a historical rolling-average (in addition to the factors noted above) as the best information available to predict reasonable future compensation levels.

2.1 Compensation Philosophy for Non-Union Employees

Toronto Hydro provides non-unionized employees with a total cash compensation package comprised of two elements: base salary and variable performance pay. Base salary compensates an employee for meeting the expectations related to their responsibilities, accountabilities, and technical skills. Variable performance pay rewards employees for their

[5] The average cost per employee is mathematically derived from the data in OEB Appendix 2-K; namely total compensation divided by total FTEs per year.
[6] For example, the results of Mercer Canada's August 2023 QuickPulse™ Canada Compensation Planning Survey show total salary increases of 3.7 percent: https://www.imercer.com/ca/ARTICLEDETAIL/annual-increase-budget-canada

contribution to achieving goals and objectives tied to the utility's strategic pillars, in combination with their successful demonstration of corporate competencies.

Each non-union position at Toronto Hydro has a salary grade with a corresponding salary range. To maintain alignment with the competitive labour market, the utility adjusts salary ranges based on annual market reviews.

Because Toronto Hydro operates in niche areas of expertise, both as part of the electricity system and as a regulated entity, the utility hires capable workers but at a less experienced level, and trains and develops them on the job. From 2019 to 2023 year-to-date, newly hired employees were brought into their roles at an average of 87 percent of the salary grade. To keep the workers that Toronto Hydro invests in training and developing on the job, the utility progresses them through the salary ranges more quickly to reflect their upskilling and acquired experience levels.

2.2 Compensation Philosophy for Bargaining Unit Employees

Over half of Toronto Hydro's employees belong to collective bargaining units represented by the Power Workers' Union ("PWU"), the Society of United Professionals - Engineers ("Society Engineers"), or the Society of United Professionals - IT ("Society IT"). Toronto Hydro's compensation costs with respect to these employees are negotiated through periodic collective bargaining in accordance with the legal duty to bargain in good faith. The utility has both contractual and statutory obligations to honour the terms of its collective bargaining agreements. [7]

[7] *Ontario Labour Relations Act,* 1995, S.O. 1995, c. 1, Sched. A, section 56.

The current collective agreement with PWU was effective as of February 1, 2022 and is valid until January 31, 2027. The utility's current collective agreement with the Society Engineers came into effect January 1, 2020 and is valid until December 31, 2023. The utility's current collective agreement with Society IT came into effect January 1, 2021 and is valid until December 31, 2025.

2.3 Benefits and Pensions

In order to remain competitive for talent, full-time employees are entitled to medical and dental benefits, short- and long-term disability income protection, life insurance, and accidental death and dismemberment insurance. Employees are also eligible to participate in the Ontario Municipal Employees Retirement System pension plan and receive post-retirement benefits. The cost of employee benefits is expected to increase from $74.5 million in 2025 to $104.6 million in 2029.

To manage benefits costs, Toronto Hydro regularly negotiates with benefit providers and conducts comprehensive vendor market reviews on a periodic basis. In 2021 Toronto Hydro conducted a vendor market review for the Employee and Family Assistance Program which resulted in the utility securing a new provider for employee mental health and overall wellness at a reduced per member rate of approximately 30 percent.

WORKFORCE STAFFING PLAN AND STRATEGY

The 2025-2029 investment plan includes necessary investments in 38 distinct work programs to address existing and emerging challenges that the utility faces in serving its customers safely, reliably and efficiently in this decade and beyond as the city of Toronto continues to grow amidst an energy transition that is creating an expanded role for electricity across key sectors of the economy.

Toronto Hydro needs a robust, engaged and highly-skilled workforce to support execution of planned capital and operations work programs outlined in Exhibits 2B and 4, Tab 2, respectively. This schedule outlines Toronto Hydro's workforce philosophy and plans to secure the resources and skill sets that the utility needs to: (i) deliver its work programs safely, reliably and efficiently, and (ii) achieve the performance outcomes that customers need and stakeholders value as outlined in Exhibit 1B, Tab 3, Schedules 1 and 2.

The evidence is organized as follows:

- Workforce Philosophy
- Workforce Drivers and Needs
- Workforce Breakdown by Segment
- Talent Development Strategy

1. WORKFORCE PHILOSOPHY

Demographic and post-pandemic societal shifts are reshaping the labour market in Canada, at the same time that technology and digital innovation are redefining the skill sets and strategies needed to ensure an agile, engaged and productive workforce. Toronto Hydro's workforce philosophy is mindful and responsive to key changes in the labour market and

employee preferences. To maintain its competitive advantage in the evolving labour market and remain an employer of choice, Toronto Hydro must invest in its greatest asset – its people. These investments entail increases in the capacity of the workforce to maintain employee wellness and avoid employee burnout through work-life balance (the right to disconnect from work). Similarly, Toronto Hydro must invest in advanced skills and capabilities to empower its workforce to excel in the face of rapid technological advancement, and changing policy requirements and evolving customer expectations.

To build and maintain a robust, diverse, engaged and productive workforce, Toronto Hydro relies on the following key tenets of its workforce philosophy:

a) **Talent Acquisition & Development**: Attract and recruit talent for the organization to fill critical roles and achieve business objectives. Provide training and development opportunities to help employees grow and acquire new skills, create career paths and implement succession plans.

a) **Workforce Culture, Diversity and Inclusion**: Create a diverse and inclusive workplace where everyone feels valued, supported and respected. Foster a growth mindset and positive culture that promotes employee engagement, wellness and work-life balance to maintain an engaged, innovative and high-performing workforce.

b) **Performance and Productivity**: Achieve objectives by setting clear expectations, providing regular feedback, and recognizing and rewarding employees who meet or exceed expectations. Embrace new technology and invest in tools and systems that can improve efficiency, automate repetitive tasks, enhance the quality of work, and promote collaboration across teams.

c) **Agility & Innovation**: Adapt to evolving business needs, emerging technologies, and changing market conditions by leveraging data and analytics to monitor market trends, measure performance, and make data-driven decisions.

2. WORKFORCE DRIVERS AND NEEDS

2.1. Challenges

Over the last decade and throughout the current rate period, Toronto Hydro focused on rebuilding and replenishing its workforce in the face of both familiar and emerging challenges. Familiar challenges for Toronto Hydro include renewing its workforce due to retirements, attracting and retaining talent, and developing new entrants to its workforce through partnerships with colleges and universities. For the last ten years, Toronto Hydro has managed the workforce renewal challenge brought by the wave of baby-boomer retirements.[1] After each retirement, the organization must deal with not only a loss of knowledge and experience, but also a need to train and develop the individuals promoted or newly hired. In addition to demographic-related challenges, Toronto Hydro employees are often sought after by other organizations that may offer similar roles in neighbouring geographic regions. A competitive labour market challenges the utility to maintain market competitiveness of its compensation and benefits programs to attract and retain employees to work in Toronto.

Although employment in the utilities sector has remained relatively stable, labour market changes, including demographic shifts, increasing competition and strong demand for workers with digital skills have led to shortages of workers trained in science, technology, engineering and mathematics (STEM), as well as in digital skills.[2] Toronto is the largest city in Canada and one of the fastest growing urban centers in North America and the demand for qualified and knowledgeable STEM resources is strong, not only with the utilities sector but among multiple sectors outside of the industry.

[1] The term “baby boomers” refers to those individuals that were born between 1947 and 1965.
[2] Mahboubi, Parisa. 2022. The Knowledge Gap: Canada Faces a Shortage in Digital and STEM Skills. Commentary 626. Toronto: C.D. Howe Institute: https://www.cdhowe.org/sites/default/files/2022-08/Commentary_626_0.pdf

Toronto Hydro also faced unprecedented challenges posed by the COVID-19 pandemic and consequent impacts. During the pandemic, Toronto Hydro's workforce numbers reached a historic low in 2021. Retirements that were expected to be paced fairly evenly over the 2020-2025 rate period were instead concentrated in years 2020 and 2021. At the same time, the pandemic temporarily suspended talent acquisition, training, and development for critical areas and skill sets established during the previous rate period. As a result, Toronto Hydro's plans to increase its staffing levels over the 2020-2024 period were delayed, particularly as it relates to the Power Line Technician trade hiring plan. The rapidly changing business environment and social distancing requirements impacting hiring for positions requiring in-person training contributed to this unavoidable hiring delay.

Toronto Hydro successfully weathered the challenges of remote work and of addressing increased safety risks, with a comprehensive infectious disease response plan. At the outset of the COVID-19 pandemic, Toronto Hydro mobilized immediately to protect its workforce and the public while continuing to provide safe and reliable delivery of power throughout the city of Toronto. The plan established protocols required to manage an infectious communicable disease outbreak to maintain the health and safety of employees and mitigate the spread of infectious disease through the workforce. Toronto Hydro did not experience any workplace transmission of COVID-19 through 2022. In recognition of its response to COVID-19, Toronto Hydro received the Most Effective Recovery Award from the Business Continuity Institute (BCI) Americas. The BCI, a global organization of business continuity and resilience professionals representing more than 100 countries worldwide, gives this award to an organization that was significantly impacted by an incident or crisis, but managed to recover and demonstrate resilience.

The COVID-19 pandemic significantly impacted traditional talent management approaches and introduced a new level of complexity in recruiting talent. Changing attitudes towards commuting to the workplace and the overall concern of extended commute times in the City of Toronto added a new layer of challenge and complexity to the utility's attraction and retention efforts.[3] The utility addressed this through flexible work policies that are responsive to changing preferences. Specifically, in 2022, Toronto Hydro transitioned to a hybrid work arrangement that enables employees who can perform their work from home with the flexibility to attend their assigned work center a minimum number of days a week and work remotely the other days. Reintegrating the workforce into the office and building a hybrid work culture where employees feel engaged was a notable challenge that Toronto Hydro worked hard to overcome over the last two years. It succeeded by adopting work policies and practices that were informed by employee feedback, and implemented incrementally with a focus on the unique needs of each operational area. This was complemented by a gradual increase in in-person employee engagement, which helped ensure the successful adoption of the new hybrid work model throughout the organization.

Once the acute challenges of the pandemic began to subside, customers, governments, and markets started coalescing around a need to accelerate the energy transition to mitigate the existential and economic impacts of climate change. As customers electrify previously non-electric energy uses (e.g. transportation, heating) and increase participation in clean energy production and management, these actions will have fundamental long-term implications

[3] In 2022, Mercer conducted the Flexible Working Policies and Practices Survey across Canada, polling employers and employees on offerings and preferences for onsite, hybrid and fully remote working arrangements. The survey indicated that 53% of employers offered and 53% of employees wanted hybrid working arrangements. https://www.imercer.com/ca/products/flexible-working policies-practices-survey-ca

for Toronto Hydro and its system, including—but not limited to—being ready to serve a future demand for electricity that is expected to roughly double over the next two decades.[4]

Given its fundamental obligation to connect customers who want to access the distribution grid, Toronto Hydro cannot enter this period of significant change unprepared to handle increased demand and consumption, bi-directional power flows, increased societal reliance on electricity, and enhanced customer expectations that naturally flow from these evolutions. As with investments in Toronto Hydro's grid, human capital investments require a long lead-time to develop and safely train. Depending on the trade, for example, it takes anywhere from four and half to six and a half years to train a new certified and skilled trades person, plus a minimum additional one to two years to develop a new front-line leader post apprenticeship. Due to the long lead time required for investment in both grid and human capital, to meet these needs Toronto Hydro must begin work today to be prepared for an accelerated energy transition in the next decade.

2.2. Capacity

As the operating conditions affected by COVID-19 pandemic stabilized in 2022, Toronto Hydro started increasing the pace of its recruitment to 'catch-up' to its projected staffing levels by the end of 2023. Yet, because the external environment has changed, these catch-up efforts are also a foundational step towards a future-ready plan that includes investments in resourcing capacity (headcount) and capabilities (enhanced skills) that are necessary to meet the challenge ahead.

Toronto Hydro needs to expand its workforce by approximately 214 resources starting in 2024 through 2029 to meet the imperatives and objectives of its 2025-2029 investment

[4] As shown in Future Energy Scenarios report filed as Exhibit 2B, Section D4, Appendices A and B.

plan.[5] These investments are necessary to: (i) ensure adequate resourcing to support the safe and efficient execution of planned work programs outlined in Exhibits 2B, Section E and Exhibit 4, Tab 2, and (ii) develop advanced capabilities to advance outcomes that matter to customers and stakeholders, including a building a more resilient and efficient grid for the future and enabling the city's economic growth and electrification.

Toronto Hydro's workforce requirements have been optimized by a decade and half journey of productivity. This includes harmonizing jobs to create a more efficient and agile workforce, outsourcing certain functions and aspect of work to focus on critical competencies and skills, and automating repetitive manual processes to provide more efficient service. These efforts produced a demonstrably lean workforce, enabling Toronto Hydro to tackle the staffing needs and challenges ahead from a position of strength.[6]

After more than a decade of realizing sustained efficiencies while managing complex operations with a flat headcount, it is no longer possible nor prudent for Toronto Hydro to meet its obligations without additional resources. As the utility takes "least regrets" actions to expand and modernize the grid to be ready and equipped for a once-in-a century transformation of the energy system, it similarly needs to invest in an expanded resource pool with new and enhanced skill sets to get the work done safely and cost-effectively.

Section 3 below provides an overview of the different segments of Toronto Hydro workforce and explains the capacity investments that Toronto Hydro intends to make over the coming years to meet the challenges ahead. The Designated and Technical Professionals segment will see the largest number of resources added with the addition of approximately 250

[5] The staffing plan is based on headcount needs and requirements over the filed period. Appendix 2-K presents the translation of the staffing plan to budgeted full time equivalents (FTEs).
[6] Please see Exhibit 4, Tab 1, Schedule 1 at section 2.

resources over the 2023-2029 period. Workers in this segment will support not only a growing capital program, but will also provide new needed capabilities related to technology, advanced data analytics and other digital skills.

2.3. Capabilities

Technological advancements and evolving customer expectations require Toronto Hydro to accelerate digital transformation to keep up with the pace of change. With increasing technology on the grid (e.g. Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI), sensors and other field monitoring technologies) comes a significant increase in the volume of data generated in the field. To effectively leverage this data and gain valuable insights that can be used for improved planning and optimized decision-making, Toronto Hydro needs to hire and develop resources with expertise in advanced data analytics, statistical modelling, data science and machine learning techniques.

Toronto Hydro must prepare to respond by attracting and developing employees with the skills and competencies to meet the technical challenges and achieve the objectives of modernizing and expanding the grid. For example, the Control Centre requires the support of a team of technical staff whose duties include work scheduling, design review, system analysis, energy management, reporting, and maintenance/development of core operating technology platforms and tools (e.g. SCADA, Energy Centre, Network Management System, etc.) Over the next several years, Toronto Hydro expects a significant increase in workload associated with these functions to support increased distribution system automation, the development and sustainment of energy management functions, distribution system growth (load and connection volumes), and the expansion of the SCADA system to enable more

remote and autonomous operational capabilities. See Exhibit 4, Tab 2, Schedule 7 – Control Centre Operations.

By employing and cultivating resources with advanced digital skills and capabilities, the utility can gain a much more comprehensive understanding of grid performance, identify anomalies, and optimize various aspects of grid operations. Data analysts empowered with the right technology tools can develop models and algorithms that enable predictive maintenance, load forecasting and demand response optimization. They can also uncover hidden relationships between variables to improve grid stability, enhance asset management strategies, and enhance outage management processes. The ability to extract actionable insights from vast amounts of grid data can enable Toronto Hydro to make better decisions and deliver enhanced value to customers. For example, with the implementation of AMI2.0 Toronto Hydro can perform advanced analytics on meter-level outage data to better understand reliability performance at the customer level, and optimize investments to enable a more resilient and efficient grid for the future.

Building advanced capabilities to leverage technology and advanced data analytics to improve existing systems and processes is a critical component of the utility's workforce strategy. To upskill its existing workforce, Toronto Hydro is taking the following actions:

- **Providing Opportunities for Skills Development:** The utility proactively identifies resourcing requirements and provides internal resources with opportunities for skills development. Multiple methods have been used to achieve successful outcomes including: (1) continuing education at post secondary institutions and certification programs, (2) experiential learning opportunities through secondments, stretch assignments and involvement on project teams, and (3) formal job-specific training on technical and soft skills. The organization's performance management system

encourages leaders to have regular meetings with employees to understand individual learning goals and structured development plans with milestones and objectives.

- **Developing and Delivering Training Programs:** As new and future skill requirements are identified, the utility develops and aligns training programs with specific learning goals and outcomes and delivers them to its workforce. Training develops transferable skills and increases the employee's capacity to learn. Training is supported with confirmation of learning and skills transfer in the field and inspections conducted by front line leaders. This ensures that the workforce knowledge has increased sufficiently to safely and efficiently apply the new skill in practice. Upskilling equips employees with the skills needed now and for the future, supports career progression and is a strategy that supports retention.
- **Maintaining Safe Ratios of Supervision and Mentorship:** Toronto Hydro conducts sophisticated long-term workforce staffing planning within its Certified and Skilled Trades and Designated and Technical Professional positions to maintain the workforce's competencies. This ensures that the learning and development opportunities afforded to apprentices remain safe as a result of Toronto Hydro established ratios of supervision and mentorship.

Toronto Hydro must invest in building a workforce with expanded skills in data analytics, data science and big data who can leverage technology solutions such as artificial intelligence (AI) software and other tools to manage and analyze large datasets towards the following types of objectives.

1. Respond to risks posed by potentially disrupting technologies to the distribution system. Grid modernization involves the integration of numerous digital technologies. Ensuring robust cybersecurity measures is of paramount importance.

To address this evolving threat landscape, there is a need to prioritize and augment capabilities and implement comprehensive strategies, such as conducting regular security audits, and deploying advanced monitoring systems. The utility must assess the security posture of grid components, such as smart meters, ADMS systems, and communication networks. Specialized knowledge is required to recommend appropriate security controls and measures. The addition of resources to support cybersecurity risk and threat management ensures the resilience and reliability of the grid system as it undergoes modernization efforts.

2. Design, operate and manage an automated and bi-directional grid that is capable of connecting and integrating higher volume of distributed energy resources (DERs). DER integration professionals collaborate with stakeholders including regulators, DER providers, and customers to develop standardized interconnection processes, address technical challenges, and streamline grid operations. With employees knowledgeable in DER integration, it is easier to unlock the full potential of DERs, maximize grid efficiency, and accelerate the transition to a clean and decentralized energy future. The utility must also invest in training activities to enhance the knowledge and capabilities of its Certified and Skilled Trades segment to safely plan and operate within an automated and bi-directional grid. This will enable Toronto Hydro to effectively manage grid variability, enhance resiliency, and optimize asset utilization.
3. Building the utility's capacity and capability to provide proactive information and service to drive improvements to customer experience, outcomes and interaction with the grid. Toronto Hydro is working to meet customers' evolving expectations of the utility. For example, as EV ownership increases and as more customers adopt DERs, Toronto Hydro anticipates an increase in customer inquiries related to these technologies, including topics such as service upgrades, connections, pricing plans

for EV charging and net metering and associated billing for DERs. The utility is looking to enhance the capabilities of its customer service representatives to ensure that Toronto Hydro is prepared to respond to customer needs in time for the energy transition.[7]

4. Building the utility's capacity and capability to respond effectively to fast-evolving regulatory policy developments, challenges and opportunities in the current business environment. The utility has extensive legal, regulatory and communication needs served by highly-trained legal, regulatory and communications professionals. This team's capacity and capabilities need to be enhanced in order to keep up with the volume and complexity of work necessary to support the utility's work program which is shaped by electrification, the energy transition, new technologies and evolving customer choice. Drivers of this increase include an increase in contract volumes, claims volumes, agreements associated with large transit projects, and legal, compliance and policy work responsive to changes in the energy sector.

Table 1 below provides a summary of the skills sets and sample jobs where the utility is investing to build the workforce of the future.

Table 1: Skill Sets and Job Types for the Future Workforce

Skill Sets	Job Types	Approximate Proportion of Staffing Plan
"Big Data" Analytics – Consolidation & Presentation of data to support Decision Making	Analysts – cross functional	23%

[7] Cross-references to 4A Customer Care program

Skill Sets	Job Types	Approximate Proportion of Staffing Plan	
Design, operational and management of distribution grid	Power Line Technician, Engineering Technologist, Power System Controller, Meter Mechanic, Meter Data Technologist, Distribution System Technologist, Dispatcher	18%	/C
Front-line Leadership	Day-to-day operations and people management	20%	/C
Financial management, regulatory affairs management, legal management, supply chain management, operations support, human resources management	Professional & supporting skills – cross functional	12%	/C
Distribution system design and engineering to support existing and new technologies (e.g. bi-directional grid, distributed energy resources)	Engineers	11%	
Customer Experience, Key Account Management, Customer Relations Management	Large Customer & Key Account Consultant Customer Relations Representative	10%	
New technical and cyber security skills to support technology advancements and innovation	IT Technical Consultant Cyber Security Specialist	7%	
TOTAL		**100%**	

3. WORKFORCE BREAKDOWN BY SEGMENT

Toronto Hydro has a robust workforce of highly-skilled employees across diverse areas of expertise. Figure 1 shows the current and future composition of the projected workforce, by segment, out the end of the decade. The skills of employees and type of work executed within each segment is discussed in detail below.

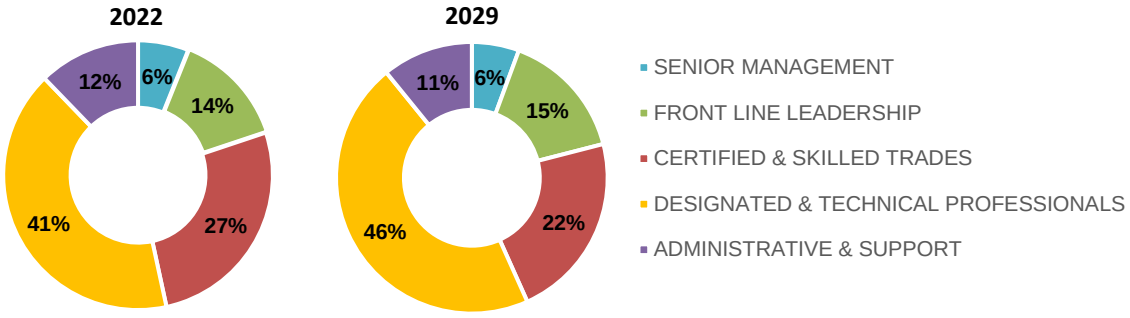


Figure 1: Projected Toronto Hydro Workforce Segments (2022 & 2029)

3.1. Certified and Skilled Trades Segment

Certified and Skilled Trades are responsible for executing the work required to construct and maintain the distribution system infrastructure, and for responding to trouble calls and emergency situations to restore power or address asset deficiencies or other circumstances that pose safety, environmental or reliability risks. Certified and Skilled Trades comprised approximately 27 percent of Toronto Hydro's workforce as of the end of 2022. Although this segment is anticipated to decrease slightly as a percent of the total population of employees because of practical limitations of safely absorbing new certified and skilled trades into the organization (i.e. maintaining the appropriate apprentice to qualified journeyperson ratios), Certified and Skilled Trades are expected to grow by approximately 40 resources by 2029 to replenish the workforce in this segment.

Below is a detailed list of the positions and associated responsibilities within this segment.

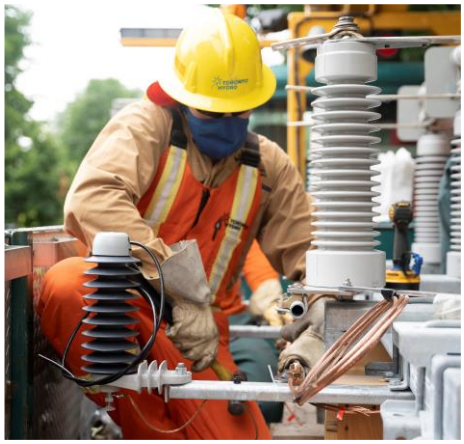
- **Certified Meter Mechanic/Tester ("CMMT"):** Installs, changes, removes, repairs, inspects, tests and calibrates of all types of meters and metering equipment for correct wiring and accuracy of metering, operation of meter test equipment according to documented procedures and to troubleshoot faults in meters.

- **Distribution System Technologist ("DST"):** In 2009, job harmonization merged six classifications into the new classification of Distribution System Technologist (DST). The DST operates, installs, commissions, constructs, repairs, maintains, and decommissions all types of substation equipment, protective relay and control systems, station metering, distribution automation equipment, and SCADA systems, including completion of all associated work orders, specifications, engineering drawings, reports, and work procedures**.**
- **Power Line Technician ("PLT")**: Constructs, operates, maintains and repairs overhead and underground electrical and distribution systems. Erects and maintains steel, wood, fiberglass, laminate and concrete poles, structures, and other related hardware. The PLT installs, maintains and repairs overhead and underground apparatus, and other associated equipment, such as insulators, cable, conductors, lightening arrestors, switches, metering systems, transformers and lighting and control systems. Splices and terminates cable and conductors to connect power distribution and transmission networks. Previously, this work had been performed by two distinct trades groups, the Certified Power Cable Person ("CPCP") and Certified Power Line Person ("CPLP"). Similar to the approach used in prior years as part of the collective bargaining process, in 2022, these two roles were harmonized into the Toronto Hydro Power Line Technician role. Graduates of the PLT Apprenticeship program will be competent to work safely on any aspect of the overhead or underground distribution system for both capital construction as well as reactive or emergency scenarios. This will provide Toronto Hydro with significantly greater flexibility in crew assignments and execution of work.
- **Power System Controller ("PSC")**: Operates the electrical distribution system to provide safe, reliable, and cost-effective delivery of electrical power on a rotating

24/7, 365 days/year shift schedule. Develops, directs, and dispatches system switching, work protection, and trouble response for planned and emergency events.



PLT - Underground Plant



PLT - Overhead Plant

Figure 2: PLT Employees at Work

3.2. Designated and Technical Professionals

Designated and Technical Professionals are responsible for planning, designing and executing work programs and for ensuring the utility's compliance with legal, regulatory, financial, and environmental requirements, applicable standards and best practices.[8] This segment comprised approximately 41 percent of Toronto Hydro's workforce as of the end of 2022, and is anticipated to grow to 46 percent with the addition of approximately 250 resources over the 2023-2029 period. The increase is driven by a multitude of factors including: (i) responding to more complex legal and regulatory requirements such as related to integration of Distribute Energy Resources ("DER"), (ii) operating in a more data-intensive

[8] For example, Toronto Hydro must ensure compliance with environment, health and safety requirements including the Utility Work Protection Code, Electrical Utility Safety Rules, *Occupational Health & Safety Act* and Regulations, ISO 14001:2015 and ISO 45001:2018 standards, and the *Environmental Protection Act*. See Exhibit 4, Tab 2, Schedule 17 – Human Resources, Environment and Safety for further details.

environment driven by technology and modernization, and (iii) supporting an increase volume of capital and operating programs over the period. All of these factors, and many others that are detailed throughout the programmatic evidence in Exhibit 4, Tab 2 translate to a corresponding increase in talent for the following positions and associated responsibilities within this segment:

- **Engineers**: Participates in short- and long-range strategic asset planning to ensure technical soundness, reliability, cost effectiveness, and safety for the utility; prepares engineering reports and studies; performs engineering analysis and evaluations; provides timely technical support/consultation, project management, and testing; develops proposals and plans; and prepares and/or reviews methods, procedures (process re-engineering), and designs. Engineers are accountable, and legally responsible, for personal engineering work product (e.g. drawings, calculations, documents, and the work of others which the engineer has signed).
- **Engineering Technologists:** Supports the formulation of electric system plans and co-ordinates system operation services with the control centre; develops distribution plans by calculating load forecasts; prepares conceptual and detailed designs and cost estimates for projects related to system expansion, rehabilitation, and maintenance of the electrical and civil infrastructure; conducts studies, prepares reports, makes recommendations relating to station and system distribution load forecasts, engineering studies, technical standards, utility materials, tools, and construction practices; and prepares, reviews, and maintains project schedules.
- **Analysts**: Enable the utility to make data driven decisions, provide valuable insights and satisfy a variety of external obligations and internal responsibilities. As systems evolve and are added and more data is produced, roles are required to analyze and integrate various data sets. Analysts in both corporate and operational areas require critical thinking, creativity, and problem-solving techniques to define needs and

recommend solutions that deliver value to stakeholders. Analysts employ a variety of tools, including: predictive analysis to elevate the customer experience; numerical skills to measure and statistically analyze large data sets; technical skills to understand business problems, organize and present data.

Without the required staffing levels of Designated and Technical professionals, Toronto Hydro would not have the necessary resources to plan and design a safe, secure and reliable distribution system in compliance with legislative and regulatory requirements, applicable standards and best practices. As shown in Figure 3 below, the capacity of this segment tracks closely with the overall size of the capital investment plan as measured by expenditures.

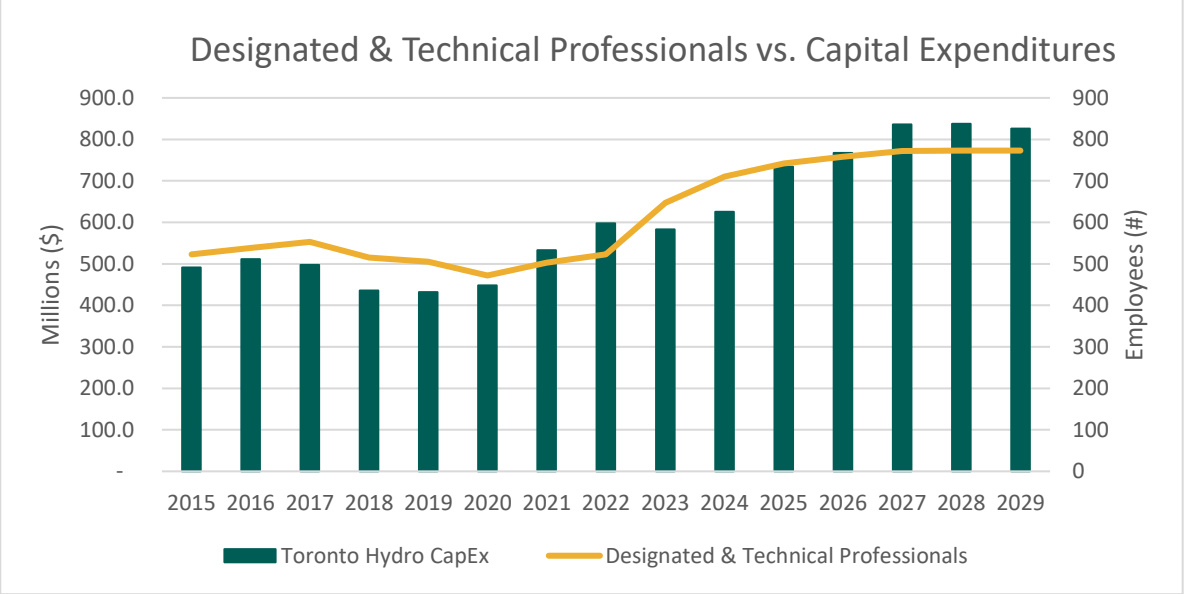


Figure 3: Designated & Technical Professionals Compared to Capital Expenditures

In addition to keeping up with increasing work volumes, the employees in this segment are tasked with designing and planning for changes to how customers use electricity and how the utility operates the grid brought by technological advancements and necessitated by

customer demands in an electrified future. This includes grid automation technologies to enhance system observability and controllability and to enable the gradual transition to a two-way power flow grid that provides customer greater choice over their electricity consumption, and the opportunity to participate in the system by selling electricity back to the grid.

Last but not least, the resources in this segment are an important source of internal talent for front line and senior management leadership roles. Investments in this segment produce proprietary industry knowledge and expertise that Toronto Hydro relies on to fulfill leadership roles efficiently and effectively through internal recruitments. In 2022, 46 percent of internally filled leadership roles (front line and senior management) were from the Designated and Technical professionals' segment.

3.3. Front Line Leadership

Front Line Leadership positions are responsible for managing and overseeing the complex design and execution of the utility's capital and operations work plans. The responsibilities associated with these positions include safety training, inspections, audits, investigations, risk management, problem-solving, staff training and development, performance management, employee engagement, coaching and mentoring.

Front Line Leadership employees are primarily trained, developed and promoted from within the organization to leverage their in-depth experience and track-record of high-performance at the utility. At the end of 2022, this segment comprised approximately 14 percent of Toronto Hydro's workforce. Over the 2025-2029 rate period, this segment must remain stable in order to oversee the delivery of the utility's work programs and ensure that internal and external resources work in a safe, productive and environmentally responsible

manner. To maintain its proportion to the overall compliment, the segment is expected to grow by approximately 80 resources from 2023-2029. Without sufficient resources in Front-Line Leadership positions, Toronto Hydro's track-record of productivity and performance would be compromised.[9]

3.4. Operational Support & Administration

Operational Support & Administration staff enable the efficient execution of work within operations, customer care and corporate functions. This segment provides administrative support to function specific management and technology systems, creates and maintains professionally formatted business documentation and makes recommendations to streamline and improve the administration, coordination and delivery of processes within the assigned business unit. Employees within this work segment are continuously reskilling and upskilling to take on higher-value work such as reporting, research and analysis tasks.

At the end of 2022, this segment comprised approximately 12 percent of Toronto Hydro's workforce. Efforts throughout the 2017 to 2022 period to streamline processes resulted in an 18 percent decrease in the number of employees in this segment. Furthermore, as a result of investments in upskilling these employees, operational support and administration staff have become a valuable pipeline for development and career progression in the organization. From 2020 to 2022, 25 percent of internal professional and certified and skilled trades recruitment was filled by employees from this segment.

This segment needs to remain stable through 2029 to support the efficient execution of work, to attract new labour market entrants to the organization, and provide a pipeline for

[9] See Exhibit 1B, Tab 3, Schedules 2 and 3 for more information about the utility's performance and productivity track-record.

other workforce segments. Without appropriate staffing levels in these positions, Toronto Hydro would not only risk a reduction in productivity as a result of higher cost resources having to perform process-focused administrative work, but would also lose the opportunity to develop a critical source of internal talent. The number of resources is expected to increase by approximately 30 over the 2023-2029 period.

3.5. Senior Management

Senior Management positions provide the leadership and strategic guidance necessary to achieve Toronto Hydro's objectives in a complex, highly-specialized and regulated environment. Senior Management leaders hold extensive portfolios of accountabilities that are responsive to dynamic systems, processes and technologies. These accountabilities are evolving as result of changes in the external environment including changing customer expectations with respect to reliability and resilience, technological advancement and emerging public policy imperatives to modernize and prepare Toronto Hydro's grid and operations for electrification.

Through well-developed processes for identifying and developing leadership potential, Toronto Hydro has successfully improved leadership bench strength and created a pool of qualified and talented employees to fill critical Senior Management positions. From 2020-2022, 93 percent of senior management roles were filled internally, with limited reliance on the external market to fill increasingly senior leadership roles. On average over the period, these roles filled approximately 60 percent faster than externally filled positions, positively impacting operational efficiency and productivity.

As of the end of 2022, this segment comprised approximately 6 percent of the workforce. Over the next rate period, Toronto Hydro needs to maintain the proportion of resources in

this segment stable in order to manage and lead the organization to achieve its core objective and rise up to the challenge of serving higher customer demand and expectations for safe, reliable and cost-effective power in an electrified future. The segment is expected to increase by approximately 20 resource over 2023-2029.

4. TALENT DEVELOPMENT STRATEGY

A strong talent attraction and engagement strategy is critical to: (i) continue to position Toronto Hydro as an employer of choice; (ii) build staff competence to address requirements, deliver plans, and integrate more technology and innovation into their work; and (iii) advance leadership skills and competence to support diversity, equity and inclusion, lead in a hybrid work environment and role model culture change. This section will outline how the utility will develop existing resources and execute an effective internal and external hiring strategy.

4.1. Existing Resources

Toronto Hydro takes a comprehensive, forward-looking approach to maximizing the value of its existing employee resources by providing timely upskilling and training opportunities, applying productivity strategies, supporting innovation, promoting from within the organization, and using management tools to maximize employee performance. Each of these approaches is discussed in detail below. Toronto Hydro relies on a combination of all these approaches to achieve organizational success and meet its human resource requirements.

4.1.1. Upskilling and Training Opportunities

Toronto Hydro provides employees with extensive training and upskilling opportunities. These opportunities serve several purposes. They ensure that employees within each

workforce segment have the requisite knowledge and skills required to perform their jobs competently, safely and in compliance with the relevant rules, codes and authorities. They also serve to enhance awareness of equity, diversity and inclusion issues in the organization, equip employees with the capabilities to meet emerging technology challenges, and prepare the right talent for promotion from within.

Toronto Hydro delivered nearly 550 training and development programs from 2020 to 2022. These programs are tailored to the work requirements of different positions across the organization. For example, within the Certified and Skilled Trades segment, Toronto Hydro is focused on providing training through a trade school that maintains safe apprentice-journeyperson ratios and equips workers with the competence to execute work efficiently and safely on electrified assets within Toronto Hydro's dense urban service territory. Toronto Hydro periodically updates the content and form of this training to reflect current best practices and deliver it in an effective manner.

Over the current rate period, Toronto Hydro transitioned 29 of its training programs from being led by instructors in-person to being delivered virtually. This conversion will eliminate the need for employees to travel to a training location, reducing vehicle emissions and increasing the number of trainees who can attend a given class session.

Toronto Hydro also delivers upskilling opportunities to its employees across all segments to enhance their technical and professional abilities and improve operational capabilities to address emerging business needs and challenges posed by technological advancement. For example, after the implementation of the new SAP system in 2018, Toronto Hydro created a group of highly-trained and skilled employees, called Enterprisers, to enable and assist SAP users through the company to unlock the full functionality of the new system.

Over the 2025-2029 rate period, Toronto Hydro intends to develop and enhance data analytics capabilities as a critical skill given increased data generated from new technologies (e.g. AMI 2.0). Toronto Hydro is continuing to develop in-house training that focuses on building employees' future-ready skills including fluency with data analysis programs such as Tableau to perform sophisticated research using modern software tools. These investments in upskilling the workforce are critical to developing advanced operational capabilities to intelligently manage a more complex and highly-utilized energy system.

Toronto Hydro is also incorporating emerging technologies in its upskilling. A Virtual Reality (VR) training module was introduced in 2022 for crew members that focuses on Pad-Mounted Switchgear operations and repair. The VR training is designed to provide crews with a realistic, interactive simulation that covers everything from inspecting the job site for hazards to safely repairing and operating the switchgear being exposed to the many hazards associated with performing this task in the field. VR training also facilitates real-time assessments and data collection.

Finally, Toronto Hydro provides education opportunities focused on building the competence of all employees on the value of diversity, equity and inclusion, the identification and understanding of unconscious bias, and the importance of inclusive leadership. 91 percent of leaders in the organization completed unconscious bias training in 2022.

Table 2: Training and Development Programs (2020-2022)

Area	2020 Courses	2021 Courses	2022 Courses
Compliance (e.g. Environmental and Safety legislative training, EUSA and ESA Rules, Confined Space, Work Protection Code, Network Switching)	52	49	51
Legislative (e.g. WHMIS, Defensive Driving, Forklift Training)	48	48	51
Apprentice (e.g. Distribution Systems Technologist, Power Systems Controllers, Certified Power Cable Persons, Certified Power Line Persons, Meter Mechanics)	20	20	27
Leadership (e.g. Safety Leadership, Performance Management, Management Control & Reporting System, Project Management, Policy Administration)	5	4	15
Technical & Customer Service (e.g. Engineering Technicians, Electrical Awareness, Project Execution, Customer Education Training)	54	51	53
Total	**179**	**172**	**197**

Investments in the development and upskilling of talent offers many benefits for the utility, including creating a valuable pipeline for fulfilling vacancies internally and leveraging career progression as a retention strategy. Front line operational support and administrative staff are a prime example of this strategy at work. From 2020 to 2022, approximately 25 percent of internal professional and certified and skilled trades recruitment was filled by employees from this segment.

4.1.2. Promotion from Within

Promotion from within the organization is a key tenet of Toronto Hydro's talent management strategy. The utility has built an internal pipeline to develop employees' skills,

experience and abilities. Developing new leaders and upskilling current employees with the potential to grow is crucial to future success. Establishing a pipeline allows Toronto Hydro to identify, develop and place the right talent in critical roles throughout the organization. Internal candidates have a strong knowledge of Toronto Hydro's culture and management systems. This knowledge is a strategic asset that the utility capitalizes on through its succession planning. Effective succession planning is an important tool for engaging, developing, and retaining employees.

Toronto Hydro successfully executes this strategy to fill positions in its Designated and Technical Professional, Certified and Skilled Trades, Front Line Leadership and Senior Management segments. Between 2020 and 2022, approximately 40 percent of vacancies were filled internally, 28 percent of which were internal promotions to more senior roles. Leadership roles are predominately developed and promoted from within the organization to realize the full benefits of investments made in employee upskilling and development, and retain their in-depth experience and track-record of high-performance at the utility. From 2020-2022, approximately 93 percent of senior management roles were filled internally.

4.1.3. Employee Performance

Toronto Hydro uses a performance-based management and compensation system to set expectations for employees, provide feedback, and recognize employees who meet and exceed expectations. The individual component of the performance management system is administered through annual performance contracts and biannual performance reviews. The utility often sees over 90 percent compliance with its performance management system, showcasing the timely utilization of setting goals and evaluating employees based on their

achievements. For management employees, performance pay is directly related to the achievement of both individual and organizational objectives.

4.2. External Hiring

While Toronto Hydro maximizes the value of its existing workforce, the utility is unable to meet the needs and drivers of its staffing plan exclusively from hiring internally. To meet its staffing needs through external recruits, Toronto Hydro employs a combination approach that includes acquiring additional talent from the market, hiring new graduates, leveraging its relationships with colleges and universities, and outsourcing work to third-party service providers where appropriate. Each of these strategies is discussed in detail below.

4.2.1. Acquiring Additional Talent from the Market

Toronto Hydro strategically recruits talent from the external market in the Greater Toronto Area from both the general and energy industries and monitors market trends such as cost of living pressures on an ongoing basis to adapt to changing conditions. The utility's external recruitment process allows it to draw from a larger supply of diverse candidates and hire specific skills that are not readily available within the organization. In addition, external recruitment is key to expanding the workforce's capacity to execute Toronto Hydro's 2025-2029 investment plan.

4.2.2. Hiring New Graduates

The complexity of Toronto Hydro's distribution system and dynamic operating conditions mean that it is optimal for the utility to supplement its hiring of skilled external resources in the market with hiring new graduates, particularly for its Certified and Skilled Trades positions where skills are not readily available in the marketplace. This hiring pipeline relies on the utility's training and apprenticeship programs to instill the specialized skills and

knowledge that are required to operate the distribution system reliably and safely. In addition, this hiring strategy allows Toronto Hydro to develop and maintain a dependable workforce that is capable of servicing the utility's operational needs well into the future. The volume of hiring through this hiring pipeline is driven by safety requirements for training on electrical apparatus that limit the number of apprentices who can be trained by a given volume of field crews.

Depending on the trade, it takes anywhere from four and half to six and a half years to train a new certified and skilled trades person, plus a minimum additional one to two years to develop a new front-line leader post apprenticeship. The development period for certified and skilled trades considers both operational and legislative requirements. Operational requirements include relevant rules, policies, procedures, construction standards and equipment to build knowledge, skills and expertise to safely operate the distribution system. Legislative requirements incorporate standard knowledge and skills set out by governing bodies such as the Ministry of Labour, Immigration, Training and Skills, the Ministries of Environment and Transportation, the Technical Safety Standards Authority and the Electrical Safety Authority. Toronto Hydro's apprenticeship program is comprehensive in that incorporates technical trades training, best practices for the design and delivery of hands-on operational and compliance training and rigorous testing at each phase of the apprenticeship to confirm milestones are met.

Over a decade ago, Toronto Hydro adopted minimum qualifications for post-secondary education in an electrical field of study for all entry level certified and skilled trades and designated technical professional roles. The organization continues to evolve minimum entry level qualifications across operational and corporate business areas and requires that new hires have a university or college diploma in a related field of study. Toronto Hydro has

elected to prescribe this requirement as post secondary students enrolled in formal learning programs are well-prepared for the workforce with future ready knowledge, skills and abilities - namely, enhanced problem-solving skills, increased ability to analyze and think critically, communication and comprehension aptitudes, and heightened initiative and resourcefulness. This strategy has proven successful for Toronto Hydro and the quality of instruction and work integrated learning programs provided through post secondary education allows for both a ready talent pool for the organization and an accelerated transition to the organization.

4.2.3. Colleges and Universities

Toronto Hydro continues to collaborate with colleges and universities to develop new curricula and explore interdisciplinary learning opportunities that enable the availability of short- and long-term workforce requirements. The utility offers valuable work experience to post secondary students across Canada through well established work integrated learning (WIL) opportunities that enable postsecondary students to apply the academic knowledge gained through studies to a practical work environment.

Investments in experiential learning have resulted in 20 percent of former co-op students finding employment at Toronto Hydro after graduation. To develop a pipeline of talent situated within the utility's geographic service territory and to mitigate risks of talent loss to neighbouring comparators, in 2020, Toronto Hydro partnered with George Brown College to influence curriculum on a new three-year Electromechanical Engineering Technology – Power and Control Diploma Program. Collaborations with institutions such as George Brown College, Georgian College and Toronto Metropolitan University support academic programs aligned to entry level qualifications for Certified and Skilled Trades and Designated and

Technical professionals and advance skill sets prior to entry for incoming talent. Such collaborations are valuable because they allow Toronto Hydro to:

- influence and shape the programs and curricula, including diversity, equity and inclusion to better match the utility's strategic goals and long-term needs;
- spread awareness about the utility's career prospects and human resource requirements;
- build recruitment relationships with future graduates; and
- help bridge the gap and remove barriers to the labour market for newcomers to the labour market.

Toronto Hydro's commitment to hiring apprentices requires careful planning and coordination to enable efficient and effective execution. Apprenticeships can be as long as six and a half years where apprentices spend time in class as well as embedded with crews to practice and refine skills in real world conditions. Hiring and training needs to be done proactively so that apprentices have sufficient time to complete their programs, with journeyperson oversight and mentoring, before becoming fully qualified to augment resourcing levels and productively contribute to program outcomes. To minimize the total cost of the apprenticeship process, recruits are typically hired in cohorts of between four and eight resources at a time. From a talent attraction perspective, aligning recruitment activities with post-secondary graduation cycles ensures the utility access to the broadest range of qualified applicants to fill available opportunities.

4.2.4. Outsourcing

Toronto Hydro relies on third-party service providers to enable the utility to resource in times of peak demand, maintain flexibility in operations, and gain access to specialized expertise and knowledge. Outsourcing decisions are continually reviewed to determine if

operational requirements and other business drivers have changed the demand for outsourced services. Outsourced services may be reintegrated to internal utility operations to improve outcomes and retain critical and complex knowledge. This is evidenced during the current rate period in that a complement of additional resources in the areas of customer care, supply chain, and fleet operations were brought in house to augment internal capabilities and maintain effective business operations. [10,11,12]

[10] Exhibit 4, Tab 2, Section 16.
[11] Exhibit 4, Tab 2, Section 15.
[12] Exhibit 4, Tab 2, Section 13.

COMPENSATION STRATEGY AND WORKFORCE GOVERNANCE

This schedule discusses Toronto Hydro's compensation strategy and workforce governance practices. Further to the information outlined in OEB Appendix 2-K (Employee Costs/Compensation Table) at Exhibit 4, Tab 4, Schedule 2, this schedule provides an overview of: 1) Compensation Costs Overview; 2) Compensation Strategy and Workforce Governance; 3) Compensation Practices for Non-Union Employees; 4) Compensation Practices for Bargaining Unit Employees; and 5) Benefits and Pensions.

1. COMPENSATION COSTS OVERVIEW

Tables 1 and 2 below summarize Toronto Hydro's total compensation costs for the current 2020-2024 and the future 2025-2029 rate periods, respectively.

Table 1: 2020-2024 Total Compensation ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge
Management (including executive)	22.0	21.5	22.5	27.0	31.1
Non-Management (union and non-union)	189.1	177.8	184.9	205.9	238.1
Total Compensation	**211.1**	**199.3**	**207.5**	**232.8**	**269.2**

Please note the numbers may not sum due to rounding.

Table 2: 2025-2029 Total Compensation ($ Millions)

Year	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Management (including executive)	32.2	33.7	35.7	37.7	39.4
Non-Management (union and non-union)	261.1	281.3	299.2	317.7	336.2
Total Compensation	**293.3**	**314.9**	**334.9**	**355.4**	**375.5**

Please note the numbers may not sum due to rounding.

Underpinning the utility's compensation costs is a compensation strategy that balances cost-effectiveness with the need to attract and retain the talent required to provide service in an increasingly complex and dynamic operating environment. According to Mercer's Compensation Benchmarking study (the "Mercer Study") which can be found at Exhibit 4, Tab 4, Schedule 5, Toronto Hydro's total compensation is positioned within a market competitive range relative to the 50th percentile of the energy market. With respect to the general industry peer group, total compensation is slightly above market due to pensions and benefits, while the total cash component of compensation is within market range. The Mercer Study affirms that Toronto Hydro's compensation strategy continues to yield good value for the utility and its customers.

Over the 2024-2029 period, Toronto Hydro expects to increase its workforce capacity by approximately 25 percent compared to 2023 levels in order to address the challenges and requirements of sustaining the grid, modernizing the utility and preparing the system for the unprecedented energy transition that is set to take place in the next decade and beyond. In addition to increasing resourcing capacity to support the execution of its capital and operations work programs, the utility is investing in attracting and upskilling employees. This includes developing advanced capabilities to integrate more technology and data analytics into the grid and operations to drive continuous improvement in

system performance and optimize planning and decision-making. Toronto Hydro's ability to recruit, attract and retain talent in key areas of its operations has led to improvements in safety, customer service, reliability, and productivity over the last 10 years as detailed in Exhibit 1B, Tab 3, Schedules 2 and 3.

To implement Toronto Hydro's workforce plan as summarized in Exhibit 4, Tab 1, Schedule 1 and detailed in Exhibit 4, Tab 4, Schedule 3 as well as the programmatic evidence in Exhibit 4, Tab 2, the forecast total compensation cost for 2029 is $375.5 million, which represents a compound annual growth rate of 6.6 percent over the total compensation costs of $211.1 million in 2020. These figures include total cash compensation costs (i.e. base salary wages, overtime and incentive payments) which are increasing by a compound annual growth rate of 3.7 percent from 2020 to 2029 on the basis of average cost per full-time employee ("FTE").[1] In preparing 2024 to 2029 total cash compensation forecasts and the various components of them, Toronto Hydro considered, and the forecasts reflect, the following inputs: (i) Toronto Hydro's obligations under collective agreements, (ii) relevant labour market data (where available),[2] and (iii) the utility's projections of outcomes of future rounds of collective bargaining that will take place throughout the forecast period. More specifically, in the absence of objective market indicators to forecast compensation increases over the 2025-2029 forecast period, the utility (in consultation with its compensation expert Mercer Canada and based on experience) relied on a historical rolling-average (in addition to the factors noted above) as the best information available to predict reasonable future compensation levels.

[1] The average cost per employee is mathematically derived from the data in OEB Appendix 2-K; namely total compensation divided by total FTEs per year.
[2] For example, the results of Mercer Canada's August 2023 QuickPulse™ Canada Compensation Planning Survey show total salary increases of 3.7 percent: <https://www.imercer.com/ca/ARTICLEDETAIL/annual-increase-budget-canada>.

2. COMPENSATION STRATEGY AND WORKFORCE GOVERNACE

Toronto Hydro's workforce is the means by which the utility delivers service and value to its customers, carries out its objectives, and complies with its mandatory obligations. The utility strives to secure and maintain a workforce that is highly skilled, agile, innovative, productive and engaged. To achieve these key outcomes in a cost-effective manner, Toronto Hydro's compensation strategy is to: (i) provide wages and benefits that are competitive in the markets where Toronto Hydro competes for talent and (ii) use a pay-for-performance model to align the workforce with the utility's core objectives, set and manage high performance expectations, foster productivity, and reward employees for their contributions to the utility's performance.

2.1 Market-Competitiveness

The utility must maintain the ability to attract, motivate, and retain employees who have the knowledge, skills, and abilities that are critical to the utility's success in meeting customer expectations and delivering customer outcomes. Toronto Hydro's compensation strategy aims to strike an appropriate balance between controlling costs and providing market-competitive compensation. In doing so, the utility examines the reasonableness and effectiveness of its compensation program in alignment with industry peers and relevant labour markets.

The effect of external pressures and shifting candidate preferences regarding work arrangements (i.e. remote vs. in-office) in a large and diverse urban city requires a strong market-competitive compensation program to attract, retain and engage employees. Toronto is the largest city in Canada and continues to be a competitive labour market. Emerging skill sets are in high demand with low supply across many other industries and

utilities.[3] Due to the uniqueness, complexity and dynamic operating conditions of Toronto Hydro's distribution plant, and competition in the labour market, it is challenging for Toronto Hydro to attract and retain skilled employees.

Moreover, the COVID-19 pandemic significantly impacted traditional approaches to talent management. According to the 2022 Canada Flexible Working Policies and Practices Survey conducted by Mercer, 53 percent of employees want hybrid work arrangements and 53 percent of employers offer a hybrid model.[4] To remain market competitive, Toronto Hydro introduced a hybrid work model.

Toronto Hydro reviews the market-competitiveness of its compensation packages for non-union employees as part of its annual business planning and budgeting process. This can include participating in compensation salary surveys offered through independent consulting firms that specialize in the compilation of aggregate compensation data. The data from these surveys gives Toronto Hydro an ability to compare its jobs relative to other comparable jobs in both the energy and general industry in order to calibrate compensation.

In addition to annual reviews in the normal course of business, the utility periodically conducts external benchmarking studies to ensure that the level, form, and mix of compensation offered by Toronto Hydro is competitive with those provided for comparable jobs in the markets where the utility competes for talent. In 2022, Toronto Hydro engaged industry-expert Mercer Canada to undertake a detailed compensation

[3] Mahboubi, Parisa. 2022. The Knowledge Gap: Canada Faces a Shortage in Digital and STEM Skills. Commentary 626. Toronto: C.D. Howe Institute: <https://www.cdhowe.org/sites/default/files/2022-08/Commentary_626_0.pdf>.
[4] Mahboubi, P. (n.d.). (rep.). *Canada Flexible Working Policies and Practices Survey*. Mercer: <https://www.imercer.com/ca/products/flexible-working-policies-practices-survey-ca>.

and benefits benchmarking study which can be found at Exhibit 4, Tab 4, Schedule 5 (the "Mercer Study").

The Mercer Study indicates that Toronto Hydro's total compensation is positioned within a market competitive range relative to the 50th percentile of the energy market. With respect to the general industry peer group, total compensation is slightly above market due to pensions and benefits, while the total cash component of compensation is market-competitive. Mercer defines "market-competitive" as "within 10 percent of the target market positioning on a position-by-position basis."[5]

2.2 Performance-Based Compensation

Toronto Hydro compensates employees based on performance, which is assessed by the competencies demonstrated and outcomes achieved in the course of employment. This performance-based compensation strategy plays a central role in delivering the utility's core objectives under the five corporate pillars described below in Table 3.

Table 3: Toronto Hydro's Corporate Pillars

Corporate Pillar	Core Objectives
 **CUSTOMER**	• Make it easy for customers to interact and transact with us • Provide value added and efficient services through various channels • Proactive and data-driven response to all customer segments • Utilize technology and analytics to meet customer's information needs

[5] Exhibit 4, Tab 4, Schedule 5 – Mercer Benchmarking Report at page 5.

Corporate Pillar	Core Objectives
 PEOPLE	• Ensure a healthy and safe work environment • Enhance diversity, equity and inclusion in the workplace • Optimize processes and invest in employee capabilities • Engage employees through purposeful work
 ENVIRONMENT	• Advance as a Sustainable Electricity Company • Reduce our environmental footprint • Enable our customers as a sustainability partner • Leverage environmental management system to achieve net zero by 2040
 OPERATIONS	• Keep the lights on • Keep our system safe • Build a grid that supports a modern city • Provide value to customers
 FINANCIAL	• Provide a fair return to our Shareholder • Continue to increase Shareholder value • Strive for strong and stable credit rating

As further detailed in Exhibit 1B, Tab 3, Schedules 1 and 2, over the last decade, Toronto Hydro's pay-for-performance model enabled the utility to achieve improvements in service quality and other performance outcomes such as:

- 60 percent improvement in employee safety record,
- 29 percent improvement in outages due defective equipment,
- 14 percent improvement in first contact resolution performance,
- 9 percent improvement to new services connected on time.

In addition to assessing employee performance based on the workforce competencies outlined in Table 4 below, Toronto Hydro's performance-based compensation strategy includes individual, divisional, and corporate performance expectations that align with the utility's core objectives. Performance expectations are set, assessed and reviewed through Toronto Hydro's performance management system.

Table 4: Toronto Hydro's Workforce Competencies and Descriptors

Workforce Competencies	Descriptors
Drives Results & Accountability	Has a clear sense of corporate direction and expectations, and holds self and others accountable to achieve objectives.
Demonstrates Customer-Focus	Models a customer-focussed approach in all decisions and actions.
Builds Strong Relationships	Builds valuable relationships across the organization and externally to support the future of Toronto Hydro.
Develops People and a Diverse & Inclusive Culture	Recognizes personal development and a strong organizational culture as integral components of an effective organization supporting diversity, equity and inclusion.
Champions Change, Productivity & Innovation	Prioritizes in innovation, continuous improvement, and productivity as essential drivers of long-term sustainability.
Demonstrates Commitment to Environment, Health & Safety	Manages risks to protect the health and safety of employees and the public, and shows a commitment to sustainability.

Toronto Hydro's corporate competencies guide the following aspects of human resources management:

- **Recruitment and Selection**: Toronto Hydro uses its corporate competencies to develop the recruitment process for a particular position and takes the competencies into consideration as part of its selection criteria.
- **Training and Development:** The corporate competencies underpin the utility's training initiatives. For example, if Toronto Hydro uses its performance management process to determine that an individual or team lacks customer

focus competencies, the utility would perform an assessment of training needs. Based on the results, the utility would implement an appropriate customer awareness training program to assist in closing this gap.

- **Performance Management and Compensation**: The corporate competencies are integrated with Toronto Hydro's compensation practices. For non-union employees, this occurs through the assignment of performance ratings, which evaluate employees' performance in relation to the corporate competencies. The performance rating is one of the components that determine base salary increases. For unionized employees, Toronto Hydro uses performance assessments tied to corporate competencies to determine base step increases for employees with a solid performance rating who are not at the top of the defined salary range.
- **Succession Planning and Promotion**: Decisions on succession planning and promotion focus on developing employees who consistently meet the corporate competencies, as indicated by their annual performance ratings.

3. COMPENSATION PRACTICES FOR NON-UNION EMPLOYEES

Toronto Hydro provides non-unionized employees with a total cash compensation package comprised of two elements: base salary and variable performance pay. Base salary compensates an employee for meeting the expectations related to their responsibilities, accountabilities, and technical skills. Variable performance pay rewards employees for their contribution to achieving goals and objectives tied to the utility's strategic pillars, in combination with their successful demonstration of corporate competencies.

Each non-union position at Toronto Hydro has a salary grade with a corresponding salary range. To maintain alignment with the competitive labour market, the utility adjusts salary ranges based on annual market reviews. Because Toronto Hydro operates in niche areas of expertise, both as part of the electricity system and in the general industry, the utility hires capable workers but at a less experienced level, and trains and develops them on the job. From 2019 to 2023 year to date, newly hired non-union employees were brought into their roles at an average of 88 percent of the salary grade. To keep the workers that Toronto Hydro invests in training and developing on the job, the utility progresses them through the salary ranges more quickly to reflect their upskilling and acquired experience levels. This progression is based on merit increases.

The variable performance pay program is an incentive performance-based compensation tool designed to retain, motivate, and reward employees for achieving performance objectives, which are established at the beginning of each calendar year and documented in an annual performance contract. Each employee's variable performance pay is based on a weighting of performance objectives, which are measured by key metrics and by individual goals set out in the employee's annual performance contract.

4. COMPENSATION PRACTICES FOR BARGAINING UNIT EMPLOYEES

Over half of Toronto Hydro's employees belong to collective bargaining units represented by the Power Workers' Union ("PWU"), the Society of United Professionals - Engineers ("Society Engineers"), or the Society of United Professionals - IT ("Society IT"). Toronto Hydro's compensation costs with respect to these employees are negotiated through periodic collective bargaining in accordance with the legal duty to bargain in good faith.

The utility has both contractual and statutory obligations to honour the terms of its collective bargaining agreements.[6]

Toronto Hydro's bargaining interests are focused on supporting the organization's ability to safely execute capital and operational programs in an efficient and cost-effective manner while preserving management's rights to manage and direct the workforce. To achieve negotiated settlements that are fair and reasonable for its employees, while continuing to provide efficient service to its customers, the utility monitors and considers external compensation data, bargaining trends and past settlements.

4.1 PWU Collective Agreement

Table 5 below summarizes the year-over-year general wage increases for PWU under the previous and current collective agreement. The current collective agreement with PWU effective as of February 1, 2022 and until January 31, 2027, resulted in a 2.6 percent average general wage increase, in line with the multi-year average general wage increases under similar collective agreements for the peer group of Ontario distributors identified in the benchmarking evidence at Exhibit 4, Tab 1, Schedule 1.[7]

Table 5: PWU General Wage Increases (2020-2026)

2020	2021	2022*	2023	2024	2025	2026
2.3%	2.3%	2.5%	2.5%	2.5%	2.5%	3.0%

New collective agreement effective February 1, 2022 until January 31, 2027.

[6] *Ontario Labour Relations Act,* 1995, S.O. 1995, c. 1, Sched. A, section 56.

[7] The peer group consists of the large and mid-sized Ontario distributors: Hydro One, Hydro Ottawa, Alectra Utilities, Elexicon Energy, London Hydro, EnWin Utilities, and Enova Power. With the exception of Elexicon and Hydro One, these distributors serve the top 10 cities in Ontario (by population size). Hydro One was included in the peer group because it serves approximately 90 percent of the service territory in the province, and Elexicon Energy was included because it is the fourth largest municipality-owned electricity distributor in the province.

In addition to general wage increases, PWU employees not already paid at the top of the wage scale are eligible, based on performance, for step increases as a result of progression on the wage scale from one step to the next.

4.2 Society Engineers Collective Agreement

The utility's current collective agreement with the Society Engineers came into effect January 1, 2020 and is valid until December 31, 2023. Table 6 below summarizes the year-over-year general wage increases for Society Engineers employees.

Table 6: Society Engineers General Wage Increases (2020-2023)

2020	2021	2022	2023
1.20%	1.50%	1.60%	2.00%

In addition to general wage increases, Society Engineers employees are also eligible, based on performance, for: (i) step increases as a result of progression on the wage scale from one step to the next if not already paid at the top of the wage scale, and (ii) variable performance pay based on achievement of the deliverables outlined in annual performance contracts, as well as the achievement of the utility's performance measures.

4.3 Society IT Collective Agreement

The Society of United Professionals was certified as the bargaining agent for applicable Information Technology employees at Toronto Hydro on November 21, 2018. On November 9, 2020, the Society of United Professionals First Collective Agreement with Society IT employees was awarded beginning January 1, 2019 and expiring December 31, 2020. The utility's current collective agreement with Society IT employees came into

effect January 1, 2021 and is valid until December 31, 2025. Table 7 below summarizes the year-over-year general wage increases for Society IT employees.

Table 7: Society IT General Wage Increases (2020-2025)

2020	2021	2022	2023	2024	2025
2.30%	1.50%	2.50%	2.50%	2.75%	3.00%

In addition to general wage increases, Society IT employees are also eligible, based on performance, for: (i) step increases as a result of progression on the wage scale from one step to the next if not already paid at the top of the wage scale, and (ii) variable performance pay based on achievement of the deliverables outlined in annual performance contracts, as well as the achievement of the utility's performance measures.

5. BENEFITS AND PENSIONS

Toronto Hydro provides a pension for fulltime employees through its membership in Ontario Municipal Employees Retirement System ("OMERS"), a multi-employer defined benefit pension plan. In addition to OMERS, Toronto Hydro provides other employment benefits to employees, including: medical insurance, including vision care, prescription drugs, and paramedical services; dental insurance, including major dental and orthodontic services; short-term disability ("STD") and long-term disability ("LTD") income protection; and life insurance and accidental death and dismemberment ("AD&D") insurance. Other benefits costs paid by Toronto Hydro include employer contributions for the following:[8]

- Workplace Safety and Insurance Board ("WSIB") premiums;

[8] Aside from pensions, all contributions are required under Canadian law.

- Pension contributions;
- Canadian Pension Plan contributions;
- Employment insurance contributions; and
- Employer health tax contributions.

Tables 8 and 9 below outline the cost of employee benefits for the current 2020-2024 and the future 2025-2029 rate periods, respectively.

Table 8: 2020-2024 Employee Benefit Costs ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge
Employee Benefits Cost	52.4	49.0	50.1	55.9	66.6

Table 9: 2025-2029 Employee Benefit Costs ($ Millions)

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Employee Benefits Cost	74.5	81.8	88.9	96.6	104.6

Toronto Hydro periodically reviews the trends and costs associated with its benefit programs to help ensure that the program is aligned with the labour markets within which Toronto Hydro competes for talent.

As part of the study filed at Exhibit 4, Tab 4, Schedule 5, Mercer Canada reviewed Toronto Hydro's market position for employer paid benefits in respect of two components: active benefits (e.g. life insurance, accidental death & dismemberment insurance, short-term disability, long-term disability, health and dental, health care spending account) and employer pension contributions.

For active benefits, Mercer found that Toronto Hydro provides a top quartile active benefits plan when compared to the energy and general industry peer groups. For pensions, relative to the overall market (which includes both defined benefit and defined contribution plans),[9] Toronto Hydro's pension arrangements through OMERS are above the 50th percentile among both the energy and general industry peer group companies. However, when considering only comparators that provide Defined Benefit pensions to new hires, Toronto Hydro's pension arrangements through OMERS are aligned to the 50th percentile relative to both the energy and general industry peer group companies.

Toronto Hydro conducts regular reviews to support effective program governance and prudent cost management while providing a comprehensive and market-competitive benefits program that supports the utility's ability to attract and retain talent in a highly competitive labour market. For example, in 2022, Toronto Hydro complete a comprehensive dependent eligibility review for all active employees with family coverage.

To manage benefits costs, Toronto Hydro also regularly negotiates with benefit providers and conducts comprehensive vendor market reviews on a periodic basis. In 2021 Toronto Hydro conducted a vendor market review for the Employee and Family Assistance Program which resulted in the utility securing a new provider for employee mental health and overall wellness at a reduced per member rate of approximately 30 percent.

Toronto Hydro offers its employees a number of health and wellness initiatives, including the aforementioned Employee and Family Assistance Program that provides employees and their dependents access to work-life/wellness resources such as support for mental

[9] Determining the benefit that a pension plan member will receive in retirement depends on the type of plan. In a defined benefit plan, members can expect a predicable monthly income in retirement. In a defined contribution plan, the future benefit can vary because it is impacted by the returns earned by the investment pool. What is defined in this type of plan is the amount of contributions put into the plan.

health and relationship counselling. In 2020, Toronto Hydro introduced a virtual healthcare program that offers 24/7 online access to healthcare professionals. The program was introduced early during the pandemic to help mitigate the risk and spread of COVID-19 by reducing the need for in-person medical walk-in clinic visits while still ensuring employees had access to medical professionals. In 2022, Toronto Hydro enhanced its coverage for mental health services (e.g. psychologists and social workers) in recognition of the rising importance of mental health wellness.

Both participating employers and their employees are required to make contributions to the OMERS pension plan. The required contribution rates are based on the employee's earnings, and are periodically reviewed by the OMERS Sponsors Corporation relative to the assets and obligations of the plan. Participating employees and employers currently contribute to OMERS 9 percent of earnings up to the Yearly Maximum Pensionable Earnings ("YMPE") and 14.6 percent on earnings above the YMPE. The YMPE is the Canada Pension Plan ("CPP") earnings limit (i.e. contributions to the CPP are made on earnings up to this limit). The OMERS contribution rate is lower up to the YMPE because OMERS is designed to work together with CPP to provide combined pension benefits.

Tables 10 and 11 below summarize Toronto Hydro's pension costs, including capitalized and expensed amounts each year, for the current 2020-2024 and the future 2025-2029 rate periods, respectively. Toronto Hydro's pension costs are recovered using a default accrual basis.

Table 10: 2020-2024 Pension Costs ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge
Pension Contributions	17.1	15.8	16.3	20.0	22.8
Less: Amount Capitalized	8.2	7.5	8.3	10.1	11.5
Amount Expensed	9.0	8.4	8.1	10.0	11.3

Please note that the numbers in the table may not sum due to rounding.

Table 11: 2025-2029 Pension Costs ($ Millions)

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Pension Contributions	24.8	26.4	28.0	29.6	31.0
Less: Amount Capitalized	12.4	13.3	14.2	15.0	15.8
Amount Expensed	12.4	13.2	13.8	14.5	15.2

Please note that the numbers in the table may not sum due to rounding.

In addition to pension benefits, Toronto Hydro pays certain medical, dental, and life insurance benefits on behalf of its retired employees. An actuarial analysis using the projected unit credit method determines the cost of these benefits. This method incorporates Toronto Hydro's best estimate of future salary levels, retirement ages of employees, health care costs, and other actuarial factors. The latest actuarial valuation was performed by Willis Towers Watson based on information current as of January 1, 2022, and forecasts of post-employment benefit costs are based on extrapolations of those results (see Exhibit 4, Tab 4, Schedule 4, Appendix A).

Tables 12 and 13 below presents Toronto Hydro's post-employment benefit costs, including capitalized and expensed amounts, for the current 2020-2024 and the future

2025-2029 rate periods, respectively. Toronto Hydro's post-employment benefit costs are recovered using a default accrual basis.

Table 12: 2020-2024 Post-employment Benefit Costs ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Bridge	2024 Bridge
Benefit Costs	15.7	14.6	13.9	11.5	13.0
Capitalized Amounts	7.4	6.9	7.0	5.8	6.5
Expensed Amounts	8.2	7.7	6.9	5.7	6.5

Please note that the numbers in the table may not sum due to rounding.

Table 13: 2025-2029 Post-employment Benefit Costs ($ Millions)

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Benefit Costs	14.1	15.0	15.8	16.6	17.4
Capitalized Amounts	7.0	7.5	8.0	8.4	8.9
Expensed Amounts	7.1	7.4	7.8	8.2	8.5

Please note that the numbers in the table may not sum due to rounding.

January 27, 2023

Ms. Stazia Harding
Toronto Hydro Corporation
14 Carlton Street
Toronto, ON
M5B 1K5

Dear Stazia:

POST-EMPLOYMENT BENEFITS FOR EMPLOYEES OF TORONTO HYDRO
2022 YEAR-END DISCLOSURES AND ESTIMATED 2023 AND 2024 BENEFIT EXPENSE UNDER INTERNATIONAL ACCOUNTING STANDARDS

As requested, this letter and appendices have been prepared for Toronto Hydro Corporation ("the Company", or "Toronto Hydro") and present the Company's liabilities and costs in respect of the following post-retirement and post-employment benefits plans ("the Plans"):

- Extended health benefits for retirees and members on disability;
- Dental benefits for retirees and members on disability;
- Life insurance benefits for retirees;
- Vested and non-vested sick leave benefits;
- OMERS top up pension;
- Executive OMERS top up pension; and
- Executive retirement allowance.

This letter and appendices have been prepared for the Company and its external reporting, for the following purposes:

130 King St. West
Suite 1500
P.O. Box 424
Toronto, Ontario M5X 1E3
Canada

T +1 416 960 2700
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Towers Watson Canada Inc.

- Determining the final calculation of the 2022 benefit expense under International Financial Reporting Standards (IFRS) in accordance with International Accounting Standards Section 19 (IAS 19),

- Providing the required information for year-end disclosure purposes as of December 31, 2022 under IAS 19, and

- Determining an estimate of the 2023 and 2024 benefit expenses under IAS 19.

The information contained in this letter and appendices are presented in thousands of Canadian dollars and are in respect of the benefits mentioned above only.

The 2022 net periodic benefit cost is based on the results of the January 1, 2020 actuarial valuation. The 2022 year-end disclosure obligation and extrapolations for 2023 and 2024 are based on the results of the January 1, 2022 actuarial valuation.

The balance of this letter sets out comments and notes to our calculations. Appendix A provides details of the relevant accounting results. Additional information regarding the summaries of the plan provisions, the membership data and the actuarial basis used in the January 1, 2022 valuation are going to be included in the forthcoming actuarial valuation report prepared by WTW.

Actuarial Assumptions and Methods

- The measurement date used for Fiscal 2022 year-end financial reporting is December 31, 2022.

- The 2022 benefit expense is based on a discount rate of 3.00% per annum and the defined benefit obligation (“DBO”) at December 31, 2022 is based on a discount rate of 5.10% per annum, as instructed by the Company. The discount rates are based on long-term high-quality Canadian corporate bond yields at December 31, 2021 and December 31, 2022, respectively.

- Other than those noted in this letter, the actuarial methods and assumptions used for the determination of the 2022 net periodic benefit cost are consistent with those used for the 2021 year-end disclosures and the actuarial methods and assumptions used for the December 31, 2022 obligation are consistent with those used for the January 1, 2022 valuation.

- The obligation as of December 31, 2022 and the 2023 and 2024 expense estimates are based on extrapolations from the January 1, 2022 valuation results for the medical, dental, life insurance, sick leave, OMERS top-up and retirement allowance benefit plans, assuming no experience gains or losses other than from actual benefit payments being different from expected, and reflecting changes in assumptions as at the measurement date. As instructed by the Company, the 2023 preliminary expense reflects a one-time adjustment to the Retirement Allowance gain/loss, reflected as at January 1, 2023, impacting 2023 preliminary gains and losses recognized in expense and OCI.

Accounting Methods

- Under IAS 19, we understand that Toronto Hydro has determined that both the non-vested sick leave benefit program and the vested sick leave benefit program should be included for post-employment benefits reporting. As such, these benefits are included in the financial information under IAS 19 presented in this letter.

- On an ongoing basis, actuarial gains and losses for all benefit plans other than the sick leave benefits plan and the incentive plan retirement allowance will be immediately recognized in other comprehensive income. Actuarial gains and losses for the sick leave benefit plan and the incentive plan retirement allowance will be recognized immediately in expense.

- On an ongoing basis, the impact of plan changes will be immediately recognized in benefit expense.

Summary of Financial Results

The summary of Fiscal 2022 benefit expense, the defined benefit liability and the DBO as at December 31, 2022, under IAS 19 is as follows (in $ 000s):

($000s)	Fiscal 2022 Net Periodic Benefit Costs	Defined Benefit Asset/(Liability) at December 31, 2022	DBO at December 31, 2022
Electric System Limited	9,255	(221,692)	221,692
Toronto Hydro Corporation	993	(5,779)	5,779
Energy Service Incorporated	34	(1,131)	1,131
LDC Unregulated	99	(1,357)	1,357
Consolidated	10,381	(229,959)	229,959

- Actual benefit payments for 2022 of $10,427,590 are based on information provided by the Company on January 10, 2023. We have projected 2023 and 2024 benefit payments based on the valuation assumptions.

Other Comments

- We understand that the post-employment benefits plans are not pre-funded, and therefore our accounting results do not consider any expected investment income on plan assets.

- As directed by the Company, the full defined benefit liability has been classified as a non-current liability.

- We understand that the Company could be making adjustments to the results presented herein, in respect to certain executive employees currently on salary continuance. Reflecting any adjustments for these participants is beyond the scope of our engagement with the Company. As instructed by the Company on November 25, 2021, we haven't made any adjustments for these participants.

- Other than those described in this letter and appendices, the Company's management has confirmed that there have been no significant events, changes to the plan provisions or changes to plan membership since January 1, 2022 for all benefit plans, that would materially affect the results of our valuations.

The breakdown of net actuarial (gain)/loss as at December 31, 2022 is as follows (in $000s):

	Electric System Limited	Toronto Hydro Corporation	Energy Service Incorporated	LDC Unregulated	Total
Demographic Assumptions:					
Sick Leave Program	(164)	-	-	-	(164)
Retirement Allowance #1	-	-	-	-	-
Other Plans	2,114	(95)	-	9	2,028
Economic Assumptions:					
Sick Leave Program	(266)	-	-	-	(266)
Retirement Allowance #1	-	(70)	-	-	(70)
Other Plans	(82,079)	(1,814)	(420)	(523)	(84,836)
Plan Experience:					
Sick Leave Program	(3,209)	-	-	-	(3,209)
Retirement Allowance #1	-	(59)	-	-	(59)
Other Plans	5,219	507	400	46	6,172
Total Net Actuarial (Gain)/Loss:					
Sick Leave Program	(3,639)	-	-	-	(3,639)
Retirement Allowance #1	-	(129)	-	-	(129)
Other Plans	(74,746)	(1,402)	(20)	(468)	(76,636)
Sub-Total	(78,385)	(1,531)	(20)	(468)	(80,404)

Actuarial Certification

The Company may make a copy of this report available to its auditors, but we make no representation as to the suitability of this report for any purpose other than that for which it was originally provided and accept no responsibility or liability to the Company's auditors in this regard. We are aware that the information contained in this report will be used to support the audit of the Company's financial statements. Except where we expressly agree in writing, this report should not be disclosed or provided to any third party, other than as provided above. WTW accepts no responsibility for any consequences arising from any other party relying on this report or any advice relating to its contents.

In preparing these results, we have relied upon information and data provided to us orally, electronically and/or in writing by the Company and other persons or organizations designated by the Company. We have relied on all the data and information provided, including plan provisions and membership data as being complete and accurate. Based on discussions with and concurrence by the plan sponsor, assumptions or estimates may have been made if data were not available. We have not independently verified the accuracy or completeness of the data or information provided, but we have performed limited checks for consistency.

We are not aware of any errors or omissions in the data that would have a significant effect on the results of our calculations.

The results presented in this report are directly dependent upon the accuracy and completeness of the underlying data and information. Any material inaccuracy in the data, plan provisions or other information provided to us may have produced results that are not suitable for the purposes of this report and such inaccuracies may produce materially different results that could require that a revised report be issued.

The results summarized in this report involve actuarial calculations that require assumptions about future events. The Company is responsible for the selection of the assumptions, as required by IAS 19. Other assumptions may also be reasonable and appropriate, and their use would produce different results.

The results provided in this report reflect data and assumptions appropriate for the purpose of the measurement. As of the date of this report, there remains significant uncertainty regarding the effects on financial markets, regulations and experience for the following:

- The long-term effects of the COVID-19 pandemic;
- Events related to Russia's military action against Ukraine that commenced on February 24, 2022

The results presented in this report make no explicit allowances for the effects of these events as at December 31, 2022. As these events evolve, there may be significant impacts on plan experience and/or assumptions use in future measurements.

The expense and obligation levels will change in the future as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions, accounting rules, legislature, and the government health care programs, or as a result of future experience gains or losses. None of these changes has been anticipated at this time but will be revealed in future accounting valuations.

The figures provided in this letter reflect, to the best of our knowledge, all of the Company's substantive commitments and obligations, as described herein. Furthermore, to the best of our knowledge, there are no subsequent events, the occurrence of which is probable and the effects of which are reasonably estimable, which have not been reflected in the figures provided as of the date of our letter.

In our opinion:

- the membership data on which the valuation is based are sufficient and reliable for purposes of the valuation;
- the assumptions are appropriate for the purposes of the valuation;
- the methods employed in the valuation are appropriate for the purposes of the valuation;
- the calculations have been made in accordance with our understanding of the requirements of IAS 19 and the Company's accounting policies.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

We are pleased to provide you with this year-end disclosure report. Please contact us if you need any additional information.

Carl Larose, FCIA
Direct Dial: (514) 982-3013

Ross Cristiano, FCIA
Direct Dial: (416) 960-2837

Toronto, Ontario
January 27, 2023

Enclosures

cc:
Sandra Lau, Claudia Oancea, Helen MacDonald, Dave Clark - THC
Edward Eun, Dion Salandy and Graham Allison - WTW

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2022 Year-End Disclosure Information ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			**January 1, 2022**		
Defined Benefit Asset/(Liability) at Beginning of Period	(297,479)	(6,205)	(1,167)	(1,791)	(306,642)
Reconciliation of Defined Benefit Obligation			**2022**		
Defined Benefit Obligation at Beginning of Period	297,479	6,205	1,167	1,791	306,642
Employer Service Cost at Beginning of Period	2,675	345	-	44	3,064
Interest Cost	8,900	212	34	55	9,201
Past Service Cost (Credit)	1,319	565	-	-	1,884
Net Actuarial (Gain) or Loss					-
Sick Leave Plan	*(3,639)*	-	-	-	*(3,639)*
Retirement Allowance Benefit	-	*(129)*	-	-	*(129)*
Other Plans	*(74,746)*	*(1,402)*	*(20)*	*(468)*	*(76,636)*
Total Net Actuarial (Gain) or Loss	(78,385)	(1,531)	(20)	(468)	(80,404)
Benefits Paid Directly by the Employer	(10,296)	(17)	(50)	(65)	(10,428)
Defined Benefit Obligation at Current Period End	221,692	5,779	1,131	1,357	229,959
Change in Plan Assets			**2022**		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	10,296	17	50	65	10,428
Benefits Paid	(10,296)	(17)	(50)	(65)	(10,428)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			**2022**		
Employer Service Cost at Beginning of Period	2,675	345	-	44	3,064
Interest Cost	8,900	212	34	55	9,201
Past Service Cost (Credit)	1,319	565	-	-	1,884
Actuarial (Gain)/Loss Recognized in Expense	(3,639)	(129)	-	-	(3,768)
Total Benefit Expense/(Income)	9,255	993	34	99	10,381
Reconciliation of Balance Sheet			**2022**		
Defined Benefit Asset/(Liability) at Prior Period End	(297,479)	(6,205)	(1,167)	(1,791)	(306,642)
Total Benefit (Expense)/Income for Period	(9,255)	(993)	(34)	(99)	(10,381)
Benefits Paid Directly by the Employer	10,296	17	50	65	10,428
Gain/(Loss) Recognized via OCI	74,746	1,402	20	468	76,636
Defined Benefit Asset/(Liability) at Current Period End	(221,692)	(5,779)	(1,131)	(1,357)	(229,959)
Change in Accumulated Other Comprehensive Income			**2022**		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	23,151	(1,934)	(2,166)	189	19,240
Actuarial (Gain)/Loss Recognized via OCI for Period	(74,746)	(1,402)	(20)	(468)	(76,636)
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	(51,595)	(3,336)	(2,186)	(279)	(57,396)
Statement of Financial Position at End of Period			**December 31, 2022**		
Defined Benefit Asset/(Liability) at Current Period End	(221,692)	(5,779)	(1,131)	(1,357)	(229,959)
Breakdown of Defined Benefit Obligation: Current and Non-Current			**December 31, 2022**		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(221,692)	(5,779)	(1,131)	(1,357)	(229,959)
Defined Benefit Asset/(Liability) at Current Period End	(221,692)	(5,779)	(1,131)	(1,357)	(229,959)

Sensitivity to Changes in Medical and Dental Trend Rate Assumption					
Effect on total of service and interest cost for 2022					
1% point increase	1,568	5	5	15	1,593
1% point decrease	(1,373)	(4)	(4)	(14)	(1,395)
Effect on accrued benefit obligation at December 31, 2022					
1% point increase	24,520	136	145	157	24,958
1% point decrease	(21,295)	(115)	(127)	(138)	(21,675)
Sensitivity to Changes in Discount Rate Assumption					
Effect on total of service and interest cost for 2022					
1% point increase	537	(23)	5	(4)	515
1% point decrease	(940)	20	(7)	1	(926)
Effect on accrued benefit obligation at December 31, 2022					
1% point increase	(26,105)	(641)	(136)	(169)	(27,051)
1% point decrease	32,130	783	166	206	33,285
Sensitivity to Changes in Mortality Rates Assumption					
Effect on accrued benefit obligation at December 31, 2022					
Set back 1 year	6,802	75	38	37	6,952
Set forward 1 year	(6,719)	(80)	(37)	(37)	(6,873)
Key Assumptions					
Discount rate at Dec 31/22 (used for Dec 31/22 obligation)	5.10%	5.10%	5.10%	5.10%	5.10%
Discount rate at Dec 31/21 (used for 2022 Benefit Costs)	3.00%	3.00%	3.00%	3.00%	3.00%
Assumed medical and dental cost trend rate at December 31, 2022					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.10%	5.10%	5.10%	5.10%	5.10%
Expected Benefit Payments					
Following Year	10,752	287	48	53	11,140
Following Year +1	11,233	244	49	55	11,581
Following Year +2	11,504	289	50	57	11,900
Following Year +3	11,692	193	51	61	11,997
Following Year +4	11,939	466	54	64	12,523
Following Year +5	12,173	408	57	67	12,705
Modified Duration at the end of the year	13.0	13.3	13.2	13.7	13.0

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2023 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			**January 1, 2023**		
Defined Benefit Asset/(Liability) at Beginning of Period	(221,692)	(5,779)	(1,131)	(1,357)	(229,959)
Reconciliation of Defined Benefit Obligation			**2023**		
Defined Benefit Obligation at Beginning of Period	221,692	5,779	1,131	1,357	229,959
Employer Service Cost at Beginning of Period	1,544	264	-	5	1,813
Interest Cost	11,111	301	56	68	11,536
Net Actuarial (Gain) or Loss	-	-	-	-	-
Sick Leave Plan	-	-	-	-	-
Retirement Allowance Benefit	-	*94*	-	-	*94*
Other Plans	-	*(94)*	-	-	*(94)*
Total Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(10,752)	(287)	(48)	(53)	(11,140)
Defined Benefit Obligation at Current Period End	223,595	6,057	1,139	1,377	232,168
Change in Plan Assets			**2023**		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	10,752	287	48	53	11,140
Benefits Paid	(10,752)	(287)	(48)	(53)	(11,140)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			**2023**		
Employer Service Cost at Beginning of Period	1,544	264	-	5	1,813
Interest Cost	11,111	301	56	68	11,536
Actuarial (Gain)/Loss Recognized in Expense	-	94	-	-	94
Total Benefit Expense/(Income)	12,655	659	56	73	13,443
Reconciliation of Balance Sheet			**2023**		
Defined Benefit Asset/(Liability) at Prior Period End	(221,692)	(5,779)	(1,131)	(1,357)	(229,959)
Total Benefit (Expense)/Income for Period	(12,655)	(659)	(56)	(73)	(13,443)
Benefits Paid Directly by the Employer	10,752	287	48	53	11,140
Gain/(Loss) Recognized via OCI	-	94	-	-	94
Defined Benefit Asset/(Liability) at Current Period End	(223,595)	(6,057)	(1,139)	(1,377)	(232,168)
Change in Accumulated Other Comprehensive Income			**2023**		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	(51,595)	(3,336)	(2,186)	(279)	(57,396)
Actuarial (Gain)/Loss Recognized via OCI for Period	-	(94)	-	-	(94)
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	(51,595)	(3,430)	(2,186)	(279)	(57,490)
Statement of Financial Position at End of Period			**December 31, 2023**		
Defined Benefit Asset/(Liability) at Current Period End	(223,595)	(6,057)	(1,139)	(1,377)	(232,168)
Breakdown of Defined Benefit Obligation: Current and Non-Current			**December 31, 2023**		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(223,595)	(6,057)	(1,139)	(1,377)	(232,168)
Defined Benefit Asset/(Liability) at Current Period End	(223,595)	(6,057)	(1,139)	(1,377)	(232,168)
Key Assumptions					
Discount rate at Dec 31/22 (used for December 31, 2023 obligation)	5.10%	5.10%	5.10%	5.10%	5.10%
Discount rate at Dec 31/22 (used for 2023 Benefit Costs)	5.10%	5.10%	5.10%	5.10%	5.10%
Assumed medical and dental cost trend rate at December 31, 2023					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.10%	5.10%	5.10%	5.10%	5.10%
Expected Benefit Payments for Following Year	11,233	244	49	55	11,581

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2024 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			**January 1, 2024**		
Defined Benefit Asset/(Liability) at Beginning of Period	(223,595)	(6,057)	(1,139)	(1,377)	(232,168)
Reconciliation of Defined Benefit Obligation			**2024**		
Defined Benefit Obligation at Beginning of Period	223,595	6,057	1,139	1,377	232,168
Employer Service Cost at Beginning of Period	1,623	277	-	5	1,905
Interest Cost	11,200	317	57	69	11,643
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(11,233)	(244)	(49)	(55)	(11,581)
Defined Benefit Obligation at Current Period End	225,185	6,407	1,147	1,396	234,135
Change in Plan Assets			**2024**		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	11,233	244	49	55	11,581
Benefits Paid	(11,233)	(244)	(49)	(55)	(11,581)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			**2024**		
Employer Service Cost at Beginning of Period	1,623	277	-	5	1,905
Interest Cost	11,200	317	57	69	11,643
Total Benefit Expense/(Income)	12,823	594	57	74	13,548
Reconciliation of Balance Sheet			**2024**		
Defined Benefit Asset/(Liability) at Prior Period End	(223,595)	(6,057)	(1,139)	(1,377)	(232,168)
Total Benefit (Expense)/Income for Period	(12,823)	(594)	(57)	(74)	(13,548)
Benefits Paid Directly by the Employer	11,233	244	49	55	11,581
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(225,185)	(6,407)	(1,147)	(1,396)	(234,135)
Change in Accumulated Other Comprehensive Income			**2024**		
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Prior Period End	(51,595)	(3,430)	(2,186)	(279)	(57,490)
Actuarial (Gain)/Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain)/Loss Recognized via OCI at Current Period End	(51,595)	(3,430)	(2,186)	(279)	(57,490)
Statement of Financial Position at End of Period			**December 31, 2024**		
Defined Benefit Asset/(Liability) at Current Period End	(225,185)	(6,407)	(1,147)	(1,396)	(234,135)
Breakdown of Defined Benefit Obligation: Current and Non-Current			**December 31, 2024**		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(225,185)	(6,407)	(1,147)	(1,396)	(234,135)
Defined Benefit Asset/(Liability) at Current Period End	(225,185)	(6,407)	(1,147)	(1,396)	(234,135)
Key Assumptions					
Discount rate at Dec 31/22 (used for December 31, 2024 obligation)	5.10%	5.10%	5.10%	5.10%	5.10%
Discount rate at Dec 31/22 (used for 2024 Benefit Costs)	5.10%	5.10%	5.10%	5.10%	5.10%
Assumed medical and dental cost trend rate at December 31, 2024					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate assumed for next year	5.10%	5.10%	5.10%	5.10%	5.10%
Expected Benefit Payments for Following Year	11,504	289	50	57	11,900

Toronto Hydro-Electric System Limited
EB-2023-0195
Exhibit 4
Tab 4
Schedule 5
ORIGINAL
(10 pages)

Non-Executive Compensation and Benefits Review

Toronto Hydro Electric System Limited

13 March 2023

Introduction and Executive Summary

Mercer Canada Limited ("Mercer") has been engaged by Toronto Hydro Electric System Limited ("THESL") to conduct a complete market review of compensation and benefits program competitiveness for union and non-union within Toronto Hydro.

The purpose of this review is to provide an independent, market-based assessment of the market positioning of THESL's non-executive total remuneration that includes base salary, short-term incentives, total cash compensation, active employee benefits, and pensions relative to the markets THESL competes with for talent. THESL employee groups considered include non-union professionals (i.e non-executive) and union positions represented by the Power Workers' Union ("PWU") and the Society of United Professionals ("SIT" or "SE").

Executive Summary

This review approach is consistent with Mercer's standard market benchmarking methodologies, and relies on compensation and benefits practices information provided by THESL, in addition to Mercer's proprietary compensation databases. Market comparisons are made to a group of peer organizations, selected by Mercer and confirmed by THESL, that are representative of the energy and general industry sectors THESL competes with for talent.

In conducting the compensation analysis, Mercer worked together with THESL to identify benchmark positions to compare to market that represent a valid cross sample of the organization's functions and levels. The breadth of benchmark positions selected is within the range of 50% to 75% of employees, considered best practice when benchmarking on an organization basis. The benchmarking review includes positions that represent approximately 67% of employees at THESL.

Mercer considers compensation levels to be within a "competitive range" if they fall within 10% of the target market positioning on a position-by-position basis (where you have a smaller sample size and higher variability in observations) and 5% on an overall organization basis (where you have a larger sample size and smaller variability in observations) when compared to target positioning (e.g., the 50th percentile).

On an overall organization basis, THESL's total remuneration, including the value of all cash compensation, benefit and pension plans are positioned within a market competitive range relative to the 50th percentile of the energy market, and are above the general industry market. The general industry market is generally representative of publicly traded, for-profit organizations. Competitive positioning varies by job and by level within THESL. Union and non-union positions are generally positioned competitively against the 50th percentile of the energy sector and at or above the market 50th percentile against the general industry due to the availability of base salary and pension and benefits in the general industry. Society and PWU represented roles are generally positioned competitively against the energy sector, and are reflective of energy sector specific positions.

Methodology

Mercer worked with THESL to determine the appropriate markets and organizations for comparison given the organizations they compete with for talent (i.e., organizations that Toronto Hydro might reasonably recruit employees from or lose employees to) and that are comparable in scope or type of operations. Two specific peer groups were identified for the purposes of the compensation and benefits review:

- **Energy Peer Group**
  - Reflects select Canadian organizations from Mercer's Total Compensation Survey ("MTCS") and proprietary custom surveys with energy industry-specific roles
  - Organizations were selected considering the comparability of their operations, relative size of revenues and full-time employee equivalents when compared to THESL, resulting in a peer group primarily consisting of other energy utilities
- **General Industry Peer Group**
  - Reflects select for-profit Canadian Organizations from Mercer's Benchmark Database ("MBD") that includes general industry roles and organizations
  - Aligned with Mercer's standard benchmarking methodology, organizations are generally within ½ to 2x the size of THESL on the basis of annual revenue
  - Where required to provide statistically significant market information for a specific position, the peer group is expanded to include organizations within 1/3 to 3x the size of THESL on the basis of annual revenue

A listing of organizations that belong to each of these peer groups for the purposes of either cash compensation, benefits or pension benchmarking is presented in Appendix A.

A sample of THESL's jobs across all grades were benchmarked against equivalent roles within organizations from the defined peer groups. Equivalences were determined on the basis of overlaps in responsibilities between THESL and survey position descriptions.

- 47 non-union jobs at THESL were matched to equivalent survey jobs and levels in the two peer groups.
- 14 union jobs were matched to equivalent survey jobs and levels in the energy peer group, as positions are generally energy industry specific in their responsibilities

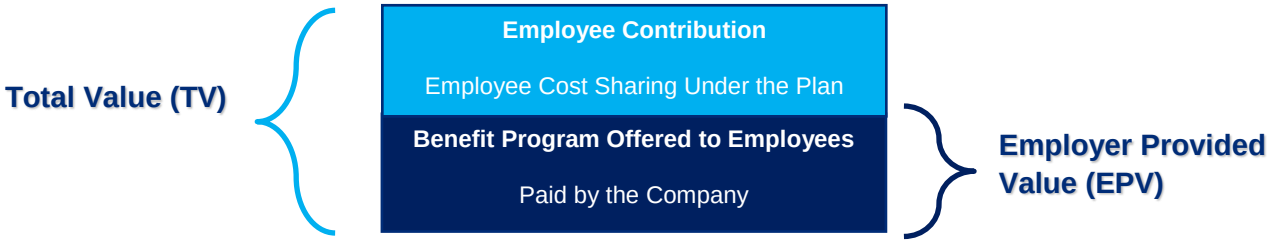
Mercer's benchmarking objective with this review is to map a reasonable sample of THESL's positions that best represent the total employee population across the different job levels in the organization. With this approach, our analysis includes 67% of the total population considered in-scope for this review. Mercer believes this to be a statistically reliable and representative sample for assessing the competitive levels of total remuneration for THESL's employees.

A listing of the specific THESL benchmark positions matched to market as part of this review is presented in Appendix B.

Cash compensation levels tend to be aligned with the scope and complexity of the individual position and as such, to the extent possible, Mercer analyzed market data specific to the individual position. Benefit and pension programs tend to be common to all participants within a defined group and, as such comparisons to market are made on a plan or aggregate basis for each employee group (e.g., non-union, Society, PWU, etc.).

For the retirement and benefits program review, Mercer similarly benchmarked THESL against the energy peer group and general industry peer groups for organizations available in the Mercer Plan Design databases considering their relative **employer provided value** ("EPV"). Relative value analysis focuses only on the plan design as it sets all other cost drivers at a common level and is more consistent when comparing the value of the benefit programs of several organizations.

We note how benchmarking Total Value (TV) compares to Employer Provided Value (EPV) for the benefits analysis:



Plans for all comparator organizations have been valued using the same earnings information and composite workforce profile. Using different earnings levels would change the dollar value of the benefit, but any change in relative value of the plan amongst the participants would not, in Mercer's opinion, be material.

As each element of the total remuneration package serves a different role, and companies may choose to offer a different pay mix in order to accomplish different objectives, Mercer recommends THESL consider the competitiveness of its total remuneration package as a whole (considering total remuneration) rather than the competitiveness of each individual compensation element. In order to provide a complete picture, report findings and observations are presented for separate compensation elements as well as aggregate total remuneration.

All compensation data is reflective of the most recently available data as of the completion of the analysis, and is presented effective for 2022.

Summary of Findings

Our commentary describes the competitiveness of THESL's base salary, short-term incentive, total cash compensation and total remuneration at an aggregate level for each grade in the organization, relative to the 50th percentile of the respective market. Based on Mercer's compensation practices and policy research, the majority of organizations target compensation at the 50th percentile of their competitive market, which balances fiduciary and cost considerations with the need to attract and retain talent.

- As stated above, Mercer considers THESL to be within the competitive range if they fall within 10% of the target market positioning on a position-by-position basis and 5% on the overall grade and organization basis.
- Market figures are presented where there is sufficient data to show the 50th percentile (Conversely, insufficient data is denoted by a "-").

The table below presents THESL's base salaries, target STI, target total cash compensation (TTC) and total remuneration (TRem) at an aggregate level, compared to the market 50th percentile across the two peer groups:

ABOVE MARKET (+5%)
BELOW MARKET (-5%)

Toronto Hydro					Energy Peer Group				General Industry Peer Group			
Grade	Base Salary ($)[1]	Target STI (%)	TTC ($)[2]	TRem ($)[3]	Base Salary ($)[1]	Target STI (%)	TTC ($)[2]	TRem ($)[3]	Base Salary ($)[1]	Target STI (%)	TTC ($)[2]	TRem ($)[3]
Y3	$190	25%	$237	$286	$211	23%	$260	$296	$196	25%	$237	$282
					-10%	2%	-9%	-3%	-3%	0%	0%	1%
Y1	$148	15%	$171	$205	$177	21%	$219	$257	$157	19%	$180	$205
					-16%	-6%	-22%	-20%	-6%	-4%	-5%	0%
W4	$139	10%	$153	$182	$149	16%	$171	$192	$130	15%	$147	$165
					-7%	-6%	-11%	-5%	7%	-5%	4%	10%
W3	$131	10%	$144	$169	$139	14%	$158	$177	$138	17%	$164	$179
					-6%	-4%	-9%	-4%	-6%	-7%	-13%	-5%
W2	$113	8%	$122	$150	$106	15%	$129	$150	$109	13%	$123	$141
					6%	-7%	-6%	0%	3%	-5%	-1%	6%
V4	$131	8%	$141	$169	$127	10%	$136	$156	$131	10%	$146	$160
					3%	-2%	4%	8%	0%	-2%	-3%	6%
V3	$123	8%	$133	$158	$123	11%	$136	$157	$113	11%	$130	$145
					0%	-3%	-2%	1%	9%	-3%	2%	9%
V2	$113	8%	$122	$145	$115	10%	$125	$142	$109	10%	$119	$131
					-2%	-2%	-2%	2%	4%	-2%	3%	11%
V1	$102	8%	$110	$133	$107	10%	$117	$134	$97	11%	$101	$114
					-5%	-2%	-6%	-1%	5%	-3%	9%	17%
V0	$90	8%	$97	$118	$87	9%	$95	$111	$76	8%	$83	$94
					3%	-1%	3%	6%	18%	0%	17%	25%
U2	$81	6%	$86	$105	$85	9%	$90	$105	$79	8%	$86	$96
					-4%	-3%	-5%	0%	2%	-2%	1%	9%
U1	$74	6%	$78	$96	$79	9%	$80	$95	$70	7%	$72	$82
					-7%	-3%	-2%	1%	6%	-1%	10%	18%
T1	$58	6%	$62	$76	$65	6%	$66	$78	$58	5%	$56	$65
					-11%	0%	-7%	-2%	0%	1%	9%	17%
SIT	$107	8%	$115	$139	$101	9%	$108	$128	$92	7%	$87	$99
					5%	-1%	7%	8%	15%	1%	33%	41%
SE	$123	8%	$133	$158	$111	10%	$122	$142	$106	10%	$116	$130
					10%	-2%	9%	11%	16%	-2%	14%	21%
PWU	$111	--	$111	$133	$101	8%	$105	$124	--	--	--	--
					10%	--	6%	7%	--	--	--	--
Overall					98%		95%	99%	103%		103%	110%

(1) Toronto Hydro base salary reflects salary structure job rates
(2) Toronto Hydro target total cash ("TCC") reflects salary structure job rates plus target short-term incentives
(3) Total remuneration ("TRem") reflects target total cash compensation plus the value of long-term incentives, pensions and benefits
Note: Figures are rounded to the nearest thousand (dollars) or percent

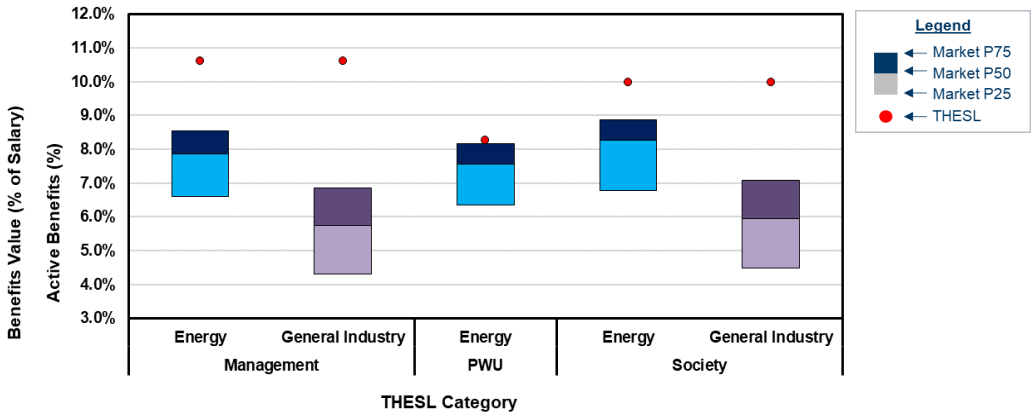
Overall, Toronto Hydro's compensation program, on a **total remuneration** basis, is closely aligned with the 50th percentile market pay levels of the energy peer group, the most comparable peer group given relative roles and responsibilities, and is above the market competitive level relative to the general industry peer group. Relative to the energy peer group, Y1 is the only grade that falls below the market 50th percentile for total remuneration. When compared to the general industry peer group, the majority of positions are positioned within or above the market 50th percentile, with the exception of W3 which is below the market competitive range.

On **base salaries** for non-union positions, Toronto Hydro is generally within the market competitive zone. Exceptions include Y1 which is below the competitive range relative to both the energy peer group and general industry peer group, and T1 which is below the competitive range relative to only the energy peer group. Salary grade V0 is above the market competitive range compared to general industry peers. Additionally, PWU and Society represented positons are paid above the competitive range relative to both the energy and general industry peer groups.

Market eligibility for **short-term incentives** (**"STI")** is generally more prevalent for team leader levels and above (i.e., close to 100% eligibility for jobs benchmarked to the W2 grade level and above). In comparison, THESL offers incentive pay for all positions, except for the PWU represented positions. On STI target opportunity, THESL is below market competitiveness for both energy and general industry peers.

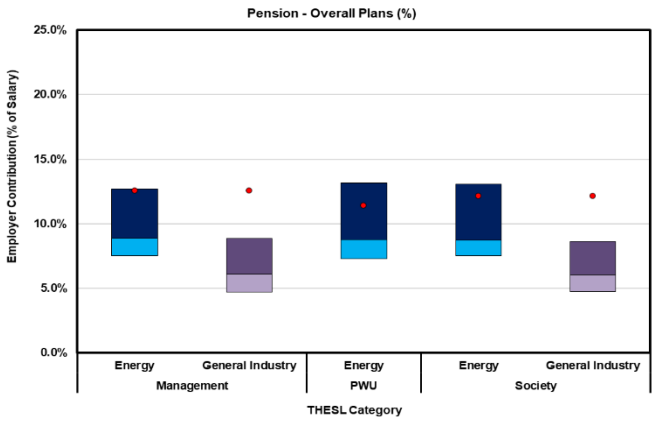
Overall, on **total cash compensation,** THESL remains within the range of market competitiveness for both the energy and general industry peer group. Grades Y3, Y1, W4 and W3 are below the competitive range relative to the energy peer group. Compared to the general industry peer group, all grades are within or above the competitive range, with the exception of W3 whose total cash compensation is below the competitive range. Consistent with base salary, PWU and Society represented positions are paid above the competitive range relative to both the energy and general industry peer groups.

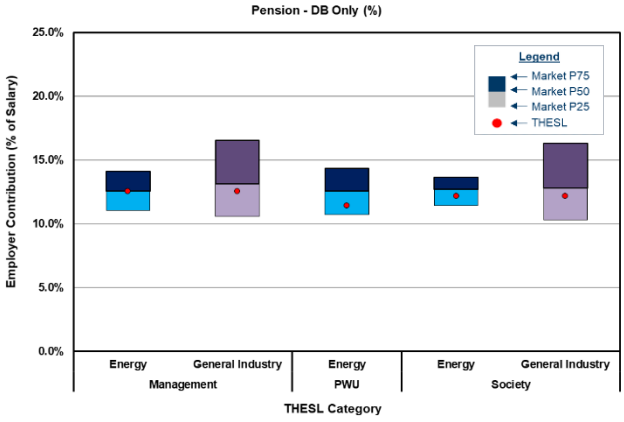
To illustrate the impact of the benefits element on total remuneration, the tables below present THESL's **active benefits** and **pension** value for each employee group considering employer-provided value, compared to the market 50th percentile across the two peer groups.



When compared to the energy and general industry peer groups, THESL provides a top quartile active benefits plan, which is the overall value of active benefits (including life insurance, accidental death and dismemberment, short-term disability, long-term disability, healthcare spending account and health and dental) across all employee groups. Overall, THESL's position for active group

benefits is driven by above market disability, health and dental benefits, many of which have been enhanced to incorporate higher maximums or annual limits in the past 5 years.





THESL's pension arrangements through OMERS for all employees are above the 50th percentile of the employer provided value among both the energy and general industry peer group companies. The energy sector market median is higher than the general industry because the energy sector has about half of the comparators providing Defined Benefits ("DB") pensions to new hires, while the general industry is dominated by Defined Contribution pension and savings plans that provide less value than DB pensions. The trend continues to be away from DB plans in the private sector, while the public sector remains mainly DB.

When considering only comparators that continue to provide DB pensions to new hires, THESL's pension for non-union employees is aligned to the 50th percentile of the employer provided value among both the energy and general industry peer group companies.

We note that the employer-provided pension value for the OMERS pension plan is set to 50% of the total value of the plan, since the cost of the plan is equally shared between Toronto Hydro and employees. Compared to a traditional single employer provided Defined Benefit pension plan, where the employer is responsible for all risk in the plan and the employee is only responsible for contributing a fixed contribution rate, this structure reduces the risk to Toronto Hydro.

Appendix A

The following companies comprise the **energy peer group** used for the purposes of the review:

ENERGY INDUSTRY COMPARATOR COMPANIES	
Alectra Inc.*	Hydro One Inc.*
Algonquin Power & Utilities Corp*	Hydro Ottawa Limited*
AltaLink L.P.	Hydro-Quebec*
ATCO Electric*	Manitoba Hydro*
BC Hydro Power & Authority*	Nalcor Energy*
Capital Power Corporation	New Brunswick Power *
ENMAX Corporation*	Nova Scotia Power (Emera, Inc.)*
EPCOR Utilities*	Ontario Power Generation*
Fortis, Inc. - FortisAlberta, Inc.	SaskPower*
Fortis, Inc. - FortisBC, Inc.	TransAlta Corporation*

(*) Energy companies from the Mercer Plan Design databases used in the benefits analysis

The following companies comprise a sample of the **general industry peers** used in the review:

GENERAL INDUSTRY COMPARATOR COMPANIES	
Aecon Group, Inc.	John Deere Canada ULC
AltaGas, Ltd.	Keyera Corp.
Capital Power Corporation	Lassonde Industries, Inc.
Colas Canada, Inc.	SaskPower
Deschênes Group Inc.	Sonepar Canada Inc.
Emera, Inc.	Stantec, Inc.
EPCOR Utilities, Inc.	TC Transcontinental
Generac Power Systems	Tourmaline Oil Corp.
Hudbay Minerals Inc	TransAlta
Hydro One, Inc.	Valero Energy, Inc.
Inter Pipeline, Ltd.	Vale Canada Limited
Linamar Corporation	Vermilion Energy, Inc.

Appendix B

Mercer worked closely with THESL to select jobs that best represent the total employee population across the different job levels in the organization. The following 47 non-bargaining positions were included within the scope of the review:

THESL Position	Grade
Director, Capital Projects	Y3
Director, Design & Construction	Y3
Controller	Y3
Director, Internal Audit & Compliance	Y3
Director, Environment, Health and Safety	Y3
Director, Commercial Legal Services	Y3
Senior Manager, Customer Support Centre	Y1
Senior Manager, Finance Systems	Y1
Senior Manager, Change Management	Y1
Senior Manager, Warehouse Mgmt & Fleet Services	Y1
Senior Manager, Regulatory Services	Y1
Senior Manager, Litigation & Privacy	Y1
Manager, Finance Management Reporting	W4
Manager, Engineering	W4
Manager, Project Execution	W3
Manager, Design	W3
Manager, Construction & Maintenance	W3
Manager, Facilities	W3
Manager, Supply Chain Services	W3
Manager, Accounts Receivable Operations	W2
Manager, Call Centre	W2
Manager, Capital Construction Analytics	W2
IT Architect	V4
Audit & Compliance Consultant	V3

THESL Position	Grade
EHS Consultant	V3
Employee Labour Relations Consultant	V3
Senior Commercial Services Counsel	V3
Regulatory Affairs Consultant	V3
Senior Financial Analyst	V2
Training Design Consultant	V2
Program Management Consultant	V2
Enterprise Risk Management Consultant	V2
External Communications Specialist	V2
Capital & Maintenance Program Analyst	V1
Asset Investment Analyst	V1
Governance Counsel	V1
Talent Management Associate	V0
Financial Analyst	V0
HR Systems Associate	V0
Payroll & Disbursements Analyst	U2
Executive Assistant	U2
Law Clerk, Litigation	U2
Operations Analyst	U1
HR Analyst	U1
Communications Coordinator, Customer Operations	U1
Human Resources Administrator	T1
Human Resources Administrator	T1

The following 14 bargaining positions were included within the scope of the review:

THESL Position	Union
IT Client Consultant	SIT
IT Technical Support Analyst	SIT
IT Technical Consultant	SIT
Engineer	SE
Cert Meter Mechanic	PWU
Programmer / Analyst	PWU
Power Line Technician	PWU

THESL Position	Union
Cert Crew Leaders, Power Line Tech	PWU
Distribution System Technologist	PWU
Power System Controller	PWU
Fleet Mechanic	PWU
Engineering Technologist Level 1	PWU
Engineering Technologist Level 2	PWU
Customer Relationship Representative	PWU



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SHARED SERVICES AND CORPORATE COST ALLOCATIONS

1. OVERVIEW

This schedule provides information about shared services and corporate cost allocations between Toronto Hydro and the affiliated corporate entities described below:

- **Toronto Hydro Corporation ("THC"):** THC provides strategic direction, corporate governance, and financial stewardship to Toronto Hydro and Toronto Hydro Energy Services Inc. ("TH Energy"). Toronto Hydro is wholly-owned by THC. THC receives shared corporate services from Toronto Hydro and provides such services to Toronto Hydro as described below.

- **TH Energy:** TH Energy's primary line of business is the provision of street lighting and expressway lighting services to the City of Toronto. TH Energy receives shared corporate services from Toronto Hydro.

For more information about these entities and their relationship to Toronto Hydro, please refer to Corporate Structure and Governance evidence at Exhibit 1C, Tab 2, Schedule 1.

This schedule also provides information about corporate cost allocations to the non-rate regulated aspects of Toronto Hydro's business (referred to as "THESU"), including climate advisory services and generation activities.

2. OEB APPENDIX 2-N

A completed copy of OEB Appendix 2-N is filed at Exhibit 4, Tab 5, Schedule 2. This appendix provides cost information and allocation details relating to each shared service provided or received by Toronto Hydro in the historical years (2020-2022), bridge years (2023-2024), and forecast years (2025-2029). Board of Directors-related costs included in THC's cost allocation to Toronto Hydro is also shown in this appendix.

3. SHARED SERVICE MODEL

Toronto Hydro's shared services methodology has not changed since the utility's last rebasing application.[1]

Each service transaction is reviewed to determine the costing formula and method of allocation. In establishing the price of a service transaction, Toronto Hydro follows the Affiliate Relationships Code ("ARC"). The ARC provides for the use of fully allocated cost-based pricing ("CBP") for shared corporate services and the use of fair market value ("FMV") where a reasonably competitive market exists. If market price can be determined, Toronto Hydro charges the higher of fully-allocated cost or market price for any non-shared corporate services that it provides to the affiliated entities, and pays the lower of fully-allocated cost or market price for any such services that it receives from the affiliated entities.

If a competitive market does not exist, Toronto Hydro uses fully-allocated cost-based pricing, which includes direct costs, indirect costs, and cost of capital, to determine the cost of providing or receiving the non-shared corporate service.

[1] EB-2018-0165, Exhibit 4A, Tab 5, Schedule 1.

With regard to these fundamental principles and historical information about the quantity of services provided, Toronto Hydro assesses the approximate annual cost of each service. At the end of the fiscal year, the estimated cost of providing or receiving each service is reconciled with the actual cost and any differences are settled.

Table 1 below provides a description of Toronto Hydro's corporate cost allocators by each functional service.

Table 1: Shared Corporate Services Primary Allocation Drivers

Functional service	Allocator	Reason
Finance (other than payroll, accounts payable, insurance)	Time allocation	Financial support, analysis, planning, calculations, and reports are more labour intensive for certain affiliates than others.
Finance – Payroll	Headcount	Amount of required payroll services, such as processing, is dependent on the number of employees.
Finance – Accounts Payable	Number of Invoices	Amount of required accounts payable services, such as processing, is dependent on the number of invoices received.
Finance – Insurance	Usage proportion	Amount of required insurance is dependent on the coverage required.
Information Technology	By employee	Required equipment and IT services are dependent on the number of employees who need equipment/services.
Public, Legal and Regulatory Affairs	Time allocation	Legal and regulatory services, including services related to councillor administration and requests, are more labour intensive for some affiliates than others.
Human Resources, Environment and Safety ("HRES") (other than Talent Management and Administration)	Headcount	Amount of required HR services, such as services related to compensation/benefits, is dependent on the number of employees.

Functional service	Allocator	Reason
HRES – Talent Management and Administration	New hires	Amount of required Talent Management services, such as hiring, is dependent on the number of new hires.
Supply Chain Service – Procurement	Number of purchase orders	Amount procured for each affiliate is dependent on the number of purchase orders.
Facilities Management	Square footage	Amount of building space required is measured in square feet.
Customer Care – Billing	Number of invoices	Amount of required accounts receivable services, such as processing is dependent on the number of invoices issued.
THC – CEO, CFO, Board of Directors	Time allocation	Services provided to certain affiliates are more labour intensive than others.

4. VARIANCE ANALYSIS

4.1 THC

Further to Appendix 2-N, Table 2 below provides a summary of the costs of shared services provided by and received by Toronto Hydro to or from THC. A variance analysis between 2020 OEB-approved and 2025 test year amounts, 2020 actuals and 2025 test year amounts, as well as 2022 actuals and 2025 test year amounts are included after the table.

Table 2: Summary of the Costs of Shared Services Provided by and Received by Toronto Hydro to/from THC ($ Millions)

Segment	Approved	Actual			Bridge		Forecast				
	2020	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Services Provided by Toronto Hydro	3.9	2.7	2.6	3.0	3.1	2.9	3.2	3.4	3.4	3.6	3.9
Services Recovered by Toronto Hydro	4.6	4.0	3.8	4.6	3.6	4.1	4.2	4.4	4.4	4.6	4.9

2020 OEB-Approved versus 2025 Test Year

- **Services Provided by Toronto Hydro:** The $0.7 million variance between the 2020 OEB approved and the 2025 test year is primarily attributable to lower than estimated support from the Public, Legal, and Regulatory and Finance programs to support corporate risk and compliance functions.
- **Services Received by Toronto Hydro:** The $0.4 million variance from the 2020 OEB approved and the 2025 test year is primarily due to lower expected stewardship costs allocated to the regulated business.

2020 Actual versus 2025 Test Year

- **Services Provided by Toronto Hydro:** The $0.5 million variance between the 2020 actual and the 2025 test year is primarily attributable to higher estimated support from the Finance and Public, Legal, and Regulatory programs to support corporate risk and compliance functions.
- **Services Received by Toronto Hydro:** The $0.2 million variance from the 2020 actual and the 2025 test year is primarily due to higher expected stewardship costs allocated to the regulated business.

2022 Actual versus 2025 Test Year

- **Services Provided by Toronto Hydro:** The $0.2 million variance between the 2022 actual and the 2025 test year is due to higher estimated support from the Finance and Public, Legal, and Regulatory programs to support corporate risk and compliance functions.

- **Services Received by Toronto Hydro:** The $0.4 million variance from the 2022 actual and the 2025 test year is primarily due to lower expected stewardship costs allocated to the regulated business.

4.2 TH Energy

Further to Appendix 2-N, Table 3 below provides a summary of the costs of shared services provided by Toronto Hydro to TH Energy. A variance analysis between 2020 actuals and 2025 test year amounts, as well as 2022 actuals and 2025 test year amounts are included after the table.

Table 3: Summary of the Costs of Shared Services Provided by Toronto Hydro to TH Energy ($ Millions)

Segment	Approved	Actual			Bridge		Forecast				
	2020	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Services Provided by Toronto Hydro	1.6	1.6	2.6	2.1	2.3	2.4	2.4	2.6	2.7	2.8	3.2

2020 OEB-Approved versus 2025 Test Year

The $0.8 million variance between the 2020 OEB approved and the 2025 test year is primarily attributable to higher estimated expenditures to support streetlighting projects.

2020 Actual versus 2025 Test Year

The $0.8 million variance between the 2020 actual and the 2025 test year is primarily attributable to higher estimated expenditures to support streetlighting projects.

2022 Actual versus 2025 Test Year

The $0.3 million variance between the 2022 actual and the 2025 test year is primarily attributable to higher estimated expenditures to support streetlighting projects.

4.3 Non-Rate Regulated Toronto Hydro Activities

Further to Appendix 2-N, Table 4 below provides a summary of the costs of shared services relating to Toronto Hydro's non-rate regulated activities (e.g. climate advisory services and generation). A variance analysis between 2020 actuals and 2025 test year amounts, as well as 2022 actuals and 2025 test year amounts are included after the table.

Table 4: Summary of the Costs of Services relating to Non-Rate Regulated Toronto Hydro Activities ($ Millions)

Segment	Approved	Actual			Bridge		Forecast				
	2020	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Services Provided by Toronto Hydro	1.7	1.5	1.7	1.6	2.0	2.5	2.8	2.4	2.4	2.5	2.6

2020 OEB-Approved versus 2025 Test Year

For non-rate regulated Toronto Hydro activities, the $1.1 million variance between the 2020 OEB Approved and the 2025 test year is primarily attributable to higher estimated expenditures to support climate advisory services.

2020 Actual versus 2025 Test Year

For non-rate regulated Toronto Hydro activities, the $1.3 million variance between the 2020 actual and the 2025 test year is primarily attributable to higher estimated expenditures to support climate advisory services.

2022 Actual versus 2025 Test Year

For non-rate regulated Toronto Hydro activities, the $1.2 million variance between the 2022 actual and the 2025 test year is primarily attributable to higher estimated expenditures to support climate advisory services.

COST OF CAPITAL

In accordance with Section 2.5 of the OEB Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022), this schedule provides an overview of Toronto Hydro's capital structure and financing plans for 2023, 2024 and 2025. Schedules 2 and 3 provide Appendix 2-OA and Appendix 2-OB for the 2025-2029 period, respectively.

1. CAPITAL STRUCTURE

Toronto Hydro's sets its capital structure for ratemaking purposes in accordance with the OEB's Cost of Capital guidelines issued in EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (December 11, 2009) ("Report of the Board"). For Toronto Hydro, the debt to equity split for the test years is set at 60:40. The debt component in each year includes a deemed 4 percent short-term debt component.

2. FINANCING PLANS

2.1 Equity

Toronto Hydro's forecasted Return on Equity ("ROE") for the 2025 Test Year is based on the OEB's formulaic approach as outlined in the Report of the Board. For 2025, the ROE calculation uses the September 2022 bond yield spread[1] and the Ten-Year Government of Canada Bond Yield Forecast.[2]

Table 1, below, shows the projected ROE for 2025, and details of the derivation based on OEB's formulaic approach.

[1] Difference between the average 30-Year A-Rated Canadian Utility bond yield from Bloomberg L.P. and the average 30-Year Government of Canada bond as published by the Bank of Canada

[2] The average of the forecast Ten-Year Government of Canada bond yield as at December 12, 2022 and September 12, 2023 from Bloomberg L.P.

Table 1: Return on Equity Forecast

Return on Equity (ROE) forecast		
Initial ROE		9.75
Change in LCBF from September 2009		
LCBF (September 2022)	3.231	
Base LCBF	4.250	
Difference	-1.020	
0.5 X Difference		-0.510
Change in A-rated Utility Bond Yield Spread from September 2009		
A-rated Utility Bond Spread (September 2022)	1.653	
Base A-rated Utility Bond Yield Spread	1.415	
Difference	0.238	
0.5 X Difference		0.119
2025 Projected ROE based on September 2022 data		**9.36**

Toronto Hydro used the 2025 ROE forecast for the purpose of calculating the 2025-2029 revenue requirement set out in Exhibit 6, Tab 1. To determine the final revenue requirement for 2025 and the subsequent years (i.e. 2026-2029) Toronto Hydro intends to rely on the ROE set by the OEB in the final quarter of 2024.

Table 2 below provides the 2018 to 2022 Deemed ROE and Achieved ROE.

Table 2: Historical 2018-2022 Deemed and Achieved ROE

	2018	2019	2020	2021	2022
Deemed (included in Rates)	9.30%	9.30%	8.52%	8.52%	8.52%
Achieved	9.33%	8.44%	5.90%	7.08%	7.44%

2.2 Financial Market Overview and Forecast

In 2023 there was a renewed upward march in interest rates, both short-term and long-term rates, as the underlying strength of economies were much firmer than expected at the start of 2023. While headline inflation is decreasing in most major economies, core inflation remains much higher than targets as job markets remain tight, consumer spending is strong, and housing stabilizes. For markets, the combination of a resilient economy and persistent underlying inflation has resulted in additional central bank short-term rate increases and higher long-term rates.

Although Canadian headline inflation declined from its peak of 8.1 percent in June 2022, the declining trend reversed in July 2023 when headline inflation came in at 3.3 percent up from 2.8 percent in June 2023. Furthermore, the core inflation (e.g. food and energy) continues to remain high at 3.6 percent.[3] The Bank of Canada increased interest rates by 25 bps both in June and July 2023 bringing the overnight rate to 5.0 percent, the highest since 2001. The Bank of Canada remains resolute in its commitment to restoring price stability for Canadians by meeting its target to bring down inflation to 2% by mid-2025, but notes progress towards price stability is slow and inflationary risks have increased. Further increases by the Bank of Canada will depend on the upcoming economic data releases.[4]

For corporate issuers looking to tap into the debt capital markets, the 2-year yield is now within reach of the 4.70 percent mark, and up 70 bps from the lows of early May. In a similar vein, the 10 and 30-year yield is around 3.60 percent, up more than 30 bps from the spring. The total Canadian Debt Market year-to-date 2023 issuances as of August 2023, which is comprised of Banks, Corporates and foreign issuers, is down approximately 22 percent

[3] Statistics Canada, Consumer Price Index, July 2023 (August 15, 2023), https://www150.statcan.gc.ca/n1/daily-quotidien/230815/dq230815a-eng.htm
[4] Bank of Canada, Monetary Policy Report – October 2023 (October 25, 2023) https://www.bankofcanada.ca/2023/10/mpr-2023-10-25/

compared to the same period in 2022. Debt issuances from the Banks and foreign issuers are down 50 percent and 55 percent respectively. However, Corporate issuances were up 59 percent. Corporate issuances were driven mainly by the Power & Utilities sector, which is up 63 percent.[5]

Corporate credit spreads started to tighten in 2022, partially offsetting the rising Government of Canada yields and allowing the absolute all-in yields of issuances to remain relatively stable during the 2022-2023 period. This is evidenced by the all-in coupon rate of 4.95 percent on THC's 30-year issuance on October 13, 2022, compared to an indicative all-in coupon rate of 4.93 percent on THC's 30-year issuance on August 28, 2023.[6] From September 2023 until 2025, the assumption is for THC's 10-year bond spread to be 150 - 170 basis points and 30-year bond spread to be 170 - 190 basis points. These spreads are determined from the weekly indicative quotes provided by designated banks in THC's revolving credit facility.

2.3 Medium and Long-Term Debt

Toronto Hydro's issues debt at the THC level via medium term notes in the Canadian public debt market. This requires THC to obtain and maintain credit ratings. As of July 1, 2023, THC's debentures were rated by DBRS and S&P as follows:[7]

Table 3: Rating of THC Debentures

Rating Agency	Commercial Paper	Long-Term Debt
DBRS	R-1 (Low)	A Stable
Standard & Poor's ("S&P")	Not rated	A Developing

[5] CIBC Canadian Corporate Debt Capital Markets (September 1, 2023).
[6] THC's public debt offering information is available at Exhibit 1B, Tab 3, Schedule 6.
[7] The most recent credit rating reports from DBRS and S&P are filed in Exhibit 1C, Tab 3, Schedule 7.

Toronto Hydro is assigned debt through promissory notes between the Toronto Hydro and its parent, THC. The promissory notes are written on the same terms as the parent debt as the borrowing is done on behalf of the corporation's affiliates. A fee of five basis points is charged for administration.

As of July 1, 2023 Toronto, Hydro had outstanding long-term debt in the amount of $2.745 billion, as detailed in Table 4 below.

Table 4: Long-Term Debt

Description	Maturity	Outstanding Principal ($)	Rate (%)
$200M Prom Note	Aug. 25, 2026	200,000,000	2.572
$200M Prom Note	Dec. 11, 2029	200,000,000	2.488
$200M Prom Note	Oct. 15, 2030	200,000,000	1.55
$150M Prom Note	Oct. 20, 2031	150,000,000	2.52
$250M Prom Note	Jun. 14, 2033	250,000,000	4.66
$200M Prom Note	May 21, 2040	200,000,000	5.59
$200M Prom Note	Sept. 16, 2044	200,000,000	4.13
$200M Prom Note	July 28, 2045	200,000,000	3.60
$200M Prom Note	Feb. 28, 2048	200,000,000	3.535
$200M Prom Note	Dec. 10, 2049	200,000,000	3.042
$200M Prom Note	Oct. 18, 2051	200,000,000	3.32
$300M Prom Note	Oct. 13, 2052	300,000,000	5.00
$200M Prom Note	Apr. 9, 2063	200,000,000	4.01
$45M Prom Note	Apr. 9, 2063	45,000,000	3.988
$45M Prom Note	Due on demand	45,000,000	4.16% (using deemed LTD rate)
Total		**2,790,000,000**	**3.65**

Forecasted new debt issuance for 2023-2025 is driven primarily by Toronto Hydro's capital plans and the repayment requirements of the maturing debt. Details of the forecasted debt issues for 2023-2025 are shown in Table 5.

Table 5: Forecasted Long-Term Debt Issues

Description	Issue Date	Term	Principal ($)	Underlying Govt Bond Rate (%)	Corporate Spread Forecast (%)	Forecast Coupon Rate (%)
$200M Prom Note (Series 21)	Oct 15, 2023	10 Years	200,000,000	3.50	1.50	**5.00**
$200M Prom Note (Series 22)	Nov 1, 2024	30 Years	200,000,000	3.95	1.90	**5.85**
$300M Prom Note (Series 23)	July 7, 2025	10 Years	300,000,000	3.75	1.70	**5.45**

Forecasted debt rates are based on the 10-Year and 30-Year Government of Canada Bond Yield Forecast (Bloomberg L.P.), when applicable, plus Toronto Hydro's estimate of corporate spreads at the time of issuance (inclusive of the five-basis points administration fee noted above).

Toronto Hydro applies the weighted average forecasted debt rates in its Cost of Capital, rather than applying the OEB's deemed debt rate, since this debt is based on market rates. Toronto Hydro proposes that the embedded debt rates set for 2025 apply throughout the 2025-2029 rate cycle.

2.4 Preferred Shares

Toronto Hydro has no plans to issue any preferred shares over the 2025-2029 period.

2.5 Short-Term Debt

Over the 2023-2025 period, Toronto Hydro plans to issue short-term debt in order to better match its liquidity needs in an effort to minimize net financing charges. THC maintains a revolving credit facility and also has the ability to issue commercial paper available for Toronto Hydro when short-term funds are required.

One-Month Banker's Acceptance rates (Bloomberg L.P.) are used as a proxy for Toronto Hydro's forecast of its short-term debt rate, plus a five-basis point administration fee. The rates are outlined in Table 6 below. The deemed short-term debt weighting of 4 percent applies to Toronto Hydro's capital structure.

Table 6: Short-Term Rates

Year	Short Term Rates
2023	5.15%
2024	5.40%
2025	5.40%

REVENUE REQUIREMENT AND SUFFICIENCY / DEFICIENCY

This Schedule provides a summary of the revenue requirement requested by Toronto Hydro for 2025. The utility's total Service Revenue Requirement is offset by revenues obtained through sources other than distribution rates, as outlined in Exhibit 6, Tab 1, Schedules 2-6. The calculation of the revenue deficiency/sufficiency does not include the clearance of deferral and variance accounts or low voltage charges. [1,2] In accordance with the Filing Requirements,[3] costs and revenues related to energy are kept separate from the determination of the distribution revenue sufficiency/deficiency.

Table 1 below summarizes Toronto Hydro's 2025 revenue requirement.

Table 1: 2025 Forecast Revenue Requirement ($ Millions)

	2025 Test Year
OM&A Expenses (incl. property taxes)	343.0
Amortization/Depreciation	285.3
Income Taxes (grossed up)	27.9
Deemed Interest Expense	143.2
Return on Deemed Equity	220.9
Service Revenue Requirement	1,020.3
Revenue Offsets	-47.9
Base Revenue Requirement	972.4

Full details on the calculation of revenue requirement, including the Determination of Net Utility Income, Statement of Rate Base, Actual Utility Return on Rate Base, Indicated Rate of

[1] Outlined in Exhibit 9, Tab 1, Schedule 1.
[2] Outlined in Exhibit 8, Tab 1, Schedule 1.
[3] OEB Filing Requirements for Electricity Distribution Rate Applications, Chapter 2 – Cost of Service (December 15, 2022), section 2.6.

Return, Requested Rate of Return, and the Deficiency in Revenue, can be found in the Revenue Requirement Workforms ("RRWF"), filed as Exhibit 6, Tab 1, Schedules 2-6.

In addition to the 2025 RRWF, Toronto Hydro is providing the RRWF for each of 2026-2029, in accordance with the Filing Requirements.[4] During the 2026 to 2029 period, the proposal is to set rates based on the Custom Revenue Cap Index[5] and not on a revenue requirement basis.

In order to meet the specific requirements of Toronto Hydro, some minor adjustments to the rates-related tabs of the OEB's RRWF were required. Appendix A to this Schedule fully documents these adjustments.

1. SERVICE REVENUE REQUIREMENT

Service revenue requirement is comprised of operating expenses (including depreciation and property taxes), cost of capital, and payments in lieu of taxes ("PILs").

Operating expenses, including administrative and general expenses, and property taxes, are explained in further detail in Exhibit 4 and summarized in Exhibit 4, Tab 1, Schedule 1.

Depreciation and amortization expenses are further discussed in detail in Exhibit 2A, Tab 2.

The weighted average cost of capital is calculated based on a weighted average of interest expense and return on equity. Toronto Hydro's capital structure for ratemaking purposes is

[4] OEB Filing Requirements for Electricity Distribution Rate Applications, Chapter 2 – Cost of Service (December 15, 2022), section 2.6.1.
[5] See Exhibit 1B, Tab 4, Schedule 1 for more information on Toronto Hydro's proposed Custom Revenue Cap Index rate framework.

determined in accordance with the OEB's cost of capital guidelines. The cost of capital, based on the OEB's deemed capital structure, is discussed in Exhibit 5, Tab 1.

Income taxes and PILs are explained in detail in Exhibit 6, Tab 2, Schedule 2.

2. REVENUE OFFSETS

In addition to revenue that Toronto Hydro earns from rates and charges set out in its tariff, it also earns other revenues from non-distribution related services, property and facility rentals, specific service charges, and short-term investment income. These other revenues offset the revenue requirement. Revenue offsets are detailed in Exhibit 3, Tab 2.

3. BASE REVENUE REQUIREMENT

The base revenue requirement is derived as service revenue requirement less revenue offsets. The base revenue requirement is allocated to and collected from the various customer classes through distribution rates.

4. OVERALL REVENUE DEFICIENCY

For 2025, the revenue deficiency is the difference between the 2025 forecast year revenue requirement and the 2025 forecast year revenues calculated at current rates.

The 2025 test year revenue is determined using the 2025 forecast of billing units at expected 2024 base distribution rates.[6]

Toronto Hydro's revenue deficiency for the 2025 test year is summarized in Table 2.

[6] Toronto Hydro has applied for 2024 distribution rates incorporating the OEB's 2024 inflation factor in EB-2023-0054, which is pending the OEB's decision as of the filing of this evidence.

Table 2: Revenue Deficiency ($ Millions)

	2025 Forecast
Service Revenue at expected 2024 Rates	918.1
Service Revenue Requirement	1020.3
Gross Revenue Deficiency	(102.2)

Full details of the calculation of revenue deficiency are shown in Tab 8 of the 2025 RRWF, filed in Exhibit 6, Tab 1, Schedule 2.

5. CAUSES OF REVENUE DEFICIENCY

The drivers of Toronto Hydro's revenue deficiency are summarized in Table 3.

Table 3: Revenue Deficiency Drivers ($ Millions)

	2020 OEB Approved	2025 Forecast	Difference	
Rate Base	4,514.8	5,901.2	1,386.4	Higher net fixed assets offset by lower working capital allowance
ROE	8.52%	9.36%	0.84%	Higher forecast ROE rate. 9.36% is based on OEB approved ROE rate for 2023.
Debt Rate	3.64%	4.04%	0.40%	Higher forecast embedded debt rates
DRIVERS OF DEFICIENCY				
OM&A	266.7[7]	343.0	76.3	Higher OM&A expenses
Depreciation	263.7	285.3	21.6	Higher rate base plus derecognition expense, partially offset by a net increase to the useful lives of distribution assets.

[7] In EB-2018-0165, the OEB approved a 2020 OM&A budget of $272.2 million and directed Toronto Hydro to amend the presentation of shared services within Other Revenue, under USoA Accounts 4375 and 4380 for revenues and expenses of non-rate regulated utility operations. Normalized for this change, the 2020 OEB-approved OM&A budget was $266.7 million.

	2020 OEB Approved	2025 Forecast	Difference	
Deemed Interest Expense	98.5	143.2	44.7	Higher rate base and higher forecast debt rates
Return on Equity	153.9	220.9	67.0	Higher rate base and higher forecast ROE rate
PILS	9.7	27.9	18.2	Higher net income
Total Service Revenue Requirement	**792.5**	**1,020.3**	**227.8**	
Distribution Revenue at 2020/24 Rates	771.4	870.2	98.8	Increase in OEB approved rates 2020-2024 and customer growth
Revenue Offsets	42.3	47.9	5.6	Increase in Other Revenues
Total Operating Revenue	**813.7**	**918.1**	**104.4**	
Total Deficiency		**102.2**	**102.2**	

Rate base increases are primarily due to fixed asset additions over the 2020-2024 period, as described in Exhibit 2A, Tab 1, partially offsetting the increase in net fixed assets is a decrease in working capital allowance based on the updated lead-lag study, as featured in Exhibit 2A, Tab 3, Schedules 1 and 2.

Debt and ROE rates are forecast to be higher in 2025 (Exhibit 5, Tab 1, Schedule 1), and the rate base to which those rates are applied is also larger as a result of capital investments during the 2020-2024 period. The result is an increased cost of capital.

The revenue deficiency arising from the 2025 OM&A costs is due to the forecast level of OM&A, as detailed in Exhibit 4, Tabs 1 and 2.

Higher depreciation amounts are primarily due to the additional capital assets included in rate base, as well as the requirements related to derecognition of assets, as discussed in Exhibit 2A, Tabs 1 and 2. This increase is partially offset by a net increase to the useful lives of distribution assets.[8]

The revenue deficiency is partially offset by higher revenue resulting from OEB-approved rate increases and customer growth over the 2020-2024 period and higher forecasted revenue offsets, as discussed respectively in Exhibit 3, Tabs 1 and 2.

[8] In accordance with the OEB's decision in the 2020-2024 Rate Application (EB-2018-0165), Toronto Hydro retained an expert consultant to complete a depreciation study, which is filed in Exhibit 2A, Tab 2, Schedule 1, Appendix D. The Study resulted in changes to asset useful lives and depreciation rates effective January 1, 2023.

APPENDIX A - MODIFICATIONS TO THE OEB's REVENUE REQUIREMENT WORK FORM

The following information details the changes that have been incorporated into the Ontario Energy Board's Revenue Requirement Workform for 2024 Filers V1.10.

1. WORKSHEET 13. RATE DESIGN

In all rate classes, the sum of revenue from the fixed and variable components adds to 100% of revenue for the class. Toronto Hydro's Unmetered Scattered Load rate class has an OEB-approved three-part rate. Therefore, the total class revenue in Cell O35 has been reallocated for a three-part rate across cells Q35, Q36, and S35. These changes are captured as follows:

- Fixed/variable split inputs (cells U35, U36, and W35)
- Monthly service charge calculations (cells AA35 and AA36)

Toronto Hydro's approved monthly service charge and kVA volumetric rates are based on 30 days of service. Both the monthly service charge and kVA volumetric rates calculation in columns AA and AE have been changed to reflect this requirement.

In addition, Toronto Hydro's volumetric rates are based on either kWh or kVA, showing 5 and 4 decimals, respectively, reflected by changes in column AI.

In the **Revenue Reconciliation** section, the total distribution revenues value needs to be converted back to 365 days of revenue and therefore reflects the "days of service" adjustment factor of 365/360, or 1.013888889, shown in cell AK25.

CORPORATE TAXES (PILS)

1. INTRODUCTION

The Revenue Requirement filed at Exhibit 6, Tab 1, Schedule 1 of this application reflects amounts for Payments in Lieu of Taxes ("PILs") of $27.9 million (excluding investment tax credits of $2.5 million reallocated to OM&A for the 2025 Test Year).[1] The 2025-2029 PILs tax models are filed at Exhibit 6, Tab 2, Schedule 2.

Table 1: Summary of PILs by Year ($ Millions)

	Bridge	Forecast				
	2024	2025	2026	2027	2028	2029
Income Taxes	9.1	27.9	30.5	20.0	56.2	47.7

Toronto Hydro used the OEB's PILs model for 2024 filers to prepare the 2025 PILs tax models. Other than the changes described below, no other changes to the OEB's PILs tax models have been made:

- All Tabs: The date in the header changed from "…2024 Filers" to "…2025 Filers".
- Tab "S. Summary":
  - Lines listed below have been added and linked to Tab "T0 PILs, Tax Provision Test" accordingly:
    - "Test Year – Grossed-up PILs before tax credits reclass to OM&A",
    - "Test Year – Tax credits reclass to OM&A:, and
    - "Test Year – Tax credits reclass to OM&A – gross up".
  - Description for "Test Year – Grossed-up PILs" changed to "Test Year – Grossed-up PILS after tax credits reclass to OM&A".

[1] Please refer to Exhibit 4, Tab 2, Schedule 20, page 2 for more details

- Tab "B. Tax Rates & Exemptions": tax rates are updated for Toronto Hydro effective January 1, 2019 to January 1, 2025.
- Tabs "B0 PILs, Tax Provision Bridge" and "T0 PILs, Tax Provision Test" for bridge and test years: added adjustments for tax credits included in OM&A. The following lines have been added:
    - "Corporate PILs/Income Tax Provision Gross Up" (only for Tab "B0 PILs, Tax Provision Bridge")
    - "Income Tax (grossed up) before tax credits reclass to OM&A"
    - "Tax credits reclass to OM&A"
    - "Tax credits reclass to OM&A – gross up", and
    - "Income Tax (grossed-up) after tax credits reclass to OM&A" (only for Tab "B0 PILs, Tax Provision Bridge").
    - Description for "Income Tax (grossed-up)" changed to "Income Tax (grossed-up) after tax credits reclass to OM&A (only for Tab "T0 PILs, Tax Provision Test")
    - Formula referencing is updated accordingly.
- Tabs "B8 Sch 8 CCA Bridge" and "T8 Sch 8 CCA Test", updated the following in the "Relevant factor" column for 2024 Bridge year and 2025 Test year:
    - Class 43.1 updated from 2.33 to 1.5
    - Class 43.2 updated from 1.0 to 0.5
    - Added Class 54 row and added relevant factor with 1.5, and
    - Other Classes updated from 0.5 to 0
- Tab "T8 Sch 8 CCA Test", updated formula in the following columns for 2025 Test year:
    - Column (9) *Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4)*

- Column (11) *UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4)*
- Column (13) *Cost of acquisitions on remainder of Class (column 3 minus column 4 plus* column 11 minus column 12)
- Column (14) *Cost of acquisitions from column 13 that are accelerated investment incentive properties (AIIP) or properties included in Classes 54 to 56*
- Column (15) *Remaining UCC (column 10 minus column 12) (if negative, enter "0")*
- Column (16) *Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 minus column 9 plus column 6 minus column 13 plus column 14 minus column 7) (if negative, enter "0")*
- Column (23) *CCA (for declining balance method, the result of column 15 plus column 18 minus column 19, multiplied by column 20 or a lower amount, plus column 12))*
- Column (24) *UCC at the end of the test year (column 10 minus column 23)*

2. PRUDENT MANAGEMENT OF PILS/TAXES

The amount of PILs paid by Toronto Hydro in any given year is correlated with net income calculated for tax purposes. Toronto Hydro manages its tax costs diligently in an effort to keep the effective rate of tax as low as possible. Where appropriate, Toronto Hydro takes advantage of available tax deductions and tax credits, such as research and development tax credits to minimize its tax burden.

3. METHODOLOGY

The methodology for calculating PILs is consistent with the principles set out in Chapter 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022), and reflects applicable legislative and regulatory changes, such as changes to corporate tax rates and capital cost allowance rates. Toronto Hydro confirms that non-recoverable expenses and expenses disallowed for regulatory purposes have been excluded from the regulatory tax calculation.

4. DISCLOSURE OF PILS TAX ADMINISTRATION AND TAX RULINGS

Toronto Hydro has not received any specific tax rulings that are inconsistent with Toronto Hydro's previously filed and approved tax model.

5. TAX STATUS

Toronto Hydro has not changed its tax status.

6. TAX REASSESSMENTS

The Ministry of Finance recently completed its review of Toronto Hydro's 2018 PILs return. The PILs amount computed reflects methodologies approved by the Ministry of Finance through its audits.

7. TAX TREATMENT OF DIVIDENDS PAID IN PRIOR YEARS

Dividends paid in the historical years were treated as payments out of tax paid retained earnings, and therefore were not treated as deductible for tax purposes.

8. LOSS CARRY-FORWARDS

Toronto Hydro does not have any non-capital or capital loss carry-forwards as of the end of December 2022, and does not expect to have such loss carry-forwards as of the end of December 2029.

9. CAPITAL COST ALLOWANCE ("CCA")

Toronto Hydro is filing this application on a forward test year basis and as a result the CCA is computed for 2025-2029 based on projections of the change in capital assets from the 2022 historical year. The calculation of the projected CCA for 2024, which is used to derive the projected undepreciated capital cost balances at January 1, 2025, can be found in Exhibit 6, Tab 2, Schedule 2. As further described below, Toronto Hydro claimed the maximum CCA amount in 2025-2029 including: applying the half year rule to any projected additions in the first year of acquisition, and providing a first year increase in CCA if the capital assets are eligible for accelerated CCA.

On June 21, 2019, Bill C-97, *the Budget Implementation Act, 2019, No. 1*, was given Royal Assent, and included various changes to the federal income tax regime. These changes introduced the Accelerated Investment Incentive ("AII") Program, which provides for a first-year increased CCA deduction ("Accelerated CCA") on eligible capital assets acquired after November 20, 2018 and available for use before 2028. Toronto Hydro confirms that the Accelerated CCA rules introduced by Bill C-97 were applied in the PILS tax models, and that the maximum Accelerated CCA (as described in below) are claimed:

- For eligible assets acquired after November 20, 2018 and put in service in the period before 2024, the Accelerated CCA is up to three times the normal first year CCA deduction.

- For eligible assets acquired after November 20, 2018 and put in service after 2023 and before 2028, the Accelerated CCA is up to two times the normal first-year CCA deduction.
- Properties included in CCA classes 43.1 (CCA rate at 30%) and 43.2 (CCA rate at 50%) are also generally eligible for an enhanced first-year CCA allowance if the eligible assets acquired after November 20, 2018 and are put in service before 2028. For these properties, the enhanced first-year CCA allowance will be an 100% deduction, with a phase out for property that becomes available for use after 2023 as described in Table 2.
- Properties included in CCA class 54 (CCA rate at 30%) are also generally eligible for an enhanced first-year CCA allowance if the eligible assets acquired after March 18, 2019 and are available for use before 2028. For these properties, the enhanced first-year CCA allowance will be an 100% deduction, with a phase out for property that becomes available for use after 2023 as described in Table 2.

Table 2: Phase-out of the enhanced first-year CCA allowance for Classes 43.1, 43.2 and 54

Year property become available for use	Normal First Year CCA (half-year rule) for classes 43.1 & 54	Normal First-year CCA (half-year rule) for class 43.2	Enhanced First-year CCA allowance
2018 – 2023 (for Classes 43.1 & 43.2) 2019 – 2023 (for Class 54)	15%	25%	100%
2024	15%	25%	75%
2025	15%	n/a	75%
2026	15%	n/a	55%
2027	15%	n/a	55%
2028 onwards	15%	n/a	n/a

During the Draft Rate Order process in the 2020-2024 application (EB-2018-0165), Toronto Hydro updated the 2020-2024 PILs forecasts to align with the OEB's Decision.[2] This update included implementing the Accelerated CCA changes described above.[3] Toronto Hydro also recorded the 2018 and 2019 revenue requirement impact of the CCA rule changes within the new sub-account of Account 1592 - PILs and Tax Variances - CCA changes.[4] [5]

In June 2022, new Federal legislation introduced in Bill C-19 permitting the "Immediate Expensing" of certain properties acquired by a Canadian Controlled Private Corporation received Royal Assent. This measure allows a qualifying corporation to expense up to $1.5 million per taxation year, for eligible property acquired on or after April 19, 2021, and becomes available for use before January 1, 2024. All other CCA claims available under existing rules would still be permitted, as long as the total CCA deduction does not exceed the capital cost of the property.

Toronto Hydro confirms that it implemented this new measure in its final 2021 and 2022 tax returns, and in the forecasted CCA calculation for 2023. Table 3 shows the CCA classes where the Immediate Expensing of $1.5 million was/is forecasted to be applied to 2021-2023 tax returns. Toronto Hydro also confirms that the impact of the Immediate Expensing measure is recorded in the sub-account of Account 1592 – PILs and Tax Variances - CCA changes. Account 1592 is discussed in further detail at Exhibit 9, Tab 1, Schedule 1.

[2] EB-2018-0165, Draft Rate Order Submission (February 12, 2020) at page 6 and Schedule 9.
[3] EB-2018-0165, Decision and Order (December 19, 2019) at page 149 and page 201.
[4] EB-2018-0165, Reply Submission (February 12, 2020) on Draft Rate Order at page 2.
[5] At OEB Staff's request EB-2018-0165, OEB Staff Submission (January 31, 2020) on Draft Rate Order at page 3; EB-2022-0065, Decision and Rate Order (December 8, 2022) at page 15.

Table 3: Application of Immediate Expensing of $1.5 million in 2021-2023 tax returns ($ Millions)

CCA class	2021 Actual	2022 Actual	2023 Forecast
8	1.2	-	1.4
10	0.3	-	-
42	-	1.5	0.1
Total	**1.5**	**1.5**	**1.5**

10. INTEREST DEDUCTION

Actual interest expense is lower than the deemed interest expense calculated based on the 2025 model, as filed at Exhibit 6, Tab 2, Schedule 2. Therefore, the difference between actual and deemed interest expense has not been deducted in calculating taxable income in the tax models for that year.

11. CAPITALIZED INTEREST

Interest is not capitalized to construction work in progress ("CWIP") for tax purposes. However, interest is capitalized for accounting purposes in the 2025 projection.

12. NON-DISTRIBUTION ELIMINATION

In this application, Toronto Hydro only included income from the rate-regulated business.

13. TAX CREDITS

Toronto Hydro expects that the level of expenditures qualifying for Scientific Research and Experimental Development ("SRED") in 2025 will be similar to expenditures in 2022. Toronto Hydro used the latest filed historical SRED credit in 2022 ($1.5 million) as projected tax credit for 2025 .

Toronto Hydro also included the Federal Apprenticeship Job Creation Tax Credit and the Ontario Co-Operative Education Tax Credit in its PILs-related revenue requirement. A projected tax credit of $0.9 million, based on the average benefit of 2020 through 2022 claims, is included in the 2025 tax models.

14. CAPITAL LEASES

Appropriate adjustments have been made in determining taxable income in the 2025 tax model with respect to leases capitalized for accounting purposes.

15. INTEGRITY CHECKS

The following integrity checks have been completed in respect of the PILs model:

- Depreciation and amortization added back agrees with the numbers disclosed in the rate base section of the application;
- Capital additions and deductions agree with the rate base section for historical, bridge and test years;
- Schedule 8 of the most recent tax return filed with the application has a closing December 31 historic year undepreciated capital cost ("UCC") that agrees with the opening bridge year UCC at January 1. A reconciliation has been provided to remove the non-distribution amounts in Exhibit 6, Tab 2, Schedule 2;
- The CCA deductions in the application's PILs tax model for historical, bridge and test years agree with the numbers in Schedule 8;
- Accounting other post-employment benefits and pension amounts added back on Schedule 1;
- Reconciliation of accounting income to net income for tax purposes agrees with the OM&A analysis for compensation and is reasonable when compared with the notes to the audited financial statements and the actuarial valuations; and

- The income tax rate used to calculate the tax expense is consistent with the current legislated rate.

16. TAX PAYABLE FILINGS

Details of actual taxes paid by Toronto Hydro from 2019 to 2022, as well as the forecasted taxes to be paid for 2023, are outlined in the table below. Explanations of the variances for the forecast years are also provided. The tax return copy for the historical year 2022 is provided in Exhibit 6, Tab 2, Schedule 3.

Table 4: Summary of Actual and Forecast Taxes Paid ($ Millions)

	Actual				Bridge
	2019	2020	2021	2022	2023
Income Taxes	31.3	2.0	8.0	7.6	3.4

The decrease/increase in PILs from year to year is mainly due to the change in net income before tax and the differences between tax and accounting treatments of various costs. These differences primarily stem from the variance between capital cost allowance and accounting depreciation, other post-employment benefit adjustments, investment tax credits and other costs.

17. PROPERTY TAX

Property taxes are discussed in the Facilities Management program at Exhibit 4, Tab 2, Schedule 12.

CONFIDENTIAL

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal Income Tax Act and Income Tax Regulations. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the General Index of Financial Information (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **canada.ca/taxes** or Guide T4012, T2 Corporation – Income Tax Guide.

055 **Do not use this area**

Identification

Business number (BN) . . . . . 001 [redacted]

Corporation's name

002 TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Address of head office

Has this address changed since the last time the CRA was notified? . . . . . 010 Yes ☐ No ☒

If **yes**, complete lines 011 to 018.

011 14 CARLTON STREET

012

City	Province, territory, or state
015 TORONTO	016 ON
Country (other than Canada)	**Postal or ZIP code**
017	018 M5B 1K5

Mailing address (if different from head office address)

Has this address changed since the last time the CRA was notified? . . . . . 020 Yes ☐ No ☒

If **yes**, complete lines 021 to 028.

021 c/o [redacted]

022 14 CARLTON STREET

023 5TH FLOOR-CORPORATE TAX DEPT

City	Province, territory, or state
025 TORONTO	026 ON
Country (other than Canada)	**Postal or ZIP code**
027	028 M5B 1K5

Location of books and records (if different from head office address)

Has this address changed since the last time the CRA was notified? . . . . . 030 Yes ☐ No ☒

If **yes**, complete lines 031 to 038.

031 14 CARLTON STREET

032

City	Province, territory, or state
035 TORONTO	036 ON
Country (other than Canada)	**Postal or ZIP code**
037	038 M5B 1K5

040 **Type of corporation at the end of the tax year** (tick one)

- ☒ 1 Canadian-controlled private corporation (CCPC)
- ☐ 2 Other private corporation
- ☐ 3 Public corporation
- ☐ 4 Corporation controlled by a public corporation
- ☐ 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . 043 Year Month Day

To which tax year does this return apply?

Tax year start (060)	Tax year-end (061)
Year Month Day	Year Month Day
2022-01-01	2022-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? . . . . . 063 Yes ☐ No ☒

If **yes**, provide the date control was acquired . . . . . 065 Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . . 066 Yes ☐ No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . . 067 Yes ☐ No ☒

Is this the first year of filing after:

Incorporation? . . . . . 070 Yes ☐ No ☒

Amalgamation? . . . . . 071 Yes ☐ No ☒

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . . 072 Yes ☐ No ☒

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . . 076 Yes ☐ No ☒

Is this the final return up to dissolution? . . . . . 078 Yes ☐ No ☒

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 Yes ☒ No ☐

If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . . 082 Yes ☐ No ☒

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085

- ☐ 1 Exempt under paragraph 149(1)(e) or (l)
- ☐ 2 Exempt under paragraph 149(1)(j)
- ☒ 4 Exempt under other paragraphs of section 149

Do not use this area

095 096 898

COST ALLOCATION

In accordance with section 2.7 of the OEB's Filing Requirements,[1] this schedule details Toronto Hydro's completed cost allocation study, inclusive of class revenue requirements, revenue-to-cost ratios and other pertinent information. Relying on the 2025 revenue requirement detailed in Exhibit 6, Toronto Hydro allocated a portion of revenue requirement to each rate classes for the purpose of calculating distribution rates for the 2025 rebasing year. Toronto Hydro's cost allocation relies on the OEB's latest cost allocation model, including the OEB's updated policy related to the Street Lighting class, subject to the adjustments noted in section 2.4 below.[2]

Consistent with the methodology relied upon in EB-2014-0116 and EB-2018-0165, Toronto Hydro completed a cost allocation study for the 2025 test year, and extended the results to allocate the 2026 to 2029 revenue requirement to rate classes. Exhibit 7, Tab 1, Schedule 3 provides a live version of the 2025 cost allocation model.

1. COST ALLOCATION MODEL

Toronto Hydro reviewed and updated all necessary inputs of the cost allocation model.

1.1 Weighting Factors for Allocation

Toronto Hydro reviewed all "default" allocators, and where available, used data specific to Toronto Hydro to determine the allocator values. The weighting factors for Services and Billing and Collections were determined as follows:

[1] Ontario Energu Board, *Filing Requirements for Electricity Distribution Rate Applications*, Chapter 2 (December 15, 2022).
[2] Ontario Energy Board, *Issuance of New Cost Allocation Policy for Street Lighting Rate Class* (June 12, 2015).

- **Services:** All rate classes, with the exception of the Competitive Sector Multi-Unit Residential ("CSMUR"), Unmetered Scattered Load ("USL") and Street Lighting classes, received a weighting factor of one, reflecting the reality that service costs greater than a basic allowance are recovered through a direct contribution from the customers. The weighting factor for the CSMUR rate class is derived by dividing the number of units by the number of buildings housing these units, as originally directed by the OEB in EB-2010-0142. For the USL and Street Lighting classes, the cost of services is directly collected from those customers, requiring that they receive a weighting factor of zero.
- **Billing and Collections:** The class-specific weighting factors reflect estimates of billing effort and costs related to each class based on the experience and expertise of Toronto Hydro's billing specialists.

In accordance with past OEB decisions, Toronto Hydro proposes to maintain the use of the modified density factor at 23 percent.[3,4] This reflects a considerably higher customer density per kilometer in Toronto compared to the OEB's default value.[5]

1.2 Load Profiles and Demand Allocators

In order to normalize for anomalous load profiles during the COVID-19 pandemic period, Toronto Hydro utilized 2019 load data for the purpose of establishing load profiles for use in cost allocation, as the years 2020-2022 were impacted by pandemic-related trends. Specifically, the utility updated the load profiles used for the demand allocators based on weather normalized hourly-metered 2019 load data for each rate class, as further described

[3] See 2015-2019 Rate Application (EB-2014-0116) and 2020-2024 Rate Application (EB-2018-0165),
[4] See Cost Allocation Model in Exhibit 7A, Tab 1, Schedule 3, E1 Categorization. The "density factor", also known as the "customer allocation component", is used to determine the proportion of customer and demand-related costs.
[5]Toronto Hydro's density of 133 customers per kilometers of line, as determined by the model, is well above the OEB's defaut of 60 customers per kilometers of line.

below. For the Residential, CSMUR and General Service rate classes Toronto Hydro used sample metering data sets, while entire rate class data sets were used for Unmetered Scatter Load Class ("USL") and Street Lighting rate classes.

The hourly load profiles were reconciled to the 2019 purchased energy and wholesale market participant data and weather normalized to 2025 heating and cooling degree days. The weather normalization methodology is based on a ratio between the 2019 weather normalized and 2019 non-weather normalized loads from the revenue load forecast. Weather normalization in the revenue load forecast is calculated by making adjustments to the monthly energy purchases either in excess or below what would be purchased under average weather conditions. Average weather conditions are based on a ten-year historical average of heating and cooling degree-days, and dew-point temperature. This methodology is in accordance with Toronto Hydro's previous filings (EB-2018-0165 and EB-2014-0116). Please refer to Exhibit 3 for more information on Toronto Hydro's weather normalization methodology for its revenue load forecast.

The load profiles were scaled to the 2025 baseline load forecast based on the ratio of 2025 kWh to 2019 kWh by class. Resulting load profiles were modified to include electric vehicles ("EVs") and distributed energy resources ("DERs") forecasted load impacts. A detailed explanation of EV and DER inclusion can be found in the integration model report prepared by ClearSpring Energy Advisors in Exhibit 3, Tab 1, Schedule 1, Appendix J. An example of the data and calculations is filed as Exhibit 7, Tab 1, Schedule 2.

1.3 Street Lighting

Initially approved by the OEB in EB-2014-0116 and followed by the latest OEB approval in EB-2018-0165, Toronto Hydro has included approved Street Lighting assets and operating

expenses in its 2025 revenue requirement. For the purposes of cost allocation, all assets and expenses are directly allocated 95 percent to the Street Lighting class, and 5 percent to the USL class. This allocation reflects prior OEB Decisions, and the fact that these assets only serve these two classes. In addition, 100 percent of the Street Lighting related revenue requirement is offset through a direct allocation to Revenue Offsets for the Street Lighting class. The effect is a revenue-to-cost ratio of 1.0 for these assets and costs.

1.4 Adjustments to Cost Allocation Model

The following adjustments were made to the OEB's cost allocation model to meet Toronto Hydro's circumstances and requirements.

- In Worksheet I6.1 Revenue, cell L39 was locked. Toronto Hydro modified the formula to calculate the revenue from three tier rates for USL rate class.
- In Worksheet I6.2 Customer Data, cells M28 and M29 were adjusted to reflect the direct assignment of meter capital and meter reading costs for the CSMUR rate class.
- In Worksheet O1 Revenue to Cost, cell J19 was modified to include the direct assignment of revenue offsets related to the Street Lighting class, as noted above.
- In Worksheet E1 Categorization, cell E24 and E25 were modified to 0.23.

2. IMPLEMENTATION OF COST ALLOCATION RESULTS

OEB's Report: Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) dated March 31, 2011 established updated "target ranges" for the revenue to cost ratios for each customer class. The OEB's review of the Street Lighting cost allocation methodology resulted in an updated target range for that rate class.[6]

[6] *Supra* note 2.

Toronto Hydro proposes to maintain 2025 cost allocation for the 2026 to 2029 years, and is not proposing any manual adjustments to Revenue to Cost ratios over this period.

Table 1 below shows the revenue to cost ratios calculated prior to and after the proposed 2025 rate design in comparison with the OEB's guideline ranges.[7] The proposed revenue to cost ratios for all Toronto Hydro rate classes are within the OEB's ranges.

Table 1: Revenue/Cost Ratios (%)

Rate Class	2020 OEB Approved	2025		OEB's Guideline Ranges
		Model	Proposed	
Residential	100.0%	102.1%	100.0%	85-115
Competitive Sector Multi-Unit Residential	100.0%	111.7%	100.0%	n/a
General Service <50kW	93.7%	97.4%	99.2%	80-120
General Service 50-999kW	105.6%	96.4%	98.9%	80-120
General Service 1000-4999kW	94.8%	94.4%	98.3%	80-120
Large Use	93.6%	97.2%	99.2%	85-115
Street Lighting	111.3%	119.4%	119.4%	80-120
Unmetered Scattered Load	120.0%	121.7%	120.0%	80-120

In accordance with past OEB decisions, rates in the Residential and CSMUR class are set such that the revenue to cost ratios are equal at unity (i.e. 1.0 or 100 percent).

With respect to the Street Lighting class, the proposed revenue to cost ratio reflects the application of the updated OEB cost allocation model, and includes the allocation of revenue offsets related to the Street Lighting assets in rate base to fully offset the costs that have been directly allocated to this class.

[7] All ratios exclude revenues and costs related to transformer ownership allowance.

Toronto Hydro engages its customers with significant unmetered load (e.g. City, telecommunications companies) as part of ongoing customer engagement. Through those interactions and direct participation by these customers in OEB rate application and policy proceedings, they have developed familiarity with the regulatory context, including the basis on which costs are allocated to them through rates. Toronto Hydro's proposed cost allocation for unmetered customers (including street lighting) follows the OEB's current methodology, which was developed in consultation with unmetered customers. With the filing of this application, Toronto Hydro is sending a communication to major customers within these classes regarding changes to rates and charges, and inviting them to participate in the proceeding.

3. COST ALLOCATION REVIEW

In the Cost Allocation and Rate Design section of its Decision in EB-2018-0165, the OEB concluded that it would be appropriate to review the characteristics of the CSMUR class and its revenue-to-cost ratios in Toronto Hydro's next rebasing application.[8] While the Decision did not specify the manner in which that review should take place, in the interest of facilitating it, in this section Toronto Hydro is setting out the background and evidence to support reconsideration of the current approach, with specific details on two opportunities to improve customer cost allocation.

3.1 Background on CSMUR Rate Class

The CSMUR class was established in Toronto Hydro's EB-2010-0142 application. In that proceeding the OEB defined suite metering, as "*the installation of a separate meter for each*

[8] EB-2018-0165, Decision and Order (December 19, 2020) at pages 156-157.

unit of a multi-unit residential building where there is no bulk meter that is used for the purposes of settlement."[9] In a Partial Decision issued July 7, 2011, the OEB determined that:

> …due to the existence of a competitive market for the provision of unit sub-metering it is appropriate to ensure that procurement choices, as between licensed distributors (suite metering) and licensed unit sub-meter providers (unit submetering) are made on a comparable economic basis both within the competitive unit sub-metering marketplace and between this competitive market place and the monopoly service…The Board has determined that the creation and maintenance of a separate rate class for multi-residential customers that at the present time are served utilizing Quadlogic technology is the most effective and transparent manner in which to address the aforementioned issues.[10]

Subsequent to the OEB's Partial Decision, Toronto Hydro submitted supplemental evidence on September 30, 2011, in which a new rate class for suite metered customers was proposed, accompanied by cost allocation evidence and proposals.[11] Among the assumptions and proposals made, Toronto Hydro included proposals for the allocation of secondary system costs for customers in the new rate class, which would recognize that a minority of such customers utilized Toronto Hydro's secondary system assets.[12] Following interrogatories, an oral hearing, argument, and other procedural matters, the OEB issued a Decision and Order on the Suite Metering Issues.[13]

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[9] EB-2010-0142, Partial Decision and Order (July 7, 2011) at page 33
[10] *Ibid.* at page 35
[11] EB-2010-0142, Exhibit L1, Tab 5, Schedule 1 (September 30, 2011)
[12] *Ibid.* at page 5
[13] EB-2010-0142, Decision and Order (February 22, 2012)

Among other findings specific to suite metering cost allocation, the OEB stated the following:

> The Board finds that no adjustment for secondary costs should be made on the basis that there is insufficient evidence on the record in this proceeding to determine an appropriate allocation of these costs between the two residential classes…The Board recognizes that many customers in the [CSMUR][14] class do not receive their service through the secondary voltage system. However, the same is true of the remaining Residential class, although proportionately to a lesser degree, based on the cost allocation studies done by BDR. The same may be true of other classes as well. The Board does not have reliable information on this record on the number of customers or their load statistics in the classes other than [CSMUR]…The Board expects that THESL will incorporate the distinction between the secondary and primary systems in future cost allocation studies, and that it will include the appropriate proportions within each class where some customers are served from the secondary system and the rest are served from the primary system.[15]

As noted by the OEB in the Decision and Order on Suite Metering Issues, Toronto Hydro did not have sufficient information at the time to determine an alternative allocation of line transformer and secondary system assets for the CSMUR, Residential and GS <50kW rate classes. Having significantly advanced its collection of customer and asset data over the last twelve years, and having improved its ability to analyze such data, Toronto Hydro is able to leverage asset and customer specific information to study CSMUR cost allocation issues that could not be examined on facts in EB-2010-0142.

[14] Original quote reads 'Quadlogic' denoting the meter type used to serve customers in the CSMUR class at that time
[15] *Supra* note 13 at page 18

3.2 Potential Refinements to CSMUR Cost Allocaiton

In reviewing the characteristics of the CSMUR rate class as noted by the OEB in the last decision, Toronto Hydro identified two potential opportunites to refine the cost allocation approach as furhter described below. These potential refinements would impact the OEB's Cost Allocation Model in tabs I6.2 and I8.

3.2.1 Customer Count

Allocating primary system, line transformer, and secondary system costs in tab I6.2 of the OEB's Cost Allocation Model requires the input of a customer base for each rate class; assigning some portion of customers to line transformer and secondary system assets. Historically, Toronto Hydro's Residential, CSMUR and GS<50 kW customer counts for primary system, secondary and line transformer costs have been equal to the number of customers in each rate class, identified by the number of meters in each rate class.

Toronto Hydro identified a potential inconsistency in the establishment of customer count for this purpose. Given there is no bulk meter associated with CSMUR accounts, the customer count in this rate class represents 'units' inside of a multi-unit building with typically one primary connection, while in large part the customer counts of other rate classes with comparable premise loads represent entire buildings, regardless of how many units may be inside of them. The result is a larger allocation of costs through tab I6.2 to the CSMUR class, despite many bulk and CSMUR buildings being comparable to each other physical loads.

In the status quo approach, applying different methods for different rate classes to allocate the primary, line transformer, and secondary assignments in tab I6.2 yields an inconsistency that warrants further consideration by the OEB and interested parties. From Toronto

Hydro's perspective, there are two alternatives to ensure consistent measurement: either (i) all customer counts reflect 'units' per within a building, or (ii) all customer counts reflect the number of buildings served. At this time, Toronto Hydro does not have sufficiently accurate or verifiable data with respect to the number of units in buildings served by bulk meters. To proceed with option (i) the utility would have to complete a detailed study by rate class or rely on estimates derived from self-declarations made under the Ontario Energy Rebate ("OER") which indicate that there are approximately 340,000 units behind bulk-meters in Toronto.

Conversely, for option (ii) Toronto Hydro was able to generate from its systems and records a representation of building count by rate class which could be used for cost allocation purposes. In order to prepare a building count by rate class, Toronto Hydro retrieved customer data from its Customer Information System ("CIS"), which included the addresses of customers across Residential, CSMUR and GS<50 kW rate classes, as well as asset data from its Geo-Electric Asset Records ("GEAR") system which catalogues Toronto Hydro's system. Utilizing a combination of customer addresses and asset data, Toronto Hydro prepared an alternative customer count for each of the Residential, CSMUR and GS<50 kW rate classes that is representative of the number of buildings served, as opposed to the number of individual meters. The status quo and alternative customer count results are shown in Table 2 below.

Table 2: Total Customer Count by Rate Class: Status Quo and Alternative

Rate Class	Status Quo	Alternative
Residential	617,563	470,705
Competitive Sector Multi-Unit Residential	98,427	383
General Service <50kW	73,396	42,864

The resulting alternative customer count has a significant decrease to the count associated with the CSMUR rate class which, all else equal, would be expected to reduce costs allocated to the CSMUR rate class.

3.2.2 Line Transformer and Secondary System

Based on improved data collection and analysis, Toronto Hydro is now in a position to provide more specific and accurate information with respect to use of line transformer and secondary system assets in the CSMUR, Residential and GS <50kW rate classes. To complete this analysis, Toronto Hydro relied on the same customer information noted above in (i.e. CIS and GEAR data, including distinct cable and transformer identification numbers). Included within GEAR, are ownership attributes, denoting whether Toronto Hydro or the customer own the line transformer or secondary assets in question.

For the CSMUR rate class, Toronto Hydro observed that 61 percent of CSMUR buildings are served by Toronto Hydro line transformers, and 30 percent are served by Toronto Hydro secondary assets. The remaining CSMUR customers are either primary-connected, or own their own line transformer and/or secondary system assets. This analysis was completed for the vast majority of the CSMUR building population, providing strong coverage of the buildings served in this rate class.

Toronto Hydro relied on the same approach described above to establish line transformer and secondary system building counts for the Residential and GS <50kW rate classes, with one exception. For the Residential class, Toronto Hydro's analysis investigated addresses (i.e. buildings) which included more than six customers, and within the GS <50 kW class the

investigation analyzed addresses (i.e. buildings) with more than one customer.[16] In Toronto Hydro's experience, it is unlikely that a significant number of Residential buildings with less than 7 customers, or GS <50 kW buildings with less than 2 customers, would have procured and subsequently managed their own line transformer and secondary system assets. The results of this analysis are presented in below in Table 3, which shows the alternative customer count of served by Toronto Hydro line transformer and secondary system assets in each rate class, relative to the total population of alternative customer counts in the class that are deemed to utilize these assets in the current model.

Table 3: Alternative Line Transformer and Secondary

	Residential		CSMUR		GS<50 kW	
	Alternative Customer Count	% of Total Alternative Customer Count	Alternative Customer Count	% of Total Alternative Customer Count	Alternative Customer Count	% of Total Alternative Customer Count
Line Transformer	470,611	99.98%	235	61.37%	42,438	99.01%
Secondary	470,093	99.87%	116	30.41%	35,553	82.95%

3.3 Potential Impact Analysis

The implementation of the cost allocation refinements outlined above in section 4.2.1 and 4.2.2, all else being equal, would result in a shifting of costs away from the CSMUR customer class. For consideration, the following table presents 2025 Revenue to Cost ("R/C") ratios for each rate class as follows:

A. Status Quo (i.e. without any refinement);
B. with Alternative Customer Count as noted in section 4.2.1;

[16] Toronto Hydro relied on the tariff sheets class definition, "residential apartment buildings or the house service of a residential apartment building with more than 6 units", presented in EB-2022-0065, Decision and Order (December 8, 2022) at pages 32-37.

C. with Alternative Line Transformer and Secondary as noted in section 4.2.2; and

D. the combined effect of B and C.

Table 4: R/C Ratios With and Without Cost Allocation Refinements

Options	A	B	C	D
Rate Class	**Status Quo**	**Alternative Customer Count**	**Alternative Line Transformer and Secondary**	**Combined**
Residential	102%	97%	100%	96%
GS <50 kW	97%	100%	102%	104%
GS 50-999 kW	96%	99%	94%	96%
GS 1,000-4,999 kW	94%	97%	94%	96%
Large Use >5MW	97%	99%	97%	99%
Street Light	119%	110%	115%	110%
Unmetered Scattered Load	122%	93%	117%	92%
CSMUR	112%	150%	133%	174%

The cost allocation issues presented above relate to the movement and re-assignment of costs between customer groups, as opposed to a net increase or decrease of costs to customers overall. As such, Toronto Hydro does not propose a particular outcome with respect to the resolution of the issues presented, and sees merit to a collaborative approach which takes into account the views, preferences and expertise of all the parties whose interests are affected by cost allocation matters. This approach can place in the current proceeding through an OEB ordered settlement process or submissions to the OEB if a settlement cannot be reached between the parties.

The Data is for Illustrative Use Only

	HouR	Cust 1	Cust 2	Cust 3	Cust 4	Cust 5	Cust 6	Cust 7	Cust 8	Cust 9	Cust 10	Total	Avg	Sample Rate Class Hourly Profile for Jan	Total of All rate Classes (Includes Sample Rate Class)	Sample Rate Class % of Sum of all Rate Classes	IESO Purchased and Whoesale Market Participants Metered Load	Sample Rate Class portion of the Total System Load.	Weather Correction Factor for Sample Rate Class is 0.964395		Demand scaled to the 2025 load forecast based on the ratio of 2025 sample rate class kWh to sample rate Class Test year kWh.	EV and DER Consumption Combined	Net Load with EV and DER Consumption
													Sample size = 10	Total Number of Customers in Sample Rate Class in test year = 20		(e) = (d) / (c)		(g) = (e) * (f)	(h) = (g) * 0.964395		(i) = (h) * 1.003497		(k) = (i) + (j)
												(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)		(i)	(j)	(k)
01-Jan-19	1	0.37	1.01	0.85	0.67	0.52	1.5	0.34	0.19	0.38	1.4	7.23	0.723	14.46	318.12	5%	349.93	15.91	15.34		15.39	2.16	17.56
01-Jan-19	2	0.25	0.92	0.58	0.62	0.51	0.99	0.56	0.19	0.54	1.45	6.61	0.661	13.22	290.84	5%	349.01	15.86	15.30		15.35	1.68	17.03
01-Jan-19	3	0.32	0.86	0.51	0.62	0.59	0.72	0.44	0.2	0.55	1.22	6.03	0.603	12.06	265.32	5%	318.38	14.47	13.96		14.01	1.28	15.29
01-Jan-19	4	0.29	0.67	0.59	0.63	0.53	0.68	0.37	0.17	0.46	1.42	5.81	0.581	11.62	174.30	7%	209.16	13.94	13.45		13.49	0.96	14.46
01-Jan-19	5	0.26	0.81	0.6	0.65	0.5	0.7	0.34	0.2	0.27	1.28	5.61	0.561	11.22	145.86	8%	175.03	13.46	12.98		13.03	0.64	13.67
01-Jan-19	6	0.33	0.87	0.61	0.72	0.6	0.8	0.6	0.22	0.39	1.44	6.58	0.658	13.16	128.97	10%	154.76	15.79	15.23		15.28	0.41	15.69
01-Jan-19	7	0.24	0.65	0.6	0.71	0.52	0.99	0.47	0.17	0.3	1.3	5.95	0.595	11.90	110.67	11%	132.80	14.28	13.77		13.82	0.23	14.05
01-Jan-19	8	0.18	0.65	0.83	0.66	0.44	0.98	0.44	0.21	0.32	1.37	6.08	0.608	12.16	109.44	11%	131.33	14.59	14.07		14.12	0.14	14.26
01-Jan-19	9	2.16	0.81	1.03	0.61	0.54	0.85	0.37	0.21	0.35	1.41	8.34	0.834	16.68	141.78	12%	226.85	26.69	25.74		25.83	0.09	25.92
01-Jan-19	10	0.63	0.59	0.79	0.63	0.54	0.67	0.47	0.36	0.32	1.44	6.44	0.644	12.88	103.04	13%	123.65	15.46	14.91		14.96	0.06	15.02
01-Jan-19	11	1.45	1.12	0.82	0.95	0.61	0.88	1.21	0.19	0.27	1.44	8.94	0.894	17.88	107.28	17%	128.74	21.46	20.69		20.76	0.06	20.82
01-Jan-19	12	0.66	1.02	0.82	0.88	0.58	0.8	0.58	0.28	0.32	1.33	7.27	0.727	14.54	116.32	13%	209.38	26.17	25.24		25.33	0.07	25.40
01-Jan-19	13	2.71	0.91	0.93	1.18	0.72	0.79	0.71	0.23	0.75	1.42	10.35	1.035	20.70	175.95	12%	193.55	22.77	21.96		22.04	0.08	22.11
01-Jan-19	14	0.83	0.95	0.8	0.96	0.62	0.87	0.59	0.19	0.58	1.67	8.06	0.806	16.12	145.08	11%	**365.04**	40.56	**39.12**	**Sample Rate Class Jan CP**	**39.25**	0.09	**39.34**
01-Jan-19	15	0.64	0.98	0.67	1.14	0.57	0.53	0.5	0.2	0.58	1.45	7.26	0.726	14.52	145.20	10%	188.76	18.88	18.20		18.27	0.13	18.40
01-Jan-19	16	0.57	0.78	0.75	0.77	1.43	0.51	0.25	0.14	0.5	1.6	7.3	0.73	14.60	160.60	9%	192.72	17.52	16.90		16.96	0.19	17.15
01-Jan-19	17	0.46	1.03	1.01	0.79	1.18	0.51	0.37	0.19	0.35	1.63	7.52	0.752	15.04	90.24	17%	261.97	43.66	**42.11**	**Sample Rate Class Jan NCP**	**42.25**	0.27	**42.53**
01-Jan-19	18	1.14	2.79	1.01	0.84	0.7	1.03	0.33	0.26	0.44	1.49	10.03	1.003	20.06	220.66	9%	264.79	24.07	23.21		23.30	0.35	23.64
01-Jan-19	19	2.29	2.4	0.88	0.89	0.78	1.13	1.33	0.52	0.96	1.51	12.69	1.269	25.38	279.18	9%	335.02	30.46	29.37		29.47	0.40	29.87
01-Jan-19	20	0.8	2.54	0.88	0.94	0.88	0.96	1.85	0.58	0.57	1.38	11.38	1.138	22.76	273.12	8%	327.74	27.31	26.34		26.43	0.44	26.87
01-Jan-19	21	1.16	2.1	1.19	1.2	0.75	1.26	0.91	0.66	0.7	1.77	11.7	1.17	23.40	304.20	8%	334.62	28.08	27.08		27.17	0.48	27.66
01-Jan-19	22	0.8	1.15	1.12	1.04	0.62	1.15	0.79	0.53	0.73	1.88	9.81	0.981	19.62	274.68	7%	329.62	23.54	22.71		22.79	0.50	23.29
01-Jan-19	23	0.6	0.98	1.02	0.79	0.63	1.12	0.51	0.81	0.7	1.93	9.09	0.909	18.18	272.70	7%	327.24	21.82	21.04		21.11	0.50	21.61
01-Jan-19	24	0.52	1.02	0.64	0.78	0.64	1.01	0.34	0.34	0.71	1.86	7.86	0.786	15.72	251.52	6%	301.82	18.86	18.19		18.26	2.55	20.81

RATE DESIGN

1. INTRODUCTION AND SUMMARY

In this application, Toronto Hydro is requesting new base distribution rates and new rate riders effective January 1, 2025. Toronto Hydro has calculated rebased distribution rates for 2025 using the OEB's standard revenue requirement methodology as set out in the Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022).[1] For the period 2026 to 2029 period, Toronto Hydro calculated distribution rates using a Custom Revenue Cap Index ("CRCI"). More details on this CRCI can be found in Exhibit 1B, Tab 4, Schedule 1.

Consistent with EB-2014-0116 and EB-2018-0165, the distribution rates calculated in this application for the outlying 2026-2029 years following the 2025 rebasing year are to be updated, finalized, and approved through annual applications to the OEB.

This schedule includes sections that cover the following areas:

- **Section 2 – 2025 Base Distribution Rates:** A description of Toronto Hydro's proposed approach to rate design and the resulting outcomes for the 2025 rebasing year, including standby rates;
- **Section 3 – 2026-2029 Rate Design:** A description of Toronto Hydro's proposed approach to 2026 to 2029 rates, relying on the CRCI;
- **Section 4 – Other Rates and Charges:** A description of Toronto Hydro's proposed approach with respect to retail transmission service sates, retailer service charges,

[1] Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications, Chapter 2 – Cost of Service (December 15, 2022), section 2.8.

regulatory charges, the smart metering charge, specific service charges, loss adjustment factors, and rate riders;

- **Section 5 - Tariff of Rates and Charges**: Provides Toronto Hydro's current and proposed tariffs; and,
- **Section 6 – Bill Impacts**: Refers to proposed bill impacts by rate class for 2025-2029, rate mitigation, and Toronto Hydro's proposed rate smoothing approach.

A summary of the total bill impacts resulting from the utility's proposals is shown in Table 1 below.

1 **Table 1: Bill Impacts –Change in Total Monthly Bill**

	Change in Bill	2025 Proposed	2026 Proposed	2027 Proposed	2028 Proposed	2029 Proposed	2025-2029 Average Annual Increase
Residential	$/30 days	$0.91	$3.44	$3.77	$3.61	$2.90	
	%	0.7%	2.5%	2.6%	2.4%	1.9%	2.0%
Competitive Sector Multi-Unit Residential	$/30 days	-$2.10	$1.86	$2.21	$1.88	$1.66	
	%	-2.8%	2.6%	3.0%	2.5%	2.1%	1.5%
General Service <50 kW	$/30 days	$7.34	$9.36	$9.73	$10.39	$7.38	
	%	2.0%	2.5%	2.5%	2.6%	1.8%	2.3%
General Service 50-999 kW	$/30 days	-$73.44	$188.05	$197.76	$217.72	$170.01	
	%	-0.5%	1.3%	1.4%	1.5%	1.2%	1.0%
General Service 1,000-4,999 kW	$/30 days	-$1,565.72	$1,657.27	$1,713.81	$1,807.60	$1,560.87	
	%	-1.0%	1.1%	1.1%	1.2%	1.0%	0.7%
Large Use	$/30 days	-$7,459.85	$6,638.41	$9,677.61	$10,769.78	$8,543.60	
	%	-1.1%	1.0%	1.4%	1.6%	1.2%	0.8%
Street Lighting	$/30 days	$13,867.36	$13,873.12	$23,380.94	$13,713.23	$17,205.38	
	%	4.4%	4.2%	6.8%	3.7%	4.5%	4.7%
Unmetered Scattered Load	$/30 days	$1.88	$2.44	$2.52	$3.15	$2.04	
	%	3.0%	3.7%	3.7%	4.5%	2.8%	3.5%

2. 2025 BASE DISTRIBUTION RATES

As 2025 is Toronto Hydro's rebasing year, distribution rates for this year have been developed on a cost of service basis. The revenue requirement for 2025 (as described in Exhibit 6, Tab 1, Schedules 1 and 2) is allocated to rate classes using the OEB's latest cost allocation model (as described in Exhibit 7, Tab 1, Schedule 1) and rates are designed to collect the allocated costs from each customer class.

2.1 Fixed versus Variable Charge

Toronto Hydro is proposing to maintain the fixed/variable split from its current rate period, as approved in EB-2018-0165, for all rate classes in all years of the 2025-2029 rate period. This approach has been approved by the OEB in numerous cost of service proceedings, including instances in which explicit approval of the maintenance of current fixed/variable splits have been provided in an adjudicated context.[2,3]

To determine Toronto Hydro's current fixed/variable split, consistent with previous applications, the utility applied 2025 forecast customer connection counts to anticipated 2024 rates to determine 2025 fixed revenue at 2024 rates. The utility subsequently applied 2025 forecast kWh and kVA billing determinants to anticipated 2024 rates, including variable distribution charges and adjustments for the transformer allowance, to determine the percentage of fixed and variable revenue relative to total revenue, by rate class. Exhibit 8, Tab 1, Schedule 2 provides details on the current fixed/variable split for each rate class utilizing this methodology.

To maintain the current period's fixed/variable split for each rate class in 2025, Toronto Hydro performed the following calculations, consistent with previous applications:

[2] For example, EB-2012-0113, EB-2011-0293, EB-2011-0319; EB-2014-0002.
[3] EB-2016-0085.

- To establish 2025 fixed charges:
    - The fixed revenue to be collected from each rate class in 2025 is calculated by taking the 2025 base revenue requirement for each rate class and multiplying by the percentage of revenue, determined in the section above, to be recovered via fixed charges; and
    - The 2025 fixed revenue by rate class is divided by the 2025 forecast customer, connection, and device count, as applicable for each rate class.
- To establish 2025 variable charges:
    - The variable revenue to be collected from each rate class in 2025 is calculated by taking the 2025 base revenue requirement for each rate class and multiplying by the percentage of revenue, determined in the section above, to be recovered via variable charges; and
    - The 2025 variable revenue by rate class is divided by 2025 forecast kWh or kVA billing determinants applicable to each rate class. This establishes the variable charges for each rate class before accounting for the transformer allowance. Subsequently, adjustments are made to applicable rate classes to account for transformer allowance.
- Fixed charges are rounded to two decimal places, while variable charges for kWh and kVA billing determinants are rounded to five and four decimal places, respectively.

2.2 Monthly Fixed Charge

Table 2 below summarizes the 2024 proposed and the 2025 proposed monthly fixed charge with the floor and ceiling values, as calculated via the cost allocation model, for each customer class.[4]

[4] The proposed monthly fixed charges for 2024 are based on the rates outlined in Toronto Hydro's 2024 rate application (EB-2023-0054), filed on September 8, 2023.

Table 2: Monthly Fixed Charge ($)

	Residential	CSMUR	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Street Lighting	USL
CA Model Floor	6.66	4.29	14.83	31.02	35.41	121.90	0.60	0.72
CA Model Ceiling	23.28	18.74	38.61	86.35	162.48	497.05	6.28	8.82
Proposed (2024)	45.93	37.68	44.31	58.88	1,109.35	4,910.79	1.87	7.25
Proposed (2025)	49.52	37.00	49.77	65.29	1,191.22	5,138.68	2.06	7.87

Proposed 2025 rates are shown on a 30-day basis. Floor, ceiling, and 2024 expected rates are not adjusted for 30-day basis, and come directly from the Cost Allocation model in Exhibit 7, Tab 1, Schedule 3.

For the Residential and Competitive Sector Multi-Unit Residential ("CSMUR") classes, the proposed fixed rate is the result of the OEB's EB-2012-0410 policy requiring fully fixed distribution rates for these classes.

2.3 Transformer Allowance

Toronto Hydro is not proposing to change its current transformer allowance rate in this application and proposes to maintain the credit provided to customers that own their transformation facilities at $0.62/kVA per 30 days.

2.4 Billing Determinants

Toronto Hydro is not putting forward any changes to the currently approved billing determinants for any customer class and proposes to continue to bill customers on a 30-day fixed portion and on a kVA or kWh variable portion. For the Unmetered Scattered Load class, customers will continue to be charged a monthly service charge, a per-connection charge, and a variable charge based on kWh.

2.5 Standby Rates

In its 2006 rate application, Toronto Hydro applied to harmonize the standby rates inherited from its six pre-amalgamation utilities. The OEB approved Toronto Hydro's proposal on an interim basis, pending a separate generic proceeding to establish standby rates for all Ontario electricity distributors.[5] As of the 2020 rebasing, Toronto Hydro continued to include these rates as part of its Custom Incentive Rates Application (EB-2018-0165). In its Decision and Order dated December 19, 2019, the OEB stated the following:

> *"The OEB approves the standby rates on an interim basis. The standby rates have been interim for many years, on the expectation that a generic rate design policy may be adopted that would eliminate the need for standby rates.*
>
> *In accordance with Chapter 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022), a distributor may seek approval for its standby charges on a final basis but must provide evidence confirming that they have advised all affected customers of the proposal. Toronto Hydro did not seek approval for its standby rates to be made final.*
>
> *Given the length of time that the standby rates have been set on an interim basis, the OEB requires Toronto Hydro to file a proposal in its next rebasing application to address this situation, unless it has been otherwise superseded by a generic policy."*

In 2020, the OEB updated Chapter 2 of its Filing Requirements for Electricity Distribution Rate Applications to introduce a requirement for distributors who have had interim approved standby rates since 2006 to seek approval for their standby rates to be made final.

[5] Application to the Ontario Energy Board by Toronto Hydro-Electric System Limited for 2006 Electricity Distribution Rates RP-2005-0020/EB-2005-0421; Decision with Reasons (April 12, 2006).

On September 28, 2023, the OEB announced a Consultation on Policy for Standby Rates (EB-2023-0278). In the letter announcing this consultation the OEB states;

> *"The Ontario Energy Board (OEB) intends to engage stakeholders to inform its approach to existing and future electricity distribution standby rates, including consideration of the approach to standby rates outlined in the OEB's Commercial and Industrial Rate Design staff paper."*

Given this announcement, Toronto Hydro submits that the best venue to determine an approach to standby rates is the recently established generic policy consultation; not this application. Consequently, and in recognition of both the OEB's previous decision and its recent policy announcement, Toronto Hydro is not proposing final standby rates in this application.

Toronto Hydro notes that technology and customers' usage of distributed energy resources ("DERs") have significantly evolved since the standby rates concept was introduced. Further, there are an increasing number of public policy imperatives (e.g. climate action, resiliency, affordability, flexibility) driving the sector to support the adoption of DERs. Standby rates, which operate to increase the amount paid by customers who utilize DERs, seem to conflict with those public policy imperatives. At the same time, regulatory policy must balance those imperatives with the interests of fair cost allocation among customers and full cost recovery for utilities.

3. 2026-2029 RATE DESIGN

Toronto Hydro proposes to update its 2026-2029 distribution rates based on the CRCI. For each of these years, base revenue requirements will be brought forward for final approval in Toronto Hydro's annual rate update applications, inclusive of actual inflation factors

applicable to those years. In each annual application, Toronto Hydro will propose new distribution rates based on the escalated base revenue requirement resulting from application of the CRCI, in accordance with the OEB's decision in this proceeding. Toronto Hydro proposes that for the years 2026 to 2029, the final approved base revenue requirements be allocated to each rate class based on the same allocations to rate classes established in this proceeding for 2025. Toronto Hydro will hold constant the fixed/variable revenue split for each rate class determined in 2025 for the purpose of designing rates from 2026 to 2029. Subsequently, the utility will calculate rates in each year relying on Toronto Hydro's 5-year customer and load forecast as approved in this application.

4. OTHER RATES AND CHARGES

4.1 Retail Transmission Service Rates ("RTSRs")

Toronto Hydro's proposed RTSRs for 2025 have been calculated using the OEB's RTSR model, as filed at Exhibit 8, Tab 5, Schedule 1 (a live MS Excel model has also been included).[6] The proposed 2025 rates in the completed RTSR model reflect projected 2025 billing units, applied to the Uniform Transmission Rates ("UTRs") available at the time of calculations.[7] Toronto Hydro will update its RTSRs prior to the implementation of 2025 rates based on the latest OEB-approved UTRs available at that time.

In order to meet Toronto Hydro's requirements for the calculation of RTSR rates, Toronto Hydro made the following changes to the OEB's RTSR model:

- The "Year" columns in Sheet 4, UTRs and Sub-Transmission were changed to reflect 2023, 2024, and 2025 years.

[6] In accordance with the OEB's Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates (June 28, 2012).
[7] EB-2023-0101, Decision and Rate Order - 2023 Uniform Transmission Rates Update (June 1, 2023).

- On Sheet 8, RTSR Rates to Forecast, the Proposed RTSR rates are calculated to 5 decimal places for kWh rates, and 4 decimal places for kW rates. The kW rates are also adjusted for 30-days of service.

Since the OEB updates UTRs annually, Toronto Hydro proposes to file updated RTSRs utilizing the latest available OEB's IRM Rate Generator Model and rates over the 2026-29 period, as part of the annual rates update process under the CRCI framework.

4.2 Retailer Service Charges ("RSCs")

Toronto Hydro's calculations and assumptions incorporate the OEB-approved 2024 RSCs.[8] The utility will update any relevant inputs prior to the implementation of 2025 rates based on the latest OEB-approved RSCs that will be available at that time. Furthermore, since the OEB updates RSCs annually, Toronto Hydro will flow through updated charges as part of the annual rates update process under the CRCI framework throughout the 2026-2029 rate period.

4.3 Regulatory Charges

This application reflects the latest OEB-approved Wholesale Market Service Rate ("WMS") rate of $0.0041/kWh, Capacity Based Recovery ("CBR") component of $0.0004/kWh applicable to Class B customers, and a Rural and Remote Rate Protection ("RRRP") rate of $0.0007/kWh.[9] The utility will update any relevant inputs prior to the implementation of 2025 rates based on the latest OEB-approved regulatory charges that will be available at that time. Furthermore, since the OEB updates regulatory charges annually, Toronto Hydro will

[8] EB-2023-0193, Decision and Order (September 26, 2023). In the matter of the inflationary adjustment effective January 1, 2024, for energy retailer service charges for electricity distributors.
[9] EB-2022-0269, Decision and Order (December 8, 2022). In the matter of regulatory charges effective January 1, 2023, for the Wholesale Market Services rate and the Rural or Remote Electricity Rate Protection charge.

flow through updated charges as part of the annual rates update process under the CRCI framework throughout the 2026-2029 rate period.

4.4 Smart Metering Charge

On September 8, 2022, the OEB issued a decision and order establishing a smart metering charge of $0.42 per month for Residential and GS< 50 kW customers effective January 1, 2023 until December 31, 2027.

Toronto Hydro implemented this charge (adjusted to $0.41 to reflect the utility's fixed charges on a 30-day basis) and included it in its proposed rates for the applicable period.

4.5 Specific Service Charges

Toronto Hydro is not proposing any changes to its specific service charges. For further details on the utility's specific service charges, please refer to Exhibit 8, Tab 2, Schedule 1.

This application reflects the latest OEB-approved distribution (wireline) pole attachment charge of $37.78 per attacher, per year, per pole.[10] The utility will update any relevant inputs prior to the implementation of 2025 rates based on the latest OEB-approved distribution (wireline) pole attachment charge that will be available at that time. Furthermore, since the OEB updates this charge annually, Toronto Hydro will flow through updated charge as part of the annual rates update process under the CRCI framework throughout the 2026-2029 rate period.

4.6 Loss Adjustment Factors

Toronto Hydro is not proposing any changes to the current OEB-approved loss adjustment factors shown in Table 4.

[10] EB-2023-0194, Decision and Order - Distribution Pole Attachment Charge for 2024 (September 26, 2023).

Table 4: Loss Adjustment Factors

	Current Approved
(A) Primary Metering Adjustment	0.9900
(B) Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
(C) Customer Less than 5,000kW	1.0249
(D) Customer Greater than 5,000kW	1.0126
Total Loss Factors	
Secondary Metered Customers	
(E) Customer Less than 5,000kW (B*C)	1.0295
(F) Customer Greater than 5,000kW (B*D)	1.0172
Primary Metered Customers	
(G) Customer Less than 5,000kW (A*E)	1.0192
(H) Customer Greater than 5,000kW (A*F)	1.0070

4.7 Rate Riders

Toronto Hydro is proposing new rate riders to clear a number of Deferral and Variance Accounts ("DVAs"). These new rate riders are discussed in the Exhibit 9, Tab 1, Schedule 1.

5. TARIFF OF RATES AND CHARGES

Toronto Hydro's current Tariff of Rates and Charges is included in Exhibit 8, Tab 3, Schedule 1 and proposed tariffs for 2025-2029 are included in Exhibit 8, Tab 3, Schedule 2.

5.1 Revenue Reconciliation

Tab 13 of each of the 2025-2029 revenue requirement workforms, filed at Exhibit 6, Tab 1, Schedules 2-6, shows the difference between revenue at the proposed rates and allocated revenue requirements by customer class.

6. BILL IMPACTS

Details of the bill impacts of the proposed rates are provided in Exhibit 8, Tab 6, Schedule 1, showing the individual and combined impacts of the distribution component, rate riders, other components (e.g. transmission and network charges), and total bill, calculated for representative levels of consumption for each rate class.

6.1 Rate Mitigation

As shown in Table 1 above, the impacts of the proposed rates for 2025-2029 on the total bill for all classes are less than 10 percent. As discussed in detail elsewhere in this application (e.g. Exhibit 1B, Tab 2, Schedule 1; Exhibit 2B; and Exhibit 4, Tab 1, Schedule 1), Toronto Hydro has incorporated consideration of rate impacts as part of its proposed capital and OM&A funding requests.

6.2 Rate Smoothing Approach

Consistent with EB-2018-0165, Toronto Hydro proposes implementation of a rate smoothing methodology, aimed at assisting customers in managing bill impacts. Toronto Hydro's proposed rate smoothing plan offers several benefits: (i) it avoids a one-time step-change increase for most customers in the rebasing year (2025), while (ii) maintaining relatively consistent year-over-year annual increases for all customer classes.

A summary of the distribution (including non-pass through rate riders) and total bill impacts resulting from the utility’s proposals is shown in Tables 5-1, 5-2, and 5-3 below.

Table 5-1: Bill Impacts – Change in Monthly Bill

		Change in Bill	2025 Proposed	2026 Proposed	2027 Proposed	2028 Proposed	2029 Proposed	2025-2029 Average Annual Increase
Residential	Distribution Subtotal A	$/30 days	$3.24	$3.40	$3.72	$3.97	$2.86	$3.44
		%	7.6%	7.4%	7.5%	7.5%	5.0%	7.0%
	Total Bill (After Taxes & Rebate)	$/30 days	$0.91	$3.44	$3.77	$3.61	$2.90	$2.93
		%	0.7%	2.5%	2.6%	2.4%	1.9%	2.0%
Competitive Sector Multi-Unit Residential	Distribution Subtotal A	$/30 days	-$1.27	$1.84	$2.18	$2.27	$1.64	$1.33
		%	-3.6%	5.4%	6.0%	5.9%	4.0%	3.6%
	Total Bill (After Taxes & Rebate)	$/30 days	-$2.10	$1.86	$2.21	$1.88	$1.66	$1.10
		%	-2.8%	2.6%	3.0%	2.5%	2.1%	1.5%
General Service <50 kW	Distribution Subtotal A	$/30 days	$14.18	$9.24	$9.61	$10.67	$7.29	$10.20
		%	12.0%	7.0%	6.8%	7.0%	4.5%	7.4%
	Total Bill (After Taxes & Rebate)	$/30 days	$7.34	$9.36	$9.73	$10.39	$7.38	$8.84
		%	2.0%	2.5%	2.5%	2.6%	1.8%	2.3%

Table 5-2: Bill Impacts – Change in Monthly Bill

		Change in Bill	2025 Proposed	2026 Proposed	2027 Proposed	2028 Proposed	2029 Proposed	2025-2029 Average Annual Increase
General Service 50-999 kW	Distribution Subtotal A	$/30 days	$235.35	$166.42	$175.01	$192.67	$150.45	$183.98
		%	13.0%	8.1%	7.9%	8.1%	5.8%	8.6%
	Total Bill (After Taxes & Rebate)	$/30 days	-$73.44	$188.05	$197.76	$217.72	$170.01	$140.02
		%	-0.5%	1.3%	1.4%	1.5%	1.2%	1.0%
General Service 1,000-4,999 kW	Distribution Subtotal A	$/30 days	$1,993.46	$1,466.61	$1,516.65	$1,599.65	$1,381.30	$1,591.53
		%	13.4%	8.7%	8.3%	8.0%	6.4%	9.0%
	Total Bill (After Taxes & Rebate)	$/30 days	-$1,565.72	$1,657.27	$1,713.81	$1,807.60	$1,560.87	$1,034.77
		%	-1.0%	1.1%	1.1%	1.2%	1.0%	0.7%
Large Use	Distribution Subtotal A	$/30 days	$10,124.44	$5,874.70	$8,564.26	$9,530.78	$7,560.71	$8,330.98
		%	13.1%	6.7%	9.2%	9.4%	6.8%	9.1%
	Total Bill (After Taxes & Rebate)	$/30 days	-$7,459.85	$6,638.41	$9,677.61	$10,769.78	$8,543.60	$5,633.91
		%	-1.1%	1.0%	1.4%	1.6%	1.2%	0.8%

Table 5-3: Bill Impacts – Change in Monthly Bill

		Change in Bill	2025 Proposed	2026 Proposed	2027 Proposed	2028 Proposed	2029 Proposed	2025-2029 Average Annual Increase
Street Lighting	Distribution Subtotal A	$/30 days	$15,917.30	$12,277.10	$20,691.10	$12,135.60	$15,226.00	$15,249.42
		%	11.0%	7.6%	11.9%	6.3%	7.4%	8.8%
	Total Bill (After Taxes & Rebate)	$/30 days	$13,867.36	$13,873.12	$23,380.94	$13,713.23	$17,205.38	$16,408.01
		%	4.4%	4.2%	6.8%	3.7%	4.5%	4.7%
Unmetered Scattered Load	Distribution Subtotal A	$/30 days	$2.96	$2.41	$2.49	$3.11	$2.01	$2.60
		%	9.5%	7.1%	6.8%	8.0%	4.8%	7.2%
	Total Bill (After Taxes & Rebate)	$/30 days	$1.88	$2.44	$2.52	$3.15	$2.04	$2.41
		%	3.0%	3.7%	3.7%	4.5%	2.8%	3.5%

SPECIFIC SERVICE CHARGES

OEB-approved service charges apply to services that are over and above Toronto Hydro's standard level of service offerings.[1] Some of these services, such as duplicate invoices, are provided at customers' request. Others result from Toronto Hydro's business operations, such as collection fees resulting from customers' non-payment of bills. The revenue from these charges offset the total revenue requirement.

For this application, Toronto Hydro proposes to leave its specific service charges unchanged.

This application reflects the latest OEB-approved distribution (wireline) pole attachment charge of $37.78 per attacher, per year, per pole.[2] The utility will update any relevant inputs prior to the implementation of 2025 rates based on the latest OEB-approved distribution (wireline) pole attachment charge that will be available at that time. Furthermore, since the OEB updates this charge annually, Toronto Hydro will flow through updated charge as part of the annual rates update process under the CRCI framework throughout the 2026-2029 rate period.

A summary of the specific service charges proposed for the 2025-2029 rate period is shown in Table 1. In addition to the charges listed in Table 1, Toronto Hydro applies late payment charges at a rate of 1.50% per month, equivalent to an effective annual rate of 19.56% per annum or a 0.04896% compounded daily rate. Historical and forecast revenues from these service charges is part of Other Revenue and further described in Exhibit 3, Tab 2.

[1] In accordance with the OEB's 2006 Distribution Rate Handbook ("DRH", May 11, 2005), Toronto Hydro bills all other services on an actual cost, time, and materials basis or as a pass-through of third-party costs.
[2] EB-2023-0194, Decision and Order - Distribution Pole Attachment Charge for 2024 (September 26, 2023).

1 **Table 1: Specific Service Charges 2025-2029**

Specific Service Charge	Existing Rates ($)	Proposed Rates ($)	Existing Versus Proposed Variance ($)
Account history	25.00	25.00	0
Duplicate invoices for previous billing	25.00	25.00	0
Request for other billing or system information	25.00	25.00	0
Easement letter	25.00	25.00	0
Income tax letter	25.00	25.00	0
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	35.00	35.00	0
Returned cheque (plus bank charges)	25.00	25.00	0
Special meter reads	55.00	55.00	0
Meter dispute charge plus Measurement Canada fees (if meter found correct)	55.00	55.00	0
Reconnection charge - at meter - during regular hours	120.00	120.00	0
Reconnection charge - at meter - after regular hours	400.00	400.00	0
Reconnection charge - at pole - during regular hours	300.00	300.00	0
Reconnection charge - at pole - after regular hours	820.00	820.00	0
Disconnect/reconnect at meter - during regular hours	120.00	120.00	0
Disconnect/reconnect at meter - after regular hours	400.00	400.00	0
Disconnect/reconnect at pole - during regular hours	300.00	300.00	0
Disconnect/reconnect at pole - after regular hours	820.00	820.00	0
Temporary service install & remove - overhead - no transformer	2,040.00	2,040.00	0
Specific charge for access to the power poles (wireline attachments) - per pole/year [3]	37.78	37.78	0

[3] As noted above, Toronto Hydro will update the pole attachment charge in accordance with future OEB orders.

1. OTHER RATES AND CHARGES

In accordance with the Filing Requirements,[4] this section describes charges that appear in Toronto Hydro's Conditions of Service but do not appear on the utility's OEB-approved tariff sheet.

The following basic connection charges, which are not included in distribution rates, recover the actual labour, materials, and equipment costs that Toronto Hydro incurs for making the indicated types of connections:[5]

1) Unmetered Connections – Overhead Supply (excludes Street Lighting):
    a) $446 standard charge plus variable costs – for source connection made at the Distributor's supply pole and where service mast located on same supply pole; and
    b) $1,011 standard charge plus variable costs – for source connection made at the Distributor's supply pole and where service mast is not located on same supply pole.
2) Street Lighting Services:
    a) $533.36 standard charge plus variable costs – for municipal lights attached to Distributor's poles and connected to Distributor's overhead 120/240 V secondary bus;
    b) $573.97 standard charge plus variable costs – for municipal lights attached to Distributor's poles in mixed used urban settings where streets are classified as collector or arterial and connected to Distributor's underground 120/240 V secondary bus; and

[4] Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications, Chapter 2 (December 15, 2022), section 2.8.5.
[5] Toronto Hydro's Conditions of Service, Revision 22 (January 1, 2023), Table 2 at page 92 and Table 6 at page 97.

c) $573.97 standard charge plus variable costs – for municipal lights attached to Municipality's poles in residential settings and connected to Distributor's underground 120/240 V secondary bus.

Toronto Hydro bills these charges directly to customers.

Table 2 below shows the total amounts Toronto Hydro collected through these charges over the 2020-2022 period. Forecast amounts are not available, as the volumes of this work depend upon the frequency of customer requests.

Table 2: Unmetered Connections and Street Lighting Services Charges ($)

	2020	2021	2022
Service Connection Contributions	154,620	112,040	84,326

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DECISION AND RATE ORDER

EB-2022-0065

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Application for rates and other charges to be effective January 1, 2023

BEFORE: **Allison Duff**
Presiding Commissioner

Michael Janigan
Commissioner

December 8, 2022

1. OVERVIEW

The Ontario Energy Board is approving changes to the rates that Toronto Hydro-Electric System Limited (Toronto Hydro) charges to distribute electricity to its customers, effective January 1, 2023.

As a result of this Decision, there will be a monthly total bill increase of $4.93 for a residential customer consuming 750 kWh. This change does not factor in applicable taxes or the Ontario Electricity Rebate.

SCHEDULE A

DECISION AND RATE ORDER

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

TARIFF OF RATES AND CHARGES

EB-2022-0065

DECEMBER 8, 2022

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0065

RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a separately metered living accommodation, where the Competitive Sector Multi-Unit Residential classification is not applicable. Eligibility is restricted to a dwelling unit that consists of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex building, with a residential zoning; a separately metered dwelling within a town house complex or apartment building; and bulk metered residential buildings with six or fewer units. Class B consumers are defined in accordance with O. Reg. 429/04. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	43.31	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until December 31, 2027	$	0.41	(per 30 days)
Rate Rider for Disposition of Stranded Meter Assets - effective until December 31, 2024	$	(0.02)	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$	(2.17)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$	(0.01)	(per 30 days)
Rate Rider for Disposition of Accounts Receivable Credits - effective until December 31, 2024	$	(0.10)	(per 30 days)
Rate Rider for Disposition of PILs and Tax Variance - effective until December 31, 2024	$	(0.31)	(per 30 days)
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kWh	0.00319	
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - Applicable only for Class B Customers - effective until December 31, 2023	$/kWh	(0.00015)	
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until December 31, 2023	$/kWh	(0.00251)	
Retail Transmission Rate - Network Service Rate	$/kWh	0.01158	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00733	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0065

COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to an account where electricity is used exclusively for residential purposes in a multi- unit residential building, where unit metering is provided using technology that is substantially similar to that employed by competitive sector sub-metering providers. Use of electricity in non-residential units of multi-unit buildings does not qualify for this classification and will instead be subject to the applicable commercial classification. Class B consumers are defined in accordance with O. Reg. 429/04. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	35.53	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until December 31, 2027	$	0.41	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$	(1.45)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$	(0.01)	(per 30 days)
Rate Rider for Disposition of PILs and Tax Variance - effective until December 31, 2024	$	(0.21)	(per 30 days)
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kWh	0.00303	
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - Applicable only for Class B Customers - effective until December 31, 2023	$/kWh	(0.00015)	
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until December 31, 2023	$/kWh	(0.00251)	
Retail Transmission Rate - Network Service Rate	$/kWh	0.01158	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00733	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0065

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	41.78	(per 30 days)
Rate Rider for Smart Metering Entity Charge - effective until December 31, 2027	$	0.41	(per 30 days)
Rate Rider for Disposition of Stranded Meter Assets - effective until December 31, 2024	$	(0.13)	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.03864	
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kWh	(0.00252)	
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kWh	(0.00002)	
Rate Rider for Disposition of Accounts Receivable Credits - effective until December 31, 2024	$/kWh	(0.00006)	
Rate Rider for Disposition of PILs and Tax Variance - effective until December 31, 2024	$/kWh	(0.00036)	
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kWh	0.00329	
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - Applicable only for Class B Customers - effective until December 31, 2023	$/kWh	(0.00015)	
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until December 31, 2023	$/kWh	(0.00251)	
Retail Transmission Rate - Network Service Rate	$/kWh	0.01127	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00656	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0065

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 50 kW but less than 1,000 kW, or is forecast to be equal to or greater than 50 kW but less than 1,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	55.52	(per 30 days)
Rate Rider for Disposition of Stranded Meter Assets - effective until December 31, 2024	$	(0.47)	(per 30 days)
Distribution Volumetric Rate	$/kVA	8.9153	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.4379)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0013)	(per 30 days)
Rate Rider for Disposition of Expansion Deposits - effective until December 31, 2024	$/kVA	(0.0699)	(per 30 days)
Rate Rider for Disposition of Accounts Receivable Credits - effective until December 31, 2024	$/kVA	(0.0005)	(per 30 days)
Rate Rider for Disposition of PILs and Tax Variance - effective until December 31, 2024	$/kVA	(0.0621)	(per 30 days)
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kVA	0.8996	(per 30 days)
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants (2023) - effective until December 31, 2023	$/kVA	0.3679	(per 30 days)
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - Applicable only for Class B Customers - effective until December 31, 2023	$/kVA	(0.0578)	(per 30 days)
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until December 31, 2023	$/kWh	(0.00251)	
Retail Transmission Rate - Network Service Rate	$/kW	3.8112	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.3701	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0065

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 1,000 kW but less than 5,000 kW, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	1,046.03	(per 30 days)
Distribution Volumetric Rate	$/kVA	7.3674	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.3301)	(per 30 days)
Rate Rider for Disposition of PILs and Tax Variance - effective until December 31, 2024	$/kVA	(0.0468)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0006)	(per 30 days)
Rate Rider for Disposition of Expansion Deposits - effective until December 31, 2024	$/kVA	(0.0527)	(per 30 days)
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kVA	1.0560	(per 30 days)
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants (2023) - effective until December 31, 2023	$/kVA	0.4277	(per 30 days)
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - Applicable only for Class B Customers - effective until December 31, 2023	$/kVA	(0.0592)	(per 30 days)
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until December 31, 2023	$/kWh	(0.00251)	
Retail Transmission Rate - Network Service Rate	$/kW	3.6824	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.3677	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0065

LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Post 2011 Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4,630.52	(per 30 days)
Distribution Volumetric Rate	$/kVA	7.9826	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(0.3894)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0006)	(per 30 days)
Rate Rider for Disposition of Expansion Deposits - effective until December 31, 2024	$/kVA	(0.0622)	(per 30 days)
Rate Rider for Disposition of PILs and Tax Variance - effective until December 31, 2024	$/kVA	(0.0552)	(per 30 days)
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kVA	1.0391	(per 30 days)
Rate Rider for Disposition of Deferral/Variance Accounts for Non-Wholesale Market Participants (2023) - effective until December 31, 2023	$/kVA	0.4119	(per 30 days)
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - Applicable only for Class B Customers - effective until December 31, 2023	$/kVA	(0.0340)	(per 30 days)
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until December 31, 2023	$/kWh	(0.00251)	
Retail Transmission Rate - Network Service Rate	$/kW	4.1977	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.6305	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0065

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires THESL to provide back- up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component - APPROVED ON AN INTERIM BASIS

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).

Service Charge	$	270.82	(per 30 days)
Distribution Volumetric Rate			
For General Service 50 - 999 kW Service Classification	$/kVA	8.9153	(per 30 days)
For General Service 1,000 - 4,999 kW Service Classification	$/kVA	7.3674	(per 30 days)
For Large Use Service Classification	$/kVA	7.9826	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0065

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand at each location is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by THESL and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments there to as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	6.84	(per 30 days)
Connection Charge (per connection)	$	0.71	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.08606	
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kWh	(0.00514)	
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kWh	(0.00003)	
Rate Rider for Disposition of Expansion Deposits - effective until December 31, 2024	$/kWh	(0.00082)	
Rate Rider for Disposition of PILs and Tax Variance - effective until December 31, 2024	$/kWh	(0.00073)	
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kWh	0.00339	
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - Applicable only for Class B Customers - effective until December 31, 2023	$/kWh	(0.00015)	
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until December 31, 2023	$/kWh	(0.00250)	
Retail Transmission Rate - Network Service Rate	$/kWh	0.00701	
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.00463	

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0065

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per device)	$	1.76	(per 30 days)
Distribution Volumetric Rate	$/kVA	39.3057	(per 30 days)
Rate Rider for Disposition of Capital Related Revenue Requirement Variance Account - effective until December 31, 2024	$/kVA	(2.4517)	(per 30 days)
Rate Rider for Disposition of Wireless Pole Attachment Revenue - effective until December 31, 2024	$/kVA	(0.0120)	(per 30 days)
Rate Rider for Disposition of Expansion Deposits - effective until December 31, 2024	$/kVA	(0.3914)	(per 30 days)
Rate Rider for Disposition of PILs and Tax Variance - effective until December 31, 2024	$/kVA	(0.3476)	(per 30 days)
Rate Rider for Disposition of Deferral/Variance Accounts (2023) - effective until December 31, 2023	$/kVA	1.0733	(per 30 days)
Rate Rider for Disposition of Capacity Based Recovery Account (2023) - Applicable only for Class B Customers - effective until December 31, 2023	$/kVA	(0.0498)	(per 30 days)
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until December 31, 2023	$/kWh	(0.00251)	
Retail Transmission Rate - Network Service Rate	$/kW	3.3900	(per 30 days)
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.8259	(per 30 days)

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030	
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004	
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005	
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0065

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the utility's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.49	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

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EB-2022-0065

ALLOWANCES

Transformer Allowance for Ownership	$/kVA	(0.62)	(per 30 days)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)	

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Account history	$	25.00
Duplicate invoices for previous billing	$	25.00
Request for other billing or system information	$	25.00
Easement letter	$	25.00
Income tax letter	$	25.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	35.00
Returned cheque (plus bank charges)	$	25.00
Special meter reads	$	55.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	55.00

Non-Payment of Account

Late payment - per month		
(effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection charge - at meter - during regular hours	$	120.00
Reconnection charge - at meter - after regular hours	$	400.00
Reconnection charge - at meter - during regular hours	$	300.00
Reconnection charge - at meter - after regular hours	$	820.00

Other

Reconnection charge - at meter - during regular hours	$	120.00
Reconnection charge - at meter - after regular hours	$	400.00
Reconnection charge - at meter - during regular hours	$	300.00
Reconnection charge - at meter - after regular hours	$	820.00
Temporary service install & remove - overhead - no transformer	$	2,040.00
Specific charge for access to the power poles (wireline attachments) - per pole/year	$	36.05

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0065

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by THESL to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	111.66
Monthly Fixed Charge, per retailer	$	44.67
Monthly Variable Charge, per customer, per retailer	$/cust.	1.11
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.66
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.66)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.56
Processing fee, per request, applied to the requesting party	$	1.11
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.47

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0295
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0172
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0192
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0070

SCHEDULE B

DECISION AND RATE ORDER

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

ACCOUNTING ORDER

EB-2022-0065

DECEMBER 8, 2022

ACCOUNTING ORDER

NEW VARIANCE ACCOUNTS – USEFUL LIFE CHANGES

In accordance with the OEB's decision on the 2020-2024 Custom IR application (EB-2018-0165), Toronto Hydro intends to complete a comprehensive depreciation study on its assets. Toronto Hydro intends to adopt changes in asset useful lives where material differences might exist between the study's recommendations and current practices. This change in useful lives would impact all components of Toronto Hydro's revenue requirement as they relate to changes in depreciation.

The purpose of the new Useful Life Changes variance accounts is to track the cumulative difference between the utility's net Plant, Property, and Equipment under its former and updated depreciation rates and any associated impacts as appropriate. The account will be effective from January 1, 2023 until the effective date of the next rebasing decision, unless otherwise directed by the OEB. The account will be cumulative and asymmetrical in favour of customers. The calculation of any entries made to the Useful Life Changes accounts and the prudence of any account balances will be subject to review and OEB approval at rebasing.

Carrying charges will apply to the opening revenue requirement balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts. The carrying charges sub-account is being established on a provisional basis, to enable the consideration of carrying charges on the variance account, based on the calculation approach approved at rebasing.

Toronto Hydro will use the following sub-accounts to record the amounts:

- Account 1508, Other Regulatory Assets, Sub-account Useful Life Changes
- Account 1508, Other Regulatory Assets, Sub-account Useful Life Changes Carrying Charges

The sample accounting entries for the variance accounts are:

A. To record entries in the Useful Life Changes variance account:
    - CR 1508 Other Regulatory Assets, Sub-account Useful Life Changes
    - DR 4305 Regulatory Debits
B. To record the carrying charges on the Useful Life Changes variance account:
    - CR 1508 Other Regulatory Assets, Sub-account Useful Life Changes Carrying Charges
    - DR 6035 Other Interest Expense

DEFERRAL AND VARIANCE ACCOUNTS

Toronto Hydro utilizes deferral and variance accounts ("DVA") in accordance with the Accounting Procedures Handbook ("APH"), and other directions issued by the OEB from time to time. This schedule summarizes Toronto Hydro's DVA balances as detailed in the continuity scheduled in Exhibit 9, Tab 2, and provides a detailed description of the accounts proposed for disposition in this application through rate riders as presented in Exhibit 9, Tab 3.[1] The evidence also identifies the new Group 2 accounts that Toronto Hydro proposes to establish for the 2025-2029 rate term,[2] in addition to the accounts the utility proposes to continue in the next period.

1. SUMMARY OF DVA BALANCES

A detailed continuity of account balances in the format provided by the OEB, including carrying costs, is presented in Exhibit 9, Tab 2, Schedule 1. Table 1 below summarizes the principal balances and carrying charges as of December 31, 2022, notes which accounts Toronto Hydro is putting forward for disposition in this application, and identifies which accounts the utility proposes to continue in the 2025-2029 rate period.

[1] Appendix B to this schedule provides the 2020-2024 Draft Accounting Orders approved in the last rebasing application (EB-2018-0165, Draft Rate Order, Schedule 18 (January 21, 2020)).
[2] Toronto Hydro proposes to establish four new Group 2 DVA accounts for the 2025-2029 rate period. Please refer to section 9 of this schedule for more information about these accounts.

Table 1: Summary of DVA Balances ($ Millions)

	Principal Balance as of Dec 31, 2022	Carrying Charge Balance as of Dec 31, 2022	Balances as of Dec 31, 2022	Proposed for Disposition (Yes/No)	To Be Continued (Yes/No)
Group 1 Accounts					
Retail Settlement Variance Account ("RSVA")[3]	165.6	2.8	168.3	No	Yes
Disposition and Recovery/Refund of Regulatory Balances ("RARA")	(7.3)	(2.0)	(9.4)	No	Yes
Smart Meter Entity Charge	(2.6)	0	(2.6)	No	Yes
Group 2 Accounts					
Capital-Related Revenue Requirement ("CRRRVA")[4]	(74.4)	(5.3)	(79.7)	No	No
Customer Choice Initiative Costs	0.1	0	0.1	Yes	No
Excess Expansion Deposits	(7.2)	(0.1)	(7.2)	Yes	Yes
Externally Driven Capital Variance Account ("EDCVA")	(0.3)	0	(0.3)	Yes	No[5]
Gain on Sale of Properties	1.5	0	1.5	Yes	Yes
Impact for USGAAP Deferral Account	(28.8)	0	(28.8)	Yes	Yes
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	0	0	0	No	Yes
PILs and Tax Variances – CCA Changes[6]	(11.6)	(0.4)	(12.0)	Yes	Yes
THESL Wireless Attachment Costs & Revenues	(1.7)	0	(1.7)	Yes	Yes
Wireline Pole Attachment Revenue Variance	1.1	0	1.1	Yes	No

[3] Includes Account 1588 – Power ($RSVA_{Power}$) and Account 1589 Global Adjustment ($RSVA_{GA}$)
[4] Balance relates to 2015-2019 activity which was approved for clearance in 2020 CIR.
[5] Toronto Hydro proposes to track that types of variances that are currently captured in the EDCVA in the new the Demand Related Variance Account ("DRVA"). Please refer to section 9.2 for further details.
[6] Balance relates to 2015-2019 activity which was approved for clearance in 2020 CIR.

	Principal Balance as of Dec 31, 2022	Carrying Charge Balance as of Dec 31, 2022	Balances as of Dec 31, 2022	Proposed for Disposition (Yes/No)	To Be Continued (Yes/No)
Renewable Generation Connection Funding Adder Deferral Account – Provincial Rate Protection Payment Variances	(3.0)	0	(3.0)	Yes	Yes
Local Initiatives Program Costs	0	0	0	No	Yes
Lost Revenue Adjustment Mechanism ("LRAM") Variance Account ("LRAMVA")	0	0	0	Yes	Yes
Gains on Sale of Properties related to the Operating Centres Consolidation Program ("OCCP")	0	0	0	Yes	Yes
Useful Life Changes	0	0	0	Yes	No
Ultra-Low Overnight ("ULO") Implementation Costs	0	0	0	Yes	No
Green Button Initiative Costs	0	0	0	Yes	No
50/60 Eglinton Proceeds of Sale Deferral Account[7]	0	0	0	Yes	Yes
Carillion Insolvency Payments Receivable Account	0	0	0	No	Yes
Getting Ontario Connected Act Variance Account	0	0	0	Yes	Yes
Total Balance	**31.2**	**(5.1)**	**26.1**		

Toronto Hydro expects the following accounts to have balances in 2024 or beyond, as outlined Summary of Proposed DVA dispositions:

1. 1568 – subaccount - LRAM Variance Account ("LRAMVA")
2. 1508 – subaccount – Gains on Sale of Properties related to the OCCP
3. 1508 – subaccount – Useful Life Changes
4. 1508 – subaccount – Ultra-Low Overnight Rate Costs

[7] Toronto Hydro seeks approval to create of this deferral account to capture and dispose additional proceeds received from the sale of 50/60 Eglinton. Please refer to section 9.4 for more information.

5. 1508 – subaccount – Green Button Initiative Costs
6. 1508 – subaccount – 50/60 Eglinton Proceeds of Sale Deferral Account
7. 1508 – subaccount – Getting Ontario Connected Act Variance Account
8. Account 1588 – Power ($RSVA_{Power}$) and Account 1589 Global Adjustment ($RSVA_{GA}$) Enhancement Model Changes

1.1 Group 1 Accounts

Below is a complete list of Toronto Hydro's Group 1 accounts:

- RSVAs includes the following OEB Accounts:
    - 1580 – Wholesale Market Service Charges ($RSVA_{WMS}$)
    - 1584 – Retail Transmission Network Charge ($RSVA_{NW}$)
    - 1586 – Retail Transmission Connection Charge ($RSVA_{CN}$)
    - 1588 – Power ($RSVA_{Power}$)
    - 1589 – Global Adjustment ($RSVA_{GA}$)
    - 1550 – Low Voltage Variance Account
- 1595—RARA: Disposition and Recovery/Refund of Regulatory Balances contains residual amounts related to clearance of DVAs previously approved by the OEB for recovery through rate riders
- 1551 – Smart Metering Entity ("SME") Charge

The OEB's Chapter 2 Filing Requirements from December 15, 2022 require all distributors to complete the GA Analysis Workform for each year that has not previously been approved by the OEB for disposition. This information can be found in Exhibit 9, Tab 2, Schedule 2.

With respect to Global Adjustment ("GA") charges, Toronto Hydro confirms that Independent Electricity System Operator ("IESO") GA charges are prorated into Regulated

Price Plan ("RPP") and non-RPP amounts. Values in the RSVA Global Adjustment account 1589 reflect the non-RPP portions only.

1.2 Group 2 Accounts (Other Regulatory Asset)

Below is a complete list of Toronto Hydro's Group 2 (Other Regulatory Asset) accounts.

- 1508 – subaccount - Capital Related Revenue Requirement ("CRRRVA")
- 1508 – subaccount - Customer Choice Initiative
- 1508 – subaccount - Excess Expansion Deposits
- 1508 – subaccount - Externally Driven Capital Variance Account ("EDCVA")
- 1508 – subaccount - Gain on Sale 2020 Decision (Gain on Sale of Properties)
- 1508 – subaccount - Impact for USGAAP Approval
- 1522 – Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges
- 1592 – PILs and Tax Variances – Capital Cost Allowance ("CCA") Changes
- 1508 – subaccount – THESL Wireless Attachments Costs and Revenues
- 1508 – subaccount - Wireline Pole Attachment Revenue Variance
- 1533 – Renewable Generation Connection Funding Adder Deferral Account, sub account – Provincial Rate Protection Payment Variances
- 1508 – subaccount - Local Initiatives Program
- 1568 – subaccount - LRAM Variance Account ("LRAMVA")
- 1508 – subaccount – Gain on sale of Properties related to OCCP Bonus Payment (variable consideration)
- 1508 – subaccount - Useful Life Changes
- 1508 - subaccount - Ultra-Low Overnight Rate Costs
- 1508 – subaccount - Green Button Initiative Costs
- 1508 – subaccount - 50/60 Eglinton Bonus Payment

- 1508 – subaccount - Carillion Insolvency Payments Receivable Account
- 1508 – subaccount – Getting Ontario Connected Act (GOCA) Variance Account

2. CARRYING CHARGES

Toronto Hydro applied carrying charges to specific accounts using the OEB's prescribed interest rates summarized in Table 2 below. For the periods after 2023 Q3, Toronto Hydro applied the 2023 Q3 as a forecast. Toronto Hydro intends to update these rates for the actual approved rates at the time of disposition of these accounts.

Table 2: Interest on Carrying charges

OEB Interest Rates Applied Calculation of Carrying Charges			
Quarter	Annual %	Quarter	Annual %
Q1 2019	2.45%	Q3 2021	0.57%
Q2 2019	2.18%	Q4 2021	0.57%
Q3 2019	2.18%	Q1 2022	0.57%
Q4 2019	2.18%	Q2 2022	1.02%
Q1 2020	2.18%	Q3 2022	2.20%
Q2 2020	2.18%	Q4 2022	3.87%
Q3 2020	0.57%	Q1 2023	4.73%
Q4 2020	0.57%	Q2 2023	4.98%
Q1 2021	0.57%	Q3 2023	4.98%
Q2 2021	0.57%		

3. PLANNED DISPOSITION OF REGULATORY ASSETS

The Report of the Board on Electricity Distributors Deferral and Variance Account Review Initiative ("EDDVAR") indicates "at the time of rebasing, all accounts should be reviewed and disposed of unless otherwise justified by the distributor or as required by a specific OEB

decision or guideline."[8] To that end, the Chapter 2 Filing Requirements specify what information distributors must file with respect to DVA reviews and dispositions. This information is provided in the sections that follow.

In section 4 of this schedule, Toronto Hydro sets out the accounts it proposes to clear beginning January 1, 2025, and in section 7, the utility identifies the proposed recovery method for each account. The amounts proposed for clearance are aligned with the balances reflected in the audited financial statements for the fiscal year ended December 31, 2022, and also include forecasted principal activity and carrying costs calculated to December 2024. Continuity schedules for all accounts proposed for disposition are provided in Exhibit 9, Tab 2, Schedule 1.

4. REGULATORY ASSET ACCOUNTS PROPOSED FOR DISPOSTION

4.1 Account 1508 - subaccount - Customer Choice Initiative Costs

On September 8, 2020, the OEB adopted final amendments (EB-2020-0152) to the Standard Supply Service Code ("SSSC"), effective October 13, 2020, which enabled electricity consumers on the Regulated Price Plan to opt out of time-of-use prices and to elect instead to be charged on the basis of tiered pricing. In response to comments on the proposed amendments, the OEB approved the establishment of a generic deferral account in which licensed, rate-regulated distributors could record their costs associated with implementing the customer choice initiative.

To comply with the customer choice initiative, Toronto Hydro implemented a complex solution requiring configuration and coding changes to the following: (1) the Customer Information System ("CIS") to automate the billing for the new pricing option, the (2)

[8] EB-2008-0046.

Customer Self-Service portal to enable customer opt-ins/opt-outs for different pricing options, and (3) development of an online calculator to provide customers insight on future bill amounts based on each customer's billing history.

The amount proposed for clearance is $0.6 million debit (recovery) from customers, based on the cumulative capital revenue requirement associated with these expenditures as of December 31, 2024, at the time of rebasing. Table 3 below shows the revenue requirement calculation.

Table 3: Revenue Requirement for Customer Choice Initiative ($ Millions)

Revenue Requirement Calculation	Actual			Forecast		Total
	2020	2021	2022	2023	2024	
Return on Equity		0.0	0.0	0.0	0.0	0.1
Interest	-	0.0	0.0	0.0	0.0	0.0
Depreciation	-	0.0	0.2	0.2	0.2	0.5
PILS	-	(0.3)	0.1	0.1	0.1	(0.1)
Revenue Requirement	**-**	**(0.2)**	**0.3**	**0.3**	**0.2**	**0.6**

4.2 Account 1508 - subaccount - Excess Expansion Deposits

In the 2020-2024 Rate Application (EB-2018-0165), the OEB approved the establishment of an Excess Expansion Deposits deferral account.[9] Pursuant to the Distribution System Code ("DSC"), Toronto Hydro may collect an expansion deposit from a customer who wants to connect to the distribution system, if Toronto Hydro must expand its system (i.e. construct new facilities or increase the capacity of existing facilities) in order to connect the customer. During the Customer Connection Horizon specified in the Offer-to-Connect ("OTC") contract, the utility is obliged to annually return the expansion deposit to the customer in proportion

[9] EB-2018-0165, Decision and Order (December 19, 2019) at page 185

to the actual connections (for residential developments) or actual demand (for commercial and industrial developments) materialized in the year. If the forecasted connections/demand do not materialize during the specified Customer Connection Horizon, utilities retain the excess portion of the expansion deposit. Although section 3.2.23 of the DSC provides that the utility does not have to return any remaining portions of the expansion deposit to the customer beyond the Customer Connection Horizon, Toronto Hydro proposed in the last rate application that the balance be returned to the ratepayers in order to protect their interests.

Table 4 presents the excess expansion deposit balances through to December 31, 2023 including carrying charges. Toronto Hydro requests the continuation of this account in the 2025-2029 rate period.

Table 4: Excess Expansion Deposits ($ Millions)

	Principal Balance as at Dec 31	Carrying Charge Balance	Total Balance as at Dec 31
2020	(14.0)	(0.5)	(14.5)
2021	(6.3)	0.1	(6.2)
2022	(7.2)	0.0	(7.2)
2023	(7.7)	(0.4)	(8.1)

4.3 Account 1508 - subaccount - Externally Driven Capital Variance Account ("EDCVA")

In the 2015-2019 Rate Application, Toronto Hydro requested (and the OEB approved) an Externally Driven Capital Variance Account to capture differences between the forecasted revenue requirement amounts included in rates related to capital expenditure for third party initiated relocation and expansion projects, and the actual revenue requirement associated

with these types of projects.[10] The continuation of this account was approved by the OEB in the 2020-2024 Rate Application, with a modification to include variances from derecognition related to the projects tracked in the account.[11] Variances tracked in this account flow from capital work undertaken as part of the Externally Initiated Plant Relocations and Expansions program ("Externally Driven Capital").[12]

Table 5 outlines the variances between the planned capital expenditures that formed the basis of the revenue requirement approved to be collected through rates in the current 2020-2024 period, and the actual and forecasted capital expenditures over the current rate period related to Externally Driven Capital.

Table 5: 2020-2024 Externally Driven Capital Expenditure ("CAPEX") Variances ($ Millions)

	Actual			Forecast		Total
	2020	2021	2022	2023	2024	
Planned CAPEX	11.4	20.8	4.6	4.7	4.5	46.1
Actual/Forecast CAPEX	8.7	9.3	12.9	15.2	8.2	54.3
Variance	**(2.7)**	**(11.5)**	**8.3**	**10.5**	**3.7**	**8.2**

Table 6 below presents the variances between the planned in-service additions that formed the basis of the revenue requirement approved to be collected through rates in the current 2020-2024 period, and actual and forecasted in-service additions over the current rate period related to work as part of the Externally Initiated Plant Relocations and Expansions program. Table 7 outlines the Revenue Requirement impacts resulting from the variances in Table 6.

[10] EB-2014-0116, Decision and Order (December 29, 2015) at page 50.
[11] EB-2018-0165, Decision and Order (December 19, 2019) at page 196.
[12] Exhibit 2B, Section E5.2.

Table 6: 2020-2024 Externally Driven Capital In-Service Additions ("ISA") Variances ($ Millions)

	Actual			Forecast		Total
	2020	2021	2022	2023	2024	
Planned ISA	11.4	20.8	4.6	4.7	4.5	46.1
Actual/Forecast ISAs	11.3	9.6	9.1	23.7	11.7	65.5
In-Service Additions Variance	**(0.0)**	**(11.2)**	**4.5**	**19.1**	**7.1**	**19.4**

Table 7: 2020-2024 Externally Driven Capital Revenue Requirement ($ Millions)

Revenue Requirement Calculation	Actual			Forecast		Total
	2020	2021	2022	2023	2024	
Rate Base	0.3	(5.2)	(9.0)	1.8	14.2	N/A
Return on equity	0.0	(0.2)	(0.4)	0.1	0.5	0.1
Interest	0.0	(0.1)	(0.2)	0.1	0.3	0.0
Depreciation	(0.6)	(0.1)	0.7	1.2	0.4	1.6
PILs	(0.2)	0.4	0.4	(0.4)	(0.3)	(0.1)
Revenue Requirement	**(0.8)**	**0.0**	**0.4**	**1.0**	**0.8**	**1.6**

Due to continued growth and infrastructure development in the city, there were a number of major projects that were either not anticipated, or were larger and more complex than anticipated, including the Port Lands Flood Protection Project, the John Street Revitalization, and the Wellington Street Revitalization. Incremental costs with respect to these projects are due to factors outside of Toronto Hydro's control, namely (i) expanded project scopes driven by third-party requirements, and (ii) significant inflationary pressures.[13]

With the total number of transit and infrastructure projects expected to increase in the 2025-2029 rate period, Toronto Hydro continues to need a high-degree of flexibility to

[13] Please see Exhibit 1B, Tab 3, Schedule 3 at pages 12-13.

manage Externally Driven Capital.[14] However, as noted below, Toronto Hydro seeks approval to record variances related to Externally Driven Capital, along with variances in other demand-related expenditures such as Customer Connections, as part of a new consolidated Demand-Related Variance Account ("DRVA"). For more information about the proposed DRVA, please refer to Exhibit 1B, Tab 2, Schedule 1, section 3.2.3.

4.4 Account 1508 - subaccount - Gain on Sale of Property Variance Account

In Toronto Hydro's 2020-2024 Rate Application (EB-2018-0165), the OEB established an account to track the variance related to gains on the disposition of utility property.[15]

Toronto Hydro owns a small number of properties with the potential to be designated as surplus, to be disposed of if the property is not suitable for future grid expansion.[16] In 2021, Toronto Hydro sold one of these properties resulting in an actual net gain of $1.6 million. Table 8 shows the calculation for the symmetrical difference between the $1.0 million gain embedded in rates and the actual gain net of tax for the sale of the property mentioned above. The amount proposed for clearance is a $3.7 million debit (recovery) from customers. Toronto Hydro requests the continuation of this account in the 2025-2029 rate period.

Table 8: Gain on Sale of Property Variance ($ Millions)

Gain on Sale (excluding carrying charges)	Actual			Forecast		Total
	2020	2021	2022	2023	2024	
Gain on Sale embedded in rates	1.0	1.0	1.0	1.0	1.0	5.0
Actual/Forecast Gain on Sale	0.0	1.6	0.0	0.0	0.0	1.6
Variance	**1.0**	**(0.6)**	**1.0**	**1.0**	**1.0**	**3.4**
Carrying Charges	**0.0**	**0.0**	**0.0**	**0.1**	**0.2**	**0.3**

[14] Exhibit 2B, Section E5.2.4.2.
[15] EB-2018-0165, Decision and Order (December 19, 2019) at page 2 and at page 188;
[16] For more details, please refer to Exhibit 2B, Section D6 at page 5

Gain on Sale (excluding carrying charges)	Actual			Forecast		Total
	2020	2021	2022	2023	2024	
Total Proposed for Clearance						**3.7**

4.5 Account 1508 - subaccount - Impact for USGAAP Deferral Account

This account captures the impact of the change in accounting for Other Pension and Employment Benefits ("OPEB") as a result of transitioning to a different accounting framework. No carrying charges were applied to the balance in this account.

In its Decision and Order (EB 2012-0079) issued on June 7, 2012, the OEB approved the use of account 1508 to capture the difference related to OPEB arising from transitioning from Canadian Generally Accepted Accounting Principles ("CGAAP") to United States GAAP ("US GAAP") on January 1, 2012. In its Decision and Order (EB 2014-0116) issued on December 29, 2015, the OEB accepted Toronto Hydro's request to continue using this deferral account to capture the impact of accounting differences related to OPEB arising from its transition from US GAAP to International Financial Reporting Standards ("IFRS") on January 1, 2015. The differences relate mainly to changes in the accounting treatment of actuarial gains and losses arising from updated actuarial assumptions and experience adjustments being recognized in other comprehensive income, but never amortized into profit or loss under IFRS.

On September 14, 2017, the OEB issued its final report on the *Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs*,[17] stating that utilities may propose disposition of this particular account if the gains and losses that are tracked in this account do not substantially offset over time.

[17] EB-2015-0040, Report of the Board, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (September 14, 2017).

In the 2020-2024 Rate Application, the OEB approved the use of the corridor approach to determine the balance in the account for disposition.[18] Under the corridor approach, actuarial gains and losses, to the extent that they fall outside a corridor of 10% of the higher of the plan asset or benefit obligation value, would get amortized to rates over a period not exceeding the expected average remaining service life ("EARSL") of the plan participants. As at December 31, 2018, the balance in this account was $48.1 million (debit balance). Of this balance, the OEB approved the recovery of $6.4 million, calculated under the corridor approach, over a 10-month period commencing on March 1, 2020.

As at December 31, 2022, the balance in this account was $28.8 million (credit balance). Toronto Hydro is seeking disposition of a portion of this balance, specifically $1.7 million, determined using the corridor approach, consistent with the methodology approved in the 2020-2024 Rate Application.

Toronto Hydro expects that the OPEB plans will continue to experience actuarial gains or losses as a result of changes in actuarial assumptions, particularly the discount rate, in the future. To record these expected changes, Toronto Hydro requests the continuation of this account in the 2025-2029 rate period.

4.6 Account 1592 – PILs and Tax Variances – CCA Changes

In a letter to all rate-regulated electricity and natural gas utilities dated July 25, 2019, the OEB established a separate sub-account of Account 1592 - PILs and Tax Variances - CCA Changes specifically for the purposes of tracking the impact of changes in capital cost allowance ("CCA") rules.[19] Pursuant to this letter, the OEB directed electricity distributors to

[18] EB-2018-0165, Decision and Order (December 19, 2019) at page 182.
[19] Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance (July 25, 2019).

use this sub-account to record the impact of the Bill C-97 CCA rule changes as well as any future CCA changes instituted by relevant regulatory or taxation bodies.

As discussed in Exhibit 6, Tab 2, Schedule 1, Toronto Hydro confirms that the revenue requirement impact of the Accelerated CCA rules introduced by Bill C-97 ("Accelerated CCA rule") were reflected in the approved 2020-2024 rates, and the entire 2018 and forecasted 2019 revenue requirement impact of the Accelerated CCA rule changes was recorded within the new sub-account of Account 1592. The impact recorded in the new sub-account of Account 1592 was approved for disposition starting on January 1, 2023, and was trued-up as part of the application for rates and other charges effective January 1, 2023.[20] Any forecasting variances over 2020-2024 period will be captured in the Capital Related Revenue Requirement Variance Account (CRRRVA) (as discussed in paragraph 5.2 in this Schedule).

As discussed in in Exhibit 6, Tab 2, Schedule 1, in Bill C-19, a new rule was introduced and received Royal Assent in June 2022, where immediate expensing would be available for "eligible property" acquired by a Canadian Controlled Private Corporation ("CCPC") on or after April 19, 2021, and that becomes available for use before January 1, 2024, up to a maximum amount of $1.5 million per taxation year. CCA deducted under this rule is allowed as long as the total CCA deduction does not exceed the capital cost of the eligible property. The PILs impact on the revenue requirement of these new immediate expensing rules to equal $0.54 million (i.e. $1.5 million x income tax rate of 26.5%, then divided by the gross-up factor (1 - 26.5%) per taxation year from 2021 to 2023. The total impact on those years is $1.6 million and $0.2 million of carrying charges is expected to be calculated on the balance by December 31, 2024. Toronto Hydro seeks clearance of a $1.8 million credit

[20] EB-2022-0065, Decision and Rate Order (December 8, 2022) at page 15.

balance. Toronto Hydro requests the continuation of this account in the 2025-2029 rate period.

4.7 Account 1508 - subaccount - Wireless Attachments

This account tracks costs and revenues associated with wireless pole attachments. Revenues recorded in this deferral account are the actual revenues received through the negotiated contracts with wireless carriers, as well as the one-time revenues collected directly to cover the one-time costs, such as any make-ready costs incurred by Toronto Hydro to accommodate an attachment on its pole. Costs recorded in the deferral account are one-time costs incurred. Table 9 shows the details of the actual and forecasted costs and revenues included in this account. Toronto Hydro seeks clearance of a $3.6 million credit balance. Toronto Hydro requests the continuation of this account in the 2025-2029 rate period.

Table 9: Wireless Attachment Costs and Revenues ($ Thousands)

	Actual			Forecast		Total
	2020	**2021**	**2022**	**2023**	**2024**	
Wireless Attachment Costs	253.2	130.1	200.3	42.4	-	626.1
Wireless Attachments Revenues	(823.5)	(832.8)	(648.1)	(802.2)	(846.9)	(3,953.4)
Wireless Attachment Costs – carrying charges	(0.4)	1.7	9.5	30.3	31.2	72.2
Wireless Attachments Revenues – carrying charges	5.7	(6.4)	(34.6)	(129.5)	(170.5)	(335.4)
Total	**(564.9)**	**(707.4)**	**(472.9)**	**(859.0)**	**(986.2)**	**(3,590.5)**

4.8 Account 1508 - subaccount - Wireline Pole Attachment Revenue Variance Account

On December 16, 2021, the OEB issued an Order (EB-2021-0302) establishing a new pole attachment charge and methodology starting in 2022,[21] and directed distributors to record variances between the newly approved OEB charge and the charge embedded in their underlying rates. This account tracks the difference between the wireline pole attachment rate ($44.50) approved by the OEB on an interim basis in the utility's 2021 Rate Application (EB-2020-0288) and the charge approved by the OEB in EB-2021-0302 ($34.76).

Table 10: Wireline Pole Attachment Rate Variances

Wireline Pole Attachment	Actual			Forecast		Total
	2020	2021	2022	2023	2024	
Number of Attachment Embedded in Rate (a)	113,630	113,630	113,630	113,630	113,630	
Pole Attachment Charge Embedded in Rates[1] (b)	$44.50	$44.50	$44.50	$44.50	$44.50	
Wireline Pole Attachment revenue embedded in Rates ($ Millions) (c = a x b)	$5.1	$5.1	$5.1	$5.1	$5.1	$25.5
Actual/Forecast Pole Attachment Charge[1] (d)	$44.50	$44.50	$34.76	$34.76	$34.76	
Actual/Forecast Wireline Pole Attachment revenue embedded in Rates ($ Millions) (e = a x d)	$5.1	$5.1	$4.0	$4.0	$4.0	$22.2
Variance ($ Millions) (c – e)			**$1.1**	**$1.1**	**$1.1**	**$3.3**
Carrying Charges ($ Millions)			**$0**	**$0.1**	**$0.1**	**$0.2**
Total Forecast for Clearance ($ Millions)						**$3.5**

4.9 Account 1533 – Renewable Generation Connection Funding Adder Deferral Account, Sub-account Provincial Rate Protection Payment Variances

In its 2015-2019 rate application (EB-2014-0116), Toronto Hydro requested (and the OEB approved) the Renewable Enabling Investments Provincial Rate Protection Recovery Variance Account.[22] The continuation of this account was approved by the OEB in the 2020-

[21] EB-2021-0302, Decision and Order (December 16, 2021) at page 3.
[22] EB-2014-0116, Decision and Order (December 29, 2015) at page 51.

2024 Rate Application.[23] This account tracks the difference between the 2020-2024 revenue requirement associated with Renewable Enabling Improvements ("REI") investments funded through Provincial Rate Protection and collected through payments from the IESO,[24] and the revenue requirement associated with actual REI investments over this period as detailed in Exhibit 2A, Tab 5, Schedule 1.

To address the distribution level constraints, Toronto Hydro planned to undertake a number of REI investments over the 2020-2024 period as part of its Generation Protection, Monitoring and Control ("GPMC") program (Exhibit 2B, Section E5.5)[25] and its Non-Wires Solutions program (formerly Energy Storage Systems).[26] However, due to the following changes and challenges, some of the planned expenditures did not materialize:

- **Generation Protection, Monitoring and Control**: Capital expenditures are forecast to be 18 percent lower than planned primarily due to a slower rate of REI projects over the current rate period than forecasted and technical challenges in undertaking station bus-tie reactors in co-ordination with the transmitter.
- **Energy Storage**: As detailed in Exhibit 2B, Section E7.2, capital expenditures are forecast to be 79 percent lower than planned due to challenges in finding a cost-effective site for an ESS installation and supply chain constraints related to the procurement of ESS technology.

As a result of the factors summarized above, Toronto Hydro forecasts the balance in this account to be $7.4 million (credit) at the end of 2024. Table 11 below presents the details:

[23] EB-2018-0165, Decision and Order (December 19, 2019) at pages 118-119.
[24] Exhibit 2A, Tab 6, Schedule 1
[25] EB-2018-0165, Exhibit 2B, Section E5.5
[26] EB-2018-0165, Exhibit 2B, Section E7.2

Table 11: REI Variance Account ($ Millions)

	Actual			Forecast		Total
	2020	2021	2022	2023	2024	
Approved Revenue Requirement	1.5	2.2	2.6	3.0	3.3	**12.6**
Actual/Forecast Revenue Requirement	0.8	1.3	1.3	1.3	0.6	**5.3**
Variance Account Balance	**(0.8)**	**(0.9)**	**(1.3)**	**(1.7)**	**(2.6)**	**(7.4)**

Toronto Hydro requests the continuation of this variance account in the 2025-2029 rate period to track variances related to REI investments as outlined in Exhibit 2A, Tab 5, Schedule 1.

4.10 Account 1568 – Lost Revenue Adjustment Mechanism ("LRAM") Variance Account ("LRAMVA")

In the 2023 Rate Application (EB-2022-0065), the OEB approved the deferral of Toronto Hydro's LRAMVA balances until its next rebasing application, in order to enable the utility to propose a modified LRAMVA threshold to account for the discontinuation of Conservation First Framework programs. In this application, Toronto Hydro seeks clearance of the 2020-2022 LRAMVA balances for the debit balance of $5.6 million.[27] Evidence supporting this request is outlined in Exhibit 9, Tab 2, Schedule 3. Toronto Hydro requests the continuation of this account in the 2025-2029 rate period.

4.11 Account 1508 - subaccount - Gains on Sale of Properties related to the Operating Centres Consolidation Program ("OCCP")

In 2018, Toronto Hydro disposed of its property at 5800 Yonge, resulting in a giveback to customers in the current 2020-2024 rate period of $73.7 million based on the fair market

[27] Toronto Hydro notes that the balances in the LRAMVA were not reported in RRR or AFS filings because the utility did not have sufficient information at the time to estimate the balances in the account.

value payment that it received for this property.[28] The gain on sale of 5800 Yonge was recorded in Account 1508 subaccount Variance Account for Gains on Sale of Properties Related to the Operating Centres Consolidation Program ("OCCP"), established by the OEB in the 2015-2019 rate application.[29]

In addition to the fair market value of this property, a variable consideration ("bonus payment") was incorporated into the Agreement of Purchase and Sale ("APS") based on the potential increase in gross floor area as a result of zoning bylaw applications submitted by the purchaser. The increase in gross floor area was achieved and Toronto Hydro intends to return this variable consideration (bonus payment) to ratepayers to offset rate pressures in the 2025-2029 period, through the OCCP variance account. The amount proposed for clearance is a $33.4 million credit to customers.

Toronto Hydro requests the continuation of this variance account in the 2025-2029 period as there may be further variable consideration available to the utility under the APS.

4.12 Account 1508 - subaccount - Useful Life Changes Variance Account

In accordance with the OEB's decision in the 2020-2024 Rate Application (EB-2018-0165), Toronto Hydro completed a Depreciation Study which is filed at Exhibit 2A, Tab 2, Schedule 1, Appendix D. Toronto Hydro adopted the changes in asset useful lives resulting from the study as of January 1, 2023. In anticipation of an overall net decrease to its depreciation expense, Toronto Hydro proposed and the OEB approved as part of the 2023 Rate Application (EB-2022-0065) a new variance account to track depreciation impacts related to expected changes to the financial useful lives of its capital assets. The OEB determined that

[28] EB-2018-0165, Draft Rate Order (January 28, 2020) at page 31.
[29] EB-2014-0116, Decision and Rate Order (March 1, 2016), Appendix E at pages 6-8.

it was appropriate to establish a new account to the benefit of customers, and "*commend[ed] Toronto Hydro for bringing forward this proposal during its Custom IR term, such that the new account may be effective January 1, 2023.*" In approving this account, the OEB accepted Toronto Hydro's offer to address the merits of different calculation approaches in its rebasing application, and approved a second account to record carrying charges on the Useful Life Change variance account. The OEB stated that the second account was being established on a provisional basis, to enable the consideration of carrying charges on the variance account based on the calculation approach approved at rebasing.[30]

Appendix B to this schedule details the calculation of the change in depreciation based on: (i) Toronto Hydro's proposed revenue requirement impact approach and (ii) the methodology of Account 1576 – CGAAP Accounting Changes, which OEB Staff proposed as an alternative in EB-2022-0065. Table 12 below presents a summary comparing both approaches:

Table 12: Comparison of Calculation Approaches for the Useful Life Changes Variance Account ($ Millions)

	2024 DVA Balance
Approach 1: Toronto Hydro's proposed approach	(136.5)
Approach 2: Account 1576 approach	(128.9)

As presented in Appendix B, Toronto Hydro's proposed methodology captures all the capital related revenue requirement impacts (i.e. return on equity, deemed interest, depreciation, and PILs) as a result of the change in depreciation in 2023 and 2024. OEB staff's proposed Account 1576 approach captures the net change in property, plant, and equipment ("PP&E")

[30] EB-2022-0065, Decision and Order (December 8, 2022) at pages 21-22.

and a return on rate base component calculated based on the number of years of rate rider disposition. The key difference is the consideration of PILs impacts in Toronto Hydro's proposed approach, as well as the application of carrying charges to the balance in the account, both of which drive a higher balance to the benefit of customers. For these reasons, the utility proposes to calculate the impact of the useful life changes per the first approach in the table above which yields a balance for clearance of $136.5 million (credit).

4.13 Account 1508 - subaccount - Ultra-Low Overnight Rate Costs

On October 18, 2022 (EB-2022-0160), the OEB proposed amendments to the Standard Supply Service Code and the Regulated Price Plan ("RPP") Manual to implement a new optional ultra-low overnight ("ULO") price plan for electricity consumers on the RPP. The Notice stated that the OEB would allow distributors to track the revenue requirement impacts of their material costs of implementing the ULO option in a deferral account.[31] On March 2, 2023, the OEB issued Accounting Order (001-2023) authorizing electricity distributors to establish two sub-accounts to Account 1508 – Other Regulatory Assets to track ULO implementation costs and relevant carrying charges.[32]

In order to implement the ULO price plan option for customers, Toronto Hydro expects to incur and capitalize by the end of the 2020-2024 period approximately $2 million in capital expenditures. The project involved a highly complex solution with a compressed timeline including configuration and coding changes to the utility's (1) Customer Information System ("CIS") to automate a new billing model with new rates configuration, (2) Customer Self-Service portal to enable customers to opt in to or opt out of the new pricing plan, (3) online

[31] EB-2022-0160, Ontario Energy Board, Notice of Proposal to Amend the Standard Supply Service Code and the Regulated Price Plan Manual (October 18, 2022) at page 6.
[32] EB-2022-0160, Ontario Energy Board, Accounting Order (001-2023) for the Establishment of a Deferral Account to Record Impacts Arising from Implementing the Ultra-Low Overnight (ULO) Regulated Price Plan Option (March 2, 2023).

calculator to provide customers billing estimates between different pricing options, and (4) meter data management systems to integrate customer usage data into the solution.

The amount proposed for clearance is based on the expected cumulative capital revenue requirement associated with these expenditures as of December 31, 2024, at the time of rebasing. Table 13 below presents the revenue requirement calculation.

Table 13: Revenue Requirement for Ultra-Low Overnight Rate Costs ($ Millions)

Revenue Requirement Calculation	Actual			Forecast		Total
	2020	2021	2022	2023	2024	
Return on Equity	-	-	-	0.0	0.1	0.1
Interest	-	-	-	0.0	0.0	0.1
Depreciation	-	-	-	0.0	0.4	0.4
PILS	-	-	-	(0.7)	0.2	(0.5)
Revenue Requirement	**-**	**-**	**-**	**(0.6)**	**0.7**	**0.1**

4.14 Account 1508 - subaccount - Green Button Initiative Costs

As noted in accounting order 003-202 issued on November 1, 2021 (EB-2021-0183), the OEB established a generic deferral account[33] for rate regulated distributors to record the incremental costs directly attributable to the implementation of the Green Button initiative, in a manner that accords with the requirements set out in Ontario Regulation 633/21 made under the *Electricity Act, 1998*.[34]

In order to implement the Green Button initiative, Toronto Hydro expects to incur and capitalize by the end of the 2020-2024 period approximately $1.1 million in capital expenditures for a solution that requires in-depth coding and configuration changes to the utility's (1) Customer Self-Service Portal to enable the registration process for customers and

[33] EB-2021-0183, OEB Letter re Green Button Implementation (October 12, 2021) at page 4.
[34] SO 1998, c 15, Sched A.

third-party energy consultants, and (2) Customer Information System ("CIS") and meter data management systems to extract customer electricity consumption data and to integrate with third-party data custodian system. The amount proposed for clearance is based on the expected cumulative capital revenue requirement associated with these expenditures as of December 31, 2024, at the time of rebasing. Table 14 below presents the revenue requirement calculation.

Table 14: Revenue Requirement for Green Button Initiative ($ Millions)

Revenue Requirement Calculation	Actual			Forecast		Total
	2020	2021	2022	2023	2024	
Return on Equity	-	-	-	-	0.0	0.0
Interest	-	-	-	-	0.0	0.0
Depreciation	-	-	-	-	0.2	0.2
PILS	-	-	-	-	(0.3)	(0.3)
Revenue Requirement	**-**	**-**	**-**	**-**	**(0.1)**	**(0.1)**

4.15 Account 1588 – Power ($RSVA_{Power}$) and Account 1589 Global Adjustment ($RSVA_{GA}$) Enhancement Model Changes

The balances within Account 1588 and Account 1589 were last approved on a final basis for year-end 2021 in Toronto Hydro's 2023 Rate Application (EB-2022-0065). In the 2024 Rate Application (EB-2023-0054), Toronto Hydro excluded the balances within Accounts 1588 and 1589 from its proposed RSVA clearances due to the need to further analyze the 2021 principal adjustment. This matter is related to the "actual" component of the 2021 principal adjustment of Account 1588 and does not impact any audited balances.

When preparing the 2024 Rate Application, the utility found that the 1588 balance was higher than usual (and above the threshold in GA Workform) and investigated the causes, finding that $5.7 million of the variance was related to reporting model enhancements. As

customer billing dates do not always align with fiscal period dates, Toronto Hydro uses a model to allocate billings into their respective periods to get a proxy for "actual" billings by period, which is used in calculating principal adjustments. In 2022, the utility enhanced the model to more accurately allocate billings to their periods. These enhancements include improved estimation logic by using actual meter data reads and improved logic to validate larger rate classes (rate classes billed on kVA load) which improve data accuracy by utilizing actual meter read data currently available in the metering systems.

The enhancements noted above were implemented in 2022, after Toronto Hydro received approval in EB-2022-0065 to dispose of the 2021-year end balances in Account 1588 and Account 1589. As part of its analysis for the 2024 Application, Toronto Hydro recalculated the 2021 Account 1588 balance using the enhanced model and found it to be higher by $5.7 million. To enable the OEB to deal with this matter efficiently and to provide Toronto Hydro additional time to assess the implications of recovering the $5.7 million (i.e. by including it in the 2022 reversal of 2021 principal adjustments), Toronto Hydro proposed to defer the review and disposition of Accounts 1588 and 1589 to this application.

Toronto Hydro hereby seeks OEB approval to clear the 2022 balances in Accounts 1588 and 1589 effective January 1, 2025, as provided in the continuity schedule at Exhibit 9, Tab 2, Schedule 1, which includes the reversal of the $5.7 million principal adjustment amount from 2021. This reversal is in line with the OEB's expectation that all principal adjustment amounts are reversed in the following year per the Global Adjustment ("GA") Analysis Workform and the February 21, 2019 Accounting Guidance.[35] Toronto Hydro submits that this request does not represent a correction of an error (per the OEB's October 31, 2019 letter regarding

[35] Accounting Procedures Handbook Update, Accounting Guidance Related to Commodity Pass-Through Accounts 1588 & 1589 (February 21, 2019) at pages 34-38.

adjustments to correct for errors after disposition) because it clearly relates to an enhancement of the model rather than an error in the utilities accounting records.[36] Nonetheless, the utility has been transparent in disclosing and explaining the matter in alignment with OEB expectations. Similarly, Toronto Hydro submits that this proposal does not represent an adjustment to an account balance that was previously approved by the OEB on a final basis, since Toronto Hydro only seeks to reverse the principal adjustment in the GA Analysis Workform according to the OEB's expectations, and does not propose to change any 2021 balances or do anything outside of normal processes. In the alternative that the OEB is inclined to view this as an adjustment, Toronto Hydro submits that it should nonetheless be approved in accordance with the February 21, 2019 Accounting Guidance and the GA Analysis Workform.

Toronto Hydro confirms that all principal adjustment amounts prior to 2021 were reversed in the following year and the utility has not made any adjustments to DVA balances that were previously approved by the OEB on a final basis. DVA balances prior to 2021 are not impacted by the above principal adjustment reversal since these have been reversed year-over-year in the Global Adjustment ("GA") Analysis Workform.

The updated balances for Accounts 1588 and 1589 clearance are reflected in the Group 1 DVA Continuity Schedule provided in Exhibit 9, Tab 2, Schedule 1 and the revised GA Analysis Workform is available in Exhibit 9, Tab 2, Schedule 2.

[36] OEB Letter Re: Adjustments to Correct for Errors in Electricity Distributor "Pass-Through" Variance Accounts After Disposition (October 31, 2019).

4.16 Account 1508 – subaccount – Getting Ontario Connected Act ("GOCA") Variance Account

On October 31, 2023, the OEB established a generic, industry-wide variance account to record incremental costs of locates resulting from the implementation of Bill 93 (*Getting Ontario Connected Act, 2022*), with an effective date of April 1, 2023.[37] As this decision was released just weeks before Toronto Hydro submitted its application to the OEB, the utility intends to file supplemental evidence to forecast the balances that it expects in this account over the current rate period.

As discussed in further detail in the Customer Operations program in Exhibit 4, Tab 2, Schedule 8, there remains a great degree of uncertainty regarding the full extent of locates-driven costs that Toronto Hydro may need to incur during the 2025-2029 rate period to achieve compliance with the legislative and regulatory requirements governing locates. For example, the Government of Ontario may introduce further legislative changes, or there may be additional material costs of coming into compliance with the performance standards set out in Ontario Regulation 87/23 made under the *Ontario Underground Infrastructure Notification System Act, 2012* ("OUINSA"),[38] which is enforced by Ontario One Call. Given these conditions, Toronto Hydro requests continuation of the GOCA account in the 2025-2029 rate period. The continuation of this account is in the best interests of ratepayers given the uncertainty that remains with respect to the locates regime in Ontario, as it allows Toronto Hydro to remain in compliance with its legal obligations under the OUINSA during the next rate term, without having to provision in its forecast of 2025-2029 rates for a higher recovery of locates costs as set out in the alternative scenario outlined in the Customer Operations program.

[37] EB-2023-0143
[38] SO 2012, c 4.

5. REGULATORY ASSET ACCOUNTS THAT ARE NOT PROPOSED FOR DISPOSTION

5.1 All RSVA Accounts except 1588 and 1589

Toronto Hydro proposed to clear most of the RSVA accounts for 2022 amounting to a $108.2 million (debit) recovery from customers as part of Toronto Hydro's 2024 Rate Application, including Account 1550 – Low Voltage Variance Account, Account 1580 – Wholesale Market Services, Account 1584 – Network, Account 1586 – Connection. As discussed above, Toronto Hydro did not request the disposition of the 2022 balances in Account 1588 – Power and Account 1589 – Global Adjustment through the 2024 Rate Application and is seeking to clear those balances through this application.

Through the discovery phase of this proceeding, Toronto Hydro intends to update the evidence to support the clearance of the RSVA accounts for the 2023 period. However, Toronto Hydro notes that it will not be proposing to dispose any residual balances in Account 1595 as any sub-accounts that have not already been approved for disposition will not meet the 2-year requirement for 2025 disposition.

5.2 Account 1508 – subaccount - Capital Related Revenue Requirement ("CRRRVA")

The Capital-Related Revenue Requirement Variance Account (CRRRVA) records the variance between the capital-related revenue requirement included in rates and the actual capital-related revenue requirement (excluding balances captured in the Externally Driven Capital Variance Account).[39] The CRRRVA is an asymmetrical account in that it only records for disposition variances that result in a credit (refund) to customers.

As noted in Exhibit 2A, Tab 1, Schedule 1, over the current rate period, Toronto Hydro's actual and forecasted in-service additions ("ISAs") are approximately 1.1 percent higher

[39] EB-2018-0165, Decision and Order (December 19, 2019) at page 193. In accordance with the OEB decision at page 43, the 2020-2024 CRRRVA includes derecognition expenses.

($33.3 million) than the planned ISAs that formed the basis of the capital-related revenue requirement approved by the OEB in setting 2020 to 2024 rates.[40]

For information purposes, Toronto Hydro notes that if this account were symmetrical, the balance would be a $48 million debit (collectible) from customers. Table 15 below provides a summary of the supporting calculation for this hypothetical scenario.

Table 15: Example of CRRRVA Calculation if the Account were Symmetrical ($ Millions)

	Actuals			Forecast		Total
	2020	**2021**	**2022**	**2023**	**2024**	
Capital-Related RR (Rate Order, Feb 12, 2020 - Table 7)	525.8	563.1	575.4	627.2	664.8	2,956.3
RR impact from the application of stretch factor to capital funding	-	(4.7)	(9.8)	(15.0)	(20.6)	(50.1)
Capital-Related RR in Approved 2020-2024 Rates	525.8	558.3	565.6	612.3	644.2	2,906.2
Sub-account 1508 - Externally Driven capital Variance Account	(0.8)	0.0	0.4	1.0	0.8	1.6
Sub-account 1508 - Customer Choice Initiatives Capital Variance Account	-	(0.2)	0.3	0.3	0.2	0.6
Sub-account 1508 - Green Button Initiative Capital Variance Account	-	-	-	-	(0.1)	(0.1)
Sub-account 1508 - Ultra-Low Overnight Rate Costs Variance Account	-	-	-	(0.6)	0.7	0.1
Sub-account 1508 - Useful Life Changes Variance Account	-	-	-	(62.4)	(68.5)	(130.9)
Other Adjustments	5.5	(0.6)	(2.9)	(5.6)	(1.5)	(5.2)
Capital-Related RR in Approved Rates eligible for CRRRVA	530.5	557.6	563.4	544.9	575.9	2,772.0
Actual Historic & Forecast Bridge Capital-Related RR	532.5	558.1	586.4	551.8	591.4	2,820.3
Sub-account 1508 - CRRRVA	**2.1**	**0.6**	**23.0**	**7.0**	**15.5**	**48.1**

Note: Rounding variances may exist

[40] Please refer to Exhibit 2A, Tab 1, Schedule 1 for more information.

Toronto Hydro proposes to discontinue this account in the 2025-2029 rate period as it has proven over the last two custom rate periods (i.e. 2015-2019 and 2020-2024) its ability to deliver multi-year capital programs within very reasonable margins of variance, as shown above. To protect customers against utility overearnings, Toronto Hydro proposes to continue the Earnings Sharing Mechanism approved in the last rate application and described below in section 5.7. Furthermore, the utility proposes to continue to tracks variances in capital expenditures that have a higher degree of sensitivity or variability due to external factors through the proposed Demand-Related Variance Account ("DRVA") outlined in section 9.2.

5.3 Account 1522 – Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges

In May 2015, the OEB commenced an industry-wide consultation on rate-regulated utility pensions and OPEBs (EB-2015-0040). The final report, entitled Regulatory Treatment of Pension and OPEB Costs and issued on September 14, 2017, established the following accounts to track the difference between the forecasted OPEB accrual amount collected in rates and the actual cash payments made, with the calculation of the carrying charges based on the cumulative differential credit balance (the cumulative accrual amount exceeds the cumulative cash payments):[41]

1) Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential;
2) Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account; and

[41] EB-2015-0040 Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (September 14, 2017) at page 21.

3) Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges.

As at December 31, 2022, there was no material balance in Account 1522, Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges.

In the last rate application, the OEB asked Toronto Hydro to gather information starting in 2020 to calculate the accrual OPEB amount based on the annual depreciation associated with its cumulative undepreciated capitalized OPEB costs in rate base.[42]

Toronto Hydro notes that while an estimate has been provided for actual depreciation, high level assumptions were necessary to arrive at the result. In-service additions in a given year typically consist of a portion of Construction Work In-Progress ("CWIP") from prior years and current year capital expenditures being placed in service. Given that OPEB costs are a component within labour costs capitalized over several programs, it cannot be tracked until placed in service posing practical limitations for identifying OPEB in CWIP related to projects that span multiple years. To address this limitation, the estimated in-service additions which are used to calculate OPEB related depreciation each year are assumed to be equal to the estimated capital expenditures associated with the OPEB accruals in that same year. While this approach calculates depreciation on a portion of current year capital expenditures in a given year that may not have yet been placed in-service, it directionally offsets the depreciation on current year in-service additions of prior year CWIP that has not been separately estimated.

[42] EB-2018-0165, Decision and Order (December 19, 2019) at page 187.

Table 16: Estimated Forecast vs. Actual Cumulative Depreciation of OPEB Costs ($ Millions)

	2020	2021	2022
Estimated Forecast Cumulative Depreciation of OPEB costs capitalized starting in 2020[43]	0.1	0.2	0.4
Estimated Actual Cumulative Depreciation of OPEB costs capitalized starting in 2020	0.2	0.4	0.5

5.4 Account 1551 – Smart Metering Entity Charges

In its role as the Smart Metering Entity ("SME"), the IESO manages the development of the meter data management/repository ("MDM/R") to collect, manage, store, and retrieve information related to the metering of customers' use of electricity in Ontario.

Effective May 1, 2013, the Smart Metering Entity charge levied and collected by the SME from all distributors identified in the OEB's annual Yearbook of Electricity Distributors was set at $0.788 per month for each Residential and General Service <50 kW customer for each distributor. The Smart Metering Entity charge was in effect from May 1, 2013 to October 31, 2018. On March 1, 2018, the OEB issued its Decision and Order (EB-2017-0290) approving a new Smart Metering Entity charge of $0.57 per month for each Residential and General Service <50 kW customer, effective from January 1, 2018 to December 31, 2022.

The previously approved Smart Metering Entity charge of $0.788 per month was collected for the first three months of 2018 and resulted in an accumulated credit of $0.66 per smart meter.

[43] EB-2018-0165, Interrogatory Response, U-Staff-196 (June 11, 2019) at page 4. Table 2 provides the accrual versus cash tracking methodology effective January 1, 2020. Consistent with Toronto Hydro's 2020-2024 rate setting approach for OM&A, 2021-2024 OPEB costs were determined by escalating the 2020 approved amounts by inflation minus the stretch factor (I-X) and therefore, differ slightly from those included in U-Staff-196.

Toronto Hydro records in Account 1551 amounts paid to the IESO through the Smart Metering Entity charge and amounts recovered from customers through the distribution Rate Rider for Smart Metering Entity Charge. Toronto Hydro proposed to clear the Smart Metering Entity Charges account for 2022 amounting to a $2.2 million credit (refund) to customers as part of Toronto Hydro's 2024 Rate Application (EB-2023-0054).

5.5 Account 1508 – subaccount - Local Initiatives Program

In a letter to all rate-regulated electricity distributors dated May 28, 2021 (EB-2021-0106), the OEB established a new deferral account for distributors partnering with the IESO in its Local Initiatives Program ("LIP") to track incremental costs incurred through this partnership. The OEB further detailed that eligible distributor costs to be recorded in this account may potentially include activities such as procurement support, providing access to data, supporting evaluation, measurement, and verification activities, and supporting marketing and outreach activities, but shall not include the cost of resources procured through the LIP. As at December 31, 2022, there was no material balance in the LIP deferral account. Toronto Hydro intends to apply for the disposition of the balance in this account in the next rebasing application, if the balance is material.

5.6 Account 1508 – subaccount - Carillion Insolvency Payments Receivable Account

In the 2020-2024 Rate Application (EB-2018-0165), the OEB established a deferral account to record the revenue requirement impact of a reduction to rate base associated with payments from Carillion (the general contractor for the Copeland Phase 1 project) to Toronto Hydro resulting from the ongoing insolvency litigation, including any prudently incurred expenses with respect to the litigation and recovery of any amount rewarded. As the insolvency litigation is still ongoing, there is no balance in this account as of year-end 2022. Toronto Hydro intends to update this evidence if the insolvency litigation concludes

while the record for this application remains open. Otherwise, Toronto Hydro requests the continuation of this account in the 2025-2029 period.

5.7 Earnings Sharing Mechanism ("ESM")

In the 2020-2024 Rate Application (EB-2018-0165), the OEB approved a cumulative, asymmetrical Earnings Sharing Mechanism ("ESM") variance account using a Return on Equity ("ROE") based calculation with all earnings in excess of 100 basis points over the approved ROE shared 50:50 with ratepayers.

Table 17 below provides a summary of Toronto Hydro's calculations to substantiate that as of year-end 2022, there is no balance in this account. Given the under earnings in the last three years,[44] Toronto Hydro does not expect to have any balance in the ESM by the end of the rate period.

Table 17: 2020-2022 ESM Calculations

		2020	2021	2022
Cumulative Adjusted NI	A=NICY+NIPY	107.1	239.5	385.4
Cumulative Actual Deemed Equity	$B=EQ_{CY}+EQ_{PY}$	1,813.6	3,683.6	5,646.4
ROE Cumulative	C=A/B	5.90%	6.50%	6.83%
ROE Approved	D	8.52%	8.52%	8.52%
ROE Over (Under)	E=C-D	**(2.62%)**	**(2.02%)**	**(1.69%)**

As directed by the OEB, Table 18 below presents the utility's ESM calculation for 2019.[45]

[44] Please see Exhibit 1B, Tab 3, Schedule 3 for more information about deemed versus actual regulatory ROE over the 2020-2022 period.
[45] EB-2018-0165, Decision and Order (December 19, 2019) at page 182. Note the 2019 ESM was also previously reported through RRR. The 2015-2018 ESM calculations can be found in EB-2018-0165, Exhibit U, Tab 9, Schedule 1 at page 14.

Table 18: 2019 ESM Calculation

		2019
OM&A [a]	*A*	268.0
Revenue Offsets [a]	*B*	(56.5)
Unadjusted non-capital revenue requirement ("Non-CRRR")	*C=A+B*	**211.5**
RRR Adjustments [b]		
Depreciation expense related to non-regulated assets (renewable energy investment)	*D*	(0.2)
Non-recoverable expenses – donations and meals	*E*	(0.4)
Subtotal	*F=C+D+E*	**210.9**
Adjustments for items not included in rates		
Amortization of 2014 balance in DVA account 1575 – IFRS USGAAP Transitional PP&E Amounts [c]	*G*	**6.6**
Amortization of capital contributions (deferred revenue) [d]	*H*	**5.9**
Past Service Costs	*I*	**(14.9)**
Actual non-CRRR items for ESM purposes	*J=F+G+H+I*	**208.5**
Less: non-CRRR embedded in rates [e, f]	*K*	**211.4**
Non-CRRR difference	*L=J-K*	(3.0)
Deemed equity portion of actual rate base [g]	*M*	1,751.8
Non-CRRR difference	*N=L/M*	(0.17%)
ESM threshold	*O*	1.00%
ESM test result	*N compared to O*	Within threshold

Rounding variances may exist.

[a] Source: RRR 2.1.7 - trial balance.

[b] Source: RRR 2.1.5.6 - Appendices 1 and 2.

[c] Source: RRR 2.1.7 - trial balance account 4310, reported as revenue offsets.

[d] Source: RRR 2.1.7 - trial balance account 4245, reported as revenue offsets.

[e] EB-2014-0116, Decision and Order (29th Dec, 2015) at page 49.

[f] 2019 non-CRRR was determined by escalating the 2015 non-CRRR amount by the inflation and X factors (i.e. 'I-X') in each year. 2015 non-CRRR was from EB-2014-0116, Draft Rate Order Update (February 29, 2016), Table 2 at page 6.

[g] Source: RRR 2.1.5.6 - ROE Summary.

To continue to protect customers against the risk of utility over-earnings, Toronto Hydro requests the continuation of the ESM in the 2025-2029 period. For more information, please refer to the Rate Framework evidence in Exhibit 1B, Tab 2, Schedule 1.

6. SUMMARY OF PROPOSED DVA DISPOSITIONS

Tables 19 and 20 below summarize Toronto Hydro's proposed disposition of regulatory assets and liabilities.

Table 19: Summary of Proposed Dispositions – Group 1 Accounts ($ Millions)

	Principal Balance as of Dec 31, 2023 (Forecast)	Carrying Charge Balance as of Dec 31, 2023 (Forecast)	Balances as of Dec 31, 2023 (Forecast)
Group 1 Accounts			
Account 1588 – Power ($RSVA_{Power}$) Enhancement Model Changes[46]	22.8	1.6	24.4
Account 1589 Global Adjustment ($RSVA_{GA}$) Enhancement Model Changes	(7.4)	(0.5)	(7.9)

Table 20: Summary of Proposed Dispositions – Group 2 Accounts ($ Millions)

	Principal Balance as of Dec 31, 2024 (Forecast)	Carrying Charge Balance as of Dec 31, 2024 (Forecast)	Balances as of Dec 31, 2024 (Forecast)	Incremental carrying charges due to rate smoothing (Forecast)	Balances including the incremental carrying charges (Forecast)
Group 2 Accounts					
Customer Choice Initiative	0.6	0.0	0.6	0.1	0.6
Excess Expansion Deposits	(7.7)	(0.8)	(8.5)	-	(8.5)
Externally Driven Capital Variance Account ("EDCVA")	1.5	0.1	1.6	0.1	1.7
Gain on Sale 2020 Decision (Gain on Sale of Properties)	3.4	0.3	3.7	0.3	4.1
Green Button Initiative Costs	(0.1)	(0.0)	(0.1)	-	(0.1)
Impact for USGAAP Deferral	(1.7)	0.0	(1.7)	-	(1.7)

[46] Includes $5.7 million principal adjustment reversal

	Principal Balance as of Dec 31, 2024 (Forecast)	Carrying Charge Balance as of Dec 31, 2024 (Forecast)	Balances as of Dec 31, 2024 (Forecast)	Incremental carrying charges due to rate smoothing (Forecast)	Balances including the incremental carrying charges (Forecast)
LRAM Variance Account ("LRAMVA")[47]	5.0	0.6	5.6	-	5.6
Operating Centers Consolidation Program ("OCCP") Bonus Payment	(31.3)	(2.0)	(33.4)	-	(33.4)
50/60 Eglinton Bonus Payment	(9.6)	(0.6)	(10.2)	(0.5)	(10.7)
PILs and Tax Variances – CCA Changes	(1.6)	(0.2)	(1.8)	-	(1.8)
Wireless Attachments	(3.3)	(0.3)	(3.6)	(0.2)	(3.8)
Wireline Pole Attachment Revenue Variance	3.3	0.2	3.5	0.3	3.8
Ultra-Low Overnight Rate Costs	0.1	0.0	0.1	-	0.1
Useful Life Changes	(130.5)	(6.0)	(136.5)	(2.6)	(139.1)
Renewable Generation Connection Funding Adder Deferral Account – Provincial Rate Protection Payment Variances	(7.4)	0.0	(7.4)	-	(7.4)
Total Balance	**(179.3)**	**(8.7)**	**(188.1)**	**(2.4)**	**(190.5)**

Toronto Hydro confirms that it has not made any adjustments to previously approved DVAs. With the exception of the LRAMVA,[48] the balances proposed for clearance match the account balances filed in the RRR as of 2022-year end, forecasted to the end of 2024.

[47] Assuming OEB approval of the LRAM calculation methodology and variance account clearance as proposed in Exhibit 9, Tab 2, Schedule 3.

[48] Toronto Hydro notes that the balances in the LRAMVA were not reported in RRR or AFS filings because, as noted in the OEB's Decision in EB-2022-0065, the utility did not have sufficient information at the time those filings to estimate the balances in the account.

7. DVA ALLOCATION AND RECOVERY METHOD

Toronto Hydro proposes to allocate the DVA balances to the customer classes based on the methodologies described in the OEB's EDDVAR report. For accounts where the EDDVAR report indicated allocation was to be determined on a case-by-case basis, Toronto Hydro has proposed an allocator. For each of the accounts requested for clearance, the following table shows the proposed rate class allocator.

Table 21: Proposed Rate Class Allocator

Account	Allocator
Customer Choice Initiative	2022 Number of RPP Customers
Excess Expansion Deposits	2022 Distribution Revenue
Externally Driven Capital Variance Account ("EDCVA")	2022 Distribution Revenue
Gain on Sale 2020 Decision (Gain on Sale of Properties)	2022 Distribution Revenue
Green Button Initiative Costs	2022 Distribution Revenue
Impact for USGAAP Deferral	2022 Distribution Revenue
LRAM Variance Account ("LRAMVA")	LRAMVA Model
Operating Centers Consolidation Program ("OCCP") Bonus Payment	2022 Distribution Revenue
50/60 Eglinton Bonus Payment	2022 Distribution Revenue
PILs and Tax Variances – CCA Changes	2022 Distribution Revenue
Wireless Attachments	Forecast 2025 Revenue Offsets
Wireline Pole Attachment Revenue Variance	Forecast 2025 Revenue Offsets
Ultra-Low Overnight Rate Costs	2022 Number of RPP Customers
Useful Life Changes	2022 Distribution Revenue
Innovation Fund	2022 Distribution Revenue

8. DEVELOPMENT OF RATE RIDERS

In accordance with the previous rate applications, Toronto Hydro puts forward a single fixed rate rider for those classes that are charged a fully fixed distribution rate (Residential and

Competitive Sector Multi-Unit Residential), and a single volumetric rate rider for all other classes for the clearance of all DVA amounts.

Toronto Hydro proposes various recovery periods for specified DVA accounts, beginning January 2025, in order to minimize and smooth out the bill impacts to all affected customers. More details on rate smoothing can be found in Exhibit 8, Tab 1, Schedule 1.

The derivation of the rate riders is shown in Exhibit 9, Tab 3, Schedule 1. The impacts of all proposed rate riders combined with the distribution rate changes are found in Exhibit 8, Tab 6, Schedule 1.

Toronto Hydro is proposing to collect the amount allocated to the Innovation Fund through a rate rider over the 2025-2029 period. Details regarding the deferral account are provided in section 9.3 below and details regarding the Innovation Fund are provided in Exhibit 1B, Tab 4, Schedule 2.

9. NEW DEFERRAL AND/OR VARIANCE ACCOUNTS

As part of the Custom Rate Framework outlined in Exhibit 1B, Tab 2, Schedule 1, Toronto Hydro seeks approval for the following new Deferral and Variance Accounts: (1) the Performance Incentive Mechanism Deferral Account, (2) Demand Related Variance Account ("DRVA"), and (3) the Innovation Fund Variance Account. In addition, Toronto Hydro seeks approval to establish the 50/60 Eglinton Proceeds of Sale Deferral Account to dispose additional proceeds received from the sale of 50/60 Eglinton. Draft Accounting Orders for these accounts are provided in Appendix C to this schedule.

9.1 Performance Incentive Mechanism Deferral Account ("PIM-DA")

Toronto Hydro seeks approval of a new deferral account – the Performance Incentive Mechanism Deferral Account ("PIM-DA") – to record earnings related to the achievement of Performance Incentive Mechanism ("PIM") as part of the Custom Rate Framework. The amounts recorded in this account would be reviewed in the next rebasing application for 2030 rates, if the PIM is approved and the targets set on the 2025-2029 Custom Scorecard are achieved (or expected to be achieved) by the end of the rate period (i.e. 2029).[49]

9.2 Demand Related Variance Account ("DRVA")

As customers, communities and governments at all levels are actively embarking on an energy transition to mitigate the existential and economic impacts of climate change, there is a greater role for electricity to play in the day-to-day energy needs of Toronto consumers to power previously non-electric energy uses (e.g. transportation and building heating systems). While there is certainty that fundamental change is ahead, there are degrees of uncertainty about how that change will unfold (e.g. the pace and adoption of electrified technologies such as EVs and heat pumps; the role of low-emission gas; and the scale of local vs. bulk electricity supply). To reconcile the impact of these emerging conditions throughout the 2025-2029 rate period, Toronto Hydro seeks approval to establish a new symmetrical variance account to protect ratepayers and the utility from structural unknowns in forecasted costs and revenues during this time of unprecedented change and transformation in the economy and energy system.

Subject to OEB approval, Account 1508 – Demand-Related Variance Account (DRVA) would record: (i) the demand-driven revenue requirement impacts arising from variances in actual versus forecast capital and operational expenditures for certain demand-based programs;

[49] Please refer Exhibit 1B, Tab 3, Schedule 1 to review the 2025-2029 Custom Scorecard proposal.

and (ii) the revenue impacts arising from variances in forecast versus actual weather-normalized billing determinants (customer count, kWh and kVA) over the rate period. To that end, the account would consist of two subaccounts:

1. The *Expenditure Variance* subaccount would record the symmetrical revenue requirement impacts, including PILs, arising from the variance between the forecast expenditures for the 2025-2029 period and actual expenditures related to the following capital and operations programs: Customer Connections, Customer Operations, Stations Expansion, Load Demand, Non-Wires Solution, Generation Protection Monitoring and Control and Externally-Initiated Plant Relocations & Expansions (collectively "Demand-Related Investments").
2. The *Revenue Variance* subaccount would record the revenue impacts resulting from weather-normalized variances in billing determinants (e.g. customer count and billed demand).

9.3 Innovation Fund Variance Account ("IFVA")

As detailed in Exhibit 1B, Tab 4, Schedule 2, Toronto Hydro proposes to create a $16 million Innovation Fund to enable the utility to overcome real and practical challenges of pursuing innovation during the 2025-2029 rate term, and advance the OEB's objectives with respect to facilitating innovation in the electricity sector. Toronto Hydro proposes to collect the amount allocated to the Innovation Fund through a rate rider (rather than through base rates) in order to provide transparency to ratepayers on the bill and flexibility to the utility to determine how the funds should be allocated across capital and operational expenditures on the basis of the selected pilot projects. The utility also proposes to establish a new symmetrical variance account to record variances between the amounts collected by the Innovation Fund rate rider and the actual costs incurred to execute selected pilot projects as part of the Innovation Fund.

9.4 50/60 Eglinton Proceeds of Sale Deferral Account

In the 2020-2024 rate application (EB-2018-0165), Toronto Hydro requested approval to clear forecasted net gains on the sale of property at 50/60 Eglinton Avenue through a rate rider without a deferral or variance account.[50] The OEB accepted the disposition of relevant amounts, noting that although the proposed refund of the proceeds of sale from the Eglinton property and other amounts is appropriate, the OEB may not permit in the future the disposition of a regulatory balance without an approved account.[51]

In addition to the sale proceeds previously refunded to ratepayers, Toronto Hydro received a variable consideration (bonus payment) from the purchaser, based on the terms of the relevant agreement of purchase and sale, which stipulate additional consideration to the utility where the purchaser achieves an increase in gross floor area as a result of zoning by-law applications. Toronto Hydro intends to return this variable consideration (bonus payment) to ratepayers in the 2025-2029 period.

With regard to the OEB's comments in the last decision, Toronto Hydro requests approval to establish a deferral account to record the variable consideration amounts received during the 2020-2024 rate period and clear the account balance in respect of such amounts, which is currently estimated to be a $10.2 million credit to customers. Toronto Hydro intends to also record in the account any potential variable consideration amounts further received in the 2025-2029 rate period.

[50] EB-2018-0165, Exhibit 8, Tab 1, Schedule at page 11.
[51] EB-2018-0165, Decision and Order (December 19, 2019) at page 183.

DRAFT ACCOUNTING ORDERS

1. NEW VARIANCE AND DEFERRAL ACCOUNTS – DRAFT ACCOUNTING ORDERS

Deferral Account for Excess Expansion Deposits – Draft Accounting Order

Toronto Hydro shall establish an account to record any excess expansion deposits as a credit to the variance account.

Carrying charges will apply to the opening balances in the accounts (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

In the next rebasing application, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following deferral accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount Excess Expansion Deposits
- Account 1508, Other Regulatory Assets, Subaccount Excess Expansion Deposits Carrying Charges

Toronto Hydro will use the following account to record the OEB-approved rate rider associated with the Excess Expansion Deposits being cleared to ratepayers:

- Account 1508 Other Regulatory Assets, Subaccount Excess Expansion Deposits (Rate Rider Account)

The sample accounting entries for the deferral accounts are provided below.

A. To record the excess expansion deposits to the deferral account:
   - Dr. 2210 Customer Deposits / 2335 Non-Current Customer Deposits
   - Cr. 1508 Other Regulatory Assets, Subaccount Excess Expansion Deposits

B. To record the carrying charges in subaccount Excess Expansion Deposits Account:
   - Dr. 6035 Other Interest Expense
   - Cr. 1508 Other Regulatory Assets, Subaccount Excess Expansion Deposits Carrying Charges

Variance Account for Gain on Sale of Property – Draft Accounting Order

Toronto Hydro shall establish an account to track the variance in actual gains on sale of utility property from the $1.0 million amount included in base rates as part of 2020 Revenue Offsets. Toronto Hydro will track the symmetrical difference between the $1.0 million gain embedded in rates and the actual gains net of tax in a given year.

Carrying charges will apply to the opening balances in the accounts (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

In the next rebasing application, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount Property Gain
- Account 1508, Other Regulatory Assets, Subaccount Property Gain Variance Account Carrying Charges

The sample accounting entries for the variance accounts are provided below.

A. To record amounts in the Property Gain Variance Accounts:
   - DR/CR 4080 Distribution Services Revenue
   - CR/DR 1508 Other Regulatory Assets, Subaccount Property Gain

B. To record the carrying charges in subaccount Property Gain Variance Account:
   - DR 6035 Other Interest Expense / CR 4405 Interest and Dividend Income
   - CR/DR 1508 Other Regulatory Assets, Subaccount Property Gain Carrying Charges

Deferral Account for Carillion Insolvency Payments Receivable – Draft Accounting Order

Toronto Hydro shall establish a deferral account to record the revenue requirement impact of a reduction to rate base associated with payments from Carillion to Toronto Hydro resulting from the ongoing insolvency litigation. The account will also record any prudently incurred expenses with respect to the litigation and recovery of any amount rewarded. At the time of the next rebasing, Toronto Hydro will remove the amount related to the litigation payment from rate base on a permanent basis and close this account.

Carrying charges will apply to the opening balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

In the next rebasing application, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following deferral accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount Carillion Insolvency Payments Receivable Account
- Account 1508, Other Regulatory Assets, Subaccount Carillion Insolvency Payments Receivable Account Carrying Charges

The sample accounting entry for the deferral accounts are provided below.

A. To record the revenue requirement on the insolvency payment in the Carillion Insolvency Payments Receivable Account:
   - DR 4080 Distribution Services Revenue
   - CR 1508 Other Regulatory Assets, Subaccount Carillion Insolvency Payments Receivable Account

B. To record any litigation incurred expenses relating to the Carillion Insolvency in the Carillion Insolvency Payments Receivable Account:
   - DR 1508 Other Regulatory Assets, Subaccount Carillion Insolvency Payments Receivable Account
   - CR XXXX Operating, Maintenance and Administration Expenses (various accounts – depends on type of expense)

C. To record the carrying charges in subaccount Carillion Insolvency Payments Receivable Account:
   - DR 6035 Other Interest Expense
   - CR 1508 Other Regulatory Assets, Subaccount Carillion Insolvency Payments Receivable Account Carrying Charges

2. UPDATE TO EXISTING VARIANCE AND DEFERRAL ACCOUNTS – DRAFT ACCOUNTING ORDERS

Variance Account for Externally Driven Capital – Draft Accounting Order

The OEB approved the continuation of a variance account related to third party-initiated relocation and expansion projects ("externally driven capital work"). This account captures variances from the approved revenue requirement associated with externally driven capital work embedded in rates, including variances in derecognition expenses related to externally driven capital work. The account shall be symmetrical and amounts recorded or recordable in this account shall not be recorded in the Capital-Related Revenue Requirement Variance Account.

Carrying charges will apply to the opening revenue requirement balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

In the next rebasing application, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount THESL Externally Driven Revenue Requirement
- Account 1508, Other Regulatory Assets, Subaccount THESL Externally Driven Revenue Requirement Carrying Charges

The sample accounting entries for the variance accounts are provided below.

A. To record balance in the Externally Driven Capital Variance Account:
   - DR 1508 Other Regulatory Assets, Subaccount THESL Externally Driven Revenue Requirement
   - CR 4080 Distribution Services Revenue

B. To record the carrying charges in subaccount THESL Externally Driven Revenue Requirement:
   - DR 1508 Other Regulatory Assets, Subaccount THESL Externally Driven Revenue Requirement Carrying Charges
   - CR 4405 Interest and Dividend Income

Earnings Sharing Mechanism ("ESM") Variance Account – Draft Accounting Order

The OEB approved a cumulative, asymmetrical ESM using a ROE-based calculation. The ESM will be cumulative in that it will be based on an evaluation of overall earnings at the end of the 2020-2024 rate period term, and it will be asymmetrical in that there will be no sharing (i.e. collection) of cumulative under-earnings from rate payers.

At the end of the 2020-2024 rate period, the ROE-based calculation will determine if there were any cumulative over-earnings associated with actual net income of the regulated utility after specific adjustments (e.g. out of period items) as reported under the Reporting and Record Keeping Requirements ("RRR") during the rate period. Cumulative over-earnings in excess of 100 basis points of the approved ROE of 8.52% will be shared 50:50 with ratepayers. The ratepayer's share of any eligible earnings will be grossed up for any tax impacts and credited to this account.

Carrying charges will apply to the opening balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

Toronto Hydro will apply to clear any balances in this account to ratepayers in the next rebasing application.

Toronto Hydro will establish the following variance accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount Earnings Sharing Mechanism Variance Account
- Account 1508, Other Regulatory Assets, Subaccount Earnings Sharing Mechanism Variance Account Carrying Charges

The sample accounting entry for the variance accounts are provided below.

A. To record amounts resulting from the operation of the ESM:
    - DR 4080 Distribution Services Revenue
    - CR 1508 Other Regulatory Assets, Subaccount Earnings Sharing Mechanism Variance Account

B. To record the carrying charges in subaccount Earnings Sharing Mechanism Variance Account:
    - DR 6035 Other Interest Expense
    - CR 1508 Other Regulatory Assets, Subaccount Earnings Sharing Mechanism Variance Account Carrying Charges

APPENDIX C: DRAFT ACCOUNTING ORDERS

Demand-Related Variance Account ("DRVA") – Draft Accounting Order

Toronto Hydro requests a symmetrical variance account (Account 1508 – Demand-Related Variance Account) that consist of two subaccounts, as follows:

- The Demand-Related Revenue Variance subaccount will record revenue variances between forecast and actual weather-normalized billing determinants.

- The Demand-Related Expenditure Variance subaccount will record the symmetrical revenue requirement impacts, including PILs, arising from the variance between the forecast expenditures for the 2025-2029 rate period and actual expenditures related to the following programs: Customer Connections (Exhibit 2B, Section E5.1), Stations Expansion (Exhibit 2B, Section E7.4), Load Demand (Exhibit 2B, Section E5.3), Non-Wires Solution (Exhibit 2B, Section E7.2), Customer Operations (Exhibit 4, Tab 2, Schedule 8), Generation Protection Monitoring and Control (Exhibit 2B, Section E5.5) and Externally-Initiated Plant Relocations & Expansions (Exhibit 2B, Section E5.2) (collectively, "Demand-Related Investments").

Carrying charges will apply to the opening balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers. Toronto Hydro will establish the following Variance Accounts to record the amounts described above:

Demand-Related Revenue Variance subaccount

- Account 1508, Other Regulatory Assets, Subaccount Demand-Related Revenue Variance Account
- Account 1508, Other Regulatory Assets, Subaccount Demand-Related Revenue Variance Account Carrying Charges

Demand-Related Expenditure Variance subaccount

- Account 1508, Other Regulatory Assets, Subaccount Demand-Related Expenditure Variance Account
- Account 1508, Other Regulatory Assets, Subaccount Demand-Related Expenditure Variance Account Carrying Charges

The sample accounting entries for the variance accounts are provided below:

Demand-Related Revenue Variance subaccount

A. To record the difference between the cumulative Demand-Related Revenue included in rates and the actual Demand-Related Revenue over the CIR period:
    - DR/CR 4080 Distribution Services Revenue
    - CR/DR 1508 Other Regulatory Assets, Subaccount Demand-Related Revenue Variance Account

B. To record the carrying charges in subaccount Demand-Related Revenue Variance Account:
    - DR/CR 6035 Other Interest Expense
    - CR/DR 1508 Other Regulatory Assets, Subaccount Demand-Related Revenue Variance Account Carrying Charges

Demand-Related Expenditure Variance subaccount

A. To record the difference between the cumulative Demand-Related Expenditure included in rates and the actual Demand-Related Expenditure over the CIR period:
    - DR/CR 4080 Distribution Services Revenue
    - CR/DR 1508 Other Regulatory Assets, Subaccount Demand-Related Expenditure Variance Account

B. To record the carrying charges in subaccount Demand-Related Expenditure Variance Account:
    - DR/CR 6035 Other Interest Expense
    - CR/DR 1508 Other Regulatory Assets, Subaccount Demand Related Expenditure Variance Account Carrying Charges

Innovation Fund Variance Account – Draft Accounting Order

Toronto Hydro requests a symmetrical variance account (Account 1508 – Innovation Fund Variance Account) to record variances between the revenue collected by the Innovation Fund rate rider and the actual costs incurred (on a revenue requirement basis) to undertake the selected innovation pilot projects.

Carrying charges will apply to the opening balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following Variance Accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount Innovation Fund Variance Account
- Account 1508, Other Regulatory Assets, Subaccount Innovation Fund Variance Account Carrying Charges

The sample accounting entry for the variance accounts are provided below.

A. To record the difference between the Innovation Fund included in the rate rider and actual revenue requirement over the CIR period:
    - DR/CR 4080 Distribution Services Revenue
    - CR/DR 1508 Other Regulatory Assets, Subaccount Innovation Fund Variance Account

B. To record the carrying charges in subaccount Innovation Fund Variance Account:
    - DR/CR 6035 Other Interest Expense
    - CR/DR 1508 Other Regulatory Assets, Subaccount Innovation Fund Variance Account Carrying Charges

Performance Incentive Mechanism Deferral Account – Draft Accounting Order

Toronto Hydro requests a deferral account (Account 1508 – Performance Incentive Mechanism Deferral Account ("PIM-DA") to record revenue earned by the utility for achieving set targets on the 2025-2029 Custom Scorecard as outlined in Exhibit 1B, Tab 3, Schedule 1.

Carrying charges will apply to the opening balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

At a later date, Toronto Hydro will apply to clear the balances in this account to ratepayers.

Toronto Hydro will establish the following Deferral Accounts to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount Performance Incentive Mechanism Deferral Account (PIM-DA)
- Account 1508, Other Regulatory Assets, Subaccount Performance Incentive Mechanism Deferral Account (PIM-DA) - Carrying Charges

The sample accounting entry for the variance accounts are provided below.

A. To record revenue earned by the utility by achieving set targets on the 2025-2029 Custom Scorecard:
    - DR 1508 Other Regulatory Assets, Subaccount Performance Incentive Mechanism Deferral Account (PIM-DA) Account
    - CR 4080 Distribution Services Revenue
B. To record the carrying charges in subaccount Performance Incentive Mechanism Deferral Account:
    - DR 1508 Other Regulatory Assets, Subaccount Performance Incentive Mechanism Deferral Account (PIM-DA) - Carrying Charges
    - CR 6035 Other Interest Expense

50/60 Eglinton Proceeds of Sale Deferral Account – Draft Accounting Order

Toronto Hydro requests a deferral account (Account 1508 – 50/60 Eglinton Proceeds of Sale Deferral Account) to record and dispose of additional proceeds received from the sale of

property at 50/60 Eglinton Avenue based on the forecasted net gains on the sale grossed up for the Payment in Lieu ("PILs") tax savings.

Toronto Hydro will establish the following to record the amounts described above:

- Account 1508, Other Regulatory Assets, Subaccount 50/60 Eglinton Avenue
- Account 1508, Other Regulatory Assets, Subaccount 50/60 Eglinton Avenue - Carrying Charges

Carrying charges will apply to the opening balances in the account (exclusive of accumulated interest) at the OEB-approved rate for deferral and variance accounts.

The sample accounting entries for the variance accounts are provided below.

A. Record the actual variable considerations received, net of taxes:
   - DR 1005 Cash
   - CR 4355 Gain on Disposition of Utility and Other Property
   - CR 2294 Accrual for Taxes, "Payments in Lieu of Taxes", etc.

B. Record the reclassification of additional proceeds, net of taxes, received from the sale of 50/60 Eglinton:
   - DR 4355 Gain on Disposition of Utility and Other Property
   - CR 1508 Other Regulatory Assets, Subaccount 50/60 Eglinton Avenue

C. Record the carrying charges in subaccount 1508 Other Regulatory Assets, Subaccount 50/60 Eglinton Avenue:
   - CR 1508, Other Regulatory Assets, Subaccount 50/60 Eglinton Avenue - Carrying Charges

- DR 6035 Other Interest Expense

2025 and Future Years Entries

D. Record transfer of balance in subaccount 1508 Other Regulatory Assets, Subaccount 50/60 Eglinton Avenue to account 1595-RARA, upon approval from OEB
    - DR 1508 Other Regulatory Assets, Subaccount 50/60 Eglinton Avenue
    - CR 1595 RARA- Subaccount 50/60 Eglinton Avenue - Approved Principal
    - DR 1508, Other Regulatory Assets, Subaccount 50/60 Eglinton Avenue - Carrying Charges
    - CR 1595 RARA- Subaccount 50/60 Eglinton Avenue – Approved Carrying Charges

E. Record the distribution of the rate rider to customers upon approval from the OEB. The offsetting credit will be applied to Account 1100 Customer Accounts Receivable since the ratepayers' bills should be reduced by the rate rider refund:
    - DR 4080 Distribution Services Revenue
    - CR 1100 Customer Accounts Receivable
    - DR 1595 RARA- Subaccount 50/60 Eglinton Avenue - Approved Principal
    - DR 1595 RARA- Subaccount 50/60 Eglinton Avenue – Approved Carrying Charges
    - CR 4080 Distribution Services Revenue

F. Record the actual PILs tax savings materialized, which is being given back to ratepayers. The PILs tax savings is the result of the rate rider cash refund to customers:
    - DR 2294 Accrual for Taxes, "Payments in Lieu of Taxes", Etc.

- CR 6110 Income Taxes
- DR 4080 Distribution Services Revenue
- CR 1595 RARA- Subaccount 50/60 Eglinton Avenue - Approved Principal

G. Record the carrying charges on the remaining balance in account 1595 RARA- Subaccount 50/60 Eglinton Avenue - Approved Principal:

- DR 6035 Other Interest Expense
- CR 1595 RARA- Subaccount 50/60 Eglinton Avenue – Carrying Charges

LOST REVENUE ADJUSTMENT MECHANISM VARIANCE ACCOUNT (LRAMVA)

In its 2023 Rate Application (EB-2022-0065), the OEB approved Toronto Hydro's proposal to defer the clearance of the 2020 and 2021 LRAMVA balances, and any future balances within the 2020-2024 rate period available at the time to this rebasing application. In accordance with that decision, Toronto Hydro hereby seeks clearance of the 2020-2022 LRAMVA balances for the savings from Conservation First Framework ("CFF") programs only. Additionally, this schedule includes the proposed adjustment to the LRAMVA threshold to account for the discontinuation of CFF programs.

The methodology applied to clear the balances in the LRAMVIA is consistent the OEB's Chapter 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (December 15, 2022), and with the methodology previously approved by the OEB in the 2021 Rate Application (EB-2020-0057).

Table 1 below provides a summary of the principal amount and carrying charges by rate class, and the resulting rate riders. Toronto Hydro proposes to clear the LRAMVA balance over a 60-month period, beginning January 1, 2025, in order to effect rate-smoothing. Rate riders were not developed for the Residential and Competitive Sector Multi-Unit Residential (CSMUR) rate classes as the eligible amounts were insignificant.

Table 1: LRAMVA Summary ($ Millions)

Rate Class	Principal for Clearance ($)	Carrying Charges ($)	Total for Clearance ($)	Proposed Rate Rider ($/kWh or $/kVA)
Residential	(0.0)	(0.0)	**(0.1)**	**-**
CSMUR	(0.0)	(0.0)	**(0.0)**	**-**
GS<50kW	(1.2)	(0.1)	**(1.3)**	**(0.00011)**

Rate Class	Principal for Clearance ($)	Carrying Charges ($)	Total for Clearance ($)	Proposed Rate Rider ($/kWh or $/kVA)
GS 50-999kW	3.0	0.4	**3.4**	**0.0288**
GS 1000-4999kW	0.8	0.1	**0.9**	**0.0195**
Large User	2.5	0.3	**2.7**	**0.1346**

Toronto Hydro seeks approval to dispose of balances associated with the following:

- Incremental first-year lost revenues for 2020, 2021 and 2022; and
- Lost revenues in 2020-2022 resulting from Conservation and Demand Management (CDM) savings persistence from the years 2018 through 2021.

Where applicable, the 2020-2022 lost revenues are based on actual CDM savings reported in the Participation and Cost Reports for the period of January 1, 2018 to April 15, 2019, and actual CFF savings for projects that were completed during the 2018-2022 period in accordance with Toronto Hydro's contractual obligations. These reports are filed as Appendices A to G to this schedule.[1]

Toronto Hydro determined the proposed amounts for clearance based on the most recent CDM input assumptions available at the time of program evaluation and using version 8.0 (2024) of the OEB's LRAMVA Workform. A copy of the LRAMVA Workform is filed at Tab 2, Schedule 3.

[1] Note that due to the size and nature of these documents, Toronto Hydro has filed this report and the Excel-based supporting documents (Appendices A-G) in Excel format only.

1. MODIFIED LRAMVA THRESHOLD

The modified LRAMVA threshold that forms that basis of the 2020-2022 LRAMVA clearance proposed includes changes with respect to two items: 1) the impact of CFF wind-down; and 2) the 2018 CDM persistence. Each of these items is discussed below.

Table 2 provides the original threshold approved by the OEB in EB-2018-0165 and the modified LRAMVA threshold that the utility applied for the LRAMVA calculations in this application reflecting the impacts of CFF wind-down and including 2018 CDM persistence.

Table 2: LRAMVA Threshold

	Residential	CSMUR	GS<50kW	GS 50-999kW	GS 1000-4999kW	Large User
	MWh	MWh	MWh	MW	MW	MW
Original[2]	28,027	3,607	48,831	458	128	144
Modified	79,894	6,443	60,610	376	112	131

1.1 CFF Wind-Down Adjustment

In EB-2018-0165, the OEB approved Toronto Hydro's most recent load forecast and the related Conservation and Demand Management ("CDM") forecast for rate-making purposes during the period when the CFF was revoked by the Ministry of Energy, Northern Development and Mines and the future direction on LRAMVA was still unknown.[3] The result is that the LRAMVA thresholds approved in the last application (EB-2018-0165) include all of the Toronto Hydro CDM programs under the CFF, while the actuals to be used for the LRAMVA calculations include only those programs that the utility continued to manage post-

[2] EB-2018-0165, Exhibit U, Tab 3, Schedule 1, Appendix E - CDM LF to LRAM Reconciliation
[3] EB-2018-0165, Decision and Order (December 19, 2019) at page 127.

CFF as contractually obligated under the CFF wind-down.[4] Calculating LRAMVA amounts using these mismatched versions of the CDM values would be inappropriate. To reconcile these changes in the calculation of the LRAMVA, Toronto Hydro proposes a modified LRAMVA threshold.

The modified LRAMVA threshold only accounts for Toronto Hydro programs that were fully discontinued and those which the utility was contractually obligated to complete as part of the CFF wind-down. In other words, the modified threshold excludes programs that were transferred to the IESO. To achieve this, Toronto Hydro removed programs that were transferred to the IESO by deducting Toronto Hydro's estimated savings for each of these programs from original threshold approved by the OEB in EB-2018-0165. To estimate Toronto Hydro's savings portion of the programs that were transferred to the IESO, Toronto Hydro utilized the following approach:

- Divide Toronto Hydro's 2015-2017 verified savings (as set out in the IESO's 2017 Final Verified Annual CDM Program Results Report)[5] by the equivalent provincial total to estimate the utility's contribution to total provincial savings as a percentage.
- Apply the percentage derive above to the provincial savings per program as outlined in the IESO's 2019-2020 Interim Framework,[6] to estimate the utility's portion of the savings.

[4] Minister's Directive, Discontinuation of the Conservation First Framework (March 21, 2019) and Minister Letter to Further Extend Conservation First Framework (December 9, 2021)
[5] Provided in Appendix A of this schedule.
[6] https://www.ieso.ca/en/Sector-Participants/Energy-Efficiency/2019-2020-Interim-Framework

1.2 2018 CDM Persistence

Toronto Hydro proposes to include 2018 CDM persistence in the modified threshold for calculating the 2020-2022 LRAMVA as this information was not included in the threshold that the OEB approved in EB-2018-0165, due to the uncertainty related to CFF.[7]

2. CONSERVATION FIRST FRAMEWORK ("CFF") ACTUAL SAVINGS

In the absence of final verified annual CDM program results to quantify 2020-2022 LRAMVA, and as specified in the OEB's Chapter 3 filing requirements, Toronto Hydro used the following information to determine the LRAMVA balances:

1. IESO's 2017 Final Verified Annual LDC CDM Program Results Report (Tab 2, Schedule 3, Appendix A)
2. The IESO's Participation and Cost Reports for January 1, 2018 through April 15, 2019 (Tab 2, Schedule 3, Appendix B);[8] these reports include incremental first-year energy savings[9]
3. The Detailed Project-Level Savings the IESO relied upon to generate the Participation and Cost Reports (Tab 2, Schedule 3, Appendix C)[10]
4. Third-party Measurement and Verification Reports for specific projects under the Process and System Upgrades Program and Monitoring and Targeting Program, which is not captured in the IESO's Participation and Cost Reports (Tab 2, Schedule 3, Appendices H-M)

[7] This proposal aligns with VECC's position in EB-2018-0165, VECC Submission (August 28, 2019).
[8] Toronto Hydro has filed the reports in Excel format.
[9] Incentives for projects paid up to the end of February 2019 were settled with the IESO by March 15, 2019 and the energy savings and demand reduction of these projects were included in the Participation and Cost Report issued by the IESO in April 2019. This was the final Participation and Cost Report issued by the IESO.
[10] Toronto Hydro has filed the report in Excel format.

5. Project-level savings related to CFF wind-down programs up to December 31, 2022 concluded during the 2018-2022 period which Toronto Hydro was contractually obligated to complete. For the Retrofit Projects (Tab 2, Schedule 3, Appendices D and G), energy savings and demand reductions are based on the list of projects for which Toronto Hydro paid incentives to customers and which had their status updated to "Project Closed" in CDM-IS system post March 1, 2019. For non-Retrofit CFF Projects (Tab 2, Schedule 3, Appendices E and F), savings are based on the list of projects for which Toronto Hydro has paid incentives and submitted project-level details to the IESO.

The rate class allocations were determined as follows:

1. **Residential Programs:** With the exception of the Instant Discount Program, Toronto Hydro allocated 100 percent of residential program savings to the Residential rate class. For the Instant Discount Program, the utility allocated 95 percent of savings to the Residential rate class and 5 percent to the CSMUR rate class, as these customers also qualify for this program. This allocation is an estimate based on Toronto Hydro's professional judgement, and is consistent with the utility's previous OEB-approved LRAM submissions.
2. **Business and Low-Income Programs:** Due to the termination of the CFF, Toronto Hydro no longer tracks project information submitted to the IESO by rate class. The utility used the most recent available data from its internal project management system to derive the rate class allocations. For the 2018-2022 rate class allocations, Toronto Hydro used a weighted average of available historical savings.
3. **Process Systems and Upgrades ("PSU") Program and Monitoring and Targeting Program:** Toronto Hydro used customer and corresponding rate class information to

determine rate class allocations for savings related to the reports prepared by ClearResult Canada Inc.

Actual CDM savings in the LRAMVA workform are listed as verified or unverified savings. Verified savings refer to CDM savings approved in Toronto Hydro's 2018-2019 LRAMVA filing (EB-2020-0057). Unverified savings refer to CDM savings that have been completed but not submitted in any previous LRAMVA filings.

Toronto Hydro confirms that the calculated savings persistence and net-to-gross factors used to derive net savings by program are based on the 2017 Final Verified Annual LDC CDM Program results.

Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5

Third Party Evaluation Reports

This document includes the following third party evaluation reports:

Monitoring & Targeting Program:

- #601752
- #601753

Process and Systems Upgrades Program:

- #600501
- #601267
- #601461
- #601491
- #601583

[redacted]

[redacted]

Monitoring & Targeting Program - ANNUAL REPORT

[redacted]- Oct 15, 2021

A schematic of the system and the location of the installed meters

- Please reference "[redacted]-Location of Monitoring Devices.pdf"

Confirmation of installation and proper operation

- Please reference "2020-06-10-NoticeOfOperation-[redacted].pdf"

Consumption data for 12 months

- For interval & totalized electricity, water & gas consumption information, please reference:
  - "Utility_Budget_Tracker_FY22_ON-MoreLife.xlsx"
  - "NA-CA-ON-1-0005_IFE-Main-Breaker_2021_09.xlsx"
  - "FY20, FY21 and FY22_HeatMap_Na-CA-ON-1-0005.xlsx"
  - "Screen Shot – [redacted] Energy Dashboard – 1, 2, 3 and 4.jpg"

List of action items/ projects/ plan to capture required savings of at least 0.2 MW and 0.2 MW x Facility Load Factor x 8760 hours;

- Non Agricultural Lighting LED Retrofit – Completed June 2021
  - Cost: $40,187
  - Consumption Savings: 111,892 kWh/yr
  - Demand Savings: 20.895 kW
  - Estimated Financial Savings: >$14,327/yr
  - Retrofit Incentive: $8,358
  - Payback without incentive: ~3 years
  - Payback with incentive: ~2.2 years

- Load Shifting & Balancing
  - Moving Grow Light Schedule to Nighttime/Off-Peak Hours to take advantage of lower Make-Up-Air external temp/humidity and improve HVAC efficiency & GA Critical Peak performance. Balance 12 hour flowering light cycles to smooth demand throughout the day & change labour, fertigation & post harvest scheduling/process to suit. Completed as part of R&D facility conversion Dec 2020-Mar 2021.
    - Cost: ~$85,000 per year – Additional Labour cost to spread out shifts outside of 8am – 6pm. $25,000 internal staff time to re-program Agricultural, Fertigation & Building Controls systems
    - Facility Peak Demand reduced FY 2020: 2045 kW, FY 21: 1845 kW, FY 22: *1313 kW.* **Total Demand Savings: 732 kW**.
    - Facility Total Energy Consumption:
      - FY 20: 9,133,838 kWh (Actual, 12 mos)

[redacted]



[redacted]

- FY 21: 7,308,081 kWh (Actual,11 mos), 7,972,452 kWh (pro-rated, 12 mos)
- FY 22: 3,004,761 kWh (Actual, YTD), 7,211,426 kWh
- **Total Annual Consumption Savings: 1,922,411 kWh/yr**

- LED Clone Carts – Non-Incented, Completed Feb 2019. Replace 400 W HPS agricultural lights & clone trays with custom built LED Clone Cards. 24-7-365 Operation.
    - 28kW Demand Savings
    - 248 MWh/yr Savings
    - CLAIMED AS NON-INCENTED SAVINGS UNDER ENERGY MANAGER PROGRAM
    - Cost: ~$45,000
    - Savings: ~22,000/year
    - Payback: ~2.1 years

Details on proposed action items / projects such as costs, timeline, payback, potential savings;

- See above

Project plan and Estimated Savings for implementation of identified projects with a pay back of less than one year

- Projects Completed, M&T Program requirements COMPLETE. See above.

Partial or major equipment or operational changes to the process within the last year.

- LED Retrofit – Non Agricultural Lighting – changed T8 Fluorescents throughout the building in non-grow licensed areas to LED linear bulbs. SaveOnEnergy Retrofit Program Project 197278.

- In late 2020 and early 2021, the facility's use changed from a production facility growing cannabis for sale to the market under the name [redacted] R&D facility – the primary facility providing R&D services to [redacted] While the grow rooms are still operating at capacity, the experiments & grow methods tested have a goal of reducing energy, water, nutrient & pest control inputs. In addition, the grow lighting schedule for 12 hour light cycle flower rooms was switched to a more balanced schedule, as evidenced by facility heat maps for FY 22 vs FY 21 or FY 20. Mom & Veg room light cycles were shifted from a schedule that coincided with the hottest and most humid times of day to a schedule that avoids these peak hours, decreasing the temp & humidity of Make Up Air and reducing energy used to cool the mom, clone, veg and flower rooms. The Monitoring & Targeting System quantified the financial benefits of the schedule changes & allows the facility to test efficacy of lower energy intensity grow methods.

- In 2019, Clone growing was done using 400 W HPS lamps & T8 Fluorescents. LED Clone carts were built and saved 28 kW of demand & 243 MWh/yr. These are NOT eligible as M&T project savings, though the savings were verified using installed M&T assets, because they were claimed as non-incented savings within [redacted] 2020 Final Energy Manager Program report to the IESO.

SAVE ON ENERGY | DELIVERY PARTNER™

CONSERVATION FIRST FRAMEWORK: MONITORING AND TARGETING PROGRAM

Monitoring and Targeting 2nd Annual Report Review

[redacted]

Project ID: Toronto-MT-601753

October 18, 2022

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited

Prepared by:

CLEAResult

393 University Avenue, Suite 1622, Toronto, ON M5G 1E6

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Monitoring and Targeting 2nd Annual Report Review

1. General Information

Facility Name/Location	
M&T System In-service Date	9/24/2019 (MM/DD/YYYY)
File Identification	Toronto-MT-601753
M&T Annual Report Review Start Date	12/5/2019 (MM/DD/YYYY)
Date of Submission of M&T Report Review	10/18/2022 (MM/DD/YYYY)
Duration of Technical Review[1] (business days)	40
Local Distribution Company (LDC)	Toronto Hydro-Electric System Limited (Toronto Hydro)
LDC Representative	
Technical Reviewer	.

2. Technical Assessment

The Technical Reviewer has completed the review of 2nd Annual Report. has exceeded their Energy Savings Target but has not achieved their Peak Demand Savings Target.

has achieved Peak Demand Savings totaling 129 kW and Annualized Electricity Savings totaling 1,253 MWh/year between September 24, 2019 and September 23, 2021, which represents 65% of their 200 kW and 106% of their 1,186 MWh Savings Target, respectively. See Section 4.3 for details.

3. Documentation Completeness

provided all required documentation, including:

- Drawings and annotated photographs of the M&T System showing installed meter locations,
- Electricity consumption data for the past 24 months,
- Confirmation of M&T system installation,
- Details on projects and project plans are sufficient for the Technical Reviewer to assess their achieved electricity savings, and

[1] Net of Participant's Information Request response time

- Equipment and operational changes over the last 24 months have been the result of the M&T System.

4. Savings Target Progress

has exceeded their second-year Annualized Electricity Savings Target but has not achieved their Peak Demand Savings Target.

4.1. ELECTRICITY SAVINGS TARGETS

In the M&T Application Review, the Technical Reviewer used monthly billing data from October 2016 to September 2017, as provided by to calculate their Energy and Peak Demand Savings Target, as depicted in Table 1 below.

Table 1: Savings Targets

Description		Value	Unit
Actual Annual Electricity Consumption of Facility	*(AA)*	16,983	MWh
One-Hour Facility Annual Peak	*(FAP)*	2,863	kW
Facility Load Factor	*(FLF = AA ÷ [FAP × 8,760 hrs])*	0.677	-
Energy Savings Target	*(0.2 × FLF × 8,760 hrs)*	1,186	MWh
Peak Demand Savings Target	*(As specified in Program Rules)*	200	kW

4.2. IMPLEMENTED AND PLANNED PROJECTS

provided a list of implemented projects, listed in Table 2.

Table 2: Implemented Projects

Project Name	Completion Date
Demand Controlled Ventilation	July 2019
Ontario Kitchen Peak Demand	November 2019
Variable Frequency Drive (VFD)	January 2020
Chiller Refurbishment	May 2020
Elevator Standby Package	June 2021
Elevator Regenerative Package	June 2021

4.3. TECHNICAL REVIEW OF ELECTRICITY SAVINGS

has completed non-incented projects at their Facility. The Technical Reviewer created an adjusted baseline model using sub-meter data in order to verify savings of eligible completed projects. This is an IPMVP Option C M&V methodology.

Baseline Energy Consumption Model

The Facility comprises a single building. Monthly electricity consumption data was available for the baseline period of September 1, 2018, to August 31, 2019. In order to adjust the baseline period energy to reporting period conditions, the Technical Reviewer created a regression model between the monthly electricity consumption, cooling degree-days (CDD), and heating degree-days (HDD) for the Baseline period.

The energy model characteristics are summarized in Table 3.

Table 3: Characteristics of the Energy Model

Variable	Model Independent Variables	Unit of Measure	t-value	p-value
A	Cooling Degree-Days (Balance Point of 18°C)	°C-day	3.43	<0.05
B	Heating Degree-Days (Balance Point of 15°C)	°C-day	-4.12	<0.05
Baseline Time Resolution	Monthly	**Model R^2 value**	0.90	
Model Start Date	1-Sep-18	**Model End Date**	31-Aug-19	
Weather Data Source	Environment Canada Outdoor average air temperature for Climate ID 6158359 (Toronto City Centre Station)			
Model Equation (kWh)	1,427.531 + 1.998 × A - 0.457 × B			

The R^2 value is 0.90 which exceeds the recommended value of 0.75.

The t-value and p-value are in ranges that suggest that the independent variables used in the model are appropriate for the prediction of electricity consumption.

Reporting Period Energy Consumption

The M&T reporting period is from September 24, 2019, to September 23, 2021. In order to assess the achieved annual energy savings, monthly electricity consumption data from the last 12 months of the reporting period, September 24, 2020, to September 23, 2021 was used. The Facility's reporting period annual energy consumption is summarized in Table 4.

Table 4. Summary of Reporting Period Annual Energy Consumption

Description	Value	Unit
Start Date	24-Sept-20	
End Date	23-Sep-21	
Duration	365	Days
Reporting Period Annual Consumption	13,161	MWh
Reporting Period Average Demand	1,502	kW

Non-Routine Adjustment

The Technical Reviewer assessed the impact of COVID-19 on the electricity consumption of [redacted] and found that the impact to be significant, as shown in Figure 1. The Electricity Savings must therefore be adjusted to exclude the impact of COVID-19 and include only the Electricity Savings from the implemented projects.

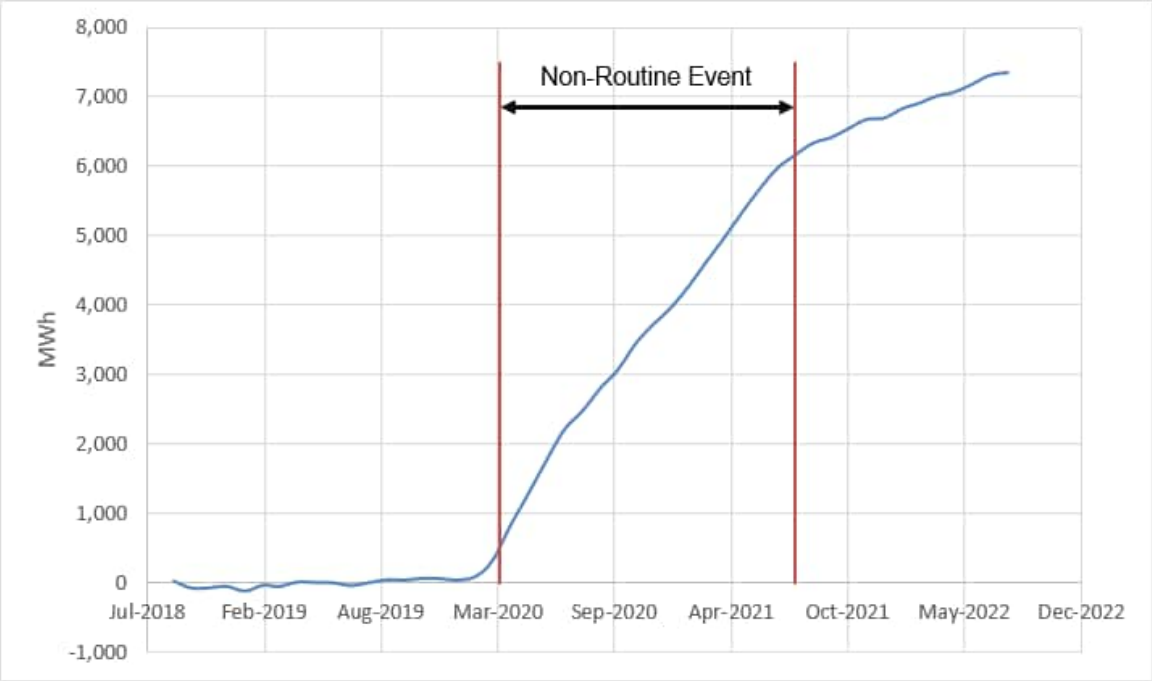

Figure 1. CUSUM of [redacted]

The Non-Routine Event (NRE) occurred from March 15, 2020 to August 31, 2021. The Technical Reviewer calculated the NRA using Method #5, as per the IPMVP guideline[2], using data from September 1, 2021 to August 31, 2022. This period is after the end of the 24-month reporting period; however, [redacted] has confirmed that no additional energy savings measures were implemented during this time. There was one major equipment upgrade unrelated to energy savings measures. A 40 hp air handling unit was replaced in June 2022, which is not expected to have a significant effect on the Facility energy consumption. Therefore, the Technical Reviewer considers this period to be representative of the savings achieved prior to Sept 23, 2021.

The NRE adjustment model characteristics are summarized in Table 5.

Table 5: Characteristics of the Energy Model

Variable	Model Independent Variables	Unit of Measure	t-value	p-value
A	Cooling Degree-Days (Balance Point of 18°C)	°C-day	6.26	<0.05
B	Heating Degree-Days (Balance Point of 15°C)	°C-day	-4.75	<0.05
Baseline Time Resolution	Monthly	**Model R^2 value**	0.94	
Model Start Date	1-Sep-21	**Model End Date**	31-Aug-22	
Weather Data Source	Environment Canada Outdoor average air temperature for Climate ID 6158359 (Toronto City Centre Station)			
Model Equation (kWh)	1,302.793 + 2,269 × A - 0.380 × B			

[2] IPMVP Application Guide on Non-Routine Events & Adjustments, October 2020 EVO 10400 – 1:2020.

In Figure 2, the effect of the NRE adjustment on the CUSUM can be seen. An NRA of -2,285 MWh was applied to the electricity savings.

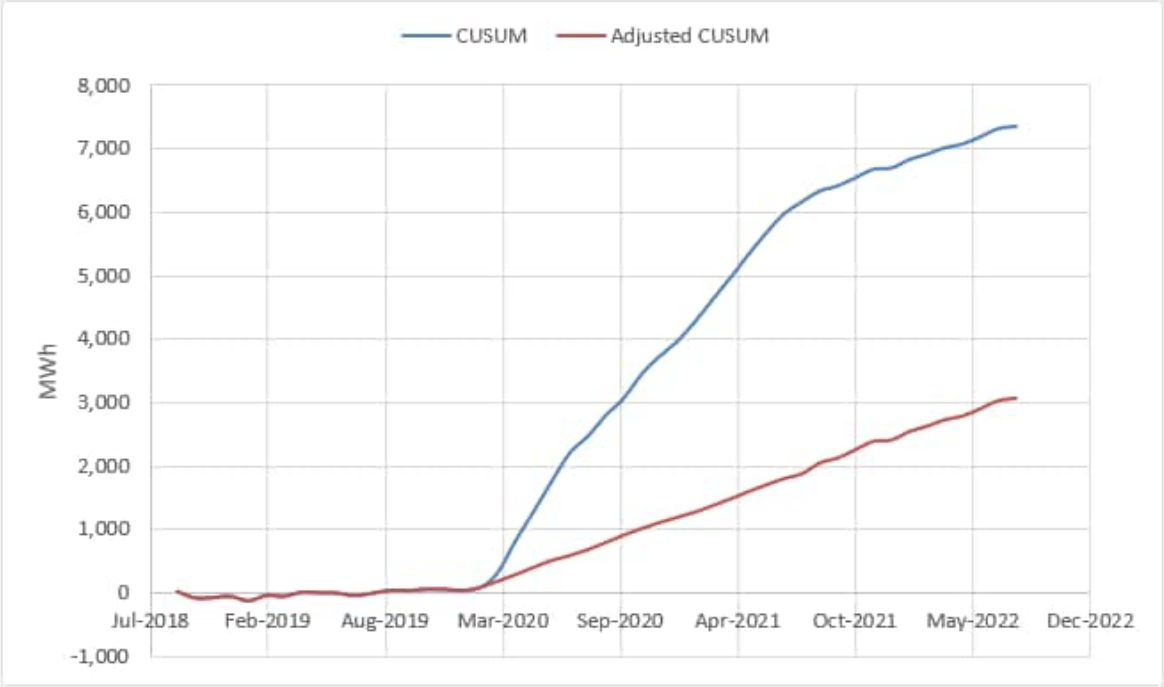

Figure 2. CUSUM With and Without NRA

Electricity Savings

The Electricity Savings are calculated according to the following formula and are summarized in Table 5. IPMVP Option C methodology was used to calculate the Electricity Savings.

Electricity Savings = ***Adjusted Baseline Energy*** – ***Reporting Period Energy*** ± ***Non-Routine Adjustments***

Table 6. Summary of Electricity Savings

Description	Value	Unit
Adjusted Baseline Annual Energy Consumption	16,700	MWh/yr
Reporting Period Annual Consumption	13,161	MWh/yr
Non-Routine Adjustment	-2,285	MWh/yr
Electricity Savings	1,253	MWh/yr
Uncertainty	52	%
Peak Demand Savings	129	kW

The uncertainty of the electricity savings is high because the savings are relatively small compared to the baseline energy. The savings represent 7.5% of the adjusted baseline energy.

5. Savings Summary

The total reviewed energy savings are summarized in Table 7 below.

Table 7. Summary of Performance

Description	kW	MWh
Total Savings	129	1,253
Savings Target	200	1,186
Percentage of Target Achieved	65%	106%

6. Future savings

[redacted] intends to continue to achieve savings using the M&T system. However, [redacted] is planning to shift focus to greenhouse gas emissions reductions within the next year. The year-over-year performance of the M&T measures should be monitored to ensure persistence.

7. Third Annual Report

[redacted] third annual report will be due on October 19, 2022.

SAVE ON ENERGY | DELIVERY PARTNER™

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted]

Cogeneration System

Project ID: Toronto-PI-600501

May 29, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Ltd.

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Revision History

Date	Description	Revision	Author
May 29 2022	M&V Report first issuance.	0	[redacted]

Approvals

	Written by	Reviewed by
Name	[redacted]	[redacted]
Date	May 24, 2022	May 25, 2022
Signature	[redacted]	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of April 3, 2021 to April 2, 2022, are 49,467 MWh, which represent 85% of the Anticipated Electricity Savings.

The Project has achieved the minimum 80% Electricity Savings threshold. Thus, the Participant is eligible for the Final Incentive Payment equal to $1,155,160, calculated in accordance with the terms of the Project Incentive Contract, for the Advanced Payment Option.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings
1st Annual	Apr 3, 2021 to Apr 2, 2022	49,467	85%	$6,530,000[2]

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of this Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the Measure.
- The Incentive based on the performance of the Measure.

In-Service Date Confirmation

The In-Service Date of April 3, 2021 was established on August 19, 2021.

Metered Data Analysis

[redacted] the Participant representative, provided the raw data to the Technical Reviewer for analysis. The raw data includes the following data at hourly intervals:

- Gross electricity generation from the gas turbine generator (GTG)
- Electricity consumption of auxiliary loads, which include the GTG package loads and fuel gas booster compressor (FGBC)

[1] Percentage of the Anticipated Electricity Savings shown in the M&V Plan.

[2] Based on the Application Review Electricity Billing Rate of $132/MWh from the Project Review.

- Natural gas consumption of each of the GTG and duct burner
- Steam produced in the heat recovery steam generators (HRSG)
- HRSG feedwater flowrate
- Combustion air cooling chilled water flowrate and supply/return temperature

The data provided is compliant with the M&V Plan.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Apr 3, 2021, 00:00		
Reporting Period End	Apr 2, 2022, 23:59		
Reporting Period Duration	8,760	hours	
Available Data	8,760	hours	
Missing Data	2	hours	See note below table.
Hours of Operation	7,463	hours	85% of the Reporting Period duration.

The Reporting Period dataset contained 2 hours of missing data on March 13, 2022, at 1 a.m. and 2 a.m., which coincides with the daylight savings time change. The Technical Reviewer assumed that the CHP system had operated during these two hours, as the data shows the CHP system operated during the adjacent hours. For each of the two hours the Technical Reviewer assumed that the gross generation was equal to the average of the gross during the adjacent hours.

Performance of the Measure

The electrical performance of this generation project is based on the following equation:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

The Reporting Period Energy for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	51,295	MWh	
Auxiliary Loads Energy	1,828	MWh	1.5% of Gross Electrical Energy (see comment below table).
Reporting Period Energy	49,467	MWh	Gross Electrical Energy– Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	5,647	kW	Reporting Period Energy ÷ Reporting Period Duration

Electricity Savings

The Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings. Since there has been no change in the Static Factors as defined in the M&V Plan Section B.5.1, Non-Routine Adjustments are not required for this Reporting Period.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Reporting Period Energy	49,467	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	49,467	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Anticipated Electricity Savings	58,008	MWh	Per the M&V Plan.
Electricity Savings as Percentage of Anticipated Electricity Savings	87%		
Average Demand Savings	5,647	kW	Obtained from Table 3.
Summer Peak Demand Savings	5,424	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm - 7:00 pm, June 1 to August 31.

The Electricity Savings of the 1st Annual Reporting Period are 49,467 MWh, which represent 85% of the Anticipated Electricity Savings. The under-performance resulted from lower than anticipated operating hours and average net operating electrical output. The CHP system was anticipated to operate 8,600 hours whereas the Reporting Period uptime was 7,463 hours. The net average operating electrical output of 6,628 kW was lower than the anticipated output of 6,745 kW.

Total System Efficiency

The CHP System's Total System Efficiency (TSE) is calculated according to the following equation.

TSE (%) = [Gross Electrical Energy + Recovered Heat Utilized] / [Fuel Energy Input]

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	51,295	MWh	Obtained from Table 3.
Recovered Heat Utilized	84,710	MWh	
Fuel Energy Input	176,148	MWh	Calculated from total volumetric natural gas consumption to the GTG and a natural gas higher heating value (HHV) of 1,052 BTU/scf provided by the Participant.
Total System Efficiency	77%		This value is higher than the 65% threshold required by the Program.

Next Reporting Period

The M&V Plan shows additional annual reporting periods following completion of the 1st Annual Reporting Period. The Technical Reviewer will send reminders to obtain M&V data at the request of the IESO.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CLEAResult

CONFIDENTIAL

M&V Report

1st Annual Report
October 29, 2018 to October 28, 2019

[redacted]

Compressed Air System Upgrade

Project: Toronto-SCP-601267

August 20, 2021

Revision 0

Prepared for:

[redacted] (the Participant)

Toronto Hydro-Electric System Limited (the LDC)

Prepared by:

CLEAResult (the Technical Reviewer)

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Energy Conservation Measure (ECM), Independent Variable, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Regression Analysis, Reporting Period, Reporting Period Energy, Savings, Standard Error, Static Factors, Uncertainty.

Approvals

	Written by Technical Reviewer	Reviewed by Engineering Manager
Name:	[redacted]	[redacted]
Date:	August 20, 2021	August 20, 2021
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
August 20, 2021	First M&V Report issuance.	0	[redacted]

1. Executive Summary

The Electricity Savings calculated for the 1st Annual Reporting Period of October 29, 2018, to October 28, 2019, are 364 MWh, which represent 191% of the Anticipated Electricity Savings.

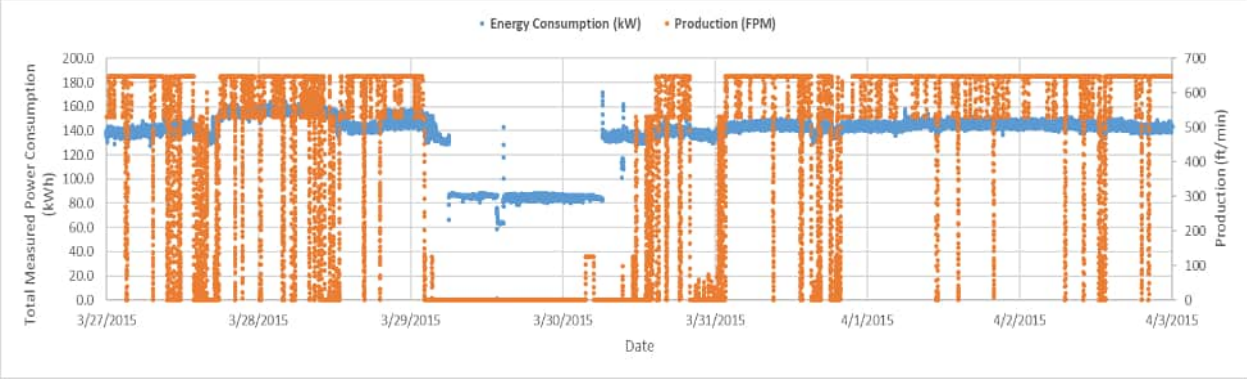
The Electricity Savings meet the 80% performance threshold required by the Program Rules.

2. Project Overview

2.1. Important Note

It has been noted that when the roofing and insulation manufacturing plant (the Facility) line speed is zero, still there are demands for the compressed air. The baseline model of the M&V Plan (Eq. 4) is capped for a minimum of 55,500 (feet per day) daily production. An average of 85.16 kWh has been identified to be a good representative of the compressors power consumption in the Baseline with no daily production.

Figure 1 Baseline Compressors' Energy Consumption and the Facility Production Rate



2.2. Baseline Energy & Anticipated Electricity Savings

The Baseline Energy and the Anticipated Electricity Savings are obtained from the M&V Plan Revision 1 dated May 31, 2017 and are presented in Table 1.

Table 1. Baseline Energy and Anticipated Electricity Savings from the M&V Plan

Description	Value	Unit
Baseline Energy	1,191	MWh/year
Anticipated Electricity Savings	191	MWh/year

This is an IPMVP Option B methodology of calculating the Electricity Savings.

This M&V Report calculates the actual Electricity Savings divided by the Anticipated Electricity Savings, to verify whether that the Project has achieved the required 80% of the Anticipated Electricity Savings.

2.3. In-Service Date and Previous Reporting Period

The In-Service Date of October 29, 2018, was established on December 13, 2018.

The 1st Quarterly Reporting Period was from October 29, 2018, to January 28, 2019.

2.4. Current Reporting Period

The 1st Annual Reporting Period is from October 29, 2018, to October 28, 2019. This Reporting Period represents 365 days (8,760 hours).

3. Reporting Period Energy

3.1. Raw Data

[redacted] the Participant representative, provided the data of electrical consumption and the Facility production to the Technical Reviewer for analysis on June 25 and August 18, 2021.

Table 2 presents an overview of the data analysis related to the Reporting Period Energy, hours of operation and duration of the Reporting Period.

Table 2. Reporting Period Hours, Durations, and Hours of Operations

Parameter	Value	Unit	Comment
Start Date of Reporting Period	October 29, 2018, 00:00	-	
End Date of Reporting Period	October 28, 2019, 23:59	-	
Reporting Period Duration	8,760	Hours	
System Hours of Operation	8,760	Hours	100% uptime
Available Metered Data	8,744	Hours	99.8% of the Reporting Period Duration.
Missing Data	16	Hours	0.2% of the Reporting Period Duration.

Missing hours replaced with the average power consumption data as the missing hours are a small portion of the reporting period. Additionally, 72 days of the production data was not provided. The Technical Reviewer assumed that the Facility's production was zero as a conservative approach.

3.2. Reporting Period Energy

The Reporting Period Energy is shown is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Reporting Period Energy	967	MWh	From the sum of measured compressor and dryer power data.
Uncertainty	± 1%		Based on compressor electric meter specifications.

4. Electricity Savings

4.1. Results

The Electricity Savings are calculated according to the following formula:

Electricity Savings = Adjusted Baseline Energy - Reporting Period Energy ± Non-Routine Adjustments

After the Baseline Period, the electric pump impellers were destroyed by the grit from the shingles. As a result, the Participant replaced four small electric pumps (less than an hours-power) with four new air operated diaphragm pumps. The air flow rate demand increases as the consequence of these new pumps and the two air compressors consume more electricity to supply the new demand.

The air flowrate of one of the diaphragm pumps has been measured as per email of January 7, 2018 from [redacted][1] on behalf of the Participant. The measured flow rate data shows minimum of 25 cfm airflow demands at the normal operation of each pump. All pumps run continuously 24/7 throughout the year[2].

An extra analysis has been done on the baseline data to define the compressors specific power. The Technical Reviewer has calculated the specific power of 20.78 kW/100 cfm when the baseline compressed air flow rates were near 100 cfm. The Technical Reviewer compared the calculated specific power with the compressor data sheet which shows 18 kW/100 cfm at rated capacity of 470 acfm and 22.2 kW at zero flow. Thus, the specific power of 20.78 kW/100 cfm is in acceptable range.

Therefore, a Non-Routine Adjustment was made to the baseline load by adding 20.78 kW for each operating hour of the Reporting Period.

The Reporting Period Energy and Electricity Savings are presented in Table 4.

[1] Email subject: "[redacted]- measured the air consumption of one of the diaphragm pumps", forwarded from "[redacted]", the LDC representative, dated January 7, 2019

[2] Email subject: "RE: Toronto-SCP-601267 - MVR-Q1 - [redacted] - measured the air consumption of one of the diaphragm pumps", from "[redacted]", dated April 1, 2019

Table 4. Calculation of Electricity Savings

Parameter	Value	Unit	Comment
Adjusted Baseline Energy	1,149	MWh	As Per M&V Baseline Energy: 1,191 MWh/year, with annual production of 4.8 million bundles of shingles.
Reporting Period Energy	967	MWh	From Table 3.
Non-Routine Adjustment	182	MWh	*20.78 kW x 8,760 h / 1,000*
Electricity Savings	**364**	**MWh**	Equal to the Adjusted Baseline Energy - Reporting Period Energy + Non-Routine Adjustment
Uncertainty of the Electricity Savings	± 22%	-	The uncertainty is due to the accuracy of the electric meters (±1%) and the baseline uncertainty (±7%).
Anticipated Electricity Savings	191	MWh	From Table 1.
Electricity Savings as a Percentage of Anticipated Electricity Savings	191%	-	This value meets the 80% performance threshold required by the Program Rules.
Average Demand Savings	42	kW	Electricity Savings divided by Reporting Period duration: *364 MWh / 8,760 h*
Summer Peak Demand Savings	51	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm -7:00 pm.

4.2. Conclusion

The Electricity Savings are 364 MWh or 191% of the Anticipated Electricity Savings for the Reporting Period. The Electricity Savings meet the performance threshold of the Program.

The main reason of the overperformance is the non-routine adjustment that is required due the installation of four new diaphragm pumps. In the absence of the non-routine adjustment the Electricity Savings are expected to be within the range of 95% to 105% of the Anticipated Electricity Savings.

4.3. Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

4.4. Electricity Savings to Date

The Electricity Savings to date are provided in Table 5.

Table 5. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings		
		MWh	% of Contracted Electricity Saving	Cost Savings ($)[3]
1st Quarterly	October 29, 2018 to January 28, 2019	58	120%	$29,900
1st Annual	October 29, 2018 to October 28, 2019	364	191%	$47,300

[3] Based on Electricity Billing Rate of 130 $/MWh, obtained from the Project Review (as per Application).

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Measurement & Verification Report
1st Annual
September 1, 2018 to August 31, 2019

[redacted]

Friday, February 21, 2020

PROJECT ID: Toronto-SCP-601461

PREPARED FOR:

Toronto Hydro-Electric System Limited

14 Carlton Street, Toronto ON M5B 1K5

PREPARED BY:

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Prepared per Program Rules version "saveONenergy Process & Systems Upgrades Program, FINAL v1.1 June 8, 2016"

Revision History

Date (MM/DD/YYYY)	Name/Description	Revision	Author
2/21/2020	First Issuance	0	[redacted]

Reviewed by:

Name: [redacted]

Signature: [redacted] Date: 2/21/2020

1. Executive Summary

The Electricity Savings for the 1st Annual Reporting Period of September 1, 2018 to August 31, 2019, are 2,217 MWh, which represents 104% of the Anticipated Electricity Savings.

The Electricity Savings meet the 80% performance threshold required by the Program Rules.

2. Project Overview

2.1. BASELINE ENERGY AND ANTICIPATED ELECTRICITY SAVINGS

The Baseline Energy and the Anticipated Electricity Savings are obtained from the M&V Plan, Rev. 2 dated May 12, 2017, and are presented in Table 1.

Table 1. Baseline Energy and Anticipated Electricity Savings from the M&V Plan

Description	Value	Unit
Baseline Energy	3,626	MWh/year
Anticipated Annual Electricity Savings	2,137	MWh/year

This M&V Report assesses the actual Electricity Savings based on raw data provided by the Participant and the methodology described in the M&V Plan. This is an IPMVP Option B methodology of calculating the Electricity Savings.

This M&V Report calculates the actual Electricity Savings divided by the Anticipated Electricity Savings, to verify whether the Project has achieved the required 80% of the Anticipated Electricity Savings.

2.2. IN-SERVICE DATE AND PREVIOUS REPORTING PERIOD

The In-Service Date is September 1, 2018, which was established on September 27, 2018.

The 1st Quarterly M&V Report covered the period of September 1 to November 30, 2018.

2.3. CURRENT REPORTING PERIOD

The 1st Annual Reporting Period is from September 1, 2018 to August 31, 2019, which represents 365 days (8,760 hours).

3. Reporting Period Energy

[redacted], on behalf of the Participant, provided the raw data to the CMVP for analysis. The raw data includes [redacted]ooling and pump electrical consumption data. The hourly energy consumption of [redacted]lectrical chillers was provided by [redacted]

Table 2 presents an overview of the data analysis related to the Reporting Period Energy and hours of operation.

Table 2. Reporting Period Hours, Duration, and Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	September 1, 2018, 00:00		Start date of the Reporting Period.
Reporting Period End	August 31, 2019, 23:59		This is the end date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date
Available Data of Enwave cooling and pump electrical consumption	8,760	hours	
Available Data of Bell electrical chillers	8,014	hours	All chillers have 746 hours of missing electricity data, except for Chiller 304A/B which has 6,576 hours of missing data. However, the hourly supplied cooling loads of all chillers are continuously available. Chiller 304A/B operates when there is an extra demand which is not the case for majority of Reporting Period. Therefore, the missing data of this chiller most likely is due chiller shutdown.
Missing Data	746	hours	The missing electricity data of the electrical chillers are replaced with the calculated electrical power obtained from supplied cooling loads. An average conversion factor of 0.589 kW/TR is used to convert the thermal energy to electrical energy. The conversion factor is calculated as per monthly average of electrical chiller consumption divided by the average monthly cooling tons that are provided in the Baseline Period.
Hours of Operation	8,760	hours	100% of the Reporting Period Duration

The Reporting Period Energy is shown is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Reporting Period Energy	1,224	MWh	Sum of energy of the chiller + chiller pump + chiller fan + EnWave pumps + EnWave chiller
Reporting Period Uncertainty	± 4.3	%	The Uncertainty is mostly due to the accuracy of the meters, along with the use of an average efficiency for the chillers.
Reporting Period Average Demand	139	kW	1,224 MWh / 8,760 hours × 1000
Reporting Period Summer Peak Demand	207	kW	Average hourly electricity demand (kW) during the summer peak period (weekdays, 1pm – 7pm, June 1 – August 31).

4. Electricity Savings

4.1. ADJUSTED BASELINE ENERGY CALCULATION

As defined in the M&V Plan, the Baseline Energy was adjusted to operating conditions of the Reporting Period using outdoor air temperature as the independent variable. The Adjusted Baseline Energy is shown in Table 4.

Table 4. Adjusted Baseline Energy

Description	Value	Unit	Comment
Reporting Period Hours of Operation	8,760	hours	
Adjusted Baseline Energy	3,441	MWh	Using the Baseline Adjustment equation as per the M&V Plan.
Baseline Peak Demand	592	kW	Obtained from the M&V Plan

4.2. RESULTS

The Electricity Savings are calculated according to the following formula:

Electricity Savings = Adjusted Baseline Energy - Reporting Period Energy ± Non-Routine Adjustment

Since there has been no change in the Static Factors as defined in the M&V Plan Section B.5.2, Non-Routine Adjustments are not required for this Reporting Period. The Reporting Period Energy, Adjusted Baseline Energy, and the Electricity Savings are presented in Table 5.

Table 5. Calculation of Electricity Savings

Description	Value	Unit	Comment
Adjusted Baseline Energy	3,441	MWh	From Table 6.
Reporting Period Energy	1,224	MWh	From Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	2,217	MWh	
Uncertainty of the Electricity Savings	± 15	%	The Uncertainty is a combination of the accuracy of the Baseline meters, the coefficient of variance for the Baseline data, the baseline adjustment equation and the Reporting Period power meters accuracy.
Anticipated Electricity Savings	2,137	MWh	From Table 1.
Electricity Savings as a Percentage of Anticipated Electricity Savings	104	%	
Summer Peak Demand Savings	384	kW	Baseline Peak Demand – Reporting Period Peak Demand

4.3. CONCLUSION

The 1st Annual Electricity Savings are 2,217 MWh and represent 104% of the Anticipated Electricity Savings.

The main reason for the slight overperformance is a minor change in the cooling demand from Bell compared to the Baseline Period.

4.4. NEXT REPORTING PERIOD AND NEXT STEPS

This is the final M&V Report, as the M&V Reporting Period is one year.

4.5. ELECTRICTY SAVINGS TO DATE

The Electricity Savings to date are presented in Table 6.

Table 6. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings		
		MWh	% of Anticipated Savings Value [1]	Cost Savings ($)[2]
1st Quarterly	Sep. 1 to Nov. 30, 2018	507	136%	$63,400
1st Annual	Sep. 1, 2018 to Aug. 31, 2019	2,217	104%	$277,000

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan

[2] Based on $125/MWh obtained from the Project Review

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M&V Report

1st Annual Report
June 2, 2018 to June 1, 2019

[redacted]

Project: Toronto-SCP-601491

July 08, 2019

Revision 0

Prepared for:

[redacted]

Toronto Hydro-Electric System Limited (the LDC)

Prepared by:

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Revision History

Date	Name/Description	Revision	Author
July 8, 2019	Y1 M&V Report issuance	0	[redacted]

Approvals

Name	Title	Signature	Date
[redacted]	[redacted]	[redacted]	July 5, 2019

1. Executive Summary

The Electricity Savings calculated for the 1st Annual Reporting Period of June 2, 2018 to June 1, 2019 are 466 MWh, which represent 98% of the Anticipated Electricity Savings.

The Electricity Savings meet the 80% performance threshold required by the Program Rules.

2. Project Overview

2.1. Baseline Energy & Anticipated Electricity Savings

The Baseline Energy and the Anticipated Electricity Savings are obtained from the M&V Plan Revision 1 dated May 24, 2017, and are presented in Table 1.

Table 1. Baseline Energy and Anticipated Electricity Savings from the M&V Plan

Description	Value	Unit
Baseline Energy	0	MWh/year
Anticipated Electricity Savings	475	MWh/year

This M&V Report assesses the actual Electricity Savings based on raw data provided and the methodology described in the M&V Plan. This is an IPMVP Option B methodology of calculating the Electricity Savings.

This M&V Report calculates the actual Electricity Savings divided by the Anticipated Electricity Savings, to verify whether the Project has achieved the required 80% of the Anticipated Electricity Savings.

2.2. In-Service Date and Previous Reporting Period

The In-Service Date of June 2, 2018 was established on June 26, 2018.

2.3. Current Reporting Period

The 1st Annual Reporting Period is from June 2, 2018 to June 1, 2019. This Reporting Period represents 365 days (8,760 hours).

3. Reporting Period Energy

3.1. Raw Data

[redacted] the Participant representative, provided the data of combined heat and power (CHP) system to the CMVP for analysis. The submitted metered data includes the hourly net CHP system electricity generation as well as the natural gas consumption.

Table 2 presents an overview of the data analysis related to the Reporting Period Energy, hours of operation and duration of the Reporting Period.

Table 2. Reporting Period Hours, Durations, and Hours of Operations

Parameter	Value	Unit	Comment
Start Date of Reporting Period	June 2, 2018, 00:00	-	
End Date of Reporting Period	June 1, 2019, 23:59	-	
Reporting Period Duration	8,760	Hours	
System Hours of Operation	8,758	Hours	99.98% uptime
Shutdown of CHP System	2	Hours	Two subsequent hours did not have electricity generation and the associated natural gas consumption readings were zero.
Missing Data	0	Hours	Data was provided for every hour of the Reporting Period.

The CHP system was operational for 8,758 hours of the 8,760 hours of the Reporting Period, equivalent to 99.98% uptime.

3.2. Reporting Period Energy

The energy generation of the CHP for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP Gross Electricity	Not Available	MWh	Sum of the hourly interval gross energy generated by the CHP system.
Auxiliary Loads	Not Available	MWh	Sum of the hourly interval auxiliary energy consumption by the CHP system.
Reporting Period Energy	466	MWh	CHP Net Electricity Generation.
Uncertainty of the Reporting Period Energy	± 2.0%	-	The uncertainty is due to the accuracy of the electric meters.

4. Electricity Savings

4.1. Results

The Electricity Savings are calculated according to the following formula:

$$\textit{Electricity Savings (MWh)} = \textit{Reporting Period Energy (MWh)} \pm \textit{Non-Routine Adjustments (MWh)}$$

Since there has been no change in the Static Factors as defined in the M&V Plan Section B.5.1, Non-Routine Adjustments are not required for this Reporting Period.

The Reporting Period Energy and Electricity Savings are presented in Table 4.

Table 4. Calculation of Electricity Savings

Parameter	Value	Unit	Comment
Baseline Energy	0	MWh	Baseline Energy is nil, due to no generation in the Baseline Period.
Reporting Period Energy	466	MWh	From Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	**466**	**MWh**	Equal to the Reporting Period Energy.
Uncertainty of the Electricity Savings	± 2.0%	-	The uncertainty is due to the accuracy of the electric meters.
Anticipated Electricity Savings	475	MWh	From Table 1.
Electricity Savings as a Percentage of Anticipated Electricity Savings	98%	-	This value meets the 80% performance threshold required by the Program Rules.
Average Demand Savings	53	kW	Electricity Savings divided by Reporting Period duration: 466 *MWh / 8,760 h*
Summer Peak Demand Savings	47	kW	Summer peak demand savings, weekdays, 1pm – 7pm, June 1 – August 31.

4.2. Conclusion

The Electricity Savings are 466 MWh or 98% of the Anticipated Electricity Savings for the Reporting Period. The Electricity Savings meet the performance threshold of the Program.

4.3. Next Steps

This is the final M&V Report, as the M&V Reporting Period is one year in duration and this Project is a Small Capital Project. No additional M&V data will be required.

4.4. Electricity Savings to Date

The Electricity Savings to date are provided in Table 5.

Table 5. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings		
		MWh	% of Contracted Electricity Saving	Cost Savings ($)[1]
1st Quarterly	June 2 to September 1, 2018	104	87%	$17,100
1st Annual	June 2, 2018 to June 1, 2019	466	98%	$76,900

[1] Based on Electricity Billing Rate of $165/MWh, obtained from the Project Application Review.

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M&V Report

1st Annual M&V Report

February 7, 2019 to February 6, 2020

[redacted] Cogeneration System

Project ID: Toronto-SCP-601583

March 26, 2020

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (the LDC)

[redacted]

Prepared by:

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Revision History

Date	Description	Revision	Author
March 26, 2020	Initial M&V Report issuance.	0	[redacted]

Approvals

Name	Title	Signature	Date
[redacted]	Energy Engineer	[redacted]	March 26, 2020

1. Executive Summary

The Electricity Savings calculated for the 1st Annual Reporting Period of February 7, 2019, to February 6, 2020, are 1,958 MWh/year, which represents 96% of the Anticipated Electricity Savings.

The Electricity Savings meet the 80% performance threshold of the Program Rules.

The Total System Efficiency achieved for the 1st Annual Reporting Period is 70%, which meets the Program Rules requirement of 65%.

2. Project Overview

2.1. Baseline Energy and Anticipated Electricity Savings

The Baseline Energy and the Anticipated Electricity Savings are obtained from the M&V Plan Rev. 3, dated March 28, 2018, and are presented in Table 1.

This is an electricity generation Project, and therefore the Baseline Energy is 0 MWh/year.

Table 1. Baseline Energy and Anticipated Electricity Savings

Description	Value	Unit
Baseline Energy	0	MWh/year
Anticipated Electricity Savings	2,049	MWh/year

This M&V Report assesses the actual Electricity Savings based on raw data provided by the Participant and the methodology described in the M&V Plan. The M&V Report calculates the actual Electricity Savings divided by the Anticipated Electricity Savings, to verify whether the Project has achieved the required 80% of the Anticipated Electricity Savings.

2.2. In-Service Date and Previous Reporting Periods

The In-Service Date of February 7, 2019, was established on February 27, 2019.

The 1st Quarterly Reporting Period was from February 7, 2019, to May 6, 2019.

2.3. Current Reporting Period

The 1st Annual Reporting Period is from February 7, 2019, to February 6, 2020, which represents 365 days (8,760 hours).

3. Reporting Period Energy

3.1. Results

[redacted] the LDC representative, provided the raw data to the CMVP for analysis. Data was provided on an hourly basis for the duration of the Reporting Period, for net electrical energy generation of each of four microturbines, total fuel consumption, and recovered thermal energy utilized by the Facility.

The IPMVP Option B methodology is used for calculating the Electricity Savings.

Table 2 presents an overview of the data analysis related to the duration of the Reporting Period, equipment hours of operation, and Reporting Period Energy.

Table 2. Reporting Period Hours, Durations and Energy

Description	Value	Unit	Comments
Reporting Period Start	Feb. 7, 2019 0:00		
Reporting Period End	Feb. 6, 2020 23:59		
Reporting Period Duration	8,760	hours	
Available Data	8,759	hours	100% of the Reporting Period Duration.
Missing Data	1	hours	0.01% of the Reporting Period Duration.
Hours of Operation	8,759	hours	100% of the Reporting Period Duration.
Reporting Period Energy	1,958	MWh	Net energy generated by the CHP System.

4. Total System Efficiency

4.1. Results

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [CHP Gross Electrical Energy (MWh) + CHP Usable Thermal Output (MWh)] ÷ [Natural Gas Consumption (m^3) × Natural Gas HHV (MWh/m^3)]

The CHP system achieved a Total System Efficiency of 70%, which meets the Program Rules minimum requirement of 65%. The TSE calculation is presented in Table 3.

Table 3. Calculation of Total System Efficiency

Description	Value	Unit	Comments
Gross Electrical Energy	2,186	MWh	Calculated using 6.6 kW of auxiliary loads for each hour of operation, per microturbine.
Utilized Thermal Output	3,273	MWh	
Natural Gas Consumption	7,818	MWh	
Natural Gas HHV	10.722	kWh/m^3	Derived from 0.0386 GJ/m3 value published by Enbridge.
Total System Efficiency	70%		Meets the 65% minimum threshold defined in the Program Rules.

5. Electricity Savings

5.1. Results

The Electricity Savings are calculated according to the following equation:

Electricity Savings = Reporting Period Energy – Baseline Energy ± Non-Routine Adjustments

The Reporting Period Energy and the Electricity Savings are presented in Table 4.

Table 4. Calculation of Electricity Savings

Description	Value	Unit	Comments
Baseline Energy	0	MWh	Obtained from Table 1.
Reporting Period Energy	1,958	MWh	Obtained from Table 2.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	**1,958**	**MWh**	*Reporting Period Energy - Baseline Energy.*
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is primarily due to the accuracy of the power meter readings.
Anticipated Electricity Savings	2,049	MWh	Obtained from Table 1.
Electricity Savings as a Percentage of Anticipated Electricity Savings	**96%**		Meets the 80% performance threshold.
Average Demand Savings	224	kW	Average net power output by the CHP system over the Reporting Period.
Peak Demand Savings	179	kW	Average net power output during the summer peak demand period, defined as Monday to Fridays, 1 pm to 7 pm, June 1 to August 31.

5.2. Conclusion

The Electricity Savings for the 1st Annual Reporting Period are 1,958 MWh which represent 96% of the Anticipated Electricity Savings, which meets the minimum threshold of 80% defined in the Program Rules. The Total System Efficiency is 70%, which meets the minimum threshold of 65% defined in the Program Rules.

The reason for the slight under-performance is the result of a lower average net power output of the CHP system (i.e., 224 kW) compared to what was anticipated as part of the M&V Plan (i.e., 235 kW). This is likely due to slight variations in the Facility electrical and thermal demand, particularly during the summer months.

5.3. Next Reporting Period and Next Steps

This is the final M&V Report, as the M&V Reporting Period is one year.

5.4. Electricity Savings to Date

The Electricity Savings to date are presented in Table 5.

Table 5. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings		
		MWh	% of Contract Savings[1]	Cost Savings[2]
1st Quarterly	Feb 7, 2019 – May 6, 2019	532	107%	$79,300
1st Annual	Feb 7, 2019 – Feb 6, 2020	1,958	96%	$291,700

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $149/MWh obtained from the Application Review.

Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5

Third Party Evaluation Reports

This document includes the following third party evaluation reports:

Process and Systems Upgrades Program:

- #601586
- #601587
- #601600
- #601723
- #601770
- #601800
- #601818

CLEAResult

CONFIDENTIAL

M&V Report

1st Annual M&V Report

July 18, 2018 to July 17, 2019

[redacted]

Project ID: Toronto-SCP-601586

August 8, 2019

Prepared for:

Toronto Hydro-Electric System Limited (the LDC)

[redacted]

Prepared by:

CLEAResult

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

Revision History

Date	Name/Description	Revision	Author
August 8, 2019	Initial M&V Report issuance	0	[redacted]

Approvals

Name	Title	Signature	Date
[redacted]	[redacted]	[redacted]	August 7, 2019

1. Executive Summary

The Electricity Savings calculated for the 1st Annual Reporting Period of July 18, 2018, to July 17, 2019, are 273 MWh which represent 94% of the Anticipated Electricity Savings.

The Electricity Savings meet the 80% performance threshold of the Program Rules.

2. Project Overview

2.1. Baseline Energy and Anticipated Electricity Savings

The Baseline Energy and the Anticipated Electricity Savings are obtained from the M&V Plan Rev. 0, dated May 11, 2017, and are presented in Table 1.

This is an electricity generation Project, and therefore the Baseline Energy is 0 MWh/year.

Table 1. Baseline Energy and Anticipated Electricity Savings

Description	Value	Unit
Baseline Energy	0	MWh/year
Anticipated Electricity Savings	292	MWh/year

This M&V Report assesses the actual Electricity Savings based on raw data provided by the Participant and the methodology described in the M&V Plan. The M&V Report calculates the actual Electricity Savings divided by the Anticipated Electricity Savings, to verify whether the Project has achieved the required 80% of the Anticipated Electricity Savings.

2.2. In-Service Date

The In-Service Date of July 18, 2018, was established on August 29, 2018. This date was conditional upon receipt of confirmation of the Environmental Activity and Sector Registration (EASR), which was issued on November 2, 2018.

2.3. Previous Reporting Periods

The 1st Quarterly Reporting Period was from July 18 to October 17, 2018, representing 92 days (2,208 hours).

2.4. Current Reporting Period

The 1st Annual Reporting Period is from July 18, 2018, to July 17, 2019, representing 365 days (8,760 hours).

3. Reporting Period Energy

3.1. Results

[redacted]the participant representative, provided the raw data to the CMVP for analysis. Net electrical energy generation and natural gas consumption data was provided on an hourly basis for the duration of the M&V Period.

The IPMVP Option B methodology is used for calculating the Electricity Savings.

Table 2 presents an overview of the data analysis related to the duration of the Reporting Period, equipment hours of operation, and Reporting Period Energy.

Table 2. Reporting Period Hours, Durations and Energy

Description	Value	Unit	Comments
Reporting Period Start	July 18, 2018 0:00		Start date and time of the Reporting Period.
Reporting Period End	July 17, 2019 23:59		End date and time of the Reporting Period.
Reporting Period Duration	8,760	hours	Reporting Period End minus Reporting Period Start.
Available Data	8,760	hours	100% of the Reporting Period Duration.
Missing Data	0	hours	0% of the Reporting Period Duration.
Hours of Operation	8,696	hours	99.3% of the Reporting Period Duration.
Reporting Period Energy	273	MWh	Net energy generated by the CHP System.

4. Electricity Savings

4.1. Results

The Reporting Period Energy and the Electricity Savings are presented in Table 3. The Electricity Savings are calculated according to the following equation:

Electricity Savings = Reporting Period Energy – Baseline Energy ± Non-Routine Adjustments

Table 3. Calculation of Electricity Savings

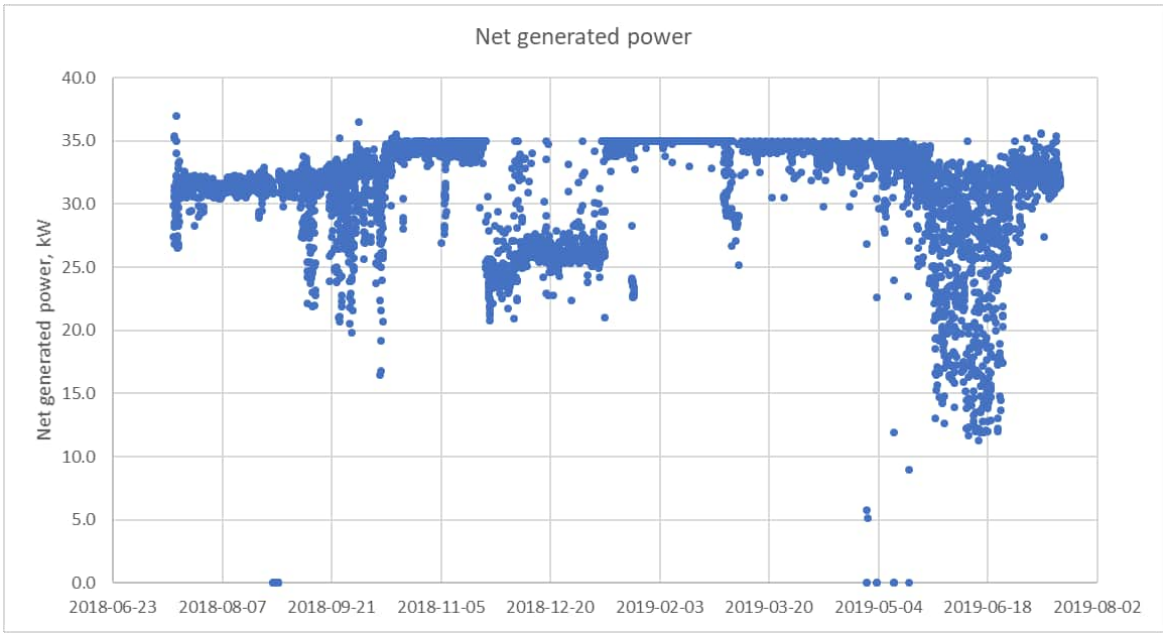
Description	Value	Unit	Comment
Baseline Energy	0	MWh	Obtained from Table 1.
Reporting Period Energy	273	MWh	Obtained from Table 2.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	**273**	**MWh**	Reporting Period Energy minus the Baseline Energy.
Uncertainty of the Electricity Savings	± 2.0%		The Uncertainty is primarily due to the accuracy of the power meter readings.
Anticipated Electricity Savings	292	MWh	From the M&V Plan.
Electricity Savings as a Percentage of Anticipated Electricity Savings	**94%**		Meets the 80% performance threshold.
Average Demand Savings	31.2	kW	Electricity Savings divided by duration of the Reporting Period.
Peak Demand Savings	29.5	kW	Peak demand period, June to August, weekdays from 1 pm – 7 pm.

4.2. Conclusion

The Electricity Savings for the 1st Annual Reporting Period are 273 MWh, which represent 94% of the Anticipated Electricity Savings for the Reporting Period. The Electricity Savings meet the 80% performance threshold of the Program Rules.

The reason for the slight under-performance is that net generated power was lower than anticipated. The System ran almost continuously, with a 99.3% uptime that approached the anticipated average 99.7% uptime. However, the Reporting Period average net output power of 31.2 kW was below the anticipated average net output power of 33.6 kW. Lower average output power occurred most consistently during December 2018, as well as during September 2018 and June 2019, as shown in Figure 1.

Figure 1. Reporting Period net generation



4.3. Electricity Savings to Date

The Electricity Savings to date are presented in Table 4.

Table 4. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings		
		MWh	% of Contract Savings[1]	Cost Savings[2]
1st Quarterly	July 18, 2018 – Oct. 17, 2018	67	94%	$9,700
1st Annual	July 18, 2018 – July 17, 2019	273	94%	$39,300

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $144/MWh obtained from the Project Review.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report
1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PI-601587

January 5, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric Systems Ltd.

Prepared by:
CLEAResult (the Technical Reviewer)
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Prepared per Program Rules version "saveONenergy Process & Systems Upgrades Program, FINAL v2.0", April 6, 2018

Revision History

Date	Description	Revision	Author
January 10, 2022	M&V Report first issuance.	0	[redacted]

Approvals

	Written by Technical Reviewer	Reviewed by Engineering Manager
Name	[redacted]	[redacted]
Date	January 10, 2022	January 10, 2022
Signature	[redacted]	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of November 2, 2020, to November 1, 2022, are 1,260 MWh, which represents 48% of the Anticipated Electricity Savings.

The significant underperformance is a result of much lower than anticipated electricity generation from the CHP System, caused by shutdown of the CHP System due to the COVID-19 pandemic and noise disturbance in the Facility. The Participant is aware of the underperformance but confirmed that they have no intention to delay the start of the Reporting Period from the In-Service Date.

The CHP System achieved a Total System Efficiency (TSE) of 58.5%, which is less than the minimum 65% Program requirement.

The Balance Incentive payable to the Participant is $111,487, which is based on the performance ratio of 48% and an adjustment to account for the low TSE. Refer to the Appendix for details on the Incentive calculation.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings
1st Quarterly	Nov 2, 2020 to Feb 1, 2021	258	39%	$33,500[2]
1st Annual	Nov 2, 2020 to Nov 1, 2021	1,260	48%	$163,800

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the Measure.
- The Incentive based on the performance of the Measure.

In-Service Date Confirmation

The In-Service Date of November 2, 2020, was established on April 14, 2021.

[1] Percentage of the Anticipated Electricity Savings shown in the M&V Plan.

[2] Based on the contracted Electricity Billing Rate of $130/MWh (see Approval Letter).

Metered Data Analysis

[redacted] a representative of the Participant, provided the M&V data on November 15, 2021, to the Technical Reviewer for analysis. The data provide includes the following, at 15-minute intervals:

- CHP system gross electrical output
- Power draw of the CHP system auxiliary components
- CHP system volumetric fuel input rate
- CHP system heat utilization

The data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Nov 2, 2020, 00:00		
Reporting Period End	Nov 1, 2021, 23:59		
Reporting Period Duration	8,760	hours	
Available Data	8,757	hours	Almost 100% of the Reporting Period Duration
Missing Data	3	hours	
Hours of Operation	6,103	hours	70% of the Reporting Period duration.

Performance of the Measure

The electrical performance of this generation project is based on the following equation:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

The Reporting Period Energy for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,296	MWh	
Auxiliary Loads Energy	36	MWh	
Reporting Period Energy	1,260	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	144	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	256	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm - 7:00 pm, June 1 to August 31.

Electricity Savings

The Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings. Since there has been no change in the Static Factors as defined in the M&V Plan Section B.5.1, Non-Routine Adjustments are not required for this Reporting Period.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Reporting Period Energy	1,260	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,260	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Anticipated Electricity Savings	2,649	MWh	
Electricity Savings as Percentage of Anticipated Electricity Savings	48%		
Average Demand Savings	144	kW	Obtained from Table 3.
Summer Peak Demand Savings	256	kW	Obtained from Table 3.

The Electricity Savings of 1st Annual Reporting Period are 1,260 MWh, which represent 48% of the Anticipated Electricity Savings. The significant under-performance is due to the following:

- The CHP System uptime was 70%, which is lower than the anticipated uptime of 96%.
- The CHP System net operating electricity generation was 206 kW, which is significantly lower than the anticipated average generation of 315 kW.

The significantly reduced uptime was a result of the following:

- Prolonged shutdown of the CHP system during the first few months of operation, which was a result of unavailability of technical personnel (due to the COVID-19 pandemic) to troubleshoot operational issues.
- Shutdown of the CHP system at night due to noise disturbances in the penthouse level of the Facility.

The Participant is aware of the underperformance but had confirmed that they have no intention to delay the start of the Reporting Period from the In-Service Date. The Participant has indicated that the noise issue has been rectified by implementing sound attenuation measures and the CHP system is currently operating throughout the day.

Total System Efficiency

The CHP System's Total System Efficiency (TSE) is calculated according to the following equation.

TSE (%) = [Gross Electrical Energy + Recovered Heat Utilized] / [Fuel Energy Input]

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	1,296	MWh	Obtained from Table 3.
Recovered Heat Utilized	1,226	MWh	
Fuel Energy Input	4,308	MWh	Calculated from total volumetric natural gas consumption and a natural gas higher heating value (HHV) of 1,020 BTU/ft^3, specified in the M&V Plan.
Total System Efficiency	58.5%		This value is lower than the 65% threshold required by the Program.

Note that the TSE of 58.5% is less than the minimum 65% Program requirement but higher than the minimum 57.5% required to be eligible for an Incentive. See the Appendix for the Incentive calculation.

Next Reporting Period

The 1st Annual Reporting Period is the final Reporting Period. Thus, there are no more reporting periods.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual M&V Reporting Period, Project Benefits, Eligible Costs and TSE, the Balance Incentive payable to the Participant is $111,487. The Incentive calculation is shown in Table A1. Note that a 15% discount was applied to the Incentive, based on Program rules, as the TSE falls between 57.5% and 60.0%.

Table A1. Incentive Calculation

Electricity Savings (MWh)	1,260
Electricity Billing Rate ($/MWh)	130[3]
Electricity Billed Savings	$163,800
Other Benefits and Costs	$0
Project Benefits	$163,800
Eligible Costs	$870,146[4]
Contracted Incentive Amount	$529,800
Incentive 1 - $200/MWh (capped at 120% of the contracted Incentive amount)	$251,960
Incentive 2 - 40% of Eligible Costs	$348,059
Incentive 3 - 1-year Payback	$706,373
Project Incentive (Minimum of 3 limiters above)	$251,960
Recommended Project Incentive (Discounted by 15% due to low TSE)	$214,166
Recommended First Payment	$102,679[5]
Recommended Balance Payment	$111,487

Table A2. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Payment
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

[3] Contracted Electricity Billing Rate (see Approval Letter)

[4] Reviewed Eligible Costs (see comment on Eligible Costs in the Payment Recommendation for the First Payment, issued on January 7, 2022).

[5] See Payment Recommendation for the First Payment.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

SAVE ON ENERGY | DELIVERY PARTNER™

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-SCP-601600

March 13, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	[redacted]
Date:	March 13th 2023	March 6th, 2023
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
March 6, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of September 28, 2021 to September 27, 2022, are 1,437 MWh, which represents 97% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $147,900. Refer to the Appendix for details.

The Electricity Savings meet the 80% performance threshold required by the Program Rules.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Sept 28 to Dec 29, 2021[3]	401	109	$57,300
1st Annual	Sept 28, 2021 to Sept 27, 2022	1,437	97	$205,610

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

Important Considerations

Please note the following:

1. The In-Service Date was originally set to January 31, 2020. However, the Participant requested the Reporting Period begin September 28, 2021. The extension was requested due to necessary equipment repairs as well as a result of the COVID-19 pandemic. Please refer to " Toronto-SCP-

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $143/MWh obtained from the Project Application Review.
[3] There were 35 hours of missing data points in the Q1 raw data. Therefore, the 1st Quarterly Reporting Period was extended by 35 hours.

601600_[redacted]Cogeneration System_Q1_MVR" for more details.

2. The natural gas flow data provided is appears to be understated relative to the ICE specifications. The annual natural gas consumption is 9.7% lower than the calculated consumption based on the hourly electricity output and the ICE specification performance. However, the most conservative Total System Efficiency estimated is 70.6% which is higher than the 65% program requirement.

In-Service Date Confirmation

The In-Service Date of January 31, 2020, was established on November 17, 2020.

1st Quarterly Report was issued on January 28, 2022 with an updated in-service date of September 28, 2021.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on January 25, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	September 28, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	September 27, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date
Available Data	8,701	hours	
Missing Data	59	hours	See comments below table
Hours of Operation	8,645	hours	99.4% of the Reporting Period Duration

The M&V data was missing (ie. the data set didn't include these hours or the cells were blank) for 59 hours:

- October 27, 2021, 16:00 to October 28, 2021, 17:00 (26 hours)
- December 12, 2021, 10:00 to December 12, 2021, 18:00 (9 hours)
- September 27, 2022, 1:00 to September 27, 2022 0:00 (24 hours)

The Technical Reviewer assumes that the CHP system did not operate during this period as the electrical output, thermal heat recovered, and natural gas consumption were missing or recorded as blank values. Therefore; the missing data was assumed to be zero gross electrical output.

Please note that these 59 hours represent 0.67% of the reporting period, which is well within the 10% missing data permissible per Section B.6.2 of the Measurement and Verification Plan. Additionally, the conservative assumption that the CHP system was not outputting any electricity during the period still meets the 80% performance threshold required by the Program Rules.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,498	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	61	MWh	Equal to 4.1% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,437	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	165	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	127	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The ICE supplier confirmed via email on January 18, 2022, that the metered power output from the ICE is gross power (i.e., does not exclude any internal or external auxiliary loads).

The Measurement and Verification Plan specifies that is the auxiliary loads are not metered, they should be determined using the equipment nameplate data; however, as a conservative approach, auxiliary loads were accounted for as 3% of the 125 kW ICE gross capacity. The auxiliary loads were applied for each unit individually (ie. if one unit was operating the loads were 3.75 kWh and 7.5 kWh if both units were operating

simultaneously). Because the System performed well above the 80% performance requirement, the Technical Reviewer deemed this approach sufficient.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,437	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,437	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,479	MWh	Obtained from the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	97%	-	
Average Demand Savings	165	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	127	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 1,437 MWh and represent 97% of the Anticipated Electricity Savings.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,498	MWh	See the comment below.
CHP Thermal Output Utilized	2,212	MWh	
Metered CHP Energy Input	4,745	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 38.4 MJ/m^3 (10.67 kWh/m^3), obtained from the M&V Plan.

Metered Total System Efficiency	78.2%	-	

The metered natural gas flow data flow data appears to be understated the energy input by 10% compared to the ICE specifications. However, when the ICE specifications are used to energy input, the TSE decreases to 70.6% which meets the 65% program requirement.

Next Reporting Period

The is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

The Incentive payable for the 1st Annual M&V Reporting Period is $147,900. Table 6 outlines the payment schedule as defined in the contract and Program Rules, for reference.

Table 6. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted]

15.7 MW CHP System

Project ID: Toronto-PI-601723

March 09, 2022

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited

[redacted]

Prepared by:

CLEAResult (the Technical Reviewer)

393 University Avenue, Suite 1622, Toronto, ON M5G 1E6

(416) 504-3400

Prepared per Program Rules version "saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018

Revision History

Date	Description	Revision	Author
March 9, 2022	M&V Report first issuance.	0	[redacted]

Approvals

	Written by Technical Reviewer	Reviewed by Engineering Manager
Name	[redacted]	[redacted]
Date	March 9, 2022	March 9, 2022
Signature	[redacted]	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of February 12, 2021, to February 11, 2022, are 128,648 MWh, which represents 163% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $1,575,093, which is equal to 10% of the Approved Incentive amount of $15,750,930[1].

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[2]	Electricity Cost Savings[3]
1st Quarterly	Feb 12 to May 11, 2021	31,541	164%	$1,675,000
1st Annual	Feb 12, 2021 to Feb 11, 2022	128,648	163%	$6,831,000

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the Measure.
- The Incentive based on the performance of the Measure.

In-Service Date Confirmation

The In-Service Date of February 12, 2021, was established on July 30, 2021.

[1] This is the maximum Participant Incentive payable, according to Section 3.3a of the terms and conditions in the Project Application, dated September 14, 2018.

[2] Percent of Anticipated Electricity Savings defined in the M&V Plan

[3] Based on $53.1/MWh obtained from the Project Application Review

Metered Data Analysis

[redacted] a representative of the Participant, provided the M&V data on March 3, 2022, to the Technical Reviewer for analysis. The data includes the following at 15-minute intervals:

- Gross electricity generation from the gas turbine generator (GTG)
- GTG auxiliary loads power consumption
- Fuel Gas Booster Compressor power consumption
- GTG and duct burner natural gas consumption
- Heat Recovery Steam Generator (HRSG) steam mass flowrate, temperature and pressure
- Economizer Feedwater temperature
- 6T Dryer exhaust gas input temperature

The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	February 12, 2021, 00:00		
Reporting Period End	February 11, 2022, 23:59		
Reporting Period Duration	8,760	hours	
Available Data	8,733	hours	
Missing Data	27	hours	The GTG was operating but data was frozen due to data communication problems. The Participant assumed missing gross generation values are 15,987 kW, which the Technical Reviewer considers to be reasonable.
Hours of Operation	8,544	hours	98% of the Reporting Period Duration

Performance of the Measure

The Electricity Savings for generation projects are calculated according to the following equation:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustment

Since there has been no change in the Static Factors as defined in the M&V Plan Section B.5.1, Non-Routine Adjustments are not required for this Reporting Period. The Reporting Period Energy and Electricity Savings are presented in Table 3 and Table 4, respectively.

Reporting Period Energy

Table 3 presents a summary of the Reporting Period Energy analysis.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP System Gross Energy	134,060	MWh	
CHP System Auxiliary Loads Energy	5,412	MWh	Represents 4% of the CHP System Gross Energy
Reporting Period Energy	128,648	MWh	Gross Energy – Auxiliary Loads Energy
Uncertainty of the Reporting Period Energy	± 2.5%	%	Primarily due to meter uncertainty.

Electricity Savings

Table 4 presents a summary of the Electricity Savings analysis.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Reporting Period Energy	128,648	MWh	Obtained from Table 3**Error! Reference source not found.**.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	128,648	MWh	
Uncertainty of the Electricity Savings	± 2.5%		Primarily due to meter uncertainty.
Anticipated Electricity Savings	79,005	MWh	Obtained from the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	163%		
Average Demand Savings	14,686	kW	Electricity Savings divided by Reporting Period duration.
Summer Peak Demand Savings	14,386	kW	Summer peak demand period is defined as June 1 to August 31, weekdays, 1:00 pm - 7:00 pm.

The 1st Annual Reporting Period Electricity Savings are 128,648 MWh and represent 163% of the Anticipated Electricity Savings.

The overperformance was due to the installation of a 15.7 MW (nameplate) CHP system whereas the Anticipated Electricity Savings are based on a 9.8 MW (nameplate) CHP system.

Total System Efficiency

The CHP System's Total System Efficiency (TSE) is calculated according to the following equation.

TSE (%) = [Gross Electrical Energy + Recovered Heat Utilized] / [Fuel Energy Input]

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	134,060	MWh	
Utilized Thermal Output	142,424	MWh	
Fuel Energy Input	394,571	MWh	Calculated from the volumetric fuel input, using a natural gas higher heating value of 10.67 kWh/m^3
Total System Efficiency	70	%	Meets the minimum 62% requirement for this Project

Next Reporting Period

The M&V Plan shows four additional annual reporting periods following completion of the 1st Annual Reporting Period. The Technical Reviewer will send reminders to the LDC to obtain M&V data.

Appendix

The Incentive is calculated in accordance with the terms for Advanced Payment in the Section 4.1b of the Project Application Form.

Table 6. Incentive Payment Schedule

Advanced Payment Schedule	Projected Date	% of Approved Amount
Payment 1	The Participant and the LDC have agreed to the M&V Plan as provided by the Technical Reviewer and the LDC is in receipt of the Participant's Performance Security.	50% of the Approved Amount
Payment 2	The Technical Reviewer has confirmed the In-Service Date & the Eligible Costs, in receipt of Invoice Reconciliation Form and the Technical Reviewer has issued the initial M&V Report.	The amount that is 90% of the Participant Incentive less the First Payment noted above (Calculated based on the initial M&V Report less the First installment)

Final Payment (Holdback)	The Technical Reviewer has issued the final M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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Measurement & Verification Report

1st Annual Report

March 27, 2019 – March 26, 2020

[redacted]

[redacted] Electric Heating Controls and Windows Upgrade

Project: Toronto-SCP-601770

August 7, 2020

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (the LDC)

[redacted]

Prepared by:
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Revision History

Date	Description	Revision	Author
August 7, 2020	Annual M&V Report, first issuance.	0	[redacted]

Approvals

Name	Title	Signature	Date
[redacted]	Energy Engineer	[redacted]	August 7, 2020

1. Executive Summary

The Electricity Savings calculated for the 1st Annual Reporting Period of March 27, 2019, to March 26, 2020, are 293 MWh which represent 115% of the Anticipated Electricity Savings.

The Electricity Savings meet the 80% performance threshold required by the Program Rules.

2. Project Overview

2.1. Baseline Energy and Anticipated Electricity Savings

The Baseline Energy and the Anticipated Electricity Savings are obtained from the M&V Plan, rev.1, dated May 8, 2018, and are presented in Table 1.

Table 1. Baseline Energy and Anticipated Electricity Savings

Description	Value	Unit
Baseline Energy	1,436	MWh/year
Anticipated Electricity Savings	254	MWh/year

This M&V Report assesses the actual Electricity Savings based on raw data provided by the Participant and the methodology described in the M&V Plan, rev.1. This is an IPMVP Option C methodology of calculating the Electricity Savings.

This M&V Report calculates the actual Electricity Savings divided by the Anticipated Electricity Savings, to verify whether the Project has achieved the required 80% of the Anticipated Electricity Savings.

2.2. In-Service Date and Previous Reporting Periods

The In-Service Date of March 27, 2019 was established on July 31, 2020.

Note that an M&V Report was not issued for the 1st Quarterly Reporting Period.

2.3. Current Reporting Period

The 1st Annual Reporting Period is from March 27, 2019, to March 26, 2020, representing 366 days (8,784 hours).

3. Reporting Period Energy

3.1. Raw Data

[redacted] (the Participant's representative) provided the Facility's hourly utility power data to the CMVP for analysis.

Table 2 presents an overview of the data analysis related to the Reporting Period duration and hours of operation.

Table 2. Reporting Period Duration and Hours of Operation

Description	Value	Unit	Comments
Reporting Period start	March 27, 2019 0:00		
Reporting Period end	March 26, 2020 23:59		
Reporting Period duration	8,784	hours	
Available data	8,784	hours	100% of the Reporting Period Duration.
Missing data	0	Hours	0% of the Reporting Period Duration.
Hours of Operation	8,784	hours	100% of the Reporting Period Duration.

There were no missing power measurements. The M&V data is the utility power data provided by LDC.

3.2. Reporting Period Energy

The Reporting Period Energy is shown in Table 3 below.

Table 3. Reporting Period Energy

Description	Value	Unit	Comments
Reporting Period Energy	1,214	MWh	Total Facility electricity consumption.
Uncertainty of the Reporting Period Energy	± 0.0%		Utility meter is assumed to have zero uncertainty.

4. Electricity Savings

4.1. Adjusted Baseline Energy

The Adjusted Baseline Energy is calculated using the energy model defined in the M&V Plan rev.1, section B.5.1. The Baseline Energy is adjusted based on the monthly heating degree days (HDD) using the following equations:

Adjusted Baseline Energy (MWh) = Sum of [Monthly Facility Adjusted Energy (kWh)] over the Reporting Period / 1,000

Monthly Facility Adjusted Energy (kWh) = 256.82 × monthly sum of HDD (ºC.days, base 16°C) + 59,076

The monthly HDDs are calculated using the average daily outdoor air temperature (obtained from Environment Canada for Toronto Pearson, WMO 71624) during the Reporting Period, based on a heating balance point of 16°C.

The Adjusted Baseline Energy for this Reporting Period is 1,507 MWh.

4.2. Results

The Electricity Savings are calculated according to the following equation:

Electricity Savings = Adjusted Baseline Energy - Reporting Period Energy ± Non-Routine Adjustments

Since there has been no change in the Static Factors as defined in the M&V Plan, rev.1 Section B.5.2, Non-Routine Adjustments are not required for this Reporting Period. The results are presented in Table 4.

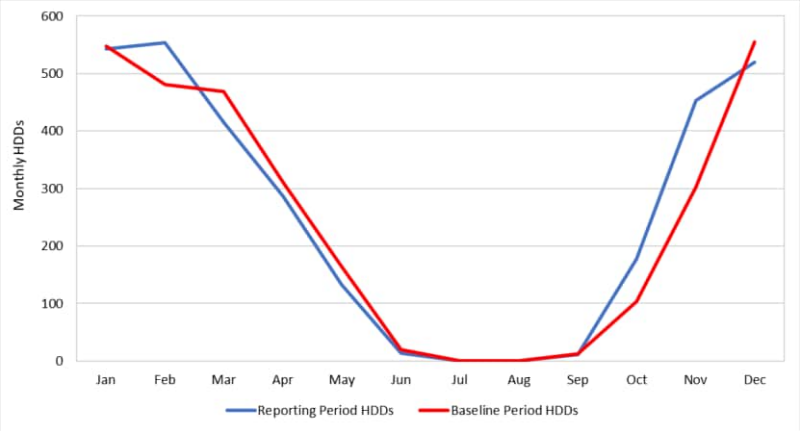
Table 4. Calculation of Electricity Savings

Description	Value	Unit	Comments
Adjusted Baseline Energy	1,507	MWh	From Section 4.1.
Reporting Period Energy	1,214	MWh	From Table 3.
Non-Routine Adjustments	0	MWh	None.
Electricity Savings	293	MWh	*Adjusted Baseline Energy - Reporting Period Energy*
Relative uncertainty of the Electricity Savings	± 46%		Based on Baseline Energy relative uncertainty of ± 9% and Reporting Period Energy relative uncertainty of ± 0%.
Anticipated Electricity Savings	254	MWh	From Table 1.
Electricity Savings as a Percentage of Anticipated Electricity Savings	115%		Meets the required 80% performance threshold as per the Program Requirements.
Average Demand Savings	33.4	kW	*Electricity Savings ÷ Reporting Period Duration*
Peak Demand Savings	5.7	kW	Summer peak demand period savings, defined as June 1 - August 31, weekdays, 1pm - 7pm.

4.3. Conclusion

The Electricity Savings are 293 MWh and represent 115% of the Anticipated Electricity Savings for this Reporting Period. One possible reason for the slightly higher than anticipated Electricity Savings is an overall colder heating season compared to the Baseline Period, as shown in Figure 1 below.

Figure 1. Monthly HDDs in Baseline and Reporting Periods



4.4. Electricity Savings to Date

The Electricity Savings to date are presented in Table 5.

Table 5. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings		
		MWh	% of Anticipated Savings Value[1]	Cost Savings[2] ($)
1st Quarterly	March 27, 2019 to June 27, 2019	N/A	N/A	N/A
1st Annual	March 27, 2019 to March 26, 2020	293	115%	$40,700

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $139/MWh obtained from the Project Review.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601800
September 16, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
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Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018”

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name:	[redacted]	[redacted]
Date:	September 16, 2022	September 16, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
September 16, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of June 30, 2021, to July 21, 2022, are 1,871 MWh, which represents 88% of the Anticipated Electricity Savings. The Total System Efficiency achieved for the 1st Annual Reporting Period is 68.3%, which meets the Program Rules minimum requirement of 65%.

Note that the original 1st Annual Reporting Period was scheduled to end on June 29, 2022. However, the Reporting Period had to be extended to July 21, 2022, as one of the engines in the combined heat and power (CHP) system was unexpectedly shutdown on May 26, 2022. The shutdown, which lasted 506 hours, was the result of a cylinder head failing, causing metal to enter a combustion chamber. The replacement was not successfully completed until June 16, 2022.

The Incentive payable to the Participant for this Reporting Period is $186,842. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Jun 30 to Sep 29, 2021	472	133%	$66,552
1st Annual	Jun 30, 2021 to Jul 21, 2022	1,871	88%	$269,464

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $144/MWh obtained from the Project Approval Letter.

In-Service Date Confirmation

The In-Service Date was set to June 30, 2021, on August 4, 2021, by the Technical Reviewer.

Metered Data Analysis

[redacted] the LDC representative, provided the M&V data on September 1, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Jun 30, 2021, 0:00		Start date of the Reporting Period.
Reporting Period End	Jul 21, 2022, 1:59		End date of the Reporting Period.
Reporting Period Duration	9,266	hours	End date minus start date.
Available Data	9,266	hours	
Missing Data	0	hours	0% of the Reporting Period Duration.
Unexpected Shutdown	506	hours	
Hours of Operation	8,431	hours	96% of the Reporting Period Duration excluding the 506 hours unexpected shutdown period.

Performance of the Measure

The electrical performance of the project is based on the reporting period energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,944	MWh	
CHP Auxiliary Loads Energy	73	MWh	3.8% of the CHP Gross Electrical Energy. See details below Table 3.
Reporting Period Energy	1,871	MWh	CHP Gross Electrical Energy – CHP Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Average Generation	214	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	209	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm - 7:00 pm, June 1 to August 31.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by the supplier of the CHP system to be 1.5 kW for each engine. The Technical Reviewer accepted this value and applied either 1.5 kW or 3 kW per CHP system operating hour, depending on whether one or two engines were operating respectively, to calculate the internal auxiliary load energy. The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,871	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,871	MWh	
Uncertainty of the Electricity Savings	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	2,125	MWh	As per the M&V Plan.
Electricity Savings as a Percentage of Anticipated Electricity Savings	88	%	
Average Demand Savings	214	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	209	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm -7:00 pm, June 1 to August 31.

The 1st Annual Reporting Period Electricity Savings are 1,871 MWh and represent 88% of the Anticipated Electricity Savings. The underperformance is the result of the Reporting Period average operating electrical output being 222 kW with 96% uptime, whereas the anticipated average operating electrical output was 243 kW with 100% uptime. Note that the original Project scope was based on the installation of four micro-turbine generators with a nominal capacity of 260 kW (i.e., 4 x 65 kW). In the completed Project, two 125 kW internal combustion reciprocating engines were installed.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Energy (MWh) + CHP Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 5. Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,944	MWh	Obtained from Table 3.
CHP Utilized Thermal Output	2,648	MWh	
Natural Gas Higher Heating Value (HHV)	10.75	kWh/m^3	As per the M&V Plan.
CHP Fuel Energy Input (HHV)	6,724	MWh	
Total System Efficiency	68.3	%	

The CHP system achieved a TSE of 68.3%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and verified Eligible Costs, the Incentive payable to the Participant is $186,842. The Master Payment Requisition will be issued once the Participant's invoice for the Incentive amount is provided.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,871	1st Annual Reporting Period Electricity Savings.
Approved Amount	$425,074	From the Project Approval Letter.
Limiter 1 - Electricity Savings	$374,255	$200 per MWh of Electricity Savings, capped at 120% of Approved Amount.
Estimated Eligible Project Costs	$1,970,000	From the Project Approval Letter.
Actual Eligible Project Costs	$1,283,465	Based on the review of invoices for the 1st payment.
Limiter 2 - Project Costs	$513,386	40% of minimum of Estimated and Actual Eligible Project Costs.
Net Benefits	$113,291	Equal to the electricity savings, calculated using a billing rate of $144/MWh, plus the Other Benefits less Other Costs from the Project Approval Letter.
Limiter 3 – 1-year Project Payback	$1,170,174	Eligible Costs minus Net Benefits.
Gross Project Incentive	$374,255	Minimum of the three limiters.
Project Incentives paid	$187,413	Paid for 1st Quarterly Reporting Period.
Study Incentive paid	N/A	Paid for Engineering Study.[3]
Incentive payable	**$186,842**	Gross incentive minus incentives paid.

Table 7 provides the Incentive payment schedule.

[3] No deduction under “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018.”

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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M&V Report

1st Annual M&V Report

June 1, 2019 to August 29, 2020

[redacted]

Process Water System Improvements

Project ID: Toronto-SCP-601818

November 16, 2020

Rev. 1

Prepared for:

Toronto Hydro-Electric System Limited (the LDC)

[redacted]

Prepared by:

CLEAResult

393 University Ave., Suite 1622

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Revision History

Date	Description	Revision	Author
Sept. 14, 2020	First M&V Report issuance.	0	[redacted]
Nov. 13, 2020	Revised analysis after consultant indicated that M&V Plan defines hourly average power to determine hours of operation. Initial analysis used the provided 15-minute interval data divided by four.	1	[redacted]

Approvals

Name	Title	Signature	Date
[redacted]	Engineering Manager	[redacted]	November 13, 2020

1. Executive Summary

The Electricity Savings calculated for the 1st Annual Reporting Period of June 1, 2019, to August 29, 2020, are 652 MWh which represent 67% of the Anticipated Electricity Savings.

The Electricity Savings do not meet the 80% performance threshold of the Program Rules.

Note that due to COVID-19, the Facility was shut down from March 19 to June 18, 2020, and the Reporting Period was extended accordingly by 91 days. The pre- and post-COVID-19 electrical performances of the measure are nearly identical, indicating a back-to-normal operation of the measure from June 2020.

2. Project Overview

2.1. Baseline Energy and Anticipated Electricity Savings

The Baseline Energy and the Anticipated Electricity Savings are obtained from the M&V Plan, rev. 0, dated December 24, 2018, and are presented in Table 1.

Table 1. Baseline Energy and Anticipated Electricity Savings

Description	Value	Units
Baseline Energy	1,922	MWh/year
Anticipated Electricity Savings	976	MWh/year

This M&V Report assesses the actual Electricity Savings based on raw data provided by the Participant and the methodology described in the M&V Plan. The IPMVP Option B methodology is used for calculating the Electricity Savings.

The M&V Report calculates the actual Electricity Savings divided by the Anticipated Electricity Savings, to verify whether the Project has achieved the required 80% of the Anticipated Electricity Savings.

2.2. In-Service Date and Previous Reporting Periods

The In-Service Date of June 1, 2019, was established on May 26, 2020.

The 1st Quarterly Reporting Period was from June 1 to August 31, 2019, representing 92 days (2,208 hours).

2.3. Current Reporting Period

The 1st Annual Reporting Period is from June 1, 2019, to August 29, 2020, representing 365 days of operation (8,760 hours). Note that due to COVID-19, the Facility was shut down from March 19 to June 18, 2020, and the Reporting Period was extended accordingly by 91 days.

3. Reporting Period Energy

3.1. Results

[redacted], the LDC representative, provided the raw data to the CMVP for analysis. The provided data included 15-minute interval amperage readings for 15 chiller plant pumps and 2 cooling tower fans, as well as amperage, voltage, and power factor for two chiller compressors. Additional spot-measured data from the variable frequency drives was already provided to correlate amperage readings to electrical power.

Table 2 presents an overview of the available data and the duration of the Reporting Period.

Table 2. Reporting Period Duration and Available Data

Description	Value	Units	Comments
Reporting Period Start	June 1, 2019 0:00		
Reporting Period End	August 29, 2020 23:59		Facility shutdown from March 19 to June 18 due to COVID-19 and Reporting Period extended by 91 days.
Reporting Period Duration	8,760	hours	Total measurement hours.
Available Data	8,278	hours	94.5% of the Reporting Period Duration (for the chiller)
Missing Data	482	hours	5.5% of the Reporting Period Duration.

From the 482 hours of missing data, 329 hours (equivalent 15-minute interval data) were due to stuck metering, resulting in constantly repeating values across all parameters. According to the consultant, this was caused by electrical system issues at the Facility that affected the building management system. It is assumed that the equipment was not operational during missing intervals, and since the Adjusted Baseline Energy is based on hours of operation, non-operational hours are equivalent to zero Electricity Savings, which is a conservative approach, as recommended by the IPMVP.

Note that there were an additional 638 hours (equivalent 15-minute interval data) when one or both compressors had missing data. As discussed with the consultant, and verified in subsequent analysis, the compressors and the evaporator pumps were highly correlated (0.82 correlation coefficient) in their operation. The missing combined compressor power was therefore estimated based on the operational status of the evaporator pumps, using either 0 kW when the pumps were off, or 37.4 kW (the measured compressor average power) when the pumps were on.

Table 3 presents the hours of operation for each group of equipment, which are used in the calculation of the Adjusted Baseline Energy. The hours of operation of a group are calculated as the total time during which the combined power of all equipment in the group (e.g., clean water pumps) was above a minimum threshold defined in the M&V Plan. Some pumps were out of operation for maintenance, but since equipment is grouped, this does not have any impact the calculations.

Table 3. Reporting Period Hours of Operation

Description	Value	Units	Comments
Chilled Water Pumps	6,291	hours	Consists of 3 pumps. Pump 3 is standby. Minimum threshold power is 5 kW.
Evaporator Pumps	6,330	hours	Consists of 2 pumps. Minimum threshold power is 1 kW.
Process Pumps	4,502	hours	Consists of 2 pumps. Minimum threshold power is 5 kW.
Condenser Pumps	4,670	hours	Consists of 2 pumps. Minimum threshold power is 5 kW. Note that Pump 4 was shut down on July 10, 2019.
Tower Fans	4,660	hours	Consists of 2 fans. Minimum threshold power is 2 kW.
Tower Pumps	5,813	hours	Consists of 3 pumps. Pump 3 is removed for maintenance. Minimum threshold power is 5 kW.
Clean Water Pumps	6,159	hours	Consists of 3 pumps. Pump 3 is not operational. Minimum threshold power is 5 kW.
Chiller (compressors)	6,255	hours	Consists of two compressors. Minimum threshold power is 5 kW.
System uptime (chiller compressors)	76%		System uptime, based on compressor hours of operation.

Table 4 presents the Reporting Period Energy for each group of equipment.

Table 4. Reporting Period Energy

Equipment	Energy, MWh	Comments
Chilled Water Pumps	72.0	
Evaporator Pumps	69.2	
Process Pumps	120.6	
Condenser Pumps	110.4	Pump 4 was shut down on July 10, 2019, and restarted Jan. 7, 2020.
Tower Fans	41.4	
Tower Pumps	129.2	Pump 3 is removed for maintenance.
Clean Water Pumps	97.4	Pump 3 is not operational.
Chiller (compressors)	220.1	
Reporting Period Energy	**860**	Total electricity consumption of the chilled water system.

4. Electricity Savings

4.1. Adjusted Baseline Energy

The Baseline Energy is adjusted to the conditions of the Reporting Period, as defined in the M&V Plan. The Adjusted Baseline Energy is calculated based on measured hours of operation during the Reporting Period and the average equipment group power measured during the Baseline Period, as shown in Table 5.

Table 5. Adjusted Baseline Energy

Equipment	Hours of Operation	Average Baseline Power, kW	Energy, MWh
Chilled Water Pumps	6,291	41.3	259.8
Evaporator Pumps	6,330	16.8	106.3
Process Pumps	4,502	55.0	247.6
Condenser Pumps	4,670	49.2	229.8
Tower Fans	4,660	4.9	22.8
Tower Pumps	5,813	25.1	145.9
Clean Water Pumps	6,159	42.3	260.5
Chiller (compressors)	6,255	38.2	238.9
		Adjusted Baseline Energy	**1,512**

4.2. Results

The Electricity Savings analysis is presented in Table 6. Electricity Savings are calculated according to the following equation:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Table 6. Calculation of Electricity Savings

Description	Value	Unit	Comments
Adjusted Baseline Energy	1,512	MWh	Obtained from Table 5.
Reporting Period Energy	860	MWh	Obtained from Table 4.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	**652**	**MWh**	
Uncertainty of the Electricity Savings	± 24%		From an estimated Baseline Energy uncertainty (±10%) and Reporting Period uncertainty (± 5%), based on underlying regression analyses and missing data estimates.
Anticipated Electricity Savings	976	MWh	Obtained from Table 1.
Electricity Savings as a Percentage of Adjusted Anticipated Electricity Savings	**67%**		Does not meet the 80% performance threshold.
Average Demand Savings	74	kW	*Electricity Savings (652 MWh) ÷ Reporting Period duration (8,760 h)*
Summer Peak Demand Savings	109	kW	Average demand savings during the Peak Demand Period, defined as June 1 – August 31, weekdays, 1pm – 7pm. *Baseline Peak Demand (273 kW, from M&V Plan) - Reporting Period Peak Demand (164 kW)*

4.3. Conclusion

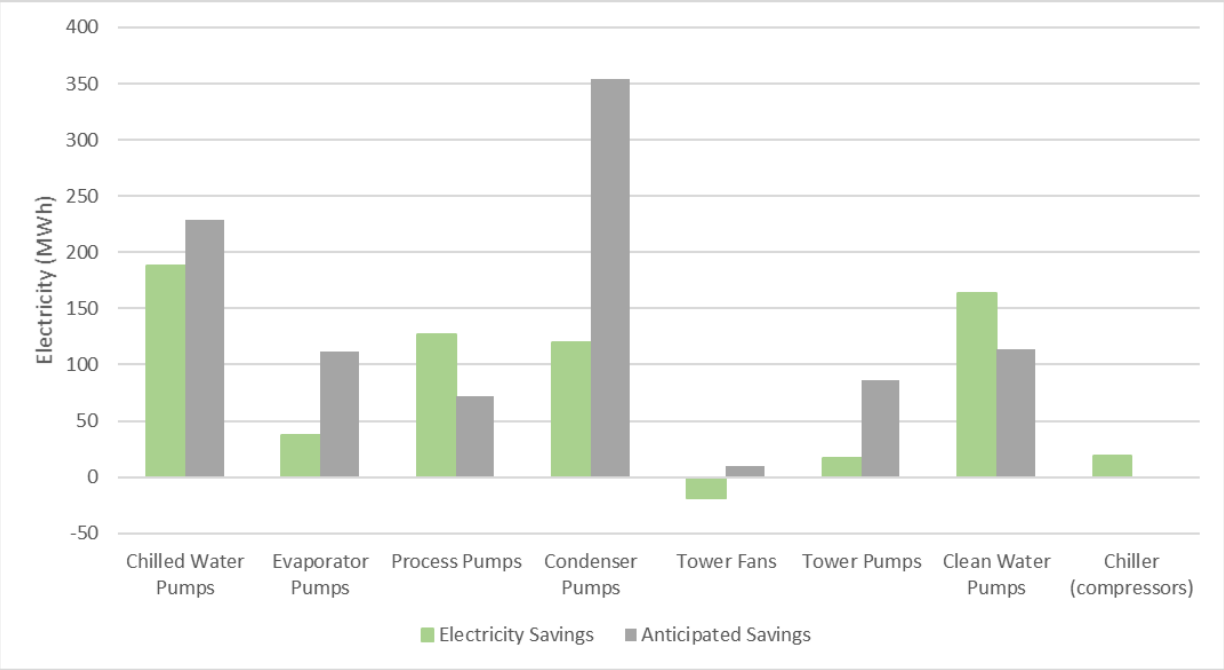
The Electricity Savings for the 1st Annual Reporting Period are 652 MWh, which represent 67% of the Anticipated Electricity Savings. The Electricity Savings do not meet the 80% performance threshold of the Program Rules.

There are several possible reasons for the observed under-performance of the System:

- The Electricity Savings were not evenly divided among the different equipment, as shown in Figure 1. While most of the pumps showed some electricity savings, the tower fans showed losses. Some equipment, such as the process pumps and clean water pumps, showed higher electricity savings than anticipated. Other equipment, particularly the condenser pumps and evaporator pumps, generated significantly lower savings than anticipated.
- The measured uptime of the chiller compressors is 76%, compared to an anticipated 86%. The rest of the equipment also showed uptimes between 54% and 76%, compared to anticipated uptimes near 85%. Fewer hours of operation result in lower electricity savings.
- Missing hours account for 5.5% of the Reporting Period duration. It is conservatively assumed that the System is not operational during this time, and therefore Electricity Savings are nil.

In addition, the pre- and post-COVID-19 electrical performances of the measure are nearly identical, indicating a back-to-normal operation of the measure from the June 2020 re-opening of the Facility (i.e., the Electricity Savings of the 1st Quarterly Reporting Period are similar to the 1st Annual Reporting Period which excludes the shutdown of the Facility due to COVID-19).

Figure 1. Actual and Anticipated Electricity Savings, by Equipment Type



4.4. Electricity Savings to Date

The Electricity Savings to date are presented in Table 7.

Table 7. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings		
		MWh	% of Contract Savings[1]	Cost Savings[2]
1st Quarterly	June 1, 2019 - August 31, 2019	156	64%	$19,500
1st Annual	June 1, 2019 - May 31, 2020	652	67%	$81,400

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $125/MWh obtained from the Project Application Review.

Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5

Third Party Evaluation Reports

This document includes the following third party evaluation reports:

Process and Systems Upgrades Program:

- #601886
- #601902
- #601906
- #601912
- #601913
- #601914
- #601915

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report
1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601886

July 21, 2022
Revision 0

Prepared for:
Toronto Hydro-Electrical System Ltd. (the LDC)

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
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Revision History

Date	Description	Revision	Author
July 21, 2022	M&V Report first issuance.	0	[redacted]

Approvals

	Written by Technical Reviewer	Reviewed by Engineering Manager
Name	[redacted]	[redacted]
Date	July 12, 2022	July 21, 2022
Signature	[redacted]	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of May 7, 2021 to May 6, 2022, are 1,780 MWh, which represent 101% of the Anticipated Electricity Savings. The Total System Efficiency achieved for the 1st Annual Reporting Period is 63.7%, which does not meet the Program Rules requirement of 65%.

The Participant is eligible for an Incentive Payment of $186,838 for this Reporting Period, calculated in accordance with the terms of the Project Agreement. See the Appendix for the Incentive calculation, which includes the penalty for not achieving the minimum 65% Total System Efficiency (TSE) requirement.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings
1st Quarterly	May 7 to Aug 6, 2021	382	94	$47,600[2]
1st Annual	May 7, 2021 to May 6, 2022	1,780	101	$221,966[2]

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data for the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the Measure.
- The Incentive based on the performance of the Measure.

In-Service Date Confirmation

The In-Service Date of May 7, 2021 was established on November 2, 2021, conditional upon the submission of the Environmental Compliance Approval (ECA). The ECA was subsequently submitted by the Participant and an unconditional In-Service Date Confirmation was issued on January 6, 2022.

[1] Percentage of the Anticipated Electricity Savings shown in the M&V Plan.

[2] Based on the Electricity Billing Rate of $124.7/MWh shown in the Approval Letter.

Metered Data Analysis

[redacted] the LDC representative, provided the raw data to the Technical Reviewer for analysis. The raw data includes the following hourly data for the CHP system:

- Net electricity generation
- Natural gas consumption
- Heat utilized

The data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	May 7, 2021, 00:00		
Reporting Period End	May 6, 2022, 23:59		
Reporting Period Duration	8,760	hours	
Available Data	8,760	hours	
Missing Data	0	hours	
Hours of Operation	8,624	hours	98.4% of the Reporting Period duration.

Performance of the Measure

The electrical performance of this generation project is based on the following equation:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Reporting Period Energy

The Reporting Period Energy for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP Net Electrical Energy	1,780	MWh	The electrical metering data provided represents the electricity generation, net of auxiliary loads
Auxiliary Loads Energy	168	MWh	Equal to 5.5 kW per micro-turbine per operating hour (see comment below table)
CHP Gross Electrical Energy	1,948	MWh	Net Electrical Energy + Auxiliary Loads Energy
Reporting Period Energy	1,780	MWh	Equal to the Net Electrical Energy
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	203	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	165	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm -7:00 pm.

The Participant provided an auxiliary load estimate of 5 to 6 kW and confirmed that the metered electrical output is net of the auxiliary loads, which is a typical arrangement for the Capstone C65 micro-turbine system. The Technical Reviewer applied an auxiliary load of 5.5 kW per micro-turbine per operating hour to calculate the Auxiliary Load Energy.

Electricity Savings

The Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings. Since there has been no change in the Static Factors as defined in the M&V Plan Section B.5.1, Non-Routine Adjustments are not required for this Reporting Period.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Reporting Period Energy	1,780	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,780	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Anticipated Electricity Savings	1,769	MWh	Per the M&V Plan.
Electricity Savings as Percentage of Anticipated Electricity Savings	101%		
Average Demand Savings	203	kW	Equal to Average Generation, obtained from Table 3.
Summer Peak Demand Savings	165	kW	Equal to Summer Peak Demand Generation, obtained from Table 3.

The Electricity Savings of the 1st Annual Reporting Period are 1,780 MWh, which represent 101% of the Anticipated Electricity Savings.

The slight overperformance resulted from higher than anticipated average operating net electrical output. The CHP system was anticipated to produce an average operating net electrical output of 202.1 kW whereas the Reporting Period average operating net electrical output was 206.4 kW. However, the higher operating electrical output was partly offset by lower than anticipated operating hours. The CHP system was anticipated to operate 8,753 hours but in the Reporting Period, the CHP system operated 8,624 hours.

Total System Efficiency

The CHP System's Total System Efficiency (TSE) is calculated according to the following equation.

TSE (%) = [Gross Electrical Energy + Recovered Heat Utilized] / [Fuel Energy Input]

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	1,948	MWh	Obtained from Table 3.
Recovered Heat Utilized	3,787	MWh	
Fuel Energy Input	8,999	MWh	Calculated from total volumetric natural gas consumption and a natural gas higher heating value (HHV) of 10.75 kWh/m^3 specified in the M&V Plan.
Total System Efficiency	63.7%		This value is lower than the 65% threshold required by the Program.

The Technical Reviewer obtained a TSE of 63.7%, which is lower than the minimum 65% required by the Program. However, the Participant is eligible for an Incentive, subject to a 5%[3] penalty. See the Appendix for the Incentive calculation.

Next Reporting Period

The 1st Annual Reporting Period is the final Reporting Period and there is no further M&V reporting, unless requested by the IESO.

[3] Based on Program Rules, a TSE that is greater than equal to 62.5% but less than 65%, results in a 5% penalty on the Incentive.

Appendix - Incentive Payment

The Participant is eligible for an Incentive Payment of $186,838 for this Reporting Period, calculated in accordance with the terms of the Project Agreement. The Incentive calculation is shown in Table 6.

Table 6. Incentive Calculation

Reporting Period Electricity Savings (MWh)	1,780
Electricity Billing Rate ($/MWh)	124.7
Electricity Billed Savings	$221,966
Net Other Benefits and Costs	-$181,382[4]
Project Benefits	$40,584
Estimated Eligible Costs	$1,500,000[4]
Actual Eligible Costs	$1,810,020
Approved Incentive Amount	$353,800[4]
Incentive 1 - $200/MWh (Capped at 120% of the contracted Incentive amount)	$355,999
Incentive 2 - 40% of Minimum of Actual and Estimated Eligible Costs	$600,000
Incentive 3 - 1-year Payback	$1,459,416
Project Incentive (Minimum of 3 limiters)	$355,999
Incentive Penalty for TSE (5%))	$17,800
Adjusted Project Incentive	$338,199
First Payment (Recommended for First Quarterly Reporting Period)	$151,361
Balance Payment	$186,838

Table 7 provides the Incentive payment schedule

[4] From the Approval Letter

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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SAVE ON ENERGY | DELIVERY PARTNER™

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601902
September 28, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
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Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018”

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name:	[redacted]	[redacted]
Date:	September 28, 2022	September 27, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
September 28, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of June 18, 2021, to June 22, 2022, are 986 MWh, which represents 94% of the Anticipated Electricity Savings. The Total System Efficiency (TSE) achieved for the 1st Annual Reporting Period is 72.9%, which meets the Program Rules minimum requirement of 65%.

Note that the original 1st Annual Reporting Period was scheduled to end on June 17, 2022. However, the Reporting Period had to be extended to June 22, 2022, as the combined heat and power (CHP) system unexpectedly shut down from April 10 to 18, 2022. The shutdown, which lasted 99 hours, was the result of a failed valve spring, which damaged the piston.

The Incentive payable to the Participant for this Reporting Period is $100,856. Refer to the Appendix for the Incentive calculation.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	June 18 to September 17, 2021	241	92%	$31,600
1st Annual	June 18, 2021 to June 22, 2022	986	94%	$129,200

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $131/MWh obtained from the Project Approval Letter.

In-Service Date Confirmation

The In-Service Date was set to June 18, 2021 on August 9, 2021, by the Technical Reviewer.

Metered Data Analysis

[redacted] the LDC representative, provided the M&V data on September 1, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	June 18, 2021, 00:00	-	Start date of the Reporting Period.
Reporting Period End	June 22, 2022, 2:59	-	End date of the Reporting Period.
Reporting Period Duration	8,760	hours	End date minus start date, excluding the period of unexpected shutdown.
Available Data	8,760	hours	
Missing Data	0	hours	0% of the Reporting Period Duration.
Hours of Operation	8,321	hours	95% of the Reporting Period Duration.

Performance of the Measure

The electrical performance of the project is based on the reporting period energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,021	MWh	
CHP Auxiliary Loads Energy	34	MWh	3.4% of the CHP Gross Electrical Energy.
Reporting Period Energy	986	MWh	CHP Gross Electrical Energy – CHP Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Average Generation	113	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	108	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm - 7:00 pm, June 1 to August 31.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by [redacted] the supplier of the CHP system, to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy. The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by [redacted], the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	986	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	986	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,052	MWh	As per the M&V Plan.
Electricity Savings as a Percentage of Anticipated Electricity Savings	94%	-	
Average Demand Savings	113	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	108	kW	Equal to Summer Peak Demand Generation from Table 3.

The 1st Annual Reporting Period Electricity Savings are 986 MWh and represent 94% of the Anticipated Electricity Savings. The underperformance is due to a lower than anticipated average net operating electrical output, which is likely a result of a change in the Project scope. The original Project scope was based on installation of a CHP system with a total nominal capacity of 160 kW, consisting of two 125 kW internal combustion reciprocating engines, one of which would have been permanently derated to 35 kW. However, only one 125 kW internal combustion reciprocating engine was installed. The anticipated average net electrical output was 129 kW. However, in this 1st Annual Reporting Period, the average net electrical output was 119 kW.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Electrical Energy (MWh) + CHP Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 5. Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,021	MWh	Obtained from Table 3.
CHP Utilized Thermal Output	1,410	MWh	
Natural Gas Higher Heating Value (HHV)	10.79	kWh/m^3	Obtained from the Enbridge Gas Composition and HHV Data in 2021.
CHP Fuel Energy Input (HHV)	3,335	MWh	Calculated using the Reporting Period total volumetric natural gas consumption and the natural gas HHV.
Total System Efficiency	72.9%	-	

The CHP system achieved a TSE of 72.9%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and verified Eligible Costs, the Incentive payable to the Participant is $100,856 The Master Payment Requisition will be issued once the Participant's invoice for the Incentive amount is provided.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	986	1st Annual Reporting Period Electricity Savings.
Approved Amount	$210,400	From the Project Approval Letter.
Limiter 1 - Electricity Savings	$197,230	$200 per MWh of Electricity Savings, capped at 120% of Approved Amount.
Estimated Eligible Project Costs	$1,948,299	From the Project Approval Letter.
Actual Eligible Project Costs	$ 693,132	Based on the review of invoices.
Limiter 2 - Project Costs	$277,253	40% of minimum of Estimated and Actual Eligible Project Costs.
Net Benefits	$21,997	Equal to the electricity savings, calculated using a billing rate of $131/MWh, plus the Other Benefits less Other Costs from the Project Approval Letter.
Limiter 3 – 1-year Project Payback	$671,135	Eligible Costs minus Net Benefits.
Gross Project Incentive	$197,230	Minimum of the three limiters.
Project Incentives paid	$96,374	Paid for 1st Quarterly Reporting Period.
Incentive payable	**$100,856**	Gross incentive minus incentives paid.

Table 7 provides the Incentive payment schedule.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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M&V Report

1st Annual Report

November 20, 2018 – November 19, 2019

[redacted] System Upgrade

Project ID: Toronto-PROJECT-601906

December 24, 2019

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (the LDC)

[redacted]

Prepared by:

CLEAResult Canada Inc.
393 University Avenue, Suite 1622
Toronto, ON, M5G 1E6
416-504-3400

Prepared per Program Rules in 'saveONenergy Process & Systems Upgrades Program, FINAL v2.0', April 6, 2018.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

Revision History

Date	Name/Description	Revision	Author
December 24, 2019	M&V Report first issuance.	0	[redacted],

Approvals

Name	Title	Signature	Date
[redacted]	Engineering Manager	[redacted]	December 24, 2019

1. Executive Summary

The Electricity Savings for the M&V Reporting Period of November 20, 2018, to November 19, 2019, are 890 MWh, which represent 122% of the Anticipated Electricity Savings.

For the Incentive payment calculation, the Electricity Savings are capped at 120% of the Anticipated Electricity Savings. The Incentive payable to the Participant for the 1st Annual Reporting Period is $90,978, pending the issuance of the Master Payment Requisition.

2. Project Overview

2.1. Baseline Energy and Anticipated Electricity Savings

The annual Baseline Energy and the Anticipated Electricity Savings are obtained from the M&V Plan, revision 1, dated December 4, 2018, and are presented in Table 1.

Table 1. Annual Baseline Energy and Anticipated Electricity Savings

Description	Value	Unit
Baseline Energy	1,807	MWh/year
Anticipated Electricity Savings	731	MWh/year

This M&V Report assesses the actual Electricity Savings based on raw data provided by the Participant and the methodology described in the M&V Plan.

The M&V Report calculates the actual Electricity Savings divided by the Anticipated Electricity Savings, to verify whether the Project has achieved the Anticipated Electricity Savings.

2.2. In-Service Date and Previous Reporting Periods

The In-Service Date is November 20, 2018, which was established on December 18, 2018.

The 1st Quarterly Reporting Period is from November 20, 2018, to February 19, 2019, representing 92 days (2,208 hours).

2.3. Current Reporting Period

The 1st Annual Reporting Period is from November 20, 2018, to November 19, 2019, representing 365 days (8,760 hours).

3. Reporting Period Energy

3.1. Raw Data

[redacted](the LDC representative) provided the raw process data to the CMVP for analysis. The raw data includes hourly pump 473 power, operational status of the 4T vacuum system (on/off), and operational data for pump 474.

Table 2 presents an overview of the data related to the duration of the Reporting Period and equipment hours of operation.

Table 2. Reporting Period Hours and missing data

Description	Value	Unit	Comments
Reporting Period Start	November 20, 2018 0:00		
Reporting Period End	November 19, 2019 23:59		
Reporting Period Duration	8,760	hours	
Available Data	8,697	hours	Hours when pump 473 power is available. Corresponds to 99.3% of the Reporting Period Duration.
Hours of Operation	8,482	hours	Hours when pump 473 power is greater than 1 kW. Corresponds to 97.5% of the Available Data hours.

3.2. Reporting Period Energy

This is an IPMVP Option B methodology of calculating the Electricity Savings.

The Reporting Period Energy is itemized in Table 3 below. Note that the 63 hours of missing pump 473 power are conservatively assumed as not operational, meaning no Electricity Savings during those hours.

Table 3. Reporting Period Energy

Description	Value	Unit	Comments
Pump 473 Average Power	115.3	kW	Average operational power (when power is greater than 1 kW).
Pump 474 Average Power	0	kW	Not operational during Reporting Period.
Reporting Period Energy	978	MWh	Total pump power (115.3 kW + 0 kW) × Reporting Period hours of operation (8,482 hours)

4. Electricity Savings

4.1. Adjusted Baseline Energy

The Adjusted Baseline Energy is calculated using pump 473 hours of operation. System (4T stock on/off) hours of operation, as defined in the M&V Plan, section B.5.2, underestimate the hours of operation because the pumps take time to shut down following a 'stock off' condition. The Adjusted Baseline Energy is 1,869 MWh, calculated as shown in Table 4.

Table 4. Adjusted Baseline Energy Calculation

Description	Value	Unit	Comments
Pump 473 Baseline Average Power	145.8	kW	From the M&V Plan.
Pump 474 Baseline Average Power	74.5	kW	From the M&V Plan.
Adjusted Baseline Energy	1,869	MWh	Total Baseline pump power (145.8 kW + 74.5 kW) × Reporting Period hours of operation (8,482 hours).

4.2. Results

The Electricity Savings are calculated according to the following equation:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Since there has been no change in the Static Factors as defined in the M&V Plan Section B.5.3, Non-Routine Adjustments are not required for this Reporting Period. The Electricity Savings results are presented in Table 5.

Table 5. Calculation of Electricity Savings

Description	Value	Unit	Comment
Adjusted Baseline Energy	1,869	MWh	From Table 4.
Reporting Period Energy	978	MWh	From Table 3.
Non-Routine Adjustments	0	MWh	None.
Electricity Savings	890	MWh	*Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments.*
Electricity Savings Uncertainty	± 5.9%		Calculated using Adjusted Baseline Energy uncertainty (± 2.5%) and Reporting Period Energy uncertainty (± 2.5%), obtained from the M&V Plan.
Anticipated Electricity Savings	731	MWh	From Table 1.
Electricity Savings as a Percentage of Anticipated Electricity Savings	122%		This ratio is capped at 120% for the Incentive payment calculation.
Average Demand Savings	102	kW	*Electricity Savings ÷ Reporting Period duration*.
Reporting Period Peak Demand	95	kW	Average demand during the summer Peak Demand Period, defined as weekdays, 1pm – 7pm, June 1 – August 31.
Baseline Peak Demand	206	kW	From the M&V Plan.
Summer Peak Demand Savings	111	kW	*Reporting Period Peak Demand - Baseline Peak Demand.*

4.3. Incentive Payment

The 1st Annual Reporting Period Incentive is outlined in Table 6. CLEAResult has received the Invoice Reconciliation Form and the invoices.

Table 6. Incentive Payments for Deferred Payment

Deferred Payment Schedule	Description	Amount
Payment 1	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the first quarterly M&V Report.	$84,462.00 (Paid)
Final Payment (Holdback)	The balance payment is the difference between the actual Participant Incentive, calculated on the basis of the first annual M&V Report, and the total payments made to date.	$90,978.00

4.4. Conclusion

The Electricity Savings are 890 MWh and represent 122% of the Anticipated Electricity Savings for the Reporting Period.

One reason for the overperformance is that the pumps take time to shut off even after the 4T equipment has cycled off. This resulted in increased hours of operation, and correspondingly increased Electricity Savings. More significantly, however, pump 473 operated at a lower than anticipated average power, particularly in the second half of the Reporting Period.

4.5. Electricity Savings to Date

The Electricity Savings to date are presented in Table 7.

Table 7. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings			
		MWh	% of Contract Savings Value [1]	Cost Savings ($)[2]	Incentive Payment ($)
1st Quarterly	Nov. 20, 2018 to Feb. 19, 2019	213	116%	$11,300	$84,462
1st Annual	Nov. 20, 2018 to Nov. 19, 2019	890	122%	$47,300	$90,978

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on the Electricity Billing Rate of $53.14/MWh obtained from the Project Review.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601912
September 21, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018”

Approvals

	Written by Technical Reviewer	Reviewed by Senior Engineer
Name:	[redacted]	[redacted]
Date:	September 16, 2022	September 21, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
September 21, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of May 28, 2021, to July 14, 2022, are 996 MWh, which represents 99.6% of the Anticipated Electricity Savings.

Note that the original 1st Annual Reporting Period was scheduled to end on May 17, 2022. However, the Reporting Period had to be extended to July 14, 2022, as the combined heat and power (CHP) system was unexpectedly shutdown on January 14, 2022, due to a low oil pressure alarm resulting from a failure of the engine valve train and a damaged piston. The repairs could not be performed until March 2, 2022, due to COVID-19 supply constraints of the equipment. Thus, the Reporting Period was extended by 1134 hours and excludes this shutdown period.

The Incentive payable to the Participant for this Reporting Period is $96,050. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	May 28 to Aug 27, 2021	258	103%	$34,000
1st Annual	May 27, 2021, to July 14, 2022	996	99.6%	$131,443

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $132/MWh obtained from the Letter of Approval.

In-Service Date Confirmation

The In-Service Date was set to May 28, 2021, on July 27, 2021, by the Technical Reviewer.

Metered Data Analysis

[redacted] from Toronto Hydro provided the M&V data on September 1, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	May 28, 2021, 00:00		Start date of the Reporting Period
Reporting Period End	July 14, 2022, 05:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date, less the 1,134 hours of unexpected shutdown period.
Available Data	8,752	hours	
Missing Data	8	hours	0.1% of the Reporting Period Duration
Hours of Operation	8,517	hours	97% of the Reporting Period Duration

The M&V data was missing the CHP system gross electrical output values for the period August 11, 2021, from 6:00 to 13:00, for a total eight hours. The Technical Reviewer assumes that the CHP system did not operate during this period as there was no natural gas consumption and replaced the missing data with zero values.

The CHP system did not operate from January 14, 2022, 09:00 to March 2, 2022, 14:00 (1,134 hours) due to an unexpected failure in the control board. The problem was investigated and subsequently fixed by the manufacturer. Therefore, the Reporting Period was extended by 1,134 hours.

Performance of the Measure

The Electricity Savings of the project is calculated using the following equation:

Electricity Savings = ***Reporting Period Energy*** ± ***Non-Routine Adjustments***

Baseline Energy

This is an electricity generation project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,027	MWh	
Auxiliary Loads Energy	31	MWh	1.8% of the CHP Gross Electrical Output. See comments below table.
Reporting Period Energy	996	MWh	Gross Electrical Energy – Reporting Period Energy
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Average Demand Generation	114	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	112	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by [redacted], the supplier of the CHP system, to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy. The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by [redacted], the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	996	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	996	MWh	

Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Annual Electricity Savings	1,000	MWh/year	Obtained from the M&V Plan, Rev 0, dated Mar 19, 2019.
Electricity Savings as a Percentage of Anticipated Electricity Savings	99.6%	-	
Average Demand Savings	114	kW	Obtained from Table 3.
Summer Peak Demand Savings	112	kW	Obtained from Table 3.

The 1st Annual Electricity Savings are 996 MWh and represent 99.6% of the Anticipated Electricity Savings. The CHP system was operated as anticipated during the 1st Annual Reporting Period.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [Gross Electrical Energy (MWh) + Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 5. Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	1,027	MWh	Obtained from Table 3
Utilized Thermal Output	1,287	MWh	
CHP Fuel Energy Input	3,441	MWh	Calculated using the metered volumetric flowrate of natural gas and natural gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan
Total System Efficiency	67.2%	-	

The CHP system achieved a Total System Efficiency of 67.2%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual M&V Report, the Incentive payable to the Participant is $96,050.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	996	Annual Electricity Savings, defined in this Report.
Estimated Eligible Project costs	$969,296	From the Project Approval Letter.
Actual Eligible Project Cost	$897,305	Based on Review of Eligible Costs as part of the Q1 Payment Recommendation.
Other Benefits	$49,326	From the Project Approval Letter.
Other Costs	$141,918	From the Project Approval Letter.
Net Project benefits	$38,851	Electricity Bill Savings + Other Benefits – Other Costs.
Approved Incentive Amount	$200,000	From the Project Approval Letter
Limiter 1 - Electricity Savings	$199,156	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Project Costs	$358,922	40% of minimum if Actual and Estimated Eligible costs.
Limiter 3 - Project Payback	$858,454	Eligible costs minus net benefits.
Project Incentive	$199,156	Minimum of the three limiters.
Project Incentive paid to Date	$103,106	Paid for 1st Quarterly Reporting Period.
Incentive payable	**$96,050**	Gross incentive minus incentive paid.

Table 7 provides the Incentive payment schedule.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual

[redacted]

Cogeneration System

Project ID: Toronto-Project-601913

June 28, 2022

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited

[redacted]

Prepared by:

CLEAResult

393 University Avenue, Suite 1622, Toronto, ON M5G 1E6

(416) 504-3400

Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018

Approvals

	Written by Technical Reviewer	Reviewed by Senior Engineer
Name:		
Date:	June 28, 2022	June 28, 2022
Signature:		

Revision History

Date	Description	Revision	Technical Reviewer
June 28, 2022	M&V Report first issuance.	0	

Summary

The Electricity Savings for the 1st Annual Reporting Period of May 27, 2021 to May 26, 2022, are 1,020 MWh, which represents 105% of the Anticipated Electricity Savings. The Total System Efficiency achieved for the 1st Annual Reporting Period is 71%, which meets the Program Rules requirement of 65%.

The Incentive payable to the Participant for this Reporting Period is $101,261. Refer Appendix for the Incentive calculation.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	May 27 to Aug 26, 2021	264	105%	$32,000
1st Annual	May 27, 2021 to May 26, 2022	1,020	105%	$123,400

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of May 27, 2021 was established on July 29, 2021.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan

[2] Based on $121/MWh obtained from the Project Approval Letter

Metered Data Analysis

[redacted] from Toronto Hydro provided the M&V data on October 1, 2021, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	May 27, 2021, 00:00		Start date of the Reporting Period.
Reporting Period End	May 26, 2022, 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date
Available Data	8,760	hours	
Missing Data	0	hours	0% of the Reporting Period Duration
Hours of Operation	8,703	hours	99.3% of the Reporting Period Duration

Performance of the Measure(s)

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = ***Adjusted Baseline Energy*** – ***Reporting Period Energy*** ± ***Non-Routine Adjustments***

Baseline Energy

This is an electricity generation Project with no prior generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy and the average and peak generation values are presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP Gross Electrical Output	1,038	MWh	
Auxiliary Loads	18	MWh	1.8% of the CHP Gross Electrical Output.
Reporting Period Energy	1,020	MWh	CHP Net Electrical Output.
Uncertainty of the Reporting Period Energy	± 2.5%	%	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	116	kW	Reporting Period Energy divided by Reporting Period Duration
Summer Peak Generation	121	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

Electricity Savings

The Baseline Energy, Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	Obtained from Table 3.
Reporting Period Energy	1,020	MWh	Obtained from Table 3..
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,020	MWh	
Uncertainty of the Electricity Savings	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter
Anticipated Electricity Savings	974	MWh	Obtained from the Table 4 of the M&V Plan, Rev 0, dated Feb 4, 2019.
Electricity Savings as a Percentage of Anticipated Electricity Savings	105	%	
Average Demand Savings	116	kW	Obtain from Table 3
Summer Peak Demand Savings	121	kW	Obtain from Table 3

The 1st Annual Electricity Savings are 1,020 MWh, which represent 105% of the Anticipated Electricity Savings. The overperformance is due to higher than anticipated hours of operation and average operating electrical load of the cogeneration system. The cogeneration system was anticipated to operate 8,568

hours with an average operating output of 113.7 kW but the actual operating hours and average output were 8,703 hours and 117.2 kW.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Electrical Energy (MWh) + Utilized Thermal Output (MWh)] / CHP Natural Gas Consumption (MWh)

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,038	MWh	
Utilized Thermal Output	1,446	MWh	
CHP Natural Gas Consumption	3,485	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.84 kWh/m^3, obtained from the Enbridge Gas website.
Total System Efficiency	71.3	%	

The CHP system achieved a Total System Efficiency of 71.3%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, the Incentive payable to the Participant is $101,260.59.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,020	1st Annual Reporting Period Electricity Savings.
Estimated Eligible Costs	969,296	As per the Project Approval Letter
Actual Eligible Costs	$884,190	Based on Review of Eligible Costs as part of the Q1 Payment Recommendation
Electricity Billed Savings	$123,425	Based on the Project Approval Letter Electricity Billing Rate of $121/MWh
Other Benefits	$52,168	From the Project Approval Letter
Other Costs	$138,633	From the Project Approval Letter
Net Project Benefits	$40,174	Electricity Billed Savings +Other Benefits – Other Costs
Approved Incentive Amount	**$194,800**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$204,008	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$353,676	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 – Project Payback	$844,015	Eligible costs minus Net Project Benefits
Gross Project Incentive	$204,008	Minimum of the three limiters.
Project Incentives paid to Date	$102,747	Paid for 1st Quarterly Reporting Period.
Incentive payable	**$101,261**	Gross incentive minus incentives paid.

Table 7 provides the Incentive payment schedule

Table 7. Incentive Calculation

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601914
August 04, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018”

Approvals

	Written by Technical Reviewer	Reviewed by Senior Engineer
Name:	[redacted]	[redacted]
Date:	July 29, 2022	August 3, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
August 4, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of May 29, 2021, to June 5, 2022, are 990 MWh, which represents 98% of the Anticipated Electricity Savings. The combined heat and power (CHP) system achieved a Total System Efficiency of 69.4%, which meets the Program's minimum requirement of 65%.

Note that the original 1st Annual Reporting Period was scheduled to end on May 28, 2022. However, the Reporting Period had to be extended to June 5, 2022, as the CHP system was unexpectedly shutdown on January 17, 2022. The shutdown, which lasted 171 hours, was a result of a control board failure, which resulted in no power supply to the control system. The repairs could not be performed until January 24, 2022, due to COVID-19 constraints that affected the delivery of the replacement parts. Thus, the Reporting Period was extended by 171 hours and excludes this shutdown period.

The Incentive payable to the Participant for this Reporting Period is $94,229. Refer to the Appendix for the Incentive calculation.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	May 29 to Aug 28, 2021	264	102%	$32,400
1st Annual	May 29, 2021, to June 5, 2022	990	98%	$121,811

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $123.02/MWh obtained from the Approval Letter.

In-Service Date Confirmation

The In-Service Date was set to May 29, 2021, on July 30, 2021, by the Technical Reviewer.

Metered Data Analysis

[redacted] from Toronto Hydro provided the M&V data on July 20, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	May 29, 2021, 00:00		Start date of the Reporting Period
Reporting Period End	June 5, 2022, 02:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus Start date, less the 171 hour unexpected shutdown period.
Available Data	8,760	hours	
Missing Data	0	hours	
Hours of Operation	8,424	hours	96.2% of the Reporting Period Duration

The CHP system did not operate from January 17, 2022, 14:00 to January 24, 2022, 15:00 (171 hours) due to an unexpected failure in the control board. The problem was investigated and fixed by the manufacturer. Therefore, the Reporting Period was extended by 171 hours.

Performance of the Measure

The Electricity Savings is calculated as follows:

$$\textit{Electricity Savings} = \textit{Reporting Period Energy} \pm \textit{Non-Routine Adjustments}$$

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electricity generation of the CHP system for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,021	MWh	
Auxiliary Loads Energy	31	MWh	3.1% of the Gross Electrical Energy. See comment below Table 3
Reporting Period Energy	990	MWh	Gross Electrical Energy – Auxiliary Loads Energy
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Average Generation	113	kW	Reporting Period Energy divided by Reporting Period Duration
Summer Peak Demand Generation	115	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

Based on discussions with [redacted], the Participant's consultant, the auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls are not metered. They were calculated by [redacted], the supplier of the CHP system, to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kWh per CHP operating hour to calculate the internal auxiliary load energy. The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by [redacted] based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the type of system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	990	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	990	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Annual Electricity Savings	1,013	MWh/Year	Obtained from the M&V Plan, Rev 0, dated Feb 12, 2019.

Electricity Savings as a Percentage of Anticipated Electricity Savings	98%	-	
Average Demand Savings	113	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	115	kW	Equal to Peak Demand Generation from Table 3.

The 1st Quarterly Electricity Savings are 990 MWh which represent 98% of the Anticipated Electricity Savings. The underperformance is due to the less than anticipated operating hours of the CHP system. The CHP system was anticipated to operate 8,590 hours annually, but the hours of operation for the Reporting Period was 8,424 hours.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [Gross Electrical Energy (MWh) + Utilized Thermal Output (MWh)] / Fuel Energy Input (MWh)

Table 5. Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	1,021	MWh	Obtained from Table 3.
Utilized Thermal Output	1,323	MWh	
Fuel Energy Input (HHV)	3,376	MWh	Calculated using the metered volumetric flowrate of natural gas and natural gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	69.4%	-	

The CHP system achieved a Total System Efficiency of 69.4%, which meet the Program Rules minimum requirement of 65%.

Next Reporting Period

The is the final M&V Report, as the M&V Reporting Period is one year. No Additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, the Incentive payable to the Participant is $94,229. The Payment Recommendation will be issued upon receipt of the Participant's invoice to Toronto Hydro for the payment amount.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	990	1st Annual Reporting Period Electricity Savings.
Estimated Eligible Costs	$964,884	As per the Project Approval Letter
Actual Eligible Costs	$1,044,361	Based on Review of Eligible Costs as part of the Q1 Payment Recommendation
Electricity Billed Savings	$121,811	Based on the Project Approval Letter Electricity Billing Rate of $123.02/MWh
Other Benefits	$37,938	From the Project Approval Letter
Other Costs	$126,924	From the Project Approval Letter
Net Project Benefits	$32,825	Electricity Billed Savings +Other Benefits – Other Costs
Approved Incentive Amount	**$202,600**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$198,035	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$385,954	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 – 1-year Project Payback	$932,059	Eligible costs minus Net Project Benefits
Recommended Project Incentive	$198,035	Minimum of the three limiters.
Project Incentive paid to Date	$103,806	Paid for 1st Quarterly Reporting Period.
Incentive payable	**$94,229**	Recommended Project – Project Incentive Paid to Date.

Table 7 provides the Incentive payment schedule.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted]

Cogeneration System

Project ID: Toronto-PROJECT-601915
July 07, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
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(416) 504-3400

Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018”

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name:	[redacted]	
Date:	July 6, 2022	July 6, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
July 7, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of May 26, 2021, to May 25, 2022, are 912 MWh, which represents 100% of the Anticipated Electricity Savings. The Total System Efficiency achieved for the 1st Annual Reporting Period is 72.7%, which meets the Program Rules requirement of 65%.

The Incentive payable to the Participant for this Reporting Period is $91,290. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	May 26 to Aug 25, 2021	237	104%	$33,500
1st Annual	May 26, 2021 to May 25, 2022	912	100%	$113,082

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date was set to May 26, 2021, on July 29, 2021, by the Technical Reviewer.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $124/MWh obtained from the Project Approval Letter.

Metered Data Analysis

[redacted] the LDC representative, provided the M&V data on June 7, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	May 26, 2021, 00:00		Start date of the Reporting Period.
Reporting Period End	May 25, 2022, 23:59		End date of the Reporting Period.
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,760	hours	
Missing Data	0	hours	0% of the Reporting Period Duration.
Hours of Operation	8,560	hours	98% of the Reporting Period Duration.

Performance of the Measure

The electrical performance of the project is based on the reporting period energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the combined heat and power (CHP) System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP Gross Electrical Output	941	MWh	
Auxiliary Loads	29	MWh	3.1% of the CHP Gross Electrical Output.
Reporting Period Energy	912	MWh	CHP Net Electrical Output.
Uncertainty of the Reporting Period Energy	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Average Generation	104	kW	
Summer Peak Demand Generation	111	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm -7:00 pm, June 1 to August 31.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	912	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	912	MWh	
Uncertainty of the Electricity Savings	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	911	MWh	As per the M&V Plan.
Electricity Savings as a Percentage of Anticipated Electricity Savings	100	%	
Average Demand Savings	104	kW	
Summer Peak Demand Savings	111	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm -7:00 pm, June 1 to August 31.

The 1st Annual Reporting Period Electricity Savings are 912 MWh and represent 100% of the Anticipated Electricity Savings.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Energy (MWh) + CHP Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 5. Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	941	MWh	
CHP Utilized Thermal Output	1,299	MWh	
Natural Gas Higher Heating Value (HHV)	10.75	kWh/m^3	As per the M&V Plan.
CHP Fuel Energy Input (HHV)	3,083	MWh	Calculated using the metered volumetric natural gas consumption and natural gas HHV value.
Total System Efficiency	72.7	%	

The CHP system achieved a TSE of 72.7%, which meets the Program Rules requirement of 65%. The Technical Reviewer also determined that when the CHP Fuel Energy Input (HHV) is quantified based on the specifications, the TSE is 67.4%. However, the Technical Reviewer has accepted the TSE based on metered CHP Fuel Energy Input (HHV) as a result of both values being above the 65% Program Rules requirement.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and verified Eligible Costs, the Incentive payable to the Participant is $91,290. The Master Payment Requisition will be issued once the Participant's invoice for the Incentive amount is provided.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	912	1st Annual Reporting Period Electricity Savings.
Approved Amount	$182,200	From the Project Approval Letter.
Limiter 1 - Electricity Savings	$182,390	$200 per MWh of Electricity Savings, capped at 120% of Approved Amount.
Estimated Eligible Project Costs	$1,024,177	From the Project Approval Letter.
Actual Eligible Project Costs	$979,095	Verified, based on invoices provided by the Participant.
Limiter 2 - Project Costs	$391,638	40% of minimum of Estimated and Actual Eligible Project Costs.
Net Benefits	$31,383	Equal to the electricity savings, calculated using a billing rate of $124/MWh, plus the Other Benefits less Other Costs from the Project Approval Letter.
Limiter 3 – 1-year Project Payback	$947,712	Eligible Costs minus Net Benefits.
Gross Project Incentive	$182,390	Minimum of the three limiters.
Project Incentives paid	$91,100	Paid for 1st Quarterly Reporting Period.
Study Incentive paid	N/A	Paid for Engineering Study.[3]
Incentive payable	**$91,290**	Gross incentive minus incentives paid.

Table 7 provides the Incentive payment schedule.

[3] Not applicable under the CFF2 framework.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5

Third Party Evaluation Reports

This document includes the following third party evaluation reports:

Process and Systems Upgrades Program:

- #601920
- #601929
- #601934
- #601935
- #601937
- #601938
- #601939

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report
1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601920
July 28, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
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Prepared per Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by Technical Reviewer	Reviewed by Senior Engineer
Name:	[redacted]	[redacted]
Date:	July 26, 2022	July 27, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
July 28, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of June 11, 2021, to June 10, 2022, are 1,047 MWh, which represents 86% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $106,739. Refer to the Appendix for the Incentive calculation.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	June 11 to September 10, 2021	259	89%	$32,116
1st Annual	June 11, 2021, to June 10, 2022	1,047	86%	$124,850

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan Rev.0 dated January 31, 2019, which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of June 11, 2021 was established on August 3, 2021.

Metered Data Analysis

[redacted] from Toronto Hydro provided the M&V data on July 20, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $124/MWh obtained from the Approval Letter.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	June 11, 2021, 0:00		Start date of the Reporting Period
Reporting Period End	June 10, 2022, 23:59		End Date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,760	hours	
Missing Data	0	hours	
Hours of Operation	8,601	hours	98.2% of the Reporting Period Duration.

Performance of the Measure

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

$$\textit{Electricity Savings} = \textit{Adjusted Baseline Energy} - \textit{Reporting Period Energy} \pm \textit{Non-Routine Adjustments}$$

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electricity generation of the combined heat and power (CHP) System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,064	MWh	
Auxiliary Loads Energy	16	MWh	1.5% of the CHP Gross Electrical Energy.
Reporting Period Energy	1,047	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Average Generation	120	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Demand Generation	119	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm - 7:00 pm.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,047	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,047	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,216	MWh	Obtained from Table 5 of the M&V Plan, Rev.0, dated January 31, 2019.
Electricity Savings as a Percentage of Anticipated Electricity Savings	86%		
Average Demand Savings	120	kW	Electricity Savings divided by Reporting Period Duration.
Summer Peak Demand Savings	119	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm - 7:00 pm.

The 1st Annual Electricity Savings are 1,047 MWh, which represent 86% of the Anticipated Electricity Savings.

The original Project scope was based on the installation of a CHP system consisting of two 75 kW internal combustion engines (ICEs), with a total nameplate capacity of 150 kW. However, the actual CHP system installed consists of a single 125 kW ICE.

The underperformance is due to the lower capacity CHP system. The CHP system was anticipated to operate with an average net operating electrical output of 142 KW but the average net operating electrical output during the Reporting Period was 122 kW. Note that the reduced electrical output was partly offset by higher operating hours in the Reporting Period 8,601 hours compared to the anticipated operating hours of 8,592.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 *TSE (%) = [Gross Electrical Energy (MWh) + Utilized Thermal Output (MWh)] / Fuel Energy Input (MWh)*

Table 5. Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	1,064	MWh	Obtained from Table 3.
Utilized Thermal Output	1,452	MWh	
Fuel Energy Input	3,512	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m_3, obtained from the M&V Plan.
Total System Efficiency	71.6	%	

The CHP System achieved a Total System Efficiency of 71.6%, which meets the Program's minimum requirement of 65%

Next Reporting Period and Next Steps

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, the Incentive payable to the Participant is $106,739. The Payment Recommendation will be issued upon receipt of the Participant's invoice to Toronto Hydro for the payment amount.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,047	1st Annual Reporting Period Electricity Savings.
Estimated Eligible Costs	$794,965	As per the Project Approval Letter
Actual Eligible Costs	$1,044,859	Based on Review of Eligible Costs as part of the Q1 Payment Recommendation
Electricity Billed Savings	$129,850	Based on the Project Approval Letter Electricity Billing Rate of $121/MWh
Other Benefits[3]	$61,696	From the Project Approval Letter
Other Costs[3]	$188,332	From the Project Approval Letter
Net Project Benefits	$3,214	Electricity Billed Savings +Other Benefits – Other Costs
Approved Incentive Amount	**$243,200**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$209,436	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$317,986	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 – 1-year Project Payback	$791,751	Eligible costs minus Net Project Benefits
Recommended Project Incentive	$209,346	Minimum of the three limiters.
Project Incentive paid to Date	$102,697	Paid for 1st Quarterly Reporting Period.
Incentive payable	**$106,739**	Recommended Project – Project Incentive Paid to Date.

Table 7 provides the Incentive payment schedule

[3] The Other Benefits and Other Costs are from the Project Approval Letter and based on the original Project Scope. Due to change in CHP system capacity and lower than anticipated Electricity Savings, the actual Other Benefits and Other Costs are expected to be different from the contracted value. However, the change should not impact the Project Incentive, given the very large margin between the $200/MWh Incentive limiter and the 1-Year Payback limiter.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted]

Cogeneration System

Project ID: Toronto-PROJECT-601929
August 04, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018”

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name:	[redacted]	[redacted]
Date:	August 4, 2022	August 2, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
August 4, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of June 8, 2021, to June 18, 2022, are 1,001 MWh, which represents 104% of the Anticipated Electricity Savings. The Total System Efficiency achieved for the 1st Annual Reporting Period is 67.2%, which meets the Program Rules requirement of 65%.

Note that the original 1st Annual Reporting Period was scheduled to end on June 7, 2022. However, the Reporting Period had to be extended to June 18, 2022, as the combined heat and power (CHP) system was unexpectedly shutdown on May 30, 2022. The shutdown, which lasted 258 hours, was the result of a phase B short, which damaged the generator. The repairs could not be performed until June 10, 2022, due to COVID-19 constraints that affected the delivery of the replacement parts.

The Incentive payable to the Participant for this Reporting Period is $98,125. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Jun 8 to Sep 7, 2021	257	106%	$34,900
1st Annual	Jun 8, 2021 to Jun 18, 2022	1,001	104%	$110,343

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $110.27/MWh obtained from the Project Approval Letter.

In-Service Date Confirmation

The In-Service Date was set to June 8, 2021, on July 29, 2021, by the Technical Reviewer.

Metered Data Analysis

[redacted] the LDC representative, provided the M&V data on July 20, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Jun 8, 2021, 00:00		Start date of the Reporting Period.
Reporting Period End	Jun 18, 2022, 17:59		End date of the Reporting Period.
Reporting Period Duration	9,018	hours	End date minus start date.
Available Data	9,018	hours	
Missing Data	0	hours	0% of the Reporting Period Duration.
Unexpected Shutdown	258	hours	
Hours of Operation	8,332	hours	95% of the Reporting Period Duration excluding the 258 hours unexpected shutdown period.

Performance of the Measure

The electrical performance of the project is based on the reporting period energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,033	MWh	
CHP Auxiliary Loads Energy	32	MWh	3.1% of the CHP Gross Electrical Energy. See details below Table 3.
Reporting Period Energy	1,001	MWh	CHP Gross Electrical Energy – CHP Auxiliary Loads Energy
Uncertainty of the Reporting Period Energy	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Average Generation	114	kW	
Summer Peak Demand Generation	115	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm -7:00 pm, June 1 to August 31.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by [redacted], the supplier of the CHP system, to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy. The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by [redacted], the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,001	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,001	MWh	
Uncertainty of the Electricity Savings	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	966	MWh	As per the M&V Plan.
Electricity Savings as a Percentage of Anticipated Electricity Savings	104	%	
Average Demand Savings	114	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	115	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm -7:00 pm, June 1 to August 31.

The 1st Annual Reporting Period Electricity Savings are 1,001 MWh and represent 104% of the Anticipated Electricity Savings. The overperformance is the result of the Reporting Period average operating electrical output being 120 kW, which is slightly higher than the anticipated average operating electrical output of 119 kW.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Energy (MWh) + CHP Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 5. Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,033	MWh	Obtained from Table 3.
CHP Utilized Thermal Output	1,371	MWh	
Natural Gas Higher Heating Value (HHV)	10.75	kWh/m^3	As per the M&V Plan.
CHP Fuel Energy Input (HHV)	3,579	MWh	Calculated using the metered volumetric natural gas consumption and natural gas HHV value.
Total System Efficiency	67.2	%	

The CHP system achieved a TSE of 67.2%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and verified Eligible Costs, the Incentive payable to the Participant is $98,125. The Master Payment Requisition will be issued once the Participant's invoice for the Incentive amount is provided.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,001	1st Annual Reporting Period Electricity Savings.
Approved Amount	$193,200	From the Project Approval Letter.
Limiter 1 - Electricity Savings	$200,132	$200 per MWh of Electricity Savings, capped at 120% of Approved Amount.
Estimated Eligible Project Costs	$1,350,299	From the Project Approval Letter.
Actual Eligible Project Costs	$655,480	Based on the review of invoices for the 1st payment.
Limiter 2 - Project Costs	$262,192	40% of minimum of Estimated and Actual Eligible Project Costs.
Net Benefits	$34,621	Equal to the electricity savings, calculated using a billing rate of $110.27/MWh, plus the Other Benefits less Other Costs from the Project Approval Letter.
Limiter 3 – 1-year Project Payback	$620,859	Eligible Costs minus Net Benefits.
Gross Project Incentive	$200,132	Minimum of the three limiters.
Project Incentives paid	$102,007	Paid for 1st Quarterly Reporting Period.
Study Incentive paid	N/A	Paid for Engineering Study.[3]
Incentive payable	**$98,125**	Gross incentive minus incentives paid.

Table 7 provides the Incentive payment schedule.

[3] No deduction under “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018.”

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report
1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601934
December 08, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared in accordance with:
Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by Technical Reviewer	Reviewed by Senior Engineer
Name:	[redacted]	[redacted]
Date:	December 8, 2022	December 8, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
December 8, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of August 17, 2021, to September 19, 2022, are 976 MWh, which represents 83% of the Anticipated Electricity Savings.

Note that the original 1st Annual Reporting Period was scheduled to end on August 16, 2022. However, the Reporting Period had to be extended to September 19, 2022, as the combined hear and power (CHP) system was unexpectedly shut down on July 28, 2022 for 798 hours, due to an issue with the Domestic Hot Water (DHW) pump which was damaged by sudden water shutdown. The repairs could not be performed until August 30, 2022, due to COVID-19 supply constraints of the equipment. Thus, the Reporting Period was extended by 798 hours and excluded this shutdown period.

The Incentive payable to the Participant for this Reporting Period is $92,252. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	August 17 to November 16, 2021	260	88%	$31,200
1st Annual	August 17, 2021, to September 19, 2022	976	83%	$117,150

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan Rev.0 dated January 30, 2019, which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan. Please note that the M&V Plan shows Anticipated Electricity Savings of 1,240 MWh which is an error. The Anticipated Electricity Savings should be 1,175 MWh, based on the Project Application Review and the Approval Letter.

[2] Based on $120/MWh obtained from the Approval Letter.

In-Service Date Confirmation

The In-Service Date of August 17, 2021 was established on September 3, 2021.

Metered Data Analysis

[redacted] from Toronto Hydro provided the M&V data on November 30, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Aug. 17, 2021, 0:00		
Reporting Period End	Sep 19, 2022, 5:59		
Reporting Period Duration	8,760	hours	End date minus start date, less the 798 hours of shutdown. See comment below table.
Available Data	8,738	hours	
Missing Data	22	hours	See comment below table.
Hours of Operation	8,345	hours	95% of the Reporting Period Duration.

The CHP system did not operate from July 28, 2022, 12:00 pm to August 30, 2022, 6:00 pm (798 hours) due to an unexpected failure in the DHW pump. The problem was investigated and subsequently fixed by the manufactured. Therefore, the Reporting Period was extended by 798 hours and excludes the 798 hours of shutdown.

The M&V data was missing the CHP system gross electrical output values for the period of May 27, 2022, 6:00 pm to May 28, 2022, 5:00 pm, for a total of 22 hours. The Technical Reviewer assumes that the CHP system did not operate during this period as there was no natural gas consumption and filled the missing data with zero gross electrical output values.

Performance of the Measure

The electrical performance of the Project is based on the Adjusted Baseline Energy and the Reporting Period Energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,011	MWh	
Auxiliary Loads Energy	35	MWh	3.4% of the CHP Gross Electrical Output. See comment below the table
Reporting Period Energy	976	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Average Generation	111	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Demand Generation	111	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm - 7:00 pm.

The auxiliary loads consist of internal and external auxiliary loads. The internal loads consist of two onboard pumps and controls, are not metered. They are estimated by [redacted], the supplier of the CHP system, to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy. The external loads consist of hot water circulation pumps and dump radiators which are the part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by [redacted] the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	976	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	976	MWh	

Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,175	MWh	Obtained from the Approval Letter.
Electricity Savings as a Percentage of Anticipated Electricity Savings	83%		
Average Demand Savings	111	kW	Equal to Average Generation from Table 3. .
Summer Peak Demand Savings	111	kW	Equal to Summer Peak Demand Generation from Table 3.

The Electricity Savings of the 1st Annual Period are 976 MWh and represent 83% of the Anticipated Electricity Savings.

The original Project scope was based on a 150 kW CHP System, consisting of two 75 kW internal combustion engines (ICEs). However, in the completed Project, one 125 kW ICE was installed. The underperformance is due to the lower capacity and lower operating hours of the CHP system. The CHP system was anticipated to operate 8,592 hours with an average net operating output of 137 kW, but during the Reporting Period the CHP operated 8,345 hours with an average net operating output of 117 kW.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [Gross Electrical Energy (MWh) + Utilized Thermal Output (MWh)] / Fuel Energy Input (MWh)

Table 5. Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	1,011	MWh	From Table 3.
Utilized Thermal Output	1,382	MWh	
Fuel Energy Input	3,264	MWh	Calculated using the metered volumetric flowrate of natural gas and natural gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan
Total System Efficiency	73.3%		

The CHP system achieved a Total System Efficiency of 73.3%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period and Next Steps

The is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, the Incentive payable to the Participant is $92,252.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	976	Annual Electricity Savings, defined in this Report.
Estimated Eligible Project costs	$794,964	As per the Letter of Approval.
Actual Eligible Project Cost	$778,354	As per vendor Invoices.
Other Benefits	$60,859	As Per the Letter of Approval.
Other Cost	$187,348	As per the Letter of Approval.
Net Project benefits	-$9,337[3]	Electricity Bill Savings + Other Benefits – Other Costs
Approved Incentive Amount	$235,000	From the Project Approval Letter
Limiter 1 - Electricity Savings	$195,254	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Project Costs	$311,342	40% of minimum if Actual and Estimated Eligible costs.
Limiter 3 - Project Payback	$787,691	Eligible costs minus net benefits.
Project Incentive	$195,254	Minimum of the three limiters.
Project Incentive paid to Date	$103,002	Paid for 1st Quarterly Reporting Period.
Incentive payable	**$92,252**	Project Incentive minus Incentive paid to date.

Table 7 provided the Incentive Payment Schedule

[3] This Net Project Benefits value is based on the Approval Letter Other Benefits and Costs value, which were based on higher electricity generation, and does not reflect the actual electricity generation. The Technical Reviewer did not revise the Other Benefits and Costs value as it should not have impact on the Project Incentive.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

SAVE ON ENERGY | DELIVERY PARTNER™

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report
1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601935
October 20, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared in accordance with:
Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by Technical Reviewer	Reviewed by:
Name:	[redacted]	[redacted]
Date:	October 20, 2022	October 20, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
October 20, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of June 9, 2021 to June 16, 2022, are 792 MWh, which represents 82% of the Anticipated Electricity Savings.

The original Reporting Period has been extended by 170 hours (approximately seven days). The combined heat and power (CHP) System was not operational for 170 hours from August 10 to August 17, 2021, due to an unexpected defect in the expansion tank bladder.

The Incentive payable (balance payment) to the Participant for this Reporting Period is $70,427. Refer to the Appendix for Incentive calculation details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	June 9 to Sep. 16, 2021[3]	222	97%	$26,900
1st Annual	June 9, 2021, to June 16, 2022	792	82%	$95,900

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan Rev.0, dated February 5, 2019, which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is June 9, 2021, which was established on July 30, 2021.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $121/MWh obtained from the Project Letter of Approval.

[3] The Reporting Period has been extended by 170 hours (approximately 7 days). Refer to Table 2 for details.

Metered Data Analysis

[redacted], from Toronto Hydro, provided the M&V data on July 20, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements. The data includes the following:

- Hourly gross electrical output of the CHP System (kW)
- Hourly recovered heat from the CHP System (kWh)
- Hourly natural gas consumption (m^3)
- Hourly external auxiliary loads (kW)

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	June 9, 2021, 0:00		
Reporting Period End	June 16, 2022, 1:59		Extended by 170 hours. See note below.
Reporting Period Duration	8,760	hours	End date minus start date, excluding the shutdown period from August 10, 17:00 to August 17, 18:00.
Available Data	8,760	hours	
Missing Data	0	hours	
Hours of Operation	8,368	hours	96% of the Reporting Period Duration.

The CHP System was shut down from August 10, 17:00 to August 17, 18:00, 2021, to replace the expansion tank. The expansion tank failed unexpectedly, due to a defect in the tank bladder.

The shut down period of 170 hours represents 1.9% of the original Reporting Period. However, the Technical Reviewer excluded the 170-hour shutdown period and extended the Reporting Period by the same amount, i.e., 170 hours from June 9, 0:00 to June 16, 1:59, 2022.

Performance of the Measures

The Electricity Savings of the Project is calculated based on the Reporting Period Energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comments
Gross Electrical energy	821	MWh	
Auxiliary Loads Energy	29	MWh	3.5% of the Gross Electrical Energy.
Reporting Period Energy	792	MWh	*Gross Electrical Energy - Auxiliary Loads Energy*
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Average Generation	90	kW	*Reporting Period Energy ÷ Reporting Period Duration*
Summer Peak Demand Generation	101	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm - 7:00 pm.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by [redacted], the supplier of the CHP system, to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy.

The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by [redacted], the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comments
Baseline Energy	0	MWh	
Reporting Period Energy	792	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	792	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	971	MWh	Obtained from the M&V Plan, Rev.0, dated February 5, 2019.
Electricity Savings as a Percentage of Anticipated Electricity Savings	82%		
Average Demand Savings	90	kW	Electricity Savings ÷ Reporting Period Duration
Summer Peak Demand Savings	101	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm - 7:00 pm

The Electricity Savings of the 1st Annual Reporting Period are 792 MWh and represent 82% of the Anticipated Electricity Savings.

The under-performance resulted from lower than anticipated annual operating hours and average net electrical output of the CHP System. The CHP System was anticipated to operate with an average operating net electrical output of 113 kW whereas the Reporting Period average operating electrical output was 95 kW (i.e., 16% less). Additionally, the operating hours of the CHP System during the Reporting Period (8,368 hours) were 3% lower than anticipated (8,592 hours). It should be noted that the Project was originally planned for a total nominal capacity of 250 kW CHP System, consisting of two 125 kW internal combustion engines (ICEs), one of which was planned to serve as standby unit. In the completed Project, only one 125 kW ICE unit was installed.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 *TSE (%) = [CHP System Gross Electrical Energy + CHP System Thermal Output Used] / CHP System Energy Input (HHV)*

Table 5 outlines the TSE calculation of the CHP System.

Table 5. Total System Efficiency

Description	Value	Unit	Comments
CHP System Gross Electrical Energy	821	MWh	From Table 3.
CHP System Thermal Output Used	1,094	MWh	
CHP System Natural Gas Consumption	245,432	m^3	
Natural Gas HHV	10.75	kWh/m^3	From the M&V Plan.
CHP System Energy Input (HHV)	2,638	MWh	
Total System Efficiency	73%		

The CHP system achieved a Total System Efficiency of 73%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period and Next Steps

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and review of the Actual Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $70,427. The Master Payment Requisition will be issued upon receipt of the Participant's invoice to the LDC for this balance payment amount.

The Project Incentive Amount of $158,499 was calculated in accordance with the Program Rules and is limited by the "$200/MWh of Electricity Savings", up to a maximum of 120% of Approved Incentive Amount.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comments
Electricity Savings (MWh)	792	Annual Electricity Savings, from Table 4.
Approved Incentive Amount ($)	194,200	From the Project Letter of Approval.
Limiter 1 - Electricity Savings ($)	158,499	$200 per MWh of Electricity Savings, limited to 120% of the Approved Incentive Amount.
Actual Eligible Costs ($)	669,988	Reviewed invoices provided by the Participant.
Estimated Eligible Costs ($)	971,398	From the Project Letter of Approval.
Limiter 2 - Eligible Costs ($)	267,995	40% of minimum Actual and Estimated Eligible Costs.
Project Net Benefits ($)	9,954	*Electricity Billed Savings + Other Benefits (from Letter of Approval) – Other Costs (from Letter of Approval)*
Limiter 3 – 1-year Payback ($)	660,035	*Actual Eligible Costs - Project Net Benefits*
Project Incentive ($)	158,499	Minimum of the three limiters.
Incentives paid to date ($)	88,072	Paid for the 1st Quarterly Reporting Period.
Incentive payable (Balance Payment) ($)	70,427	*Project Incentive – Incentives paid to date*

Table 7 shows the payment schedule as defined in the Project Letter of Approval and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment	After issuance of the final (Y1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted]

Cogeneration System

Project ID: Toronto-PROJECT-601937
August 10, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
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(416) 504-3400

Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018”

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name:	[redacted]	[redacted]
Date:	August 10, 2022	August 10, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
August 10, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of June 3, 2021, to June 7, 2022, are 997 MWh, which represents 102% of the Anticipated Electricity Savings. The Total System Efficiency achieved for the 1st Annual Reporting Period is 69.1%, which meets the Program Rules minimum requirement of 65%.

Note that the original 1st Annual Reporting Period was scheduled to end on June 2, 2022. However, the Reporting Period had to be extended to June 7, 2022, as the combined heat and power (CHP) system was unexpectedly shutdown on September 3, 2021. The shutdown, which lasted 101 hours, was the result of a glycol pump failure, resulting in a glycol leak within the unit. The replacement was not successfully completed until September 7, 2021.

The Incentive payable to the Participant for this Reporting Period is $100,713. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Jun 3 to Sep 2, 2021	249	101%	$30,100
1st Annual	Jun 3, 2021 to Jun 7, 2022	997	102%	$120,627

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $121/MWh obtained from the Project Approval Letter.

In-Service Date Confirmation

The In-Service Date was set to June 3, 2021, on August 16, 2021, by the Technical Reviewer.

Metered Data Analysis

[redacted], the LDC representative, provided the M&V data on July 20, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Jun 3, 2021, 00:00		Start date of the Reporting Period.
Reporting Period End	Jun 7, 2022, 4:59		End date of the Reporting Period.
Reporting Period Duration	8,861	hours	End date minus start date.
Available Data	8,861	hours	
Missing Data	0	hours	0% of the Reporting Period Duration.
Unexpected Shutdown	101	hours	
Hours of Operation	8,361	hours	95% of the Reporting Period Duration excluding the 101 hours unexpected shutdown period.

Performance of the Measure

The electrical performance of the project is based on the reporting period energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,027	MWh	
CHP Auxiliary Loads Energy	30	MWh	2.9% of the CHP Gross Electrical Energy. See details below Table 3.
Reporting Period Energy	997	MWh	CHP Gross Electrical Energy – CHP Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Average Generation	114	kW	
Summer Peak Demand Generation	107	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm -7:00 pm, June 1 to August 31.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by the supplier of the CHP system to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy. The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by [redacted], the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	997	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	997	MWh	
Uncertainty of the Electricity Savings	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	980	MWh	As per the M&V Plan.
Electricity Savings as a Percentage of Anticipated Electricity Savings	102	%	
Average Demand Savings	114	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	107	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm -7:00 pm, June 1 to August 31.

The 1st Annual Reporting Period Electricity Savings are 997 MWh and represent 102% of the Anticipated Electricity Savings. The overperformance is the result of the Reporting Period average operating electrical output being 119 kW, which is higher than the anticipated average operating electrical output of 112 kW.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Energy (MWh) + CHP Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 5. Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,027	MWh	Obtained from Table 3.
CHP Utilized Thermal Output	1,481	MWh	
Natural Gas Higher Heating Value (HHV)	10.75	kWh/m^3	As per the M&V Plan.
CHP Fuel Energy Input (HHV)	3,629	MWh	Calculated using the volumetric natural gas consumption from the specifications and natural gas HHV value.
Total System Efficiency	69.1	%	

The CHP system achieved a TSE of 69.1%, which meets the Program Rules minimum requirement of 65%. The Technical Reviewer noted that the natural gas readings were relatively low compared to the specs and that the CHP utilized thermal output had readings greater than the available heat, as per the specs.

Therefore, the CHP utilized thermal output was limited to the specifications and the natural gas consumption was determined based on the specifications in order to quantify TSE.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and verified Eligible Costs, the Incentive payable to the Participant is $100,713. The Master Payment Requisition will be issued once the Participant's invoice for the Incentive amount is provided.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	997	1st Annual Reporting Period Electricity Savings.
Approved Amount	$196,000	From the Project Approval Letter.
Limiter 1 - Electricity Savings	$199,383	$200 per MWh of Electricity Savings, capped at 120% of Approved Amount.
Estimated Eligible Project Costs	$824,463	From the Project Approval Letter.
Actual Eligible Project Costs	$720,639	Based on the review of invoices for the 1st payment.
Limiter 2 - Project Costs	$288,256	40% of minimum of Estimated and Actual Eligible Project Costs.
Net Benefits	$36,937	Equal to the electricity savings, calculated using a billing rate of $121/MWh, plus the Other Benefits less Other Costs from the Project Approval Letter.
Limiter 3 – 1-year Project Payback	$683,703	Eligible Costs minus Net Benefits.
Gross Project Incentive	$199,383	Minimum of the three limiters.
Project Incentives paid	$98,670	Paid for 1st Quarterly Reporting Period.
Study Incentive paid	N/A	Paid for Engineering Study.[3]
Incentive payable	**$100,713**	Gross incentive minus incentives paid.

Table 7 provides the Incentive payment schedule.

[3] No deduction under “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018.”

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601938
September 16, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018”

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name:	[redacted]	[redacted]
Date:	September 16, 2022	September 16, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
September 16, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of May 26, 2021, to May 25, 2022, are 921 MWh, which represents 124% of the Anticipated Electricity Savings. The Total System Efficiency (TSE) achieved for the 1st Annual Reporting Period is 73.3%, which meets the Program Rules minimum requirement of 65%.

The Incentive payable to the Participant for this Reporting Period is $104,440. Refer to the Appendix for the Incentive calculation.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	May 26 to August 25, 2021	241	342%	$29,200
1st Annual	May 26, 2021 to May 25, 2022	921	124%	$111,500

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date was set to May 26, 2021 on August 4, 2021, by the Technical Reviewer.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $121/MWh obtained from the Project Approval Letter.

Metered Data Analysis

[redacted] the LDC representative, provided the M&V data on September 1, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	May 26, 2021, 00:00	-	Start date of the Reporting Period.
Reporting Period End	May 25, 2022, 23:59	-	End date of the Reporting Period.
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,760	hours	
Missing Data	0	hours	0% of the Reporting Period Duration.
Hours of Operation	8,188	hours	93.5% of the Reporting Period Duration.

Performance of the Measure

The electrical performance of the project is based on the reporting period energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP Gross Electrical Energy	951	MWh	
CHP Auxiliary Loads Energy	30	MWh	3.2% of the CHP Gross Electrical Energy.
Reporting Period Energy	921	MWh	CHP Gross Electrical Energy – CHP Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Average Generation	105	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	106	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm - 7:00 pm, June 1 to August 31.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by [redacted], the supplier of the CHP system, to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy. The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by [redacted], the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	921	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	921	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	746	MWh	As per the M&V Plan.
Electricity Savings as a Percentage of Anticipated Electricity Savings	124%	-	
Average Demand Savings	105	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	106	kW	Equal to Summer Peak Demand Generation from Table 3.

The 1st Annual Reporting Period Electricity Savings are 921 MWh and represent 124% of the Anticipated Electricity Savings. The overperformance is due to higher average electrical output from June to September 2022 compared to the Project Review anticipated average electrical output. Based on the original operating criteria, a significant turn-down of the engines was expected in the summer months in order to minimize the amount of CHP heat wasted due to lower heating loads. However, there doesn't appear to any thermal load following during the Reporting Period. Additionally, per the M&V Plan, the original Project scope included installation of three 65 kW microturbine cogeneration units (one backup). In the completed Project, one 125 kW reciprocating engine cogeneration unit was installed. Microturbine systems typically have higher auxiliary load electricity consumption than reciprocating engines due to the presence of a gas compressor. This resulted in a higher net electricity generation.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Energy (MWh) + CHP Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 5. Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	951	MWh	Obtained from Table 3.
CHP Utilized Thermal Output	1,291	MWh	
Natural Gas Higher Heating Value (HHV)	10.79	kWh/m^3	Obtained from the Enbridge Gas Composition and HHV Data in 2021.
CHP Fuel Energy Input (HHV)	3,059	MWh	
Total System Efficiency	73.3%	-	

The CHP system achieved a TSE of 73.3%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and verified Eligible Costs, the Incentive payable to the Participant is $104,440. The Master Payment Requisition will be issued once the Participant's invoice for the Incentive amount is provided.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	921	1st Annual Reporting Period Electricity Savings.
Approved Amount	$149,200	From the Project Approval Letter.
Limiter 1 - Electricity Savings	$179,040	$200 per MWh of Electricity Savings, capped at 120% of Approved Amount.
Estimated Eligible Project Costs	$883,463	From the Project Approval Letter.
Actual Eligible Project Costs	$770,082	Based on the review of invoices.
Limiter 2 - Project Costs	$308,033	40% of minimum of Estimated and Actual Eligible Project Costs.
Net Benefits	$31,280	Equal to the electricity savings, calculated using a billing rate of $121/MWh, plus the Other Benefits less Other Costs from the Project Approval Letter.
Limiter 3 – 1-year Project Payback	$738,802	Eligible Costs minus Net Benefits.
Gross Project Incentive	$179,040	Minimum of the three limiters.
Project Incentives paid	$74,600	Paid for 1st Quarterly Reporting Period.
Incentive payable	**$104,440**	Gross incentive minus incentives paid.

Table 7 provides the Incentive payment schedule.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report
1st Annual Reporting Period

[redacted]

Cogeneration System

Project ID: Toronto-PROJECT-601939

July 11, 2022

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited

[redacted]

Prepared by:

CLEAResult

393 University Avenue, Suite 1622, Toronto, ON M5G 1E6

(416) 504-3400

Prepared in accordance with Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by Technical Reviewer	Reviewed by Senior Engineer
Name:	[redacted]	[redacted]
Date:	July 6, 2022	July 8, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
July 11, 2022	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of May 27, 2021, to May 26, 2022, are 1,031 MWh, which represents 106% of the Anticipated Electricity Savings. The Total System Efficiency achieved for the 1st Annual Reporting Period is 77%, which meets the Program Rules requirement of 65%.

The Incentive payable to the Participant for this Reporting Period is $103,330. Refer Appendix for the Incentive calculation.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	May 27 to Aug 26, 2021	259	106%	$33,929
1st Annual	May 27, 2021, to May 26, 2022	1,031	106%	$135,022

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of May 27, 2021 was established on August 11, 2021.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan

[2] Based on $131/MWh obtained from the Project Approval Letter

Metered Data Analysis

[redacted] from Toronto Hydro provided the M&V data on June 7, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	May 27, 2021, 00:00		Start date of the Reporting Period.
Reporting Period End	May 26, 2022, 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date
Available Data	8,760	hours	
Missing Data	0	hours	0% of the Reporting Period Duration
Hours of Operation	8,442	hours	96.4% of the Reporting Period Duration

Performance of the Measure(s)

The electrical performance of the project is based on the reporting period energy, as follows:

Electricity Savings = ***Reporting Period Energy*** ± ***Non-Routine Adjustments***

Baseline Energy

This is an electricity generation Project with no prior generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy and the average and peak generation values are presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,047	MWh	Metered total gross electricity generation.
Auxiliary Loads Energy	17	MWh	Metered to auxiliary load. Equal to 1.6% of the Gross Electrical Energy.
Reporting Period Energy	1,031	MWh	Gross Electrical Energy-Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	%	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	118	kW	Reporting Period Energy divided by Reporting Period Duration
Summer Peak Generation	113	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

Electricity Savings

The Baseline Energy, Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	Obtained from Table 3.
Reporting Period Energy	1,031	MWh	Obtained from Table 3..
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,031	MWh	
Uncertainty of the Electricity Savings	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter
Anticipated Electricity Savings	968	MWh	Obtained from the Table 4 of the M&V Plan, Rev 0, dated Feb 4, 2019.
Electricity Savings as a Percentage of Anticipated Electricity Savings	106	%	
Average Demand Savings	118	kW	Obtain from Table 3
Summer Peak Demand Savings	113	kW	Obtain from Table 3

The 1st Annual Electricity Savings are 1,031 MWh, which represent 106% of the Anticipated Electricity Savings. The overperformance is due to higher than anticipated hours of operation and average operating

electrical output of the cogeneration system. The cogeneration system was anticipated to operate 8,148 hours with an average operating output of 119 kW, but the actual operating hours and average output were 8,442 hours and 122 kW, respectively.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Electrical Energy (MWh) + Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,047	MWh	Obtained from Table 3
CHP Utilized Thermal Output	1,601	MWh	
CHP Fuel Energy Input	3,464	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan
Total System Efficiency	76.5	%	

The CHP system achieved a Total System Efficiency of 76.5%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, the Incentive payable to the Participant is $103,330.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,031	1st Annual Reporting Period Electricity Savings.
Estimated Eligible Costs	$1,299,299	As per the Project Approval Letter
Actual Eligible Costs	$1,053,409	Based on Review of Eligible Costs as part of the Q1 Payment Recommendation
Electricity Billed Savings	$135,022	Based on the Project Approval Letter Electricity Billing Rate of $131/MWh
Other Benefits	$50,893	From the Project Approval Letter
Other Costs	$134,316	From the Project Approval Letter
Net Project Benefits	$51,599	Electricity Billed Savings +Other Benefits – Other Costs
Approved Incentive Amount	**$193,600**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$206,141	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$421,364	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 – Project Payback	$1,001,800	Eligible costs minus Net Project Benefits
Gross Project Incentive	$206,141	Minimum of the three limiters.
Project Incentives paid to Date	$102,811	Paid for 1st Quarterly Reporting Period.
Incentive payable	**$103,330**	Gross incentive minus incentives paid.

Table 7 provides the Incentive payment schedule

Table 7. Incentive Calculation

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5

Third Party Evaluation Reports

This document includes the following third party evaluation reports:

Process and Systems Upgrades Program:

- #601940
- #601941
- #601947
- #601948
- #601953
- #601955
- #601962

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report
1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601940
October 25, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared in accordance with:
Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by Technical Reviewer	Reviewed by:
Name:	[redacted]	[redacted]
Date:	October 25, 2022	October 25, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
October 25, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of June 22, 2021 to June 21, 2022, are 915 MWh, which represents 111% of the Anticipated Electricity Savings.

The Incentive payable (balance payment) to the Participant for this Reporting Period is $85,594. Refer to the Appendix for Incentive calculation details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	June 22 to September 21, 2021	246	190%	$33,000
1st Annual	June 22, 2021 to June 21, 2022	915	111%	$122,700

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan Rev.0 dated March 27, 2019, which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is June 22, 2021, which was established on August 11, 2021.

Metered Data Analysis

[redacted], from Toronto Hydro, provided the M&V data on July 20, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements and includes the following:

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $134/MWh obtained from the Project Letter of Approval.

- Hourly gross electrical output of the CHP System (kW)
- Hourly recovered heat from the CHP System (kWh)
- Hourly natural gas consumption by the CHP System (m^3)
- Hourly external auxiliary loads (kW)

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	June 22, 2021, 0:00		
Reporting Period End	June 21, 2022 23:59		
Reporting Period Duration	8,760	hours	
Available Data	8,760	hours	
Missing Data	0	hours	
Hours of Operation	8,470	hours	97% of the Reporting Period Duration.

Performance of the Measure

The Electricity Savings of the Project is calculated based on the Reporting Period Energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comments
Gross Electrical energy	943	MWh	
Auxiliary Loads Energy	27	MWh	2.9% of the Gross Electrical Energy.
Reporting Period Energy	915	MWh	*Gross Electrical Energy - Auxiliary Loads Energy*
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Average Generation	105	kW	*Reporting Period Energy ÷ Reporting Period Duration*
Summer Peak Demand Generation	109	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm - 7:00 pm.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by [redacted], the supplier of the CHP system, to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy.

The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by [redacted], the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comments
Baseline Energy	0	MWh	
Reporting Period Energy	915	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	915	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	823	MWh	Obtained from the M&V Plan, Rev.0, dated March 27, 2019.
Electricity Savings as a Percentage of Anticipated Electricity Savings	111%		
Average Demand Savings	105	kW	*Electricity Savings ÷ Reporting Period Duration*
Summer Peak Demand Savings	109	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm - 7:00 pm.

The Electricity Savings of the 1st Annual Reporting Period are 915 MWh and represent 111% of the Anticipated Electricity Savings.

The over-performance resulted from higher than anticipated average net electrical output of the CHP System. The CHP System was anticipated to operate with an average operating net electrical output of 94 kW whereas the Reporting Period average operating electrical output was 108 kW (i.e., 15% more). The operating hours of the CHP System during the Reporting Period (8,470 hours) were 3% lower than anticipated (8,760 hours). It should be noted that the Project was originally planned for a total nominal capacity of 195 kW CHP system, consisting of three 65 kW micro-turbines, with one unit as an emergency backup. In the completed Project, one 125 kW internal combustion engine (ICE) was installed.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 *TSE (%) = [CHP System Gross Electrical Energy + CHP System Thermal Output Used] / CHP System Energy Input (HHV)*

Table 5 outlines the TSE calculation of the CHP System.

Table 5. Total System Efficiency

Description	Value	Unit	Comments
CHP System Gross Electrical Energy	943	MWh	From Table 3.
CHP System Thermal Output Used	1,248	MWh	
CHP System Natural Gas Consumption	287,190	m^3	
Natural Gas HHV	10.75	kWh/m^3	From the M&V Plan.
CHP System Energy Input (HHV)	3,087	MWh	
Total System Efficiency	71%		

The CHP system achieved a Total System Efficiency of 71%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period and Next Steps

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and review of the Actual Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $85,594. The Master Payment Requisition will be issued upon receipt of the Participant's invoice to the LDC for this balance payment amount.

The Project Incentive Amount of $183,091 was calculated in accordance with the Program Rules and is limited by the "$200/MWh of Electricity Savings", up to a maximum of 120% of Approved Incentive Amount.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comments
Electricity Savings (MWh)	915	Annual Electricity Savings, from Table 4.
Approved Incentive Amount ($)	164,600	From the Project Letter of Approval.
Limiter 1 - Electricity Savings ($)	183,091	$200 per MWh of Electricity Savings, limited to 120% of the Approved Incentive Amount.
Actual Eligible Costs ($)	643,354	Reviewed invoices provided by the Participant.
Estimated Eligible Costs ($)	861,931	From the Project Letter of Approval.
Limiter 2 - Eligible Costs ($)	257,342	40% of minimum Actual and Estimated Eligible Costs.
Project Net Benefits ($)	41,166	*Electricity Billed Savings + Other Benefits (from Letter of Approval) – Other Costs (from Letter of Approval)*
Limiter 3 – 1-year Payback ($)	602,188	*Actual Eligible Costs - Project Net Benefits*
Project Incentive ($)	183,091	Minimum of the three limiters.
Incentives paid to date ($)	97,497	Paid for the 1st Quarterly Reporting Period.
Incentive payable (Balance Payment) ($)	85,594	*Project Incentive – Incentives paid to date*

Table 7 shows the payment schedule as defined in the Project Letter of Approval and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment	After issuance of the final (Y1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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Please note:

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

SAVE ON ENERGY | DELIVERY PARTNER™

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601941
August 17, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018”

Approvals

	Written by:	Reviewed by:
Name:	[redacted]	[redacted]
Date:	August 17, 2022	August 16, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
Auguest 17, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of June 25, 2021, to June 24, 2022, are 1,884 MWh, which represents 94% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $174,084. Refer to the Appendix for the Incentive calculation.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Jun 25 to Sep 24, 2021	511	101%	$61,800
1st Annual	Jun 25, 2021, to June 24, 2022	1,884	94%	$228,009

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date was set to June 25, 2021, on August 16, 2021, by the Technical Reviewer.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $121/MWh obtained from the Project Approval Letter.

Metered Data Analysis

[redacted]from Toronto Hydro-Electric System Limited, provided the M&V data on July 20, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	June 25, 2021, 00:00		Start date of the Reporting Period
Reporting Period End	June 24, 2022, 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date
Available Data	8,760	hours	
Missing Data	0	hours	0% of the Reporting Period Duration
Hours of Operation	8,542	hours	97.5% of the Reporting Period Duration

Performance of the Measure

The electrical performance of the project is based on the reporting period energy, as follows:

Electricity Savings = ***Reporting Period Energy*** ± ***Non-Routine Adjustments***

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the cogeneration system for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,942	MWh	
Auxiliary Loads Energy	58	MWh	3% of the CHP Gross Electrical Output. See comment below table.
Reporting Period Energy	1,884	MWh	Gross Electrical Energy – Reporting Period Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Average Generation	215	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	228	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by [redacted], the supplier of the CHP system, to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy. The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by [redacted], the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,884	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,884	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Annual Electricity Savings	2,002	MWh/Year	Obtained from the M&V Plan, Rev 0, dated February 11, 2019.
Electricity Savings as a Percentage of Anticipated Electricity Savings	94%	-	
Average Demand Savings	215	kW	Obtained from Table 3.
Summer Peak Demand Savings	228	kW	Obtained from Table 3.

The 1st Annual Electricity Savings are 1,884 MWh and represent 94% of the Anticipated Electricity Savings. The underperformance is due to less than anticipated operating hours of the cogeneration system and the average hourly generated electricity. The cogeneration system was anticipated to operate with an uptime of 98%, whereas the uptime in the Reporting Period was only 97.5%. The cogeneration system was anticipated to have an average net operating electrical output of 234 kW in comparison to the average net operating electrical output of 221 kW in the 1st Annual Reporting Period.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Electrical Energy (MWh) + Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 5. Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	1,942	MWh	
Utilized Thermal Output	2,593	MWh	
Natural Gas Higher Heating Value (HHV)	10.84	kWh/m^3	From the latest published HHV data for natural gas by Enbridge.
Fuel Energy Input (HHV)	6,479	MWh	Calculate using the metered volumetric natural gas consumption and the natural gas HHV.
Total System Efficiency	70.0%	-	

The CHP system achieved a Total System Efficiency of 70.0%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual M&V Report, the Incentive payable to the Participant is $174,084. The Master Payment Requisition will be issued once the Participant's invoice for the Incentive amount is provided.

The Incentive is based on the $200/MWh of the Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,884	1st Annual Reporting Period Electricity Savings.
Approved Amount	$400,400	From the Project Approval Letter
Estimated Eligible Project Costs	$1,380,344	From the Project Approval Letter.
Actual Eligible Project Costs	$1,550,032.67	Based on review of invoices for the 1st Payment Recommendation
Electricity Billed Savings	$228,009	Based on electricity billing rate of $121/MWh from the Project Approval Letter
Other Benefits	$106,292	From the Project Approval Letter
Other Costs	$246,299	From the Project Approval Letter
Net Benefits	$88,002	Electricity Billed Savings + Other Benefits – Other Costs
Limiter 1 - Electricity Savings	$376,875	$200 per MWh of Electricity Savings, capped at 120% of the Approved Amount.
Limiter 2 - Project Costs	$552,138	40% of minimum of Estimated Eligible Project Costs and Actual Eligible Project Costs.
Limiter 3 - Project Payback	$1,292,342	Eligible Project Costs minus Net Benefits.
Project Incentive	$376,875	Minimum of the three limiters.
Incentive Paid for the 1st Quarterly Reporting Period	**$202,791**	
Balance Incentive payable	**$174,084**	As per Table 7.

Table 7 provides the Incentive payment schedule.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report
1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601947
November 16, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared in accordance with:
Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by Technical Reviewer	Reviewed by:
Name:	[redacted]	[redacted]
Date:	November 16, 2022	November 16, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
November 16, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of June 19, 2021 to June 18, 2022, are 965 MWh, which represents 99.7% of the Anticipated Electricity Savings.

The Incentive payable (balance payment) to the Participant for this Reporting Period is $96,337. Refer to the Appendix for Incentive calculation details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	June 19 to September 18, 2021	244	100.1%	$32,000
1st Annual	June 19, 2021, to June 18, 2022	965	99.7%	$126,500

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan Rev.0 dated February 19, 2019, which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is June 19, 2021, which was established on August 16, 2021.

Metered Data Analysis

[redacted], from Toronto Hydro, provided the M&V data on July 20, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements and includes the following:

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $131/MWh obtained from the Project Letter of Approval.

- Hourly gross electrical output of the CHP System (kW)
- Hourly recovered heat from the CHP System (kWh)
- Hourly natural gas consumption of the CHP System (m^3)
- Hourly external auxiliary loads (kW).

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	June 19, 2021, 0:00		
Reporting Period End	June 18, 2022, 23:59		
Reporting Period Duration	8,760	hours	
Available Data	8,760	hours	
Missing Data	0	hours	
Hours of Operation	8,397	hours	96% of the Reporting Period Duration.

Performance of the Measure

The Electricity Savings of the Project is calculated based on the Reporting Period Energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comments
Gross Electrical Energy	1,005	MWh	
Auxiliary Loads Energy	39	MWh	3.9% of the Gross Electrical Energy.
Reporting Period Energy	965	MWh	*Gross Electrical Energy - Auxiliary Loads Energy*
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Average Generation	110	kW	*Reporting Period Energy ÷ Reporting Period Duration*
Summer Peak Demand Generation	111	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm - 7:00 pm.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by [redacted], the supplier of the CHP system, to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy.

The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by [redacted], the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comments
Baseline Energy	0	MWh	
Reporting Period Energy	965	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	965	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	968	MWh	Obtained from the M&V Plan, Rev.0, dated February 19, 2019.
Electricity Savings as a Percentage of Anticipated Electricity Savings	99.7%		
Average Demand Savings	110	kW	*Electricity Savings ÷ Reporting Period Duration*
Summer Peak Demand Savings	111	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm - 7:00 pm.

The Electricity Savings of the 1st Annual Reporting Period are 965 MWh and represent 99.7% of the Anticipated Electricity Savings. The CHP system performed as anticipated.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP System Gross Electrical Energy + CHP System Thermal Output Used] / CHP System Energy Input (HHV)

Table 5 outlines the TSE calculation of the CHP System.

Table 5. Total System Efficiency

Description	Value	Unit	Comments
CHP System Gross Electrical Energy	1,005	MWh	From Table 3.
CHP System Thermal Output Used	1,354	MWh	
CHP System Natural Gas Consumption	313,727	m^3	
Natural Gas HHV	10.75	kWh/m^3	From the M&V Plan.
CHP System Energy Input (HHV)	3,373	MWh	
Total System Efficiency	70%		

The CHP system achieved a Total System Efficiency of 70%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period and Next Steps

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and review of the Actual Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $96,337. The Master Payment Requisition will be issued upon receipt of the Participant's invoice to the LDC for this balance payment amount.

The Project Incentive Amount of $193,086 was calculated in accordance with the Program Rules and is limited by the "$200/MWh of Electricity Savings", up to a maximum of 120% of Approved Incentive Amount.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comments
Electricity Savings (MWh)	965	Annual Electricity Savings, from Table 4.
Approved Incentive Amount ($)	193,600	From the Project Letter of Approval.
Limiter 1 - Electricity Savings ($)	193,086	$200 per MWh of Electricity Savings, limited to 120% of the Approved Incentive Amount.
Actual Eligible Costs ($)	873,395	Reviewed invoices provided by the Participant.
Estimated Eligible Costs ($)	1,401,299	From the Project Letter of Approval.
Limiter 2 - Eligible Costs ($)	349,358	40% of minimum Actual and Estimated Eligible Costs.
Project Net Benefits ($)	47,412	*Electricity Billed Savings + Other Benefits (from Letter of Approval) – Other Costs (from Letter of Approval)*
Limiter 3 – 1-year Payback ($)	825,983	*Actual Eligible Costs - Project Net Benefits*
Project Incentive ($)	193,086	Minimum of the three limiters.
Incentives paid to date ($)	96,749	Paid for the 1st Quarterly Reporting Period.
Incentive payable (Balance Payment) ($)	96,337	*Project Incentive – Incentives paid to date*

Table 7 shows the payment schedule as defined in the Project Letter of Approval and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment	After issuance of the final (Y1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601948
September 13, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018”

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name:	[redacted]	[redacted]
Date:	September 13, 2022	September 12, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
September 13, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of July 7, 2021, to July 16, 2022, are 924 MWh, which represents 97% of the Anticipated Electricity Savings. The Total System Efficiency achieved for the 1st Annual Reporting Period is 65.1%, which meets the Program Rules minimum requirement of 65%.

Note that the original 1st Annual Reporting Period was scheduled to end on July 6, 2022. However, the Reporting Period had to be extended to July 16, 2022, as the combined heat and power (CHP) system was unexpectedly shutdown on November 29, 2021. The shutdown, which lasted 220 hours, was the result of a glycol leak in the exhaust heat exchanger. The replacement was not successfully completed until December 8, 2021.

The Incentive payable to the Participant for this Reporting Period is $80,736. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Jul 7 to Oct 6, 2021	262	109%	$34,900
1st Annual	Jul 7, 2021 to Jul 6, 2022	924	97%	$122,900

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $133/MWh obtained from the Project Approval Letter.

In-Service Date Confirmation

The In-Service Date was set to July 7, 2021, on August 17, 2021, by the Technical Reviewer.

Metered Data Analysis

[redacted], the LDC representative, provided the M&V data on September 1, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Jul 7, 2021, 00:00		Start date of the Reporting Period.
Reporting Period End	Jul 16, 2022, 3:59		End date of the Reporting Period.
Reporting Period Duration	8,980	hours	End date minus start date.
Available Data	8,980	hours	
Missing Data	0	hours	0% of the Reporting Period Duration.
Unexpected Shutdown	220	hours	
Hours of Operation	8,317	hours	95% of the Reporting Period Duration excluding the 220 hours unexpected shutdown period.

Performance of the Measure

The electrical performance of the project is based on the reporting period energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP Gross Electrical Energy	963	MWh	
CHP Auxiliary Loads Energy	39	MWh	4.0% of the CHP Gross Electrical Energy. See details below Table 3.
Reporting Period Energy	924	MWh	CHP Gross Electrical Energy – CHP Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Average Generation	105	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	114	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm - 7:00 pm, June 1 to August 31.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by the supplier of the CHP system to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy. The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	924	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	924	MWh	
Uncertainty of the Electricity Savings	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	956	MWh	As per the M&V Plan.
Electricity Savings as a Percentage of Anticipated Electricity Savings	97	%	
Average Demand Savings	105	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	114	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm -7:00 pm, June 1 to August 31.

The 1st Annual Reporting Period Electricity Savings are 924 MWh and represent 97% of the Anticipated Electricity Savings. The underperformance is the result of the Reporting Period average operating electrical output being 116 kW (based on a 95% uptime), which is lower than the anticipated average operating electrical output of 117 kW (based on a 93% uptime).

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Energy (MWh) + CHP Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 5. Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	963	MWh	Obtained from Table 3.
CHP Utilized Thermal Output	1,214	MWh	
CHP Fuel Energy Input (HHV)	3,341	MWh	Calculated using a regression model, which correlates energy input with gross electrical output, developed using energy input data provided in the engine performance specifications. See comment below table.
Total System Efficiency	65.1	%	

The CHP system achieved a TSE of 65.1%, which meets the Program Rules minimum requirement of 65%. Note that the fuel energy input determined using natural gas readings is significantly lower than the energy input obtained using the regression model, suggesting that the natural gas readings are erroneous and

possibly not corrected to standard conditions. Therefore, the fuel energy input used in the TSE calculation is based on the regression model relative to engine performance specifications.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and verified Eligible Costs, the Incentive payable to the Participant is $80,736. The Master Payment Requisition will be issued once the Participant's invoice for the Incentive amount is provided.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	924	1st Annual Reporting Period Electricity Savings.
Approved Amount	$191,200	From the Project Approval Letter.
Limiter 1 - Electricity Savings	$184,815	$200 per MWh of Electricity Savings, capped at 120% of Approved Amount.
Estimated Eligible Project Costs	$1,376,868	From the Project Approval Letter.
Actual Eligible Project Costs	$737,887	Based on the review of invoices for the 1st payment.
Limiter 2 - Project Costs	$295,155	40% of minimum of Estimated and Actual Eligible Project Costs.
Net Benefits	$52,447	Equal to the electricity savings, calculated using a billing rate of $133/MWh, plus the Other Benefits less Other Costs from the Project Approval Letter.
Limiter 3 – 1-year Project Payback	$685,439	Eligible Costs minus Net Benefits.
Gross Project Incentive	$184,815	Minimum of the three limiters.
Project Incentives paid	$104,079	Paid for 1st Quarterly Reporting Period.
Study Incentive paid	N/A	Paid for Engineering Study.[3]
Incentive payable	**$80,736**	Gross incentive minus incentives paid.

Table 7 provides the Incentive payment schedule.

[3] No deduction under “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018.”

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report
1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601953
November 14, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared in accordance with:
Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by Technical Reviewer	Reviewed by:
Name:	[redacted]	[redacted]
Date:	November 3, 2022	November 3, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
November 14, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of June 9, 2021 to June 18, 2022, are 1,008 MWh, which represents 99% of the Anticipated Electricity Savings.

The original Reporting Period has been extended by 235 hours (approximately 10 days). The combined heat and power (CHP) System was not operational for 235 hours from November 23 to December 3, 2021, due to an exhaust gas heat exchanger leakage. Refer to Table 2 for details.

The Incentive payable (balance payment) to the Participant for this Reporting Period is $102,767. Refer to the Appendix for Incentive calculation details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	June 9 to September 8, 2021	249	103%	$30,100
1st Annual	June 9, 2021, to June 18, 2022	1,008	99%	$122,000

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan Rev.1 dated February 15, 2019, which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is June 9, 2021, which was established on August 17, 2021.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $121/MWh obtained from the Project Letter of Approval.

Metered Data Analysis

[redacted], from Toronto Hydro, provided the M&V data on July 20, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements and includes the following:

- Hourly gross electrical output of the CHP System (kW)
- Hourly recovered heat from the CHP System (kWh)
- Hourly natural gas consumption by the CHP System (m^3)
- Hourly external auxiliary loads (kW)

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	June 9, 2021, 0:00		
Reporting Period End	June 18, 2022, 18:59		Extended by 235 hours. See note below.
Reporting Period Duration	8,760	hours	End date minus start date, excluding the shutdown period from Nov. 23, 23:00 to Dec. 3, 17:59, 2021.
Available Data	8,760	hours	
Missing Data	0	hours	
Hours of Operation	8,409	hours	96% of the Reporting Period Duration.

The CHP System was shutdown from November 23, 23:00 to December 3, 17:59, 2021, to replace the exhaust gas heat exchanger which was leaking glycol.

The shutdown period of 235 hours represents 2.7% of the original Reporting Period. The Technical Reviewer excluded the 235-hour shutdown period and extended the Reporting Period by the same amount, i.e., 235 hours from June 9, 0:00 to June 18, 18:59, 2022.

Performance of the Measure

The Electricity Savings of the Project is calculated based on the Reporting Period Energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comments
Gross Electrical energy	1,042	MWh	
Auxiliary Loads Energy	34	MWh	3.2% of the Gross Electrical Energy.
Reporting Period Energy	1,008	MWh	*Gross Electrical Energy - Auxiliary Loads Energy*
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Average Generation	115	kW	*Reporting Period Energy ÷ Reporting Period Duration*
Summer Peak Demand Generation	114	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm - 7:00 pm.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by [redacted], the supplier of the CHP system, to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy.

The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by [redacted] the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comments
Baseline Energy	0	MWh	
Reporting Period Energy	1,008	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,008	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,019	MWh	Obtained from the Project Letter of Approval.
Electricity Savings as a Percentage of Anticipated Electricity Savings	99%		
Average Demand Savings	115	kW	*Electricity Savings ÷ Reporting Period Duration*
Summer Peak Demand Savings	114	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm - 7:00 pm.

The Electricity Savings of the 1st Annual Reporting Period are 1,008 MWh and represent 99% of the Anticipated Electricity Savings.

The slight under-performance resulted from lower than anticipated annual operating hours. The operating hours of the CHP System during the Reporting Period (8,409 hours) were 2% lower than anticipated (8,592 hours). However, the CHP System was anticipated to operate with an average operating net electrical output of 118.8 kW whereas the Reporting Period average operating electrical output was 119.9 kW (i.e., 1% more).

The Project was originally planned for a total nominal capacity of 250 kW CHP system, consisting of two 125 kW internal combustion engines (ICEs), with one unit as an emergency backup. In the completed Project, one 125 kW ICE unit was installed.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 *TSE (%) = [CHP System Gross Electrical Energy + CHP System Thermal Output Used] / CHP System Energy Input (HHV)*

Table 5 outlines the TSE calculation of the CHP System.

Table 5. Total System Efficiency

Description	Value	Unit	Comments
CHP System Gross Electrical Energy	1,042	MWh	From Table 3.
CHP System Thermal Output Used	1,434	MWh	
CHP System Natural Gas Consumption	340,206	m^3	
Natural Gas HHV	10.75	kWh/m^3	From the M&V Plan.
CHP System Energy Input (HHV)	3,657	MWh	
Total System Efficiency	68%		

The CHP system achieved a Total System Efficiency of 68%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period and Next Steps

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and review of the Actual Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $102,767. The Master Payment Requisition will be issued upon receipt of the Participant's invoice to the LDC for this balance payment amount.

The Project Incentive Amount of $201,648 was calculated in accordance with the Program Rules and is limited by the "$200/MWh of Electricity Savings", up to a maximum of 120% of Approved Incentive Amount.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comments
Electricity Savings (MWh)	1,008	Annual Electricity Savings, from Table 4.
Approved Incentive Amount ($)	203,800	From the Project Letter of Approval.
Limiter 1 - Electricity Savings ($)	201,648	$200 per MWh of Electricity Savings, limited to 120% of the Approved Incentive Amount.
Actual Eligible Costs ($)	724,644	Reviewed invoices provided by the Participant.
Estimated Eligible Costs ($)	984,769	From the Project Letter of Approval.
Limiter 2 - Eligible Costs ($)	289,858	40% of minimum Actual and Estimated Eligible Costs.
Project Net Benefits ($)	43,771	*Electricity Billed Savings + Other Benefits (from Letter of Approval) – Other Costs (from Letter of Approval)*
Limiter 3 – 1-year Payback ($)	680,873	*Actual Eligible Costs - Project Net Benefits*
Project Incentive ($)	201,648	Minimum of the three limiters.
Incentives paid to date ($)	98,881	Paid for the 1st Quarterly Reporting Period.
Incentive payable (Balance Payment) ($)	102,767	*Project Incentive – Incentives paid to date*

Table 7 shows the payment schedule as defined in the Project Letter of Approval and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment	After issuance of the final (Y1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] CHP System

Project ID: Toronto-PROJECT-601955

April 10, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	[redacted]
Date:	April 10th 2023	April 10th 2023
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
April 10, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of May 27, 2021, to June 9, 2022, are 1,011 MWh, which represents 86% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $96,316, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates[1]	Electricity Savings (MWh)	% of Anticipated Electricity Savings[2]	Electricity Cost Savings[3]
1st Quarterly	May 27 to August 30, 2021	265	90%	$34,980
1st Annual	Jul 1, 2022 to Jun 30, 2023	1,011	86%	$133,461

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of May 27, 2021 was established on August 9, 2021.

The 1st Quarterly Report was issued on October 20, 2021.

[1] The 1st Quarterly Reporting Period was extended by 89 hours (approximately 3.7 days) and the 1st Annual Reporting Period was extended by 331 hours (approximately 13.8 days). See Meter Data Analysis for more details.

[2] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[3] Based on $132/MWh obtained from the Project Application Review.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on September 1, 2022 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	May 27, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	June 9, 2022 18:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date, excluding the 331 shutdown hours outlined below.
Available Data	8,760	hours	
Missing Data	486	hours	5.5% of the Reporting Period Duration. Missing Recovered Heat data only.
Hours of Operation	8,459	hours	96.6% of the Reporting Period Duration

[redacted], the CHP equipment provider, provided a summary of unscheduled maintenance that was completed on the CHP system during the 1st Annual Reporting Period. All the dates the CHP was not operating normally or the system was chut off for repairs is provided below:

- August 21, 2021, 2:00 to August 24, 2021, 21:00 (89 hours)
- August 31, 2021, 6:00 to September 2, 2021, 17:00 (59 hours)
- February 28, 2022, 20:00 to March 3, 2022, 15:00 (67 hours)
- April 1, 2022, 23:00 to April 4, 2022, 16:00 (65 hours)
- April 16, 2022, 22:00 to April 18, 2022, 20:00 (46 hours)
- April 27, 2022, 13:00 to April 27, 2022, 15:00 (2 hours)
- May 5, 2022, 20:00 to May 5, 2022, 23:00 (3 hours)

The 1st Annual Reporting period was extended by 331 hours to account for these shutdown periods.

In addition to the dates noted above, the domestic hot water heat exchanger was bypassed from August 21 to September 16, 2021 while [redacted] waited for a replacement heat exchanger to arrive. The 486 hours the heat recovery system was not operational is addressed further in this report, under Total System Efficiency.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,047	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	36	MWh	Equal to 3.5% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,011	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	120	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	117	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The auxiliary loads consist of internal and external auxiliary loads. The external auxiliary loads consist of hot water circulation pumps and dump radiators and were porivded hourly as part of the metered Reporting Period data. However, the internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. [redacted] estimates these to be 1.5 kW.

The Technical Reviewer used the hourly external auxiliary loads provided and an additional 1.5 kW per CHP operating hour to calculate the total auxiliary load energy. The total annual auxiliary energy is 3.5% of the annual Gross electricity energy, which appears to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,011	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,011	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,176	MWh	Obtained from the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	86%	-	
Average Demand Savings	120	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	117	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 1,011 MWh and represent 86% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 160 kW, consisting of two 125 kW ICEs, one of which to be permanently derated to 35 kW. In the completed Project, only one 125 kW ICE was installed. The under-performance resulted from lower than anticipated average electrical output of the CHP System. The average gross electrical power generated during the Reporting Period (120 kW) is approximately 17% lower than the anticipated average output in the Application Review (145 kW).

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,047	MWh	See the comment below.
CHP Thermal Output Utilized	1,434	MWh	
CHP Energy Input	3,393	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	73.2%	-	

Due to damage to the heat exchanger and the wait for replacement equipment, the Participant was not able to utilize the thermal output of the CHP system for 468 hours. During this period, the average hourly heat

recovered was 1.5 kW; however, the average available heat from the CHP based on the electricity output and the CHP part load specifications was 165 kW. As a result, the system achieved a TSE of 73.2%, which meets the Program Rules minimum requirement of 65%, which is considered to be conservative.

Next Reporting Period

The is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, the Incentive payable to the Participant is $96,316.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Annual Electricity Savings (MWh)	1,011	From Table 4
Actual Eligible Costs	**$1,025,644**	Per the vendor invoices.
Electricity Billed Savings	$133,452	Based on the Project Approval Letter Electricity Billing Rate of $132/MWh
Other Benefits	$55,201	From the Project Approval Letter
Other Costs	$162,417	From the Project Approval Letter
Net Project Benefits	$26,236	Electricity Billed Savings +Other Benefits – Other Costs
Approved Incentive Amount	**$235,200**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$202,200	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$410,258	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 – Project Payback	$999,408	Eligible costs minus Net Project Benefits
Project Incentive	$202,200	Minimum of the three limiters.
Project Incentive paid to Date	$105,884	Paid for 1st Quarterly Reporting Period.
Final Incentive payable	**$96,316**	Project Incentive minus Incentive paid to date.

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

SAVE ON ENERGY | DELIVERY PARTNER™

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report
1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601962
November 22, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared in accordance with:
Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by Technical Reviewer	Reviewed by:
Name:	[redacted]	[redacted]
Date:	November 22, 2022	November 22, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
November 22, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of June 18, 2021 to June 17, 2022, are 1,003 MWh, which represents 101% of the Anticipated Electricity Savings.

The Incentive payable (balance payment) to the Participant for this Reporting Period is $97,866. Refer to the Appendix for Incentive calculation details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	June 18 to September 17, 2021	259	225%	$34,700
1st Annual	June 18, 2021, to June 17, 2022	1,003	101%	$134,400

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan Rev.0 dated April 5, 2019, which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is June 18, 2021, which was established on August 30, 2021.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $134/MWh obtained from the Project Letter of Approval.

Metered Data Analysis

[redacted], from Toronto Hydro, provided the M&V data on July 20, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements and includes the following:

- Hourly gross electrical output of the CHP System (kW)
- Hourly recovered heat from the CHP System (kWh)
- Hourly natural gas consumption of the CHP System (m^3)
- Hourly external auxiliary loads (kW)

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	June 18, 2021, 0:00		
Reporting Period End	June 17, 2022, 23:59		
Reporting Period Duration	8,760	hours	
Available Data	8,732	hours	
Missing Data	28	hours	0.3% of the Reporting Period Duration.
Hours of Operation	8,455	hours	97% of the Reporting Period Duration.

The CHP data collection system was not recording the metered data during the period from June 12, 9:00 to June 13, 12:59, 2022. The missing data represents 28 hours or 0.3% of the Reporting Period. The Technical Reviewer assumed that the CHP System was not generating electricity during the missing period, to be conservative.

Performance of the Measure

The Electricity Savings of the Project is calculated based on the Reporting Period Energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comments
Gross Electrical Energy	1,029	MWh	
Auxiliary Loads Energy	27	MWh	2.6% of the Gross Electrical Energy.
Reporting Period Energy	1,003	MWh	*Gross Electrical Energy - Auxiliary Loads Energy*
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Average Generation	114	kW	*Reporting Period Energy ÷ Reporting Period Duration*
Summer Peak Demand Generation	115	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm - 7:00 pm.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by [redacted], the supplier of the CHP system, to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy.

The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by [redacted], the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comments
Baseline Energy	0	MWh	
Reporting Period Energy	1,003	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,003	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	995	MWh	Obtained from the M&V Plan, Rev.0, dated April 5, 2019.
Electricity Savings as a Percentage of Anticipated Electricity Savings	101%		
Average Demand Savings	114	kW	*Electricity Savings ÷ Reporting Period Duration*
Summer Peak Demand Savings	115	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm - 7:00 pm.

The Electricity Savings of the 1st Annual Reporting Period are 1,003 MWh and represent 101% of the Anticipated Electricity Savings.

The slight over-performance resulted from higher than anticipated annual operating hours of the CHP System. The operating hours of the CHP System during the Reporting Period (8,455 hours) were approximately 12% greater than anticipated (7,529 hours). However, the CHP System was anticipated to operate with an average operating net electrical output of 132.1 kW whereas the Reporting Period average operating electrical output was 118.6 kW (i.e., 10% less).

It should be noted that the Project was originally planned for a total nominal capacity of 160 kW CHP System, consisting of a single internal combustion engine (ICE). In the completed Project, one 125 kW ICE unit was installed.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 *TSE (%) = [CHP System Gross Electrical Energy + CHP System Thermal Output Used] / CHP System Energy Input (HHV)*

Table 5 outlines the TSE calculation of the CHP System.

Table 5. Total System Efficiency

Description	Value	Unit	Comments
CHP System Gross Electrical Energy	1,029	MWh	From Table 3.
CHP System Thermal Output Used	1,585	MWh	
CHP System Natural Gas Consumption	313,799	m^3	
Natural Gas HHV	10.75	kWh/m^3	From the M&V Plan.
CHP System Energy Input (HHV)	3,373	MWh	
Total System Efficiency	77%		

The CHP system achieved a Total System Efficiency of 77%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period and Next Steps

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and review of the Actual Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $97,866. The Master Payment Requisition will be issued upon receipt of the Participant's invoice to the LDC for this balance payment amount.

The Project Incentive Amount of $200,532 was calculated in accordance with the Program Rules and is limited by the "$200/MWh of Electricity Savings", up to a maximum of 120% of Approved Incentive Amount.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comments
Electricity Savings (MWh)	1,003	Annual Electricity Savings, from Table 4.
Approved Incentive Amount ($)	199,000	From the Project Letter of Approval.
Limiter 1 - Electricity Savings ($)	200,532	$200 per MWh of Electricity Savings, limited to 120% of the Approved Incentive Amount.
Actual Eligible Costs ($)	721,725	Reviewed invoices provided by the Participant.
Estimated Eligible Costs ($)	830,930	From the Project Letter of Approval.
Limiter 2 - Eligible Costs ($)	288,690	40% of minimum Actual and Estimated Eligible Costs.
Project Net Benefits ($)	65,349	*Electricity Billed Savings + Other Benefits (from Letter of Approval) – Other Costs (from Letter of Approval)*
Limiter 3 – 1-year Payback ($)	656,376	*Actual Eligible Costs - Project Net Benefits*
Project Incentive ($)	200,532	Minimum of the three limiters.
Incentives paid to date ($)	102,666	Paid for the 1st Quarterly Reporting Period.
Incentive payable (Balance Payment) ($)	97,866	*Project Incentive – Incentives paid to date*

Table 7 shows the payment schedule as defined in the Project Letter of Approval and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment	After issuance of the final (Y1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5

Third Party Evaluation Reports

This document includes the following third party evaluation reports:

Process and Systems Upgrades Program:

- #601964
- #601965
- #601978
- #601981
- #602011
- #602015

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601964
August 30, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
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Prepared per Program Rules version "saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018"

Approvals

	Written by:	Reviewed by:
Name:	[redacted]	[redacted]
Date:	August 30, 2022	August 30, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
Auguest 30, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of June 3, 2021, to June 24, 2022, are 996 MWh, which represents 98% of the Anticipated Electricity Savings.

Note that the original 1st Annual Reporting Period was scheduled to end on June 2, 2021. However, the Reporting Period had to be extended to June 24, 2022, as the cogeneration system unexpectedly shut down from August 20 to 25, 2021, and from November 20 to December 7, 2021. The shutdown in August, which lasted 117 hours, was the result of low oil pressure caused by the failure of pump P1. On November 20, 2021, a leak was detected in the engine exhaust gas heat exchanger, forcing the system to be shut down until December 7, 2021, for 408 hours.

The Incentive payable to the Participant for this Reporting Period is $102,015. Refer to the Appendix for the Incentive calculation.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Jun 3 to Sep 2, 2021	245	96%	$33,100
1st Annual	Jun 3, 2021, to June 24, 2022	996	98%	$134,451

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $135/MWh obtained from the Project Approval Letter.

In-Service Date Confirmation

The In-Service Date was set to June 3, 2021, on August 30, 2021, by the Technical Reviewer.

Metered Data Analysis

[redacted] from Toronto Hydro-Electric System Limited, provided the M&V data on July 20, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	June 3, 2021, 00:00		Start date of the Reporting Period
Reporting Period End	June 24, 2022, 20:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date, excluding the periods of unexpected shutdown.
Available Data	8,760	hours	
Missing Data	0	hours	0% of the Reporting Period Duration
Hours of Operation	8,338	hours	95.2% of the Reporting Period Duration

On August 20, 2021, the cogeneration system unexpectedly shut down due to low oil pressure as a result of a failure in pump P1. The system was repaired and put into service on August 25, 2021. The Reporting Period was extended by 117 hours in order to exclude the period of the unexpected shutdown.

There was a second unexpected shutdown of the cogeneration system on November 20, 2021, due to insufficient glycol pressure. The investigation revealed that the exhaust gas heat exchanger had developed a leak. The affected equipment was replaced, and the system resumed normal operation on December 7, 2021. The Reporting Period was extended by 408 hours to account for this unexpected outage.

Performance of the Measure

The electrical performance of the project is based on the reporting period energy, as follows:

Electricity Savings = ***Reporting Period Energy*** ± ***Non-Routine Adjustments***

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the cogeneration system for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,022	MWh	
Auxiliary Loads Energy	26	MWh	2.5% of the CHP Gross Electrical Output. See the comment below table.
Reporting Period Energy	996	MWh	Gross Electrical Energy – Reporting Period Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Average Generation	114	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	109	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by [redacted], the supplier of the CHP system, to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy. The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by [redacted], the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	996	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	996	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Annual Electricity Savings	1,016	MWh/Year	Obtained from the M&V Plan, Rev 0, dated April 5, 2019.
Electricity Savings as a Percentage of Anticipated Electricity Savings	98%	-	
Average Demand Savings	114	kW	Obtained from Table 3.
Summer Peak Demand Savings	109	kW	Obtained from Table 3.

The 1st Annual Electricity Savings are 996 MWh and represent 98% of the Anticipated Electricity Savings. The underperformance is due to less than anticipated operating hours of the cogeneration system. The cogeneration system was anticipated to operate with an uptime of 98%, whereas the uptime in the Reporting Period was only 95%.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Electrical Energy (MWh) + Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 5. Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	1,022	MWh	
Utilized Thermal Output	1,560	MWh	
Natural Gas Higher Heating Value (HHV)	10.84	kWh/m^3	From the latest published HHV data for natural gas by [redacted].
Fuel Energy Input (HHV)	3,416	MWh	Calculate using the metered volumetric natural gas consumption and the natural gas HHV.
Total System Efficiency	75.6%	-	

The CHP system achieved a Total System Efficiency of 75.6%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual M&V Report, the Incentive payable to the Participant is $102,015. The Master Payment Requisition will be issued once the Participant's invoice for the Incentive amount is provided.

The Incentive is based on the $200/MWh of the Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	996	1st Annual Reporting Period Electricity Savings.
Approved Amount	$203,200	From the Project Approval Letter
Estimated Eligible Project Costs	$830,930	From the Project Approval Letter.
Actual Eligible Project Costs	$984,900.67	Based on review of invoices for the 1st Payment Recommendation
Electricity Billed Savings	$134,451	Based on the electricity billing rate of $135/MWh from the Project Approval Letter
Other Benefits	$53,227	From the Project Approval Letter
Other Costs	$128,037	From the Project Approval Letter
Net Benefits	$59,641	Electricity Billed Savings + Other Benefits – Other Costs
Limiter 1 - Electricity Savings	$199,186	$200 per MWh of Electricity Savings, capped at 120% of the Approved Amount.
Limiter 2 - Project Costs	$332,372	40% of the minimum of Estimated Eligible Project Costs and Actual Eligible Project Costs.
Limiter 3 - Project Payback	$771,289	Eligible Project Costs minus Net Benefits.
Project Incentive	$199,186	Minimum of the three limiters.
Incentive Paid for the 1st Quarterly Reporting Period	**$97,171**	
Balance Incentive payable	**$102,015**	As per Table 7.

Table 7 provides the Incentive payment schedule.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601965
September 19, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018”

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name:	[redacted]	[redacted]
Date:	September 19, 2022	September 16, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
September 19, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of June 24, 2021, to July 19, 2022, are 1,009 MWh, which represents 108% of the Anticipated Electricity Savings. The Total System Efficiency (TSE) achieved for the 1st Annual Reporting Period is 73.3%, which meets the Program Rules minimum requirement of 65%.

Note that the original 1st Annual Reporting Period was scheduled to end on June 23, 2022. However, the Reporting Period had to be extended to July 19, 2022, as the combined heat and power (CHP) system was unexpectedly shutdown as per the details in Table 1.

Table 1. Unexpected Shutdowns

Start Date	End Date	Hours	Description
September 1, 2021	September 15, 2021	352	Wiring harness failure and supply issues.
January 15, 2022	January 26, 2022	264	Cylinder head failure and supply issues.

The Incentive payable to the Participant for this Reporting Period is $101,398. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 2.

Table 2. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Jun 24 to Oct 8, 2021	253	107%	$33,800
1st Annual	Jun 24, 2021 to Jul 19, 2022	1,009	108%	$135,150

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $134/MWh obtained from the Project Approval Letter.

- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date was set to June 24, 2021, on September 1, 2021, by the Technical Reviewer.

Metered Data Analysis

[redacted] the LDC representative, provided the M&V data on September 1, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 3 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 3. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Jun 24, 2021, 0:00		Start date of the Reporting Period.
Reporting Period End	Jul 19, 2022, 15:59		End date of the Reporting Period.
Reporting Period Duration	9,376	hours	End date minus start date.
Available Data	9,376	hours	
Missing Data	0	hours	0% of the Reporting Period Duration.
Unexpected Shutdown	616	hours	
Hours of Operation	8,464	hours	97% of the Reporting Period Duration excluding the 616 hours unexpected shutdown period.

Performance of the Measure

The electrical performance of the project is based on the reporting period energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the CHP System for this Reporting Period is presented in Table 4.

Table 4. Reporting Period Energy

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,035	MWh	
CHP Auxiliary Loads Energy	27	MWh	2.6% of the CHP Gross Electrical Energy. See details below Table 4.
Reporting Period Energy	1,009	MWh	CHP Gross Electrical Energy – CHP Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Average Generation	115	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	116	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm - 7:00 pm, June 1 to August 31.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by the supplier of the CHP system to be 1.5 kW. The Technical Reviewer accepted this value for purposes of assessing the internal auxiliary load energy. The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 5. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 5. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,009	MWh	Obtained from Table 4.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,009	MWh	
Uncertainty of the Electricity Savings	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	937	MWh	As per the M&V Plan.
Electricity Savings as a Percentage of Anticipated Electricity Savings	108	%	
Average Demand Savings	115	kW	Equal to Average Generation from Table 4.
Summer Peak Demand Savings	116	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm - 7:00 pm, June 1 to August 31.

The 1st Annual Reporting Period Electricity Savings are 1,009 MWh and represent 108% of the Anticipated Electricity Savings. The overperformance is the result of the Reporting Period average operating electrical output being 119 kW with 97% uptime, whereas the anticipated average operating electrical output was 146 kW with 73% uptime. Note that the Project was originally planned for one 160 kW internal combustion engine (ICE) cogeneration unit. In the completed Project, one 125 kW ICE was installed.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Energy (MWh) + CHP Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 6. Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,035	MWh	Obtained from Table 4.
CHP Utilized Thermal Output	1,598	MWh	
CHP Fuel Energy Input (HHV)	3,593	MWh	Calculated using a regression model, which correlates energy input with gross electrical output, developed using energy input data provided in the engine performance specifications. See comment below table.
Total System Efficiency	73.3	%	

The CHP system achieved a TSE of 73.3%, which meets the Program Rules minimum requirement of 65%. Note that the fuel energy input determined using natural gas readings is lower than the energy input

obtained using the regression model, suggesting that the natural gas readings are possibly not corrected to standard conditions. Therefore, the fuel energy input used in the TSE calculation is based on the regression model relative to engine performance specifications.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and verified Eligible Costs, the Incentive payable to the Participant is $101,398. The Master Payment Requisition will be issued once the Participant's invoice for the Incentive amount is provided.

Table 7 outlines the Incentive payment calculation using the latest available information.

Table 7. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,009	1st Annual Reporting Period Electricity Savings.
Approved Amount	$187,400	From the Project Approval Letter.
Limiter 1 - Electricity Savings	$201,722	$200 per MWh of Electricity Savings, capped at 120% of Approved Amount.
Estimated Eligible Project Costs	$830,930	From the Project Approval Letter.
Actual Eligible Project Costs	$636,220	Based on the review of invoices for the 1st payment.
Limiter 2 - Project Costs	$254,488	40% of minimum of Estimated and Actual Eligible Project Costs.
Net Benefits	$63,460	Equal to the electricity savings, calculated using a billing rate of $134/MWh, plus the Other Benefits less Other Costs from the Project Approval Letter.
Limiter 3 – 1-year Project Payback	$572,760	Eligible Costs minus Net Benefits.
Gross Project Incentive	$201,722	Minimum of the three limiters.
Project Incentives paid	$100,324	Paid for 1st Quarterly Reporting Period.
Study Incentive paid	N/A	Paid for Engineering Study.[3]
Incentive payable	**$101,398**	Gross incentive minus incentives paid.

Table 8 provides the Incentive payment schedule.

[3] No deduction under “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018.”

Table 8. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report
1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601978
September 16, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited (the LDC)
[redacted]

Prepared by:
CLEAResult
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared per Program Rules version "saveONenergy Process & Systems Upgrades Program, FINAL v2.0
April 6, 2018

Approvals

	Written by Technical Reviewer	Reviewed by Senior Engineer
Name:	[redacted]	[redacted]
Date:	September 12, 2022	September 15, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
September 16, 2022	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of June 30, 2021 to July 6, 2022, are 953 MWh, which represents 89% of the Anticipated Electricity Savings. The Total System Efficiency (TSE) achieved in the 1st Annual Reporting Period is 71.6%, which meets the Program Rules minimum requirement of 65%.

Note that the original 1st Annual Reporting Period was scheduled to end on June 29, 2022. However, the Reporting Period had to be extended to July 6, 2022, as the combined heat and power (CHP) system unexpectedly shut down from February 13 to 19, 2022. The shutdown, which lasted 150 hours, was the result of a failed spring in the cylinder head that induced metal into the combustion chamber. Due to COVID-19 supply constraints, the issue could not be rectified until February 19, 2022.

The Incentive payable to the Participant for this Reporting Period is $ 94,436.00. Refer Appendix for the Incentive calculation.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Jun 30 to Sep 29, 2021	243	90%	$29,100
1st Annual	Jun 30, 2021, to July 6, 2022	953	89%	$114,400

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan

[2] Based on $120/MWh obtained from the Approval Letter

In-Service Date Confirmation

The In-Service Date was set to June 30, 2021, on August 16, 2021, by the Technical Reviewer.

Metered Data Analysis

[redacted] the LDC representative, provided the M&V data on September 1, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	June 30, 2021, 00:00		
Reporting Period End	July 6, 2022, 5:59		
Reporting Period Duration	8,760	hours	End date minus start date. Excludes the 150-hour unexpected shutdown period
Available Data	8,760	hours	
Missing Data	0	hours	
Hours of Operation	8,461	hours	96.6% of the Reporting Period Duration

The CHP system was unexpectedly shutdown for 150 hours, between 12 p.m. on February 13, 2022 and 6 p.m. on February 19, 2022. The shutdown was a result of was the result of a failed spring in the cylinder head that induced metal into the combustion chamber. Due to COVID-19 supply constraints, the issue could not be rectified until February 19, 2022. These 150 hours were excluded from the Reporting Period and the end date of the original M&V Reporting Period was extended by 150 hours to 6 p.m. on July 6, 2022, to compensate for the 150-hour downtime.

Performance of the Measure

The electrical performance of the project is calculated using the following equation:

Electricity Savings = ***Reporting Period Energy*** ± ***Non-Routine Adjustments***

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy of the CHP system for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	987	MWh	
Auxiliary Loads Energy	33	MWh	Equal to 3.4% of the Gross Electrical Energy.
Reporting Period Energy	953	MWh	Gross Electrical Energy – Auxiliary Loads Energy
Uncertainty of the Reporting Period Energy	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Average Generation	109	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	112	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm - 7:00 pm, June 1 to August 31.

Electricity Savings

The Reporting Period Energy and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Reporting Period Energy	953	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	953	MWh	
Uncertainty of the Electricity Savings	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,069	MWh	Obtained from the Table 5 of the M&V Plan, Rev0, dated February 15, 2019.
Electricity Savings as a Percentage of Anticipated Electricity Savings	89	%	
Average Demand Savings	109	kW	Equal to Average Generation from Table 3
Summer Peak Demand Savings	112	kW	Equal to Summer Peak Demand Generation from Table 3.

The 1st Annual Electricity Savings are 953 MWh, which represent 89% of the Anticipated Electricity Savings.

The reason for the underperformance could be a result of a change in scope of the Project. The original Project scope was based on installation of a 140 kW CHP system, consisting of two 75 kW internal combustion engines (ICEs), both of which would have been permanently derated to 70 kW. Instead, one 125 kW ICE was installed. Additionally, the anticipated uptime and average operating electrical output were 124.5 kW and 98%, respectively. However, in this 1st Annual Reporting Period, these values were 113 kW and 96.6%, respectively.

Total System Efficiency

The TSE of the CHP system is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy (MWh) + Utilized Thermal Output (MWh)] / Fuel Energy Input (MWh)

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	987	MWh	Obtained from Table 3
Utilized Thermal Output	1,319	MWh	
Natural gas Higher Heating Value (HHV)	10.75	kWh/m^3	As per the M&V Plan.
Fuel Energy Input	3,220	MWh	Total volumetric natural gas consumption x Natural gas HHV
Total System Efficiency	71.6	%	

The CHP system achieved a TSE of 71.6%, which meets the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required unless requested by the IESO

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and review of the Eligible Costs), the Balance Incentive payable to the Participant is 94,436.00. The Master Payment Requisition will be issued once the Participant's invoice for the Incentive amount is provided.

Table outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	953	1st Annual Reporting Period Electricity Savings.
Approved Amount	$213,800	From the Approval Letter.
Incentive Limiter 1 - Electricity Savings	$190,656	$200 per MWh of Electricity Savings, capped at 120% of the Approved Amount.
Estimated Eligible Project Costs	$788,274	From the Approval Letter
Actual Eligible Project Costs	$635,169	Based on the review of invoices from the 1st Payment Recommendation.
Incentive Limiter 2 - Project Costs	$254,068	40% of minimum of Estimated and Actual Eligible Costs.
Electricity Billing Rate ($/MWh)	120	From the Approval Letter
Electricity Billed Savings	$114,393	Electricity Savings x Electricity Billing Rate
Other Benefits	$45,267	From the Approval Letter
Other Costs	$146,470	From the Approval Letter
Net Benefits	$13,190	Electricity Billed Savings + Other Benefits – Other Costs .
Incentive Limiter 3 – 1-Year Project Payback	$621,979	Eligible Project Costs - Net Benefits.
Project Incentive	$190,656	Minimum of the three Incentive limiters.
Project Incentive Paid to Date	$96,220	Paid for 1st Quarterly Reporting Period.
Balance Incentive payable	**$94,436**	Gross incentive minus incentives paid.

Table 7 provides the Incentive payment schedule.

Payment	Projected Milestone	Payment Amount
First Payment	After issuance of the initial (1st Quarterly) M&V Report.	50% of Participant Incentive, . The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Balance Payment	After issuance of the final (1st Annual) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601981
September 13, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018”

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name:	[redacted]	[redacted]
Date:	September 13, 2022	September 13, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
September 13, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of May 26, 2021, to July 24, 2022, are 976 MWh, which represents 109% of the Anticipated Electricity Savings. The Total System Efficiency (TSE) achieved for the 1st Annual Reporting Period is 63.7%, which does not meet the Program Rules minimum requirement of 65%.

Note that the original 1st Annual Reporting Period was scheduled to end on May 25, 2022. However, the Reporting Period had to be extended to July 24, 2022, as the combined heat and power (CHP) system was unexpectedly shutdown as per the details in Table 1.

Table 1. Unexpected Shutdowns

Start Date	End Date	Hours	Description
September 6, 2021	September 23, 2021	425	Broken shaft in pump and supply issues.
November 24, 2021	December 3, 2021	216	Generator shorted to ground and supply issues.
February 24, 2022	March 9, 2022	313	Failed inverter control board and supply issues.
May 14, 2022	June 2, 2022	467	Failed cylinder in engine and supply issues.

The Incentive payable to the Participant for this Reporting Period is $96,227. Refer to the Appendix for the Incentive calculation, which includes the penalty for not achieving the minimum 65% TSE requirement.

The Electricity Savings for each Reporting Period to date are presented in Table 2.

Table 2. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	May 26 to Aug 25, 2021	259	172%	$31,600
1st Annual	May 26, 2021 to Jul 24, 2022	976	109%	$119,100

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $122.01/MWh obtained from the Project Approval Letter.

- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date was set to May 26, 2021, on September 2, 2021, by the Technical Reviewer.

Metered Data Analysis

[redacted] the LDC representative, provided the M&V data on September 1, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 3 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 3. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	May 26, 2021, 00:00		Start date of the Reporting Period.
Reporting Period End	Jul 24, 2022, 4:59		End date of the Reporting Period.
Reporting Period Duration	10,181	hours	End date minus start date.
Available Data	10,181	hours	
Missing Data	0	hours	0% of the Reporting Period Duration.
Unexpected Shutdown	1,421	hours	
Hours of Operation	8,525	hours	97% of the Reporting Period Duration excluding the 1,421 hours unexpected shutdown period.

Performance of the Measure

The electrical performance of the project is based on the reporting period energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electrical generation of the CHP System for this Reporting Period is presented in Table 4.

Table 4. Reporting Period Energy

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,011	MWh	
CHP Auxiliary Loads Energy	34	MWh	3.4% of the CHP Gross Electrical Energy. See details below Table 3.
Reporting Period Energy	976	MWh	CHP Gross Electrical Energy – CHP Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Average Generation	111	kW	
Summer Peak Demand Generation	113	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm - 7:00 pm, June 1 to August 31.

The auxiliary loads consist of internal and external auxiliary loads. The internal auxiliary loads, which consist of two onboard pumps and controls, are not metered. They are estimated by the supplier of the CHP system to be 1.5 kW. The Technical Reviewer accepted this value and applied 1.5 kW per CHP operating hour to calculate the internal auxiliary load energy. The external auxiliary loads consist of hot water circulation pumps and dump radiators. The external loads were part of the metered Reporting Period data. However, it appears that the hourly values provided for the external auxiliary loads were determined by the Participant's consultant, based on power ratings from equipment specifications and operating status. Both the internal and external auxiliary load values appear to be reasonable based on the CHP system installed.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 5. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 5. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	976	MWh	Obtained from Table 4.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	976	MWh	
Uncertainty of the Electricity Savings	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	893	MWh	As per the M&V Plan.
Electricity Savings as a Percentage of Anticipated Electricity Savings	109	%	
Average Demand Savings	111	kW	Equal to Average Generation from Table 4.
Summer Peak Demand Savings	113	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm -7:00 pm, June 1 to August 31.

The 1st Annual Reporting Period Electricity Savings are 976 MWh and represent 109% of the Anticipated Electricity Savings. The overperformance is the result of the Reporting Period average operating electrical output being 119 kW (based on a 97% uptime), which is higher than the anticipated average operating electrical output of 102 kW (based on a 100% uptime).

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Energy (MWh) + CHP Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 6. Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,011	MWh	Obtained from Table 4.
CHP Utilized Thermal Output	1,198	MWh	
Natural Gas Higher Heating Value (HHV)	10.75	kWh/m^3	As per the M&V Plan.
CHP Fuel Energy Input (HHV)	3,466	MWh	
Total System Efficiency	63.7	%	

The CHP system achieved a TSE of 63.7%, which does not meet the Program Rules minimum requirement of 65%. As such, the incentive is discounted by 5% as indicated in Table 7.

Table 7. Discount in Incentive based on TSE Range

TSE Range	% Discount in Incentive
62.5% ≤ TSE < 65.0%	5% discount
60.0% ≤ TSE < 62.5%	10% discount
57.5% ≤ TSE < 60.0%	15% discount
TSE < 57.5%	Considered a default of the Participant agreement

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and verified Eligible Costs, the Incentive payable to the Participant is $96,227. The Master Payment Requisition will be issued once the Participant's invoice for the Incentive amount is provided.

Table 8 outlines the Incentive payment calculation using the latest available information.

Table 8. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	976	1st Annual Reporting Period Electricity Savings.
Approved Amount	$178,600	From the Project Approval Letter.
Limiter 1 - Electricity Savings	$195,291	$200 per MWh of Electricity Savings, capped at 120% of Approved Amount.
Estimated Eligible Project Costs	$883,463	From the Project Approval Letter.
Actual Eligible Project Costs	$702,518	Based on the review of invoices..
Limiter 2 - Project Costs	$281,007	40% of minimum of Estimated and Actual Eligible Project Costs.
Net Benefits	$33,775	Equal to the electricity savings, calculated using a billing rate of $122.01/MWh, plus the Other Benefits less Other Costs from the Project Approval Letter.
Limiter 3 – 1-year Project Payback	$668,743	Eligible Costs minus Net Benefits.
Gross Project Incentive	$195,291	Minimum of the three limiters.
Adjusted Gross Project Incentive	$185,527	5% TSE penalty applied.
Project Incentives paid	$89,300	Paid for 1st Quarterly Reporting Period.
Study Incentive paid	N/A	Paid for Engineering Study.[3]
Incentive payable	**$96,227**	Gross incentive minus incentives paid.

Table 9 provides the Incentive payment schedule.

[3] No deduction under “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018.”

Table 9. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted]

Compressed Air Project Phase II

Project ID: Toronto-PROJECT-602011

October 05, 2020

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited

[redacted]

Prepared by:

CLEAResult (the Technical Reviewer)

393 University Avenue, Suite 1622, Toronto, ON M5G 1E6

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Prepared per Program Rules version "saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018".

Revision History

Date	Name/Description	Revision	Author
October 5, 2020	M&V Report First Issuance	0	[redacted]

Approvals

Name	Title	Signature	Date
[redacted]	Energy Engineer	[redacted]	October 5, 2020

Summary

The Electricity Savings for the 1st Annual Reporting Period of September 1, 2019 to August 31, 2020, are 1,113 MWh, which represents 110% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $222,549. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Sep 1 to Nov 30, 2019	301	120%	$26,000
1st Annual	Sep 1, 2019 to Aug 31, 2020	1,113	110%	$96,000

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan, which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date is September 1, 2019, which was established on November 22, 2019.

Metered Data Analysis

[redacted](the Participant representative) provided the raw process data to the CMVP for analysis, which included hourly compressor electrical power and discharge pressure for the eight compressors, compressed air flow rate at four points, and hourly dryer power. Additional measurements and specifications were provided for non-routine adjustments related to changes in compressed air usage from the Baseline Period. The provided data is compliant with the M&V Plan requirements.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $86.4/MWh obtained from the Project Application Review.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period duration, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	September 1, 2019 0:00		Start date of the Reporting Period
Reporting Period End	August 31, 2020 23:59		End date of the Reporting Period
Reporting Period Duration	8,784	hours	End date minus start date
Available Data	8,699	hours	
Missing Data	85	hours	1% of the Reporting Period Duration
Hours of Operation	8,528	hours	97% of the Reporting Period Duration

The missing data represents 85 hours, or 1% of the Reporting Period. For periods of missing data, the compressed air system's equipment was assumed to be operating at the average power for that equipment over the Reporting Period.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Adjusted Baseline Energy

As defined in the M&V Plan, the Baseline Energy is adjusted to the operating conditions of the Reporting Period, as shown in Table 3. The Adjusted Baseline Energy is calculated using the energy model defined in the M&V Plan, section B.6.2. The energy model is used to predict compressor power given the average daily compressed air flow, with air flow adjustments for the different measures. Note that measure 3 in the M&V Plan was not implemented, and measure 2 was modified to include redesigned blowers. This average compressor power is multiplied by the daily hours of operation to obtain daily compressor energy.

Added to the compressor energy is an adjustment for the energy consumption of measure 4, which is based on the number of dust collector transfers per day. The Adjusted Baseline Energy of the refrigerated dryer is also added to the compressor energy.

Table 3. Adjusted Baseline Energy

Description	Value	Unit	Comment
Compressors (measure 1, measure 2, non-routine adjustments)	16,158	MWh	Calculated using air flow-based energy model from M&V Plan: *Compressor power (kW) = 0.1527 × adjusted daily average flow rate (scfm) + 308.92* Includes air flow adjustments for measures 1 and 2, and non-routine adjustments.
Compressors (measure 4)	101	MWh	Based on reduction in daily number of dust collector transfers.
Refrigerated Dryer	780	MWh	Calculated using average baseline dryer power (91 kW) and new dryer hours of operation (8,569 hours).
Adjusted Baseline Energy	17,038	MWh	Sum of compressor and dryer energy.

Reporting Period Energy

The Reporting Period Energy is itemized in Table 4 below. Note that missing hours for each compressor and the dryer were conservatively extrapolated to the full Reporting Period duration of 8,784 hours.

Table 4. Reporting Period Energy

Description	Measured consumption, MWh	Available Data, hours	Extrapolated Consumption, MWh	Comment
Compressor 1	723	8,776	724	
Compressor 2	7,934	8,776	7,941	
Compressor 3	4,872	8,776	4,877	
Compressor 4	1,448	8,776	1,449	
Compressor 5	138	8,731	139	
Compressor 6	148	8,731	149	
Compressor 7	116	8,731	117	
Compressor 8	173	8,699	175	
Refrigerated Dryer	355	8,776	356	Calculated from measured amperage, assumed 575 V and 0.87 power factor.
Reporting Period Energy			15,926	Sum of extrapolated consumption.
Uncertainty			± 1.5%	Estimated uncertainty due to metering and adjustment uncertainty.

Non-Routine Adjustments

There were several modifications to the compressed air system since the M&V Plan was issued. These changes require Non-Routine Adjustments, and they are accounted for by adjusting the average compressed air flow input parameter to the energy model regression equation. These changes and their compressed air flow impact are itemized in Table 5.

Table 5. Compressed Air Flow Impact for Non-Routine Adjustments

Name	Description	Date Range	Flow Adjustment, scfm
Q1 Reporting Period			
Air knives	Two air knives installed on bin feeder to clear pack material build-up. Operational when bin feeder is running, 6,600 hours/year. Rated at 139 scfm.	Aug. 2018 to Aug. 31, 2020	109.2
Air spargers	Two air spargers installed on PRD stack to clear pack material build-up. Operate intermittently on timer.	Sept. 2018 to Aug. 31, 2020	17.4
Packlift blower	Originally the Secondary Packlift Blower operated on compressed air, but it was changed to operate using a fan blower. Rated as a reduction of 283 scfm.	Sept. 2018 to Aug. 31, 2020	-283.0
Air lines on bandsaw	Two 5/16” air lines, regulated down to 50 psig, added to conveyor to clear pack material build-up on bandsaw T-01.	Dec. 2018 to Aug. 31, 2020	146.0
Baler replacement	Baler cylinder was replaced and now runs off plant compressed air. Runs continuously when line is running. Rated at 47 scfm.	Jan. 2019 to Aug. 31, 2020	47.0
Air horn	Air horn added for emergency cooling of melter brick. Runs continuously. Rated at 126 scfm. Adjustment effective from Sept. 11, 2019.	Sept. 11, 2019 to mid-2020	126.0
Y1 Reporting Period			
Air horns 2.0	The air horns are ASI-1000 models, rated for 90 psi air, which are rated for 64 scfm. Three air horns were installed on Feb. 1, 2020, with a fourth installed on Feb. 18, 2020. One air horn was removed on Mar. 5, 2020.	Feb. 1, 2020 to Mar. 5, 2020	64.0
Gas burners	Each burner has a 3/8” and a 1/4” compressed air line feeding it. It is approximated that each burner consumes 245.7 scfm. One burner was installed on Feb. 1, 2020 and the second on Feb. 19, 2020. Both burners were removed Feb. 24, 2020. Both burners were re-installed on Feb. 27, 2020 but solely for this day. On Mar. 5, 2020, one burner was installed solely for this day.	Feb. 1, 2020 to Mar. 5, 2020	245.7
Air lances	The air lances were manufactured on site, with an orifice size of 1/2”. It is approximated that each air lance consumes 172 scfm. Three air lances were installed on Feb. 1, 2020.	Feb 1., 2020 to Aug. 31, 2020	172.0

Electricity Savings

The Adjusted Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 6. Non-Routine Adjustments have been applied as compressed air flow adjustments to the energy model, as described in the Non-Routine Adjustment section above. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 6. Electricity Savings

Description	Value	Unit	Comment
Adjusted Baseline Energy	17,038	MWh	From Table 4.
Reporting Period Energy	15,926	MWh	From Table 3.
Non-Routine Adjustments	0	MWh	Non-Routine Adjustments are accounted for through additional compressed air flow, included in the Adjusted Baseline Energy calculation. See Table 5.
Electricity Savings	1,113	MWh	*Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments*
Electricity Savings Uncertainty	± 80%		Calculated using the Adjusted Baseline Energy uncertainty (± 5%) and the Reporting Period Energy uncertainty (± 1.5%), obtained from the M&V Plan.
Anticipated Electricity Savings	1,008	MWh	From Table 1.
Electricity Savings as a Percentage of Anticipated Electricity Savings	110%		
Average Demand Savings	127	kW	*Electricity Savings ÷ Reporting Period duration*
Reporting Period Peak Demand	1,818	kW	Average demand during the summer Peak Demand Period, defined as weekdays, 1pm – 7pm, June 1 – August 31.
Baseline Peak Demand	2,132	kW	From the M&V Plan.
Summer Peak Demand Savings	314	kW	*Reporting Period Peak Demand - Baseline Peak Demand*

The 1st Annual Electricity Savings are 1,113 MWh and represent 110% of the Anticipated Electricity Savings.

The main reason for the overperformance is most likely due to the high uncertainty associated with the measurement and verification methodology of this Project, where a small change in the input of the calculation can generate large changes in the Electricity Savings. The high uncertainty is due to the small amount of Electricity Savings (6.5%) compared to the Adjusted Baseline Energy.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

APPENDIX
Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable to the Participant is $222,549, less any payment made to date. Note that this is based on the $200/MWh incentive limiter, capped at 120% of the Anticipated Electricity Savings.

The Technical Reviewer used the Project Application Review metrics to estimate the Incentive, which are summarized in Table 7.

Table 7. Incentive Estimation Metrics

Billing Rate ($/MWh)	86.4
Other Costs & Benefits ($/year)	0
Eligible Costs ($)	466,451[3]
Payment Option	Deferred

Table 8 provides the Incentive payment schedule.

Table 8: Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

[3] Eligible Costs based on the review of the invoices provided.

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M&V Report

1st Annual Report

April 25, 2019 – April 24, 2020

[redacted]

Electric Heating Controls Upgrade Phase 2

Project ID: Toronto-PROJECT-602015

May 8, 2020

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (the LDC)

[redacted]

Prepared by:

CLEAResult Canada Inc.
393 University Avenue, Suite 1622
Toronto, ON, M5G 1E6
416-504-3400

Prepared per Program Rules version "saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018".

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Revision History

Date	Name/Description	Revision	Author
May 8, 2020	M&V Report first issuance.	0	[redacted]

Approvals

Name	Title	Signature	Date
[redacted]	Energy Engineer	[redacted]	May 5, 2020

1. Executive Summary

The Electricity Savings for the 1st Annual Reporting Period of April 25, 2019 to April 24, 2020 are 386 MWh which represent 92% of the Anticipated Electricity Savings.

The total Incentive payable to the Participant for the 1st Annual Reporting Period is estimated at $77,165.42. The final payment is $27,005.42, pending issuance of the Master Payment Requisition.

2. Project Overview

2.1. Baseline Energy and Anticipated Electricity Savings

The annual Baseline Energy and the Anticipated Electricity Savings are obtained from the M&V Plan Rev. 0, dated December 28, 2018, and are presented in Table 1.

Table 1. Annual Baseline Energy, and Anticipated Electricity Savings

Description	Value	Unit
Baseline Energy	4,219	MWh/year
Anticipated Electricity Savings	418	MWh/year

This M&V Report assesses the actual Electricity Savings based on raw data provided by the Participant and the methodology described in the M&V Plan. This is an IPMVP Option C methodology of calculating the Electricity Savings.

This M&V Report calculates the actual Electricity Savings divided by the Anticipated Electricity Savings, which is the ratio by which the incentive is pro-rated, capped at 120%.

2.2. In-Service Date and Previous Reporting Period

The In-Service Date is April 25, 2019, which was established on September 23, 2019.

The 1st Quarterly Reporting Period was from April 25 to July 24, 2019, representing 91 days (2,184 hours).

2.3. Current Reporting Period

The 1st Annual Reporting Period is from April 25, 2019 to April 24, 2020, representing 366 days (8,784 hours).

3. Reporting Period Energy

3.1. Results

[redacted](the LDC representative) provided the raw process data to the CMVP for analysis. Table 2 presents an overview of the data analysis related to the duration of the Reporting Period and equipment hours of operation.

Table 2. Reporting Period Hours and Missing Data

Description	Value	Unit	Comments
Reporting Period Start	April 25, 2019 0:00		
Reporting Period End	April 24, 2020 23:59		
Reporting Period Duration	8,784	hours	
Available Meter Data	8,784	hours	100% of the Reporting Period Duration.
Missing Data	0	hours	0% of the Reporting Period.
Hours of Operation	8,784	hours	100% of the Available Meter Data.

The Reporting Period Energy is shown in Table 3 below.

Table 3. Reporting Period Energy

Description	Value	Unit	Comments
Reporting Period Energy	3,659	MWh	Total Facility electricity consumption (utility meter 9154617).
Uncertainty	± 0.5%		Utility meters are assumed to have an uncertainty of ± 0.5%.

4. Electricity Savings

4.1. Adjusted Baseline Energy

The Adjusted Baseline Energy is calculated using the energy model defined in the M&V Plan, section B.5.1. The energy model is based on average daily temperature, obtained for the Toronto City weather station (WMO 71508) from Environment and Climate Change Canada. The Adjusted Baseline Energy for this Reporting Period is 4,044 MWh.

4.2. Results

The Electricity Savings are calculated according to the following equation:

Since there has been no change in the Static Factors as defined in the M&V Plan Section B.5.2, Non-Routine Adjustments are not required for this Reporting Period. The Reporting Period Energy, Adjusted Baseline Energy and Electricity Savings results are presented in Table 4.

Table 4. Calculation of Electricity Savings

Description	Value	Unit	Comments
Adjusted Baseline Energy	4,044	MWh	From Section 4.1.
Reporting Period Energy	3,659	MWh	From Table 3.
Non-Routine Adjustments	0	MWh	None.
Electricity Savings	386	MWh	
Electricity Savings Uncertainty	± 109%		From the Baseline Energy uncertainty (± 10.4%) and the Reporting Period Energy uncertainty (± 0.5%).
Anticipated Electricity Savings	418	MWh	From Table 1.
Electricity Savings as a Percentage of Anticipated Electricity Savings	92%		Note that the Incentive Payment is pro-rated from the contracted amount based on this percentage.
Average Demand Savings	44	kW	*Electricity Savings ÷ Hours of operation*.
Summer Peak Demand Savings	0	kW	The Measures are not operational during the summer Peak Demand Period, and any differences are due to overall Facility demand changes in the Reporting Period. As a result, any peak demand savings evaluated in the analysis cannot be interpreted as such, since the system is not operational.

4.3. Incentive Payment

The 1st Annual Reporting Period Incentive is outlined in Table 5. CLEAResult has received the Invoice Reconciliation Form and the invoices.

Table 5. Incentive Payments for Deferred Payment

Deferred Payment Schedule	Description	Amount ($)
Payment 1	50% of Participant Incentive, calculated based on Electricity Savings in the first quarterly M&V Report.	$50,160.00 (PAID)
Final Payment (Holdback)	The balance payment is the difference between the actual Participant Incentive, calculated on the basis of the first annual M&V Report, and the total payments made to date.	$27,005.42

4.4. Conclusion

The Electricity Savings are 386 MWh and represent 92% of the Anticipated Electricity Savings for the Reporting Period.

It should be noted that the Uncertainty on the Electricity Savings is significant, as explained in the M&V Plan. This is because the Electricity Savings are small relative to the Baseline Energy, shown in Table 1.

4.5. Electricity Savings to Date

The Electricity Savings to date are presented in Table 6.

Table 6. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings		
		MWh	% of Contract Savings Value [1]	Cost Savings ($)[2]
1st Quarterly	April 25, 2019 to July 24, 2019	56	296%	$5,400
1st Annual	April 25, 2019 to April 24, 2020	386	92%	$37,000

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on the Electricity Billing Rate of $96/MWh obtained from the Project Review.

Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5

Third Party Evaluation Reports

This document includes the following third party evaluation reports:

Process and Systems Upgrades Program:

- #601601
- #601602
- #601814
- #601869
- #601883
- #601885
- #601910
- #601911

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-[redacted]-601601

July 14, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	July 14, 2023	July 14th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
July 14, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of August 27, 2021 to August 26, 2022, are 1,118 MWh, which represents 99% of the Anticipated Electricity Savings.

The In-Service Date was originally set to January 1, 2020. However, the Participant requested the Reporting Period begin August 27, 2021, due to necessary equipment repairs as well as a result of the COVID-19 pandemic affecting normal operations.

The Incentive payable to the Participant for this Reporting Period is $112,600. Refer to the Appendix for details.

The Electricity Savings meet the 80% performance threshold required by the Program Rules.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Aug 27 to Nov 26, 2021	285	100%	$40,185
1st Annual	Aug 27, 2021 to Aug 26, 2022	1,118	99%	$157,638

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of January 1, 2020, was established on November 17, 2020.

1st Quarterly Report was issued on January 27, 2022 with an updated in-service date of August 27, 2021.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $141/MWh obtained from the Project Application Review.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on January 25, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	August 27, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	August 26, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date
Available Data	8,760	hours	
Missing Data	0	hours	0% of the Reporting Period Duration
Hours of Operation	8,529	hours	97.4% of the Reporting Period Duration

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,176	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	58	MWh	Equal to 4.9% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,118	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	128	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	121	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The ICE supplier confirmed via email on January 18, 2022, that the metered power output from the ICE is gross power (i.e., does not exclude any internal or external auxiliary loads). As a conservative approach, auxiliary loads were assumed to be 3% of the 125 kW ICE gross capacity. The auxiliary loads were applied for each unit individually (ie. if one unit was operating the loads were 3.75 kWh and 7.5 kWh if both units were operating simultaneously). Because the System performed well above the 80% performance requirement, the Technical Reviewer deemed this approach sufficient.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,118	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,118	MWh	Equal to the Reporting Period Energy.
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,126	MWh	Obtained from the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	99%	-	
Average Demand Savings	128	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	121	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 1,118 MWh and represent 99% of the Anticipated Electricity Savings.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,176	MWh	See the comment below.
CHP Thermal Output Utilized	1,384	MWh	
CHP Energy Input	3,582	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 37.3 MJ/m^3 (10.36 kWh/m^3), obtained from the Canada Energy Regulator's Energy conversion tables.
Metered Total System Efficiency	71.5%	-	

The system achieved a TSE of 71.5%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

The is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

The Incentive payable for the 1st Annual M&V Reporting Period is $112,600. Table 6 outlines the payment schedule as defined in the contract and Program Rules, for reference.

Table 6. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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Please note:

Capitalized terms used in this document have the meaning given to them either in the Save on Energy Process and Systems Upgrade Program Rules, or the IPMVP Core Concepts dated October 2016 and Uncertainty Assessment for IPMVP, dated April 2018, as applicable.

IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

SAVE ON ENERGY | DELIVERY PARTNER™

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-[redacted]601602

July 20, 2023

Revision 1

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	July 14, 2023	July 14th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
July 14, 2023	M&V Report first issuance.	0	[redacted]
July 20, 2023	Tables 6 and 7 added to Appendix	1	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of September 8, 2021 to September 7, 2022, are 1,431 MWh, which represents 110% of the Anticipated Electricity Savings.

The In-Service Date was originally set to January 28, 2020. However, the Participant requested the Reporting Period begin Septpember 8, 2021, due to necessary equipment repairs as well as a result of the COVID-19 pandemic affecting normal operation.

The Incentive payable to the Participant for this Reporting Period is $130,200. Refer to the Appendix for details.

The Electricity Savings meet the 80% performance threshold required by the Program Rules.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Sept 8 to Dec 12, 2021[3]	394	122%	$56,400
1st Annual	Sept 8, 2021 to Sept 7, 2022	1,431	110%	$204,633

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of January 28, 2020, was established on November 17, 2020.

1st Quarterly Report was issued on January 28, 2022 with an updated in-service date of September 8, 2021.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $143/MWh obtained from the Project Application Review.
[3] There were 115 hours of missing data points in the raw data. Therefore, the 1st Quarterly Reporting Period was extended by 115 hours.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on January 25, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	September 8, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	September 7, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date
Available Data	8,645	hours	
Missing Data	115	hours	1.3% of the Reporting Period Duration.
Hours of Operation	8,557	hours	97.7% of the Reporting Period Duration

115 hours of data, or 1.3% of the Reporting Period, is missing. Since this represents less than 10% of the total data for the Reporting Period, the available data was used for the analysis and the missing hours assumed to represent 0 MWh savings, per Section B.6.2. of the M&V Plan.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,493	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	63	MWh	Equal to 4.2% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,431	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	165	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	100	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The ICE supplier confirmed via email on January 18, 2022, that the metered power output from the ICE is gross power (i.e., does not exclude any internal or external auxiliary loads). As a conservative approach, auxiliary loads were assumed to be 3% of the 125 kW ICE gross capacity. The auxiliary loads were applied for each unit individually (ie. if one unit was operating the loads were 3.75 kWh and 7.5 kWh if both units were operating simultaneously). Because the System performed well above the 80% performance requirement, the Technical Reviewer deemed this approach sufficient.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,431	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,431	MWh	Equal to the Reporting Period Energy.
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,302	MWh	Obtained from the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	110%	-	
Average Demand Savings	165	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	100	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 1,431 MWh and represent 110% of the Anticipated Electricity Savings.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,493	MWh	
CHP Thermal Output Utilized	1,843	MWh	
CHP Energy Input	4,450	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 37.3 MJ/m^3 (10.36 kWh/m^3), obtained from the Canada Energy Regulator's Energy Conversion tables.
Metered Total System Efficiency	75.0%	-	

The system achieved a TSE of 75.0%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

The is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $130,200, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Anticipated Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,431	From Table 4
Estimated Eligible Costs	**$1,541,326**	From the SCP Agreement, Schedule "B".
Actual Eligible Costs	$9,622,565	From the 1st Master Payment Requisition.
Electricity Billed Savings	$204,633	Based on the Project Review Electricity Billing Rate of $143/MWh
Other Costs	$120,764	From the SCP Agreement, Schedule "B".
Net Project Benefits	$83,869	Electricity Billed Savings - Other Costs
Approved Incentive Amount	**$260,400**	From the SCP Agreement, Schedule "B".
Limiter 1 - Electricity Savings	$260, 400	100% of the Approved Incentive Amount, if Performance is >80%..
Limiter 2 - Eligible Costs	$616,530	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$1,457,457	Eligible costs minus Net Project Benefits
Project Incentive	$260,400	Minimum of the three limiters.
Incentives paid to date	**$ 130,200**	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$130,200**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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This document was prepared by Aladaco Consulting Inc. for the Independent Electricity System Operator (IESO) and exclusively for the purposes set out in the Program Management Agreement between the IESO and Aladaco Consulting Inc., as may be amended and restated from time to time.

This document was prepared based on information available to Aladaco Consulting Inc. at the time of preparation, and is subject to all limitations, assumptions and qualifications contained herein. In addition, financial or other projections contained herein are based upon assumptions concerning future events and circumstances over which Aladaco Consulting Inc. has no control. Such projections are by their nature uncertain and should be treated accordingly and read in the full context of this document, including such projects.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK : PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report
1st Annual Reporting Period

[redacted] Cogeneration System

April 26, 2023

Revision 0

Project ID:

TorontoHydro-SCP-601814-[redacted]-Cogeneration System-Y1-MVR

Prepared for:

Toronto Hydro-Electric System Limited

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements (FINAL v2.0 April 6, 2018)

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	April 26, 2023	April 27th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
April 26, 2023	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of November 1, 2021 to November 14, 2022 are 311 MWh, which represents 125% of the Anticipated Electricity Savings. The Incentive payable to the Participant for this Reporting Period is $30,394, calculated in accordance to Program Rules. Refer to the Appendix for details.

Note that the Participant submitted an Application[1] for this Project on September 1, 2020, which was after the Application submission deadline however, in an email dated July 19, 2021, the IESO confirmed their acceptance of the Application and Anticipated Electricity Savings.

The original Reporting Period of November 1, 2021, to November 1, 2022, was extended by 14 days to November 14, 2022. The 14-day extension was a result of 14 days of erroneous data provided during the Q1 Reporting Period, for the period from January 22 to February 5, 2022. The combined heat and power (CHP) System operated during this period, however, the metered data recorded erroneous values due to an unexpected defect in the PLC system.

During the course of construction of the Cogeneration System, the Applicant installed and commissioned an Absorption Chiller which now forms part of the combined Cogeneration System originally shown in Figure 1 of the M&V Plan. The Absorption Chiller was not previously considered in the M&V Plan nor in the previously issued Q1 M&V Report. As the Absorption Chiller is receiving waste heat energy from the turbines exhaust gases and providing cooling to the facility the decision was made to include the equipment within this report. Aladaco Consulting received confirmation from Toronto Hydro to include the Absorption Chiller in an email dated April 20, 2023. This item is covered in more detail in the Non-Routine Adjustments section.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[2]	Electricity Cost Savings[3]
1st Quarterly	November 1,2021 to February 14, 2022	101	118%	$15,600
1st Annual	November 1,2021 to November 14, 2022	311	125%	$48,240

[1] The Application was submitted under the Conservation First Framework (CFF), Final V2.0.

[2] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[3] Based on $155/MWh obtained from the Project Approval Letter.

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan rev.0, dated February 15, 2019, which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of November 1, 2021, was established on February 7, 2022.

Metered Data Analysis

[redacted], a representative of Toronto Hydro, provided the M&V data on February 15, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Nov. 1, 2021, 0:00		Start date of the Reporting Period.
Reporting Period End	Nov. 14, 2022, 23:00		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date less data removed
Available Data	8,760	hours	
Missing Data	336	hours	4% of the Reporting Period Duration
Hours of Operation	8,741	hours	99.8% of the Reporting Period Duration

The original Q1 data included 237 hours of erroneous data for the period from January 22, 3:00 to January 31, 23.00, 2022. The CHP system operated during this period, however, the metered data recorded erroneous values for all the parameters, due to an unexpected defect in the PLC system. The erroneous data represented 10.7% of the Q1 dataset. This data was replaced by 237 hours of valid data

during the period February 1 to February 14, 2022 (336 hours). Thus the remaining 3 Quarters of data required to complete the Year 1 Reporting Period begins February 14, 2022 through November 14, 2022.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Reporting Period Energy – Baseline Energy ± Non-Routine Adjustments

Reporting Period Energy

The electrical consumption of the System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	505	MWh	Calculated using hourly Net Electrical Energy and Auxiliary Load Energy of 5.5 kW per CHP system operating hour.
Gas Turbine Auxiliary Loads Energy	48	MWh	9.5% of the Gross Electrical Energy.
Absorption Chiller Electrical Load	14	MWh	*Absorption Chiller Electrical Load = 3.8 kW of Chiller Electrical Power x (Chiller Operating Hours)* As per Absorption Chiller Specification Sheet. See note below.
Reporting Period Energy	443	MWh	CHP Net Electrical Output.
Uncertainty of the Reporting Period Energy	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Average Demand	50.6	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Demand	44	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm -7:00 pm,

Additional loads for chilled water and cooling tower pumps were not considered as they form part of the larger facility's chilled water loop. The Participant reported that the operation of these pumps did not increase as a result of the addition of the Absorption Chiller. Additionally, Chiller Data was not provided for the period of November 1, 2021 to January 1, 2022. It was assumed that the chiller was not operational over this period as there is no cooling demand at the facility during the winter months.

Non-Routine Adjustments

The Facility currently operates two CHP systems, each consisting of a micro-turbine generator and a heat recovery system. The two CHP systems are identical in capacity, i.e., 65 kW each. One of the CHP systems (Unit #1) was implemented under a previous PSU Project (Toronto-SCP-601491) and has confirmed In-

Service Date of June 2, 2018. The review of this M&V Report is for the second CHP system (Unit #2), implemented under the second PSU Project (Toronto-SCP-601814).

As per the M&V Plan Rev.0 dated February 15, 2019, Unit #1 has priority over Unit #2 for the purposes of determining the Reporting Period Energy, whereby if the combined electricity generated by the two CHP systems exceeds the full load output of a single CHP system, then the apportionment of electricity generation between the two generators will be such that Unit #1 will be allocated the full load output, while Unit #2 will be allocated the remainder of the electricity generation. For each hour in the dataset, the full load output of the Unit#1 was determined based on the outside air temperature (OAT). The relationship between OAT and electrical output was established in the Project Review.

The Baseline Energy for Unit #2 is considered 0 kWh as Unit #2 has no prior generation. However, the adjustment of electricity generation for the two CHP systems, based on priority, was treated as a Non-Routine Adjustment. The Non-Routine Adjustment is calculated to be -132 MWh for the 1st Annual Reporting Period.

The inclusion of the Absorption Chiller, which was not previously considered in previous reports relating to this project, primarily affected the Total System Efficiency calculations. There was a slight adjustment to the Reporting Period Energy to account for additional system loads, however after accounting for the previously discussed Non-Routine Adjustment the final Adjusted Reporting Period Energy did not change as a result of the Abosrtion Chiller addition.

The Total System Efficiency (TSE) calculation required adjustment to account for the inclusion of Absorption Chiller. The Recovered Thermal Output is the cooling energy generated in the Absorption Chiller through the use of waste heat from the Micro-Turbine exhaust. The Participant was only able to provide data for the combined energy contribution from both Micro-Turbines to the Chilled Water supply, so to account for Unit #2's contribution for TSE purposes the total Chilled Water Energy was proportionally attributed based on the amount of generation produced per hour. The following data was provided by the Participant for the Absorption Chiller:

Table 4. Absorption Chiller Data

Description	Quantity	Unit	Comment
Chilled Water Flow Rate	6 minutes of 1-second interval readings on Sept. 28, 2021 from 16:63:58 to 16:56:57	Gal/min	
Chilled Water Out	15-minute intervals (January 1, 2022 to November 14, 2022)	Deg F	Chilled water temperature from the absorption chiller
Chilled Water In	15-minute intervals (January 1, 2022 to November 14, 2022)	Deg F	Chilled water temperature to the absorption chiller

The Flow Rate data provided by the Participant was from the commissioning of the Absorption Chiller and a non-permanent meter for which no specifications were provided. As the pumps associated with the Absorption Chiller are not VFD equipped it is assumed that the Flow Rate is constant when the Chiller is in operation. This is further supported by the metered flow rate closely matching the specified flow rate from the Absorption Chiller specification sheet.

Chilled water temperatures are metered by the Absorption Chiller using Resistance Temperature Detectors for which no specifications or accuracy information was provided.

To determine the TSE contribution from the Absorption Chiller the following formula was used:

Eq. 1 *Unit#2 Absorption Chiller Recovered Thermal Output (MWh) = (Total Chilled Water Heat Recovery) × (Unit #2 Proportional Energy Contribution) (over the Reporting Period)*

Eq. 1a *Total Chilled Water Heat Recovery (MWh) = Sum of (Chiller Hours of Operation) × Chilled Water Delta T × Chilled Water Flow Rate × (Chilled Water Density) × Chilled Water Specific Heat)*

Eq. 1b *Chilled Water Density = The density of water taken at the average temperature of the chilled water during all (Chiller Operating Hours)*

Eq. 1c *Chiller Operating Hours = Chiller was assumed to be operating whenever the Chilled Water Out was a lower temperature than the Chilled Water In*

Eq. 1d *Unit #2 Proportional Energy Contribution = Unit #2 Gross Electrical Energy ÷ (Unit #1 Gross Electrical Energy + Unit #2 Gross Electrical Energy)*

The Adjusted Total System Efficiency was calculated as:

Eq. 2 *Adjusted TSE (%) = [Gross Electrical Energy + Total Recovered Thermal Output + Unit #2 Absorption Chiller Recovered Thermal Output] ÷ Total Natural Gas Energy Input*

Electricity Savings

The Reporting Period Energy, the Non-Routine Adjustment, and the Electricity Savings are presented in Table 5. The original M&V Plan prescribed IPMVP Option B methodology of calculating the Electricity Savings, however after the Non-Routine Adjustmeents and the inclusion of the Absorption Chiller this report uses an IPMVP Option A methodology, with Net Electrical Generation, Natural Gas Consumption, Heating Water Temperature, and Chilled Water Temperatures being the measured variables. Chiller Operating Hours, Water flow rates and parasitic loads were unmetered and based on spot measurements, equipment specifications, or inferred from other metered data.

Table 5. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	443	MWh	Obtained from Table 3.
Non-Routine Adjustment	-132	MWh	Calculated as per the M&V Plan and as described in the Non-Routine Adjustments section.
Electricity Savings	311	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.

Anticipated Electricity Savings	249	MWh	Obtained from the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	125%		
Average Demand Savings	36	kW	Electricity Savings divided by Reporting Period Duration.
Summer Peak Demand Savings	22	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm -7:00 pm,

The 1st Annual Electricity Savings are 311 MWh and represent 125% of the Anticipated Electricity Savings.

The main reason for the overperformance is the increased operating hours of Unit #2 Micro-Turbine during the facility cooling season. This operation was facilitated by the use of the Absorption Chiller which allowed for greater generation with only a minor impact to TSE. Unit #2 had a 99.8% uptime as compared to a 50.7% uptime estimated at Application Review.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 3 TSE (%) = [CHP System Gross Electrical Energy + CHP System Usable Thermal Output] / CHP System Natural Gas Consumption

The Adjusted TSE including Non-Routine Adjustments is calculated according to the following equation:

Eq. 2 Adjusted TSE (%) = [Gross Electrical Energy + Total Recovered Thermal Output + Unit #2 Absorption Chiller Recovered Thermal Output] ÷ Total Natural Gas Energy Input

Table 6. Total System Efficiency

Description	Value	Unit	Comment
Unit #2 Gross Electrical Energy	505	MWh	
Total Recovered Thermal Output	814	MWh	
Unit #2 Natural Gas Consumption	230,867	m^3	
Natural Gas HHV	10.75	kWh/m^3	From the M&V Plan
Total Natural Gas Energy Input (HHV)	2,481	MWh	
Total System Efficiency	53.2%		
Absorption Chiller Recovered Thermal Output	317	MWh	Unit#2 absorption chiller recovered thermal output
Adjusted Total System Efficiency	66.0%		

Inclusion of the Absorption Chiller increased the Adjusted TSE value above the required minimum 57.5% required by Program Rules. The main reason for the underperformance of the TSE is due to the increased operation of the Cogeneration System, particularly during the summer months. During Application Review it was assumed that the Cogeneration System would only operate during the winter and shoulder seasons when the facility had heating demand.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, the recommended Incentive Amount of $30,394 was calculated in accordance with the Program Rules and is limited by the "$200/MWh of Electricity Savings", up to a maximum of 120% of Approved Incentive amount. The Final Incentive Payment is the Gross Project Incentive of $59,760, less the Q1 Incentive Payment. The Final Incentive Payment is pending the issuance of the Master Payment Requisition.

Description	Value	Comment
Electricity Savings (MWh)	311	Annual Electricity Savings, as defined in this Report
Limiter 1 - Electricity Savings	$62,245	$200 per MWh of Electricity Savings
Actual Project Costs	$405,911	From the Invoice Reconciliation Form
Limiter 2 - Project Costs	$162,364	40% of Eligible costs
Net benefits	$21,240	Includes electricity savings at $155/MWh and Other Costs from Project Letter of Approval
Limiter 3 - Project Payback	$384,671	Eligible costs minus net benefits
Limiter 4 – 120% of Pre-Approved Incentive	$59,760	From Project Letter of Approval
Gross Project Incentive	$59,760	Minimum of the four limiters
Total Payments to Date	$29,367	From Q1 Master Payment Requisition
Incentive Payable	**$30,394**	*Gross Project Incentive – Total Payments to Date*

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted]

Project ID: Toronto-SCP-601869

June 20, 2023
Revision 0

Prepared for:
Toronto Hydro-Electric System Ltd. (the LDC)

Prepared by:
Aladaco Consulting Inc (The Technical Reviewer)

Revision History

Date	Description	Revision	Author
June 20, 2023	M&V Report first issuance.	0	[redacted]

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name	[redacted]	
Date	June 20, 2023	June 20th, 2023
Signature	[redacted]	[redacted]

Summary

The Electricity Savings for the Year 1 Reporting Period of March 29, 2022 to March 28, 2023, are 207.78 MWh, which represent 73.7% of the Anticipated Electricity Savings.

Note that the Project's In-Service Date was November 23, 2021. However, the start of the Year 1 Period was delayed to March 29, 2022 due to a significant underperformance resulting from the following:

- A 7-hour shutdown every night during the period November 23 to December 29, 2021 as the sound enclosure on the combined heat and power (CHP) system was not fully constructed and the shutdown was required to abide by the noise bylaws.
- A complete shutdown of the CHP system during the period December 30, 2021 to February 15, 2022, to modify the CHP system's enclosure in order to discharge the exhaust gas further away from the building.
- On March 10, 2022, Enbridge gas had shut off the main gas supply, which resulted in tripping of the CHP system. A mechanical contractor who was at the Facility to restart the boilers after the gas supply was restored tempered with the CHP system's controller, in an attempt to bring the system back into operation. As a result, the CHP system was started but was operating under its old scheduled hours (overnight shutdown) until March 28, 2022, when the problem was identified and corrected.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings
1st Quarterly	Mar 29, 2022 to Jun 28, 2022	51	75%	$7,196[2]
1st Annual	Mar 29, 2022 to Mar 28, 2023	207.78	73.7%	$29,089[2]

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data for the Reporting Period.
- The Reporting Period Energy.

[1] Percentage of the Anticipated Electricity Savings shown in the M&V Plan.

[2] Based on the Electricity Billing Rate of $140/MWh from the Project Review.

- The electrical and thermal performance of the Measure.
- The Incentive based on the performance of the Measure.

In-Service Date Confirmation

The In-Service Date of November 23, 2021 was established on January 28, 2022.

Metered Data Analysis

[redacted], the LDC representative, provided the raw data to the Technical Reviewer for analysis. The raw data includes the following hourly interval data for the combined heat and power (CHP) system:

- Gross electricity generation
- Natural gas consumption
- Heat utilized

The data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Mar 29, 2022, 00:00		
Reporting Period End	Mar 28, 2023, 23:00		
Reporting Period Duration	8,760.0	hours	
Available Data	8,760.0	hours	
Downtime	258.0	hours	Data reported as “0”, assumed unit not running, equivalent to 2.9% of the time.
Hours of Operation	8,502.0	hours	Unit running 97.1% of the Reporting Period duration.

Performance of the Measure

The electrical performance of this generation project is based on the following equation:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Reporting Period Energy

The Reporting Period Energy for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	216.91	MWh	
Auxiliary Loads Energy	9.13	MWh	Represents 4.2% of the Gross Electrical Energy. See comment below.
Reporting Period Energy	207.78	MWh	Gross Electrical Energy - Auxiliary Loads Energy
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	24.8	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	30.8	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm -7:00 pm.

The M&V data did not include metered data for the CHP system auxiliary loads. However, the Participant's representative provided the following information regarding the auxiliary loads:

- The metered electrical output readings are net of the dry cooler load.
- The auxiliary loads, which need to be accounted for to calculate the net electricity generation consists of two hot water circulation pumps, with a total nameplate rating of 1.44 hp.

The Technical Reviewer calculated that total auxiliary loads electricity consumption of 9.13MWh by multiplying the nameplate rating of the pumps with the Reporting Period operating hours.

Electricity Savings

The Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings. Since there has been no change in the Static Factors as defined in the M&V Plan Section B.5.1, Non-Routine Adjustments are not required for this Reporting Period.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Reporting Period Energy	207.78	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	207.78	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Anticipated Electricity Savings	282.00	MWh	Per the M&V Plan.
Electricity Savings as Percentage of Anticipated Electricity Savings	73.7%		
Average Demand Savings	24.8	kW	Equal to Average Generation, obtained from Table 3.
Summer Peak Demand Savings	30.8	kW	Equal to Summer Peak Demand Generation, obtained from Table 3.

The Electricity Savings of the Year 1 Reporting Period are 207.78 MWh, which represent 73.7% of the Anticipated Electricity Savings.

The underperformance resulted from a lower than anticipated net operating electrical output of the CHP system. The CHP system was anticipated to have an average net operating electrical output of 32 kW. However, the Reporting Period average net operating electrical output was 24.8 kW.

Total System Efficiency

The CHP System's Total System Efficiency (TSE) is calculated according to the following equation.

TSE (%) = [Gross Electrical Energy + Recovered Heat Utilized] / [Fuel Energy Input]

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	216.91	MWh	Obtained from Table 3.
Recovered Heat Utilized	336.44	MWh	
Fuel Energy Input	780.42	MWh	Calculated using the total volumetric natural gas consumption and a natural gas higher heating value (HHV) of 10.75 kWh/m^3 shown in the M&V Plan.
Total System Efficiency	70.9%		This value is higher than the minimum 65% required by the Program.

The Technical Reviewer obtained a TSE of 70.9%, which is higher than the minimum 65% required by the Program.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

The Participant is eligible for an Incentive Payment of $41,555 for this Reporting Period, calculated in accordance with the terms of the Project Agreement.

Table 6. Incentive Calculation

Y1 Electricity Savings (MWh)	207.78
Electricity Billing Rate ($/MWh)	$140
Electricity Billed Savings	$29,089
Net Other Benefits and Costs – Per Contract[3]	$5,762
Net Project Benefits	$34,851
Estimated Eligible Costs – Per Contract	$231,938
Actual Eligible Costs – Per Invoice Reconciliation Form	$327,035
Approved Incentive Amount – Per Letter of Approval	$56,400
Incentive Limiter 1 - $200/MWh	$41,555
Incentive Limiter 2 - 40% of Eligible Costs (lower of Estimated or Actual)	$92,775
Incentive Limiter 3 - 1-year Payback	$197,087
Project Incentive (Minimum of 3 limiters)	$41,555
5% Penalty for TSE < 65%	$0
Adjusted Incentive	$41,555
Q1 Incentive Paid[4]	$0
Payable Incentive - Balance Year 1	$41,555

[3] Note that there are discrepancies in the project benefits and costs values within the Project Contract, Application Review, and Application Letter of Approval. The Technical Reviewer used the values from the Project Contract to assess Incentive Limiter 3, however has confirmed that there is no impact on the incentive payable in any case (i.e. using any of the values specified within these documents).

[4] Note that no Q1 incentive was paid as the Q1 Performance Ratio was below 80%.

Table 7 provides the Incentive payment schedule.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Calculated Amount
Payment 1 (Not Paid)	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. Not paid due to project not achieving 80% performance.
Final Payment (Payable)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report
1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601883

July 4, 2022
Revision 0

Prepared for:
Toronto Hydro-Electrical System Ltd. (the LDC)

Prepared by:
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Revision History

Date	Description	Revision	Author
July 4, 2022	M&V Report first issuance.	0	[redacted]

Approvals

	Written by Technical Reviewer	Reviewed by Engineering Manager
Name	[redacted]	
Date	June 28, 2022	June 30, 2022
Signature	[redacted]	

Summary

The Electricity Savings for the 1st Annual Reporting Period of April 7, 2021, to April 6, 2022, are 497 MWh, which represent 95% of the Anticipated Electricity Savings. The Total System Efficiency achieved for the 1st Annual Reporting Period is 58%, which does not meet the Program Rules requirement of 65%.

The Participant is eligible for an Incentive Payment of $38,243 for this Reporting Period, calculated in accordance with the terms of the Project Agreement. See the Appendix for the Incentive calculation, which includes the penalty for not achieving the minimum 65% Total System Efficiency (TSE) requirement.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings
1st Quarterly	Apr 7 to Jun 6, 2021	116	87	$15,045[2]
1st Annual	Apr 7, 2021 to Apr 6, 2022	497	95	$64,408[2]

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data for the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the Measure.
- The Incentive based on the performance of the Measure.

In-Service Date Confirmation

The In-Service Date of April 7, 2021, was established on November 2, 2021, conditional upon the submission of the Environmental Compliance Approval (ECA). The ECA was submitted by the Participant on December 16, 2021.

[1] Percentage of the Anticipated Electricity Savings shown in the M&V Plan.

[2] Based on the Electricity Billing Rate of $129.7/MWh shown in the Approval Letter.

Metered Data Analysis

[redacted] the LDC representative, provided the raw data to the Technical Reviewer for analysis. The raw data includes the following hourly data for the CHP system:

- Net electricity generation
- Natural gas consumption
- Heat utilized

The data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Apr 7, 2021, 00:00		
Reporting Period End	Apr 6, 2022, 23:59		
Reporting Period Duration	8,760	hours	
Available Data	8,760	hours	
Missing Data	0	hours	
Hours of Operation	8,738	hours	99.7% of the Reporting Period duration.

Performance of the Measure

The electrical performance of this generation project is based on the following equation:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Reporting Period Energy

The Reporting Period Energy for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP Net Electrical Energy	497	MWh	The electrical metering data provided represents the electricity generation, net of auxiliary loads
Auxiliary Loads Energy	48	MWh	Equal to 5.5 kW per operating hour (see comment below table)
CHP Gross Electrical Energy	545	MWh	Net Electrical Energy + Auxiliary Loads Energy
Reporting Period Energy	497	MWh	Equal to the Net Electrical Energy
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	57	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	46	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm -7:00 pm.

The Participant provided an auxiliary load estimate of 5 to 6 kW and confirmed that the metered electrical output is net of the auxiliary loads, which is a typical arrangement for the Capstone C65 micro-turbine system. The Technical Reviewer applied an auxiliary load of 5.5 kW per operating hour to calculate the Auxiliary Load Energy.

Electricity Savings

The Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings. Since there has been no change in the Static Factors as defined in the M&V Plan Section B.5.1, Non-Routine Adjustments are not required for this Reporting Period.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Reporting Period Energy	497	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	497	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Anticipated Electricity Savings	524	MWh	Prorated Anticipated Electricity Savings per the M&V Plan.
Electricity Savings as Percentage of Anticipated Electricity Savings	95%		
Average Demand Savings	57	kW	Equal to Average Generation, obtained from Table 3.
Summer Peak Demand Savings	46	kW	Equal to Summer Peak Demand Generation, obtained from Table 3.

The Electricity Savings of the 1st Annual Reporting Period are 497 MWh, which represent 95% of the Anticipated Electricity Savings.

The underperformance resulted from lower than anticipated average operating net electrical output. The CHP system was anticipated to produce an average operating net electrical output of 60 kW whereas the Reporting Period average operating net electrical output was 57 kW.

Total System Efficiency

The CHP System's Total System Efficiency (TSE) is calculated according to the following equation.

TSE (%) = [Gross Electrical Energy + Recovered Heat Utilized] / [Fuel Energy Input]

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	545	MWh	Obtained from Table 3.
Recovered Heat Utilized	805	MWh	
Fuel Energy Input	2,314	MWh	Calculated from total volumetric natural gas consumption and a natural gas higher heating value (HHV) of 10.75 kWh/m^3 specified in the M&V Plan.
Total System Efficiency	58.3%		This value is lower than the 65% threshold required by the Program.

The Technical Reviewer obtained a TSE of 58.3%, which is lower than the minimum 65% required by the Program. However, the Participant is eligible for an Incentive, subject to a 15%[3] penalty. See the Appendix for the Incentive calculation.

Next Reporting Period

The 1st Annual Reporting Period is the final Reporting Period and there is no further M&V reporting, unless requested by the IESO.

[3] Based on Program Rules, a TSE that is greater than equal to 57.5% but less than 60%, results in a 15% penalty on the Incentive.

Appendix - Incentive Payment

The Participant is eligible for an Incentive Payment of $38,243 for this Reporting Period, calculated in accordance with the terms of the Project Agreement. The Incentive calculation is shown in Table A1.

Table A1. Incentive Calculation

Reporting Period Electricity Savings (MWh)	497
Electricity Billing Rate ($/MWh)	129.7
Electricity Billed Savings	$64,408
Net Other Benefits and Costs	-$37,347[4]
Project Benefits	$27,061
Estimated Eligible Costs	$480,000[4]
Actual Eligible Costs	$865,654.69
Approved Incentive Amount	$104,800[4]
Incentive 1 - $200/MWh (Capped at 120% of the contracted Incentive amount)	$99,318
Incentive 2 - 40% of Minimum of Actual and Estimated Eligible Costs	$192,000
Incentive 3 - 1-year Payback	$452,939
Project Incentive (Minimum of 3 limiters)	$99,318
Incentive Penalty for TSE (15%))	$14,898
Adjusted Project Incentive	$84,420
First Payment (Recommended for First Quarterly Reporting Period)	$46,177
Balance Payment	$38,243

[4] From the Approval Letter

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report Year 1 Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601885

April 27, 2023
Revision 0

Prepared for:
Toronto Hydro-Electrical System Ltd. (the LDC)

Prepared by:
Aladaco Consulting Inc. (the Technical Reviewer)

Revision History

Date	Description	Revision	Author
April 27, 2023	Y1 M&V Report first issuance.	0	[redacted]

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name	[redacted]	
Date	April 27, 2023	April 28, 2023
Signature	[redacted]	[redacted]

Summary

The Electricity Savings for Year 1 Reporting Period of February 1, 2022 to January 31, 2023, are 942.24 MWh, which represent 91.0%% of the Anticipated Electricity Savings.

The Participant is eligible for an Incentive Payment of $72,998 for this Reporting Period, calculated in accordance with the terms of the Project Agreement. Note that the Incentive Payment was impacted by a 5% Total System Efficiency Penalty (TSE) for a TSE of 64.8%. See the Appendix for the Incentive calculation.

Note that the Project's In-Service Date was September 16, 2021. However, the start of the Reporting Period was delayed to February 1, 2022, to allow the Participant to rectify issues with the heat recovery system and natural gas readings, which were identified as the In-service Date confirmation.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings
1st Quarterly	Feb 1 to Apr 30, 2022	259	102	$31,024[2]
1st Annual	Feb 1, 2022 to Jan 31, 2023	942	91	$113,069[2]

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data for the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the Measure.
- The Incentive based on the performance of the Measure.

In-Service Date Confirmation

The In-Service Date of September 16, 2021 was established on January 25, 2022. However, the start of the Year 1 Reporting Period was delayed to February 1, 2022.

[1] Percentage of the Anticipated Electricity Savings shown in the M&V Plan.

[2] Based on the Electricity Billing Rate of $120/MWh shown in the Approval Letter.

Metered Data Analysis

[redacted], the LDC representative, provided the raw data to the Technical Reviewer for analysis. The raw data includes the following hourly data for the CHP system:

- Net electricity generation
- Natural gas consumption
- Heat Recovered

The data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Feb 1, 2022, 01:00		One hour after actual Reporting Period
Reporting Period End	Feb 1, 2023, 00:00		One hour after actual Reporting Period
Reporting Period Duration	8,760	hours	
Available Data	8,757	hours	
Missing Data	3	hours	Assumed Missing Data = Units Not Running
Hours of Operation	8,757	hours	99.97% of the Reporting Period duration.

Performance of the Measure

The electrical performance of this generation project is based on the following equation:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Reporting Period Energy

The Reporting Period Energy for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP Net Electrical Energy	942.24	MWh	The electrical metering data provided represents the electricity generation, net of auxiliary loads
Auxiliary Loads Energy	93.63	MWh	Equal to 5.5 kW per micro-turbine per operating hour (see comment below table)
CHP Gross Electrical Energy	1,035.87	MWh	Net Electrical Energy + Auxiliary Loads Energy
Reporting Period Energy	942.24	MWh	Equal to the Net Electrical Energy
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	107.6	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	84.7	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm -7:00 pm.

The Participant provided an auxiliary load estimate of 5 to 6 kW and confirmed that the metered electrical output is net of the auxiliary loads, which is a typical arrangement for the Capstone C65 micro-turbine system. The Technical Reviewer applied an auxiliary load of 5.5 kW per micro-turbine per operating hour to calculate the Auxiliary Load Energy. Data shows that during Year 1 only 1 Unit was in operation during 490 hours. This was taken into account to calculate the total Auxiliary Load consumption.

Electricity Savings

The Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings. Since there has been no change in the Static Factors as defined in the M&V Plan Section B.5.1, Non-Routine Adjustments are not required for this Reporting Period.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Reporting Period Energy	942.24	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	942.24	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Anticipated Electricity Savings	1,035	MWh	Annual Anticipated Electricity Savings per Letter of Approval
Electricity Savings as Percentage of Anticipated Electricity Savings	91.0%		

Average Demand Savings	107.6	kW	Equal to Average Generation, obtained from Table 3.
Summer Peak Demand Savings	84.7	kW	Equal to Summer Peak Demand Generation, obtained from Table 3.

The Electricity Savings of Year 1 Period are 942.24 MWh, which represent 91.0% of the Anticipated Electricity Savings.

The underperformance resulted from lower than anticipated average operating net electrical output. The CHP system was anticipated to produce an average operating net electrical output of 118 kW (per Application Review document) whereas the Reporting Period average operating net electrical output was 107.6 kW. An important factor was that only 1 Unit was in operation during 490 hours, which was not anticipated.

Total System Efficiency

The CHP System's Total System Efficiency (TSE) is calculated according to the following equation.

TSE (%) = [Gross Electrical Energy + Recovered Heat Utilized] / [Fuel Energy Input]

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	1,035.87	MWh	Obtained from Table 3.
Recovered Heat Utilized	1,753.24	MWh	
Fuel Energy Input	4,306.55	MWh	Calculated from total volumetric natural gas consumption and a natural gas higher heating value (HHV) of 10.75 kWh/m specified in the M&V Plan.
Total System Efficiency	64.8%		This value is lower than the minimum 65% required by the Program.

The Total System Efficiency (TSE) was determined to be 64.8%, which falls short of the anticipated TSE of 73.1% (per Application Review document). In an effort to understand the reason for the difference, we compared the Y1 values with the anticipated values and found:

- Total Gross Generation is 7% lower than anticipated.
- Total Heat Recovered is 10% lower than anticipated.
- Natural Gas consumption is 3% higher than anticipated.

While it is difficult to draw a conclusion without a detailed analysis, it seems that both the electrical efficiency and the thermal efficiency of the units are responsible as they don't correlate with higher gas consumption as could be expected.

Note that there were some issues[3] with the natural gas readings and heat recovery system which were identified as the In-service Date confirmation stage, which resulted in an invalid Total System Efficiency value. However, these issues appear to have been rectified by the Participant before the start date of the Year 1 Reporting Period.

Per the PSU Project Terms and Conditions Section 3.3 c) a 5% discount is applied to the Participant Incentive where the M&V Report demonstrates the CHP project achieves a TSE between 62.5 and 65% (rounded to the second decimal). More information on the incentive calculation can be found in the Appendix.

Next Reporting Period

This is the final Reporting Period. No additional data is required.

[3] Refer to email with subject heading "[redacted]

Appendix - Incentive Payment

The Participant is eligible for an Incentive Payment of $72,998 for this Reporting Period, calculated in accordance with the terms of the Project Agreement.

Table 6. Incentive Calculation

Y1 Electricity Savings (MWh)	942
Electricity Billing Rate ($/MWh)	120
Electricity Billed Savings	$113,069
Net Other Benefits and Costs – Per Letter of Approval	-$71,647
Net Project Benefits	$41,422
Actual Eligible Costs – Per Cost Reconciliation Form	$1,336,461
Approved Incentive Amount – Per Letter of Approval	$207,000
Incentive Limiter 1 - $200/MWh (Capped at 120% of the contracted Incentive amount)	$188,448
Incentive Limiter 2 - 40% of Actual Eligible Costs	$534,585
Incentive Limiter 3 - 1-year Payback	$1,295,040
Project Incentive (Minimum of 3 limiters)	$188,448
5% Penalty for TSE < 65%	$9,422
Adjusted Incentive	$179,026
Q1 Incentive Paid	$106,028
Payable Incentive - Balance Year 1	$72,998

Table 7 provides the Incentive payment schedule.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Calculated Amount
Payment 1 (Paid)	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive was calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Payable)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601910

June 05, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	June 5, 2023	June 1, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
June 1, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 26, 2021, to December 25, 2022, are 798 MWh, which represents 90% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $84,727, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 26, 2021 to Mar 25, 2022	205	84%	$25,056
1st Annual	Dec 26, 2021 to Dec 25, 2022	798	90%	$97,763

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of December 26, 2021, was established on February 8, 2022.

The 1st Quarterly Report was issued on July 8, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $122.51/MWh obtained from the Project Application Review.

Metered Data Analysis

[redacted], a representative of THES, provided the M&V data on May 10, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 26, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 25, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	Hours	End date minus start date.
Available Data	8,668	Hours	
Missing Data	92	Hours	1.1% of the Reporting Period Duration.
Hours of Operation	8,667	Hours	99.99% of the Reporting Period Duration

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	821	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	23	MWh	Equal to 2.0% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	798	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	91	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	95	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The Participant's consultant, [redacted], has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. The Gross Electrical Energy of 821 MWh is net of the internal auxiliary loads. The 23 MWh Auxiliary Loads Energy was calculated based on the 2.62 kW external auxiliary load and 8,667 operating hours.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] where a similar type of CHP system, involving Yanmar CP35D1 engines, and a similar hot water heat recovery system were present.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	798	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	798	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	891	MWh	Obtained from the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	90%	-	
Average Demand Savings	91	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	95	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 798 MWh and represent 90% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 125 kW, consisting of two 125 kW internal combustion engines, one of which to be used for emergency backup only. In the completed Project, three 35 kW ICEs were installed with a nominal capacity of 105 kW. The under-performance resulted from lower than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (91 kW) is approximately 12% lower than the anticipated average output in the Application Review (104 kW).

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	821	MWh	See comment below table.
CHP Thermal Output Utilized	1,064	MWh	
CHP Energy Input	2,850	MWh	See comment below table.
Total System Efficiency	66.1%	-	

The CHP Energy Input was determined using the Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m3, obtained from the M&V Plan. The TSE of 66.1% exceeds the minimum 65% Program Requirement.

Next Reporting Period

The is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, the Incentive payable to the Participant is $84,727.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Annual Electricity Savings (MWh)	798	From Table 4
Actual Eligible Costs	**$585,669**	Per the vendor invoices.
Electricity Billed Savings	$97,763	Based on the Project Approval Letter Electricity Billing Rate of $122.51/MWh
Other Benefits	$37,354	From the Project Approval Letter
Other Costs	$116,586	From the Project Approval Letter
Net Project Benefits	$18,531	Electricity Billed Savings +Other Benefits – Other Costs
Approved Incentive Amount	**$178,200**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$159,600	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$234,268	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$567,138	Eligible costs minus Net Project Benefits
Project Incentive	$159,600	Minimum of the three limiters.
Project Incentive paid to Date	$74,873	Paid for 1st Quarterly Reporting Period.
Final Incentive payable	**$84,727**	Project Incentive minus Incentive paid to date.

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601911

June 05, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	June 5, 2023	June 1, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
June 1, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 24, 2021, to December 23, 2022, are 1,095 MWh, which represents 119% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $127,346, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 24, 2021 to Mar 23, 2022	257	100%	$32,933
1st Annual	Dec 24, 2021 to Dec 23, 2022	1,095	119%	$140,152

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of December 24, 2021, was established on February 16, 2022.

The 1st Quarterly Report was issued on July 8, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $128/MWh obtained from the Project Application Review.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on May 10, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 24, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 23, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data			
Electrical and Thermal Meters	*8,687*	*hours*	
Natural Gas Meter	*7,684*	*hours*	
Missing Data			
Electrical and Thermal Meters	*73*	*hours*	*0.8% of the Reporting Period Duration.*
Natural Gas Meter	*1,076*	*hours*	*12.3% (See comment below table)*
Hours of Operation	8,683	hours	99.95% of the Reporting Period Duration

When providing the raw data, [redacted] noted that natural gas data from May 12 to June 23, 2022 was missing. This was due to the existing gas meter failing and the delay to replace the meter. The missing data represents 1,076 hours or 12.3% of the Reporting Period. The Technical Reviewer has used the CHP electrical output and the part-load data for the Yanmar CP35D1 in order to calculate the natural gas consumption during this period.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,118	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	23	MWh	Equal to 2.0% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,095	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	125	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	124	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The Participant's consultant, [redacted] has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. The Gross Electrical Energy of 1,118 MWh is net of the internal auxiliary loads. The 23 MWh Auxiliary Loads Energy was calculated based on the 2.62 kW external auxiliary load and 8,683 operating hours.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] where a similar type of CHP system, involving Yanmar CP35D1 engines, and a similar hot water heat recovery system were present.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,095	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,095	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	920	MWh	Obtained from the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	119%	-	
Average Demand Savings	126	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	124	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 1,095 MWh and represent 119% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 130 kW, consisting of three 65 kW micro-turbines, one of which to be used for emergency backup only. In the completed Project, four 35 kW ICEs were installed with a nominal capacity of 140 kW. The over-performance resulted from higher than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (125 kW) is approximately 19% higher than the anticipated average output in the Application Review (105 kW).

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,118	MWh	See comment below table.
CHP Thermal Output Utilized	1,499	MWh	
CHP Energy Input	3,694	MWh	See comment below table.
Total System Efficiency	70.8%	-	

The CHP Energy Input was calculated using two methods, based on the availability of natural gas flowrate data:

- When the metered volumetric flowrate data was available, the energy input was determined using the Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m3, obtained from the M&V Plan.
- When the meter flowrate data was not available, the energy input was calculated using the CHP units' electrical output and the part-load data for the Yanmar CP35D1.

The TSE of 70.8% exceeds the minimum 65% Program Requirement.

Next Reporting Period

The is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, the Incentive payable to the Participant is $127,346.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Annual Electricity Savings (MWh)	1,095	From Table 4
Actual Eligible Costs	**$753,479**	Per the vendor invoices.
Electricity Billed Savings	$140,160	Based on the Project Approval Letter Electricity Billing Rate of $128/MWh
Other Benefits	$50,888	From the Project Approval Letter
Other Costs	$139,908	From the Project Approval Letter
Net Project Benefits	$51,140	Electricity Billed Savings +Other Benefits – Other Costs
Approved Incentive Amount	**$184,000**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$219,000	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$301,392	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$720,339	Eligible costs minus Net Project Benefits
Project Incentive	$219,000	Minimum of the three limiters.
Project Incentive paid to Date	$91,654	Paid for 1st Quarterly Reporting Period.
Final Incentive payable	**$127,346**	Project Incentive minus Incentive paid to date.

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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Please note:

Capitalized terms used in this document have the meaning given to them either in the Save on Energy Process and Systems Upgrade Program Rules, or the IPMVP Core Concepts dated October 2016 and Uncertainty Assessment for IPMVP, dated April 2018, as applicable.

IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5

Third Party Evaluation Reports

This document includes the following third party evaluation reports:

Process and Systems Upgrades Program:

- #601916
- #601917
- #601921
- #601922
- #601923
- #601924
- #601930
- #601932

SAVE ON ENERGY | DELIVERY PARTNER™

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601916

July 28, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	July 28, 2023	July 28th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
July 28, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of July 1, 2022, to June 30, 2023, are 814 MWh, which represents 90% of the Anticipated Electricity Savings.

The in-service date is December 22, 2022; however, THES approved a Reporting Period of July 1, 2022 to June 30, 2023 due to an error in the grid import settings identified by [redacted], the Participant's consultant.

The Incentive payable to the Participant for this Reporting Period is $87,700, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	July 1 to Sept 30, 2022	195	83%	$24,777
1st Annual	July 1, 2022 to Jun 30, 2023	814	90%	$103,427

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 22, 2021, which was established on January 31, 2022.

The 1st Quarterly Report was issued on September 9, 2022, for a Reporting Period of December 22, 2021 to March 21, 2022.

A revised 1st Quarterly Report was issued on March 13, 2023, for a Reporting Period of July 1 to September 30, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $127.06/MWh obtained from the Project Letter of Approval.

Metered Data Analysis

[redacted], a representative of THES, provided the M&V data on July 12, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Jul 1, 2022 00:00		Start date of the Reporting Period.
Reporting Period End	Jun 30, 2023 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date, excluding the shutdown periods noted below.
Available Data	8,693	hours	See comments below.
Shutdown Periods	945	hours	10.9% of the Available Data. See comments below.
Missing Data	67	hours	0.8% of the Reporting Period Duration.
Hours of Operation	8,691	hours	99.2% of the Reporting Period Duration.

[redacted] provided a summary of unscheduled shutdowns that occurred during the 1st Annual Reporting Period. All the dates the CHP was not operating normally or the system was shut off for repairs are provided below:

- November 1, 6:00 to November 7, 12:59, 2022 (151 hours) due failure of Unit #3,
- November 17, 15:00 to November 22, 12:59, 2022 (118 hours) due failure of Unit #3,
- January 4, 7:00 to January 12, 13:59, 2023 (199 hours) due failure of Unit #2, and
- February 24, 14:00 to March 16, 10:59, 2023 (477 hours) due failure of Unit #2.

The shutdown periods represent 945 hours total, which is divided between two separate data sets as follows:

- Unit #2 – 676 hours which represents 7.8% of the total data for the Reporting Period, and
- Unit #3 – 269 hours which represents 3.1% of the total data for the Reporting Period.

In addition to the dates noted above, there were 67 hours of missing data, or 0.8% of the Reporting Period, with no explanation provided by [redacted]. Since the total unavailable for each data sets represents less than 10% of the total data for the Reporting Period, the analysis was completed per Section B.6.2. of the M&V Plan, in the following way (agreed to by THES):

- The remaining 92.2% of the Unit #2 data and 96.9% of the Unit #3 data was used to predict the units' operation during the unscheduled shutdowns using a linear extrapolation, and
- The missing hours are assumed to represent 0 MWh savings.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	811	MWh	CHP System Gross Electrical Output is the sum of the following: • Unit #1 – 296 MWh • Unit #2 – 251 MWh • Unit #3 – 264 MWh
Annualized Gross Electricity Energy	837		Annualized CHP System Gross Electrical Output is the sum of the following: • Unit #1 – 296 MWh • Unit #2 – 270 MWh • Unit #3 – 271 MWh
Auxiliary Loads Energy	23	MWh	Equal to 2.7% of the Gross Electrical Energy. See comment below table.
Reporting Period Energy	814	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	93	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	93	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

[redacted] has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that

are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	814	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	814	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	904	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	90%	-	
Average Demand Savings	93	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	93	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 814 MWh and represent 90% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 130 kW, consisting of three 65 kW micro-turbines, one operating as emergyency backup only. In the completed Project, three 35 kW internal combustion engines were installed with a nominal capacity of 105 kW. The under-performance is due to this re-design which resulted in a lower than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (93 kW) is approximately 10% lower than the anticipated average output in the Application Review (103 kW) which reflects the 19% decrease in system capacity.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	811	MWh	See comments below table.
CHP Thermal Output Utilized	1,028	MWh	See comments below table.
CHP Energy Input	2,749	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan. See comments below table.
Total System Efficiency	66.9%	-	

The CHP energy input and outputs are the sums of the available data, they have not been extrapolated to account for the shutdown periods. The system achieved a TSE of 66.9%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $87,700, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	814	From Table 4
Eligible Costs	**$588,652**	**From the 1st Master Payment Requisition.**
Electricity Billed Savings	$103,427	Based on the Project Approval Letter Electricity Billing Rate of $127.06/MWh
Other Benefits	$49,478	From the Project Approval Letter
Other Costs	$121,113	From the Project Approval Letter
Net Project Benefits	$31,792	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$180,800**	**From the Project Approval Letter**
Limiter 1 - Electricity Savings	$162,800	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$235,461	40% of the minimum of Actual and Estimated Eligible costs.
Limiter 3 - Project Payback	$556,860	Eligible costs minus Net Project Benefits
TSE Incentive Discount	$0	0% discount for TSE ≥ 65.0%
Project Incentive	**$162,800**	**Minimum of the three limiters – TSE Incentive Discount**
Incentives paid to date	$75,100	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$87,700**	**Project Incentive - Incentives paid to date**

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601917

July 06, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	July 6th, 2023	July 6th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
July 6th, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 23, 2021 to December 22, 2023, are 1,004 MWh, which represents 108% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $94,394, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 23, 2021, to Mar 22, 2022	262	114%	$32,488
1st Annual	Dec 23, 2021, to Dec 22, 2022	1,004	108%	$124,496

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 23, 2021, which was established on February 2, 2022.

1st Quarterly Report was issued on December 7, 2022.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on May 10, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $124/MWh obtained from the Project Letter of Approval.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 23, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 22, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,620	hours	
Missing Data	140	hours	1.6% of the Reporting Period Duration.
Hours of Operation	8,617	hours	98.37% of the Reporting Period Duration

There were 140 hours of missing data, or 1.6% of the Reporting Period, which represents less than 10% of the total data for the Reporting Period. The available data was used for the analysis and the missing hours assumed to represent 0 MWh savings, per Section B.6.2. of the M&V Plan.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,026	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	22	MWh	Equal to 2.2% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,004	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	115	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	119	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

[redacted] has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,004	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,004	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	932	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	108%	-	
Average Demand Savings	115	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	119	kW	Equal to Summer Peak Generation from Table 3.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

The 1st Annual Electricity Savings are 1,004 MWh and represent 108% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 125 kW, consisting of a single 125 kW internal combustion engine (ICE). In the completed Project, four 35 kW ICEs were installed with a nominal capacity of 140 kW. The over-performance is due to this re-design which resulted in higher than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (115 kW) is approximately 8% higher than the anticipated average output in the Application Review (106 kW) which reflects the 12% increase in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,026	MWh	See the comment below.
CHP Thermal Output Utilized	1,443	MWh	
CHP Energy Input	3,419	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	72.2%	-	

The system achieved a TSE of 72.2%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $94,394, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,004	From Table 4
Eligible Costs	**$816,746**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$124,496	Based on the Project Approval Letter Electricity Billing Rate of $124/MWh
Other Benefits	$47,391	From the Project Approval Letter
Other Costs	$133,504	From the Project Approval Letter
Net Project Benefits	$38,383	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$186,400**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$200,800	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$326,698	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$778,363	Eligible costs minus Net Project Benefits
Project Incentive	$200,800	Minimum of the three limiters.
Incentives paid to date	**$106,406**	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$94,394**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601921

October 10, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	October 10, 2023	September 19, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
October 10, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of March 25, 2022 to March 24, 2023, are 1,035 MWh, which represents 108% of the Anticipated Electricity Savings.

The original in-service date was December 24, 2021. However, one of the four units was not working properly after commissioning and THES has approved a Reporting Period starting March 25, 2022. This change was approved after the 1st Quarterly Report was issued.

The Incentive payable to the Participant for this Reporting Period is $125,374, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 24, 2021 to Mar 23, 2022	221	85%	$26,741
1st Annual	Mar 25, 2022, to Mar 24, 2023	1,035	108%	$125,235

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 24, 2021, which was established on March 9, 2022.

The 1st Quarterly Report was issued on September 21, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $121/MWh obtained from the Project Letter of Approval.

Metered Data Analysis

[redacted], a representative of THES, provided the M&V data on June 1, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Mar 25, 2022 00:00		Start date of the Reporting Period.
Reporting Period End	Mar 24, 2023 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date, excluding the shutdown periods noted below.
Available Data	8,116	hours	
Shutdown Periods	556	hours	6.9% of the Available Data.
Missing Data	88	hours	1.1% of the Reporting Period Duration.
Hours of Operation	8,115	hours	98.92% of the Reporting Period Duration – Shutdown Periods

[redacted] the Participant's consultant, provided a summary of unscheduled shutdowns that occurred during the 1st Annual Reporting Period. All the dates the CHP was not operating normally or the system was shut off for repairs are provided below:

- May 5, 7:00 to May 10, 12:59, 2022 (126 hours) due damage to the telemetry controller, which needed to be sent for repairs.
- May 26, 7:00 to June 3, 11:59, 2022 (197 hours) due to a gas leak.
- December 17, 14:00 to December 22, 10:59, 2022 (117 hours) due to a short circuit failure.
- December 23, 14:00 to December 28, 9:59, 2022 (116 hours) due an air/fuel sensor failure.

The shutdown periods represent 556 hours total, which represents 6.9%, or less than 10%, of the total data for the Reporting Period. In addition to the dates noted above, there were 88 hours of missing data, or 1.1% of the Reporting Period, with no explanation provided by [redacted]

Since the total unavailable data represents less than 10% of the total data for the Reporting Period, the analysis was completed per Section B.6.2. of the M&V Plan, in the following way:

- The remaining 92.0% of data was used to predict the CHP system operation during the unscheduled shutdowns using a linear extrapolation, and
- The missing hours are assumed to represent 0 MWh savings.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,058	MWh	CHP System Annualized Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	23	MWh	Equal to 2.1% of the Annualized Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,035	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	118	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	130	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

[redacted] has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefore, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,035	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,035	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	956	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	108%	-	
Average Demand Savings	118	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	130	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 1,035 MWh and represent 108% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 130 kW, consisting of three 65 kW micro-turbines, one operating as emergency backup only. In the completed Project, four 35 kW internal combustion engines were installed with a nominal capacity of 140 kW. The over-performance is due to this re-design which resulted in a higher than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (118 kW) is approximately 8% higher than the anticipated average output in the Application Review (109 kW) which reflects the 8% increase in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	991	MWh	See the comment below.
CHP Thermal Output Utilized	1,186	MWh	
CHP Energy Input	3,281	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	66.4%	-	

The CHP energy input and outputs are the sums of the available data, they have not been extrapolated to account for the shutdown periods. The system achieved a TSE of 66.4%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $125,374, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,035	From Table 4
Eligible Costs	**$808,168**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$125,235	Based on the Project Approval Letter Electricity Billing Rate of $121/MWh
Other Benefits	$51,336	From the Project Approval Letter
Other Costs	$140,491	From the Project Approval Letter
Net Project Benefits	$36,080	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$191,200**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$207,000	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$323,267	40% of the minimum of Actual and Estimated Eligible Costs.
Limited 3 - Project Payback	$772,088	Eligible Costs minus Net Project Benefits
TSE Incentive Discount	$0	No discount for TSE ≥ 65.0%
Project Incentive	**$207,000**	**Minimum of the three limiters – TSE Incentive Discount**
Incentives paid to date	$81,626	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$125,374**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601922

June 22, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	June 22nd, 2023	June 22nd, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
June 21, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 24, 2021 to December 23, 2022, are 1,003 MWh, which represents 112% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $108,537, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 24, 2021, to Mar 23, 2022	263	102%	$32,612
1st Annual	Dec 24, 2021, to Dec 23, 2022	1,003	112%	$124,372

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 24, 2021, which was established on March 9, 2022.

1st Quarterly Report was issued on December 7, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $124/MWh obtained from the Project Application Review.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on May 10, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 24, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 23, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,475	hours	
Missing Data	285	hours	3.3% of the Reporting Period Duration.
Hours of Operation	8,474	hours	96.74% of the Reporting Period Duration

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,025	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	22	MWh	Equal to 2.2% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,003	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	114	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	118	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The Participant's consultant, [redacted], has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,003	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,003	MWh	Equal to the Reporting Period Energy
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	899	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	112%	-	
Average Demand Savings	114	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	118	kW	Equal to Summer Peak Generation from Table 3.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

The 1st Annual Electricity Savings are 1,003 MWh and represent 112% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 130 kW, consisting of three 65 kW micro-turbines, one of which to be standby only. In the completed Project, four 35 kW ICEs were installed with a nominal capacity of 140 kW. The over-performance resulted from higher than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (114 kW) is approximately 12% higher than the anticipated average output in the Application Review (103 kW).

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,025	MWh	See the comment below.
CHP Thermal Output Utilized	1,474	MWh	
CHP Energy Input	3,347	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	74.7%	-	

The system achieved a TSE of 74.7%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $108,537, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,003	From Table 4
Eligible Costs	**$774,683**	From the 1st Master Payment Requisition (Actual Estimated Costs are lower than Estimated Eligible Costs)
Electricity Billed Savings	$124,372	Based on the Project Approval Letter Electricity Billing Rate of $124/MWh
Other Benefits	$47,873	From the Project Approval Letter
Other Costs	$133,319	From the Project Approval Letter
Net Project Benefits	$38,926	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$179,800**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$200,600	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$309,873	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$735,757	Eligible costs minus Net Project Benefits
Project Incentive	$200,600	Minimum of the three limiters.
Incentives paid to date	**$92,063**	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$108,537**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Quarterly Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601923
August 11, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018”

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name:	[redacted]	
Date:	August 3, 2022	August 10, 2022
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
August 11, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Quarterly Reporting Period of December 23, 2021, to March 22, 2022, are 275 MWh, which represents 94% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $110,155. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 23, 2021 to Mar 22, 2022	275	94%	$36,025
1st Annual	Dec 23, 2021 to Dec 22, 2022	N/A	N/A	N/A

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date was set to December 23, 2021, on February 2, 2022, by the Technical Reviewer.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $131/MWh obtained from the Project Approval Letter.

Metered Data Analysis

[redacted] the LDC representative, provided the M&V data on May 3, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	December 23, 2021, 0:00		Start date of the Reporting Period.
Reporting Period End	March 22, 2022, 23:59		End date of the Reporting Period.
Reporting Period Duration	2,160	hours	End date minus start date.
Available Data	2,160	hours	
Missing Data	0	hours	0% of the Reporting Period Duration.
Hours of Operation	2,156	hours	99.8% of the Reporting Period Duration.

Performance of the Measure

The electrical performance of the Project is based on the reporting period energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electricity generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	281	MWh	
Auxiliary Loads Energy	5.7	MWh	2% of the CHP Gross Electrical Output. See details below Table 3.
Reporting Period Energy	275	MWh	Gross Electrical Energy – Auxiliary Load Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Average Generation	127	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	N/A	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm - 7:00 pm, June 1 to August 31.

The Participant's consultant, [redacted], has indicated that the electrical output readings included in the M&V dataset, are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. These loads draw their power directly from the internal combustion engines (ICEs). However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. The Gross Electrical Energy of 281 MWh is net of the internal auxiliary loads. The 5.7 MWh Auxiliary Loads Energy was calculated based on the 2.62 kW external auxiliary load and 2,156 operating hours.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	275	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	275	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	294	MWh	Based on the anticipated annual electricity savings, pro-rated for this Reporting Period according to Table 5 of the M&V Plan.

[3] The spot metering of the pumps was done at another Facility operated by Toronto Community Housing Corporation (TCHC) and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Electricity Savings as a Percentage of Anticipated Electricity Savings	94%		
Average Demand Savings	127	kW	Equal to Average Generation from Table 3
Summer Peak Demand Savings	N/A	kW	Equal to Summer Peak Demand Generation from Table 3.
Projected Annual Electricity Savings	1,102	MWh/year	For Incentive evaluation purposes only. Assumes the same performance (i.e., 94%) is applicable to the entire 1st Annual Reporting Period.

The 1st Quarterly Electricity Savings are 275 MWh, which represents 94% of the Anticipated Electricity Savings. The slight underperformance is likely due to a lower than anticipated uptime of one CHP system.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Energy (MWh) + CHP Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 5. Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	281	MWh	From Table 3.
Utilized Thermal Output	434	MWh	
Natural Gas Higher Heating Value (HHV)	10.75	kWh/m^3	As per the M&V Plan.
CHP Fuel Energy Input (HHV)	940	MWh	Calculated using the Reporting Period metered total natural gas volumetric flowrate and the natural gas HHV.
Total System Efficiency	75.95	%	

The CHP Gross Electrical Energy of 281 MWh is net of internal auxiliary loads. Thus, the actual Gross Electrical Energy is expected to be slightly higher than 281 MWh. Due to lack of data on the internal auxiliary loads, the Technical Reviewer did not account for the internal auxiliary loads to calculate the Gross Electrical Energy. Additionally, the calculated value of TSE 76% is a conservative value given that the actual Gross Electricity is higher than 281 MWh.

The TSE of 76% exceeds the minimum 65% Program Requirement. Note that this TSE value is for information purposes only as the TSE value from the 1st Annual Reporting Period will be used to assess whether the Project has met the minimum 65% Program Requirement and whether an Incentive penalty needs to be applied.

Next Reporting Period

The Participant will need to provide the metered data for the next Reporting Period in the same format as previously provided. The review of the next M&V Report (1st Annual Report) will include the analysis of the Electricity Savings and calculation of the Incentive for the 1st Annual Reporting Period.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Quarterly M&V Reporting Period, the Incentive payable to the Participant is $110,155, subject to review of Eligible Costs.[4] The Master Payment Requisition will be issued once the Participant has provided the required supporting information, including information required to review the Eligible Costs.

Table 6 outlines the Incentive payment calculation using the latest available information. The Projected Annual Electricity Savings of 1,102 MWh results in an Incentive of $220,310, which is based on the $200/MWh of Electricity Savings limiter (capped at 120% of the Approved Amount in the Project Approval Letter), as per the Program Rules. The Incentive payable for the 1st Quarterly Reporting Period is $110,155, which is 50% of $220,310. Note that the Eligible Costs used in the Incentive calculation are from the Project Approval Letter. The actual Eligible Costs will be reviewed as part of the Payment Recommendation process.

Table 6. Incentive Calculation

Description	Value	Comment
Projected Electricity Savings (MWh)	1,102	Projected Annual Electricity Savings, based on applying the 1st Quarterly Reporting Period Performance Ratio of 94% to the Annual Anticipated Electricity Savings of 1,176 MWh.
Estimated Eligible Costs	$1,983,299	As per the Project Approval Letter
Electricity Billed Savings	$144,303	Based on the Project Approval Letter Electricity Billing Rate of $131/MWh
Other Benefits	$66,869	From the Project Approval Letter
Other Costs	$184,129	From the Project Approval Letter
Net Project Benefits	$27,043	Electricity Billed Savings +Other Benefits – Other Costs
Approved Incentive Amount	**$235,200**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$220,310	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$793,320	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 – Project Payback	$1,956,256	Eligible costs minus Net Project Benefits
Project Incentive	**$220,310**	Minimum of the three limiters.
Incentive payable for 1st Quarterly Reporting Period	**$110,155**	50% of the Project Incentive

Table 7 provides the Incentive payment schedule.

[4] Note the incentive could be impacted if the actual Eligible Costs are lower than the amount in the Project Approval Letter.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601924

June 22, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	June 22nd, 2023	June 22nd, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
June 22, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 23, 2021 to December 22, 2022, are 1,091 MWh, which represents 73% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $109,829.50, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 23, 2021, to Mar 22, 2022	281	73%	$37,092
1st Annual	Dec 23, 2021, to Dec 22, 2022	1,091	73%	$144,012

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 23, 2021, which was established on February 23, 2022.

1st Quarterly Report was issued on September 14, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on the Application Review Electricity Billing Rate of $132/MWh. Note, the Electricity Billing Rate in the Project Letter of Approval ($71.49/MWh) appears incorrect.

Metered Data Analysis

[redacted] representative of THES, provided the M&V data on May 10, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 23, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 22, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,525	hours	
Missing Data	235	hours	2.7% of the Reporting Period Duration. See comments below table.
Hours of Operation	8,673	hours	99.01% of the Reporting Period Duration

There was a total of 235 hours missing from the data set; however, 149 of those hours show only natural gas consumption data missing. This missing data is discussed in more detail in the Total System Efficiency section found further in this report.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,113	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	23	MWh	Equal to 2.0% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,091	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	125	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	113	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The Participant's consultant, [redacted], has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,091	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,091	MWh	Equal to the Reporting Period Energy
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,490	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	73%	-	
Average Demand Savings	125	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	113	kW	Equal to Summer Peak Generation from Table 3.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

The 1st Annual Electricity Savings are 1,091 MWh and represent 73% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 195 kW, consisting of two 125 kW internal combustion engines (ICEs), one of which to be permanently derated to 70 kW. In the completed Project, four 35 kW ICEs were installed with a nominal capacity of 140 kW. The under-performance resulted from this re-design which resulted in lower than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (125 kW) is approximately 27% lower than the anticipated average output in the Application Review (170 kW) which reflects the 28% decrease in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,113	MWh	See the comment below.
CHP Thermal Output Utilized	1,476	MWh	
CHP Energy Input	3,754	MWh	See comment below table.
Total System Efficiency	69.0%	-	

The system achieved a TSE of 69.0%, which exceeds the Program Rules minimum requirement of 65%.

The CHP energy input was calculated in two ways:

- From March 25, 2022 at 6:00 to March 31, 2022 at 10:59 the gross electrical output of each ICE along with part load data for the Yanmar CP31D1 model was used to calculate the natural gas consumption.
- The remainder of the Reporting Period was calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, which was obtained from the M&V Plan.

Figure 1 shows the CHP system operation for both methods detailed above and indicates that the calculated natural gas consumption aligns well with the metered consumption for a similar time period.

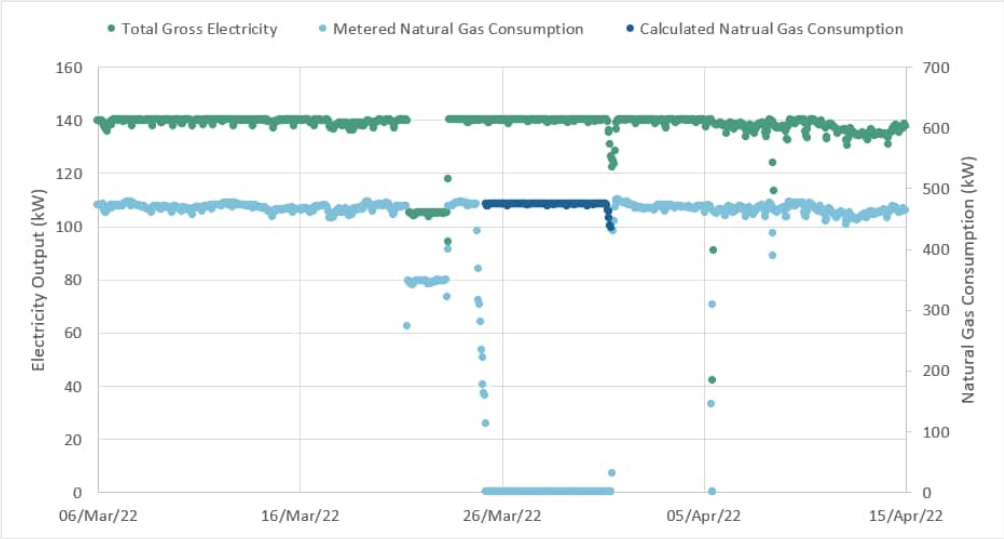

Figure 1. CHP System's gross electrical output and natural gas consumption

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $109,829.50, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,091	From Table 4
Eligible Costs	**$776,359.06**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$144,012.00	Based on the Application Review Electricity Billing Rate of $132/MWh
Other Benefits	$64,444.00	From the Project Approval Letter
Other Costs	$170,996.00	From the Project Approval Letter
Net Project Benefits	$37,460.00	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$298,000.00**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$218,200.00	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$310,543.62	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$738,899.06	Eligible costs minus Net Project Benefits
Project Incentive	$218,200.00	Minimum of the three limiters.
Incentives paid to date	$108,370.50	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$109,829.50**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601930

October 17, 2023

Revision 1

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	October 11th, 2023	October 11th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
October 11, 2023	M&V Report first issuance.	0	[redacted]
October 17, 2023	M&V Report second issuance – the Reporting Period End Date was amended to September 27, 2023, 23:59	1	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of September 28, 2022, to September 27, 2023, are 743 MWh, which represents 92% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $72,500, calculated in accordance with Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Sept 28 to Dec 27, 2022	194	94%	$25,608
1st Annual	Sept 28, 2022, to Sept 27, 2023	743	92%	$98,076

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of July 15, 2022, was established on August 26, 2022. However, THES has approved a Reporting Period starting September 28, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $132/MWh obtained from the Project Application Review.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on October 10, 2023, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Sept 28, 2022, 00:00		Start date of the Reporting Period.
Reporting Period End	Sept 27, 2023, 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,760	hours	
Missing Data	0	hours	0% of the Reporting Period Duration.
Hours of Operation	8,495	hours	96.97% of the Reporting Period Duration and 98.89% of the Estimated Hours of Operation.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	765	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	22	MWh	Equal to 2.9% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	743	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	85	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	79	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.The Reporting Period does not include the Summer Peak period.

The Participant's consultant, [redacted], has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	743	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	743	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	807	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	92%	-	
Average Demand Savings	85	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	79	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 743 MWh and represent 92% of the Anticipated Electricity Savings.

The underperformance of the Project can be primarily attributed to the lower than expected average generation value of the combined CHP system. The Application Review estimated an Average Generation value of 92 kW. The Reporting Period Analysis resulted in an Average Generation of 85 kW (92%). Additionally, Summer Peak Demand Savings were expected to achieve a 91 kW average reduction, where only a 79 kW (87%) reduction was observed.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	765	MWh	
CHP Thermal Output Utilized	1,123	MWh	
CHP Energy Input	2,750	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	68.7%	-	

The system achieved a TSE of 68.7%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $72,500, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	743	From Table 4
Eligible Costs	**$642,962**	From the 1st Master Payment Requisition (Actual Eligible Costs are lower than Estimated Eligible Costs)
Electricity Billed Savings	$98,076	Based on the Project Approval Letter Electricity Billing Rate of $132/MWh
Other Benefits	$37,398	From the Project Approval Letter
Other Costs	$105,730	From the Project Approval Letter
Net Project Benefits	$29,744	Electricity Billed Savings + Other Benefits – Other Costs
Approved Incentive Amount	**$161,400**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$148,600	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$257,185	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$613,218	Eligible costs minus Net Project Benefits
Project Incentive	$148,600	Minimum of the three limiters.
Incentives paid to date	$76,100	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$72,500**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

Disclaimer and Limitations

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

SAVE ON ENERGY | DELIVERY PARTNER™

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601932

July 06, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	July 6th, 2023	July 5th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
July 6th, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 23, 2021 to January 28, 2023, are 841 MWh, which represents 89% of the Anticipated Electricity Savings.

The original Reporting Period has been extended by 885 hours (approximately 37 days). Please refer to Table 2 for details.

The Incentive payable to the Participant for this Reporting Period is $84,758, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 23, 2021, to Mar 27, 2022	208	88%	$28,080
1st Annual	Dec 23, 2021, to Jan 28, 2023	841	89%	$113,535

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 23, 2021, which was established on February 23, 2022.

The 1st Quarterly Report was issued on December 8, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $135/MWh obtained from the Project Letter of Approval.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on May 10, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 23, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Jan 28, 2023 20:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date, excluding the shutdown periods noted below.
Available Data	8,537	hours	
Missing Data	223	hours	2.5% of the Reporting Period Duration.
Hours of Operation	8,534	hours	97.42% of the Reporting Period Duration

[redacted], the Participant's consultant, provided a summary of unscheduled shutdowns that occurred during the 1st Annual Reporting Period. All the dates the CHP was not operating normally or the system was shut off for repairs are provided below:

- January 14, 20:00 to January 19, 16:59, 2022 (117 hours) due to an unexpected transformer failure.
- July 18, 11:00 to August 19, 2022, 10:59 (768 hours) due to leak that shorted out the CHP control system and a pump seal failure.

The 1st Annual Reporting period was extended by 885 hours to account for these shutdown periods.

In addition to the dates noted above, there were 223 hours of missing data, or 2.5% of the Reporting Period with no explanation provided by [redacted]. As this represents less than 10% of the total data for the Reporting Period, the available data was used for the analysis and the missing hours assumed to represent 0 MWh savings, per Section B.6.2. of the M&V Plan.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	863	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	22	MWh	Equal to 2.6% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	841	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	96	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	98	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

[redacted] has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	841	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	841	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	946	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	89%	-	
Average Demand Savings	96	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	98	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 841 MWh and represent 89% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 125 kW, consisting of a single 125 kW internal combustion engine (ICE). In the completed Project, three 35 kW ICEs were installed with a nominal capacity of 105 kW. The under-performance is due to this re-design which resulted in lower than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (96 kW) is approximately 11% lower than the anticipated average output in the Application Review (108 kW) which reflects the 16% decrease in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	863	MWh	See the comment below.
CHP Thermal Output Utilized	1,210	MWh	
CHP Energy Input	2,970	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	69.8%	-	

The system achieved a TSE of 69.8%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $84,758, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	841	From Table 4
Eligible Costs	**$702,516**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$113,535	Based on the Project Approval Letter Electricity Billing Rate of $135/MWh
Other Benefits	$42,824	From the Project Approval Letter
Other Costs	$133,514	From the Project Approval Letter
Net Project Benefits	$22,845	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$189,200**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$168,200	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$281,006	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$679,671	Eligible costs minus Net Project Benefits
Project Incentive	$168,200	Minimum of the three limiters.
Incentives paid to date	**$83,442**	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$84,758**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5

Third Party Evaluation Reports

This document includes the following third party evaluation reports:

Process and Systems Upgrades Program:

- #601936
- #601943
- #601950
- #601954
- #601973
- #601977

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601936

June 22, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	June 22nd, 2023	June 22nd, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
June 22, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of April 13, 2022 to April 12, 2023, are 1,088 MWh, which represents 71% of the Anticipated Electricity Savings.

Note the In-Service Date of the Project is December 29, 2021. However, the start of the Reporting Period was delayed to April 13, 2022 to allow the Participant to rectify issues with the combined heat and power (CHP) system's heat recovery system, which could have impacted the Project's ability to meet the Total System Efficiency (TSE) requirement.

The Incentive payable to the Participant for this Reporting Period is $101,397.50, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Apr 13 to Jul 12, 2022	285	76%	$35,521
1st Annual	Apr 13, 2022, to Apr 12, 2023	1,088	71%	$131,681

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 29, 2021, which was established on February 23, 2022.

1st Quarterly Report was issued on August 15, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on the Projecy Letter of Approval Electricity Billing Rate of $121.03/MWh.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on May 10, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Apr 13, 2022 00:00		Start date of the Reporting Period.
Reporting Period End	Apr 12, 2023 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,483	hours	
Missing Data	277	hours	3.2% of the Reporting Period Duration.
Hours of Operation	8,483	hours	96.84% of the Reporting Period Duration

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,110	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	22	MWh	Equal to 2.0% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,088	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	124	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	130	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The Participant's consultant, [redacted], has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,088	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,088	MWh	Equal to the Reporting Period Energy.
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,524	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	71%	-	
Average Demand Savings	124	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	130	kW	Equal to Summer Peak Generation from Table 3.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

The 1st Annual Electricity Savings are 1,088 MWh and represent 71% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 195 kW, consisting of two 125 kW internal combustion engines (ICEs), one of which to be permanently derated to 70 kW. In the completed Project, four 35 kW ICEs were installed with a nominal capacity of 140 kW. The under-performance resulted from this re-design which resulted in lower than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (124 kW) is approximately 29% lower than the anticipated average output in the Application Review (174 kW) which reflects the 28% decrease in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,110	MWh	See the comment below.
CHP Thermal Output Utilized	1,511	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m3, which was obtained from the M&V Plan.
CHP Energy Input	3,655	MWh	See comment below table.
Total System Efficiency	71.7%	-	

The system achieved a TSE of 71.7%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $101,397.50, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,088	From Table 4
Eligible Costs	**$786,635.01**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$131,680.64	Based on the Project Approval Letter Electricity Billing Rate of $121.03/MWh
Other Benefits	$78,570.00	From the Project Approval Letter
Other Costs	$198,346.00	From the Project Approval Letter
Net Project Benefits	$11,904.64	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$304,800.00**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$217,600.00	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$314,654.00	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$774,730.37	Eligible costs minus Net Project Benefits
Project Incentive	$217,600.00	Minimum of the three limiters.
Incentives paid to date	$116,202.50	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$101,397.50**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601943

August 30, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	August 30, 2023	August 29, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
August 30, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of April 20, 2022 to May 8, 2023, are 764 MWh, which represents 89% of the Anticipated Electricity Savings.

The In-Service Date of the Project is December 23, 2021. However, the start of the Reporting Period was delayed to April 20, 2022 due to [redacted] shutting off the CHP system while investigating an electrical issue at the facility.

The Incentive payable to the Participant for this Reporting Period is $63,600, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	April 20 to August 7, 2022	201	104%	$24,532
1st Annual	April 20, 2022 to May 8, 2023	764	89%	$93,246

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of December 23, 2021, was established on January 28, 2022.

The 1st Quarterly Report was issued on July 28, 2023.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $122.05/MWh obtained from the Project Application Review.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on June 2, 2023, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	April 20, 2022 00:00		Start date of the Reporting Period.
Reporting Period End	May 8, 2023 19:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date, excluding the shutdown periods noted below.
Available Data	8,723	hours	
Missing Data	37	hours	0.4% of the Reporting Period Duration.
Hours of Operation	8,717	hours	99.51% of the Reporting Period Duration.

[redacted] the Participant's consultant, provided a summary of unscheduled shutdowns that occurred during the 1st Annual Reporting Period. In June 2022, they discovered that the facility's domestic hot water thermostatic mixing valve (TMV) had failed, which negatively affected the CHP system's useful thermal output and, thus, its Total System Efficiency. Due to this failure, the CHP system was shut off for the following period:

- June 17, 13:00 to July 7, 8:59, 2022 (452 hours).

The 1st Annual Reporting period was extended by 452 hours to account for this unscheduled shutdown period.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	787	MWh	CHP System Gross Electrical Output.
Auxiliary Loads Energy	23	MWh	Equal to 2.8% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	764	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	87	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	79	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The Participant's consultant, [redacted], has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	764	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	764	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	854	MWh	Obtained from Table 5 of the M&V Plan

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Electricity Savings as a Percentage of Anticipated Electricity Savings	89%	-	
Average Demand Savings	87	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	79	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 764 MWh and represent 89% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 125 kW, consisting of two 125 kW internal combustion engines (ICEs), one of which was stand-by. In the completed Project, three 35 kW ICEs were installed with a nominal capacity of 105 kW. The under-performance is due to this re-design which resulted in lower than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (87 kW) is approximately 11% lower than the anticipated average output in the Application Review (97 kW) which reflects the 16% decrease in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	787	MWh	See the comment below.
CHP Thermal Output Utilized	991	MWh	
CHP Energy Input	2,649	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	67.1%	-	

The system achieved a TSE of 67.1%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $63,600, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Annual Electricity Savings (MWh)	764	From Table 4
Eligible Costs	**$523,490**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$93,246	Based on the Project Approval Letter Electricity Billing Rate of $122.05/MWh
Other Benefits	$37,179	From the Project Approval Letter
Other Costs	$114,646	From the Project Approval Letter
Net Project Benefits	$15,779	Electricity Billed Savings + Other Benefits – Other Costs
Approved Incentive Amount	**$170,800**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$152,800	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$209,396	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$507,710	Eligible costs minus Net Project Benefits
Project Incentive	$152,800	Minimum of the three limiters.
Incentives paid to date	$89,200	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$63,600**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted] Cogeneration System

July 7, 2023

Revision 0

Project ID: Toronto-PROJECT-601950

Prepared for:

Toronto Hydro-Electric System Limited (the LDC)

[redacted]

Prepared by:

Aladaco Consulting Inc. (the Technical Reviewer)

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	July 6, 2023	July 7th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
July 7, 2023	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 24, 2021, to December 23, 2022, are 933 MWh, which represent 92% of the Anticipated Electricity Savings. The Incentive payable (balance payment) to the Participant for this Reporting Period is $80,740, calculated in accordance with Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 24, 2021, to Mar 23, 2022	267	104%	$35,713
1st Annual	Dec 24, 2021, to Dec 23, 2022	933	92%	$124,965

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan Rev.0, dated March 1, 2019, which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data for the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the Measure.
- The Incentive based on the performance of the Measure.

In-Service Date Confirmation

The In-Service Date is December 24, 2021, which was established on January 28, 2022.

Metered Data Analysis

[redacted] the LDC representative, provided the M&V data on June 2, 2023, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

[1] Percentage of the Anticipated Electricity Savings shown in the M&V Plan.

[2] Based on the Electricity Billing Rate of $134/MWh shown in the Approval Letter.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 24, 2021, 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 23, 2022, 23:59		End date of the Reporting Period.
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,541	hours	
Missing Data	219	hours	3% of the Reporting Period Duration. See note below.
Hours of Operation	8,538	hours	97% of the Reporting Period duration.

The raw data provided by the Participant included the following periods of missing generation data for the combined heat and power (CHP) System:

- 11 hours from May 17, 7:00 to May 17, 17:00, 2022.
- 166 hours from August 16, 13:00 to August 23, 10:00, 2022.
- 42 hours scattered during the period of October 6 to November 9, 2022.

The total missing data (219 hours) represents 3% of the Reporting Period duration. In an email dated June 2, 2023, Toronto Hydro explained the following reasons for the CHP System shutdown:

- May 17, 2022: Downtime on all CHP units due to electrical issue.
- August 16, to August 23, 2022: Downtime on all CHP units due to equipment issues.

For the periods of missing data, the CHP System was assumed to be not operational for conservativeness, i.e., no generation.

Performance of the Measure

The Electricity Savings of this cogeneration Project is calculated based on the following equation:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Reporting Period Energy

The electricity generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comments
Gross Electrical Energy	955	MWh	Metered electrical output from the CHP System. see note below.
Auxiliary Loads Energy	22	MWh	Equal to 2.62 kW per operating hour. see note below.
Reporting Period Energy	933	MWh	CHP Net Electrical Output. = *Gross Electrical Energy – Auxiliary Loads Energy*
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	106	kW	= *Reporting Period Energy ÷ Reporting Period Duration*
Summer Peak Demand Generation	111	kW	Summer Peak Demand Period is defined as Monday to Friday, 1:00 pm - 7:00 pm, June 1 to August 31.

The Participant's consultant, [redacted], has indicated that the electrical output readings included in the M&V dataset, are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. These loads draw their power directly from the internal combustion engines (ICEs). However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. The Gross Electrical Energy of 955 MWh is net of the internal auxiliary loads. The 22 MWh Auxiliary Loads Energy was calculated based on the 2.62 kW external auxiliary load and 8,538 operating hours.

Non-Routine Adjustments

The Technical Reviewer did not identify any Non-Routine Event; therefore, a Non-Routine Adjustment is not required.

Electricity Savings

The Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comments
Reporting Period Energy	933	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	933	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,019	MWh	From the Project Letter of Approval.
Electricity Savings as Percentage of Anticipated Electricity Savings	92%		
Average Demand Savings	106	kW	Equal to Average Generation, obtained from Table 3.
Summer Peak Demand Savings	111	kW	Equal to Summer Peak Demand Generation, obtained from Table 3.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

The Electricity Savings of the 1st Annual Reporting Period are 933 MWh, which represent 92% of the Anticipated Electricity Savings. The underperformance is likely due to the lower than anticipated net electrical output and hours of operation of the CHP System.

The CHP System was anticipated to produce an average net electrical output of 116 kW, whereas the Reporting Period average net electrical output was 106 kW. This is likely due to a change in system configuration; the Project was originally planned for two 125 kW cogeneration systems (one operational standby). In the completed Project, four 35 kW ICEs were installed with a total capacity of 140 kW.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + Recovered Heat Utilized] / Fuel Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comments
Gross Electrical Energy	955	MWh	Obtained from Table 3. See note below.
Recovered Heat Utilized	1,137	MWh	
Fuel Energy Input	3,080	MWh	Calculated from total volumetric natural gas consumption and a natural gas higher heating value (HHV) of 10.75 kWh/m^3 specified in the M&V Plan.
Total System Efficiency	68%		

The CHP Gross Electrical Energy of 955 MWh is net of internal auxiliary loads. Thus, the actual Gross Electrical Energy is expected to be slightly higher than 955 MWh. Due to lack of data on the internal auxiliary loads, the Technical Reviewer did not account for the internal auxiliary loads to calculate the Gross Electrical Energy. However, the internal auxiliary loads expected to be within the metering uncertainty shown in Table 4. Additionally, the calculated TSE of 68% is a conservative value given that the actual Gross Electrical Energy is higher than 955 MWh.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $80,740, pending issuance of the Master Payment Requisition. The Net Project Incentive Amount of $186,515 was calculated in accordance with the Program Rules and is limited by the "$200/MWh of Electricity Savings", up to a maximum of 120% of the Approved Incentive Amount.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comments
Electricity Savings (MWh)	933	Annual Electricity Savings, from Table 4.
Limiter 1 - Electricity Savings ($)	186,515	$200 per MWh of Electricity Savings, limited to 120% of the Approved Incentive Amount.
Actual Eligible Costs ($)	800,944	Reviewed invoices provided by the Participant.
Estimated Eligible Costs ($)	971,573	From the Project Letter of Approval.
Limiter 2 - Eligible Costs ($)	320,378	40% of minimum Actual and Estimated Eligible Costs.
Project Net Benefits ($)	41,556	= *Electricity Billed Savings + Other Benefits (from Letter of Approval) – Other Costs (from Letter of Approval)*
Limiter 3 – 1-year Project Payback ($)	759,388	= *Actual Eligible Costs - Project Net Benefits*
Approved Incentive Amount ($)	203,800	From the Project Letter of Approval.
Net Project Incentive ($)	**186,515**	Minimum of the three limiters.
Incentives paid to date ($)	**105,775**	Paid for the 1st Quarterly Reporting Period.
Incentive payable (Balance Payment) ($)	**80,740**	= *Net Project Incentive – Incentives paid to date*

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601954

July 27, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	July 27, 2023	July 27th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
July 27, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 22, 2021, to December 21, 2022, are 1,081 MWh, which represents 106% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $108,122.50, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 22, 2021, to Mar 21, 2022	272	106%	$35,904
1st Annual	Dec 22, 2021, to Dec 21, 2022	1,081	106%	$142,692

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 22, 2021, which was established on January 28, 2022.

The 1st Quarterly Report was issued on July 5, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $132/MWh obtained from the Project Letter of Approval.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on June 2, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 22, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 21, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date, excluding the shutdown periods noted below.
Available Data	8,020	hours	
Shutdown Periods	627	hours	7.8% of the Available Data.
Missing Data	113	hours	1.4% of the Reporting Period Duration.
Hours of Operation	8,020	hours	98.61% of the Reporting Period Duration – Shutdown Periods

[redacted] the Participant's consultant, provided a summary of unscheduled shutdowns that occurred during the 1st Annual Reporting Period. All the dates the CHP was not operating normally or the system was shut off for repairs are provided below:

- December 30, 4:00, 2021 to January 5, 10:59, 2022 (151 hours) due failure of Unit #4.
- February 19, 16:00 to March 7, 11:59, 2022 (380 hours) due failure of Unit #1.
- July 26, 6:00 to July 30, 5:59, 2022 (96 hours) due gas upgrades that resulted in Unit #1 being turned off.

The shutdown periods represent 627 hours total, which represents 7.8%, or less than 10%, of the total data for the Reporting Period. In addition to the dates noted above, there were 113 hours of missing data, or 1.4% of the Reporting Period, with no explanation provided by[redacted]

Since the total unavailable data represents less than 10% of the total data for the Reporting Period, the analysis was completed per Section B.6.2. of the M&V Plan, in the following way:

- The remaining 90.8% of data was used to predict the CHP system operation during the unscheduled shutdowns using a linear extrapolation, and
- The missing hours are assumed to represent 0 MWh savings.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,103	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	23	MWh	Equal to 2.1% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,081	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	123	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	110	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

[redacted] has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,081	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,081	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,020	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	106%	-	
Average Demand Savings	123	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	110	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 1,081 MWh and represent 106% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 125 kW, consisting of two 125 kW internal combustion engines (ICEs), one operating as emergyency backup only. In the completed Project, four 35 kW ICEs were installed with a nominal capacity of 140 kW. The over-performance is due to this re-design which resulted in a higher than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (123 kW) is approximately 6% higher than the anticipated average output in the Application Review (116 kW) which reflects the 12% increase in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,024	MWh	See comments below table.
CHP Thermal Output Utilized	1,283	MWh	See comments below table.
CHP Energy Input	3,404	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan. See comments below table.
Total System Efficiency	67.8%	-	

The CHP energy input and outputs are the sums of the available data, they have not been extrapolated to account for the shutdown periods. The system achieved a TSE of 67.8%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $108,122.50, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,081	From Table 4
Eligible Costs	**$761,764**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$142,692	Based on the Project Approval Letter Electricity Billing Rate of $132/MWh
Other Benefits	$43,541	From the Project Approval Letter
Other Costs	$127,581	From the Project Approval Letter
Net Project Benefits	$58,652	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$204,000**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$216,200	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$304,706	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$703,112	Eligible costs minus Net Project Benefits
TSE Incentive Discount	$0	5% discount for TSE ≥ 62.5% and < 65.0%
Project Incentive	**$216,200**	**Minimum of the three limiters – TSE Incentive Discount**
Incentives paid to date	$108,077.50	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$108,122.50**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601973

July 25, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	July 25th, 2023	July 24th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
July 25th, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 22, 2021 to December 21, 2022, are 1,143 MWh, which represents 94% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $119,138, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 22, 2021, to Mar 21, 2022	274	90%	$35,894
1st Annual	Dec 22, 2021, to Dec 21, 2022	1,143	94%	$149,733

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 22, 2021, which was established on January 28, 2022.

The 1st Quarterly Report was issued on August 16, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $131/MWh obtained from the Project Letter of Approval.

Metered Data Analysis

[redacted]a representative of THES, provided the M&V data on June 1, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 22, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 21, 2022 20:59		End date of the Reporting Period
Reporting Period Duration	8,760	Hours	End date minus start date, excluding the shutdown periods noted below.
Available Data	8,729	Hours	
Missing Data	31	Hours	0.4% of the Reporting Period Duration.
Hours of Operation	8,727	Hours	99.62% of the Reporting Period Duration

31 hours, or 2.5% of the Reporting Period, were missing. As this represents less than 10% of the total data for the Reporting Period, the available data was used for the analysis and the missing hours assumed to represent 0 MWh savings, per Section B.6.2. of the M&V Plan.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,166	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	23	MWh	Equal to 2.0% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,143	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	130	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	130	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

[redacted] has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,143	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,143	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,217	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	94%	-	
Average Demand Savings	130	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	130	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 1,143 MWh and represent 94% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 160 kW, consisting of a two 125 kW internal combustion engines (ICE), one permanently derated to 35 kW. In the completed Project, four 35 kW ICEs were installed with a nominal capacity of 140 kW. The under-performance is due to this re-design which resulted in lower than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (130 kW) is approximately 6% lower than the anticipated average output in the Application Review (139 kW) which reflects the 13% decrease in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,166	MWh	See the comment below.
CHP Thermal Output Utilized	1,438	MWh	
CHP Energy Input	3,950	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	65.9%	-	

The system achieved a TSE of 65.9%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $119,138, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,143	From Table 4
Eligible Costs	**$749,206**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$149,733	Based on the Project Approval Letter Electricity Billing Rate of $131/MWh
Other Benefits	$64,394	From the Project Approval Letter
Other Costs	$163,417	From the Project Approval Letter
Net Project Benefits	$50,710	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$243,400**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$228,600	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$299,682	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$698,496	Eligible costs minus Net Project Benefits
Project Incentive	$228,600	Minimum of the three limiters.
Incentives paid to date	**$109,462**	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$119,138**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report
1st Annual Reporting Period

[redacted] Cogeneration System

June 14, 2023
Revision 0

Project ID: Toronto-PROJECT-601977

Prepared for:

Toronto Hydro-Electric System Limited (the LDC)

[redacted]

Prepared by:

Aladaco Consulting Inc. (the Technical Reviewer)

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	June 14, 2023	June 14th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
June 14, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 23, 2021, to December 22, 2022, are 737 MWh, which represents 85% of the Anticipated Electricity Savings. The Incentive payable (balance payment) to the Participant for this Reporting Period is $75,054, calculated in accordance with Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 23, 2021, to Mar 29, 2022	216	84%	$28,711
1st Annual	Dec 23, 2021, to Dec 22, 2022	737	85%	$98,026

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan Rev.0, dated March 27, 2019, which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The Project's In-Service Date is December 23, 2021, which was established on February 23, 2022.

Metered Data Analysis

[redacted]a representative of Toronto Hydro, provided the M&V data, on May 10, 2023, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $133/MWh obtained from the Project Approval Letter.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	December 23, 2021, 00:00		Start date of the Reporting Period.
Reporting Period End	December 22, 2022, 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,716	hours	See note below.
Missing Data	44	hours	0.5% of the Reporting Period Duration.
Hours of Operation	8,445	hours	96.4% of the Reporting Period Duration.

The generation data was not collected during the following periods:

- August 9, 2022, from 03:00 am to 24:00 am (22 hours).
- September 4, 2022, from 03:00 am to 24:00 am (22 hours).

The total missing data (44 hours) represents 0.5% of the Reporting Period duration. In an email dated May 10th, 2023, the Participant confirmed that the combined heat and power (CHP) System was operational during these periods and the missing data was replaced with representative data from the previous day.

Performance of the Measure

The Electricity Savings of this cogeneration Project is calculated based on the following equation:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Reporting Period Energy

The Reporting Period Energy of the System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comments
Gross Electrical Energy	759	MWh	CHP System Gross Electrical Output (See note below).
Auxiliary Loads Energy	22	MWh	Equal to 2.9% of the Gross Electrical Energy (See note below).
Reporting Period Energy	737	MWh	CHP Net Electrical Output. = *Gross Electrical Energy - Auxiliary Loads Energy*
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	84	kW	= *Reporting Period Energy ÷ Reporting Period Duration*
Summer Peak Generation	76	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm -7:00 pm.

The Participant's consultant, [redacted]., has indicated that the electrical output readings included in the M&V dataset, are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. These loads draw their power directly from the internal combustion engines (ICEs). However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. The Gross Electrical Energy of 759 MWh is net of the internal auxiliary loads. The 22 MWh Auxiliary Loads Energy was calculated based on the 2.62 kW external auxiliary load and 8,445 operating hours.

Non-Routine Adjustments

The Technical Reviewer did not identify any Non-Routine Event; therefore, a Non-Routine Adjustment is not required.

Electricity Savings

The Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comments
Reporting Period Energy	737	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	737	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	865	MWh	Obtained from the M&V Plan.
Electricity Savings as a Percentage of Anticipated Electricity Savings	85%		
Average Demand Savings	84	kW	Equal to Average Generation, obtained from Table 3.
Summer Peak Demand Savings	76	kW	Equal to Summer Peak Demand Generation, obtained from Table 3.

The Electricity Savings of the 1st Annual Reporting Period are 737 MWh, which represent 85% of the Anticipated Electricity Savings.

The Project scope was originally based on installation of three 65 kW micro-turbines with a total nominal capacity of 195 kW. However, the installed system comprises of three 35 kW ICEs with a total nominal capacity of 105 kW. The underperformance is a result of the lower capacity of the installed CHP System. The average anticipated net operating electrical output was 119 kW, but the actual average net operating electrical output was 87 kW.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Total System Efficiency

The CHP System's Total System Efficiency (TSE) is calculated according to the following equation.

TSE (%) = [Gross Electrical Energy + Recovered Heat Utilized] / Fuel Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comments
Gross Electrical Energy	759	MWh	Obtained from Table 3. (See comment below table).
Recovered Heat Utilized	1,198	MWh	
Fuel Energy Input	2,730	MWh	Calculated from total volumetric natural gas consumption and a natural gas higher heating value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	71.7%		Exceeds the minimum 65% required by the Program.

The CHP Gross Electrical Energy of 759 MWh is net of internal auxiliary loads. Thus, the actual Gross Electrical Energy is expected to be slightly higher than 759 MWh. Due to lack of data on the internal auxiliary loads, the Technical Reviewer did not account for the internal auxiliary loads to calculate the Gross Electrical Energy. Therefore, the calculated TSE of 71.7% is a conservative value given that the actual Gross Electrical Energy is higher than 759 MWh.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $75,054, pending issuance of the Master Payment Requisition. The Net Project Incentive Amount of $147,407 was calculated in accordance with the Program Rules and is limited by the "$200/MWh of Electricity Savings", up to a maximum of 120% of the Approved Incentive Amount.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comments
Electricity Savings (MWh)	737	Annual Electricity Savings, from Table 4.
Limiter 1 - Electricity Savings ($)	147,407	$200 per MWh of Electricity Savings, limited to 120% of the Approved Incentive Amount.
Actual Eligible Costs ($)	608,706	Reviewed invoices provided by the Participant.
Estimated Eligible Costs ($)	886,931	From the Project Letter of Approval.
Limiter 2 - Eligible Costs ($)	243,482	40% of minimum Actual and Estimated Eligible Costs.
Project Net Benefits ($)	29,532	*= Electricity Billed Savings + Other Benefits (from Letter of Approval) – Other Costs (from Letter of Approval)*
Limiter 3 – 1-year Project Payback ($)	579,174	*= Actual Eligible Costs - Project Net Benefits*
Approved Incentive Amount ($)	173,000	From the Project Letter of Approval.
Net Project Incentive ($)	**147,407**	Minimum of the three limiters.
Incentives paid to date ($)	**72,353**	Paid for the 1st Quarterly Reporting Period.
Incentive payable (Balance Payment) ($)	**75,054**	*= Net Project Incentive – Incentives paid to date*

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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